PETROBRAS ENERGIA PARTICIPACIONES SA
Form 20-F
June 30, 2004

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 20-F

ANNUAL REPORT PURSUANT TO SECTION 13
OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended: December 31, 2003

Commission file number 333-11130

PETROBRAS ENERGÍA PARTICIPACIONES S.A.

(Exact name of Registrant as specified in its charter)

N/A	**REPUBLIC OF ARGENTINA**
(Translation of Registrant s name into English)	(Jurisdiction of incorporation of organization)

Maipú 1, 22nd Floor
(C1084ABA) Buenos Aires
Argentina
(Address of principal executive offices)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each Class	Name of Each Exchange On Which Registered
American Depositary Shares, each representing 10 Class B shares	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

The number of outstanding shares of each of the issuer s classes of capital or common stock as of December 31, 2003 was:

Class B Ordinary Shares, par value Ps.1.00 per share	2,132,043,387

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the

past 90 days:

Yes x No o

Indicate by check mark which financial statement item the Registrant has elected to follow:

Item 17 o Item 18 x

The following disclosure item is omitted from Item 18 in this annual report: the financial statements for Compañia de Inversiones de Energía S.A., a company of which we held 50% of the share capital as of December 31, 2003 and over which we exercised joint control.

TABLE OF CONTENTS

Table of Contents

INTRODUCTION

All references in this annual report to:

Petrobras Energía Participaciones, we, us, our, and similar terms refer to Petrobras Energía Participaciones S.A. and its subsidiaries, but excludes affiliates and companies under joint control. Prior to July 2003, our corporate name was Perez Companc S.A.

Petrobras Energía refers to Petrobras Energía S.A., a 98.21% owned subsidiary of Petrobras Energía Participaciones together with its controlled subsidiaries, but excludes affiliates and companies under joint control. Prior to July 2003, the corporate name of Petrobras Energía was Pecom Energía S.A.

Argentine pesos , pesos or P$ refer to the currency of the Republic of Argentina.

U.S. dollars or U.S.$ refer to the currency of the United States of America.

FORWARD-LOOKING STATEMENTS

Some of the information included in this annual report contains information that is forward looking, including statements regarding, among other items, future earnings and operating results, capital expenditures, competition and sales, oil and gas reserves and prospects and trends in the oil and gas, refining and petrochemicals and electricity industries.

Certain statements contained in this annual report are forward-looking statements and are not based on historical fact, such as statements containing the words believe, may, will, estimate, continue, anticipate, intend, ex similar words. These forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed in Item 4. Information About Us, Item 5. Operating and Financial Review and Prospects and elsewhere in this annual report. Factors that could cause actual results to differ materially and adversely include, but are not limited to:

- changes in general economic, business, political or other conditions in Argentina or changes in general economic or business conditions in Latin America;
- the availability of financing at reasonable terms to Argentine companies, such as us;
- changes in the price of hydrocarbons;
- changes to our capital expenditure plans;
- changes in laws or regulations affecting our operations;
- increased costs; and
- other factors discussed under Risk Factors in Item 3 of this annual report.

We believe that our estimates are reasonable, but you should not unduly rely on these estimates, which are based on our current expectations. We undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for us to predict all of these factors.

Further, we cannot assess the impact of each factor on our business or the extent to which any factor, or combination of factors, may cause actual results to be materially different from those contained in any forward-looking statements.

Table of Contents

Item 1. IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISERS

Not applicable.

Item 2. OFFER STATISTICS AND EXPECTED TIMETABLE

Not applicable.

Item 3. KEY INFORMATION

SELECTED FINANCIAL DATA

The financial information set forth below may not contain all of the financial information that you should consider when making an investment decision. This information should be read in conjunction with, and is qualified in its entirety by reference to, the Risk Factors included in this annual report. See Risk Factors. You should also carefully read our financial statements and Item 5. Operating and Financial Review and Prospects included in this annual report for additional financial information about us.

Our financial statements are prepared in accordance with Argentine GAAP which differs in certain significant respects from U.S. GAAP. Note 22 to our financial statements provides a description of the principal differences between Argentine GAAP and U.S. GAAP as they relate to us, and note 23 provides a reconciliation to U.S. GAAP of net income, shareholders equity and certain other selected financial data. Neither the effects of inflation accounting nor the proportional consolidation of Distrilec Inversora S.A., a company under joint control which we refer to as Distrilec, under Argentine GAAP have been reversed in the reconciliation to U.S. GAAP. The proporational consolidation of Compañía de Inversiones de Energía S.A., another company under joint control which we refer to as CIESA, in 2001 and 2003 under Argentine GAAP has been reversed in the reconciliation to U.S. GAAP.

We are a holding company whose only asset is our 98.21% equity interest in Petrobras Energía. We were organized as a result of a spinoff of Petrobras Energía shares by Sudacia S.A., effective July 1, 1998. We acquired control of Petrobras Energía on January 25, 2000 as a result of the completion of an exchange offer of our Class B shares for 69.29% of Petrobras Energía s outstanding common stock. Prior to January 25, 2000, our only asset was a minority interest in Petrobras Energía.

Our financial data relating to the fiscal years ended December 31, 2003, 2002 and 2001 set forth below have been derived from our financial statements included in this annual report. Our financial statements as of and for the years ended December 31, 2002 and December 31, 2001 have been restated to reflect changes in generally accepted accounting principles in Argentina, which we refer to as Argentine GAAP. See Item 5. Operating and Financial Review and Prospects Critical Accounting Policies. Our balance sheet as of December 31, 2003 and 2002 and the related consolidated statements of income, changes in shareholders equity and cash flows for each of the three fiscal years ended December 31, 2003, 2002, 2001 included in this annual report have been audited by Pistrelli, Henry Martin y Asociados S.R.L., a member firm of Ernst & Young Global. Selected financial data for the fiscal years ended December 31, 2000 and 1999 has not been restated to reflect the changes in Argentine GAAP, and accordingly are not comparable to the financial data for the fiscal years ended December 31, 2003, 2002 and 2001. Argentine law does not require that we restate these financial statements and any such restatement cannot be prepared without unreasonable effort or expense.

Due to the inflationary environment in Argentina in 2002, and the conditions created by the Public Emergency Law, the Professional Council of Economic Sciences of the City of Buenos Aires, or CPCECABA, approved on March 6, 2002 Resolution MD No. 3/02 applicable to financial statements for fiscal years or interim periods ending on or after March 31, 2002. Resolution MD No. 3/02 required the reinstatement of the adjustment-for-inflation method of accounting in financial statements, which provides that all recorded amounts arising between August 31, 1995 and December 31, 2001 be stated in constant currency as of December 31, 2001.

On July 16, 2002, the Argentine government issued Decree No. 1,269/02, instructing the National Securities Commission (*Comisión Nacional de Valores*), which we refer to as CNV, and other regulatory authorities

Table of Contents

to issue the necessary regulations for the delivery to such authorities of balance sheets or financial statements prepared in constant currency. On July 25, 2002, under Resolution No. 415/02, the CNV reinstated the requirement to submit financial statements in constant currency. As the inflation rate stabilized, on March 25, 2003, Decree No. 664/03 rescinded the requirement that financial statements be prepared in constant currency. On April 8, 2003, the CNV issued Resolution No. 441/03 discontinuing inflation accounting as of March 1, 2003.

In accordance with the above, for comparative purposes, our financial statements for the fiscal years ended December 31, 2001 and 2002, were restated in constant pesos as of February 28, 2003, based on changes in the Argentine wholesale price index published by the National Institute of Statistics and Census (*Instituto Nacional de Estadísticas y Censas*), which we refer to as the INDEC. This price index does not reflect any specific variation in the price of products and services sold by us, and, therefore, variations in gains (losses) for both periods include positive or negative price variations that may be higher or lower than the price variations for the products or services sold by us. The selected financial data for the fiscal years ended December 31, 2000 and 1999 has also been restated in constant pesos as of February 28, 2003.

In accordance with the procedure set forth in Technical Resolutions Nos. 4 and 19 of the Argentine Federation of Professional Councils in Economic Science, or FACPCE, we have consolidated line by line on a proportional basis our financial statements with the companies in which we exercise joint control. See Item 5. Operating and Financial Review and Prospects Overview. In the consolidation of companies over which we exercise joint control, the amount of the investment in the subsidiaries under joint control and the interest in their income (loss) and cash flows are replaced by our proportional interest in the subsidiary s assets, liabilities and income (loss) and cash flows.

Petrobras Energía Participaciones s net income per share under Argentine and U.S. GAAP was calculated as follows:

diluted net income per share was calculated by dividing net income by the average number of shares outstanding during each year (assuming all Class A shares are converted into Class B Shares);

for 2003 and 2002, net income per share was calculated by dividing net income by the average number of shares outstanding during each year. As of October 2002, all outstanding Class A shares were converted into Class B shares;

for 2001 and 2000, basic net income per Class A share was calculated by dividing net income by the sum of (1) the average number of Class A shares outstanding during 2001 and 2000, respectively, and (2) the average number of Class B shares outstanding during 2001 and 2000, respectively, multiplied by 1.5; and

for 2001 and 2000, basic net income per Class B share has been calculated by multiplying (A) the quotient attained by dividing net income by the sum of (1) the average number of Class A shares outstanding during 2001 and 2000, respectively, and (2) the average number of Class B shares outstanding during 2001 and 2000, respectively, multiplied by 1.5(B) by 1.5.

Our basic net income per share for the fiscal years 2001 and 2000 was calculated in the manner described above because Class B shares were entitled to dividends equal to 150% of dividends that were paid with respect to Class A shares.

Table of Contents

Income Statement Data

	Year Ended December 31,				
	2003	2002[1]	2001[1]	2000[1] [2]	1999[1] [2]
	(in millions of pesos, except for per share amounts, share capital and operating information or as otherwise indicated)				
Income Statement Data					
Argentine GAAP:					
Net sales	5,494	5,106	5,170	3,185	
Cost of sales	(3,386)	(3,284)	(3,347)	(2,161)	
Gross profit	2,108	1,822	1,823	1,024	
Administrative and selling expenses	(559)	(609)	(665)	(385)	
Exploration expenses	(196)	(58)	(41)	(13)	
Other exploitation (expense) income, net	(121)	(28)	23	22	
Exploitation income	1,232	1,127	1,140	648	
Equity in earnings of affiliates	163	(638)	119	189	143
Financial income (expense) and holding gains (losses)	(417)	(1,827)	(573)	(325)	
Other (expense) income, net	(421)	(187)	(88)	132	
Income (loss) before income tax and minority interest in subsidiaries	557	(1,525)	598	644	143
Income tax provision	(18)	(82)	(385)	(41)	
Minority interest in subsidiaries	(158)	28	(112)	(15)	
Net income (loss)	381	(1,579)	101	588	143
Basic net (loss) income per share:					
Class A [3]			0.035	0.215	0.323
Class B	0.179	(0.744)	0.053	0.322	
Diluted net (loss) income per share	0.179	(0.744)	0.047	0.288	
Number of shares outstanding (millions):					
Class A[3]			628	628	628
Class B	2,132	2,132	1,504	1,504	
U.S. GAAP:					
Net sales	5,078	5,182	4,630	3,343	
Operating income	622	830	853	864	
	109	(1,868)	(2,254)	286	242

Income (loss) from continuing operations(5)					
Income (loss) from discontinued operations	(39)	135	12	38	0.547
Cumulative effect of changes in accounting principles	30	179			
Net income (loss)(4)	100	(1,554)	(2,266)	324	242
Basic net (loss) income per share					
Class A:(3)			(0.786)	0.119	0.547
Class B:	0.047	(0.729)	(1.179)	0.178	
Diluted net (loss) income per share	0.047	(0.729)	(1.063)	0.157	
Basic net (loss) income per share:					
Class A:(3)					
Continuing Operations			(0.782)	0.105	0.323
Discontinued Operations			(0.004)	0.014	
Class B:					
Continuing Operations	0.051	(0.876)	(1.172)	0.157	
Discontinued Operations	(0.018)	0.063	(0.006)	0.021	
Cumulative effect of changes in accounting principles	0.014	0.084			

(1) Expressed in constant pesos as of February 28, 2003, except share capital and operating information.

(2) Selected financial data for the fiscal years ended December 31, 2000 and 1999 has not been restated to reflect recent changes in Argentine GAAP, and accordingly are not comparable to the financial data for the fiscal years ended December 31, 2003, 2002 and 2001. See Item 5. Operating and Financial Review and Prospects Critical Accounting Policies.

(3) As of October 2002, there are no Class A shares outstanding.

(4) As of January 1, 2002, we have applied SFAS No. 142, Goodwill and Other Intangible Assets, effective as of January 1, 2002, and SFAS No. 143, Accounting for Asset Retirement Obligations, effective as of January 1, 2003. If the new standards had been effective and applied before January 1, 2001, net income (loss) for the years ended December 31, 2003, 2002 and 2001, would have been 70; (1,723) and (2,265), respectively.

(5) After minority interest in subsidiaries and income tax (expense) benefit.

4

Table of Contents

Balance Sheet Data

	Year Ended December 31,				
	2003	2002[1]	2001[1]	2000[1] [2]	1999[1] [2]
	(in millions of pesos, except for per share amounts, share capital and operating information or as otherwise indicated)				
Argentine GAAP					
Consolidated Balance Sheet					
Assets					
Current Assets					
Cash	153	93	98	59	
Investments	802	664	1,254	543	
Trade receivables	886	784	1,108	908	
Other receivables	861	734	397	470	
Inventories	319	356	346	374	
Other assets	3	178			
Total current assets	3,024	2,809	3,203	2,354	
Non-current Assets					
Trade receivables	36	21	21	7	
Other receivables	131	220	370	162	
Inventories	61	39	240	205	
Investments	1,284	1,103	1,341	2,750	1,627
Property, plant and equipment	11,559	10,433	11,633	6,572	
Other assets	43	24	63	11	
Total non-current assets	13,114	11,840	13,668	9,707	1,627
Total assets	16,138	14,649	16,871	12,061	1,627
Liabilities					
Current liabilities					
Accounts payable	860	651	852	547	
Short-term debt	3,204	1,543	3,501	1,625	
Payroll and social security taxes	93	76	99	75	
Taxes payable	172	133	145	138	
Other current liabilities	423	372	563	97	
Total current liabilities	4,752	2,775	5,160	2,482	

Non-current liabilities					
Accounts payable	7	9	4	20	
Long-term debt	5,098	6,130	4,114	3,100	
Other liabilities	279	641	368	303	
Reserves	277	86	61	55	
Total non-current liabilities.	5,661	6,866	4,547	3,478	
Total liabilities	10,413	9,641	9,707	5,960	
Transitory Differences					
Measurement of derivative financial instruments designated as effective hedge	(18)				
Foreign currency translation	(56)				
Total transitory differences	(74)				
Minority interest in subsidiaries	966	556	1,133	149	
Total Shareholders Equity	4,833	4,452	6,031	5,953	1,627
Total liabilities and shareholders equity	16,138	14,649	16,871	12,062	1,627
Capital Stock	2,132	2,132	2,132	2,132	628
Dividends[3]					
per Class A share				0.0208	0.0238
per Class B share				0.0317	
U.S. GAAP					
Total assets	14,508	16,108	20,264	15,794	
Shareholders equity	4,523	4,499	6,403	8,406	1,508

(1) Expressed in constant pesos as of February 28, 2003, except share capital and operating information.

(2) Selected financial data for the fiscal years ended December 31, 2000 and 1999 has not been restated to reflect recent changes in Argentine GAAP, and accordingly are not comparable to the financial data for the fiscal years ended December 31, 2003, 2002 and 2001. See Item 5. Operating and Financial Review and Prospects Factors Affecting our Consolidated Results of Operations Critical Accounting Policies Change in Accounting Standards.

(3) Dividends declared in 2000 and 1999 as expressed in U.S. dollars would equal amounts in historical pesos since the exchange rate between the peso and the U.S. dollar was fixed at a one-to-one ratio during those years in accordance with the Convertibility Law.

EXCHANGE RATES

Prior to December 1989, the Argentine foreign exchange market was subject to exchange controls. Between April 1, 1991, when Law No. 23,928 and Decree No. 529/91 (together referred to as the Convertibility Law) became effective, and January 5, 2002, the peso was freely convertible into U.S. dollars at a fixed one-to-one exchange rate. Pursuant to the Convertibility Law, the Central Bank of Argentina, which we refer to as the Central Bank, had to (i) maintain a reserve in foreign currencies, gold and certain public bonds denominated in foreign currency equal to the amount of outstanding Argentine currency and (ii) sell U.S. dollars to any requesting person at a fixed U.S.$1.00 to P$1.00 exchange rate. In addition, on January 12, 1995, the Central Bank issued Communication A 2298 which provided that all exchange transactions made with the Central Bank also had to be made at a fixed U.S.$1.00 to P$1.00 exchange rate.

On January 6, 2002, the Argentine Congress passed the Public Emergency and Foreign Exchange System Reform Law No. 25,561, which superseded certain provisions of the Convertibility Law, including the fixed one-to-one exchange rate. This law granted the federal executive branch the power to set the exchange rate between the peso and foreign currencies and to issue regulations related to the foreign exchange market. On January 6, 2002, the executive branch established a temporary dual exchange rate system. As of February 11, 2002, a single and free exchange market has been established for all exchange transactions. Within this new exchange regime and for the purpose of supporting the peso exchange rate, the Central Bank has intervened several times in the exchange market by selling U.S. dollars.

In light of a growing demand for U.S. dollars during the six months ended June 30, 2002 and the shortage of U.S. dollars available to satisfy this demand, the Argentine government adopted a series of measures to mitigate the demand for U.S. dollars and increase its U.S. dollar reserve base. As a result, (i) the export sector has had to exchange on a daily basis its non-Argentine currency into Argentine pesos through the Central Bank, (ii) new restrictions on the transfer of funds abroad were implemented, (iii) the purchase of foreign exchange was limited and (iv) requirements relating to the purchase of foreign currency from banks and exchange agencies became more stringent. Under these guidelines, the demand from private parties for U.S. dollars significantly declined and the Central Bank gradually started to accumulate U.S. dollar reserves.

In 2003, the balance of trade yielded a strong surplus, which, together with the continuing default in partial foreign debt payments by the government, caused an excess supply of foreign currency. As a result, the peso appreciated significantly against the U.S. dollar during 2003, notwithstanding the Central Bank s efforts to curtail these effects on the exchange rate through numerous currency purchases.

The following table sets forth, for the periods indicated, the high, low, average and period end exchange rates for the purchase of U.S. dollars, expressed in nominal pesos per U.S. dollar. The Federal Reserve Bank of New York does not report a noon buying rate for pesos.

	Exchange Rate			
	High	**Low**	**Average(1)**	**Period End**
	(in pesos)			
Year Ended December 31,				
1999	1.00	1.00	1.00	1.00
2000	1.00	1.00	1.00	1.00

2001	1.00	1.00	1.00	1.00
2002	3.90	1.60	3.14	3.38
2003	3.37	2.73	2.95	2.94
Three months ended March 31, 2004	2.96	2.85	2.90	2.86
Latest Six Months				
December, 2003[(2)]	2.99	2.94	2.96	2.94
January, 2004[(2)]	2.93	2.85	2.89	2.89
February, 2004[(2)]	2.96	2.92	2.93	2.92
March, 2004[(2)]	2.93	2.86	2.90	2.86
April, 2004[(2)]	2.87	2.80	2.83	2.86
May, 2004[(2)]	2.97	2.84	2.92	2.97

(1) Based on monthly average exchange rates.

(2) Source: Banco de la Nación Argentina.

On June 11, 2004, the exchange rate for the purchase of U.S. dollars published by Banco de la Nación Argentina was P$2.97 per U.S. dollar.

Table of Contents

RISK FACTORS

Factors Relating to Argentina

Overview

We are an Argentine corporation. As of December 31, 2003, approximately 64% of our total assets, 69% of our net sales, 58% of our combined crude oil and gas production and 40% of our proved oil and gas reserves were located in Argentina. Fluctuations in the Argentine economy and government actions adopted by the Argentine government have had and will continue to have a significant effect on Argentine private sector entities, including us. Specifically, we have been affected and might be affected by inflation, interest rates, the value of the peso against foreign currencies, price controls, regulatory policies, business regulations, tax regulations and in general by the political, social and economic scenario in and affecting Argentina.

The Argentine economy has experienced significant volatility.

The Argentine economy has experienced significant volatility in recent decades, characterized by periods of low or negative growth and high and variable levels of inflation and currency devaluation. In 1988, 1989 and 1990, the annual inflation rates were approximately 388%, 4,924% and 1,344%, respectively, based on the Argentine consumer price index and approximately 422%, 5,386% and 798%, respectively, based on the Argentine wholesale price index. As a result of inflationary pressures, the Argentine currency was devalued repeatedly during the 1960s, 1970s and 1980s, and macroeconomic instability led to broad fluctuations in the real exchange rate of the Argentine currency relative to the U.S. dollar. To address these pressures, the Argentine government during this period implemented various plans and utilized a number of exchange rate systems and controls.

In April 1991, the Argentine government launched a plan aimed at controlling inflation and restructuring the economy, enacting the Convertibility Law. The Convertibility Law fixed the exchange rate at one peso per U.S. dollar and required that the Central Bank maintain reserves in gold and foreign currency at least equivalent to the monetary base. Following the enactment of the Convertibility Law, inflation declined steadily and the economy experienced growth through most of the period from 1991 to 1997. In the fourth quarter of 1998, however, the Argentine economy entered into a recession that caused the gross domestic product to decrease by 3.4% in 1999, 0.8% in 2000, 4.4% in 2001 and 10.9% in 2002. As discussed below, in 2003, the Argentine economy began to recover with GDP growing 8.7%.

Argentina experienced a severe recession and significant political and social instability during 2001 and 2002, and economic turmoil and recession may occur again in the future.

Beginning in the second half of 2001, Argentina s recession worsened significantly. As the public sector s creditworthiness deteriorated, interest rates reached record highs, bringing the economy to a virtual standstill. The lack of confidence in the country s economic future and its ability to sustain the peso s parity with the U.S. dollar led to a massive withdrawal of deposits from banks and capital outflows.

To prevent further capital outflows, on December 1, 2001, the Argentine government implemented a number of monetary and exchange control measures that mainly included restrictions on the free disposition of funds deposited with banks and the practical impossibility of making transfers of foreign currency abroad, with the exception of certain transactions subject, in some cases, to the previous authorization of the Central Bank. Foreign currency resulting from export sales was required to be deposited with Argentine Banks, to the extent no prior exemption mechanisms were in place.

The measures were perceived as further paralyzing the economy for the benefit of the financial system, and caused a sharp rise in social discontent, ultimately triggering public protests, outbreaks of violence and the looting of stores throughout Argentina. On December 20, 2001, after declaring a state of emergency and suspending civil liberties, President Fernando de la Rúa tendered his resignation to Congress. After a series of interim presidents, on January 1, 2002, Eduardo Duhalde was appointed by Congress at a joint session to complete the remaining term of former President de la Rúa.

Table of Contents

The new President, among other measures, ratified the suspension of payment of a portion of Argentina s sovereign debt declared by Interim President Rodríguez Saá.

On January 6, 2002, the Argentine Congress enacted the Public Emergency Law, which introduced dramatic changes to Argentina s economic model and put an end to the U.S. dollar-peso parity established since the enactment of the Convertibility Law in 1991, leading to a significant devaluation of the Argentine peso.

The Public Emergency Law also empowered the federal executive branch of Argentina to implement, among other things, additional monetary, financial and exchange measures to overcome the economic crisis in the short term, such as determining the rate at which the peso was to be exchanged into foreign currencies.

The federal executive branch implemented a number of far-reaching initiatives, which included:

- pesification of certain assets and liabilities denominated in foreign currency and held in the country;

- rescheduling of bank deposits, with the subsequent ability for owners of such deposits to receive certain dollar-denominated government bonds maturing in ten years or peso-denominated government bonds maturing in three or five years or bills with specific terms in lieu of payment of such deposits;

- amendment of the charter of the Central Bank authorizing it to issue money in excess of the foreign currency reserves, to grant short-term loans to the federal government and to provide financial assistance to financial institutions with liquidity or solvency problems;

- issuance by the federal government of bonds to compensate banks for losses resulting from the different pesification rates applicable to deposits and U.S. dollar obligations assumed in Argentina;

- pesification of all private agreements entered into as of January 6, 2002 at the P$1=U.S.$1 exchange rate and subsequent adjustment thereof by the Benchmark Stabilization Coefficient, published by the Central Bank;

- pesification and elimination of indexing clauses on utility rates, fixing those rates in pesos at the P$1=U.S.$1 exchange rate; and

- implementation of taxes on hydrocarbon exports and certain oil by-products, among others.

Commercial and financial activities were virtually paralyzed in 2002, further aggravating the economic recession, which included a 10.9% decline in GDP in 2002.

The crisis and the government s reactions to the crisis severely weakened the Argentine banking system. A few small banks went into liquidation, and credit became scarce for the public and private sectors.

Towards the end of 2002, the Argentine government implemented different measures aimed at unblocking the economy and abrogating certain restrictions to gradually normalize the foreign exchange market and the commercial and financial flow of foreign currency.

On April 27, 2003, presidential elections took place. Since none of the presidential candidates captured either 45% of the votes or a 10% margin of victory, the former-President Carlos Menem and Néstor Kirchner, the two candidates with the most votes in the first round, entered a run-off election that was scheduled to have taken place on May 18, 2003. However, Carlos Menem dropped out of the Argentine presidential election, and, thus, Nestor Kirchner automatically became the country s newly elected president. On May 25, 2003, Mr. Kirchner took office as Argentina s president.

In September 2003, Argentina and the International Monetary Fund, or IMF, reached a three-year stand-by credit agreement, which set specific fiscal targets for 2004. This new agreement guaranteed the refinancing of all principal maturities of credit facilities granted by multilateral agencies.

Table of Contents

In 2003, the Argentine economy began to recover with GDP growing 8.7%. This recovery, at first based almost exclusively on import substitution, broadened as the level of consumption and investment increased. Reflecting the economic recovery, Argentine stock exchange indices displayed great dynamism in 2003, and both labor indicators and salary purchasing power registered consistent improvements during this year. The balance of trade exhibited a strong surplus, favored by an increase in commodity prices, which, together with the continuity of the partial foreign debt payment default, caused an excess supply of foreign currency. The peso appreciated significantly against the U.S. dollar during 2003, even as the Central Bank made numerous currency purchases to attempt to maintain a high rate of exchange. Inflation was below 4% during 2003.

Although the social and economic situation has improved, important issues remain unresolved, such as renegotiating the external public debt and public utility contracts, restructuring the financial system and redesigning the federal fiscal regime. Argentine government actions concerning the economy, including with respect to inflation, interest rates, price controls, foreign exchange controls and taxes, have had, and may continue to have, a material adverse effect on private sector entities, including us. We cannot provide any assurance that future economic, social and political developments in Argentina, over which we have no control, will not further impair our business, financial condition, or results of operations or impair our ability to make payments of principal and/or interest on our outstanding indebtedness.

Argentina s insolvency and default on its public debt could limit or impair Argentina s economic recovery.

Because Argentina failed to meet fiscal targets, including those for the fourth quarter of 2001, on December 5, 2001, the IMF suspended further disbursements. This decision deepened the economic and financial crisis.

On December 23, 2001, interim President Rodríguez Saá declared the suspension of debt payments on approximately U.S.$63 billion of Argentina s sovereign debt, which amounted to approximately U.S.$144.5 billion as of December 31, 2001. On January 2, 2002, President Duhalde ratified this decision.

On September 22, 2003, the Argentine government presented bondholders with a proposal for restructuring the country s defaulted bonds at the IMF/World Bank annual meeting in Dubai, United Arab Emirates. Under the proposal, sovereign bonds issued before December 31, 2001 would be eligible for the proposed bond exchange, which we refer to as Eligible Debt, maintaining a strict equitable principle among all kinds and classes of creditors. The Eligible Debt would comprise approximately U.S.$100 billion, issued under 152 different series of bonds, seven different currencies and eight different governing laws. Past due interest payments since the early 2002 default would not be paid, and principal would be reduced by 75%. The stated main objective of the government s proposal is to restore solvency through improvements in the Debt/GDP and Debt Service/Fiscal Revenues ratios, reaching a new debt profile that would be consistent with Argentina s payment capacity. The proposal was not well received by bondholders.

In March 2004, within the framework of a second review of the three-year agreement subscribed with the IMF, the government committed itself to taking decisive steps towards the restructuring of the public debt. In this regard, the federal executive branch issued a decree appointing the syndicate of banks that will assist the government in the restructuring.

On June 1, 2004, the Argentine government announced a new proposal to restructure the country s defaulted debt. This new proposal includes a plan to pay accrued interest on the defaulted bonds for the period commencing on the date the country defaulted on its sovereign debt until either December 31, 2003 or June 30, 2004 depending on the level of acceptance of the proposal, and an option for existing bondholders to exchange their bonds for one of three types of bonds, namely par, quasi-par and discount bonds, which have coupons pegged to the country s growth in GDP and with terms ranging from 20 to 32 years. This offer has not been launched, and we cannot predict whether bondholders will adhere to the offer, when and if launched. The government expects to complete the exchange process before the end of the year.

The Argentine government s current insolvency, its inability to obtain financing and the uncertainties surrounding the restructuring process, which is described as one of the most complex in history and has led and may continue to lead to a growing number of lawsuits by creditors until a final agreement is reached, may affect significantly the government s ability to implement reforms and restore sustainable economic growth. This could further undermine the maintenance of the economic recovery experienced during 2003 and may result in recession, higher inflation, greater unemployment and social unrest. If this happens, our financial condition and results of operations would be adversely affected.

The devaluation of the peso creates greater uncertainty as to Argentina s economic future.

The peso has been subject to large devaluations in the past and may be subject to significant fluctuations in the future.

The Public Emergency Law put an end to ten years of U.S. dollar-peso parity and authorized the Argentine government to set the exchange rate between the peso and foreign currencies, and issue regulations related to foreign exchange markets. After devaluing the peso, the Argentine government initially established a dual exchange rate of P$1.40 per U.S. dollar for certain transactions and a free-floating rate for all other transactions. This dual system was later eliminated in favor of a single free-floating exchange rate for all transactions.

Since the end of the U.S. dollar-peso parity, the peso has fluctuated significantly. As a result, the Central Bank has taken several measures to stabilize the exchange rate and preserve its reserves. See Exchange Rates.

The marked peso devaluation during 2002 adversely affected our results and financial position. All of our financial debt and a significant portion of our affiliates debt are denominated in U.S. dollars. Before the enactment of the Public Emergency Law, our cash flow, usually denominated in U.S. dollars or dollar-adjusted, provided a natural hedge against exchange rate risks. The new Argentine regulatory framework, however, limited our ability to mitigate the impact of the peso devaluation. Pesification of utility rates, regulatory issues related to the renegotiation of pesified utility rates, new taxes on hydrocarbon exports and the implementation of regulations to prevent an increase in prices to final users in the domestic market had a significant impact in such respect.

As from the second half of 2002, domestic prices of the main commodities have significantly recovered in line with export prices. In addition, we aggressively pursued a trade policy of opening and consolidation of export markets to capitalize on domestic and export price asymmetries. In light of the above strategies and the strength of our foreign operations with a cash flow primarily denominated in U.S. dollars, our exposure to peso fluctuations has dropped, and we have substantially recovered our ability to naturally hedge our cash exposure to U.S. dollar liabilities.

We cannot assure you, however, that the Argentine government will not adopt new regulations or make regulatory changes that prevent or limit us from offsetting the risk derived from our exposure to the U.S. dollar.

Inflation may escalate and undermine any hope for continued economic growth in Argentina.

On January 24, 2002, the Argentine government amended the charter of the Central Bank to allow the Central Bank to print currency without having to maintain a fixed and direct relationship to foreign currency and gold reserves. This change allows the Central Bank to make short-term advances to the federal government to cover its anticipated budget deficits and to provide assistance to financial institutions with liquidity or solvency problems.

There is considerable concern that, if the Central Bank prints currency to finance public sector spending, to assist financial institutions in distress or to prevent a further appreciation of the peso, significant inflation could result. During 2002, the Argentine consumer price index increased 40.98%, and the wholesale price index increased 118.2%. During 2003, within a substantially different economic scenario, such indices increased only 3.7% and 2.0%, respectively.

In the past, inflation has materially undermined the Argentine economy and the government s ability to stimulate economic growth. The variability of inflation in Argentina makes it impossible to estimate how our activities and results of operations will be affected in the future. Sustained inflation in Argentina, without a corresponding increase in the price of our products in the local market, would have a negative effect on our results of operations and financial position.

Exchange controls may further impair our ability to service our foreign currency-denominated debt obligations.

After December 2001, the Argentine authorities implemented a number of monetary and currency exchange control measures that included restrictions on the withdrawal of funds deposited with banks and tight restrictions on foreign transfers, including restrictions relating to the servicing of foreign debt, with the exception of those related to foreign trade and other authorized transactions. Although these control measures have been relaxed and, during 2003, the Central Bank issued a number of regulations aimed at gradually normalizing the domestic exchange market, we cannot assure you as to how long these more flexible regulations will be in effect or whether they will become more restrictive again in the future.

Pursuant to Decree No. 1589/89 relating to the deregulation of the upstream oil industry, companies engaged in oil and gas production in Argentina are free to sell and dispose of the hydrocarbons they produce, and are entitled to maintain outside Argentina up to 70% of the foreign currency proceeds from crude oil and gas exports. These companies are required to repatriate the remaining 30% through the Argentine exchange markets. During 2002, controversies arose among producers and the authorities regarding the enforceability of the right to freely dispose of up to 70% of the proceeds from foreign currency export sales. These controversies were the subject of legal challenges, and many federal judges have pronounced on and recognized the prima facie validity of producers rights. In December 2002, we filed with a federal court of the Province of Santa Cruz, a temporary injunction against the federal executive branch, requesting the maintenance of the status quo that allows us to freely dispose of up to 70% of our export proceeds. This right was prima facie admitted by the court. On December 31, 2002, Decree No. 2703/02, effective as of January 1, 2003, was enacted. This decree recognized the right of oil and gas producers to dispose of 70% of the proceeds from foreign currency export sales, but had no provisions related to such right during 2002. In order to avoid any uncertainty regarding the application of this right in 2002, in February 2003, we filed a civil action of certainty, requesting that the court recognize our right to freely dispose up to 70% of our export proceeds in 2002, based on the effectiveness of Decree No. 1589/89. This was admitted prima facie by the court.

If the Argentine government decides further to tighten its transfer restrictions by, among other things, eliminating Decree No. 1589/89 or otherwise, we may be unable to make principal or interest payments when they become due.

Limits on exports of hydrocarbons could lower our anticipated dollar-denominated cash receipts.

On May 23, 2002, the Argentine government enacted Decree No. 867/02 declaring a state of emergency in the supply of hydrocarbons in Argentina until September 30, 2002 and empowering the Secretary of Energy to determine the volume of crude oil and liquefied petroleum gas, which we refer to as LPG, produced in Argentina that should be sold in the local market. In addition, by Resolution No. 140/02, temporary limits were established for hydrocarbon exports during the months of June, July, August and September of 2002. Resolution No. 140/02 was repealed on July 26, 2002 by Resolution No. 341/02.

Argentina is suffering an energy crisis. In light of this situation, the Secretary of Energy issued Resolution No. 265/2004 on March 26, 2004, pursuant to which limits on natural gas exports may be imposed and, in fact, some limits have already been imposed. This resolution instructs the Undersecretary of Fuels to create a program for the rationing of gas exports and for the regulation of the use of transportation capacity. In compliance with this instruction, the Undersecretary of Fuels issued Disposition No. 27/04 implementing this program. Both regulations were issued as temporary measures in order to avoid a crisis in the local supply of natural gas and, consequently, in the supply of electricity to the wholesale electricity market. We do not believe that these measures will have a material adverse effect on our results or financial condition, but we cannot assure you that this will be the case.

Additionally, in April of 2004, in order to facilitate the recovery of gas prices, the Secretary of Energy entered into an agreement with natural gas producers requiring them to sell a specified amount of gas in the local regulated market for prices determined in accordance with a roadmap that culminates with the expected complete deregulation of wellhead prices for natural gas by January of 2007. See Item 4. Information About Us Regulation of Our Businesses The Argentine Gas Industry and Regulatory Framework Adjustment of the Price of National Gas in Wellhead.

We cannot assure you that the Argentine government will not impose additional export restrictions on hydrocarbons. If it were to do so, we would receive lower dollar-denominated cash receipts, which might limit our ability to service our U.S. dollar-denominated debt.

Export taxes on our products have negatively affected, and may continue to negatively affect, the profitability of our operations.

Effective as of March 2002, the Argentine government adopted a 20% export tax on crude oil exports and a 5% tax on exports of certain oil by products. Diesel oil s effective export tax from June until July 31, 2002 was 20%. In May 2004, the Argentine government increased to 25% the export tax on crude oil exports, increased the export tax on LPG oil exports to 20% and imposed a 20% tax on all gas exports.

We cannot assure you that the Argentine government will reduce the current export tax rates or will not increase them further. We do not know the government s future intentions in regard to export taxes.

Price controls have affected, and may continue to affect, our results of operations and capital expenditures.

For the purposes of reducing inflationary pressures generated by the sharp Argentine peso devaluation, the Argentine government issued a set of regulations aimed at controlling the increase in prices to end users. These regulations were particularly focused on the energy sector.

Under the Public Emergency Law, our ability to increase the price of energy and gas sold in the domestic market is limited, especially in connection with sales agreements entered into with utility companies and energy sales in the spot market. This limitation, within the context of the peso devaluation and subsequent inflation, resulted in a substantial change in the economic and financial balance of our energy and gas related businesses, significantly affecting our operating results and prospects. As a result, gas investments, especially at the Neuquén basin, were postponed.

With respect to crude oil prices, in January 2003, at the federal executive branch s request, hydrocarbon producers and refineries executed a temporary agreement in connection with crude oil, gasoline and diesel oil price stability in the domestic market. After successive renewals, the term of this agreement was extended until May 2004. This agreement provided for crude oil deliveries to be invoiced and paid based on the West Texas Intermediate Crude reference price, or WTI, of U.S.$28.5 per barrel instead of the actual relevant WTI. Any positive or negative difference between the actual relevant WTI, not exceeding U.S.$36 per barrel, and the reference price would be paid out of any balance generated in periods where the actual WTI is below U.S.$28.5 per barrel. Refineries, in turn, would reflect the crude oil reference price in domestic market prices. In February 2004, a new agreement corresponding to the period beginning on March 1, 2004 and ending on April 30, 2004 was reached between producers and refineries, but the Secretary of Energy has not yet approved this agreement because it contains a difference concerning the interest rate to be used to calculate the debt between producers and refiners. If the situation continues in the future, producers shall be forced to reinvoice refiners in order to adjust prices. Notwithstanding this situation, beginning in May 2004, hydrocarbon producers and refineries have informally agreed that while the WTI per barrel ranges between U.S.$32 and U.S.$42, crude oil deliveries will be invoiced and paid based on a reference price equal to (i) 86% of the WTI as long as this price does not exceed U.S.$ 36 per barrel, or (ii) 80% of the WTI, in cases where this price exceeds U.S.$36 per barrel.

With respect to electricity generation, the Argentine government implemented the pesification of dollar-denominated prices in the wholesale electricity market, and through Resolution No. 08/02 of the Secretary of Energy, set a price cap for the energy sold in the spot market of P$120/MWh. This is the maximum price for an efficient generation company, regardless of the actual marginal cost of electricity generation. Resolution No. 240/03 effective since August 15, 2003, established that the cost of liquid fuels in thermal power plants and water in hydroelectric plants was excluded from the determination of electricity prices. This resolution was temporarily suspended on October 9, 2003, and then put into effect again by the Secretary of Energy on January 30, 2004. These measures represent deviations from the marginal cost system implemented in 1992 and from the provisions in Electricity Law No. 24,065, which allow for an adequate return on investment in a competitive environment based on a marginal price system. Thermal power generating companies, however, may cover variable operating costs through certain mechanisms. See Item 4. Information About Us Regulation of Our Businesses The Argentine Electricity Industry and Regulatory Framework Dispatch.

In addition, due to the government s decision to suspend the seasonal increases in electricity prices, electricity prices have not reflected production costs. As a result, the Stabilization Fund (*Fondo de Estabilización*) was exhausted and Compañia Administradora del Mercado Eléctrico S.A., or CAMMESA, which we refer to as the

Table of Contents

Wholesale Market Manager, could not settle accounts with market agents. As a palliative measure, in December 2003 the Argentine government made a P$150 million contribution to the Stabilization Fund under Decree No. 1181/03 and on March 2004, under Decree No. 365/04, made a further contribution of P$200 million. In February 2004, in an effort to restore the Stabilization Fund, the government reinstated the seasonal adjustment in electricity prices for the February-April 2004 period, but on May 2004, the government suspended seasonal adjustments again. As of May 2004, the Stabilization Fund has a deficit of P$650 million.

In light of the uncertainties prevailing in Argentina, we have made progress in renegotiating the terms and conditions of gas and electricity sale agreements entered into with industrial clients in order to adjust prices to reflect the new economic conditions. In this regard, we have reached commercial agreements that gradually increase sale prices to reflect the effects of the peso devaluation. We, as well as others, have attempted to maximize export opportunities in an effort to capitalize on variations between domestic and export prices, by effectively encouraging the opening and consolidation of new markets. During 2003, we started to export gas to Chile from the Austral basin.

The Argentine government is expected to gradually restore the economic and financial balance in the natural gas and electricity sectors, in compliance with the respective regulatory frameworks. However, our results and capital expenditure plans may be negatively affected if the Argentine government continues issuing additional decrees or exerting political pressure to curb price increases or control exports or if it applies its regulatory emergency authority to fix prices or adopts other laws to stabilize prices or supply.

The pesification of utility rates has affected and may continue to affect the operations of our affiliated utility companies.

The Public Emergency Law pesified tariffs for public utility services and prohibited the increase of such tariffs based on indexation factors. Tariffs were converted into pesos at a P$1=U.S.$1 parity. Pursuant to this law, the Argentine federal executive branch is authorized to renegotiate the terms of contracts relating to the provision of public utility services. The criteria for such renegotiation must take into account: (i) the impact of tariffs on economic competitiveness and on income distribution, (ii) the quality of the service and capital expenditure programs, in cases where they were required in the contracts, (iii) the interest of the customers and accessibility to the services, (iv) the safety of the systems and (v) the companies profitability.

On February 12, 2002, the federal executive branch issued Decree No. 293/02 under which the Ministry of Economy was empowered to renegotiate utility contracts and a Public Works and Services Contract Renegotiation Committee, which we refer to as the Renegotiation Committee, was created, the members of which, among them a representative of customers, were appointed through Decree No. 370/02. The Renegotiation Committee s mission is to provide advice to and assist the Ministry of Economy, which must submit a renegotiation proposal to the federal executive branch or otherwise recommend the termination of concession contracts. Such proposal or recommendation is subsequently submitted to the relevant congressional commissions for analysis. The Renegotiation Committee, however, failed to achieve its intended goal due to successive actions to protect constitutional rights (*acciones de amparo*) brought by the Argentine National Ombudsman (*Defensor del Pueblo de la Nación*).

In order to secure the supply of utilities, and in line with the renegotiation process, the federal executive branch authorized an increase in gas and electricity rates under Decree No. 146/03. Such increase was 10% for Transportadora Gas del Sur S.A., or TGS, 9% for Edesur S.A., or Edesur, and 22% for Compañía de Transporte de Energía Eléctra en Alta Tensión Transener S.A., or Transener and 18% for Empresa de Transporte de Energía Eléctrica por Distribución Troncal Sociedad Anónima Transba S.A. or Transba The Argentine National Ombudsman and consumer organizations challenged the increase. On February 25, 2003, a Court of First Instance issued a provisional remedy and suspended the rate increase authorized under Decree No. 146/03.

In July 2003, the Utilities Contract Renegotiation and Analysis Committee, or UNIREN, was created within the scope of the Ministries of Economy and Production and Federal Planning, Public Investment and Services. UNIREN, as successor of the Renegotiation Committee, was created to, among other things, assist in the contract renegotiation process for public works and services, subscribe comprehensive or partial agreements and submit regulatory projects concerning temporary price and rate adjustments. To date, no substantial progress has been made in the renegotiation process.

On October 1, 2003, the Argentine Congress enacted a law whereby the term granted to the federal executive branch under the Public Emergency Law to renegotiate contracts with privatized utility companies was extended until December 2004. In addition, under such law the federal executive branch may fix temporary utility rates until completion of the renegotiation process.

We cannot anticipate the outcome of the current renegotiation process. If utility companies contracts are renegotiated, the new terms could be less favorable than the current terms. If so, the results of operations and financial position of utility companies could be severely affected. Even if these contracts are renegotiated with more favorable terms, such terms could be insufficient to prevent a material adverse effect on the results of operations and financial position of utility companies. The problems faced by our affiliated utilities have adversely impacted our net income and our ability to receive dividends from these companies. Whereas we received dividends from these companies in 2000 and 2001, we did not receive dividends from them in 2002 or 2003. See Item 5. Operations and Financial Review and Prospects Overview.

The devaluation and pesification of utility rates have resulted in payment defaults by some of our affiliates.

The new macroeconomic scenario after enactment of the Public Emergency Law deeply changed the economic and financial balance of utility companies. The tremendous effect of devaluation, within a context where revenues remained unchanged as a consequence of the pesification of rates and financial debts with foreign creditors were primarily denominated in foreign currency, affected the financial position, results of operations and cash generation ability of utility companies.

CIESA and Transener have defaulted on their debt and are attempting to restructure it. On February 24, 2003, TGS started an overall restructuring process for substantially all its financial debt. This process mainly aims at extending short-term maturities, modifying certain financial restrictions contemplated in financial agreements and adjusting interest rate and repayment terms to align cash flows required to repay the debt with its expected cash flows, with no principal reductions.

TGS first attempted to reach an agreement with creditors through a pre-packaged out-of-court reorganization agreement (*Acuerdo Preventivo Extrajudicial*), or APE, which is a new structure permitted by Argentine law. An APE essentially permits a company to restructure its debt pursuant to an agreement approved by two-thirds of its creditors, which we refer to as the Requisite Majority, and which is then endorsed by an Argentine Court. Since TGS could not achieve this Requisite Majority, on May 14, 2003, it withdrew the restructuring proposal and simultaneously announced the postponement of the payment of interest on its financial debt. TGS is currently conducting negotiations with its main creditors.

Transener has been notified of a request by one of its creditors for the commencement of involuntary bankruptcy proceedings against it and of requests for attachment of approximately U.S.$11.5 million in accounts receivable from CAMMESA. Transener is pursuing all reasonable defenses to protect its rights.

The management of our different affiliated utility companies have formulated and implemented an action plan aimed at offsetting the negative impact of the current conditions. We cannot assure you that these plans will prove to be successful or that these plans will help meet the companies established goals.

We could lose some or all of our ownership in these companies if any necessary debt restructuring is unsuccessful and creditors proceed against the assets of the defaulting affiliates, although the outcome of such procedure is uncertain due to the procedural difficulties of Argentine bankruptcy courts and laws relating to the ownership of Argentine utilities. In addition, as part of a debt restructuring, creditors may require an equity stake in these companies, thereby reducing our equity interest. If our equity interest were reduced, our share of any future cash dividends and equity in earnings from affiliates from these companies would decrease in line with the decrease in our ownership interest.

Table of Contents

Factors Relating to Venezuela

Political and social events in Venezuela may negatively affect our Venezuelan operations.

Operations in Venezuela have become an important part of our businesses. In 2003, production in Venezuela accounted for 27.3% of the total average production in barrels of oil equivalent. As of December 31, 2003, a significant share of our total combined proved reserves was located in Venezuela. Accordingly, our operations are affected by political developments in Venezuela.

Effective January 2002, the Venezuelan government adopted a new law whereby royalty payments increased from 16.67% to 30%. This had a significant adverse impact on the results of certain of our fields.

In February 2002, as a result of the capital drain that had started a few years before and the fall in economic activity caused by production cuts mandated by the Organization of Petroleum Exporting Countries, or OPEC, Venezuela was forced to abandon the exchange rate system that it had maintained for some time. Venezuela s currency, the Bolivar, was allowed to float against the U.S. dollar, leading to a significant devaluation.

In April 2002, the President of Venezuela, Hugo Chávez, was removed from power but subsequently returned to the presidency after a few days. He was removed by the military after heavy political backlash over the implementation of his social programs and decision to change management at Petróleos de Venezuela S.A., or PDVSA, the state-owned oil company.

The political crisis deepened in the last months of 2002, with less support for President Chávez and increased violence. In December 2002, in the face of Chávez s refusal to permit a referendum that would determine whether to accelerate elections, a general strike organized by the Coordinadora Democrática was initiated. A number of sectors, including PDVSA workers, joined the strike; as a result, oil production plummeted. The strike was accompanied by increased capital drains, loss of bank deposits and a material deterioration of the country s tax situation as a result of reduced tax revenues. Credit rating agencies downgraded Venezuela s debt ratings. Taking into account the economic deterioration brought by the strike, opposition forces decided to lift the strike in February 2003. The government, in turn, was able to resume control over PDVSA and to partially reinstate production, after dismissing a large number of PDVSA employees.

After discussions between the government and the opposition resumed, an agreement was reached to hold a referendum on President Chávez s future tenure. In June 2004, the Venezuelan Justicia Electoral determined that the opposition to Hugo Chávez had gathered the necessary support to force a referendum on Chávez s mandate, which is scheduled to occur in August of 2004. New riots and social protests are expected.

Amid this continuing struggle, the economy has suffered. A significant loss in reserves and capital flight was recorded. In addition, the country was plunged into in an unprecedented recession, which significantly increased inflation, unemployment and violence rates.

For the reasons mentioned above, the government adopted emergency measures including:

- closing the foreign exchange market and implementing strict exchange controls;
- implementing price controls over basic goods;
- importing fuel; and

increasing governmental control over PDVSA.

While these measures enabled a gradual recovery of reserves as oil production returned to normal levels, with high crude oil prices, the restrictions resulted in a sharp decline in overall imports and affected the general level of activity, particularly in the non-oil sector. Venezuela experienced both shortage problems and the emergence of a black market. The unemployment rate rose as poverty indices soared.

By the end of 2003, Venezuela experienced:

- the establishment of a foreign exchange parallel market with a U.S. dollar exchange rate close to 3,000 Bolivar s per U.S. dollar as compared to an official rate of 1,600 Bolivar s per U.S. dollar, which was reflected in the price level;
- an 11% decline in GDP, resulting in a decline of over 20% in the last two years;
- an unemployment rate close to 20%; and
- inflation of approximately 27%.

We are required to deliver all of our oil equivalent production in Venezuela to PDVSA, and accordingly PDVSA has become one of our most important customers.

Since oil production activities in Venezuela are closely monitored by the government through PDVSA, our operations in Venezuela could be affected by political and social riots, including strikes and other forms of political protest, similar to those experienced during the first quarter of 2003. Due in part to the oil strike at PDVSA in 2002, our daily sales volume of oil equivalent decreased 12.5% during 2003. In addition to these effects, Venezuela s complex crisis could have other unforeseen effects, which may have an adverse impact on our results of operations.

The Venezuelan government may, at its own discretion, decide to enact additional laws to modify the terms and conditions of our operating agreements that could negatively impact our operations. Such changes may include increased royalty payments or production cuts. In addition, since Venezuela is an OPEC member country, we are subject to any decision related to production cuts that OPEC may adopt.

Factors Relating to Us

Decline in oil prices affect our operating results and capital expenditures.

Oil prices in Argentina and other Latin American countries reflect world market prices. World oil prices are determined by global supply and demand factors over which we have no control. Oil prices have fluctuated widely over the last ten years. During 2003, 2002 and 2001, the average WTI was U.S.$31, U.S.$26 and U.S.$26 per barrel, respectively.

Because a substantial amount of our revenue is derived from sales of oil, any decline in the price of oil may affect our operating results and the amount and timing of our projected capital expenditures. Although we regularly evaluate the opportunity to enter into derivative transactions to mitigate our exposure to changes in the price of crude oil and crude oil by-products, if oil prices decline significantly, we may have to dramatically cut capital expenditures, and this could adversely affect our production forecasts in the medium term and our hydrocarbon reserve estimates.

The lack of financing alternatives may impact the execution of our strategic business plan.

After the default on the Argentine sovereign debt, Argentine companies have had significantly fewer opportunities to access international credit markets. Non-Argentine financial markets and institutions are reluctant to lend additional capital and grant loans to Argentine entities and companies. In addition, as a result of the default in payment of loans and other financial liabilities in Argentina on the part of the government and private entities and the massive withdrawal of money from accounts opened with financial institutions in Argentina and from the Argentine financial market in general, the opportunities to obtain financing at attractive rates in Argentina continue to be very limited.

Although we have thus far been able to fulfill our financings needs throughout the Argentine crisis (we were the first Argentine company to place a new issuance of debt which was not associated or part of a debt restructuring in the international capital markets since the Argentine governement defaulted on its debt), the prospects for all Argentine companies, including us, of accessing financial markets in the near or medium-term continue to be challenging. If we are unable to access the financial markets, we may have to reduce our projected capital expenditures in order to meet our contractual obligations. This may in turn affect the implementation of our business plan for 2004 and our long-term prospects.

Production of oil in Block 31 in Ecuador is significantly delayed, and this delay has and will continue to affect our results. Further delays could result in an increase in our operating losses related to our group of assets in Ecuador.

Our oil fields in an area referred to as Block 31 in Ecuador are located in the Amazon jungle in the northeastern part of the country where no significant infrastructure currently exists for the production of hydrocarbons.

Investments of approximately U.S.$800 million are estimated to be required for Block 31 s development in full. Initial investments in the amount of approximately U.S.$150 million must be effectively made before the start of the production phase, which is currently scheduled for 2006. The decline in our capital expenditures following the Argentine crisis resulted in significant delays with respect to our original plan for Block 31 s development. Our investments are dependent upon our ability to increase capital expenditures in future periods and to access the financial markets.

Future oil production in Block 31 will be shipped through a heavy crude oil pipeline known as Oleoducto de Crudos Pesados. We entered into a contract with Oleoducto de Crudos Pesados Ltd., or OCP, whereby 80,000 barrels per day of oil transportation capacity was committed on a ship or pay basis for a 15-year term as from the date OCP starts operations. Our annual cost associated with this oil transportation capacity is approximately P$220 million. Transportation capacity costs are billed by OCP on a monthly basis and charged to expensed by us as incurred.

OCP started commercial operations on November 10, 2003. As of that date, we have had to comply with our contractual obligations with respect to our committed acquired capacity by paying a fee which as of December 31, 2003 was estimated to be P$7.53 per barrel.

We currently estimate that, during the contract s term, oil production will be lower than our committed transportation capacity. We have reached this belief based on, among other reasons, the delays involved in the development of Block 31, the new schedule of investments required for the joint development of Blocks 18 and 31 and a revised outlook on the potential of Block 31. As of December 31, 2003, we have recorded an impairment allowance of P$321 million to adjust the book value of a group of assets in Ecuador to its recoverable value.

If we cannot increase capital expenditures in future periods, production from Block 31 will be delayed further. In addition, once development projects are commenced, unforeseen delays in our drilling activities may occur, which could result in significant additional delays in production. See Our drilling activities may be adversely affected by events beyond our control. Furthermore, we cannot assure you that, if required investments were made, future production levels would reach estimated production levels. As a result of these scenarios, we may have future operating losses to the extent that our revenues do not compensate our operating expenses and such losses shall be recognized when incurred.

Our oil and gas proved reserve estimates are not 100% accurate and may be subject to revision.

We estimate our proved developed crude oil and natural gas reserves by using geological and engineering data to demonstrate with reasonable certainty whether they are recoverable in future years from known reservoirs under existing economic and operating conditions. These estimates are audited by Gaffney, Cline & Associates, an international technical consulting firm for the oil and gas industry. Nonetheless, reserve estimates are based, in part, on subjective judgments and as a consequence are not 100% accurate, and, thus, may be subject to revision. Crude oil and natural gas reserves are reviewed annually to take into account production levels, field reviews, the addition of new reserves from discoveries, new economic conditions and other factors. Although we believe our proved reserve estimates fairly present the amount of reserves available to us, proved reserve estimates could be materially different from the quantities of crude oil and natural gas that are ultimately recovered.

Table of Contents

We may not be able to replace our oil and gas reserves.

The rate of production from oil and gas properties generally declines, and the cost of such production generally increases, as reserves are depleted. Without successful exploration and development activities or reserve acquisitions, our proved reserves will decline as oil and gas are produced from our existing proved developed reserves. We cannot guarantee that our exploration, development and acquisition activities will result in significant additional reserves or that we will continue to be able to drill productive wells at acceptable costs. Our ability to replace our reserves is also dependent upon our capital expenditures. In 2002, we reformulated our investment plan and adopted a restrictive expense and investment policy. This has significantly limited our reserve replacement ratio.

Looking towards the future, we have limited capital resources to implement an ambitious capital expenditure program. In addition, as long as the financial debt remains unpaid, we must comply with a series of restrictions and covenants, including restrictions on capital expenditure levels.

Our drilling activities may be adversely affected by events beyond our control.

Oil and gas drilling activities are subject to numerous risks, many of which are beyond our control. Our operations may be curtailed, delayed or canceled as a result of weather conditions, mechanical difficulties, shortages or delays in the delivery of equipment and compliance with governmental requirements. Drilling may involve unprofitable efforts, not only with respect to dry wells, but also with respect to wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a return on the investment or a recovery of drilling, completion and operating costs.

Our oil and gas operations may be affected by standard industry operating risks.

Our operations are subject to all of the risks normally incident to the operation and development of oil and gas properties and the drilling of oil and gas wells, including the risk of fire, explosions, blow outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, ruptures or discharges of toxic gases. The occurrence of these industry operating risks could cause us to suffer substantial losses, including losses due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damages and clean up responsibilities, and penalties and suspension of operations.

Our activities may be adversely affected by events in other countries in which we do business.

As we expand our operations in other countries, we may be increasingly affected by the following factors and developments: political and economic uncertainties; expropriation of property and cancellation or modification of contract rights; regulatory changes; currency exchange fluctuations and other risks arising out of the imposition of foreign investment or capital controls, and risks of loss in countries due to civil strife, acts of war, guerilla activities and insurrection.

Our operations run the risk of causing environmental damage, and any changes in environmental laws may increase our operational costs.

The nature of some of our operations forces us to undertake risks that may cause environmental as well as other types of damage.

In 2003, we hired an international consulting firm to perform an environmental and safety audit on our operations. The report ratified the high environmental standards under which our operations are performed and also identified a series of actions necessary for our operations to be in full compliance with current laws and regulations, to satisfy future requirements and, in the absence of local laws, to comply with applicable international standards. We have decided to implement the actions recommended by the audit. Consequently, over the next several years we will make investments to improve prevention systems and production facilities, among other things, in the amount of approximately U.S.$23 million, and we will implement several corrective and remediation actions, some of which are already underway.

Table of Contents

Notwithstanding our decision to implement actions recommended by the environmental audit and our commitment to our environmental, health and safety efforts, we cannot assure you that our operations will not cause environmental or other damages or that any such damages will not result in legal liabilities to us.

We are subject to extensive environmental regulation both in Argentina and in the other countries in which we operate. Additionally, local, provincial and national authorities in Argentina are moving toward more stringent enforcement of applicable environmental laws, which may require us to incur higher compliance costs. We cannot predict what additional environmental legislation or regulations will be enacted in the future or the potential effects on our financial position and results of operations.

We operate some of our businesses pursuant to concessions and licenses that are subject to termination.

The terms of the concessions under which some of our businesses operate typically require the operator to meet specified requirements and to maintain minimum quality and service standards. Failure to comply with these criteria could result in the imposition of fines or other government actions. In addition, in extreme cases our license or concession may be terminated or revoked. Although we have materially complied with the terms and conditions of our licenses and concessions in the past and expect to do so in the future, we cannot assure you that our businesses will be able to comply fully with the terms and conditions of their licenses.

Regarding utility companies, the freezing of rates, in addition to increased operating and financing costs, had a significant adverse impact on the utilities cash flow and capital expenditure plans. Although these companies have continued to maintain acceptable service quality levels, their ability to continue meeting these levels will be seriously affected if the Argentine government does not adopt structural measures allowing for a recovery of these companies economic-financial balance.

Our activities may be adversely affected by competition.

Activities in the energy business are highly competitive and are expected to remain competitive in the future.

We compete with other companies, including leading international oil and gas companies in Argentina and the rest of Latin America. Some of these companies may have greater financial and other resources than us and, as a result, may be in a better position to compete for future business opportunities. In addition, other alternative sources of energy are expected to come into operation in the future.

We cannot assure you that we will maintain our current competitive position in the regional energy markets. In addition, we cannot predict with reasonable certainty the magnitude and speed of evolution of such potential competitive threats or their effect on our operations.

Item 4. INFORMATION ABOUT US

OUR HISTORY AND DEVELOPMENT

Our History

We are an Argentine based holding company and operate exclusively through our subsidiary Petrobras Energia and its subsidiaries which are engaged in oil and gas exploration and production, refining, petrochemicals, electricity generation, transmission and distribution and hydrocarbons marketing and transportation. We conduct operations in Argentina, Bolivia, Brazil, Ecuador, Peru and Venezuela. We are a corporation organized and existing under the laws of the Republic of Argentina with a duration of 99 years from the date of our incorporation, September 25, 1998. Our legal name is Petrobras Energía Participaciones S.A. and we are known commercially as Petrobras Energía Participaciones. Our principal executive offices are located at Maipú 1, 22nd Floor, C1084ABA Buenos Aires, Argentina, Telephone: 54 11 4344-6000.

Our original name was PC Holdings S.A. We were formed in 1998 as a result of a spinoff by Sudacia S.A. of its equity interest in Petrobras Energía. At the time of the spinoff, we and Sudacia S.A. were wholly owned by members of the Perez Companc family. In addition, Petrobras Energía was also controlled at the time by members of the Perez Companc family. We were formed for the sole purpose of owning shares of Petrobras Energía. As of December 31, 1998 and 1999, we owned 16.15% and 28.92%, respectively, of Petrobras Energía s common stock.

We acquired control of Petrobras Energía on January 25, 2000 as a result of the consummation of an exchange offer pursuant to which we issued 1,504,197,988 Class B shares, with one vote per share, in exchange for 69.29% of Petrobras Energía s outstanding capital stock, thereby increasing our ownership interest in Petrobras Energía to 98.21%. Since January 26, 2000, our Class B shares have been listed on the Buenos Aires Stock Exchange and our American Depositary Shares, each representing ten Class B shares, have been listed on the New York Stock Exchange. At the time, we were controlled by members of the Perez Companc family, who owned all of our Class A shares. Those Class A shares had five votes per share until October 17, 2002, when all Class A shares converted into Class B shares upon their purchase by Petrobras.

In July 2000, we completed the change in our corporate name from PC Holdings S.A. to Perez Companc S.A.

On October 17, 2002, Petrobras Participacões, S.L., a wholly owned subsidiary of Petróleo Brasileiro S.A. PETROBRAS, or Petrobras, acquired from the Perez Companc family and Fundación Perez Companc their entire ownership interest, or 58.6%, of Petrobras Energía Participaciones s capital stock. Petrobras is the largest integrated oil, gas and energy company in Brazil. It is engaged in a broad range of oil and gas activities, including crude oil and natural gas exploration and production, refining, transportation, marketing and distribution of oil products, petrochemicals, natural gas and power. Petrobas is a mixed-capital company with a majority of its voting capital owned by the Brazilian federal government. Prior to that date, the Perez Companc family, together with Fundación Perez Companc, had owned at least half of the share capital issued by Petrobras Energía Participaciones.

On April 4, 2003, at a regular and special shareholders meeting, shareholders approved the change of our corporate name to Petrobras Energía Participaciones S.A. from Perez Companc S.A. On the same date, shareholders of Pecom Energía S.A., or Pecom, approved the change of its name to Petrobras Energía S.A. Both changes were registered with the National Corporate Registrant (*Inspección General de Justicia*) on July 17, 2003.

On May 13, 2003, the CNDC approved the purchase of 58.62% of Petrobras Energía Participaciones S.A s capital stock.

History of Petrobras Energía

Petrobras Energía was founded in 1946 as a shipping company by the Perez Companc family. In the mid-1950 s Petrobras Energía began its forestry operations when it acquired an important forestry area in northeastern Argentina. In 1960, Petrobras Energía began servicing oil wells, and, over time, its maritime operations were gradually discontinued and replaced by oil-related activities. The development of Petrobras Energía s oil and gas business is marked by two significant events. The first occurred in the early 1990s, when Petrobras Energía was

Table of Contents

awarded concessions to operate Puesto Hernandez, the second most important oilfield in Argentina, and the Faro Virgenes and Santa Cruz II areas in the Austral basin, Argentina s most important area of oil and gas production. As a result of this and other concessions, Petrobras Energía has become one of the largest oil and gas producers in Argentina.

The second milestone in Petrobras Energía s oil and gas operations occurred in 1994 when Petrobras Energía bid on and was awarded an exploration and production service contract for the Oritupano Leona area in Venezuela. Over the last few years Petrobras Energía has expanded its operations rapidly in Venezuela, Peru, Ecuador, Brazil and Bolivia as part of its strategy to become a leading integrated energy company in Latin America.

Petrobras Energía developed its other energy businesses primarily through the acquisition of interests in state-owned companies that were privatized by the Argentine government between 1990 and 1994. Petrobras Energía acquired interests in companies operating in refining and petrochemicals, hydrocarbon transportation and distribution and power generation, transmission and distribution. These companies have formed the core of Petrobras Energía s energy businesses.

In addition to the energy sector, Petrobras Energía has in the past conducted operations in other industries, including construction, telecommunications and mining. Petrobras Energía entered the construction business in the 1970s when it acquired Sade S.A. Petrobras Energía entered the telecommunications business when it acquired an interest in Nortel Inversora S.A., the controlling shareholder of Telecom Argentina, an Argentine telephone services provider, in the early 1990s when the Argentine government privatized the telecommunications industry. These businesses were sold by Petrobras Energía during the late 1990s as part of Petrobras Energía s strategy to focus its operations on the energy sector. As a result of these divestitures and the development of Petrobras Energía s energy businesses over the last decade, Petrobras Energía has become a vertically integrated energy company.

Capital Expenditures and Divestitures

For a description of our most significant divestitures see Item 5. Operating and Financial Review and Prospects Factors Affecting Our Consolidated Results of Operations and Business Overview Divestments of non-core assets. For a description of our capital expenditures see Item 5. Operating and Financial Review and Prospects Liquidity and Capital Resources.

BUSINESS OVERVIEW

Our Strategy

Our long-term strategy is to grow as an integrated energy company with a leading presence in Latin America as part of the Petrobras group, while focusing on profitability as well as social responsibility.

We will continue to integrate our business in order to take full advantage of our significant hydrocarbon reserves.

We consider the following objectives essential in our efforts to meet these goals:

- a disciplined use of capital, with a view to optimizing our debt to capital ratio. Our level of investment will be guided primarily by funds generated internally, with priority given to projects with better potential of generating profits on an accelerated basis and financial solvency as the starting point for our growth strategy;
- a commitment to protect the quality of our goods and services, the environment and the health and safety of our employees, contractors and neighboring communities;

the adoption of corporate governance practices in line with international best practices;

a style of management that favors communication and teamwork, fostered by the value of the people that work in our organization; and

Table of Contents

the development of new business opportunities, by maximizing potential synergies and capitalizing on complementary business opportunities with Petrobras.

We currently manage our activities, with the support of the corporate staff, in five business segments: Oil and Gas Exploration and Production, Hydrocarbon Marketing and Transportation, Refining, Petrochemicals, and Electricity.

OIL AND GAS EXPLORATION AND PRODUCTION

Overview

The core of our operations is the oil and gas exploration and production business segment. In line with our profitability and cash generation goals, this business segment s strategy is based on the following: (1) sustained growth of operations by capitalizing on our experience and presence in almost all Latin American oil producing countries, (2) aggressive field exploration as a significant vehicle for growth, (3) monetization of our oil and gas reserves, (4) low lifting costs, and (5) investment portfolio optimization.

We currently conduct oil and gas exploration and production operations in Argentina, Venezuela, Peru, Bolivia and Ecuador.

As of December 31, 2003, our combined crude oil and natural gas proved reserves, including our shares of the reserves of our unconsolidated investees, were estimated at 758.1 million barrels of oil equivalent, approximately 53% of which were proved developed reserves and approximately 47% of which were proved undeveloped reserves. Crude oil accounted for approximately 75.1% of our combined proved reserves, while natural gas accounted for about 24.9%. As of December 31, 2003, 40.1% of our total combined proved reserves were located in Argentina and 59.9% were located abroad. Over the last few years, total reserves located abroad have become an increasing component of our assets portfolio, consistent with our strategy aimed at growing as an integrated energy company throughout Latin America. Pursuant to this strategy, between 2001 and 2003, total investments outside of Argentina accounted for 65% of our total investments.

For the year ended December 31, 2003, our combined crude oil and natural gas production, including our share of the production of our unconsolidated investees, averaged 158.6 thousand barrels of oil equivalent per day (114.6 thousand oil barrels and 264 million cubic feet of natural gas per day). Approximately 49.6% of our oil production and 23.4% of our gas production were outside of Argentina. In particular, in 2003, Venezuelan production became a main component of our total production, accounting for 27.3% of our total average production in barrels of oil equivalent.

Deliveries of oil equivalent, including those relating to unconsolidated investees, totaled 161.3 thousand barrels of oil equivalent per day.

As of December 2003, we had total proved reserves equal to 13.1 years of production at 2003 oil and gas production levels.

Our integrated business vision places our refining, petrochemicals and electricity businesses as primary links in our business value chain, through which the potential of our significant hydrocarbon reserves may be maximized. Integration with our refining business segment enables us to process a large part of our crude oil production in Argentina. The Genelba Power Plant allows us to use approximately 2.8 millions cubic meters of natural gas per day of our own reserves. In addition, we supply gas to our petrochemical operations in Argentina.

Investments

Significant investments made by us in the past have laid a foundation for the expansion and growth of our oil and gas exploration and production segment. During 1999-2001, investments totaled P$3,165 million.

The 2002 fiscal year marked a change in our investment history. The magnitude and complexity of the crisis that broke out in Argentina late in 2001 and the limited opportunities to access the capital markets forced us to reformulate our growth strategy. Given this new environment, we developed a new strategy that prioritizes cash generation and the maintenance of adequate liquidity levels. This has resulted in more restrictive expense and investment policies. As a result, capital expenditures in 2002 totaled only P$596 million, a relatively low amount compared to our historical average investment levels.

The reduced pace of investments influenced our growth objectives in the short term, mainly affecting our future production volumes of oil and gas. In addition, reduced investments delayed the development of new exploitation areas and related production.

In 2003, as the Argentine economy began to improve, our operating cash flow recovered and our liquidity approached our target levels, which allowed our investment levels to partially recover. In 2003, capital expenditures totaled P$696 million, accounting for a 17% increase compared to 2002. Capital expenditures in 2003 focused on maintaining production and increasing cash flow generation, while prioritizing investments in countries and in products with higher profit margins.

Our Oil and Gas Exploration and Production Interests

We generally participate in exploration and production activities in conjunction with joint venture partners, as is commonplace in the oil and gas exploration and production business. Contractual arrangements among participants in a joint venture are usually governed by an operating agreement, which provides that costs, entitlements to production, and liabilities are to be shared according to each party s percentage interest in the joint venture. One party to the joint venture is usually appointed as operator and is responsible for conducting the operations under the overall supervision and control of an operating committee that consists of representatives of each party to the joint venture. While operating agreements generally provide for liabilities to be borne by the participants according to their respective percentage interest, licenses issued by the relevant governmental authority generally provide that participants in joint ventures are jointly and severally liable for their obligations to that governmental authority pursuant to the applicable license. In addition to their interest in field production, contractual operators are generally paid their production costs on a monthly basis by their partners in proportion to their participation in the relevant field. Our joint venture partners are oil companies that are active in Argentina and subsidiaries of overseas oil companies.

As of December 31, 2003, we had interests in 24 oil fields, 17 of which are oil and gas producing fields and seven of which are located in exploration areas, four in Argentina and three outside of Argentina. We are, directly or indirectly, the contractual operator of 21 of the 24 fields in which we have an interest.

As of December 31, 2003, our total gross and net productive wells were as follows:

	Oil	Gas	Total
Gross productive wells	4,373	227	4,600
Net productive wells	3,609	200	3,809

Table of Contents

As of December 31, 2003, our total producing and exploration acreage, both gross and net, is shown in the following table:

	Average (thousands of acres)			
	Producing(1)		Exploration(1)	
	Gross	Net(2)	Gross	Net(2)
Argentina	4,027	3,211	911	887
Peru	116	116		
Venezuela	585	379	363	181
Ecuador	281	197	494	494
Bolivia	56	56		
Total	5,065	3,959	1,768	1,562

(1) Producing acreage includes all areas in which we produce commercial quantities of oil and gas. Exploration acreage includes all areas in which we are allowed to perform exploration activities but where commercial quantities of oil and gas are not produced.

(2) Net interests represent our fractional ownership working interest in the gross acreage.

Production

Argentine Production

Argentina is currently the fourth largest oil producer in Latin America after Mexico, Venezuela and Brazil. In 2003, Argentina s daily production was approximately 720 thousand barrels, accounting for approximately 8.1% of the region s total production. Production from Mexico, Venezuela and Brazil accounts for about 37.7%, 22.6% and 17.2%, respectively, of total oil production in Latin America.

According to statistical data for 2002, Argentina has the second largest amount of natural gas proved reserves in Latin America. Reserve volumes in Argentina coupled with its highly developed gas infrastructure, both for the domestic and export markets, has enabled the country to position itself as an energy leader in the region. Considering its significant gas reserves, as well as the tremendous growth in electric power generation supplied by natural gas in the southern part of South America, Argentina is expected to consolidate its position as a large gas exporter to Chile, Brazil and Uruguay.

Since the privatization of natural gas utilities in 1992, the natural gas industry in Argentina has grown significantly as a result of a number of factors, including: (i) an increase in gas availability, (ii) increased and improved transportation and distribution, (iii) environmental efficiency, (iv) low prices as compared to international levels and (v) alternative fuels in the domestic market. As a result of natural gas s competitiveness, demand for gas significantly increased from 17,800 million cubic meters in 1990 to 43,466 million cubic meters in 2003, and natural gas became the preferred fuel for both residential and industrial users as well as electricity generation companies.

In response to this increased demand for natural gas, we made significant investments in each step of the natural gas chain during the last decade. Transportation and distribution licensees, in turn, also made sizable investments. As a result, our gas transportation capacity doubled from 67 million cubic meters per day to 115 million cubic meters per day and distribution networks increased in size by 53%. These investments allowed for exports to bordering countries and led to a suspension of imports. The higher gas availability resulting from the expansion of gas pipelines and distribution networks caused the tripling of the number of compressed natural gas, or CNG, stations. CNG is the least expensive and least polluting motor fuel. As a result, Argentina currently has the largest CNG-fueled vehicle fleet in the world.

Notwithstanding this segment s potential, the Public Emergency Law has significantly changed the applicable regulatory framework and has adversely affected the economic attractiveness of the gas business. Following enactment of this law, there has been an abrupt reduction of investment in exploration activities in Argentina. This reduction, combined with the increase in demand, has significantly reduced Argentina s horizon of reserves, which decreased from approximately 25 years of production in the beginning of the 1990s to a 14-year reserve by the end of 2002. Without a clear path to price recovery, there may be structural uncertainties as to the future potential of the gas industry and the consequent integral use of reserves.

In the fiscal year ended December 31, 2003, our oil and gas production accounted for 4.6% and 3.9% of total oil and gas production in Argentina, respectively. As of December 31, 2003, we had interests in ten Argentine oil and gas production fields, with production rights in 3,211 thousand net acres.

Our production is concentrated in two basins, the Neuquén and the Austral basins. This positioning helps to optimize our operating efficiency and capitalize on the operating synergies of our own assets. The Neuquén basin is the most important area in Argentina in terms of oil and gas production. We own 579 thousand net acres under production concessions. Our most important fields in the Neuquén basin are 25 de Mayo-Medanito S.E., Puesto Hernández and Río Neuquén. In the Austral basin we own 2,632 thousand net acres under production concessions, with Santa Cruz I and Santa Cruz II being our most important fields in that basin.

In line with our current strategy, we have implemented the following initiatives during the last three years:

In February 2001, we completed an asset swap with Repsol-YPF S.A. having an economic impact as from January 1, 2001, whereby: (i) we added a 30% and 62.2% interest in Santa Cruz I and Santa Cruz II areas, respectively, and (ii) assigned our 50% interest in Manantiales Behr and Restinga Alí joint ventures and our 40.5% equity interest in Andina Corporation, a company controlling 50% of Empresa Petrolera Andina S.A. of Bolivia. This transaction enabled us to monetize our oil and gas reserves and optimize our assets portfolio, strengthening our position in the Austral basin by divesting non-core assets located in Bolivia and in the San Jorge basin in Argentina.

In October 2001, we sold our exploitation rights in the Pampa del Castillo-La Guitarra area and our 13.79% equity interest in Terminales Marítimas Patagónicas. As a strategic milestone, this transaction represented the end of our oil operations at the Golfo San Jorge basin.

In June 2003, we sold our 50% equity interest in the Faro Vírgenes concession area to Geodyne Energy Inc. s Argentine branch. The Faro Vírgenes area was a low production asset with little potential and high operating costs.

In August 2003, we sold our 85% interest in the Catriel Oeste area to Central International Corporation s Argentine branch. The Catriel Oeste was a low production asset with little potential and high operating costs.

Rights to develop oil and gas fields in Argentina are granted through concessions and exploration permits. Concessions are generally granted for periods of 25 years and are typically renewable for a maximum term of ten years, and permits are generally granted for initial periods of three years. The concessions for all production areas in Argentina typically provide for the free availability of oil. All permanent fixtures, materials and equipment are under the control of the concessionaire, although they revert to the Argentine government at the end of the concession. Royalties are paid to the respective Argentine provinces for the production of crude oil and the volumes of natural gas produced for sale. These royalties are 12% of the wellhead price for oil and gas. The wellhead price used to determine the royalty cost is similar to the final sales price less treatment, storage and transportation costs.

Production outside of Argentina

As a result of the substantial investments we have made in the rest of Latin America in recent years, as of December 31, 2003, 59.9% of our combined proved reserves were located outside of Argentina. In addition, approximately 49.6% of our oil production and 23.4% of our gas production came from outside Argentina in 2003. We have interest in seven oil and gas production fields outside of Argentina: Oritupano-Leona, Acema, La

Concepción and Mata in Venezuela, Lote X in Peru, Block 18 in Ecuador and Colpa Caranda in Bolivia.

Table of Contents

Venezuela

Venezuela is an important country in the international oil market. With proven reserves of approximately 77.8 billion barrels of crude oil in 2003, Venezuela possesses the largest proven reserves in the Western Hemisphere and has 7% of the total reserves on earth. Its commercial production is concentrated in the basins of Zulia and Barinas-Apure in the western part of the country and in the basins of the Estados Monagas and Anzoátegui in the eastern part of the country. Venezuela also has billions of barrels of heavy duty crude and bitumenes, the great majority of which is situated in the Faja Petrolífera of Orinoco.

In 2002, Venezuela produced approximately 2.6 million barrels of crude oil a day, of which close to 407,000 barrels were consumed in the local market and the rest were exported. It is worth noting that production levels were affected by a general strike that took place in the beginning of December of 2002 and lasted until February of 2003. See Item 3. Key Information Risk Factors Factors Related to Venezuela.

Production from Venezuela has become an important part of our total production, accounting for 27.3% of the total average production in barrels of oil equivalent in 2003.

In Venezuela, our rights are held under operating service contracts.

In 1994, during the second round of operating agreements, we were awarded the first service contract by PDVSA at the Oritupano-Leona field to provide production services for a 20-year period, which may be extended for an additional ten-year period. Oritupano-Leona is a 215 thousand net acre block located in the Oriental basin that includes 263 producing wells.

The Oritupano Leona joint venture s sole customer for the sale of oil production is PDVSA. Per our operating service agreement, PDVSA is the sole owner of the facilities, assets and/or operating equipment used by the joint venture to conduct the activities provided for in this agreement. For the provision of production services, we receive a variable fee based on production volumes plus an additional fee for reimbursement of capital expenditures, on a quarterly basis during the first ten-year term of the agreement. Expenses related to investments made thereafter will be recovered over the rest of the term. Any of these unpaid expenses will bear interest of up to 1% over the London Interbank Offered Rate, or LIBOR, annual rate. The contract has a cap (maximum total fee) on the amount which we can collect, which is reset quarterly based on the market price of oil. As of December 2003, this cap was approximately U.S.$28.72 per barrel.

In 1997, PDVSA awarded us three 20-year service contracts for the exploration and production of Acema, La Concepción and Mata blocks in the so-called Third Round bids. The bids were initially made through joint ventures. Currently, we have a 90% interest in the La Concepción block and a 86.23% interest in the Acema and Mata oil blocks, which, together with the La Concepción, block we refer to as the Third Round Blocks. La Concepción is a 55 thousand net acre block located in the Maracaibo basin, with 92 producing wells. Acema and Mata, located in the Oriental basin, are 64 thousand and 45 thousand acre blocks with 22 and 53 producing wells, respectively. According to the concession contracts, PDVSA will be the sole owner of the facilities, assets, and operating equipment. We receive a fee for each barrel delivered which has a fixed component related to contractual baseline production and a variable component related to the incremental production that covers investments and production costs, plus a gross profit up to a maximum that is tied to a basket of international oil prices.

Effective January 2002, the Venezuelan government adopted a new law whereby royalty payments increased from 16.67% to 30%. This law had a significant adverse impact on the operating results of our Third Round Blocks. We are taking every necessary step to partially reverse this increase, since under a new hydrocarbons law the federal executive may reduce such royalties by up to 20%.

The government of Venezuela may set a limit on our oil production under the terms of the service agreements. Venezuela is a member of OPEC and has set forth a policy of strict compliance with the production quotas decided within OPEC. According to the Venezuelan Hydrocarbon Law, any decisions made by the federal administration in connection with agreements or international treaties involving hydrocarbons are applicable to any party that carries out the activities governed by the law. As a result of this, if there are production cuts approved by OPEC, these cuts affect private producers as well as PDVSA. See Regulation of Our Businesses The

26

Venezuela Petroleum and Gas Industry and Regulatory Framework.   Production cuts were only contemplated by the third round operating agreements, which we refer to as the Third Round Agreements, but not by the second round operating agreements, which we refer to as the Second Round Agreements, which apply to the Oritupano-Leona field. Although no production cuts have been ordered under the Second Round Agreements to date, it is not completely clear whether the constitutional principle that prohibits retroactive application of the law will protect Second Round Agreements against future production cuts.

Peru

In 1996, we acquired 30-year oil and 40-year natural gas production rights in Lote X, a 116 thousand acre block in Peru s Talara basin, through a public bidding process. The purchase included all of the then existing assets on the site. The concession agreement provides for the free availability of hydrocarbons. As of December 31, 2003, Lote X had 2,366 productive wells. We have entered into a long-term sales contract under which Perupetro S.A., the Peruvian state-owned company which we refer to as Perupetro, is obligated to purchase all of our production at market prices. Hydrocarbon sales are subject to royalty payments of 24% of the sales price. The sales contract is set to expire in July 2006.

In June 2003, the Peruvian government approved the National Law for the Promotion of Investment in the Exploitation of Resources and Marginal Reserves of Hydrocarbons (*Ley para la Promoción de la Inversión en la Explotación de Recursos y Reservas Marginales de Hidrocarburos a Nivel Nacional*) through which Perupetro is authorized to reduce the level of royalty payments. This reduction would be contingent on the concessionairés agreeing to minimum production levels and work programs. Under this scheme, we entered into an agreement with Perupetro, modifying the original terms of our concession, in which we promised to invest U.S.$65 million during the first five years and U.S.$33 million in the following two years, in exchange for a reduction in royalty payments, which, under current conditions, we estimate would decline to 16.5%. This agreement becomes valid simultaneously with the promulgation of the Supreme Decree (*Decreto Supremo*) approving the modification of our concession.

Peru production accounted for 8.1% of our total average production in barrels of oil equivalent in 2003.

Bolivia

Petrobras Energía has a 100% interest in the oil and gas fields of Colpa Caranda and has operated them since 1989. Colpa Caranda is a 56 thousand net acre block located in the Sub Andina Central basin that has 55 producing wells. Approximately 88.6% of our proved developed reserves in Bolivia are gas. These fields, which originally supplied Bolivian gas exports to Argentina, currently have priority in the dispatch of gas to the Santa Cruz-São Paulo pipeline that transports gas to Brazil. Bolivia production accounted for 3.8% of our total average production in barrels of oil equivalent in 2003.

Ecuador

In 2001, we acquired a 70% interest in Block 18, located in the Oriente basin of Ecuador. Block 18 is a field covering 197 thousand acres and having a significant potential of 28º to 33° API light crude oil reserves. The concession for production activities in Block 18 will be for an initial 20-year term as from October 2002. Once this term expires, the Ecuadorian hydrocarbons law provides for the possibility of an additional five-year extension period.

In October 2002, the Hydrocarbons National Directorate approved the development plan for the Pata field in Block 18, thereby initiating its production phase until October 2022. The Government has the right to take 35% of production, in kind. Exploratory activities will continue for an additional three-year period ending October 2005.

In August 2002, Petroecuador, the Ecuadorian state-owned oil company, subscribed to a joint exploitation agreement for the Palo Azul field in Block 18. In December of 2002, the Palo Azul development plan was approved and has been extended until December 2022. The general terms of the agreement include differential production sharing percentages according to a formula that takes into account the final selling price of Palo Azul s crude oil and the level of total proved reserves. Specifically, if Palo Azul s crude oil sells at a price less than U.S.$15 per barrel, the State s share of crude oil equals 30%. If crude oil sells at a price greater or equal to U.S.$24 per barrel, the

Table of Contents

State s share of crude oil equals about 50%. For all other price ranges, a scale was agreed with Petroecuador. Palo Azul s selling price is computed by considering the WTI crude oil benchmark minus the market discount for the Oriente crude oil. The agreement provides for the free availability of crude oil.

Block 18 has eight productive wells, two of which are located at the Pata field and six of which are located at the Palo Azul field. In addition, the area has early production facilities which can handle a daily gross production of 20 thousand barrels.

Mexico

In 2003, as part of the bidding launched by Petróleos Mexicanos, or PEMEX, for the operation of areas under multiple service contracts, contracts for the Cuervito and Fronterizo blocks were awarded to a joint venture composed of Petrobras, Teikoku and Diavaz. Under an operating agreement, we will act as contractor and provide the joint venture with the technical and operating support required for the operation of the Cuervito and Fronterizo blocks.

Table of Contents

Statistical Information Relating to Oil and Gas Production

The following table sets forth our oil and gas fields production as of December 31, 2003. In addition, the table includes our percentage interest in the oil and gas production of each field, the number of producing wells and the expiration date of the concessions. Although some of these concessions may be extended at their expiration, the expiration dates set forth below do not include any such extensions.

Production Areas	Location	Basin	2003 Production		Oil and Gas Wells	Interest	Expiration
			Oil[(1)]	Gas[(2)]			
Argentina							
25 de Mayo Medanito S.E.	La Pampa and Rìo Negro	Neuquén	4,982	1,314	461	100.00%	2016
Catriel Oeste[(3)]	Rìo Negro	Neuquén	258	240		85.00%	2016
Jagüel de los Machos	Rìo Negro and La Pampa	Neuquén	1,296	3,630	73	100.00%	2015
Faro Vírgenes U.T.E.[(4)]	Santa Cruz	Austral		127		50.00%	2016
Puesto Hernández	Mendoza and Neuquén	Neuquén	5,661		580	38.45%	2016
Bajada del Palo La Amarga Chica	Neuquén	Neuquén	101		4	80.00%	2015
Santa Cruz II	Santa Cruz	Austral	4,705	24,307	76	100.00%	2017
Río Neuquén	Neuquén and Rìo Negro	Neuquén	843	12,060	134	100.00%	2019
Entre Lomas	Neuquén and Rìo Negro	Neuquén	711	1,282	327	17.90%	2016
Veta Escondida and Rincón de Aranda U.T.E.	Neuquén	Neuquén				55.00%	2016
Aguada de la Arena	Neuquén	Neuquén	75	5,626	9	80.00%	2022
Santa Cruz I U.T.E.	Santa Cruz	Austral	2,466	25,243	77	71.00%	2016
Outside of Argentina							
Colpa Caranda	Bolivia		491	13,095	55	100.00%	2029
Oritupano Leona	Venezuela	Oriental Maturin	8,221		263	55.00%	2014
Acema	Venezuela	Oriental Maturin	943		22	86.23%	2017
La Concepción	Venezuela	Lago Maracaibo	3,994	6,848	92	90.00%	2017
Mata	Venezuela	Oriental Maturìn	1,510		53	86.23%	2017
Lote X	Peru	Talara	4,239	2,570	2,366	100.00%	2024

Block 18	Ecuador	Oriente	1,344		8	70.00%	2022
Total			41,840	96,342	4,600		

(1) in millions of barrels

(2) in billions of cubic feet

(3) In August of 2003, we sold our 85% interest in Catriel Oeste concession area to Central International Corporation, Argentine Branch.

(4) On June 26, 2003, we sold our 50% interest in Faro Vírgenes concession area to Geodyne Energy Inc. s Argentine Branch.

In 2003, our annual production from producing oil fields, including our oil fields in Bolivia, Venezuela, Peru and Ecuador, was 41.8 million barrels of oil, 21.1 million of which were produced in Argentina. Our annual production of gas amounted to 96.3 million cubic feet, 73.8 million cubic feet of which were produced in Argentina.

Table of Contents

The following table sets forth our average daily production of oil, including other liquid hydrocarbons, for the three fiscal years ended December 31, 2003, 2002 and 2001. This table includes our proportionate share of the production of both our consolidated subsidiaries and our unconsolidated investees.

	Year ended December 31,		
	2003	2002	2001
	(average barrels per day)		
Argentina	57,803	56,746	67,671
Outside of Argentina	56,827	58,917	60,484
Total	114,630	115,663	128,155

The following table sets forth our average daily gas production for the three fiscal years ended December 31, 2003, 2002 and 2001. This table includes our proportionate share of the production of both our consolidated subsidiaries and our unconsolidated investees.

	Year ended December 31,		
	2003	2002	2001
	(average Mcf per day)		
Argentina	202,272	252,559	273,414
Outside of Argentina	61,679	61,238	65,912
Total	263,951	313,797	339,326

The following table sets forth the average sales price per barrel of oil and per thousand cubic feet of gas for each geographic area for the three fiscal years ended December 31, 2003, 2002 and 2001, of our consolidated subsidiaries.

	Year ended December 31,		
	2003	2002	2001
Argentina			
Oil (in pesos per BOE)	69.80	65.88	40.56
Gas (in pesos per 1,000 cubic feet)	1.76	1.97	2.40
Outside of Argentina			

Oil (in pesos per BOE)	52.70	50.70	30.84
Gas (in pesos per 1,000 cubic feet)	4.37	4.52	3.34

30

Table of Contents

The following table sets forth our average lifting cost, royalties and depreciation cost of oil and gas fields in each geographic area for the three fiscal years ended December 31, 2003, 2002 and 2001. This table includes our proportionate share of the production of our consolidated subsidiaries.

	Year ended December 31,		
	2003	2002	2001
	(in pesos per BOE)		
Argentina			
Lifting Cost	6.45	5.77	5.98
Royalties	5.37	5.28	3.94
Depreciation	10.02	9.61	8.09
Total	21.84	20.66	18.01
Outside of Argentina			
Lifting Cost	9.42	10.41	5.87
Royalties	5.52	5.45	3.38
Depreciation	12.78	15.41	6.92
Total	27.72	31.27	16.17

The following table sets forth the average reserve replacement cost and the finding and development costs of oil and gas from all fields for the three fiscal years ended December 31, 2003, 2002 and 2001. This table includes our proportionate share of the production of both our consolidated subsidiaries and our unconsolidated investees.

	Year ended December 31,		
	2003	2002	2001
	(in pesos per BOE)		
Reserve replacement cost	41.85	(1)	26.80
Finding and development costs	13.51	10.63	14.99

(1) In 2002, there was no net increase in reserves.

Exploration

Overview

We believe that an increase in exploration is essential to maintain and grow our reserve base. Exploration is a key activity to sustain a high reserve replacement ratio.

We use 3-D seismic technology to ensure a technologically sound prospect portfolio and a high success rate. The integration of well and 3-D seismic data into subsurface models is critical for exploration drilling, field delineation and optimization of the appraisal of well locations.

Table of Contents

The following table lists our oil and gas fields in exploration areas as of December 31, 2003, the location of the basin in each area, our ownership interest and the expiration date of the exploration permits for each field.

	Location	Basin	Interest	Expiration
Argentina				
Glencross	Santa Cruz	Austral	96.68%	1999(1)
Estancia El Chiripá	Santa Cruz	Austral	100.00%	2006(1)
Santa Cruz I Oeste	Santa Cruz	Austral	50.00%	2006(1)
CAM-2A Norte	Santa Cruz	Austral	50.00%	2004
Outside of Argentina				
San Carlos	Venezuela	Guarico	50.00%	2005
Tinaco	Venezuela	Guarico	50.00%	2005
Block 31	Ecuador	Oriente	100.00%	2024

(1) We have requested that the lot be declared operational and are awaiting a response from the relevant authorities.

Exploration in Argentina

As of December 31, 2003, we hold interest in 911 thousand gross acres (887 thousand net acres) of basin area in Argentina available for exploration. Under exploration licenses we hold interests in Glencross, Santa Cruz I Oeste and CAM-2A exploratory areas. We may continue to acquire acreage positions in the future as the Argentine government offers additional exploration permits through license bidding rounds.

We compete with other oil and gas producers in Argentina for the acquisition of new properties.

The following table sets forth the number of wells we drilled in Argentina, and the results thereof, for the periods indicated. A well is considered productive for purposes of the following table if it justifies the installation of permanent equipment for the production of oil and gas. A well is deemed to be a dry hole if it is determined to be incapable of commercial production. Gross wells drilled in the tables below refers to the number of wells completed during each fiscal year, regardless of the spud date, and net wells drilled relates to the fractional ownership working interest in wells drilled. This table includes wells drilled by both our consolidated subsidiaries and unconsolidated investees.

	Year ended December 31,		
	2003	**2002**	**2001**
Gross wells drilled			
Exploratory			
Productive wells			
Oil			
Gas			

Dry		1	1
Total		1	1
Development			
Productive wells			
Oil	169	109	137
Gas	8	7	20
Dry	8	4	3
Total	185	120	160

	Year ended December 31,		
	2003	2002	2001
Net wells drilled			
Exploratory			
Productive wells			
Oil			
Gas			
Dry		1	1
Total		1	1
Development			
Productive wells			
Oil	105.2	78.7	110.6
Gas	6.6	5.8	14.6
Dry	6.2	2.8	3.0
Total	118.0	87.3	128.2

During 2002, we farmed out a 50% interest in Santa Cruz I exploratory block. The buyer committed to make all the investments necessary to acquire and process 500 km2 of 3-D seismic lines and to drill five wells. However, we remain responsible for conducting operations in this block.

Exploration Outside of Argentina

As of December 31, 2003, we hold interests in 857 thousand gross acres (675 thousand net acres) outside of Argentina available for exploration. We hold interests in three oil and gas exploration fields outside of Argentina: San Carlos and Tinaco in Venezuela and Block 31 in Ecuador. We continue to seek new business opportunities in Peru, Bolivia, Ecuador and Venezuela.

Table of Contents

The following table sets forth our drilling activities outside of Argentina for the three years ended December 31, 2003, 2002 and 2001. A well is considered productive for purposes of the following table if it justifies the installation of permanent equipment for the production of oil and gas. A well is considered to be a dry hole if it is determined to be incapable of commercial production. This table includes both our consolidated subsidiaries and unconsolidated investees.

	Year ended December 31,		
	2003	**2002**	**2001**
Gross wells drilled			
Exploratory			
Productive wells			
Oil	2		
Gas			
Dry	1	2	
Total	3	2	
Development			
Productive wells			
Oil	20	2	35
Gas	1		3
Dry			1
Total	21	2	39
Net wells drilled			
Exploratory			
Productive wells			
Oil	1.4		
Gas			
Dry	1.0	1.1	
Total	2.4	1.1	
Development			
Productive wells			
Oil	17.7	1.1	19.5
Gas	0.6		3.0
Dry			1.0
Total	18.3	1.1	23.5

Venezuela

We began exploration activities in the San Carlos region of western Venezuela under a contract entered into with PDVSA through its subsidiary, Corporación Venezolana de Petróleo S.A., in July 1996. The block is located in the areas of Cojedes and Portuguesa and extends across 125 thousand acres. We are required to pay all exploration costs in the block. The exploration activities in this block started late in 1996 and the work commitments for the first stage of the exploration process were fulfilled with the acquisition of 2-D seismic data and the drilling of 2 exploratory wells. Total expenditures required for initial exploration in the block were U.S.$32 million. Our exploration activities in this block yielded gas findings.

In June 2001, upon the opening of free gas exploration areas, we were awarded a license for the exploration and production of gas in the Tinaco area, a field adjacent to the San Carlos field, with an area of 238 thousand acres. This event is an important step in the development of the San Carlos block, since it would enable us to confirm related natural gas reserves. The contractual work commitments included the acquisition of 200 km of 2-D seismic data.

During 2003, the conditions prevailing in the political, economic and social arena in Venezuela prevented the performance of the 2-D seismic works in the Tinaco area. These works will be completed throughout the first half of 2004. Depending on the seismic results obtained, an exploratory well may be drilled in 2005.

If gas reserves are commercialized in the future, we will be required to pay 23.21% in royalties.

In connection with the joint future gas production of both blocks, we negotiated the conversion of the San Carlos contract into a contract with similar conditions as those appearing in the Tinaco contract.

In October 2002, we subscribed to an association agreement, which we refer to as the Transfer of Interest Agreements, with Teikoku Oil Co. Ltd., or Teikoku, whereby we transferred 50% of our rights and obligations in and to gas production in San Carlos and Tinaco exploratory areas.

The Transfer of Interest Agreement, which is subject to approval by the Venezuelan Ministry of Energy and Mines, provides for an initial cash payment of U.S.$1 million and a subsequent payment of U.S.$2 million for the financing of the exploratory investment program in the Tinaco area in relation to geological studies, 2-D seismic shooting and 2-D seismic evaluation and interpretation. Furthermore, in the event a joint commercial development in this area is agreed upon, we will receive a supplementary payment in the amount of U.S.$3 million.

Ecuador

In Ecuador, we hold a 100% interest in Block 31. In 1996, Petroecuador called the Eighth Round of International Bids for the performance of exploration and production activities in the Amazon Region, and we were awarded Block 31. This block is located in a highly sensitive ecological area of the Amazon jungle in the central part of the eastern border of the upper Amazon basin and covers an area of 494 thousand net acres.

For the full development of the block, we estimate that approximately U.S.$800 million in investments will be required. Initial investments in the amount of approximately U.S.$150 million are necessary prior to the production phase. Changes in our investment scenario following the Argentine crisis have resulted in significant delays to our original investment plan for the area s development.

Under the concession contract, the exploration program is divided into two phases, with the first phase having expired in July 2001 and the second in June 2003. To fulfill the committed work program, 1,200 km of 2-D seismic lines were acquired and three exploratory wells were drilled.

We have conducted the following works in Block 31: 1,382 km of 2-D seismic, 167 km ^{2} of 3-D seismic, and the drilling of four exploratory wells in Apaika, Nenke, Obe and Minta. All the wells were successful and led to the discovery of the Apaika/Nenke, Obe, and Minta fields. Interpretation of 600 km of 2-D seismic acquired in the eastern and northeastern areas of the block was also performed. The 3-D seismic cube (167 km2) was reprocessed to ensure better adjustment to 2-D seismic. In March 2004, the Minister of Energy of Ecuador approved an environmental impact study, completing all of the required steps for the approval of the development plan. Following approval of the environmental study, a twenty-year exploitation period has begun, during which, in the initial three-year period, the plan contemplates investments of U.S.$75 million. We are obligated to give Petroecuador a guaranty of 20% of this amount.

According to the block s production sharing agreement, Petroecuador is entitled to a crude oil production take of about 15% to 17%, depending on the field s daily crude oil production and crude oil gravity. The Block 31 concession provides for the free availability of crude oil.

Future oil production in Block 31 will be shipped through a heavy crude oil pipeline known as Oleoducto de Crudo Pesados in which we currently have an 11.42% interest. We have entered into a 15-year ship or pay transportation contract under which OCP has committed to provide us with a shipping capacity of 80,000 barrels per day. OCP started commercial operations on November 10, 2003 and since that date, we have had to comply with our contractual obligations with respect to our committed acquired capacity by paying a transportation capacity fee. We currently estimate that during the contract s term, oil production will be lower than our committed transportation capacity. Accordingly, as of December 31, 2003, we have recorded an impairment allowance of P$321 to adjust the book value of our group of assets in Ecuador to its recoverable value. See Item 3. Key Information Risk Factors Factor Relating to Us Production of oil in Block 31 in

Table of Contents

Ecuador is significantly delayed, and this delay has and will continue to affect our results. Further delays could result in an increase in our operating losses related to our group of assets in Ecuador.

As a way of maximizing the value of this asset and enhancing its potential, we are considering a number of alternatives, including the addition of a new partner who could speed up the development of the block or a potential sale of all or a portion of our interest in Block 31. A transaction involving a sale of all or part of our interest in Block 31 may likely involve a sale or other disposition of all or a portion of our interests in Block 18 and in OCP.

Peru

In 1998, Petrobras Energía entered into exploration agreements for Lote XVI, in which it has a 100% interest. Exploratory investments were first made in this block in 1999, with the shooting of 50 km2 of 3-D seismic lines. During 2002, interpretation of the block geology was concluded and a location was selected for the drilling of an exploration well in 2003. Due to the disappointing results of the exploration, in May 2003, we decided not to proceed to the next phase.

In the Ucayali basin, two blocks were awarded to a consortium formed by Petrobras Energía and Repsol-YPF S.A., the latter being the operator of both blocks. Seven-year exploration contracts were signed in September 1998 for Lote 34 and in November 1998 for Lote 35. We had a 40% interest in Lote 34 and a 35.15% interest in Lote 35. Both contracts provide for an initial two-year exploration phase, each with a commitment of 500 km 2-D seismic line acquisition and the reprocessing of 1,000 km of existing 2-D seismic data. The subsequent five one-year exploration periods are optional, and each period requires the drilling of an exploration well or compensatory exploratory seismic. The wildcat Mashansha 35-13-IX in the Lote 35 was drilled in 2002. The well resulted in a dry hole with sparse oil shows. In 2003, after a thorough evaluation of the well results and the impact on the additional exploration objectives, it was decided not to continue in both blocks due to the limited remaining exploration potential.

In 2001, we executed a concession contract for hydrocarbon exploration and production in Lote 99, a block located in the Ucayali basin. We hold a 100% interest in Lote 99. The concession program requires a minimum exploration program of seven years divided into five periods. Exploration during the first 18-month period included geological surveys and the reprocessing and reinterpretation of 900 km2 of seismic data. In 2003, after evaluating the exploration results, we decided not to proceed to the next stage.

In May 2004, we entered into a contract with Repsol Exploración Perú S.A. to perform certain exploration activities jointly in Lot 57. Petrobras Energía has an option to participate in Lot 57 by acquiring a 35.15% interest from Repsol, which currently holds a 76.15% interest in Lot 57. Burlington Resources Perú Ltd. is Repsol s partner in the shared risk agreement with Perupetro for the exploration and exploitation of hydrocarbons in Lot 57.

In the Lote 63 area, the survey period has concluded and an exploration contract will be negotiated with Perupetro.

Reserves

We believe our estimates of remaining proved recoverable oil and gas reserve volumes to be reasonable. These estimates have been prepared in accordance with Rule 4-10 of Regulation S-X under the U.S. Securities Act. Gaffney, Cline & Associates, Inc., an international technical and management advisory firm for the oil and gas industry, audited our oil and gas reserves as of December 31, 2003, 2002 and 2001.

The estimated reserves were subjected to economic tests to determine economic limits. These estimated reserves in Argentina, Peru and Bolivia are stated prior to the payment of any royalties, as they have the same attributes as taxes on production and, therefore, are treated as operating costs. In Ecuador, due to the type of contract in which the government has the right to a percentage of production and takes it in kind, reserves are stated after such percentage. In Venezuela, the government maintains full ownership of all hydrocarbons in such areas. Reserve volumes in Venezuela are computed by multiplying our percentage interest by the gross proved recoverable volumes for the contract area. In Venezuela, for the Acema, Mata and La Concepción areas, 30% royalties are paid, calculated based on the crude wellhead estimated price. Under contractual terms the Third Round Block s royalties are deducted from the sales price. Pursuant to operating agreements in force, we are exempt from production royalty payments in the Oritupano Leona field.

As of December 31, 2003, liquid hydrocarbon and natural gas proved reserves, audited by Gaffney, Cline & Associates, Inc., amounted to 758.1 million barrels of oil equivalent (569.1 million barrels of oil and 1,134.8 billion cubic feet of natural gas, representing a 6.7% decline compared to the reserves certified as of December 31, 2002 (a decline of 4.2% for liquid hydrocarbons and 13.6% for natural gas)).

As of December 2003, total proved reserves represented, at 2003 oil and gas production levels, a 13.1-year production.

During the 2002-2003 period, after the change in the investment scenario for our businesses following the Argentine crisis, we focused on maintaining adequate liquidity levels and cash generation, and this focus affected our reserve replacement strategy. Production of proved undeveloped reserves was prioritized relative to prior years, with a reduced emphasis on exploration and acquisition activities, which had historically been a major source of reserve replacement. This had a negative impact on the addition of reserves.

Therefore, during 2003 the reserve replacement ratio was 33%, reflecting production of 57.9 million barrels of oil equivalent which was partially offset by a net addition of 19.3 million barrels of oil equivalent, as reflected below:

Secondary recovery projects that added 26.7 million barrels of oil equivalent.

Extensions of known accumulations and discoveries that added 33 million barrels of oil equivalent reflecting good results from drilling and recovery.

Technical reviews, based on the performance of the different fields and the projects implemented during 2003, resulted in reductions of previous estimates by 40.4 million barrels of oil equivalent at fields where secondary recovery operations were performed.

In addition, in 2003, the sale of the Catriel Oeste and Faro Vírgenes areas in Argentina reduced our reserves by 15.9 million barrels of oil equivalent.

Liquid hydrocarbons and natural gas account for 75.1% and 24.9%, respectively, of total proved reserves, and 59.9% are located outside of Argentina. Proved reserves outside Argentina increased as a percentage of proved reserves. This increase reflects principally lower investments in gas projects in Argentina, which were scaled back in light of low domestic prices, with a consequent reduction in additions from recoveries, extensions and discoveries.

Table of Contents

The table below sets forth, by geographic area, total proved reserves and proved developed reserves of crude oil, condensate and natural gas liquids and natural gas reserves at the indicated dates.

	Crude oil, condensate and natural gas liquids in thousands of barrels			**Natural gas in millions of cubic feet**			
	Argentina	**Outside of Argentina**	**Total**	**Argentina**	**Outside of Argentina**	**Total**	**Combined MMBOE(1)**
Total proved reserves as of December 31, 2001	237,280	501,892	739,172	1,129,486	495,053	1,624,539	1,009.9
Proved developed reserves as of December 31, 2001	151,924	203,808	355,732	561,834	290,638	852,472	497.8
Increase (decrease) originated in:							
Revisions of previous estimates	(14,868)	(113,425)	(128,293)	(258,150)	(123,594)	(381,744)	(191.9)
Improved recovery	4,195	3,510	7,705	76,371	9,687	86,058	22.0
Extensions and discoveries	6,938	10,057	16,995	88,265	10,662	98,927	33.5
Purchase of proved reserves in place	516		516				0.5
Sale of proved reserves in place							
Year s production	(20,719)	(21,498)	(42,217)	(92,184)	(22,352)	(114,536)	(61.3)
Total proved reserves as of December 31, 2002	213,342	380,536	593,878	943,788	369,456	1,313,244	812.7
Proved developed reserves as of December 31, 2002	146,319	177,876	324,195	554,104	209,854	763,958	451.5
Increase (decrease) originated in:							
Revisions of previous estimates	(19,026)	(3,278)	(22,304)	(131,964)	23,110	(108,854)	(40.4)
Improved recovery	10,082	15,392	25,474		7,261	7,261	26.7
Extensions and discoveries	3,258	18,303	21,561	61,370	7,571	68,941	33.0
Purchase of proved reserves in place							
Sale of proved reserves in place	(7,707)		(7,707)	(49,450)		(49,450)	(15.9)
Year s production	(21,097)	(20,743)	(41,840)	(73,825)	(22,517)	(96,342)	(57.9)
Total proved reserves as of December 31, 2003	178,852	390,210	569,062	749,919	384,881	1,134,800	758.2
Proved developed reserves as of	122,085	169,925	292,010	455,465	207,144	662,609	402.4

December 31, 2003

(1) Millions of barrels of oil equivalent.

There are many uncertainties in estimating quantities of proved reserves and in projecting future rates of production and the timing of development expenditures, including certain factors that are beyond our control. The reserve data set forth in this annual report solely represents estimates of our proved oil and gas reserves. Reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of a reserve estimate stems from available data, engineering and geological interpretation and judgment of reserves and reservoir engineering. As a result, different engineers often obtain different estimates. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimate, so the reserve estimates at a specific time are often different from the quantities of oil and gas that are ultimately recovered. Furthermore, estimates of future net revenues from our proved reserves and the present value thereof are based upon assumptions about future production levels, prices and costs that may not prove to be correct over time. Forecasts of future prices, costs and production levels are subject to great uncertainty and may not prove to be correct over time. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Accordingly, we cannot assure that any specified production levels will be reached or that any cash flow arising therefrom will be produced. The actual quantity of our reserves and future net cash flows therefrom may be materially different from the estimates set forth in this annual report.

We replace our reserves through the acquisition of new producing fields, new exploration of our existing fields, the exploration of new fields, and by proving up reserves in existing fields. Proving up is the process by which additional reserves classified as probable and possible reserves in a producing field are accessed and reclassified as proved reserves. We prove up reserves with reservoir management techniques by implementing waterflood and enhanced oil recovery projects. Reservoir management techniques currently used include water injection and drilling of horizontal wells, including producing and injection wells. In addition, technologies such as 3-D seismic process, horizontal and step out wells, underbalance drilling and reservoir numerical stimulation are also used.

Transportation and Sales

In Argentina, we transport our oil and gas production in several ways depending on the infrastructure availability and the cost efficiency of the transportation system in a given location. We use the Argentine oil pipeline system and oil tankers to transport oil to customers. Oil is customarily sold through FOB contracts, and therefore, producers are responsible for transporting oil produced from the field to a port for shipping, with all costs and risks associated with transportation borne by the producer. Gas, however, is sold at the delivery point of the gas pipeline system near the field, and, therefore, the customer bears the total transportation costs and all risks associated therewith. Oil and gas transportation in Argentina operates in an open access non-discriminatory environment under which producers have equal and open access to the transportation pipelines. The privatization of the pipeline system has led to capital investments in the systems, which have increased their capacity. For the foreseeable future, our oil and gas production is not expected to require increased capacity. In addition, we maintain limited storage capacity at each oil site and at the terminals from which oil is shipped. In the past, these capacities have been sufficient to store oil without reducing current production during temporary unavailability of the pipeline systems, due, for example, to maintenance requirements or temporary emergencies.

With respect to production from Block 18 in Ecuador, oil is transported by a system which has a current transportation capacity of 17,000 barrels per day. This capacity will be increased to 40,000 barrels per day. Once the Palo Azul field has been completely developed, a 12-inch diameter and 35 km long oil pipeline will be constructed from the oil treatment plant to Lago Agrio to transport production through the OCP or the Sistema de Oleoducto Transecuatoriano in accordance with the commercial circumstances prevailing at that time.

Future oil production from Block 31 will be transported through the OCP. With respect to future oil production from Blocks 18 and 31, we have entered into an agreement with OCP to ensure an 80,000 barrels per day oil transportation capacity. See Business Overview Hydrocarbon Marketing and Transportation OCP.

During the fiscal year ended December 31, 2003, our main customers were PDVSA, Perupetro, Repsol-YPF S.A., Trading y Transporte S.A., and Glencore AG, which accounted for approximately 11%, 7%, 5% and 4%, respectively, of total consolidated oil and gas sales, calculated on an unhedged basis. Intercompany sales, mainly to the refining business segment, accounted for 34%.

We sell a significant volume of our oil production to export markets. In the current Argentine scenario, we, as well as other Argentine energy companies, have sought to optimize export opportunities with a view to capitalizing on domestic and export price asymmetries by effectively encouraging the opening and consolidation of new markets. In such respect, during the first quarter of 2003, we started exporting gas to Chile from the Austral basin.

During 2003, oil and gas exports totaled approximately P$474 million or 16% of total consolidated oil and gas sales (calculated on an unhedged basis). In 2003, exports sales were made principally to Chile.

Competition

Our oil and gas related businesses are subject to oil price fluctuations determined by international market conditions. In executing our strategy to expand our oil and gas operations both in and outside of Argentina, we face competition from oil and gas producers throughout the world.

HYDROCARBON MARKETING AND TRANSPORTATION

The hydrocarbon marketing and transportation segment serves to link our energy businesses.

In the marketing business, we provide oil, gas and LPG brokerage services to producing companies who prefer outsourcing oil, gas and LPG sales. This business enables us to position ourselves as a major commercial service provider since it assists clients not only in sales but also in logistics, foreign trade and market knowledge.

We are engaged in the hydrocarbon transportation business through our interest in TGS, Oleoductos del Valle S.A., or Oldelval, and OCP.

Gas Transportation TGS

We hold, directly or indirectly, a 35% interest in TGS. TGS is controlled by CIESA, which, together with other companies of the Petrobras Energía group and the Enron group, own 70% of TGS capital stock. CIESA, in turn, is owned on a 50/50 basis by Enron Corporation, or Enron, and us.

An ownership committee composed of an equal number of our representatives and those of Enron manages the activities of TGS and CIESA. We appoint the chairman of the board and the chief executive officer of both TGS and CIESA. TGS and Enron have entered into a technical services agreement under which TGS pays Enron an annual fee equal to the greater of (i) P$3 million or (ii) 7% of the amount obtained after subtracting P$3 million from the net income before financial income (expense) and income taxes. We share in these management fees through an agreement with Enron in which we are reimbursed for any costs associated with any service provided by TGS on behalf of Enron and a percentage of the exploitation income. In June 2004, the Federal Entity of Gas Regulation, or ENARGAS, authorized the assignment by Enron of its duties under this agreement to us. Both Enron and we have a right of first refusal on the transfer of CIESA s shares, and preferential rights to any shares issued by CIESA.

Pursuant to the regulatory framework, gas transportation and distribution rates were established under the Natural Gas Law and the Concession Contract, which provide the methodology of calculation and adjustment frequency of natural gas rates charged to end users by distribution companies. As a result of the reforms implemented under the Public Emergency Law, which, among other things, provided for the conversion into pesos of utility rates and the elimination of indexation of such rates, the gas transportation business currently operates in an uncertain environment. See Regulation of Our Businesses.

As a result of this abrupt change in rules, CIESA failed to repay corporate notes with a principal amount of U.S.$220 million and derivative instruments of approximately U.S.$2 million. In addition, TGS is seeking to restructure substantially all of its financial debt and is currently in discussions with its principal creditors. See Item 3. Key Information Risk Factors The devaluation and pesification of utility rates have resulted in payment defaults by some of our affiliates.

In April 2004, CIESA s shareholders reached a mutual settlement agreement by which Petrobras Energía and Enron agreed to release each other from all claims related to their investments in CIESA and TGS. In addition, in order to facilitate a future restructuring of CIESA s financial debt, both parties agreed to a two-stage transfer involving their equity interests in TGS and CIESA. In stage one, we will transfer our 7.35% direct interest in TGS to Enron, and, in stage two, CIESA will transfer a 4.3% interest in TGS to Enron. In exchange, Enron will place its shares of CIESA in trust, 40% in stage one and the remaining 10% in stage two. We will not hold directly or indirectly more than our current 50% shareholding in CIESA. These transfers are subject to several conditions, one of which is approval by ENARGAS. In May 2004, the bankruptcy court with jurisdiction over Enron also approved the terms of this settlement agreement. CIESA initiated discussions with its creditors regarding a possible restructuring.

As far as the regulated segment is concerned, TGS is the gas transportation licensee in the south of Argentina. TGS has an exclusive license due to expire in 2027 with an option to extend for ten additional years if certain conditions are met, and as such is the largest transporter of natural gas in Argentina and all of Latin America. TGS currently delivers approximately 60% of the country s total gas consumption through more than 7,400 km of gas pipelines with a transportation capacity of approximately 62.5 million cubic meters per day, substantially all of

Table of Contents

which is committed under firm transportation contracts. Under these firm transportation contracts, the capacity is reserved and paid for irrespective of the actual use by the customer. Almost all capacity of the gas transportation pipelines in Argentina is currently apportioned among gas distribution companies, large industrial customers and gas-fired power plants under firm long-term contracts. In 2003, TGS renewed firm transportation agreements covering approximately 12.9 million cubic meters per day. This enabled it to extend the total average life of its firm transportation contracts to approximately nine years. In addition, TGS provides interruptible transportation services under which gas transportation is dependent on the availability of capacity.

The TGS pipeline system connects major gas fields in southern and western Argentina with distributors of gas in those areas and in the city of Buenos Aires and the greater Buenos Aires area. The service area includes approximately 4.6 million end users (approximately 3.2 million of which belong to the greater Buenos Aires area), which are directly served by distribution companies. In addition, TGS provides transportation services on a direct basis to major industries located in TGS s operating area. The firm transportation capacity committed to industrial clients represents approximately 20% of TGS s total capacity.

Since the start of operations in 1992, TGS has made investments of about U.S.$1.2 billion, doubling the value of its assets. As a result of such investment 850 km of gas pipelines were laid in addition to the existing pipelines, and compression power was increased by 58.8% from 339,000 HP in 1992 to 538,220 HP in 2003. Therefore, transportation capacity increased from 42.8 million cubic meters per day to 62.5 million cubic meters per day at the end of 2003.

Gas transportation companies in Argentina operate in an open access non-discriminatory environment under which producers, distributors and certain third parties have equal and open access to the transportation pipelines and distribution system. See Regulation of Our Businesses The Argentine Gas Industry and Regulatory Framework.

As a consequence of the enactment of the Public Emergency Law, revenues from the regulated segment strongly decreased compared to TGS s total revenues. In 2003, the gas transportation segment accounted for 47% of TGS s total revenues compared to 57% in 2002 and to approximately 80% since the start of the service supply until 2001. TGS continues seeking new alternatives aimed at growing its business and mitigating the effects derived from such law. Along these lines, in 2003, TGS entered into an agreement with a consortium producing gas at the Austral basin, formed by Total Austral S.A., Panamerican Sur S.R.L. and Wintershall Energía S.A., for the purpose of providing Argentine natural gas to Methanex, a leading company in the production of methanol located in Chile.

In view of the set of measures taken by the Argentine government aiming to lessen the impact of the energy crisis emerging in 2004, TGS is currently analyzing several alternatives along with the government, with the object to implement the expansion of the San Martín gas pipeline. In furtherance of this goal, TGS launched an Open Season, which offers 2.9 MMm3/d of firm transportation capacity in service as from the middle of 2005. In connection with this additional capacity, TGS would not only render the service of transportation but the operation and maintenance of the facilities as well.

In addition to the natural gas transportation regulated service, TGS is one of the leading processors of natural gas and one of the largest marketers of natural gas liquids, or NGL, and provides other unregulated services in the gas industry, through the General Cerri Complex located near Bahía Blanca, in the Province of Buenos Aires. TGS has two gas processing plants at the General Cerri Complex: (i) an ethane, propane, butane and natural gasoline turboexpander separating plant and (ii) an absorption plant which separates propane, butane and gasoline from the gas transported through the TGS pipeline system, with a gas processing capacity of 43 million cubic meters per day and a storage capacity of 54,840 tons. From 2001 to 2002, as a result of the agreements entered into with natural gas producers in the Neuquén basin, TGS managed to restructure the business and became the owner of a portion of the Cerri Complex production. TGS was able to increase, through these agreements, the richness of the gas reaching the complex for processing, and thus minimized the impact of competitive projects.

The economic crisis during 2002 presented an opportunity for TGS, as 33% of its total NGL production is exported, enabling TGS to benefit from devaluation of the peso. In addition, local market prices increased in order to maintain parity with export prices. The combination of these factors led to an increase in TGS revenues.

Table of Contents

Revenues from unregulated services compared to TGS s total revenues increased from 37% in 2002 to 48% in 2003. This evidences the growing relative significance of this business. This improvement substantially reflects the deterioration of the regulated gas transportation business and favorable domestic market prices in line with international prices.

TGS is an important midstream service provider in Argentina offering commercial and financial structuring, turnkey construction and the operation and maintenance of surface facilities (gathering, conditioning and transportation).

Through the provision of midstream services, TGS provides integral solutions for natural gas supply from the wellhead to transportation, including conditioning, gathering and gas compression, which services are generally provided to producers at the wellhead. Such services also include those related to the construction, operation and maintenance of gas pipelines and treatment plants provided by TGS itself or through its related companies, Gas Link S.A., or LINK, and Transporte y Servicios de Gas en Uruguay S.A., or TSGU. TGS is developing a strategy geared towards becoming one of the main service providers in Argentina. During 2003, TGS completed the renegotiation with this segment s clients of the outstanding midstream services agreements that were still pesified. As a result of this renegotiation, TGS improved the profitability associated with such agreements while its clients secured a long-term supply of services.

TGS has a 49% interest in LINK, a company engaged in the construction, operation and maintenance of the gas pipeline connecting the TGS system and the Cruz del Sur gas pipeline that links Argentina to Uruguay and is likely to be extended to Brazil. This pipeline is approximately 40 km long, has a current transportation capacity of 1 million cubic meters per day and started operations in October 2002.

Under the agreement for the supply of Argentine natural gas to Methanex in Chile, TGS will install a 12,700 HP compressor plant on the General San Martín pipeline, and, through its affiliated company Emprendimientos de Gas del Sur S.A., or EGS, will construct a 6 km long gas pipeline with an initial capacity of 1 million cubic meters per day (with a 1.2 million cubic meters per day extension scheduled for 2009) which will link TGS s main system to the Chilean border. TGS, through its interest in EGS, connects its gas transportation system to the Chilean market. TGS and TSGU have a 49% and a 51% interest in EGS, respectively. In turn, 49% of TSGU s capital stock is owned by TGS.

The following chart shows statistical information relating to TGS s business segments for fiscal years ended December 31, 2003, 2002 and 2001.

	2003	2002	2001
Regulated Segment			
Total available capacity at year end (in MMm3/d)	62.5	62.5	62.5
Average firm committed capacity (in MMm3/d)	61.7	61.4	60.7
Average daily deliveries (in MMm3/d)	52.6	49.4	46.7
Annual load factor	85%	80%	77%
Unregulated Segment			
Liquids total production (in thousand tons)	929.1	908.5	822.3
Processing capacity at year end (in MMm3/d)	43.0	43.0	43.0

Oldelval

Oldelval, a company in which we have a 23.1% interest, holds the concession for the transportation of crude oil through 888 km-long oil pipelines with 1,706 km of installed piping, between the Neuquén basin and Puerto Rosales (located in the Province of Buenos Aires) for a 35-year period starting in 1993 with an option to renew for ten years. Oldelval s other shareholders are Repsol-YPF, Petrolera San Jorge, Pluspetrol, Pan American and Tecpetrol.

The Allen/Puerto Rosales section transportation capacity is of approximately 265,000 barrels per day, with a 173,000 m3 storage capacity. In 2003 and 2002, Oldelval transported approximately 65 million and 66 million of oil barrels, respectively, from the Neuquén basin to the Atlantic coast.

Table of Contents

The applicable laws governing the transportation of hydrocarbons through oil pipelines, which are based on the free access notion, assign loading preference quotas to pipeline owners based on their shareholdings. Oil transportation rates are set by the Argentine Secretary of Energy.

OCP

The Government of Ecuador awarded OCP with the construction and operation for a 20-year term of the 503 km long pipeline that runs from the northeastern region of Ecuador to the Balao distribution terminal on the Pacific Ocean coast. As of December 31, 2003, we held an 8.96% interest in OCP. In May 2004, Techint International Construction Corporation, or Tenco, exercised an option to sell to us its shares and subordinated debt in OCP, comprising a 2.46% ownership interest. In accordance with the terms of the option, we paid U.S.$14 million for Tenco s ownership interests in OCP. Consequently, our interest in OCP increased to 11.42%. OCP s other shareholders are Encana, Perenco, Occidental and Repsol-YPF.

The oil pipeline has a 450,000 barrels per day transportation capacity of which at least 390,000 barrels per day have been committed to OCP shareholders under a ship or pay contract for transportation of their production. Since the oil pipeline runs across ecologically sensitive areas, the pipeline was construed under stringent environmental protection and technical standards.

The construction of the oil pipeline was performed by Techint International Construction Corporation and was completed during 2003. After testing the system at its maximum capacity and the approval by the Ministry of Energy and Mines of Ecuador, the oil pipeline officially started operations on November 10, 2003.

OCP s original budget amounted to U.S.$1,210 million, U.S.$900 million of which was funded by banking institutions, U.S.$250 million of which was funded by subordinated loans from shareholders and U.S.$60 million through capital contributions. We made contributions in the amount of U.S.$9 million and were granted a 15% shareholding interest. The total construction cost of the oil pipeline amounted to U.S.$1.4 billion, which was U.S.$190 million in excess of the original budget. The need for additional financing was satisfied through loans and capital contributions by shareholders in the amount of U.S.$150 million and U.S.$40 million, respectively. We did not make any such contributions and our equity interest was diluted from 15% to 8.96%.

Regarding future production from Blocks 18 and 31 in Ecuador, we, through Petrobras Energía Ecuador, entered into the ship or pay contract with OCP, whereby OCP has committed to transport 80,000 barrels per day for a 15-year term, as from the start of its operations. We, as well as the remaining producers, must pay transporation capacity fee.

Competition

TGS s gas transportation business, which provides an essential service in Argentina, faces only limited direct competition. In view of the characteristics of the markets in which TGS operates, it would be very difficult for a new entrant in the transportation market to pose a significant competitive threat to TGS, at least in the short to medium term. In the longer term, the ability of new entrants to successfully penetrate TGS s market would depend upon a favorable regulatory environment, an increasing and unsatisfied demand for gas by end users, and sufficient investment in gas transportation to accommodate increased delivery capacity from the transportation systems.

On a day-to-day basis, TGS competes, to a limited extent, with Transportadora de Gas del Norte S.A. for interruptible transportation services and for new firm transportation services made available as a result of expansion projects from the Neuquén basin to the greater Buenos Aires area. Interruptible transportation services accounted for only 4.5% of TGS s regulated net revenues for 2003. The relative volumes of such services will depend principally upon the specific arrangements between buyers and sellers of gas in such areas, the perceived quality of services offered by the competing companies, and the applicable rate for each company.

With respect to NGL processing activities, TGS competes with MEGA S.A., which owns a gas processing plant at the Neuquén basin and has a processing capacity of approximately 36 million cubic meters per day. Early in 2001, operations at this processing complex began and the gas from this basin reached TGS Cerri Complex with a low liquid content. In order to mitigate this effect, TGS increased the rich gas contribution to the system under agreements subscribed with gas producers at the Neuquén Basin and was able to restore NGL production levels at

Cerri Complex to levels similar to those recorded prior to the start of MEGA S.A. operations. In addition, a third of this production is marketed abroad and domestic market prices were increased to reach, in terms of U.S. dollars, parity with dollar-based export prices. Our controlling company, Petrobras, has a 34% interest in MEGA S.A. MEGA S.A. s other shareholders are Repsol-YPF (38%) and Dow Chemical (28%).

REFINING

Our presence in the refining business moves us toward vertical integration of our operations. The refining business is a tool that enables us to capitalize on our significant hydrocarbon reserves. Refining operations are a necessary link in the business value chain, which starts with crude oil exploration and ends with customer service. Our refining segment offers the most immediate prospects of further developing and taking advantage of business opportunities jointly with Petrobras, and some opportunities have already begun to materialize for us.

Our refining operations are located in Argentina and Bolivia. In Argentina, we operate our own refinery in San Lorenzo and have a 28.5% interest in Refinería del Norte S.A., which we refer to as Refinor. In Bolivia, as of December 31, 2003, we had a 49% interest in Empresa Boliviana de Refinación, which we refer to as EBR.

The Refining Business in Argentina

During recent years, the Argentine liquid fuel market was adversely affected by the growth of CNG as substitute fuel. The high taxes imposed on gasoline and, to a lesser extent, on diesel consumption, still affect the market, encouraging the use of CNG to the detriment of liquid fuels. Thus, the gasoline domestic market shrank 10% in 2003 in line with the downward trend of the previous eight years. The drop in the demand for gasoline totaled approximately 48% in the 1995-2003 period. Our share of the gasoline market has climbed to 3.1% from 2.9%.

Demand for diesel grew 4% in 2003, the first a recovery after a four-year decline, halting a prolonged downward trend in the market which had resulted in a 14% drop from 1999-2002.

Refining Division

We operate a refinery in San Lorenzo, Province of Santa Fé, strategically located along the central product distribution systems. The refinery capacity is approximately 37,700 barrels of oil per day, enabling us to process a large part of our crude oil production in Argentina.

The refinery has three atmospheric distillation units, two vacuum distillation units, a heavy diesel oil thermal cracking unit and an aircraft fuel production unit, which produce the following products: premium and regular gasoline, jet fuel, diesel oil, fuel oil, kerosene, solvents, aromatics and asphalts.

The refinery has two fuel storage and dispatch plants located in the Provinces of Santa Fe and Buenos Aires, respectively. At our Dock Sud facilities, in the Province of Buenos Aires, crude oil is received, stored and dispatched. The Dock Sud facility has a total storage capacity of 60,000m3. Crude oil is received from the oil pipeline connecting Bahía Blanca with Dock Sud and is dispatched to tankers transporting the oil to the San Lorenzo refinery. In addition, the San Lorenzo refinery located on the right bank of the Paraná River, with access from the so-called hydroway forming part of the Océano-Santa Fé trunk navigation route, has three docks for 250 meter-long vessels having 70,000 ton displacement.

As of December 31, 2003, we had a commercial network of 119 retail outlets, including 84 gas stations (eight directly operated by us), 20 diesel centers, six mobile diesel centers and nine agro-service centers, located in the Provinces of Santa Fé, Buenos Aires, Entre Ríos, Corrientes, Santiago del Estero, Tucumán, San Juan, San Luis, Catamarca, Chaco, Formosa, Salta, Mendoza and Córdoba. In line with our business integration strategy, we continue to expand our own retail network following a medium-term plan aimed at selling the largest volume of fuels produced by us. In order to reposition the gas station network and to leverage the synergies with our controlling shareholder, during 2003 we agreed to use the Petrobras brand name in seven gas stations that we own. Over the last few years, Petrobras has built an excellent image for its brands, products, and services in Argentina, currently competing with the image of the leading companies in the country. Negotiations continue over a long-term agreement for the use of the Petrobras brand in all our retail network.

In addition, we subscribed to an agreement to market Lubrax lubricants in our gas station network. These lubricants manufactured by Petrobras attained a 8.5% share of the domestic market in a relatively short period of time and experienced the highest growth rate among lubricants in 2003. The technical, commercial and advertising efforts Petrobras is making for the development of the Lubrax brand give considerable support to our sales growth in this business.

The following table shows production and sales figures for the Refining Division for the fiscal years ended December 31, 2003, 2002 and 2001:

	Year Ended December 31,		
	2003	2002	2001
Production (thousands of tons)			
Virgin naphtha	417	325	324
Diesel oil	613	499	522
Other products	619	507	527
Sales (thousands of tons/m3)			
Aromatics (thousands of tons)	56	67	65
Benzene (thousands of tons)	50	44	45
Gasoline (thousand m3)	119	123	126
Diesel oil (thousand m3)	883	622	743
Other medium distillates (thousand m3)	11	13	24
Asphalts (thousands of tons)	86	43	79
Reformer plant products (thousands of tons)	79	65	69
Other heavy products (thousands of tons)	418	374	266
Paraffins (thousands of tons)	151	138	97
Sales (in millions of pesos)			
Argentina	956	636	702
Outside of Argentina	346	372	86
Total	1,302	1,008	788

During 2003 our refinery processed an average of 32.6 thousand barrels per day. Crude oil volumes processed accounted for about 86% of the refining capacity.

During 2003, 210,000 cubic meters of diesel oil were sold to EG3 S.A., which we refer to as EG3, a company controlled by Petrobras, which caused an increase in crude oil processing at our San Lorenzo refinery to levels much higher than those recorded over the last few years and on profitable terms for us. This was possible because EG3 had been forced to import diesel oil since its production capacity at the Bahía Blanca Refinery is insufficient to supply its extensive retail outlet network. Since our diesel oil production at San Lorenzo exceeds the demand from our gas station network, significant volumes were exported to other countries in the region. Therefore, attractive long-term business opportunities may exist for both companies.

As of December 31, 2003, considering statistical data for the last month, we had a market share of approximately 3.1% in the gasoline market, 4.6% in the diesel oil market, 23.6% in the asphalt market and 15.1% in the fuel oil market. In addition, our share in the gas oil bunker (intermediate fuel oil) market totaled 23.2%.

Refinor

We have a 28.5% interest in Refinor. Refinor s other two shareholders are Repsol-YPF (50%) and Pluspetrol Exploración y Producción S.A. (21.5%).

Refinor owns the only refinery located in Campo Durán, Province of Salta, in the northern region of Argentina. Refinor s refining capacity is 26,000 barrels of oil per day and its natural gas processing capacity is 19 million cubic meters per day. Refinor receives crude oil and natural gas from the oil and gas fields located at the northwestern region of Argentina and Bolivia. It has an atmospheric distillation unit, a vacuum distillation unit, a catalytic reformer plant, two turboexpander plants and a compressor plant. Refinor produces diesel oil, fuel oil,

Table of Contents

motor gasoline, virgin naphtha, propane, butane, raw gasoline and LPG. It is the leaching LPG producer based on volume produced in the northern region of Argentina and the third largest producer in the country. In May 2003, a gathering and compression system that takes enriched gas from the Chango Norte field began operations. This system required an investment of approximately U.S.$13 million.

As of December 31, 2003, Refinor had a commercial network comprising 65 gas stations (14 owned by Refinor) located in the Provinces of Salta, Tucumán, Jujuy, Córdoba, Santiago del Estero, Catamarca and Chaco and started developing the commercial network in Bolivia, where it has five gas stations under its brand and two more under development. For logistics and distribution purposes, Refinor operates a 1,112 km poliduct that extends from our compression station in Campo Durán (Salta) to Montecristo (Córdoba). Along the pipeline, layout product recompression stations are located at Urundel (Salta), Lavallén (Jujuy), Cobos and Piedras (Salta) and Quilino (Córdoba). The pipeline supplies the following dispatch plants:

General Mosconi (Salta), with a 9,908 m3 storage capacity (fuels);

General Güemes (Salta), with a 1,800 m3 storage capacity (liquefied gas), and which started operations in 2003 replacing the old Tres Cerritos dispatch plant;

Banda del Río Salí (Tucumán), with a 57,508 m3 storage capacity (fuels); and

Leales (Tucumán), with a 5,054 m3 storage capacity (liquefied gas).

In addition, the poliduct discharges a large volume of product, petrochemical gasoline and liquefied gas at the Terminal Station located at Montecristo (Córdoba), and such products are then dispatched in the area or sent to San Lorenzo, Province of Santa Fé.

In 2003, Refinor commenced the commercialization of LPG in bulk, with 1,150 tons/year.

The following table sets forth Refinor s sales and production for the fiscal years ended December 31, 2003, 2002 and 2001:

	Year ended December 31,		
	2003	**2002**	**2001**
Production (thousands of tons/m3)			
Gasoline (thousand m3)	122	121	125
Virgin naphtha (thousand m3)	420	473	514
Diesel oil (thousand m3)	330	335	368
Natural gasoline (thousand m3)	129	134	137
Propane/butane (thousand tons)	313	287	241
Other products (thousand m3)	138	100	75
Sales (thousands of tons/m3)			
Gasoline (thousand m3)	121	122	139
Virgin naphtha (thousand m3)	550	611	619
Diesel oil (thousand m3)	378	374	368
Propane/butane (thousand tons)	297	274	239
Other products (thousand m3)	97	103	75

Sales (in millions of pesos)			
Argentina	490	428	350
Outside of Argentina	373	412	241
Total	863	840	591

In 2003, Refinor s sales through its service centers had a share in the motor gasoline and diesel oil markets in the northwest of Argentina of 25% and 18.2%, respectively. In addition, Refinor reached a 55% share in the diesel oil import market in Bolivia.

Table of Contents

Empresa Boliviana de Refinación

We have a 49% interest in Empressa Boliviana de Refinanción, or EBR. Petrobras is its strategic partner, with a 51% interest.

EBR owns two Bolivian refineries located in Cochabamba and Santa Cruz de la Sierra, with an estimated maximum production capacity of 48,000 barrels of oil per day, accounting for 95% of Bolivia s total refining capacity. In 2003, an average of 32,600 barrels per day were processed.

EBR wholly owns Empresa Boliviana de Distribución, or EBD, a company having a commercial network of 81 gas stations, six of which were incorporated during the last fiscal year. In 2003, EBD continued implementing the Integrated Gas Stations concept in Bolivia, by offering supplemental products, while focusing on first-class customer services, product quality and quantity.

Competition

We compete in Argentina with Repsol-YPF, Shell and Esso, who combined have a predominant share in this market.

Table of Contents

PETROCHEMICALS

Overview

Our strategy in this segment is to optimize the oil-refined products-polymer chain. The petrochemicals business is an integral part in our strategy of vertically integrating our operations by taking advantage of operating synergies and positioning us as a low-cost producer of hydrocarbons, thereby allowing us to reap the benefits of our significant hydrocarbon reserves.

Our petrochemical operations are performed in Argentina and Brazil, through the production of a wide array of products, such as styrene, polystyrene, synthetic rubber, fertilizers and polypropylene, both for the domestic and export markets.

We are the only producer of styrene monomer, polystyrene and elastomers in Argentina and the only integrated producer from oil and natural gas to plastic products (such as bioriented polystyrene sheets) or the production of fertilizers.

Through Innova, our wholly owned subsidiary in Brazil, we have the region s largest installed capacity for the production of styrene and polystyrene, with the benefit of providing service to clients from both locations.

In Argentina, we supply more than one-third of the Argentine fertilizer market with a wide array of specific solutions and are the only liquid fertilizer producer in the region.

We also have a 40% interest in Petroquímica Cuyo S.A., which accounts for a portion of our petrochemical operations.

Argentine Operations

Argentine Styrenics Division

The Styrenics Division has a plant at Puerto General San Martín, Province of Santa Fé, with a production capacity of 110,000 tons of styrene per year and 55,000 tons of synthetic rubber per year, and a plant at Zárate, Province of Buenos Aires, with a production capacity of 66,000 tons of polystyrene per year and 14,000 tons of bioriented polystyrene per year. This state-of-the-art plant in Zárate is the only one of its type in Latin America.

As part of our efforts to achieve full integration, we use a large amount of styrene for the production of polystyrene and synthetic rubber.

In March of 2004, we acquired from Imperial Chemical Industries an ethylene plant which is located in San Lorenzo and has a production capacity of 18,000 tons per year. The increased production capacity of ethylene will allow us to increase our production of ethylbenzene and to take advantage of the spare capacity of the plant. This, in turn, will allow Innova to increase production of styrene and operate at full capacity.

Our greater production of styrene monomers will enable us to meet the growing demand in the region.

As of December 31, 2003, our estimated share in the domestic market was: styrene 100%, polystyrene 70%, styrene butadiene rubber, or SBR, combined with the market for nitrite butadiene rubber, or NBR, approximately 90%.

Exports are a significant part of our business. Recent changes in trade policy have helped us to consolidate our position in foreign markets, especially in Mercosur and in Chile. In 2003, we exported 47%, 61% and 45% of our total sales volumes of styrene, rubber and polystyrene, respectively. With respect to styrene, our position in the Chilean market was further consolidated, and we were able to maintain a leading position in the Mercosur region, considering market shares both in Argentina and Brazil through Innova. In addition, a record was set for the export of bioriented polystyrene (8 thousand tons), the main destinations being the European and United States markets. SBR export volumes were in line with 2002 volumes, consolidating our presence in the Brazilian market.

Table of Contents

Fertilizers Division

We are pioneers in the production and distribution of fertilizers in Argentina. As leader in the market, we developed a new liquid product line during recent years with wide acceptance among agricultural producers.

The Fertilizers Division has a plant located at Campana, Province of Buenos Aires, with a production capacity of 190,000 tons/year of urea. In 2003, we doubled the installed production capacity of UAN, our liquid fertilizer (a composition of urea and amonium nitrate) to 475,000 ton/year. We are the only producer of liquid fertilizer in Latin America. Liquid storage capacity has been increased to 40,000 tons, which together with an automatic and computerized loading facility, has allowed us to manage the growth in liquids production.

During 2003, we started the construction of a 130,000 ton/year thiosulfate fertilizer plant, which required investments of approximately U.S.$8 million. Thiosulfate fertilizer has been designed to incorporate nitrogen for wheat and corn and sulfur for soybean, with great success in pre-marketing.

We have 700 customers throughout Argentina, and 130 are distributors with their own storage facility centers, complementing our warehouses and assistance centers in Buenos Aires, Santa Fé, Mendoza and Tucumán provinces.

The following table sets forth production and sales by major product for both the Styrenics and Fertilizers Divisions for the fiscal years ended December 31, 2003, 2002 and 2001:

	Year ended December 31,		
	2003	2002	2001
Production (thousands of tons)			
Styrene (1)	106	98	95
Synthetic rubber (2)	56	51	47
Urea	193	190	180
UAN	184	145	110
Polystyrene	57	61	62
Bops	11	6	6
Sales (in millions of pesos)			
Styrene (1)	124	100	63
Synthetic rubber (2)	161	138	94
Fertilizers	304	259	228
Polystyrene and Bops (3)	180	170	120
Other products and services	23	26	16
Total	792	693	521
Export Sales (in millions of pesos)	260	223	106

(1) Including styrene monomer and by-products.

(2) Including SBR, NBR and butadiene.

(3) Net of 5, 25 and 9 intercompany eliminations.

Petroquímica Cuyo

Petroquímica Cuyo S.A., which we refer to as Cuyo, is primarily involved in the production and marketing of polypropylene. We and Admire Trading Company are Cuyo s main shareholders, with a 40% and 50.5% interest, respectively. Cuyo s industrial plant, located at Luján de Cuyo, Province of Mendoza, has a production capacity of approximately 100,000 tons/year. The quality and specialization of products have enabled Cuyo to enter international markets and export to several countries in the world, especially to Mercosur member countries and Chile.

Approximately 87% of the propylene feedstock required for Cuyo s operations is supplied by Repsol-YPF from its Luján de Cuyo refinery under a long-term contract set to expire in 2014.

Table of Contents

Cuyo is a licensee of the Novolen Technology Holding company, a member of the ABB Lumus Group, engaged in the production and marketing of polypropylene. In addition, it maintains transfer, assistance and technology upgrade agreements, allowing it to be a leading company in product applications and to serve the market with world-class processes and products.

The following table sets forth Cuyo s production and sales for the fiscal years ended December 31, 2003, 2002 and 2001.

	Year ended December 31,		
	2003	2002	2001
Production (thousand of tons)	87	84	80
Sales (in millions of pesos)	225	200	132

Brazilian Operations

Our petrochemical operations in Brazil are conducted through Innova, our wholly owned subsidiary. Innova is the first integrated plant in Latin America for the production of ethylbenzene, styrene and polystyrene in one site, located at Triunfo Petrochemical Pole, Rio Grande do Sul, in the south of Brazil. The styrene plant has a production capacity of 250,000 tons per year and the polystyrene plant has a production capacity of 120,000 tons per year. Our styrene and polystyrene plants began commercial operations in January and October 2000, respectively. Copesul, a Brazilian company, supplies the benzene and ethylene feedstock necessary for the production of styrene pursuant to a long-term contract.

The polystyrene plant uses approximately 110,000 tons of styrene monomer as the feedstock to produce two grades of polystyrene (Crystal and High Impact). The remainder is sold mainly in the Brazilian market for the production of synthetic rubber, expanded polystyrene, polyester and acrylic resins.

As of December 31, 2003, Innova was Brazil s largest styrene producer and merchant (not including styrene used in the production of polystyrene), and one of Brazil s largest polystyrene producers and merchants, with an estimated 47% and 26% market share, respectively.

Sony Corporation recognized Innova as Green Partner, which is only awarded by Sony after a thorough examination of suppliers. Innova is the only polystyrene supplier in Brazil to receive this recognition. In addition, Yakult approved a polystyrene grade developed by Innova, making Innova the third supplier in the world recognized by this client.

The following table sets forth Innova s production and sales of styrene and polystyrene for the fiscal years ended December 31, 2003, 2002 and 2001.

	2003	2002	2001
Production (in thousands of tons)			
Styrene	175	179	165
Polystyrene	86	96	92

Sales (in millions of pesos)			
Styrene	216	234	100
Polystyrene	255	298	183
Other	31	29	14
Total sales	502	561	297

Table of Contents

Competition

The petrochemical markets in which we compete are highly cyclical, and our results in these businesses are heavily influenced by world market conditions. We are the only producer of styrene and synthetic rubber in Argentina, but compete with other foreign producers, especially those in Brazil. In the fertilizers market, we compete with Profertil S.A., a local urea and ammonia producer with a production capacity of one million tons per year and other players who import and mix fertilizers such as Cargill, Nidera and Hidro Agri Arg. Profertil is owned by Repsol-YPF and Agrium S.A. In the polypropylene business, Petroken S.A is Cuyo s main competitor with a production capacity of 180,000 tons per year.

In Brazil, we mainly compete with Dow Chemical and BASF, who, after expansion of their San Paulo plants in 2001, have a polystyrene production capacity of 190 and 180 thousand tons per year, respectively. In addition, Videolar, a Brazilian producer, operates a 120 thousand ton capacity plant in Manaos. Nevertheless, we do not believe our revenues will be adversely affected, considering the strategic geographical location of our plants and their target markets, in addition to Innova s low cost producer nature. Based on the above, we believe we will maintain our current market position in the future.

Table of Contents

ELECTRICITY

In the electricity business, we are involved in all three industry segments: generation, transmission and distribution. Thus, we are positioned as a major player in the Argentine electricity market.

We believe that electricity generation allows us to accelerate monetization of our significant gas reserves. Electricity transmission and distribution provides us with new growth opportunities, adding value through the sale of power and energy services to end users, as well as, through the development of cutting-edge technology.

We conduct electricity generation activities through our Genelba Power Plant in the Province of Buenos Aires and Pichi Picún Leufú hydroelectric complex, or HPPL, in the Comahue region, on the Limay River, Province of Neuquén. In addition, we have a 9.19% interest in Hidroneuquén S.A., a company controlling 59% of Hidroeléctrica Piedra del Aguila S.A., a hydroelectric complex located on the Limay River, in the Comahue region, in the dividing line between the Provinces of Neuquén and Río Negro. We are engaged in the transmission business through our interests in Transener (through Compañía Inversora en Transmisión Eléctrica Citelec S.A., or Citelec), Enecor S.A. and Yacylec S.A, and the electricity distribution business through our interest in Edesur (through Distrilec).

The enactment of the Public Emergency Law deeply changed the economic and financial balance of utility companies. The tremendous effect of the devaluation, within a context where revenues remained unchanged as a consequence of the pesification of rates and where financial debts were primarily denominated in foreign currency, affected the utilities financial position, results of operations and the cash generation ability required to comply with financial obligations.

The Argentine Electricity Market

In Argentina, in the early 1990s, within the state-reform general framework, the Argentine government carried out a deep restructuring of the electricity sector transforming it into a more decentralized model with greater private sector participation. Up to then, the electricity system was characterized by the inability to meet the requirements of short- and long-term demand and a low service quality standard, all within a framework of a limited financing capacity on the part of the state to make necessary investments.

Electricity demand in Argentina has strongly increased over the last few years. Over the last 11 years, electricity demand increased at an average rate of 5%, exceeding the GDP growth for the same period. In 2003, electricity demand grew approximately 7.8% to 77,738 GWH from 72,107 GWH in 2002. This improvement is mainly due to the recovery following the economic crisis in 2002.

As of December 2003, installed generation capacity reached 22,500 MW, which accounted for a growth of approximately 70% from the time of the privatization of electricity services. Within this context, it is worth noting the growth in the installed capacity of non-nuclear thermal power plants and hydroelectric plants. As of December 31, 2003, thermal and hydroelectric power accounted for 46.7% and 44.7%, respectively, of total supply. In the case of non-nuclear thermal units, the new plants have substantially increased their operating efficiency by incorporating cutting-edge technology, such as combined cycles, which allowed the reduction of the average unavailability of thermal units from 50% to approximately 20%. Serving as an integrating link, the system s transportation capacity increased by 20% between 1994 and 2003. These improvements in the installed capacity enabled plants to meet the growth in demand in Argentina and also allowed for the start of exports to neighboring countries.

Electricity Generation

Genelba Power Plant and Pichi Picún Leufú Hydroelectric Complex

Our Genelba Power Plant is a 660MW combined cycle gas-fired generating unit located at the central node in the Argentine electricity network, at Marcos Paz, about 50 km from the city of Buenos Aires. As part of our strategy to increase vertical integration, the Genelba Power Plant allows us to use approximately 2.8 million cubic meters per day of our own gas reserves.

Table of Contents

The Genelba Power Plant, which commenced commercial operations in February 1999, has two gas-fired turbines that receive gas through an 8 km duct connected to the transportation system operated by TGS. The electricity produced at the Genelba Power Plant is distributed via the national grid through a connection to the Ezeiza transformer station (owned by Transener) and is located only 1 km away from the Genelba Power Plant.

The allocation of electricity dispatch to the Wholesale Electricity Market, or WEM, whether the electricity is produced for firm contracts or for the spot market, is subject to market rules based on the lowest variable cost of electricity generation. See Regulation of Our Businesses The Argentine Electricity Industry and Regulatory Framework. Since the Genelba Power Plant uses combined cycle technology for a natural gas-fired power plant, our short-run variable cost is expected to be lower than the cost of other thermoelectric power plants, granting significant competitive advantages for the Genelba Power Plant. Therefore, CAMMESA is expected to dispatch the Genelba Power Plant s generating capacity before that of most other thermoelectric plants, and the Genelba Power Plant is estimated to operate at an approximately 76% capacity on a month-to-month basis.

The development and implementation of the Primary Frequency Response, or PFR, operation mode along with the full combined cycle represents a milestone in the Genelba Power Plant operation. The associated system was designed by the plant engineers and the Genelba Power Plant was the first of its type worldwide to provide this service to the interconnected system. In 2003, the U.S. Patent Office granted us patent rights on this system, and currently steps are being taken to obtain patents in Europe and Argentina.

We were awarded a 30-year concession beginning in August 1999 for hydroelectric power generation at Pichi Picún Leutú hydroelectric complex, or at HPPL. Our total investment in the construction of the complex was P$291 million. The complex has three generating units with an installed capacity of 285MW. Units 1 and 2 began commercial operations during the third quarter of 1999, and Unit 3 started commercial operations in December 1999.

Pursuant to our concession contract and under Section 43 of Law 15,336, as amended by Law 23,164, since August 2003 we have paid 1% in hydroelectric royalties, which will be increased by 1% annually until reaching a 12% maximum tax rate, on the amount resulting from applying to the energy sold the tariff corresponding to block sales. In addition, we pay the Argentine government a monthly fee for the use of the water source amounting to 0.5% of the amount used in the calculation of the hydroelectric royalties mentioned above.

In order to secure completion of the works within the term of the concession and to ensure certain minimum profitability levels needed to make the investment viable, the Secretary of Energy granted us P$25 million from the Unified Fund, section 37, Law 24,065. For the purposes of determining whether this amount should be reimbursed or not, a system fixing a support price for the electric power generated by the hydroelectric complex and sold at the WEM was implemented. This support price system will be implemented during a ten-year period divided into two five-year consecutive periods as of December 1999. For implementation purposes, an Annual Monomic Support Price, or AMSP, of P$0.021 per Kwh and P$0.023 per Kwh was fixed for the first and second periods, respectively. In order to determine the amount to be reimbursed, annually and during the term mentioned above, the difference between the annual average monomic price for generation at the complex node and the above-mentioned AMSP, valued by the energy generated by the complex during such year, will be considered. Taking into account the hydroelectric complex s energy sales prices and price estimates for the remaining period of the first five-year term, and considering that the price support system described above guarantees the viability of our project by providing us with a minimum return on investment, as of December 31, 2003, we recognized P$15 million in income from the fund.

The Genelba Power Plant and HPPL, together, account for approximately 6.7% of the power used by, and approximately 6.6% of the power generated for, the Argentine electricity system. The joint operation of the generating units minimizes income volatility, capitalizing on the natural barriers existing among the different energy resources used for power generation.

The following chart details energy generation and sales figures for the Genelba Power Plant and HPPL for the fiscal years ended December 31, 2003, 2002 and 2001.

	For the year ended December 31,		
	2003	2002	2001
Generation (Gwh)	5,400	5,278	4,732
Sales (Gwh):			
Contracted sales	1,588	1,569	1,140
Spot market	4,450	4,402	4,152
Total sales	6,038	5,971	5,292
Sales (in millions of pesos)	235	196	266

Piedra del Aguila

We, through our 9.19% interest in Hidroneuquén S.A., have an indirect 5.4% interest in Hidroeléctrica Piedra del Aguila S.A., or HPDA.

Piedra del Aguila hydroelectric complex has 1,400 MW of installed capacity and four vertical axis turbosets. During 2003, HPDA sold 5,333 GWh in the WEM, 5,170 GWh of which were supplied by its own generation (close to its historical average) and 163 GWh were purchased in the spot market.

On June 30, 2002, Piedra del Aguila announced the suspension of principal and interest payments on its financial debt; since then, HPDA has been involved in a restructuring process.

Electricity Transmission: Transener, Yacylec and Enecor

Transener

We currently own an indirect participation of 32.5% in Transener. We have committed ourselves to divesting our aggregate equity interest in Transener (under Law No. 24,065 which provides for the Electricity Regulatory framework) based on the Argentine Antitrust Commission s resolution under which the transaction involving the purchase of Petrobras Energía Participaciones majority stock by Petrobras Participacoes S.L. was approved. Such transaction will be subject to supervision by the Argentine regulatory entity for electricity, Ente Nacional Regulador de la Electricidad, or ENRE, and must be approved by the Argentine Secretary of Energy. No time limits have been set to effect this divestment.

Transener is controlled by Citelec, who owns 65% of the capital of Transener. Citelec, in turn, is owned 49.993% by us, 42.493% by National Grid Finance B.V. and 7.514% by Dolphin Fund Management, or Dolphin. In March 2004, subject to the approval from the Argentine Antitrust Commission, Dolphin acquired a 42.493% interest in Citelec from National Grid Finance B.V. If this transaction is approved, we have already notified both Dolphin and National Grid Finance B.V. of our intention to exercise our preemptive right to acquire 0.007% of Citelec s share capital from National Grid Finance B.V., increasing our shareholding in Citelec to 50.00%.

Transener is the leading power transmission company in Argentina.

Under a 95-year concession, which is due to expire in 2088, Transener operates approximately 7,500 km of extra high and high voltage power lines (most of them 500 Kv lines) and 32 transformer stations. This network is the core of the power transmission system in Argentina.

Transener was awarded an exclusive license for the rest of the term of the original concession to construct, maintain and operate the fourth line of the Comahue-Buenos Aires electricity transmission system, which began operations late in 1999, and consists of 1,292 km of 500 Kv electricity lines.

Transener operates approximately 90% of the Argentine extra high voltage power transmission system.

Table of Contents

In July 1997, Transener was awarded the exclusive 95-year concession to operate Empresa de Transporte de Energía Eléctrica por Distribución Troncal de la Provincia de Buenos Aires S.A., or Transba S.A., or Transba, which expires in 2091. Transba operates approximately 5,991 km of electricity transmission lines (most of them 132 KV lines) and 82 transformer stations.

Transener and Transba jointly operate approximately 75% of the Argentine high-voltage power transmission system.

We have agreed with the National Grid to jointly manage Transener and Transba and to share equally in the management fees received under a management agreement with Transener. In addition, shareholders have a right of first refusal in any transfer of Transener s shares. Under the concession agreement with the government, certain shares of Transener are pledged in favor of the grantor as guarantee for the execution of obligations under such agreement.

Transener generates additional income related to its power transmission services, from the supervision of the construction and operation of certain assets connected with the networks and other external services provided to third parties. In this respect, efforts are being made by Transener to expand its activities abroad, supported by its quality engineering and experienced technical personnel.

In order to meet the commitments arising from two contracts with foreign joint ventures in Brazil, the company Transener Internacional Limitada, with offices in Brasilia, was organized. During 2003, Transener Internacional Limitada consolidated its operation and maintenance activities in Brazil, reaching a high operating efficiency level.

During 2003, in line with Transener s strategy to expand its operations at a regional level, the development of the brand insertion policy continued in Latin America, allowing for the dissemination of Transener s capabilities.

The following chart details the evolution of Transener s failure rate for the fiscal years ended December 31, 2003, 2002 and 2001. The failure rate represents the service quality provided by the company to users. The maximum admissible failure rate under the concession contract is 2.50 failures per year per every 100 km.

	For the year ended December 31,		
	2003	**2002**	**2001**
Transener failure rate	0.51	0.57	0.60

Maintenance of this low failure rate resulted from operating improvements, acquisition of special equipment and agreements with public safety agencies.

The provisions of the Public Emergency Law have severely affected the economic and financial balance of Transener s business. Within this framework, Transener publicly announced the suspension of principal and interest payments on all its financial debts. Transener retained an international financial advisor to assist it in developing a restructuring plan for all its banking and financial liabilities. Transener has been notified of a request by one of its creditors for the commencement of involuntary bankruptcy proceedings against it and of requests for attachment of approximately U.S.$11.5 million in accounts receivable from CAMMESA. Transener is pursuing all reasonable defenses to protect its rights.

Yacylec

Yacylec S.A., which we refer to as Yacylec, is an independent transmission company formed by a consortium of construction and engineering companies of Argentina and Europe, including Empresa Nacional de Electricidad S.A. of Spain, or Endesa, Impregilo International Infraestructures N.V. of The Netherlands and Dumez S.A. of France, which currently hold 22.2%, 18.67% and 1.78% of Yacylec, respectively. We have a 22.22% direct interest in this consortium. The consortium operates and maintains the 500 Kv and 280 km-long electric power transmission line from Yacyretá hydroelectric complex to the Argentine national grid under a 95-year concession that expires in 2091. Under the concession agreement, ENRE s approval is necessary to transfer or sell shares representing up to 49% of the capital stock. If that percentage is higher, a public tender must be called in order to award such shares to the best bidder.

Under the shareholders agreement, shareholders have a right of first refusal in any transfer of shares.

Enecor

Enecor is an electricity transmission company. We own a 69.99% interest and Impregilo International Infrastructures N.V. of The Netherlands owns the remaining interest in the company. Enecor has a 95-year concession, expiring in 2088, to construct, operate and maintain approximately 22 km of electricity lines and a 500 Kv/132 Kv transformer station in the Province of Corrientes. Under the concession contract, certain shares of Enecor are pledged in favor of the Province of Corrientes. As collateral for the amounts owed by the Dirección Provincial de Energía de Corrientes, or DPEC, to Enecor, the province of Corrientes has assigned to Enecor (i) all royalty credits it has against the Comisión Técnica Mixta de Salto Grande for the sales of electricity generated by the Salto Grande Hydroelectric Power Complex, and (ii) the funds that belong to the Province under the Fondo de Desarrollo Eléctrico del Interior, or FEDEI.

Enecor is collecting such guarantees because the DPEC has failed to pay tariffs to Enecor since September 1999. However, as a result of lower hydropower generation and the issuance of Resolution SE 406/03, which affected all generators by establishing a priority for canceling existing debts subject to the Stabilization Fund having sufficient monies (coming from either the adjustment of the seasonal price or the Federal Government), Enecor s revenues have been seriously affected. Enecor is taking appropriate administrative and legal actions with respect to these matters, but we cannot assure that these actions will result in a favorable outcome to Enecor.

Electricity Distribution: Edesur

In 1992, Edesur, was awarded an exclusive license by the Argentine government to distribute electricity in the southern area of the Federal Capital and 12 districts of the Province of Buenos Aires, serving a residential population of approximately six million inhabitants and a client portfolio of approximately 2.1 million. The license will expire in 2087 and is extendable for an additional 10-year period. Edesur was created as part of the privatization of the Buenos Aires electricity distribution network. We own 48.5% of Distrilec which, in turn, owns 56.35% of Edesur.

We and the Enersis/Chilectra group, owned by Endesa, are the only shareholders in Distrilec and, under a shareholders agreement, each have the right to elect an equal number of directors. The Enersis/Chilectra group had challenged the validity of the shareholders agreement in an arbitration proceeding, and in September 2002, the International Chamber of Commerce issued a final award which was fully in our favor and determined that each group has the right to appoint five directors of Distrilec.

The unanimous approval of the board of directors is necessary for any lien on Edesur s shares or any merger, reorganization, dissolution or spin-off of Distrilec. Shareholders also have a right of first refusal on any transfer of shares and preferential rights on any new issue of shares.

Chilectra entered into a 15-year management agreement with Edesur that expires in 2007. Under the agreement, Chilectra receives management fees of U.S.$1 million plus 10% of exploitation income per year. We are reimbursed for costs incurred by it in connection with the management agreement.

Under the concession contract, Edesur has a fixed cap on what it may charge each customer for the distribution of electricity to that customer. However, Edesur may pass through to the customer the cost of the electricity purchased, limited only by the pre-adjusted seasonal WEM price. Customers are divided into tariff categories based on the type of consumption required. Under the current regulations, large users may purchase energy and power directly from the WEM. Edesur charges these large users a wheeling fee for the provision of distribution services. Residential consumers purchase power only from distributors. These customers are generally daylight and weather sensitive and their consumption of electricity is different in summer and winter. Peak demand occurs in July, when there is the least amount of sunlight, and in January, which is usually the hottest summer month.

Table of Contents

The enactment of the Public Emergency Law significantly affected Edesur s economic and financial balance and its ability to comply with its contractual commitments. For this reason, Edesur s efforts were focused on refinancing financial liabilities, reducing risks and optimizing working capital. Based on these guidelines, Edesur has managed to refinance all of its financial debt, achieving a better maturity profile and lower average costs.

The chart below sets forth Edesur s annual power sales for each type of customer for the fiscal years ended December 31, 2003, 2002 and 2001.

	Annual sales in Gwh		
Type of customer	**2003**	**2002**	**2001**
Residential	4,304	4,597	4,632
General	2,785	2,439	2,844
Large users	5,569	5,123	5,433
Total	12,658	12,159	12,909

During the period since privatization, Edesur has made investments of over U.S.$1.2 billion and increased the equipment s average useful life from 17 to 24 years by incorporating new facilities and revamping the existing ones. As a result of such investments, Edesur was able to provide over a 35% rise in demand and maximum output compared to the first years of the concession of operation. In addition, investments enabled Edesur to reduce total energy loss through the system. This loss had accounted for 26% of total electricity received in 1992 but currently accounts only for 11.8%. Quality of service supplied to customers improved and the number and duration of interruptions declined by more than 70%. Edesur has added more than 200,000 new customers to its system since 1992, with a 12% increase in the number of customers last year alone. Some of these customers were added as a result of new electricity lines, and others who had been receiving electricity outside the system are now fully connected and accurately billed. Edesur has also substantially reduced overdue payments from customers and is implementing more efficient billing and collection practices.

Based on a functional organization and a prevention approach in the development of its activities, Edesur made significant efforts to consolidate the electricity system structure and incorporate new technologies with a view to meeting the new challenges of an increasingly demanding and competitive market. In order to meet its clients new requirements, Edesur took actions geared towards the development of new products and services, while it redesigned existing ones.

Competition

We compete with other generators in the WEM, both in the spot market and for contracts (mainly short-term contracts). The price received by us for energy generation is determined by the WEM dispatch marginal cost rules and by rules and regulations enacted following the Argentine crisis and the adoption of the Public Energy Law. See Regulation of our Businesses The Argentine Electricity Industry and Regulatory Framework.

Divestments of non-core assets

The sale of a controlling interest in the company that directly controlled us to Petrobras represents a major milestone in the development of our strategy to focus and concentrate on our core businesses.

The agreements executed in connection with the transfer of our control granted Petrobras an option whereby, if within 30 days after closing of the stock purchase transaction, we did not consummate the sale of assets related to the farming, forestry and mining businesses, Petrobras would be entitled, but not obligated, to cause the seller to acquire such assets in the amount of U.S.$190 million.

In line with the provisions of the agreements mentioned above, during 2002 we sold the asset portfolio associated with our mining, farming and forestry businesses. As a part of these divestments, we are involved in the following transactions:

In July 2002, we sold to Anglogold our 46.25% indirect equity interest in Cerro Vanguardia S.A., and certain related assets. The transaction price amounted to U.S.$90 million, and the transaction resulted in a P$123 million gain for us.

In September 2002, we sold to Argentina Farmland Investors LLC our 100% equity interest in Pecom Agropecuaria S.A. The transaction price amounted to U.S.$53 million, resulting in a P$27 million gain for us.

In December 2002, we sold our forestry business assets, including a total area of about 169,000 hectares of forestry land located in the Province of Misiones, Corrientes and Buenos Aires and a sawmill with a 90,000 m3/year capacity. The sales price was U.S.$53.16 million, resulting in a P$153 million loss for us.

In addition, the following transactions were performed:

In April 2002, under an asset swap, we transferred to IRHE (Argentine Branch) and GENTISUR S.A. (a company wholly owned by IRHE) our 50% interest in Pecom Agra with a value of U.S.$30 million, resulting in a P$81 million gain. These parties, in turn, transferred to us a 0.75% interest in Puesto Hernández UTE, with a value of U.S.$4.5 million, a 7.5% interest in Citelec, with a value of U.S.$15 million and a 9.19% interest in Hidroneuquén S.A, with a value of U.S.$5.5 million.

In October 2002, we sold to Sudacia S.A., a company controlled by the Perez Companc family, our 66.67% equity interest in Conuar, including a 68% interest in Fabricación de Aleaciones Especiales S.A., for U.S.$8 million. No gain or loss was recorded in connection with the sale.

In April 2000, we sold our interest in Servicios Especiales San Antonio S.A., a company engaged in the business of providing production well services to the oil industry in Argentina, Bolivia, Peru and Venezuela, for P$133 million, resulting in a gain of P$103 million.

All these transactions helped to (i) enhance our asset portfolio, (ii) move forward with the strategy focused on energy operations to become an integrated energy company, and (iii) consolidate a high potential and profitable business portfolio.

Insurance

We carry insurance covering all operating risk damages, with assets valued at current market replacement cost. The coverage limit for each and every loss in our oil and gas exploration and production businesses is the total value at risk for each location: U.S.$370 million for each and every loss in our styrenics petrochemical businesses; U.S.$150 million for each and every loss in our fertilizers business; U.S.$80 million for each and every loss in our refining business; U.S.$180 million with respect to our thermoelectric generation businesses; and U.S.$217 million for each and every loss in the hydroelectric generation power plant. In addition, we carry insurance of up to U.S.$100 million for ocean marine and non-ocean marine third-party liability, U.S.$7.5 million for well control costs in Argentine fields, U.S.$40 million for wells in Bolivia, U.S.$40 million for wells in Ecuador, U.S.$25 million for fields in Venezuela and U.S.$10.5 million for cargo transportation by sea or river. In addition, we carry insurance for workmen s compensation and automobile liabilities.

Our coverage include the following different types of deductibles: (1) U.S.$10,000,000 for combined claims for property damage and business interruption for all our businesses, except for the oil and gas exploration and production businesses, (2) U.S.$ 10,000,000 for claims for each property of our oil and gas exploration and production businesses, (3) U.S.$5,000,000 for in well control costs, and (4) U.S.$5,000,000 in non-ocean marine third-party liability, and (5) U.S.$5,000,000 in ocean-marine third-party liability. Our insurance decisions are based on our requirements and available commercial and market opportunities.

Pursuant to the resolutions adopted by the ordinary shareholders meeting held on April 4, 2003, the Board of Directors was authorized to determine the most economically appropriate coverage, including a program of self-insurance covering directors and senior officers liabilities.

Table of Contents

Patents and Trademarks

Minor portions of our commercial activities are conducted under licenses granted by third parties, including Petrobras. Royalties related to sales associated with such commercial activities are paid under the relevant licenses. We use the name Petrobras with the permission of Petrobras.

Environmental

Environment, Quality, Occupational Health and Safety (EQOHS)

In 1993, we started to implement our environmental strategy. Since then, environmental protection, employee health and safety and the continuous improvement of our management quality have been an integral part of our business.

Policies and Directives

We have issued policies, goals and plans emphasizing environmental care and control. Through these policies and standardized management systems designed to implement these policies, we have undertaken the commitment to ensure the quality of our products and services, to preserve the overall environment in which we operate, and the safety and health of our personnel, contractors and neighboring communities.

The consolidation of our management system for quality, safety, environment and occupational health has been reinforced by the implementation of the same directives used by Petrobras in Brazil, which we now apply to each of our business units in order to create and improve our systems. Each business unit is focused on complying with these goals and closely monitors its progress, thereby continuously seeking improvement. We call this process Programa de Seguridad de los Procesos , or PSP.

Performance Assessment

The possible environmental, safety and occupational health impacts that are directly or indirectly related to our operations are measured through risk analysis to ensure their treatment and solution. In that respect, each business unit has set up adequate procedures which are regularly reviewed and which are based on standards and directives that we have established.

The performance of our environmental management system is evaluated every month. We verify compliance by our different business units with goals with respect to reduced atmospheric gas emissions, reduced discharges of liquid effluents and the treatment or reduction of waste. We also monitor safety indicators such as the frequency of lost time due to injury, lost work days, and the total recordable incident rate. We will take and have taken corrective and preventive measures in order to improve our results with respect to each of these indicators and the overall safety of our personnel.

We have more than 90 certifications in environment (ISO 14001), quality, (ISO 9001) and safety and occupational health (OHSAS 18001/IRAM 3800), which are maintained through regular third-party audits.

Many of our achievements in this continuous process to achieve excellence have been enhanced through our integration with Petrobras. Since July 2003, we have put into operation the project Inventory System of Atmospheric Emissions initiated in September 2002 by Petrobras. The main goal of this project is the creation of a tool to be applied to the management of atmospheric emissions. The work consists of the creation of a collection, utilization and communication data system that permits the systematic environmental evaluation of our emissions, the identification of critical issues and the technological analysis of improvements that can be put into place to reduce these emissions.

Environmental Audit

Following the change of our controlling shareholder and pursuant to our goal of continuously improving our environmental, health and safety management, in 2003 we hired an international consulting firm to conduct an environmental and safety audit of all our operations.

59

Table of Contents

The final audit report issued by this consulting firm confirmed the high environmental standards of our operations and identified a series of actions necessary for our operations to be in full compliance with current laws and regulations, to satisfy future requirements and, in the absence of local laws, to comply with applicable international standards. We have decided to implement these actions. Consequently, over the next several years we plan on making investments to improve, among other things, our prevention systems and production facilities at a cost of approximately U.S.$23 million, and we plan to also implement several corrective and remediation actions several of which are already underway.

REGULATION OF OUR BUSINESSES

The Argentine Petroleum Industry and Regulatory Framework

Overview

The Argentine oil and gas industry operates under Law No. 17,319 which we refer to as the Hydrocarbons Law, enacted in 1967, and the Natural Gas Law No. 24,076, enacted in 1992. The Hydrocarbons Law allows the federal executive branch of the Argentine government to establish a national policy for the development of Argentina s hydrocarbon reserves, with the principal purpose of satisfying domestic demand.

A new regulatory framework was required in order to respond to several changes in the Argentine oil and gas industry after the privatization of Yacimientos Petrolíferos Fiscales Sociedad del Estado, or YPF, and Gas del Estado, or GdE. Pursuant to Law No. 24,145, the Argentine government transferred to the provinces ownership of oil and gas reserves located within their territories. The transfers will be implemented once (i) the Hydrocarbons Law is modified for the purpose stated in Law No. 24,145, which is referred to as the Privatization Law, and (ii) the rights of holders of existing exploration permits and production concessions, as applicable, have expired. In connection with this legislation, certain issues remain unresolved with respect to the relevant regulatory authority of the federal executive branch and the provinces, regarding oil and gas exploration, production, and transportation activities.

Exploration and Production

The Hydrocarbons Law sets forth the basic legal framework for the current regulation of oil and gas exploration and production in Argentina. The Hydrocarbons Law permits surface reconnaissance of territory not covered by exploration permits or production concessions upon authorization of the Secretary of Energy and with permission of the property owner. Information gained as a result of surface reconnaissance must be provided to the Secretary of Energy, who is prohibited from disclosing such information for a period of two years, without the permission of the party that conducted the reconnaissance, except in connection with the grant of exploration permits or production concessions.

The Hydrocarbons Law provides for the grant of exploration permits by the federal executive branch following submissions of competitive bids. Permits granted to third parties in connection with the deregulation and demonopolization process were granted in accordance with procedures specified in certain decrees, known as the Oil Deregulation Decrees, issued by the federal executive branch. In 1991, the federal executive branch established a program under the Hydrocarbons Law, known as the Argentina Exploration Plan, pursuant to which exploration permits may be auctioned. The holder of an exploration permit has the exclusive right to perform the operations necessary or appropriate for the exploration of oil and gas within the area specified by the permit. Each exploration permit may cover only unexplored areas up to 10,000 km2 (15,000 km2 offshore), and may have a term of up to 14 years (17 years for offshore exploration).

In the event that the holder of an exploration permit discovers commercially exploitable quantities of oil or gas, the holder may apply for, and is entitled to receive, an exclusive concession for the production and development of such oil and gas. A production concession vests in the holder the exclusive right to produce oil and gas from the area covered by the concession for a term of 25 years (plus, in certain cases, a part of the unexpired portion of the underlying exploration permit), which may be extended for an additional ten-year term by application to the federal executive branch. A production concession also entitles the holder to obtain a transportation concession for the transport of the oil and gas produced.

Holders of exploration permits and production concessions are required to carry out all necessary works to find or extract hydrocarbons, using appropriate techniques, and to make the investments specified in such holders permits or concessions. In addition, these holders are required to avoid damage to oil fields and waste of hydrocarbons, to adopt adequate measures to avoid accidents and damage to agricultural activities, the fishing industry, communications networks and the water table, and to comply with all applicable federal, provincial and municipal laws and regulations.

Holders of production concessions are also required to pay a 12% royalty to the government of the province in which production occurs, calculated on the wellhead price (equal to the FOB price less transportation costs and certain other reductions) of crude oil and natural gas produced. The Hydrocarbons Law authorizes the government to reduce royalties up to 5% based on the productivity and location of a well and other special conditions. Any oil and gas produced by the holder of an exploration permit prior to the grant of a production concession is subject to the payment of a 15% royalty.

Exploration permits and production or transportation concessions are subject to termination in the event of certain breaches or defaults of laws or regulations or upon the bankruptcy of the concessionaire. Upon the expiration or termination of a production concession, all oil and gas wells, operating and maintenance equipment and facilities ancillary thereto automatically revert to the Argentine government, without payment to the concessionaire.

Net Worth Requirements

Resolution No. 193/03 of the Secretary of Energy implements mandatory minimum net worth requirements for companies that wish to acquire or maintain exploration permits, exploration concessions, and hydrocarbon transportation concessions in Argentina.

The Secretary of Energy has historically required companies that wish to obtain these permits or concessions to comply with certain minimum net worth and economic and financial solvency requirements. Along these lines, the Hydrocarbons Law and subsequent regulations provide for certain economic and financial solvency requirements for carrying out these activities. However, prior to the issuance of Resolution No. 193/03, there were no resolutions that established specific required amounts, but rather, the Secretary of Energy determined the amount that would be required to comply with the solvency requirement on a case by case basis. Resolution No. 193/03 sets forth minimum net worth requirements, as well as, alternative economic and financial guarantees that can be complied with to obtain permits or concessions.

This resolution also provides that, in order to be a holder of a permit or concession, the company or group of companies (for example, companies associated through a joint operating or joint venture agreement) shall have a minimum net worth of P$2,000,000 for land-based areas and U.S.$20,000,000 for off-shore areas. This minimum net worth amount must be maintained during the whole term of the permit or concession. The breach of this obligation may result in sanctions, including fines, or even the revocation of a company s registry with the Secretary of Energy as a petroleum company. To comply with these requirements other local Argentine companies or foreign companies may grant financial support or guarantees of up to 70% of the minimum net worth requirements in favor of the entity requesting a permit or concession.

Security Zones Legislation

Pursuant to provisions of Argentine law that restrict the ability of non-Argentine companies to own real estate, oil concessions or mineral rights located within, or with respect to, areas defined as security zones (principally areas located on the border of Argentina s national geographic limits), prior approval by the Argentine government for any additional acquisition of real estate, mineral rights, oil or other Argentine government concessions located within, or with respect to, the security zones may be required if (i) non-Argentine shareholders acquire control of us or (ii) the majority of our shares become owned by non-Argentine shareholders.

Transportation

The Hydrocarbons Law grants hydrocarbon producers the right to obtain from the federal executive branch a 35-year transportation concession for the transportation of oil, gas and their by-products through public tenders.

Producers granted a transportation concession remain subject to the provisions of the Natural Gas Law, and in order to transport their hydrocarbons do not need to participate in public tenders. The term of a transportation concession may be extended for an additional ten years upon application to the federal executive branch.

Transporters of hydrocarbons must comply with the provisions established by Decree No. 44/91, which implements and regulates the Hydrocarbons Law as it relates to the transportation of hydrocarbons through oil pipelines, gas pipelines, multiple purpose pipelines and/or any other services provided by means of permanent and

Table of Contents

fixed installations for transportation, loading, dispatching, tapping, compression, conditioning infrastructure, and hydrocarbon processing. This decree is applicable currently and primarily to oil pipelines and not to gas pipelines. (Gas pipelines are subject to ENARGAS regulations.)

The transportation concessionaire has the right to transport oil, gas, and petroleum products and to construct and operate oil pipelines and gas pipelines, storage facilities, pumping stations, compressor plants, roads, railways, and other facilities and equipment necessary for the efficient operation of an oil, gas and petroleum product pipeline system. While the transportation concessionaire is obligated to transport hydrocarbons on a non-discriminatory basis on behalf of third parties for a fee, this obligation applies only if such producer has surplus capacity available, and after such producer s own transportation requirements are satisfied.

Depending on whether it is gas or crude oil that is transported, transportation tariffs are subject, respectively, to approval by ENARGAS or the Secretary of Energy. Resolution No. 5/04 of the Secretary of Energy sets forth:

(i) maximum amounts for tariffs on hydrocarbon transportation through oil pipelines, and multiple purpose pipelines, as well as the tariffs on storage, use of buoys, and the handling of liquid hydrocarbons; and

(ii) maximum deduction amounts that may be applied in connection with crude oil transportation by producers that, as of the date of the regulation, transport their production through their own unregulated pipelines, for the purpose of assessing royalties.

Upon expiration of a transportation concession, ownership of the pipelines and related facilities is granted to the Argentine government at no cost.

Refining

Hydrocarbon refining activities by oil producers and other third parties are subject to Law 13,660 and Oil Deregulation Decrees, which provide the basic regulatory framework for these activities in Argentina. The Secretary of Energy is the authority that enforces Law 13,660 and its regulations.

Hydrocarbon refining activities are subject to registration requirements established by the Secretary of Energy, such as the requirement to register with the registry of oil companies, which is granted on the basis of general, financial, and technical standards. Furthermore, liquid fuel retail outlets, points of sale for fuel fractioning, resale to large users, as well as, supply contracts entered into between service stations and each oil company are required to be registered in registers created by the Secretary of Energy.

Refiners are authorized to freely market their products in the national and export markets (subject, in the case of exports of diesel and liquefied petroleum gas, to prior regulation) and to freely install gas stations identified with their own or third parties representative flag, provided that their own gas stations or those directly operated by oil companies do not exceed 40% of their distribution network (subject, in the case of exports of diesel and liquefied petroleum gas, to prior registration).

This regulatory empowerment of the Secretary of Energy is also delegated to the provinces and municipal districts, and, therefore, refining activities must also comply with provincial and municipal safety and technical regulations. The installation and operation of gas stations must not only comply with technical, safety, and quality standards set by the Secretary of Energy, but their authorization also requires compliance with municipal regulations.

Market Regulation

Under the Hydrocarbons Law and the Oil Deregulation Decrees, the holders of exploitation concessions have the right to freely dispose of their production either through sales in the domestic market or abroad.

Pursuant to Decree No. 1589/89, relating to the deregulation of the upstream oil industry, companies engaged in oil and gas production in Argentina are free to sell and dispose of the hydrocarbons they produce and are entitled to keep out of Argentina up to 70% of the foreign currency proceeds they receive from crude oil and gas sales, while being required to repatriate the remaining 30% through Argentine exchange markets. During 2002, as a result of the reestablishment of a system that requires exporters of domestic products to repatriate foreign currency amounts generated by their exports, many controversies arose among producers and the authorities regarding the enforceability of the right to freely dispose of up to 70% of their foreign currency. These controversies were even subject to legal suit, and many federal judges have pronounced on and recognized the prima facie validity of producers rights. In December 2002, we filed before a federal court of the Province of Santa Cruz, a temporary injunction against the federal executive branch, requesting the maintenance of the status quo which allows us to freely dispose of up to 70% of our export proceeds. This right was prima facie admitted by the court. On December 31, 2002, Decree No. 2703/02, effective as of January 1, 2003, was enacted. This decree declared the right to dispose of 70% of foreign currency but had no provisions related to this right during 2002. Therefore, in order to avoid any uncertainty regarding the application of this right during 2002, in February 2003, we filed a civil action of certainty, requesting that the court recognize our right to freely dispose of up to 70% of our foreign proceeds in 2002, based on the effectiveness of Decree No. 1589/89.

The Hydrocarbons Law authorizes the federal executive branch to regulate the Argentine oil and gas markets and prohibits the export of crude oil during any period in which the federal executive branch finds domestic production to be insufficient to satisfy domestic demand. In the event the federal executive branch restricts the export of oil and petroleum products or the free disposal of natural gas, the Oil Deregulation Decrees provide that producers, refiners and exporters shall receive a price, in the case of crude oil and petroleum products, not lower than that of similar imported crude oil and petroleum products and, in the case of natural gas, not less than 35% of the international price per cubic meter of Arabian light oil, at 34 degrees.

On May 23, 2002, the Argentine government issued decree No. 867/02 declaring an emergency in the supply of hydrocarbons in Argentina through October 1, 2002. This decree authorized the Secretary of Energy to determine quotas on the minimum volumes of petroleum and LPG produced in Argentina that must be sold on the domestic market. By means of Resolution No. 140/02, the Secretary of Energy established that in June, July, August and September of 2002, only 36% of the oil produced in each preceding month could be exported. In addition, during this emergency period, no producer or exporter of oil was permitted to export a volume of oil higher than the volume it exported during the equivalent months of 2001. The emergency resolution was amended and finally repealed on July 26, 2002.

Argentina is currently suffering an energy crisis, and there is an agreement in principle, subject to the approval of the federal executive branch, for gas producers to sell a minimum specified amount in the local market in exchange for price increases. This proposal may change during the approval process. See Item 3. Key Information Risk Factors Factors Relating to Argentina Limits on exports of hydrocarbons could lower our anticipated dollar-denominated cash receipts.

Taxation

Holders of exploration permits and production concessions are subject to federal, provincial, and municipal taxes and regular customs duties on imports. The Hydrocarbon Law grants such holders a legal guarantee against new taxes and certain tax increases at the provincial and municipal levels. Permit holders and concessionaires must pay an annual surface tax based on the area held.

On January 6, 2002, the Argentine Congress enacted the Public Emergency Law. Pursuant to the Public Emergency Law, all foreign-denominated bank deposits were converted into peso-denominated bank deposits at a rate of P$1.4 per U.S. dollar, and all dollar-denominated debts with Argentine financial institutions were converted into peso-denominated debts at a rate of one-to-one. Under the Public Emergency Law, the Argentine Congress delegated the right to issue secured government bonds to the federal executive branch in order to compensate it for the effect of pesification and to ameliorate the situation of financial institutions.

The Public Emergency Law established a five-year export tax on hydrocarbon exports as security for these bonds, and empowered the federal executive branch to establish the applicable tax rate. By virtue of Decree No. 310/02, the federal executive branch determined that the applicable tax rate would be 20% on crude oil and 5% on petrochemical and oil by-products. On May 13, 2002, by Decree No. 809/02, the federal executive branch temporarily extended the 20% export tax to other hydrocarbon exports, such as petrochemical and oil by-products, stating that the 20% export tax applicable to hydrocarbon exports would be reduced to 5% on October 1, 2002.

Through Resolution No. 77, the Secretary of Energy regulates the payment of tolls by persons and companies that are subject to audit and control under technical and security regulations for the fractionation and sale of liquid gas and the transportation of liquid hydrocarbons and its derivatives through pipelines. It provides the methods and terms and conditions for payment of the tolls.

Stability of Diesel Prices Supply to the Domestic Market

Decrees No. 645/02 and 652/02 and Resolution No. 38/02 of the Secretary of Energy were published in the *Official Gazette* on April 22, 2002 and were aimed at overcoming the diesel fuel supply shortage.

Decree No. 645/02 provides that diesel exports must be registered and empowers the Secretary of Energy to expand the list of hydrocarbons subject to registration, depending on the condition of the domestic market. The Secretary of Energy has also been authorized to discontinue the registration system if the situation in the domestic market so warrants.

Resolution No. 202/02 of the Secretary of Energy, dated December 19, 2002, modified Decree No. 645/02 by canceling the registration system established by that decree for crude oil export transactions. This resolution also provides for the automatic registration and approval of diesel oil and liquefied petroleum gas exports such that simple evidence of a receipt of the form signed by an attorney of the export company is considered sufficient evidence of the registration and approval of the transaction.

By means of Decree No. 652/02, the federal executive branch ratified the diesel supply stability agreement for public transportation services, dated April 19, 2002, among the national government and hydrocarbon producing and refining companies. Under the agreement:

(i) refining companies agreed to supply the domestic market with diesel for the public transportation service at a set maximum price until July 31, 2002;

(ii) hydrocarbon manufacturers agreed to supply local refineries with the same amount of crude oil that they had supplied in the first quarter of 2002, plus an additional amount (with a fixed price and exchange rate), until July 31, 2002; and, in turn,

(iii) the national government agreed to allow manufacturing companies to offset against export duties:

- the amount of any costs, penalties and indemnities incurred due to the total or partial cancellation of supply to third parties, which were incurred for purposes of complying with the stability agreement; and

- any differences between the fixed price and exchange rate set by the agreement and market prices and rates.

The parties also agreed that, if the fixed price and exchange rate at which manufacturers have agreed to sell their products exceeds a certain limit, either party may request that the agreement be renegotiated. If no agreement is reached in this respect, then the agreement may be terminated.

Decree No. 652/02 has been extended by means of Decree Nos. 1,912/02, 704/03, 447/03 and 301/04 until December 31, 2003.

Subsequently, Decree No. 1,912/02 ratified the agreement on extension of the stability agreement and the first quarterly agreement. Under the extension to the stability agreement, the national government agreed to issue a resolution that would provide for the reduction of export duties imposed on diesel, from a 20% rate to a 5% rate, retroactive as of August 1, 2002.

The first quarterly agreement aimed at limiting diesel volumes that must be provided to public transportation companies at contractually discounted prices, by establishing an information and verification system. The refining companies were entitled to compensation for any differences between the net income that refining companies obtained from the sale of diesel at the market price compared to that obtained from sales at agreed upon prices. The amount of that economic compensation is verified by the Secretary of Energy, who issues a certificate permitting the refining companies to obtain from producers a rebate on the unit price of crude oil equal to the value of the compensation. Producers, in turn, may discount the amount of such rebate from export duties.

Since ratification of the first quarterly agreement, a series of extension agreements has been executed and ratified through Decrees No. 704/03 and No. 447/03. In turn, Decree No. 576/03 empowered the Cabinet of Ministers until December 31, 2003 to execute new agreements with the companies, as well as to enter into amendments to these agreements, in order to secure a continued supply of diesel at a discounted price.

Stability of Fuel Prices

With respect to crude oil prices, in January 2003, at the federal executive branch s request, hydrocarbon producers and refineries executed a temporary agreement in connection with crude oil, gasoline and diesel oil price stability in the domestic market. After successive renewals, the term of this agreement was extended until May 2004. This agreement provided for crude oil deliveries to be invoiced and paid based on the West Texas Intermediate Crude reference price, or WTI, of U.S.$28.5 per barrel instead of the actual relevant WTI. Any positive or negative difference between the actual relevant WTI, not exceeding U.S.$36 per barrel, and the reference price would be paid out of any balance generated in periods where the actual WTI is below U.S.$28.5 per barrel. Refineries, in turn, would reflect the crude oil reference price in domestic market prices. In February 2004, a new agreement corresponding to the period beginning on March 1, 2004 and ending on April 30, 2004 was reached between producers and refineries, but the Secretary of Energy has not yet approved this agreement because it contains a difference concerning the interest rate to be used to calculate the debt between producers and refiners. If the situation continues in the future, producers shall be forced to reinvoice refiners in order to adjust prices. Notwithstanding this situation, beginning in May 2004, hydrocarbon producers and refineries have informally agreed that while the WTI per barrel ranges between U.S.$32 and U.S.$42, crude oil deliveries will be invoiced and paid based on a reference price equal to (i) 86% of the WTI as long as this price does not exceed U.S.$36 per barrel, or (ii) 80% of the WTI, in cases where this price exceeds U.S.$36 per barrel.

Royalties

The national government has provided that the Central Bank will be responsible for issuing the regulations that may be required to apply the provisions of Section 5 of Decree No. 1,589/89, which will permit producing companies to dispose of their proceeds from sales in the domestic market, and the national government has described the manner in which these regulations shall apply during the course of the Argentine economic crisis.

Under Resolution No. 76/02 of the Ministry of Economy, royalties on oil exports must be fixed taking into account the seller exchange rate of Banco de la Nación Argentina on the day before the royalty is paid.

However, from December 2001 until May 2002, producers and refiners agreed to negotiate a reduced exchange rate in order to moderate the impact of the devaluation in product prices. Producers calculated and paid royalties according to this reduced exchange rate. These calculations have been rejected by Argentine Provinces, which have presented claims for any shortfall arising from this agreement.

The Argentine Gas Industry and Regulatory Framework

Background

In 1992, the Natural Gas Act and related decrees of the federal executive branch were passed providing for the privatization of GdE. The Natural Gas Act and the related decrees provided for, among other things, the transfer of substantially all the assets of GdE to two transportation companies and eight distribution companies. The transportation assets were divided into two systems on a geographical basis, the northern and southern area pipeline systems, designed to give both systems access to gas sources and to main centers of demand, including the greater Buenos Aires region. The distribution assets were also divided on a geographical basis.

A majority stake in each of the ten companies was sold to private bidders through a public tender process. Each consortium of bidders was required to be qualified on the basis of technical merit, including having a consortium participant with previous experience as an operator of gas transportation or distribution facilities. Accordingly, each consortium included one or more significant international operators.

The Natural Gas Act and related decrees granted each privatized company a license to operate the transferred assets, established a regulatory framework for the privatized industry based on open, non-discriminatory access, and created ENARGAS to regulate the transportation, distribution, marketing and storage of natural gas. The Natural Gas Act also provided for the regulation of wellhead gas prices in Argentina for a period of between one and two years beginning in June 1992 with prices to be deregulated no later than June 1994. Pursuant to a subsequent decree, gas prices were deregulated as of January 1, 1994. Since the deregulation, prices have risen with variances based on the basin and the season of the year.

As part of the privatizations, the concessionaires assumed a series of obligations aimed at correcting the previous situation. In particular, concessionaires agreed to incorporate modern technology and make greater investments in equipment, thereby improving quality and safety levels to comply more closely with international standards and ensuring a supply necessary to meet a growing demand. In addition, operating efficiencies were sought, with a view to sharing these benefits with the consumers through tariff rebates.

In exchange, the companies were entitled to tariff levels that ensured a reasonable and fair profit, comparable with profits at the domestic and international levels. In line with that objective, tariffs were to be denominated in U.S. dollars, in order to permit companies to better match their income with their expenses and investments, which in large part were tied to foreign markets, both through the import of specialized equipment and foreign financing.

Regulatory Framework

Natural gas transportation and distribution companies operate in an open access, non-discriminatory environment under which producers, large users and certain third parties, including distributors, are entitled to equal and open access to the transportation pipelines and distribution system in accordance with the Natural Gas Act, applicable regulations and the licenses for privatized companies. In addition, a regime of concessions under the Hydrocarbons Law is available to exploitation concessionaires to transport their own gas production.

The Natural Gas Act prohibits gas transportation companies from buying and selling natural gas. Additionally, gas producers, storage companies, distributors and consumers who contract directly with producers may not own a controlling interest (as defined in the Natural Gas Act) in a transportation company. Furthermore, gas producers, storage companies and transporters may not own a controlling interest in a distribution company, and no seller of natural gas may own a controlling interest in a transportation or distribution company (unless such seller neither receives nor supplies more than 20% of the gas received or transported, on a monthly basis, by the relevant distribution or transportation company).

Contracts between affiliated companies engaged in different stages in the natural gas industry must be reported to ENARGAS. ENARGAS may disapprove such contracts only if it determines that they were not entered into on an arm s-length basis.

ENARGAS

ENARGAS is an autonomous entity which functions under the Ministry of Economy and Public Works and Services of Argentina and is responsible for a wide variety of regulatory matters, including the approval of rates and rate adjustments and transfers of controlling interests in the distribution and transportation companies. ENARGAS is governed by a Board of Directors composed of five full-time directors who are appointed by the federal executive branch subject to confirmation by the Argentine Congress.

ENARGAS has its own budget which must be included in the Argentine national budget and submitted to Congress for approval. ENARGAS is funded principally by annual control and inspection fees that are levied on regulated entities in an amount equal to the approved budget, net of collected penalties, and allocated proportionately to each regulated entity.

Conflicts between two regulated entities or between a regulated entity and a third-party arising from the distribution, storage, transportation or marketing of natural gas must first be submitted to ENARGAS for its decision. ENARGAS s decisions may be appealed through an administrative proceeding to the Ministry of Economy or directly to the federal courts.

Table of Contents

Rate Regulation

Overview

Since the adoption of the Public Emergency Law and the other emergency measures taken by the Argentine government in early 2002, the regulation of public utility tariffs including those for gas transportation and distribution has changed dramatically. The rapid implementation of these rate changes has resulted in a complex and often conflicting legal framework. Although the rate regulations described below are still in effect, in practice, they have for the most part been superseded by new regulations which we summarize later in this annual report. See Public Emergency Law. We cannot provide assurance on which regulatory scheme will ultimately be implemented by the Argentine government once it acts to conform the conflicting regulations.

The Natural Gas Act regulates the rates for gas transportation and distribution services, including those of TGS. Under the TGS license, TGS is permitted to adjust rates (i) semi-annually to reflect changes in the U.S. Producer Price Index, and (ii) every five years in accordance with efficiency and investment factors to be determined by ENARGAS. In addition, subject to ENARGAS s approval, rates may be adjusted from time to time to reflect cost variations resulting from changes in the tax regulations (other than income tax) applicable to TGS, and for objective, justifiable and non-recurring circumstances.

The Natural Gas Act provides that the tariffs for natural gas charged to end users by distribution companies shall consist of the sum of three components: (i) the price of gas purchased; (ii) the transportation tariff for transporting gas from the production area through the distribution system; and (iii) the distribution tariff. The rates of TGS are expressed in U.S. dollars and are adjusted every five years in accordance with efficiency and investment factors determined by ENARGAS. The ratemaking methodology contemplated by the Natural Gas Act and the TGS license is the price-cap with periodic review methodology, a type of incentive regulation which allows regulated companies to retain a portion of the economic benefits arising from efficiency gains.

Under the terms of the TGS gas transportation license, TGS could increase rates semi-annually based on the U.S. producer price index. In January 2000, ENARGAS, TGS and the other gas transportation and distribution companies agreed to postpone the Producers Price Index, or PPI, adjustment scheduled for January 2000. In August 2000, Decree No. 669/00 was issued which (i) allowed TGS to bill its customers retroactively for the January 2000 PPI rate adjustment over a 12-month period, and (ii) postponed any further PPI rate adjustments until July 2002. Decree No. 669/00 allows TGS to bill its customers retroactively for these postponed PPI rate adjustments beginning in July 2002. Decree No. 669/00 also allows TGS to add an interest charge to its bills in order to compensate it for the delay in billing these PPI rate adjustments.

In late August 2000, a court proceeding was commenced, which challenged the legality of Decree No. 669/00, claiming that the PPI rate adjustments contradict the Convertibility Law. The court suspended the application of Decree No. 669/00 and, subsequently, ENARGAS notified TGS that it should not apply any PPI rate adjustments until the court proceeding is resolved. As a result of the enactment of the Public Emergency Law, ENARGAS notified TGS of the suspension of the second five-year review of its tariffs. This review had begun in 2000. Because of certain provisions of the Public Emergency Law and our contract renegotiation efforts, we do not expect that Decree No. 669/00 will be upheld nor do we expect that TGS will ultimately be able to retroactively bill its clients for PPI rate adjustments.

Notwithstanding the foregoing, through Decree No. 689/02, the federal executive branch exempted the following from the pesification required by the Public Emergency Law and Decree No. 214/02: (i) tariffs for the regulated transportation of natural gas destined for export; (ii) agreements for the transportation of natural gas destined for export; and (iii) purchase and sale contracts for natural gas destined for export whose terms had been originally fixed in a currency other than the Argentine peso (these contracts are to be invoiced and paid in U.S. dollars at an exchange rate of P$1/U.S.$1).

Decrees No. 689/02 and 704/02 excluded from pesification the obligations to pay in foreign currency incurred by individuals or companies residing or located outside Argentina, payable with funds coming from abroad, to individuals or companies residing or located in the country. Under Resolution No. 2,774/02, which was based on these decrees, ENARGAS reinstated the PPI index as an adjustment coefficient for transportation tariffs in respect of gas destined for exportation, and consequently, with respect to natural gas destined for exportation, approved the tariff schedules presented by TGS effective as of July 1, 2002, and permitted the denomination of the charges related to each type of service to be in U.S. dollars.

Public Emergency Law

The Public Emergency Law established that in contracts related to public works and services, clauses setting forth the price of such works and services in foreign currencies and indexation clauses based on foreign price indices or any other indexation mechanisms are no longer valid. Prices and tariffs resulting from those clauses had to be converted into pesos at a conversion rate of P$1=U.S.$1. Pursuant to this law, the Argentine federal executive branch is authorized to renegotiate the terms of these contracts. The criteria for these renegotiations include:

- the impact of tariffs on economic competitiveness and income distribution;
- the quality of the services to be provided and/or the capital expenditure programs provided for in the contracts;
- the interests of customers and accessibility to the services;
- the safety of the systems; and
- the provider s profitability.

On February 12, 2002, the federal executive branch issued Decree No. 293/02, putting the Ministry of Economy in charge of the renegotiation of contracts related to public works and in charge of selecting a Renegotiation Committee, which committee includes a representative of customers and assists the Ministry in the renegotiations. Since July 2003, by means of Decree No. 311/03, the renegotiation process has been conducted by the Union of the Renegotiation and Analysis of Public Service Contracts (*Unidad de Renegociación y Análisis de Contratos de Servicios Públicos*), which is comprised of the relevant secretaries of state with jurisdiction over the specific utility sector undergoing the renegotiation process. The Ministry of Economy was required to submit a renegotiation proposal or a rescission recommendation to the federal executive branch within 120 days of February 15, 2002. This proposal or recommendation would then be submitted to Argentine Congress for their review.

On March 21, 2002, the Renegotiation Committee delivered to the licensed companies guidelines on the renegotiation process approved by the Ministry of Economy. In April 2002, these licensed companies submitted to the Renegotiation Committee the information required by the guidelines and agreed to cooperate in finding realistic and possible solutions within a serious economic and social crisis of the country.

Early in August 2002, the Renegotiation Committee asked the licensees to set forth the tariff increases requested by each, and they, in turn, requested a public hearing for a discussion on this issue.

The process of contract renegotiation unilaterally imposed by the government did not show any significant progress in the year following its enactment. In the course of 2002, the public hearings convened for the tariff review were suspended by the Argentine courts. Within this framework, Resolution No. 38/02 of the Ministry of Economy ordered the regulatory agencies to suspend their five-year reviews on gas and electricity tariffs. This suspension does not cover the seasonal adjustments for producers, which is defined by the Secretary of Energy. Resolution No. 75/02 has approved the seasonal adjustment for the electricity market from May to October 31, 2002.

The national government tried to grant a tariff increase through Decree No. 2,437/02, which was also invalidated by the courts. In light thereof, the federal executive branch issued Decree No. 120/03, which tried to cast the Public Emergency Law in a manner that would permit an immediate grant of tariff increases to the licensed companies on account of future renegotiation of the contracts. In January 2003, the federal executive branch issued Decree No.

146/03, which establishes tariff increases as of January 30, 2003. Thereafter, a number of organizations representing consumers filed amparo proceedings to revoke those tariff increases and obtained judgments favorable to their claims.

Table of Contents

On December 4, 2003, Law 25,820 was promulgated, which extended up to December 31, 2004 the public emergency declared by Law 25,561 on social, economic, administrative, financial and foreign exchange matters, and the delegation of powers provided to the federal executive branch to renegotiate the tariffs of the public services and license contracts. This law empowers the federal executive branch to negotiate tariffs without being constrained by the applicable regulatory frameworks. Any legally permitted revisions of any current tariff must be authorized by the applicable regulatory agency to the extent these revisions fall within the scope of the renegotiation process led by the executive branch. Also, any agreed transitory changes to the utility service agreements and/or licenses must be considered in the definitive agreements.

Modifications to the Regulatory Framework

On February 16, 2004, Decree No. 180/04 was published in the Official Gazette providing for:

(i) the creation of a trust fund (the trust will be funded by tariffs payable by users of the service, special credit programs and contributions from direct beneficiaries);

(ii) the creation of an electronic market to coordinate spot transactions of the sale of natural gas and secondary market transactions for transportation and distribution of natural gas;

(iii) the expansion of section 34 of Decree No. 1738 that regulates Gas Law 24,076 to prohibit distributors or their shareholders from having a controlling participation in more than one dealing company; and

(iv) an authorization by the Secretary of Energy to take all necessary measures to maintain an adequate level of services in the event that it verifies that the system could face a supply crisis.

Adjustment of the Price of Natural Gas in Wellhead

On February 16, 2004, Decree No. 181/04 was published in the Official Gazette that instructed the Secretary of Energy to design a framework for the normalization of prices of natural gas at the wellhead. This framework is to be applicable to both distributors and major consumers. The decree authorizes the Secretary of Energy to negotiate with gas producers on a price framework for the adjustment of prices in sale contracts to distributors. It also authorizes the Secretary of Energy to determine a category of users who will not be able to buy gas from distributors but, rather, must buy directly from producers. A new mechanism for protection of this new category of consumers must be established to guaranty supply and price, and must be extended to July 31, 2005.

The decree further states that prices resulting from sales pursuant to the agreement with producers shall be the prices used as a reference for calculating and paying royalties. These prices will also be used by ENARGAS in calculating any necessary adjustments in tariffs that result from variations in the price of purchased gas. The decree also states that the framework shall adjust tariffs corresponding to form R for Residential Services and P for General Services. In addition, the decree states that all agreements for the sale of natural gas shall be filed with the gas electronic market, and the Secretary of Energy has the authority to regulate the sale of gas (i) between producers, and (ii) between producers and the dealers who they either control or are affiliated with.

On April 2, 2004, the Secretary of Energy entered into an agreement with natural gas producers, in which the following was agreed to:

the minimum volumes that natural gas producers must supply to the local market, including specified amounts for: (i) distributors who supply industrial users, (ii) clients of distributors (the New Direct Consumers) who are prohibited from buying directly from distributors and must buy directly from producers, and (iii) power stations that generate electricity for the local market;

the authorization of the producers to increase the prices of natural gas according to a price roadmap which differs for each basin and that culminates in complete deregulation of the wellhead price of natural gas by January 1, 2007;

the obligation of the distribution and generation companies to renegotiate the price and volumes of their supply contracts with producers who are also a party to the agreement. If an agreement is not reached after a 45-day period, producers are released from their obligation to supply natural gas to these distribution and generation companies;

the New Direct Customers have regulated prices through June 31, 2005; and

notice of all new supply agreements must be given to the Secretary of Energy and will be published in the electronic gas market once this market starts functioning.

This agreement has already been approved by Resolution No. 208 of the Ministry of Federal Planning, Public Investment and Utilities. The public hearings at ENARGAS took place on May 6, 2004.

In addition, on March 24, 2004, under Resolution No. 265 the Secretary of Energy imposed certain restrictions in order to avoid a crisis in the supply of gas to the domestic market. Specifically, export authorizations and exports of natural gas surplus volumes were suspended and the Undersecretary of Fuels was instructed to create a program for the rationalization of gas exports and the use of the country s transportation capacity.

Under Resolution No. 27/04, which was issued by the Undersecretary of Fuels, a Program for the Rationalization of Natural Gas Exports was approved and is in effect as long as natural gas volumes in the Argentine system fail to satisfy the domestic demand. In addition, an order of priority for the selection of companies that will be subject to export suspension restrictions was established taking into account the following factors: (i) the degree of compliance with the producers commitment of gas supply to the domestic market (these commitments were established by each producer at the time the corresponding gas export authorization was granted), (ii) the history of sales to the domestic market, and as divided between sales to distributors and sales to direct consumers, and (iii) the impact that this suspension would have on the domestic market supply.

Except as expressly authorized by the Undersecretary of Fuels, no export authorizations will be granted if such authorizations would result in export volumes (not including surplus volumes) higher than those exported in 2003. For calculation purposes, volumes for each month will be compared with figures from the corresponding month of the previous year. In addition, excess volumes, if any, already exported by a producer will be offset until the end of the third quarter of 2004.

Producers that have not maintained the level of sales to the domestic market committed at the time of requesting their export authorizations will receive the average basin price for the domestic market as published by ENARGAS. On the other hand, producers who have complied with their obligations with respect to the supply of the domestic market will receive a value for their natural gas equal only to the value actually received under their respective export agreement.

On June 18, 2004 the Secretary of Energy passed Resolution 659/2004 by which the Complementary Program to Supply the Domestic Market of Natural Gas, which we refer to as the Complementary Program, was approved. The Complementary Program replaces the Program of Natural Gas Exportations and Transportation Capacity Rationing, which had been approved by Disposition 27/2004 issued by the Undersecretary of Fuels. The Complementary Program commenced on June 24, 2004 and partially eliminates the monthly and quarterly limits on the export of natural gas which was applicable under Disposition 27/2004.

On April 21, 2004, the Argentine government reached a six-month agreement with the Bolivian government. This agreement allowed Argentina to import up to 4 million cubic meters of natural gas from Bolivia per day. Also in April 2004, Resolution 185/04 of the Ministry of Federal Planning, Public Investment and Utilities was issued creating trust funds with the objective of financing infrastructure works in gas transportation.

On May 26, 2004, under Resolution 503/04 the Secretary of Energy approved a method for priority use of transportation for the supply by distributors of uninterruptible natural gas. This resolution is effective through August 31, 2004.

Table of Contents

Also in May 2004, under Executive Order 645/04, the government imposed a 20% export tax on all natural gas exports.

The Argentine Electricity Industry and Regulatory Framework

Background

Prior to 1991, virtually all of the electricity supply industry in Argentina was controlled by the public sector. Inefficient management and inadequate capital expenditures under that regime resulted in the deterioration of quality in service and physical equipment, poor financial condition and high rates for poor service.

Accordingly, the Argentine government enacted Decree No. 634/02 in March 1991, and the Argentine Congress enacted Law 24,065, known as the Regulatory Framework Law, in January 1992, establishing guidelines for the restructuring and privatization of the electricity sector within the framework of Law 23,696. The new regulatory framework of the sector established, as separate areas, the generation, transportation and distribution of electricity, and adopted separate regulatory regimes for each, thereby moving to a decentralized model with an increased participation in the private sector.

The privatization process began in February 1992 with the sale of several large thermal generation facilities, previously operated by Servicios Eléctricos del Gran Buenos Aires and has continued with the sale to the private sector of transmission and distribution facilities, as well as additional thermoelectric and hydroelectric generation facilities. The companies that have received concessions have also assumed a series of commitments to improve the quality and safety of the industry. They also plan to ensure supply by incorporating modern technologies and by making large investments in equipment and works.

Due to privatization, a higher level of quality has been achieved, with fewer losses of grid capacity during peak times. Wholesale prices have also been reduced as a direct result of new generation equipment in place of less cost-efficient power plants.

In order for the flow of revenues to be more closely associated with expenses and investments, the operations of the sector were denominated in U.S. dollars. This was because private operators often funded their large works through foreign lending institutions due to difficulty in obtaining significant amounts of financing at adequate rates in the domestic market.

Regulatory Framework

Overview

The Secretary of Energy regulates electric power supply and grants and controls electricity sector concessions at the national level through the National Directorates for Coordination and Regulation of Prices and Rates and for Electricity Planning. The Federal Board of Electric Power, made up of representatives from each province, is an advisory body to the Secretary of Energy, which coordinates policies for the electricity sector. The Federal Entity of Electricity Regulation, or ENRE, is an autonomous body which reports to the Secretary of Energy and has overall supervisory power in the electricity industry. It is managed by a board of five members selected by the federal executive branch, two of whom are individuals from a list proposed by the Federal Board of Electric Power. The members of the board of directors of ENRE are not allowed to have any economic interest in the areas under their jurisdiction.

ENRE s purpose is to pursue the objectives set out in the Regulatory Framework Law and provide regulations regarding security, the standard quality of service, and procedures for technical areas such as metering and interpretation. Accordingly, ENRE s specific duties, among others, include: (i) establishing a tariff collection mechanism; (ii) establishing the criteria and conditions for awarding concessions; and (iii) safeguarding public safety, environmental protection and property rights relating to the construction and operation of generation, transmission, and distribution facilities.

ENRE has mandatory jurisdiction over all disputes between generators, transmitters and distributors in matters relating to the public supply, distribution and transportation of electricity. If ENRE becomes aware of practices that are inconsistent with the Regulatory Framework Law and other regulations, it is empowered to notify the interested parties, hold hearings and take the appropriate authorized action. In particular, ENRE can apply penalties for noncompliance with the Regulatory Framework Law and initiate and pursue legal actions to ensure compliance therewith. Appeals to ENRE s decisions may be filed directly before the Secretary of Energy and the courts.

ENRE is required to prepare an annual budget and to submit it to the regulated entities for approval. These regulated entities are required to pay a fee to ENRE on the basis of the approved budget and their respective share in the total gross profit of all regulated entities. In addition to revenues from regulated entities from this fee, ENRE is entitled to retain cash from fines and seizures.

Structure

Under the current regulatory structure, generation of electricity in Argentina is organized as a competitive market, the Wholesale Electricity Market in which independent generators sell the power they produce to other generators, distribution companies, large scale users and into the spot market. The generation of electricity is characterized under the law as a public utility and as such is not highly regulated. In contrast, the transmission and distribution of electricity are considered public services and as such are licensed by the national and/or the provincial government. Transporters are obliged to permit third parties to have access to any available transmission capacity, but are not themselves authorized to buy or sell electricity, and are entitled to charge a toll for the provision of transmission services. Distributors are also regulated through the establishment of rates and specifications for quality of service. They are required to satisfy demand in their markets and, as long as they have any distribution capacity available, they have to permit large scale users, who have purchased electricity from a different source, to transmit such electricity through their network. Large scale users include (i) major large users, meaning consumers with a demand of at least 1.0 MW of electricity who are willing to execute contracts with a duration of at least one year and who purchase electricity through contracts that require that the suppliers meet at least 50% of their demand, and (ii) minor large users, meaning consumers with a demand between 0.1 MW and 2.0 MW of electricity who are willing to execute contracts with a duration of at least two years and who purchase electricity through contracts that require that the suppliers meet 100% of their demand.

Management and Operations of the WEM

The activities of participants in the WEM are governed by the terms of the Regulatory Framework Law. Additionally, CAMMESA was specifically created by the federal government to perform the necessary administrative functions of the WEM. CAMMESA s capital stock is distributed equally among the entities representing generation companies, transmission companies, distribution companies, large scale users and the Secretary of Energy, each of which has the right to nominate two of CAMMESA s directors. The Secretary of Energy has a veto right over the decisions taken by CAMMESA. CAMMESA s operating costs are covered by mandatory contributions made by all the members of the WEM. CAMMESA does not itself buy or sell electricity, but it manages the physical transactions of the system and commercial transactions on the spot market.

In addition to the national structure of the WEM, medium-voltage transmission and distribution of electricity (except in the city of Buenos Aires, the greater Buenos Aires area and the city of La Plata) are also subject to provincial regulation. In particular, provincial governments may, in certain cases, forbid the direct sale of electricity to large scale users within their own jurisdiction. Large scale users connected to the national interconnected system (described below), however, cannot be prevented from purchasing electricity directly from generators.

Dispatch

The dispatch of generating units into the WEM is managed by CAMMESA based on the short-run marginal cost of each unit on the system. CAMMESA defines the marginal cost of thermoelectric generating units for dispatching purposes as the cost of fuel delivered (natural gas, fuel oil, diesel oil or coal) for such unit to produce 1kWh. The marginal cost of hydroelectric plants with reservoirs that are overflowing is determined by a model that takes into account existing reservoir levels and projected hydroelectrical conditions for the subsequent six months. The marginal cost associated with flow-through hydroelectric generating units is zero, meaning that such units are the first to be dispatched.

Table of Contents

Generation companies advise CAMMESA on a weekly basis of their anticipated available energy and other relevant information such as fuel type, price and anticipated consumption. CAMMESA then ranks each generating unit according to that unit s marginal costs, taking into consideration the minimum operating load needed to keep generating units on line and expenses incurred in shutting down and restarting generating units. Based on this ranking, and in order for CAMMESA to obtain the lowest overall system cost, generating units are dispatched to the network successively from the lowest cost generating unit to the highest cost generating unit until the demand for electricity is met. CAMMESA is responsible for administering all transactions through the WEM, but is not involved in the actual settlement of transactions between generators, distributors and large users that have entered into either long-term or medium-term contracts.

CAMMESA makes optimum dispatch arrangements without taking into account the existence of long-term and medium-term agreements between generators, distributors and large scale users. CAMMESA also administers an option market in which generators may enter into option contracts known as cold reserve contracts. Finally, CAMMESA coordinates the dispatching of generators in the spot market.

As a consequence of the crisis in Argentina, the Secretary of Energy issued Resolution 2/02, which pesified the prices of power and the reference prices of fuels at an exchange rate of P$1=U.S.$1. This placed a limit on the generators stated prices. Resolution No. 8/02 established market prices that accounted for part of the variable costs in production declared by the generators, and it also established a maximum price of $120/MWh. Resolution No. 82/03 suspended the last seasonal increase of prices. Under Resolution No. 240/03, in connection with the spot market, generators are able to set a market price without considering potential restrictions in the supply of gas, and those generators, with costs higher than the established price, are individually paid their variable costs of production. By means of Resolution No.406/03 the Secretary of Energy established that all credits pending of payment by CAMMESA as a consequence of the deficit of the Stabilization Fund (due to the suspension of the seasonal increase of prices) should be consolidated and paid once this fund has sufficient monies.

Resolution SE No. 984/03 authorized the WEM to call for bids for reserve of available capacity fuel for the Argentine winter period from May through October 2004. We participated with a bid of 550 MW from the Genelba Power Plant and were awarded in advance U.S.$29,072,736.

Resolution SE No. 93/04 authorized summer quarterly rescheduling for the WEM, for the period from February up to April 30, 2004, establishing new reference seasonal prices for power and electricity.

Generation

Power plants in Argentina are classified by the type of energy source used hydroelectric, nuclear and thermoelectric (gas, fuel oil, diesel oil or coal). Power plants are also classified by capacity, defined as the net output the station is capable of sustaining for an indefinite period without causing damage to the station, which is referred to as declared net capacity.

Transmission

In Argentina, bulk transfer of electricity is achieved by means of a national interconnected system, or NIS, which consists mainly of overhead lines and substations and covers approximately 90% of the territory of Argentina. Practically all of the NIS 500 kV transmission lines have been privatized and are owned by Transener. Apart from Transener, there are five other regional subtransmission companies in charge of transmitting energy at 132 kV and 330 kV voltages, and almost all large power plants use the NIS. Supply points connect the NIS to distribution systems and large users. In addition, there are two international connections: one between the Argentine transmission system and the Uruguayan transmission system, and the other between Argentina and Brazil, which permit the import or export of electricity between these systems. The cost of transmission is charged to generators, distributors and large users. The transportation cost is made up of a variable charge corresponding to the energy transmitted across the system, and a fixed charge for (1) connection to the system, (2) transformation and (3) transmission capacity. Transmission companies operate as common carriers and must provide open access to all generation companies. Transener s rates are set by the concession contract and are to be subject to revision by ENRE. The law provides that services provided by transmission companies must be offered at fair and reasonable rates which yield sufficient income to meet reasonable operating costs applicable to service, taxes, depreciation and a reasonable rate of return. The rate of return should bear a relationship to (i) the energy costs, (ii) the use of transmission lines and (iii) the degree of operating efficiency of the business, and should be similar, as an industry average, to that of other domestic or international activities of similar or comparable risk. The rates that Transener may charge have been modified by the Public Emergency Law. See " The Argentine Gas Industry and Regulatory Framework Public Emergency Law.

Pursuant to Resolution No. 1650/98, ENRE approved an 8% overall reduction of Transener s tariffs for the second tariff period, July 1998 June 2003, retroactive to July 17, 1998. In addition, a bonus subject to compliance with certain quality parameters was approved, and currently, Transener s quality levels entitle it to a bonus of approximately P$2.5 million.

Since the beginning of the second tariff period, Transener s income from transportation capacity and connection has been reduced annually through the application of an efficiency ratio established by ENRE. Pursuant to Resolution No. 1319/98, the efficiency ratio applicable to the second tariff period is approximately 0.5% per annum.

Distribution

Electricity is transferred from the NIS supply points to consumers by means of distribution systems consisting of a widespread network of overhead lines, underground cables and substations having successively lower voltages (220 kV and below). In general, electricity users in Argentina are the users of the distributor within whose area of distribution the premises of such consumer are located. Each user is charged in accordance with the applicable tariff. Distributors charges seek to recover the various costs associated with supply, including the electricity purchase costs and transmission and distribution charges, in addition to, the added value of distribution. In accordance with Law 24,065, and in the case of transmission companies, services provided by electricity distributors must be offered at fair and reasonable rates which yield sufficient income to meet reasonable operating costs applicable to service, taxes, depreciation and a reasonable rate of return. The rate of return should bear a relationship to the degree of operating efficiency of the business, and should be similar, as an industry average, to that of other domestic or international activities of similar or comparable risk. Similarly, distributors are required to include a representative figure for the acquisition cost of electricity from the WEM in the electricity sales price to end-users.

Each distributor operates in accordance with a concession agreement executed between itself and the Argentine government or provincial government, depending on whether the distributor is under federal or provincial jurisdiction, which provides for, among other things, the area of its concession, the quality of service that it is required to provide, the tariffs it is permitted to charge and its obligation to satisfy demand. ENRE, in the case of distributors under the federal jurisdiction (Edenor, Edesur and Edelap), and the provincial regulatory agencies in each of the provinces, monitor compliance by the distributor with the provisions of the concession agreement and the regulatory framework and provide a mechanism for public hearings at which complaints against the distributor can be heard and resolved.

Rate Adjustment Method

Under the terms of the concession contract, the rate adjustment structure applicable by Edesur is calculated in U.S. dollars but stated in Argentine pesos, taking into account the rate for conversion into Argentine pesos provided for in section 3, Decree No. 2128/91, containing the regulations under Law 23,928. Distribution costs are adjusted on an annual basis and, among other things, are subject to the application of the U.S. wholesale price index for industrial products.

Since the adoption of the Public Emergency Law and other emergency measures taken by the Argentine government in early 2002, the regulation of public utility tariffs, including those related to transportation and distribution of electricity, has changed dramatically. The rapid implementation of these rate changes has resulted in a complex and oftentimes conflicting legal framework. Although the rate regulations described below are still in effect, in practice they have been superseded by the new regulations described under The Argentine Gas Industry and Regulatory Framework Public Emergency Law. We cannot assure which regulatory scheme will ultimately be implemented by the Argentine government once it acts to conform the conflicting regulations.

On December 2, 2003, Law 25,820 was promulgated, which extended until December 31, 2004 the public emergency declared by Law 25,561 on social, economic, administrative, financial and foreign exchange matters, and the delegation of powers therein provided to the federal executive branch to renegotiate the tariffs of the public services and license contracts. This authorization empowers the national executive branch to negotiate such tariffs without being constrained by the applicable regulatory frameworks. The legally permitted revisions of any current tariff should be decided by the applicable regulatory agency to the extent that these revisions fall within the scope of the renegotiation process led by the federal executive branch. In addition, the transitory changes made to the utility service agreements and/or licenses should be considered in the definitive agreements that may be reached with respect thereto.

The Venezuelan Petroleum and Gas Industry and Regulatory Framework

Overview

The Venezuelan state is owner of all hydrocarbon fields and as such has established methods different from Argentina for the regulation of the exploitation of hydrocarbon located in Venezuelan fields.

The Gas Hydrocarbons Organic Law published on September 23, 1999 in Official Gazette No. 36,793, was issued to regulate the exploitation of free gas and the transportation, distribution, collection, storage, industrialization, handling and internal and external commerce of associated gas and free gas, permitting the private sector s participation in these activities. This was later regulated by Decree No. 840 of May 31, 2000.

In December 1999, the new Venezuelan Constitution became effective, which contains provisions related to petroleum activity. Article 12 of the Constitution states that oil fields are the property of the Venezuelan state. Article 302 of the Constitution reserves petroleum activity to the Venezuelan state. Article 303 of the Constitution states that, PDVSA or the entity created for the management of petroleum activity (except for affiliates, strategic associations, companies or any other company set up to develop PDVSA s business) is owned by Venezuelan state.

The new Hydrocarbons Organic Law published on November 13, 2001 in Official Gazette No. 37,323 was issued, effectively reversing most prior related legislation, except for the Gas Hydrocarbons Organic Law, and granted ample opportunity for the private sector to participate in the industry, limiting the activities reserved by the Venezuelan state to primary activities, and to the sale of crude oil and specific products.

The purpose of the Hydrocarbons Organic Law is to regulate everything related to the exploration, exploitation, refinery, industrialization, transportation, storage, commercialization and conservation of hydrocarbons, and everything related to refined products and works that the performance of these activities require. The law sets forth the following principles: (i) hydrocarbon fields are public property, (ii) hydrocarbon activities are activities of public utility and of social interest, and (iii) activities described in the law are subject to decisions of the Venezuelan state adopted in connection with international treaties and agreements on hydrocarbons.

The Performance of Hydrocarbon Related Activities

The primary activities expressly reserved by law to the Venezuelan state can only be performed by: (i) the executive branch, (ii) wholly owned state entities, or (iii) companies in which the Venezuelan state owns at least 50% of the capital stock. Activities related to the internal and external sale of natural hydrocarbons and the derivatives, specifically mentioned by the executive branch, can only be performed by wholly owned state entities. Installations and existing facilities dedicated to the refining of natural hydrocarbons in the country and to the transportation of products and gas are reserved to the Venezuelan state.

Hydrocarbon refining activities may be carried out by the Venezuelan state and private entities, in a joint effort or separately. Those activities relating to the internal and external sale of derivative products, which have not been reserved by the executive branch to be carried out by wholly owned state entities, may be carried out directly by (i) the Venezuelan state, (ii) by wholly owned state entities, (iii) by entities with public and private capital in any proportion, or (iv) by private entities. Pursuant to Decree No. 1,648 dated January 15, 2002, activities related to the exportation and importation of products derived from hydrocarbons that have been carried out in the past by wholly owned state entities shall continue to be carried out in such manner until those products are specifically excluded in order to create an international market for them. Internal commercial activities regarding services deemed as public

Table of Contents

may be performed by anyone who obtains a permit. The sale of refined hydrocarbons may be performed by (i) the Venezuelan state, (ii) its wholly owned state entities, (iii) entities with public and private capital in any proportion, and (iv) private entities.

In order for the Venezuelan state to carry out its activities, the executive branch is authorized to create, through a Council of Ministers, wholly owned state entities of any kind, including corporations. These entities may also create other entities, with the approval of their shareholders, or modify their corporate purpose, merge, enter into joint ventures, liquidate, and create affiliates. These wholly owned state entities are regulated by (i) Decree No. 1,648 and its regulations, (ii) their by-laws, (iii) dispositions of the executive branch and certain entities connected with the Ministry of Energy and Mines, and (iv) applicable law. They are also subject to local and international inspection and audit and must comply with guidelines and policies of the executive branch administered through the Ministry of Energy and Mines.

The private sector may participate in primary hydrocarbon related activities only through entities in which the Venezuelan state holds the majority of the capital. The creation of these entities and the conditions under which they will carry out their activities must be previously approved by the National Assembly, which may modify the conditions proposed or set forth conditions that it, itself, considers suitable. These entities must meet the following minimum conditions: (i) must have a maximum duration of 25 years (which may be extended for 15 years), (ii) must provide information regarding location, orientation and extension of the area, (iii) all of their assets must be reserved and turned over to the Venezuelan state once the activity ends, and (iv) any dispute among its shareholders must be resolved through private negotiations or arbitration and shall be subject to the Venezuelan legal system.

Licenses and permits

Entities that wish to carry out activities related to the refining of natural hydrocarbons must obtain a license from the Ministry of Energy and Mines. This license is subject to certain conditions. Entities that wish to carry out activities related to the processing of refined hydrocarbons must obtain a permit from the Ministry of Energy and Mines. This permit is also subject to certain conditions. Entities that wish to carry out activities related to the domestic sale of refined hydrocarbons must obtain a permit from the Ministry of Energy and Mines.

Relevant tax features

Income Tax

Venezuelan income tax law imposes a tax at a rate of 50% on the net taxable income of persons involved in hydrocarbon related activities, or activities related to the purchase or acquisition of hydrocarbons and derivatives for exportation. These persons may be authorized to deduct from their income tax 8% of the value of new investments in fixed assets up to a maximum amount equal to 2% of their annual income for the relevant fiscal year. Any excess may be used in the following three fiscal years. Four percent of certain investments in high waters may also be deducted. Accelerated amortization and depreciation of fixed assets and direct or indirect expenses necessary for the drilling of oil wells is permitted.

Activities related to the exportation of extra-heavy hydrocarbons through vertically integrated projects or the exploration or exportation of natural non-associated gas are subject to a 34% rate.

Contractors dedicated to exploration and production activities under operative agreements with state companies are subject to a 34% rate.

Value Added Tax

Subject to certain exceptions, in particular for exporting companies, imports and local purchases of goods and services are subject to a value added tax, or VAT, at a rate of 16%, with a limited number of goods and services subject to a VAT at a rate of 8%.

In operative contracts for the rehabilitation of marginal fields, the VAT on goods and services acquired by the contractor in the name of the state company shall be considered directly charged, under the Third Round Agreements, to that entity and, therefore, will have no economic effect on the contractor.

Municipal Taxes

Hydrocarbon activity is not subject to municipal taxes, as taxes on this activity are exclusively reserved for the national executive branch.

Income from contractors that have entered into operative contracts with state companies for the rehabilitation of marginal fields is subject to a tax on gross income. The municipality in which the contractors perform their activities sets this rate. Under the Second Round Agreements, municipal taxes paid by a contractor can be recovered from the state. However, under the Third Round Agreements, only municipal taxes in excess of 41% of gross income may be recovered from the state, subject to certain conditions.

Additional Matters

OPEC

Venezuela is a founding member of the Organization of Petroleum Exporting Countries. In the past, PDVSA, under instructions from the Ministry of Energy and Mines, has adjusted its own production to assure that Venezuela as a whole complies with the production ceilings set forth by OPEC.

The Venezuelan government has created a policy of strict compliance with the production quotas decided within OPEC. Article 6 of the new Hydrocarbons Law extends reductions such as those that may be set forth by OPEC to all persons that perform activities regulated by the Hydrocarbons law. As a result of this, if there are productions cuts, these cuts may directly affect private producers and contractors as well as PDVSA.

Under agreements that specifically contemplate production costs (e.g., the Third Round Agreements), the reductions that may be imposed on the contractor may not exceed the percentage of reduction in production requested from petroleum companies that operate in Venezuela as a whole, including Petróleos Venezuela, S.A. and its affiliates. These reductions must be determined in each case with respect to available production capacity. If the contractor cannot recuperate losses resulting from these production cuts by increasing production to an adequate level, it has the right to extend the original 20 year term of its operating agreement in order to produce the same quantity that it would have produced without the production cut.

Exchange Control System

On February 5, 2003, the Venezuelan government set forth an exchange control system (Exchange System Agreement No. 1 of February 5, 2003, as amended on March 19, 2003). These regulations state that companies set up for the purpose of developing any of the activities described in the Hydrocarbons Organic Law may maintain outside of Venezuela accounts in currency other than the currency of Venezuela in banking or similar institutions only for purposes of meeting their obligations outside Venezuela, which obligations must be verified by the Central Bank of Venezuela. Any other foreign currency generated by such companies must be sold to the Central Bank of Venezuela. These companies do not have the right to acquire foreign currency from the Central Bank of Venezuela to make foreign currency payments. These limitations do not apply to contractors who have entered into operative agreements, and, thus, act on account of the PDVSA. These companies are only obligated to sell to the Central Bank of Venezuela any foreign currency that they voluntarily bring into Venezuela.

The Bolivian Petroleum and Gas Industry and Regulatory Framework

Overview

In Bolivia, the System of Regulation by Sectors, or SRS, has the responsibility to regulate, control and supervise telecommunications, electricity, hydrocarbons, transportation and water activities, to assure that they operate efficiently, protecting the interest of users, service providers and the Bolivian state by contributing to the development of the country.

The SRS Law of October 1994 created the SRS and defined the functions of the General Superintendent and the general attributes of the Sectors Superintendent. The SRS Law and its regulations include provisions related to antitrust and competition, appeal mechanisms, and procedures to address claims from users.

Subsequently, laws were enacted that regulate different public services, including hydrocarbons. In particular, these laws create rules related to the granting of rights, prices and tariffs, quality of services, coverage, technological innovation, entry and exit control, use of natural recourses, users claims, and they regulate issues related to industrial organization, identifying the different market structures of each industry.

Hydrocarbons Law 1689

Pursuant to the Hydrocarbons Law 1689 of April 30, 1996, the right to explore and exploit hydrocarbons fields and to commercialize their products is exercised by the Bolivian state through Yacimientos Petrolíferos Fiscales Bolivianos, or YPFB, which enters into shared risk agreements that may not exceed 40 years for the exploration, exploitation and commercialization of hydrocarbons. YPFB also administers and audits the shared risk agreements. All controversies arising between YPFB and the contractors under shared risk agreements must be resolved through arbitration with application of Bolivian law.

The holders of shared risk agreements shall have the right to explore, exploit, extract, transport and commercialize production. Volumes needed to satisfy internal demand for natural gas and to comply with the exportation agreement entered into by YPFB are not freely disposable, and the Hydrocarbons Superintendent periodically sets these volumes.

Producers of hydrocarbons have the right to construct and operate pipelines for transportation of their own or third parties production.

The refining and industrialization of hydrocarbons and the commercialization of hydrocarbon products is not restricted and may be carried out by any entity with due registration from the Hydrocarbons Superintendent, as long as that entity complies with specific legal requirements.

The Ecuadorian Petroleum and Gas Industry and Regulatory Framework

Legal and Regulatory Framework

Petroleum activity in Ecuador is regulated by (i) the Hydrocarbons Law (of Ecuador) and its regulations, (ii) certain Ministry of Energy and Mines regulations, and (iii) the specific terms of a tender for public auction.

Regulatory Authorities

The executive branch, led by the President of the Republic, regulates hydrocarbon policies. The Ministry of Energy and Mines sends hydrocarbon policies to the President for his consideration.

Audit Authorities

The National Directorate of Hydrocarbons, who is under the authority of the Ministry of Energy and Mines, is the technical and administrative entity in charge of controlling and auditing hydrocarbon operations. The National Directorate for Environmental Protection, who is also under the authority of the Ministry of Energy and Mines, is in charge of approving environmental impact studies and environmental management plans.

Exploration and Exploitation of Hydrocarbons

Hydrocarbons and related products are the property of the Ecuadorian state. Hydrocarbon activities are performed by the Empresa Estatal de Petroleos Ecuador, which we refer to as Petroecuador, by and through third parties.

The award of exploration and exploitation agreements is performed through a special tender mechanism implemented by relevant authorities. In order to reach the exploitation phase, the contractor may only retain those areas with commercially exploitable hydrocarbons. If the contractor fails to comply with this requirement, it will be forced to return those areas to the state. The exploration and exploitation agreements for crude oil in Ecuador are generally divided into two stages. The first stage, or the exploration period, lasts four years and is renewable for another two years. The second stage, or the exploitation period, may be up to twenty years in duration and is renewable. Both exploration and exploitation agreements require an exploratory program agreeable to all parties. A minimum average investment of U.S.$120 to U.S.$180 per hectare, either on land and/or in seawater, shall be made during each of the first three years of the exploration period. Royalties are paid as follows: (i) 12.5% for daily gross production levels less than 30,000 barrels, (ii) 14% when these daily levels are between 30,000 and 60,000 barrels, and (iii) 18.5% when gross production exceeds 60,000 barrels per day. With respect to contracts for specified services or for marginal or participation fields, the contractor is not obliged to pay royalties. The contractor may not sell any of the assets related to the agreement without authorization from the Ministry of Energy and Mines. At the end of the term of the agreement, the contractor shall deliver to Petroecuador, at no cost, all these assets.

The contractor assumes at its own risk and expense all investments, costs and expenses required to perform these hydrocarbon related activities, and, in turn, it has the right to receive a portion of the production of the area covered by the agreement, with Petroecuador having the right to the other portion. Petroecuador may enter into joint venture agreements by contributing rights over areas, fields, hydrocarbons or other rights. Petroecuador s joint venture party, in turn, acquires these rights and is obligated to make the investments agreed to by the parties. In services agreements, the contractor shall provide exploration and exploitation services in the agreed area at its own risk and expense. If the contractor finds commercially exploitable fields, it shall have the right to be reimbursed for its investments, costs and expenses and will also have the right to be paid for its services.

Prior to initiating any work, an environmental impact study and an environmental management plan must be prepared. Consultation and participation procedures, referred to in the National Constitution, must be complied with while taking into consideration local rules of the citizens in the affected area, as well as the rules applicable to all other citizens.

The Brazilian Petrochemical Industry and Regulatory Framework

Overview

The petrochemical industry in Brazil transforms crude oil by-products or natural gas into widely used consumer and industrial goods. The Brazilian petrochemical industry is generally organized into three sectors, each characterized by the stage of transformation of various petrochemical feedstocks: first generation companies, second generation companies and third generation companies.

First Generation Companies

Brazil s first generation companies, which are referred to as crackers, break down or crack naphtha, their principal feedstock, into basic petrochemicals. The crackers currently purchase their naphtha, which is a by-product of the oil refining process, from Petrobras. The basic petrochemicals produced by the crackers include olefins, primarily ethylene, propylene and butadiene and aromatics, such as benzene, toluene and xylenes. Companhia Petroquímica do Nordeste, or Copene, Companhia Petroquímica do Sul, or Copesul, and Petroquímica União S.A., or PQU Brazil s three crackers sell these basic petrochemicals to second generation companies. The basic petrochemicals, which are in the form of either gases or liquids, are transported to the second generation companies nearby plants through pipelines for further processing.

Second Generation Companies

Second generation companies process the basic petrochemicals purchased from the crackers to produce intermediate petrochemicals. These intermediate petrochemicals include:

polyethylene, ethylene oxide, polystyrene and polyvinylchloride, or PVC, each produced from ethylene;

polypropylene, oxo-alcohols and acrylonitrile, each produced from propylene;

caprolactam, produced from benzene;

purified terephtalic acid, or PTA, produced from p-xylene; and

styrene butadiene rubber and polybutadiene, each produced from butadiene.

There are approximately 48 second generation companies operating in Brazil, including Innova. The intermediate petrochemicals are produced in solid form as plastic pellets or powders and in liquid form and are transported by truck to third generation companies, which generally are not located near the second generation production facilities.

Third Generation Companies

Third generation companies, known as transformers, purchase the intermediate petrochemicals from the second generation companies and transform them into final products. These final products include:

plastics produced from polyethylene, polypropylene and PVC;

acrylic fibers produced from acrylonitrile;

polyester produced from PTA and ethylene glycol;

nylon produced from caprolactam; and

elastomers produced from butadiene.

The third generation companies produce a variety of consumer and industrial goods, including containers and packaging materials, such as bags, film and bottles, textiles, detergents and paints as well as automobile parts, toys and consumer electronic goods. There are over 6,000 third generation companies operating in Brazil.

Petrochemical Complexes

The production of first and second generation petrochemicals in Brazil centers around three major complexes. These are the Northeast Complex, the São Paulo Petrochemical Complex, which we refer to as the São Paulo Complex, and the Southern Petrochemical Complex, which we refer to as the Southern Complex. Each complex has a single first generation producer or cracker, and several second generation companies which purchase feedstock from the crackers.

The Northeast Complex, located in the municipality of Camaçari in the State of Bahia, began operations in 1978. The Northeast Complex consists of approximately 25 second generation companies, situated around Copene as the raw materials center. Copene has at present an ethylene capacity of 1.2 million metric tons per annum.

The São Paulo Complex, at Capuava in the State of São Paulo, was created in 1972 and is the oldest petrochemical complex in Brazil. Its raw material center, PQU, supplies first generation petrochemicals to 15 second generation companies. PQU has an ethylene production capacity of 500,000 metric tons per annum.

The Southern Complex, located in the municipality of Triunfo (where Innova is located) in the Southern State of Rio Grande do Sul, is based around the raw materials center, Copesul, and includes eight second generation companies, including Innova. In July 1999, Copesul finalized an expansion project which increased ethylene production capacity to 1,135,000 metric tons per annum from 680,000 metric tons per annum.

Environmental, Health and Safety Standards

Innova is subject to Brazilian federal, state and local laws and regulations governing the protection of the environment. Innova is regulated at the federal level primarily by the Brazilian Institute of the Environment and Renewable Natural Resources (*Instituto Brasileiro de Meio Ambiente e Recursos Naturais Renováveis*) and by National Council of the Environment (*Conselho Nacional do Meio Ambiente*), or CONAMA.

Table of Contents

Pursuant to federal and state environmental laws and regulations, Innova is required to obtain permits for its manufacturing facilities. Authorities in the state where a plant is located may regulate its operations by prescribing specific environmental standards in its operating permits. These environmental standards are prescribed and updated by governmental regulations. In addition, Innova must satisfy regulatory authorities that the operation, maintenance, termination and reclaiming of facilities are in compliance with regulations and are not prejudicial to the environment.

Environmental regulations apply to all operations of Innova, and in particular to the discharge, handling and disposal of gaseous, liquid and solid products and by-products of Innova s manufacturing activities. Rules issued by CONAMA and by state authorities also prescribe preventive measures relating to environmental pollution and waste treatment requirements. In addition, the transportation and storage of Innova s products and supplies are subject to specific standards designed to prevent spills, leakages and other accidents.

Environmental regulations have imposed increasingly strict standards, higher fines, greater exposure to liability and increased operating costs and capital expenditures. In addition, civil, administrative and criminal sanctions, including fines and the revocation of licenses may apply to violations of environmental regulations. Under applicable law, Innova is strictly liable for environmental damages. Innova actively participates in the responsible care program, which establishes international standards for environmental and occupational health and safety practices for chemical manufacturers.

Innova is also subject to federal, state and local laws and regulations that prescribe occupational health and safety standards. In accordance with such laws and regulations, Innova is required to report on its occupational, health and safety records on a yearly basis to the local office of the Ministry of Labor in each of the states in which it operates. In addition, Innova is subject to all federal, state and local government regulation and supervision generally applicable to companies engaged in business in Brazil, including labor laws, social security laws, public health, consumer protection, securities laws and antitrust laws.

Table of Contents

ORGANIZATION STRUCTURE

Table of Contents

The following is a summary diagram of our material subsidiaries and affiliates as of the date of this annual report, including information about ownership, business segment and location:

Table of Contents

PROPERTY, PLANTS AND EQUIPMENT

We have freehold and leasehold interests in various countries in South America, but there is no specific one that is individually material to our company. The majority of our property, consisting of oil and gas reserves, service stations, refineries, petrochemical plants, power plants, manufacturing facilities, power distribution systems, stock storage facilities, gas pipelines, oil and gas wells, pipelines and corporate office buildings, is located in Argentina. We also have significant interests in crude oil and natural gas operations outside Argentina in Venezuela, Ecuador, Bolivia and Peru, two refineries in Bolivia, and a petrochemical plant in Brazil. For a more detailed description of our property, plants and equipment, including information on our oil and gas reserves and production see Business Overview.

Table of Contents

Item 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

In addition to the management discussion below, you should carefully read Petrobras Energía Participaciones s consolidated financial statements and selected financial data included elsewhere in this annual report for additional financial information about us. Our consolidated financial statements were prepared in accordance with Argentine GAAP, which differs in certain significant respects from U.S. GAAP. Note 22 to our consolidated financial statements provides a description of the principal differences between Argentine GAAP and U.S. GAAP as they relate to us, and note 23 provides the reconciliation to U.S. GAAP of net income, shareholders equity and certain other selected financial data.

OVERVIEW

We are a holding company whose only asset is our 98.21% equity interest in Petrobras Energía common stock. We acquired control of Petrobras Energía on January 25, 2000 as a result of the completion of an exchange offer of our Class B shares for 69.29% of Petrobras Energía s common stock. See note 12 to our financial statements for further information relating to our exchange offer. Prior to January 25, 2000, our only asset was our minority interest in Petrobras Energía. As of December 31, 1999, we owned 28.92% of Petrobras Energía s capital stock.

We are an integrated energy company engaged in oil and gas exploration and production, refining, petrochemicals, electricity generation, transmission and distribution and hydrocarbons marketing and transportation. We conduct operations in Argentina, Bolivia, Brazil, Ecuador, Peru and Venezuela. Our long-term strategy is to grow as an integrated energy company with a leading presence in Latin America as part of the Petrobras group, while focusing on profitability as well as social responsibility.

In accordance with the procedures set forth in Technical Resolutions Nos. 4 and 19 of the FACPCE beginning in 2003, we were required to consolidate on a proportional basis the financial statements of companies over which we exercise joint control. We have restated our financial statements as of and for the years ended December 31, 2001 and 2002 to reflect this change as well as recent changes in Argentine GAAP. See note 3 to our consolidated financial statements. The tables below present selected consolidated financial data of Petrobras Energía and its subsidiaries including the proportional consolidation of certain companies under joint control, as compared to such data excluding the proportional consolidation of such companies under joint control, in each case for the fiscal years indicated.

Table of Contents

	With Proportional Consolidation For the Year Ended December 31,			Without Proportional Consolidation For the Year Ended December 31,		
	2003	2002	2001	2003(1)	2002(1)	2001(1)
Net sales	5,494	5,106	5,170	4,615	4,587	3,614
Costs of sales	(3,386)	(3,284)	(3,347)	(2,813)	(2,878)	(2,459)
Gross profit	2,108	1,822	1,823	1,802	1,709	1,155
Administrative and selling expenses	(559)	(609)	(665)	(464)	(532)	(510)
Exploration expenses	(196)	(58)	(41)	(196)	(58)	(41)
Other exploitation income (loss) net	(121)	(28)	23	(104)	(28)	20
Exploitation income(2)	1,232	1,127	1,140	1,038	1,091	624
Equity in earnings of affiliates	163	(638)	119	373	(647)	204
Financial income (expense) and holding gains (losses)	(417)	(1,827)	(573)	(569)	(1,659)	(451)
Other expenses, net(3)	(421)	(187)	(88)	(407)	(178)	(14)
Income (loss) before income tax and minority interest in subsidiaries	557	(1,525)	598	435	(1,393)	363
Income tax provision	(18)	(82)	(385)	(47)	(209)	(249)
Minority interest in subsidiaries	(158)	28	(112)	(7)	23	(13)
Net income (loss)	381	(1,579)	101	381	(1,579)	101

(1) For a reconciliation of our results to our results as adjusted to reflect the elimination of proportional consolidation see Reconciliation Tables at the end of this Item 5.

(2) As used in this annual report, exploitation income means gross profit plus or minus administrative and selling expenses, exploration expenses and other exploitation income (expense), net. We present exploitation income as an indicator of our income from operations. Other jurisdictions define operating income to include certain expenses that we do not present as part of our operating income.

(3) Includes impairment charges for some of our assets including our assets in Ecuador.

In the columns above showing our results without proportional consolidation, the results of companies under joint control are shown under equity in earnings of affiliates.

The companies over which we exercise joint control are Distrilec, CIESA and Citelec. Joint control exists where all the shareholders have resolved, on the basis of written agreements, to share the power to define and establish a company s operating and financial policies.

In the consolidation of companies over which we exercise joint control, the amount of our investment in the subsidiary under joint control and our interest in its income (loss) and cash flows are replaced by our proportional interest in the subsidiary s assets, liabilities, income (loss) and cash flows. Related party receivables, payables and transactions within the consolidated group and companies under joint control have been eliminated in the consolidation pro rata to the shareholding of the controlling company.

We consolidated proportionally line by line the assets, liabilities, income (loss) and cash flows of Distrilec for all periods covered by the financial statements included in this annual report.

We consolidated proportionally line by line the assets, liabilities, income (loss) and cash flow of CIESA for the 2003 and 2001 fiscal years. For the 2002 fiscal year, however, we did not proportionately consolidate on a line by line basis the assets, liabilities, earnings and cash flow of CIESA, since, as of December 31, 2002 our equity interest in such company had a P$33 million negative value. Since we have not assumed any commitments to make capital contributions or provide financial assistance to CIESA, such shareholding was valued at zero and CIESA s results were not consolidated.

In accordance with Argentine GAAP, we did not consolidate proportionally line by line our financial statements with the financial statements of Citelec because we have committed to sell our interest in Citelec to comply with the restrictions imposed by the Argentine authorities in connection with the transfer of our control to Petrobras.

The discussion of our results and financial condition below is presented both on the basis of our consolidated financial data with the proportional consolidation of such joint controlled companies as described above and without proportional consolidation. The financial data discussed below excluding proportional consolidation is not directly comparable to the corresponding financial data set forth in our financial statements included in this annual report.

Both CIESA and Distrilec are primarily engaged in regulated energy businesses in Argentina, through TGS and Edesur, respectively. Both have been significantly affected by the Argentine crisis and the Public Emergency Law. CIESA and TGS have defaulted on their debt and are in restructuring discussions with their creditors. See Factors Affecting Our Consolidated Results of Operations Economic and Political Developments in Argentina Impact on our Investments in Utility Companies. There are significant uncertainties regarding the ability of CIESA and TGS to continue operating as going concern. We are not committed, and do not expect, to make any further capital contributions or financial assistance to CIESA, TGS and Distrilec, and we have not received dividends from these companies since 2001. Accordingly, our management analyzes our results and financial condition separately from the results and financial conditions of these companies and we believe financial information without proportional consolidation is useful to investors in evaluating our financial condition and results of operations.

FACTORS AFFECTING OUR CONSOLIDATED RESULTS OF OPERATIONS

Economic and Political Developments in Argentina

We are an Argentine corporation with 63.6% of our total assets, 69.2% of our net sales, 58% of our combined crude oil and gas production and 40% of our proved oil and gas reserves located in Argentina as of December 31, 2003. Fluctuations in the Argentine economy and actions adopted by the Argentine government have had and will continue to have a significant effect on Argentine private sector entities, including us. Specifically, we have been affected and might be affected by inflation, interest rates, the value of the peso against foreign currencies, price controls, regulatory policies, business regulations, tax regulations and in general by the political, social and economic environment in and affecting Argentina.

Starting in the second half of 1998 and through 2002, the Argentine economy was mired in a severe economic recession, with GDP declining 3.4% in 1999, 0.8% in 2000, 4.4% in 2001 and 10.9% in 2002. In 2002, the peso was devalued by 237.0% (having reached 290% as of June 25, 2002), and Argentina experienced a rise in the wholesale price index of 118.2% and in the consumer price index of 41%.

Our financial results were negatively impacted by drastic political and economic changes that took place in Argentina in 2002. The decrease in industrial output led to decreased demand for energy products in Argentina, particularly for petrochemical and refined products. In late 2002, as the foreign exchange and capital flows began to stabilize, the Argentine government gradually began to lift some of the monetary and exchange control measures it had implemented to prevent a collapse of the banking system. The lifting of these measures served to boost economic activity.

In 2003, the Argentine economy began to recover, with GDP growing 8.7%. This recovery, at first based almost exclusively on import substitution, broadened as the level of consumption and investment increased. Reflecting the economic recovery, Argentine stock exchange indices displayed great dynamism in 2003, and both labor indicators and salary purchasing power registered consistent improvements during the year.

The long-term evolution of the Argentine economy, however, remains uncertain. While economic, political and social conditions have improved, the country still faces significant challenges, including the restructuring of Argentina s sovereign debt, the renegotiation of utility contracts, the restructuring of the financial system and reforms to Argentina s tax regime. In light of this uncertain situation, the following discussion may not be indicative of our current or future results of operations, liquidity or capital resources. The recent volatility of the Argentine economy has affected the comparability of our results in the last three years. The following discussion should be read in conjunction with, and is qualified in its entirety by, the risk factors contained in this annual report. See Item 3. Key Information Risk Factors Factors Relating to Argentina.

Table of Contents

The most important factors arising from Argentina s economic crisis that have affected our results of operations are the following:

Argentine Peso Devaluation

During 2002, following the government s termination of the peso s one-to-one exchange rate parity with the U.S. dollar, the peso registered a significant devaluation against foreign currencies, losing 238% of its value against the U.S. dollar. As of December 31, 2002, the peso s nominal exchange rate was P$3.38 to U.S.$1, up from a P$1 to U.S.$1 rate as of December 31, 2001. In 2003, however, in part as a result of the measures adopted by the Argentine government to stabilize the exchange rate, the peso began to recover its value. As of December 31, 2003, the peso exchange rate stood at P$2.94 to U.S.$1.

Since all of our financial debt and a significant portion of our affiliates debt is denominated in U.S. dollars, the marked devaluation of the peso in 2002 adversely affected our financial position.

Our exposure to the peso s devaluation was also aggravated by the pesification of utility rates and other measures implemented by the Public Emergency Law. Prior to the enactment of this law in January 2002, our cash flows were usually denominated in U.S. dollars or U.S. dollar-adjusted, which provided hedging against exchange rate risks. The new Argentine regulatory framework, however, limited our ability to mitigate the impact of the peso devaluation and prevented us from increasing the prices of our products in the domestic market to offset the devaluation of the peso.

Despite these restrictions, starting in the second half of 2002, domestic prices for the main commodities recovered in line with export prices. In addition, in 2002 we aggressively pursued a trade policy of opening and consolidating export markets to capitalize on domestic and export price asymmetries. Based on the above strategies and the solid positioning of our foreign operations, which have cash flows primarily denominated in U.S. dollars, our exposure to peso fluctuations has dropped and we have recovered our ability to naturally hedge our cash exposure to U.S. dollar liabilities.

Effects of Inflation

In 2002, in light of the peso devaluation and the economic instability that the country suffered during this year, Argentina experienced a significant increase in inflation (40.98% and 118.2% measured in terms of the consumer price index and the wholesale price index, respectively). This was in sharp contrast with 2001, when Argentina actually experienced deflationary conditions (negative 1.5% and negative 5.3% measured in terms of the consumer price index and the wholesale price index, respectively) due to the constraints of the Convertibility Law. In 2003, as the peso exchange rate and economic conditions stabilized, the inflation rate declined significantly, to 3.7% and 2.0%, measured in terms of the consumer price index and the wholesale price index, respectively.

As a result of the high inflation in 2002, Argentine GAAP reintroduced inflation accounting. The most important impact of inflation on results was the incorporation into our financial statements of the effect of exposure of our monetary assets and liabilities to inflation and the restatement in constant currency of the rest of our income statement accounts. See Critical Accounting Policies Inflation accounting.

In March 2003, in response to the economic stabilization, the Argentine government issued Decree No. 664, which provided that financial statements for fiscal years ended after such date must be stated in nominal currency. Accordingly, starting on March 1, 2003, we discontinued inflation accounting and the corresponding restatement of our financial statements. See Critical Accounting Policies Inflation accounting.

Table of Contents

Impact on our Investments in Utility Companies

The new macroeconomic scenario after enactment of the Public Emergency Law deeply changed the economic and financial balance of utility companies. The tremendous effect of the devaluation, within a context where revenues remained unchanged as a consequence of the pesification of rates and financial debts primarily denominated in foreign currency materially and adversely affected the utility companies financial position, results of operations and the cash generation ability required to comply with financial obligations.

The Public Emergency Law ordered the pesification of utility rates payable in U.S. dollars, fixing them at the exchange rate of P$1= U.S.$1, and the elimination in utility contracts of certain indexation clauses. In addition, the Public Emergency Law granted the Argentine government broad authority to renegotiate utility contracts. This authority has been extended to December 2004. See Item 3. Key Information Risk Factors Factors Relating to Argentina The pesification of utility rates has negatively affected and may continue to affect the operations of our affiliated utility companies and Item 4. Information about Us Regulation of Our Businesses. Congress has also authorized the government to fix utility rates until completion of the renegotiation process. We cannot predict the outcome of this rate renegotiation process.

Inability to Pay Debts

In light of the adverse conditions faced by utility companies, TGS, CIESA and Transener have defaulted on their debt and are trying to restructure it.

Although we do not currently consider it very likely in light of procedural difficulties related to bankruptcy laws and actions in Argentina concerning utility companies, there is a risk that we may lose, in whole or in part, our equity interest in these companies in the event the restructuring process fails and creditors bring legal actions to collect against the assets of these affiliates. As part of the debt restructuring, creditors might demand an interest in these companies capital stock, thus resulting in the subsequent reduction of our equity interest in such utility companies.

Valuation of our Interests in Utility Companies

The impact of the measures adopted by the Argentine government on the financial statements of our affiliate utility companies was recognized according to the assessments and estimates conducted by their respective managements. Actual future results may differ from the assessments and estimates so conducted, and the differences may be significant. Therefore, the financial statements of such companies may not report all adjustments that could arise from such a situation. It is not possible to predict the future evolution of the Argentine economy or its impact on the economic and financial situation of these companies.

As of December 31, 2003, the value of our net investments in CIESA, TGS and Citelec was P$190 million, P$167 million and P$158 million, respectively. In our view, the book value of these investments is below their recoverable value as determined by the market price. Estimates on the recoverable value of these interests, however, is subject to significant uncertainties. Accordingly, in the current situation, the market value of listed shares of these companies is the most objective method of estimating the net realizable value of such holdings. We note that as time goes by and the regulatory problems faced by these companies continue unresolved, the reliability and applicability of any values that might be used to assess the recoverable value of these interests are likely to diminish.

As of December 31, 2002, the value of our net investments in CIESA, TGS and Citelec was P$0, P$88 million and P$71 million, respectively. As of December 31, 2002, our equity interest in CIESA would have accounted for a P$33 million negative shareholders equity. However, since we did not assume commitments to making capital contributions or providing financial assistance to CIESA, such shareholding was valued at zero, limiting the recognition of related losses to such book value. Our equity

interest in Citelec was recorded net of a P$66 million impairment charge to write off the book value of Citelec.

As of December 31, 2001, the value of our net investments in CIESA, TGS and Citelec was P$398 million, P$172 million and P$243 million.

For a description of the evolution of our equity interests in the earnings of our affiliated utility companies see Year Ended December 31, 2003 Compared to Year Ended December 31, 2002 Equity in Earnings of Affiliates and Year Ended December 31, 2002 Compared to Year Ended December 31, 2001 Equity in Earnings of Affiliates.

As from 2003, we are required by Argentine GAAP to account for CIESA on the basis of the proportional consolidation method.

Taxes on Exports

On March 1, 2002, the Argentine government imposed a 20% tax on exports of crude oil and a 5% tax on exports of certain oil by-products, which are due to expire in five years. Our export products became subject to these taxes starting on April 1, 2002. These new taxes forced us to redesign our business strategies, giving priority to crude oil refining and the subsequent sale of refined products, both in the domestic and foreign markets. As a result, sales volume of crude oil among our business segments increased to 31.7 thousand barrels per day or 21.6% in 2003, while exports of crude oil declined approximately 50%. Our relationship with Petrobras is a key component of this strategy. In our refining business in 2003, 210 thousand cubic meters of diesel oil were sold to EG3, a company controlled by Petrobras. This allowed us to increase crude oil volumes processed at the San Lorenzo refinery to levels significantly higher than those recorded over the last few years, at a profit.

In May 2004, the Argentine government increased to 25% the export tax on crude oil exports, increased the export tax on LPG oil exports to 20% and imposed a 20% export tax on all gas exports.

Commodities Prices

Although the implementation of our risk management strategy (described below) reduces our exposure to fluctuations in the prices of hydrocarbons, our results of operations are exposed to changes in the international prices of crude oil, petrochemical and refined products.

In addition, while our reporting currency is the Argentine peso, a significant portion of our revenues are denominated in or indexed to the U.S. dollar, reflecting in part the important contribution of exports and foreign operations to our business. Accordingly, changes in the peso exchange rate may have a considerable impact on the prices of the commodities we sell as reported in pesos, thereby affecting our revenues.

In 2003, the price of crude oil, gasoline, diesel oil and electricity increased 4.8%, 16.5%, 7.3% and 20.4%, respectively, while the price of styrene recorded a 9% decline. In 2002, the price of crude oil, styrene and polystyrene recorded increases of 62%, 72% and 37%, respectively.

Price Stabilization and Supply

For the purpose of lessening inflationary pressures caused by the sharp devaluation of the peso in 2002, the Argentine government issued a set of regulations aimed at controlling the increase in prices payable by the final customer. These regulations focused particularly on the energy sector.

Pursuant to the Public Emergency Law, we were precluded from increasing the price of the gas and energy we sold in the domestic market, especially for energy sales pursuant to agreements with utility

companies and sales in the spot market. This has changed our outlook for the gas business, and, as a consequence, we have postponed some investments in the gas sector, particularly in the Neuquén basin.

In January 2003, at the request of the Argentine government, hydrocarbon producers and refineries (including us) entered into a temporary agreement to maintain price stability for crude oil, gasoline and diesel oil in the domestic market. This agreement requires crude oil deliveries to be invoiced and paid based on a WTI of U.S.$28.5 per barrel. Any differences between the actual WTI price and this price will be recorded and will accrue interest. Producers will be compensated by selling at the agreed price while the actual WTI falls below the agreed price. Refineries, in turn, will reflect the crude oil reference price in domestic market prices. This agreement has had no considerable effect on our results, given the strong integration of our upstream and downstream operations in Argentina. After successive renewals, this agreement expired in May 2004. Thereafter, hydrocarbon producers and refineries executed a new agreement effective until June of 2004, which provided that, while the WTI per barrel ranges between U.S.$32 and U.S.$42, crude oil deliveries will be invoiced and paid considering a reference price equal to (i) 86% of the WTI as long as such price does not exceed U.S.$36 per barrel, or (ii) 80% of the WTI, in cases when this price exceeds U.S.$36 per barrel.

In 2002, the Argentine government also ordered the pesification of dollar-denominated prices in the WEM and established a cap on the price of energy sold in the spot market. The government established a maximum price of P$120/MWh, regardless of the actual marginal cost of electricity generation. This diverged from the marginal cost system implemented in 1992 and from the provisions in Electricity Law No. 24,065, which permit an adequate return on investment in a competitive environment based on a marginal price system. We note, however, that thermoelectric generators may cover variable operating costs through certain mechanisms.

As a result of the government s decision to maintain seasonal prices for electricity unchanged following the adoption of the Public Emergency Law, these prices have not adequately reflected generating costs. As a result, the funds in the Stabilization Fund were depleted, which prevented CAMMESA (the administrator of the WEM) from settling its accounts with market agents. This has resulted in a delay in the payment of our receivables from CAMMESA. To address this situation, the Ministry of Energy issued Resolution No. 240/03 (effective August 15, 2003), which prevented the cost of liquid fuels in power plants and of water in hydroelectric plants from being included in the determination of electricity prices. Implementation of this resolution was temporarily suspended on October 9, 2003. In addition, due to the government s decision to suspend the seasonal increases in electricity prices, electricity prices have not reflected production costs. As a result, the Stabilization Fund was exhausted and CAMMESA could not settle accounts with market agents. In December 2003, the Argentine government made a P$150 million contribution to the Stabilization Fund and in March 2004 made a further contribution of P$200 million. In February 2004, with a view to restoring the Stabilization Fund, the government reinstated the seasonal adjustments for the February-April 2004 period, but on May 2004, the government suspended once again, the seasonal increases in electricity prices. As of May 2004, the Stabilization Fund had a deficit of P$650 million.

In light of the uncertainties prevailing in Argentina, we have made progress in renegotiating the terms and conditions of gas and electricity sale agreements entered into with our industrial clients in order to adjust prices to reflect the new economic conditions. In this regard, we have reached commercial agreements that gradually increase sale prices to reflect the effects of the peso devaluation. We, as well as others, have attempted to maximize export opportunities in an effort to capitalize on variations between domestic and export prices, by effectively encouraging the opening and consolidation of new markets. During 2003, we started to export gas to Chile from the Austral basin.

Impairment of assets

The peso devaluation and the enactment of the Public Emergency Law, in addition to all subsequent events, resulted in a dramatic change in the estimation of the future evolution of results and cash flow of certain of our businesses and assets. Considering the prevailing uncertainty of Argentina s economic recovery and the recoverability of certain assets and businesses, we adjusted the book value of certain investments and assets to the respective recoverable value.

Table of Contents

(i) Gas areas in Argentina: Due to the strong deterioration of domestic prices of gas and energy produced and to the limited possibilities of negotiating price increases within the context of the Public Emergency Law, we adjusted the book value of certain investments in gas areas in Argentina to their recoverable value, accounting for impairment charges in the amount of P$37 million in 2003 and P$44 million in 2002.

(ii) Argentine government bonds: Following the default by Argentina on its sovereign debt and related uncertainty, we have created a provision for the decrease in value of our investments in dollar-denominated Argentine government bonds. This provision amounted to P$23 million at December 31, 2003, as compared to P$30 million at December 31, 2002. We are authorized to apply the nominal value of these bonds toward the payment of our Argentine federal tax liabilities. As a matter of prudence, we reduce the provision only when we use the bonds to reduce our tax liabilities.

(iii) Tax loss carry forwards: In view of the uncertainty surrounding our ability to apply these tax losses, we recorded a charge of P$134 million corresponding to the allowance of tax loss carried forward accumulated as of December 31, 2001.

(iv) Minimum presumed income tax credit: Considering prospects for the evolution of the results of our operations and the uncertainty regarding our ability to use amounts paid under alternative minimum tax rules for the reduction of our future income taxes, we recorded P$19 million and P$103 million charges in 2002 and 2001, respectively, in respect of the amounts paid as minimum taxes.

Operations in Ecuador

In connection with the future exploitation of Blocks 18 and 31, in Ecuador, we entered into a contract with OCP whereby an 80,000 barrels per day oil transportation capacity was committed to for a 15-year term as from the date that OCP starts operations.

OCP s commercial operations began on November 10, 2003. From this date, we are required to comply with our ship or pay contractual obligations for the aggregate oil volume committed and, by paying a fee, which as of December 31, 2003 was estimated to be P$7.53 per barrel. Our annual cost associated with this oil transportation capacity is approximately P$220 million. Transportation capacity costs are billed on a monthly basis and charged to expenses by us as incurred.

We estimate that oil production from Blocks 18 and 31 will be lower than our transportation capacity commitment. We have generally based this estimate on the delays involved in the development of Block 31, the new Schedule of investments required for the joint development of Blocks 18 and 31 and a revised outlook of the potential of Block 31. Notwithstanding this, we will still be required to comply with our payment obligations with respect to the aggregate oil volume to which we have committed.

Accordingly, as of December 31, 2003, we recorded a P$321 million impairment allowance in connection with our group of assets in Ecuador. During 2002, we recorded a P$63 million loss in connection with our investments in Ecuador.

Block 31

Block 31 is an exploratory area with a significant reserve potential. Under the concession contract, the exploration program is divided into two phases, which expired on July 2001 and June 2003, respectively. The committed investment demands the acquisition of 1,200 km of 2-D seismic and the drilling of three exploration wells.

Petrobras Energía performed the following works at Block 31: 1,382 km of 2-D seismic, 167 km^2 of 3-D seismic and drilling of four exploration wells at Apaika, Nenke, Obe and Minta. All wells proved to be successful and permitted the discovery of the Apaika-Nenke, Obe and Minta fields.

For the development of the whole block, we estimate that total investments will amount approximately U.S.$800 million, U.S.$150 million of which must be invested before the start of the production phase, which is scheduled for 2006. The significant drop in the level of our capital expenditures, however, has caused significant delays when compared to the original plan we designed for the area s development. See Decline in Historical Capital Expenditures.

Following the successful efforts method of accounting (see Critical Accounting Policies Successful efforts method of accounting) that we have implemented in our oil and gas production and exploration activities, and considering both the current development stage for Block 31 and the schedule of future investments in line with the currently expected cash flow, during 2003 we charged to expense P$141 million in capitalized exploratory wells investments in connection with Block 31 and we expect to charge to expense additional amounts in 2004.

We are currently evaluating several alternatives for Block 31, including recruiting a new partner to accelerate investment execution and the potential sale of part or all of our interest in our Block 31 asset.

Decline in Historical Capital Expenditures

As a result of the size and complex nature of the crisis that broke out in Argentina late in 2001 and the few opportunities to access the capital markets, we had to take a new approach to our growth strategy and consequently made radical changes in our short- and medium-term outlook. In this new scenario, throughout 2002, we reformulated the investment program dynamics, prioritizing cash generation and the maintenance of adequate liquidity levels. This resulted in more conservative expense and investment policies.

In addition, pursuant to the agreements we subscribed to in 2002 in connection with the refinancing of our financial debt, and as long as the refinanced debt remains unpaid, we must comply with a number of restrictions and commitments, including, among others, restrictions on capital expenditure levels. Pursuant to these agreements, we are not permitted to make capital expenditures exceeding U.S.$450 million in 2004, U.S.$425 million in 2005 and U.S.$475 million in each of 2006 and 2007. These limits may be increased through: (i) revenues from the sale of capital assets, (ii) 50% of excess cash from the preceding fiscal year, (iii) cash provided by capital increases, subordinated debt and the financing of investment projects, and (iv) 50% of cash provided by new debt. Conversely, the aggregate amount of our dividends will reduce the limit on capital expenditures.

In 2002, our capital expenditures (which includes the sum of (a) the acquisition of (i) property, plant and equipment, (ii) interest in companies and (iii) oil and gas areas and (b) contributions and advances to unconsolidated affiliates) totaled P$732 million (excluding capital expenditures of companies under our joint control), significantly lower than our capital expenditures in 2001, which were P$1,756 million, and 2000, which were P$1,272 million. In the past, our significant investments have laid the foundations for our operation s expansion and growth. During 2002, we made important divestments of non-core assets amounting to P$593 million, which helped us to finance our capital expenditures during that year.

The reduced pace of investments during 2002 changed our growth objectives in the short-term, mainly affecting oil and gas future production volumes. In addition, reduced investments will delay development of new exploitation areas and related production.

In 2003, the recovery of the Argentine economy triggered the recovery of operating cash flow and liquidity levels. This allowed us to increase our capital expenditures (excluding capital expenditures of companies under our joint control) by P$46 million, to P$778 million. This level of capital expenditures, however, remains low by historical standards.

As long as the Argentine economic recovery continues, we expect to gradually return to the level of capital investment from previous years, subject to covenant restrictions in our outstanding debt. See Liquidity and

Table of Contents

Capital Resources Description of Indebtedness. Our capital investment strategy will focus on disciplined growth based on a solid financial foundation, with priority given to profitable projects with faster returns.

Divestment of Non-Core Assets

The change in Petrobras Energía Participaciones controlling shareholder represents a major milestone in our strategy and business focus.

The agreements executed in connection with the transfer of control to Petrobras granted Petrobras an option whereby, if, within 30 days after closing of the sale, we did not consummate the sale of assets related to the farming, forestry and mining businesses, Petrobras would be entitled but not obliged to cause the seller to acquire such assets in the amount of U.S.$190 million.

In line with the provisions of the agreements mentioned above, during 2002 we sold the asset portfolio associated with our mining, farming and forestry businesses.

In July 2002, we sold to Anglogold our 46.25% indirect equity interest in Cerro Vanguardia S.A. in addition to related assets. The transaction price amounted to U.S.$90 million, and the operation accounted for a P$123 million gain.

In September 2002, we sold to Argentina Farmland Investors LLC our 100% equity interest in Pecom Agropecuaria S.A. s capital stock. The transaction amounted to U.S.$53 million, accounting for a P$27 million gain.

In December 2002, we sold our forestry business assets, including a total area of about 169,000 hectares of forestry land located in the Provinces of Misiones, Corrientes and Buenos Aires and a sawmill with a 90,000 m3/year capacity. Considering the sale price (U.S.$53 million), we recorded a P$153 million loss.

In addition, the following divestitures were made:

In April 2002, under an asset swap, we sold to IRHE (Argentine Branch) and GENTISUR S.A. (a company wholly owned by IRHE) our 50% interest in Pecom Agra with a value of U.S.$30 million, accounting for a P$81 million gain. In return, the parties transferred to us a 0.75% interest in Puesto Hernández UTE, with a value of U.S.$4.5 million, a 7.5% interest in Citelec, with a value of U.S.$15 million, and a 9.187% interest in Hidroneuquén S.A, with a value of U.S.$5.5 million.

In October 2002, we sold to Sudacia S.A., a company controlled by the Perez Companc Family, a 66.67% equity interest in Conuar, including a 68% interest in Fabricación de Aleaciones Especiales S.A., for U.S.$8 million. No gain or loss was recorded for the sale.

In 2003, we sold our interest in the Catriel Oeste and Faro Vírgenes areas. These assets had low production levels, no significant potential and high operating costs.

In June 2003, we sold to Geodyne Energy Inc., Argentina Branch, a 50% interest in the Faro Vírgenes area concession, accounting for a P$11 million loss. Payments in connection with this transaction will be made during a ten year term, in quarterly installments, with a value in U.S. dollars calculated based on 8.8% of the total quarterly gas production from the Faro Vírgenes area. We have the option of receiving directly such gas production.

In August 2003, we sold to Central International Corporation, Argentine Branch, an 85% interest in the Catriel Oeste area concession. Considering the transfer price (U.S.$7 million), we recorded a P$28 million loss.

These transactions have helped us to enhance the quality of our assets portfolio and move forward with a strategy focused on becoming an integrated energy company, and consolidate a business portfolio with a high potential for growth and profitability.

Table of Contents

Management of Crude Oil Price Risk

In line with the business integration goal, our risk management policy focuses on measuring our net risk exposure and monitoring the risks that affect our overall portfolio of assets. By focusing on our overall asset portfolio, we are able to naturally hedge some of our risks. This has helped us to integrate our businesses and grow more efficiently. Additionally, the knowledge acquired from this process enables us to better allocate capital.

We use hedging derivative instruments, such as futures, swaps, options and other instruments, to mitigate risks related to results and cash flow volatility as a result of fluctuations in the price of crude oil. Since 2002, we have intensified the use of options, which provide increased flexibility by protecting us from decreases in commodity prices, while allowing us to benefit from future increases in prices.

On January 1, 2003, Technical Resolutions Nos. 16, 17, 18, 19 and 20 of the FACPCE became effective and introduced material changes in the guidelines regarding the recognition, measurement and disclosure of derivatives and hedging transactions. See Critical Accounting Policies Change in Accounting Standards. These new regulations, whose principles are consistent with the international accounting standards issued by the International Accounting Standards Committee, or IASC, provide that financial derivatives are recorded at their fair value and that changes in the accounting measurement of such derivatives are recognized: (i) if the derivative financial instrument is designated as an effective hedge, under Transitory differences Measurement of derivative financial instruments designated as effective hedge and are subsequently reclassified to income (loss) for the year or years in which the hedged item affects such results, or (ii) if the financial derivative instrument is not designated as an effective hedge, in the income statement under Financial Income (Expense) and Holding Gains (losses). The new regulations thus permit recognition of accounting measurements under clause (i) above on a very restrictive basis, since a hedge is deemed effective if at its inception and during its life, its changes offset between 80% and 125% of the changes in the hedged item.

Based on the information above and in view of the high crude oil prices recorded during 2003, 2002 and 2001, we recognized: (i) for instruments that qualify for hedge accounting, reduced sales in the amount of P$81 million in 2003, P$373 million in 2002 and P$341 million in 2001, and (ii) for instruments that do not qualify for hedge accounting, financial losses of P$298 million in 2003, P$470 million in 2002 and a P$8 million gain in 2001.

Political and Economic Situation in Venezuela

As a result of the events that took place in 2002 and early in 2003, Venezuela was plunged into an unprecedented recession that significantly increased the level of inflation, unemployment and violence.

On December 2, 2002, opposing political parties, together with the labor union and business confederations, called a national civic strike, involving the country s main production areas, including PDVSA. This strike extended to February 2, 2003, when it was partially lifted. Some of the political and economic effects of the strike are listed below:

- a significant reduction in oil production to below 1 million barrels per day (from 3.2 million barrels per day prior to the crisis), and a heavily weakened PDVSA, with more than 18,000 laid-off workers and a large portion of its facilities out of operation. This prevented Venezuela s compliance with OPEC production quotas;

- a significant reduction in the level of Venezuela s international reserves to below U.S.$10 billion, which prevented the country from meeting its minimum imports needs;

- high levels of unemployment, inflation and credit risk, with an unemployment rate in excess of 20% and difficulties in meeting domestic demand for fuel; and difficulties in supplying fuel to the domestic Venezuelan market.

Table of Contents

The deteriorating conditions forced the Venezuelan government to adopt several emergency measures, including: (i) closure of the foreign exchange market and adoption of strict foreign exchange controls, (ii) implementation of price control over the basic basket of goods, (iii) fuel imports and (iv) greater governmental control over PDVSA. Notwithstanding these measures, Venezuela s problems continued. By year end 2003, a foreign exchange market parallel to the official market had developed, where the Bolivar reached rates as high as Bs.3,000 per U.S.$1, compared to the official rate of Bs.1,600 per U.S.$1.

The crisis at PDVSA and the national strike that ended on February 2003, affected operations at our oil fields located in the eastern region of Venezuela. In the fields of Oritupano-Leona, Mata and Acema production declined 40.2% in the first quarter of 2003 (to 30.4 thousand barrels per day), compared with the first quarter of 2002. The situation improved after the strike was lifted. Currently production from these fields is at full capacity.

We designed and implemented a number of strategies to address the challenges raised by the Venezuelan crisis. Accordingly, after the end of the strike, five wells were drilled ahead of schedule at Oritupano-Leona. These measures enabled us to lessen the adverse effects of the crisis.

In 2003 and 2002, we registered a P$27 million and a P$42 million allowance, respectively, for the book value of loans granted to our joint venture partners in Venezuela. These allowances were recorded to reflect our estimate of the recoverable value of these loans.

Since the Venezuelan government, through PDVSA, closely monitors oil production activities in Venezuela, operations in this country could be affected if political and social riots, including strikes and other forms of political protest, affect our operating capacity in Venezuela. In addition, since Venezuela is an OPEC member country, we are subject to any decision related to production cuts OPEC may adopt, as was the case in 2002. In addition to these effects, Venezuela s complex crisis could have other unforeseen effects that may have an adverse impact on our results of operations.

Association Agreement in San Carlos and Tinaco

In October 2002, we subscribed to an association agreement with the oil company Teikoku whereby we transferred 50% of our rights and obligations involved in gas production in the San Carlos and Tinaco exploratory areas located in Cojedes, Venezuela.

The transfer of interest agreement (which is subject to approval by the Venezuelan Ministry of Energy) provides for an initial cash payment of U.S.$1 million and a subsequent disbursement of U.S.$2 million for the financing of the exploratory investments program in the Tinaco area in relation with geological studies, 2-D seismic shooting and 2-D seismic evaluation and interpretation. Furthermore, in the event a joint commercial development in such area is agreed upon, we will receive a supplementary payment in the amount of U.S.$3 million. In light of the transfer of 50% of our interests in the San Carlos and Tinaco areas, as of December 31, 2002, we recorded a P$37 million loss reflecting the write off of the exploration investments we made prior to that date.

During 2003, the political, economic and social conditions in Venezuela prevented us from performing our minimum 2-D seismic work commitments in the Tinaco area. We currently expect to complete this work in the first half of 2004. Depending on the seismic results, we may drill an exploratory well in 2005. Following the successful efforts method of accounting (see Critical Accounting Policies Successful efforts method of accounting) that we have implemented to record oil and gas exploration and production activities, as of December 31, 2003, we charged to exploration expenses the remaining capitalized investments in the San Carlos area in the amount of P$29 million.

Environmental Matters

Quality control, health and safety and environmental protection are integral components of our business. See Item 4. Information About Us Business Overview Environmental.

Table of Contents

In 2003 we retained an international consulting company to conduct an environmental audit of our operations in light of applicable laws, future requirements and, in the absence of local applicable guidelines, international standards. The final audit report ratified the high environmental standards under which our operations are conducted and set forth an action plan to enforce our Safety, Environmental and Occupational Health Policy. To execute this action plan, over the next few years we will make investments of approximately U.S.$23 million to improve, among other things, our prevention systems and production facilities. In addition, we will implement several corrective and remediation actions, for which a P$45 million loss was recorded during 2003. Including this figure, in 2003 we recorded expenses of P$58 million for environmental remediation activities. In 2002, our environmental remediation loss expense was P$15 million.

DISCUSSION OF RESULTS

The following tables set out net sales, gross profit and exploitation income for each of our business segments for the years ended December 31, 2003, 2002 and 2001, both excluding the proportional consolidation of the companies under common control required by recent changes to Argentine general accounting standards and including proportional consolidation. Net sales eliminations relate to intersegment sales. Gross profit eliminations relate to adjustments related to intersegment sales and costs associated with such sales.

Substantially all of our intersegment sales are related to sales of oil and gas to our refining, petrochemicals and electricity businesses. The business segment year-to-year comparisons that follow the table do not exclude intersegment sales.

Table of Contents

Without Proportional Consolidation

	For the year ended, December 31,		
	2003	2002	2001
	(in millions of pesos)		
Net Sales (1)			
Oil and Gas Exploration and Production	P$ 2,729	P$2,806	P$1,975
Hydrocarbon Marketing and Transportation	75	16	85
Refining	1,302	1,008	788
Petrochemicals	1,294	1,254	818
Electricity	244	248	364
Other Investments and Eliminations	(1,029)	(745)	(416)
Total	P$ 4,615	P$4,587	P$3,614
Gross Profit (2)			
Oil and Gas Exploration and Production	P$ 1,281	P$1,206	P$ 787
Hydrocarbon Marketing and Transportation	4	5	23
Refining	123	64	77
Petrochemicals	312	362	152
Electricity	94	50	112
Other Investments and Eliminations	(12)	22	4
Total	P$ 1,802	P$1,709	P$1,155
Exploitation income (3)			
Oil and Gas Exploration and Production	P$ 861	P$ 902	P$ 575
Hydrocarbon Marketing and Transportation	11	16	36
Refining	54		5
Petrochemicals	185	251	59
Electricity	108	57	138
Other Investments			
Corporate and Other Discontinued Investments	(180)	(135)	(189)
Total	P$ 1,039	P$1,091	P$ 624

(1)

Royalties with respect to the oil and gas business are accounted for as a cost or production and are not deducted in determining net sales. Eliminations correspond to sales between our business units.

(2) Net sales less cost of sales. Eliminations correspond to sales between our business units and their associated costs.

(3) As used in this annual report, exploitation income means gross profit plus or minus administrative and selling expenses and other exploitation income (expense), net. We present exploitation income as an indicator of our income from operations. Other jurisdictions define operations income to include certain expenses that we do not present as part of our operating income.

With Proportional Consolidation

	For the year ended, December 31,		
	2003	2002	2001
	(in millions of pesos)		
Net Sales (1)			
Oil and Gas Exploration and Production	P$ 2,729	P$2,806	P$1,975
Hydrocarbon Marketing and Transportation	521	16	695
Refining	1,302	1,008	788
Petrochemicals	1,294	1,254	818
Electricity	691	766	1,286
Corporate and Other Discontinued Investments and Eliminations	(1,043)	(744)	(392)
Total	P$ 5,494	P$5,106	P$5,170
Gross Profit (2)			
Oil and Gas Exploration and Production	P$ 1,281	P$1,206	P$ 787
Hydrocarbon Marketing and Transportation	240	5	398
Refining	123	64	77
Petrochemicals	312	362	152
Electricity	168	158	380
Corporate and Discontinued Other Investments and Eliminations	(16)	27	29
Total	P$ 2,108	P$1,822	P$1,823
Exploitation Income (3)			
Oil and Gas Exploration and Production	P$ 861	P$ 902	P$ 575
Hydrocarbon Marketing and Transportation	205	16	378
Refining	54		5
Petrochemicals	185	251	59
Electricity	112	89	287
Corporate and Other Discontinued Investments and Eliminations	(185)	(131)	(164)
Total	P$ 1,232	P$1,127	P$1,140

(1) Royalties with respect to the oil and gas business are accounted for as a cost or production and are not deducted in determining net sales. Elimination corresponds to sales between our business units.

(2) Net sales less cost of sales. Eliminations correspond to sales between our business units and their associated costs.

(3) As used in this annual report, exploitation income means gross profit plus or minus administrative and selling expenses and other exploitation income (expense), net. We present exploitation income as an indicator of our income from operations. Other jurisdictions define operations income to include certain expenses that we do not present as part of our operating income.

Table of Contents

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Net income: In 2003, we reported net income of P$381 million, compared to a net loss of P$1,579 million in 2002. This shift principally reflects improvements in Argentina s economic conditions during 2003, including an 8.7% increase in GDP, as compared to the 11% contraction in 2002, the impact of the appreciation of the peso against the U.S. dollar on the income from our utility affiliates and a reduction in interest expense. Notwithstanding this improvement in the Argentine economy, significant obstacles to a sustained recovery remain, including the refinancing of Argentina s sovereign debt and the renegotiation of utility contracts. These ongoing obstacles could undermine the recovery of our operations.

Net sales: In 2003, our net sales increased by P$388 million or 7.6% to P$5,494 million, from P$5,106 million in 2002. Our net sales for 2003 reflect P$432 million and P$447 million corresponding to our share of the net sales of CIESA and Distrilec, respectively, for that year (net of P$4 million in intercompany sales). Our net sales for 2002 reflect P$519 million corresponding to our share of Distrilec s net sales for that year.

In 2003, without proportional consolidation, our net sales increased P$28 million or 0.6% to P$4,615 million from P$4,587 million in 2002, due to an increase in sales from each of our Refining, Hydrocarbon Marketing and Transportation, and Petrochemicals business segments. Refining registered the highest increase in net sales to P$1,302 million from P$1,008 million, boosted by a 24.4% increase in sales volumes and, to a lesser extent, higher prices. Sales from our Hydrocarbon Marketing and Transportation segment grew by P$59 million, while sales from our Petrochemicals segment grew by P$40 million. These increases were partly offset by a 2.7% reduction in sales from our Oil and Gas Exploration and Production business, to P$2,729 million (including intercompany sales in the amount of P$944 million) from P$2,806 million in 2002 (including intercompany sales in the amount of P$773 million). This reduction resulted from a 7.7% drop in sales volumes of oil equivalent, which was partly offset by a 5.8% increase in sales prices.

Gross Profit: In 2003, our gross profit increased by P$286 million or 15.7% to P$2,108 million, from P$1,822 million in 2002. Our gross profit for 2003 reflects P$232 million and P$74 million corresponding to our share of the gross profits of CIESA and Distrilec, respectively, for that year. Our gross profit for 2002 reflects P$113 million corresponding to our share of Distrilec s gross profit for that year.

In 2003, without proportional consolidation, our gross profit increased by P$93 million or 5.4% to P$1,802 million, from P$1,709 million in 2002, primarily due to higher margins for crude oil, refined products and generation activity. Reflecting these higher margins, our gross profit from Oil and Gas Exploration and Production increased by P$75 million, our gross profit from Refining activity increased by P$59 million and our gross profit from our Electricity business increased by P$44 million. In contrast, the gross profit from our Petrochemicals business declined by P$50 million, commensurate with the decline experienced in the industry internationally.

Administrative and selling expenses: In 2003, our administrative and selling expenses decreased by P$50 million or 8.2% to P$559 million, from P$609 million in 2002. Our administrative and selling expenses for 2003 reflect P$30 million and P$65 million corresponding to our share of the administrative and selling expenses of CIESA and Distrilec, respectively, for that year. Our administrative and selling expenses for 2002 reflect P$77 million corresponding to our share of Distrilec s administrative and selling expenses for that year.

In 2003, without proportional consolidation, our administrative and selling expenses declined by P$68 million or 12.8% to P$464 million, from P$532 million in 2002. This drop is primarily due to the impact of the peso appreciation on expenses incurred outside Argentina.

Exploration expenses: In 2003, exploration expenses increased P$138 million or 237.9% to P$196 million, from P$58 million in 2002, mainly as a result of the charge to income of P$141 million in capitalized exploratory wells investments in Block 31. See Oil and Gas Exploration and Production.

Other exploitation income (expense), net: In 2003, our other operating expenses increased on a net basis by P$93 million or 332.1% to P$121 million, from P$28 million in 2002. Our net other exploitation expenses for 2003 reflect P$12 million and P$5 million corresponding to our share of the net other exploitation expenses of CIESA and Distrilec, respectively, for that year. Distrilec (which was subject to proportional consolidation in 2002) did not register, on a net basis, any other exploitation expenses in 2002.

In 2003, without proportional consolidation, our other exploitation expenses increased on a net basis by P$76 or 271.4%, to P$104 million from P$28 million in 2002. This increase is mainly attributable to environmental remediation expenses (P$58 million in 2003) and other allowances (P$32 million in 2003).

Exploitation income: In 2003, our exploitation income increased by P$105 million or 9.31% to P$1,232 million, from P$1,127 million in 2002. Our exploitation income for 2003 reflects P$194 million and P$4 million corresponding to our share of the exploitation income of CIESA and Distrilec, respectively, for that year (net of P$4 million in intercompany operations). Our exploitation income for 2002 reflects P$36 million corresponding to our share of Distrilec s exploitation income for that year (net of intercompany operations).

In 2003, without proportional consolidation, our exploitation income declined P$53 million or 4.9% to P$1,038 million, from P$1,091 million in 2002. This decline resulted primarily from the significant increase in exploration expenses and environmental remediation expenses and contingencies.

Equity in earnings of affiliates: In 2003, our equity interest in the earnings of affiliates accounted for a P$163 million gain, compared to a P$638 million loss in 2002, mainly as a result of improved earnings from Citelec, our affiliate utility companies. In 2003, but not in 2002 CIESA s results were consolidated into our financial statements pursuant to the proportional consolidation method. In 2002, CIESA reported a significant loss. See Overview.

Without applying proportional consolidation, our equity in earnings of affiliates would have been a P$373 million gain in 2003, compared to a P$647 million loss in 2002, which includes a P$59 million gain from Cerro Vanguardia, which was sold in 2002. As a result of the appreciation of the peso and reduction of the inflation rate in 2003, our equity share in the earnings of our affiliate utility companies (CIESA, TGS, Distrilec and Citelec) accounted for a P$316 million gain in 2003, compared to a P$732 million loss in 2002. The increased equity gains also resulted from increased earnings of P$19 million, P$26 million and P$13 million at Refinor, Cuyo and Inversora Mata S.A., respectively. These increased earnings were partly offset by P$17 million and P$9 million reductions in the earnings of Empresa Boliviana de Refinación and Oldelval, respectively.

For a discussion of our equity in the earnings of companies over which we exercise joint control in 2003 and the factors that affected these companies results during that year, see Equity in Earnings of Affiliates and Companies under Joint Control.

Financial income (expense) and holding gains (losses): In 2003, our financial expenses and holding losses decreased by P$1,410 million or 77.2% to P$417 million, from P$1,827 million in 2002. Our financial expenses and holding losses for 2003 reflect P$124 million corresponding to our share of CIESA s financial and holding gains for 2003, and P$28 million corresponding to our share of Distrilec s financial and holding gains for 2003. Our financial expenses and holding losses for 2002 reflect P$168 million corresponding to our share of Distrilec s financial expenses and holding losses for that year.

In 2003, without proportional consolidation, our financial expenses and holding losses declined to P$569 million from P$1,659 in 2002. This reduction is mainly attributable to the following factors:

- Gains from foreign exchange and exposure to inflation of P$136 million in 2003 on our net borrowing position, as compared to a loss of P$370 million in 2002, principally reflect the effects of the peso appreciation and inflation on our net borrowing position.

A P$349 million drop in net interest expense, to P$423 million in 2003 from P$772 million in 2002, resulting from the appreciation of the peso and an 8% reduction in the average amount of our dollar-denominated indebtedness.

A 37.4% reduction in losses attributable to derivative instruments that do not qualify for hedge accounting, to P$294 million in 2003 from P$470 million in 2002. In nominal terms, the loss for 2003 was actually higher than the loss in 2002, mainly due to the increase in the future curve of reference crude oil prices. In constant currency, however, the loss for 2002 is higher than for 2003 due to the effects of the adjustment for inflation. This increase was partially offset by the peso appreciation during 2003.

Other expenses, net: In 2003, our other expenses increased on a net basis by P$234 million or 125% to P$421 million, from P$187 million in 2002. Our net other expenses for 2003 reflect P$1 million and P$13 million corresponding to our share of the net other expenses of CIESA and Distrilec, respectively, for that year. Our net other expenses for 2002 reflect P$9 million corresponding to our share of Distrilec s net other expenses for that year.

In 2003, without proportional consolidation, our other expenses, net increased by P$229 million or 128.6% to P$407 million, from P$178 million in 2002. These increased expenses reflected:

an impairment allowance for our operations in Ecuador (See Factors Affecting Our Consolidated Results of Operation Operations in Ecuador) of P$309 million;

a P$39 million loss attributable to the sale of oil and gas areas;

a P$37 million impairment charge for oil production areas (see Factors Affecting Our Consolidated Results of Operations Association Agreement in San Carlos and Tinaco); and

a P$27 million allowance for the book value of loans granted to joint-venture partners in Venezuela.

These expenses for 2003 compare to the following other expenses for 2002:

a P$63 million allowance for operations in Ecuador;

a P$44 million impairment charge for gas production areas;

a P$37 million loss attributable to the assignment of a 50% interest in San Carlos area;

a P$42 million allowance for the book value of loans granted to joint venture partners in Venezuela;

a P$17 million charge for the accelerated amortization of financial debt issuance costs;

a P$10 million impairment charge for an interest in Hidroneuquén; and

P$78 million income from divestment of non-core assets.

Income tax: In 2003, our income tax charge decreased by P$64 million or 78.1% to P$18 million, from P$82 million in 2002. Our income tax charge for 2003 reflects a P$58 million gain corresponding to our share of CIESA s income tax for that year, and a P$29 million loss corresponding to our share of Distrilec s income tax for that year. Our income tax provision for 2002 reflects a P$127 million gain corresponding to our share of Distrilec s income tax for that year.

In 2003, without proportional consolidation, our income tax provision declined P$162 million or 77.5% to P$47 million, from P$209 million in 2002. This decline reflects the inclusion of the following items in 2002: (i) an allowance for tax losses and a minimum presumed income tax of P$134 million and P$19 million, respectively, in line with the uncertain economic context prevailing in Argentina, and (ii) a P$19 million provision attributable to Conuar, an asset we sold in 2002.

103

Oil and Gas Exploration and Production

Exploitation income: Exploitation income for this segment decreased 4.5% in 2003, to P$861 million from P$902 million in 2002. This drop was due primarily to a significant increase in exploration expenses and a decline in sales volumes, which were partially offset by a rise in sales prices resulting from changes in our price hedging strategies and a 19% increase in the WTI.

Net sales: Net sales for 2003 declined P$77 million or 2.7% to P$2,729 million (including intercompany sales in the amount of P$944 million), from P$2,806 million in 2002 (including intercompany sales in the amount of P$773 million). This drop is attributable to a 7.7% decline in sales volumes of oil equivalent, which was partially offset by a 5.8% increase in sales prices.

Combined oil and gas sales volumes declined 7.7% in 2003 to 157.9 thousand barrels of oil equivalent per day, from 171.1 thousand barrels of oil equivalent per day in 2002. Oil sales volumes decreased 5% in 2003 to 111.2 thousand barrels per day, from 117.1 thousand barrels per day in 2002, while gas sales volumes declined 13.5% to 280.0 million cubic feet per day, from 323.6 million cubic feet per day in 2002. This significant drop in sales volumes is primarily attributable to the decline in the level of activity of our operations in Venezuela, which was affected by the oil strike that took place at the beginning of 2003, and to the restrictive investment policy implemented by us in 2002 in light of the Argentine crisis. While this policy protected our operating cash flow in 2002, it delayed the development of hydrocarbon projects. The decline of our operation in Venezuela, however, was offset by the start of commercial operations in Ecuador, with production reaching a total of 3.9 thousand barrels per day. In addition, gas sales volumes declined due to price restrictions in the Argentine market, which discouraged production.

During 2003, the average crude oil sales price per barrel, including the effects of hedging transactions and taxes on exports (as discussed below), increased 4.8% to P$61.2, from P$58.4 in 2002. This increase reflected a 19% increase in the average WTI to U.S.$31.1 per barrel, and changes in our hedging policy. This increase was partially offset by the effect of the peso appreciation against the U.S. dollar during 2003, which had a negative impact on dollar-denominated flows from foreign operations and exports.

In 2003, our crude oil price hedging policy accounted for P$85 million in reduced net sales, compared with P$373 million in 2002. These reduced losses mainly reflect a change in our hedging strategy. During 2003, we relied on option contracts that allowed us more flexibility to benefit from price increases. Conversely, in 2002 hedging instruments consisted primarily of swap agreements, with fixed sales prices.

In 2003, Argentine taxes on exports resulted in a reduction in net sales of P$60 million, compared to P$84 million in 2002, reflecting a 50% drop in export volumes.

Net Sales in Argentina: In 2003, overall sales in Argentina decreased by P$69 million or 4.3% to P$1,538 million, from P$1,607 million in 2002, due to a 10.9% decrease in combined oil and gas daily sales volumes, to 90.4 thousand barrels of oil equivalent from 101.5 thousand barrels of oil equivalent in 2002.

Crude oil sales in Argentine declined P$22 million or 1.5% to P$1,401 million, from P$1,423 million in 2002. This reduction in crude oil sales is mainly attributable to a 7.1% decline in sales volumes to 55.0 thousand barrels per day, which was partially offset by a 6.1% increase in average sales prices. Gas sales in Argentina dropped by P$46 million or 25.1% to P$137 million, from P$183 million in 2002. This drop in gas sales resulted from the combined effect of reduced sales volumes and reduced prices. Daily gas sales volumes declined 16.2% to 212.8 million cubic feet, from 253.9 million cubic feet in 2002, while gas sales price dropped 11.1% to P$1.76 per thousand cubic feet, from P$1.98 per thousand cubic feet in 2002. The Public Emergency Law has prevented nominal sales prices from changing significantly.

In 2003, the volume of intercompany sales in Argentina, particularly to the Refining business, increased 21.6% to 31.7 thousand barrels per day.

Table of Contents

Net Sales Outside of Argentina: In 2003, combined oil and gas sales outside of Argentina decreased 0.7% to P$1,191 million, from P$1,199 million in 2002. Oil and gas total sales volumes declined to 67.4 thousand barrels of oil equivalent per day or 3.0% with respect to 2002. The average sales price for oil per barrel rose to P$52.7 or 3.9% from P$50.7 in 2002, mainly due to the rise in the international reference price and the change in our hedging policy (as discussed above).

Below is an overview of 2003 sales figures for each country in which we have oil and gas operations:

Venezuela: Oil and gas sales decreased P$106 million or 15.1% to P$594 million, from P$700 million in 2002, due to the following factors:

- the average price of oil per barrel decreased 3.6% to P$40.4, from P$41.9 in 2002. This decline was attributable to the effect of the appreciation of the peso, which was partially offset by the change in the hedging policy (as discussed above) and the increase in the WTI; and

- daily sales volume of oil equivalent decreased 12.5% to 42.8 thousand barrels of oil equivalent, from 48.9 thousand barrels of oil equivalent in 2002, primarily as a result of the oil strike that took place at the beginning of 2003, and the natural field decline resulting from our restrictive investment policy in 2002.

Bolivia: Oil and gas sales decreased P$4 million or 3.6% to P$108 million, from P$112 million in 2002, due primarily to a 7.4% reduction in the sale price of gas to P$5.24 per thousand cubic feet, from P$5.66 per thousand cubic feet in 2002. This decline in the gas sales price was partially offset by the combined oil and gas daily sales volumes, which increased 5.5% to 7.7 thousand barrels of oil equivalent, from 7.3 thousand barrels of oil equivalent in 2002.

Peru: Oil and gas sales increased 4.2% to P$374 million, from P$359 million in 2002, due to the following factors:

- sales price increased 1.3% to P$78.5 per barrel, from P$77.5 per barrel in 2002, as a result of the change in our hedging policy (as discussed above) and the increase in international prices, which were partially offset by peso appreciation; and

- oil and gas daily deliveries increased 2.4% to 13.0 thousand barrels of oil equivalent per day, from 12.7 thousand barrels of oil equivalent per day in 2002, as a consequence of improved well productivity resulting from workover tasks.

Ecuador: Oil sales increased 310.7% to P$115 million, from P$28 million in 2002, due to the approval of the development plan for Block 18, which was obtained in the fourth quarter of 2002. After obtaining this approval, we were able to start drilling activities, particularly at the Palo Azul field, where we currently operate five wells which yielded a production of 17 thousand barrels per day in December (before deduction on account of the Ecuadorian government s interest and before deducting royalties). Daily crude oil sales volumes (net of the Ecuadorian government s interest), increased to 3.9 thousand barrels per day, at a price of P$79.2 per barrel.

Gross profit: In 2003, gross profit for the Oil and Gas Exploration and Production segment increased 6.2% to P$1,281 million, from P$1,206 million in 2002. The gross margin on sales rose to 46.9% from 43% in 2002. This increase in margins is primarily attributable to the rise in sale prices.

Administrative and selling expenses: In 2003, administrative and selling expenses for this segment totaled P$178 million, compared to P$224 million in 2002. This drop is attributable to the appreciation of the peso in 2003, which reduced the peso equivalent of expenses incurred abroad.

Table of Contents

Exploration expenses: In 2003, exploration expenses increased by P$138 million or 237.9% to P$196 million, from P$58 million in 2002. Exploration expenses during 2003 reflected the charge to income of P$141 million exploration investments in Block 31 (in Ecuador), and P$30 million exploration investments in the San Carlos area (in Venezuela). In addition, expenses were recorded for non-producing exploration wells in the Santa Cruz II Oeste area in Argentina and Lote XVI in Peru and the investment in seismic testing related to such wells.

In 2002, the Chontayacu well in Block 18 (Ecuador) was drilled and did not prove to be successful. In addition, 238 km of 2-D seismic were shot in Block 31. In Argentina and Peru, expenses in connection with the Chiripá well in the Santa Cruz II Oeste area and the Mashansha well in Lote 35, respectively, were charged to income.

Other exploitation income (loss), net: In 2003, other exploitation expenses for this segment increased on a net basis by P$24 million or 109.1% to P$46 million, from P$22 million in 2002. This increase was primarily a result of environmental remediation expenses in the amount of P$26 million, and other allowances in the amount of P$32 million. These effects are offset by the favorable settlement of certain commercial claims in Venezuela.

Hydrocarbon Marketing and Transportation

Our results for this segment in 2003 reflect the proportional consolidation of CIESA. In 2002, CIESA s results were not proportionally consolidated. See Overview.

Exploitation income: In 2003, our exploitation income for this segment increased by P$189 million or 1181.3% to P$205 million, from P$16 million in 2002. Our exploitation income for this segment in 2003 reflects P$194 million corresponding to our share of CIESA s exploitation income for that year.

In 2003, without proportional consolidation, our exploitation income for this segment decreased 31.3% to P$11 million, from P$16 million in 2002.

Net Sales: Our operations in this segment include oil, gas and LPG brokerage services, with significantly different margins subject to the specific characteristics of each operation.

In 2003, our net sales for this segment increased by P$505 million or 3156.3% to P$521 million, from P$16 million in 2002. Our net sales for this segment in 2003 reflect P$446 million corresponding to our share of CIESA s net sales for that year.

In 2003, without proportional consolidation, our aggregate net sales significantly increased, to P$75 million from P$16 million in 2002, principally as a result of increased volume in our oil brokerage operations.

Gross profit: In 2003, our gross profit for this segment increased by P$235 million to P$240 million, from P$5 million in 2002. Our gross profit for this segment in 2003 reflects P$236 million corresponding to our share of CIESA s gross profit for that year.

In 2003, without proportional consolidation, our gross profit decreased to P$4 million from P$5 million in 2002, as a result of a reduction in margins in the brokerage business.

Other exploitation income, net: In 2003, we registered other net exploitation expenses for this segment in the amount of P$1 million, compared to other net exploitation income in the amount of P$13 million in 2002. The other net exploitation expenses for this segment in 2003 reflect P$12 million corresponding to our share of the other net exploitation expense of CIESA for that year.

In 2003, excluding proportional consolidation, we registered other net exploitation income in the amount of P$11 million, a 15.4% decrease from the P$13 million in other net exploitation that we registered in 2002.

In 2003, the income from the advisory services we provided to TGS s technical operator was P$12 million, as compared to P$13 million in 2002.

Refining

Exploitation income: In 2003, exploitation income for this segment totaled P$54 million, while no significant results were recorded in this segment in 2002. The improvement resulted from a significant increase in sales volumes and margins.

Net sales: In 2003, net sales of refined products increased P$294 million or 29.2% to P$1,302 million, from P$1,008 million, due to a 24.4% increase in sales volumes and higher prices, particularly in the domestic market. Below we highlight certain significant trends in sale prices and volumes for refined products in 2003:

In an effort to optimize our margins in this segment, we adopted changes in the mix of the refined products we sell and of our distribution channels. Domestic sales of refined products increased 41%, mainly due to increased diesel oil sales to other oil companies operating in Argentina. Exports of refined products, on the other hand, dropped 2%.

In 2003, average sales prices of diesel oil, gasoline, aromatics and reformer plant by-products increased 7%, 16%, 14% and 9%, respectively. Taxes on exports of refined products imposed by the Argentine government starting on April 2002 totaled P$9 million in 2003 and P$14 million in 2002, decreasing revenues.

Crude oil volumes processed in 2003 averaged 32.6 thousand barrels per day, a 19.9% increase from 2002. During 2003, in order to maximize our overall results in light of the applicable tax regime, integration of our refining and exploration and production operations increased. Accordingly, we prioritized the refining of crude oil over crude oil exports given the 20% export tax on crude oil imposed in Argentina in March 2002.

Sales volumes of diesel oil grew 41.9% in 2003, to 882.6 thousand cubic meters, reflecting a 62.3% increase in sales volumes for diesel oil in the domestic market. This increase resulted primarily from increased sales to oil companies operating in Argentina, particularly EG3 (a company controlled by Petrobras) and, to a lesser extent, a 4.2% recovery of the domestic demand for this product, which was driven by demand from the farming sector. The increase in domestic sales of diesel oil in 2003 was partly offset by an 18.3% drop in exports to bordering countries, particularly to Paraguay.

Total gasoline sales volumes declined 2.9% in 2003, to 119.2 thousand cubic meters, reflecting a 4.6% drop in our sales volumes in Argentina. This decline in domestic gasoline sales resulted primarily from a 10% reduction in total domestic demand for gasoline, due to increased use of CNG as a substitute fuel.

Sales volumes of reformer plant by-products grew 21.8% in 2003, to 79 thousand tons, as a result of a 14% increase in domestic sales and a 54% rise in exports.

Sales volumes for heavy distillates grew 12% in 2003, to 438 thousand tons, due primarily to a 63% increase in domestic sales as a result of increased demand for fuel oil and the increase in crude oil volumes processed. The increase in domestic sales was partially offset by a 1% drop in export volumes.

Asphalt sales volumes grew 102.4% in 2003, to 86 thousand tons, as a result of our active trade policy, and a 110% increase in domestic sales, due to a rise in road construction and specific public works (such as the construction of the Rosario-Victoria Bridge). In addition, 2003 was a record year for asphalt exports, with exports to Bolivia and Paraguay increased 90% compared to 2002, reflecting increased demand in these countries.

Sales volumes of paraffins increased 9.4% in 2003, to 151 thousand tons, due to a 32% rise in domestic sales, resulting from increased demand. This increase was offset by a 4% drop in exports, particularly to the United States and countries bordering Argentina.

Table of Contents

Sales volumes of aromatic products decreased 16.1%, to 56 thousand tons, as a result of a 27.5% drop in domestic sales, which was offset by a 41.6% increase in exports, particularly to countries bordering Argentina.

Gross profit: In 2003, gross profit for this segment increased P$59 million or 92.2% to P$123 million, from P$64 million in 2002, due to higher sales volumes and improved gross margins. The gross margin on sales of refined products increased to 9.5% from 6.3%. This increase is attributable to a 4.5% rise in average sales prices, that was only partially offset by a 2.3% increase in the cost of crude (from 78.9 P$ per barrel in 2002 to 80.7 P$ per barrel in 2003). While the average WTI increased by 19% in 2003, the appreciation of the peso during this year helped to contain the rise in our crude acquisition costs (which are dollar-based).

Administrative and selling expenses: In 2003, administrative and selling expenses for the Refining segment increased P$9 million or 18.8% to P$57 million, from P$48 million. This increase resulted primarily from increased commercial expenses associated with the expansion of our gas station network.

Other exploitation expenses, net: In 2003, other exploitation expenses for the refining segment decreased on a net basis to P$12 million, from P$16 million in 2002. Idle-facility costs accounted for a P$6 million loss in 2003, compared to a P$10 million loss in 2002. In addition, P$8 million environmental remediation expenses were recorded for this segment in 2003.

Petrochemicals

International and Regional Overview: In 2003, the styrenics business was marked by a strong increase in the international prices for its primary raw materials. In line with the upward trend of oil prices, prices for benzene and ethylene increased approximately 27% and 25%, respectively, in 2003. International prices of styrene and polystyrene increased approximately 15%. As a result of the increase in the costs of raw materials, spreads (i.e., the difference between the sales price and the cost of raw materials) for styrenics decreased in 2003, particularly the spread for styrene, which decreased 21% and, to a lesser extent, the spread for polystyrene, which decreased 4%.

The demand for styrenics in Argentina increased considerably in 2003, due to the strong recovery in the country s economic activity. The demand for styrene increased 38%, for polysterene 14% and for rubber 19%. In Brazil, the demand for styrene rose 8% in 2003, while the demand for polystyrene dropped 10%.

The Mercosur region and Chile continued to record a shortage of styrene. The excess supply of polystyrene, on the other hand, continued to increase, due to increased production and lower demand for this product in the Brazilian market.

In the fertilizers business, international prices for urea significantly increased in 2003 to an average of U.S.$139 per ton, from an average of U.S.$94 per ton in 2002. This increase resulted primarily from increased demand in the southeastern region of Asia, as well as a lower global supply resulting from the high cost of natural gas in the major manufacturing centers of urea around the world.

Our fertilizers business also benefited from improved conditions in the Argentine farming sector, resulting from favorable international prices for grains, significant growth in sown areas, record soybean harvest and an increased use of nutrient mixes. Droughts in the Provinces of Córdoba, La Pampa and Buenos Aires did not affect this general positive trend. Total demand for fertilizers in Argentina recorded a 31% increase in 2003.

Exploitation income: In 2003, exploitation income for the Petrochemicals segment decreased P$66 million or 26.3% to P$185 million, from P$251 million in 2002, mainly as a result of the decrease in the spreads.

Net sales: In 2003, net sales for the Petrochemical segment increased P$40 million or 3.2% to P$1,294 million, from P$1,254 million in 2002, mainly as a result of increased sales volumes in Argentina. We highlight below certain sales figures and trends for this segment:

Styrenics Argentina: In 2003, total sales of styrenics from our Argentine operations increased P$34 million or 7.5% to P$485 million (including exports to Innova in the amount of P$5 million), from P$451 million in 2002 (including exports to Innova in the amount of P$26 million). In 2003, total sales volumes for styrenics increased to 104 thousand tons from 84 thousand tons in 2002. Average sales prices for styrenics did not register significant changes compared to 2002, as the alignment with international reference prices was offset by the appreciation of the peso.

Sales volumes for styrene increased approximately 38% in 2003, due to increased domestic demand for this products and export growth. The greater level of exports is attributable to increased shipments to Chile reflecting the consolidation of our presence in this country s styrene market.

Sales volumes for polystyrene decreased approximately 11.7% in 2003, due to a 43% drop in exports resulting from lower shipments to Brazil and Europe. These lower shipments in part reflect our efforts to increase exports of styrene to certain regional markets from which we can extract greater profit margins. A 6% increase in sales volume of polystyrene to the domestic Argentine market, resulting from the country s economic recovery, partly offset the decline in the volume of exports of this product.

Sales volumes for Bioriented Polystyrene, or BOPS, increased approximately 56% in 2003, due primarily to a 74% increase in exports, which resulted from increased shipments to the U.S.A. and Europe. In addition, BOPS sales volumes to the domestic Argentine market increased 11% due to the country s economic recovery.

Sales volumes for rubber increased approximately 11%, as a result of the recovery of the Argentine economy and an increase in our market share.

Styrenics Brazil: In 2003, sales of styrenics from Innova (our Brazilian petrochemical subsidiary) decreased P$59 million or 11% to P$502 million, from P$561 million in 2002, as a result of the decline in sales volumes and prices. Total sales volumes of styrenics from Innova declined 7% in 2003, reflecting a 3.9% reduction in sales volumes to the Brazilian domestic market (from 176 thousand tons in 2002 to 169 thousand tons in 2003). This reduction in domestic sales volumes was mainly the result of a 13% decline in local sales of polystyrene, due to a drop in demand for this product in Brazil. Local sales of styrene, on the other hand, did not reflect significant changes from the levels recorded in 2002. Export volumes of styrenics from our Brazilian operation declined 17% in 2003, as the decline in international margins for polystyrene limited the opportunities to export polystyrene to markets outside of the region. The average sales price of styrenics from our Brazilian operations dropped 4%, as the appreciation of the peso offset the increase in the international prices of polymers.

Fertilizers: In 2003, sales of fertilizer increased 16.4% to P$312 million, from P$268 million in 2002, due primarily to a 32% increase in sales volumes that was caused by increased demand for nutrient mixes in Argentina. A 38% increase in sales of liquid fertilizers in 2003 also improved overall fertilizer sales. This improvement in sales of liquid fertilizers reflected the consolidation of our leading position in the Argentine fertilizer market, particularly in the liquid fertilizers segment. Average sales prices for fertilizers dropped 11% in 2003, due to the effects of the peso appreciation that offset the increase in dollar-denominated prices, and the strong growth in sales of liquid fertilizer, which have lower unit prices than solid fertilizers.

Gross profit: In 2003, gross profit for the Petrochemicals segment decreased P$50 million or 13.8% to P$312 million, from P$362 million in 2002. Gross margin for this segment decreased to 24.1% in 2003 from 28.9% in 2002, due to an increase in the international prices for raw materials. We highlight below certain significant trends in this segment:

Styrenics Argentina: In 2003, gross profit for styrenics from our Argentine operations increased 2.4% to P$129 million, from $126 million in 2002, reflecting increased volumes. Gross margin on sales in these products, on the other hand, declined to 26.6% in 2003 from 27.8% in 2002, mainly as a result of the increased cost of raw materials.

Styrenics Brazil: In 2003, gross profit for styrenics from our Brazilian operations declined 13.6% to P$89 million, from P$103 million in 2002. Gross margin for these products declined to 17.8% in 2003 from 18.4% in 2002, mainly as a result of the increased cost of raw materials.

Fertilizers: In 2003, gross profit for our fertilizers business declined 29.3% to P$94 million, from P$133 million in 2002. Gross margins for fertilizers declined to 30.1% in 2003 from 49.6% in 2002, mainly due to a reduction in the average sales price of fertilizer products as explained above and a change in the product mix. Our margins in this segment were adversely affected by the increase in resales by us of fertilizer volumes with a unit cost higher than that of our own fertilizer products.

Administrative and selling expenses: In 2003, administrative and selling expenses for the Petrochemical segment declined P$12 million or 10% to P$110 million, from P$122 million in 2002, mainly as a result of the impact of the significant appreciation of the peso on our costs incurred in Brazil.

Other exploitation expenses, net: In 2003, other exploitation expenses for this segment, accounted on a net basis for a P$17 million loss, attributable to future environmental remediation expenses. This compared to a P$11 million gain in 2002, attributable to the collection of insurance compensation for a loss occurred at Innova s ethylbenzene plant and certain tax credits from our operations in Brazil.

Electricity

Our results for this segment in 2003 and 2002 reflect the proportional consolidation of Distrilec. See Overview.

Exploitation income: In 2003, our exploitation income for this segment increased by P$23 million or 25.9% to P$112 million, from P$89 million in 2002. Our exploitation income for this segment in 2003 and 2002 reflects P$4 million and P$32 million, respectively, corresponding to our share of Distrilec s exploitation income for these years.

In 2003, without proportional consolidation, our exploitation income for this segment increased P$51 million or 89.5% to P$108 million, from P$57 million in 2002 (which includes P$10 million from the exploitation income of Conuar Fae, a company that was divested in the fourth quarter of 2002), due primarily to an increase in the price of electricity and lower production costs.

Net sales: In 2003, our net sales for this segment decreased by P$75 million or 9.8% to P$691 million, from P$766 million in 2002. Our net sales for this segment in 2003 and 2002 reflect P$447 million and P$518 million, respectively, corresponding to our share of Distrilec s net sales for these years.

In 2003, without proportional consolidation, our net sales for this segment increased P$38 million or 18.4% to P$244 million, from P$206 million in 2002 (excluding P$42 million in net sales of Conuar/Fae in 2002, which we sold in that year).

Net sales from generation: In 2003, net sales for our electricity generation business increased P$39 million or 19.9% to P$235 million, from P$196 million in 2002. This increase resulted from a 20.4% increase in average sales prices, which is attributable primarily to the following factors:

as a result of changes in the regulatory framework, payments of additional compensation from the Argentine Stabilization Fund were received between March and October of 2003 for guaranteed supply to the electricity market during the winter season. These additional payments accounted for a P$17 million increase in sales;

an increase of approximately 7% in the demand for electricity, which, as a result of the limited availability of natural gas during the winter season (due to lower temperatures and increased consumption by industries), required energy dispatch from less efficient machines, which resulted in higher market prices. The reduction in the availability of gas did not affect the activity of the Genelba Power Plant due to the gas supply contract it had in effect during 2003); and

reduced flows from incoming rivers during the second half of the year, which shifted generation away from low-cost hydroelectric plants. This reduction in river flows was caused by a mild summer, which resulted in less snow water supplying the river basins.

In 2003, net sales from the Genelba Power Plant increased P$34 million or 21% to P$196 million, from P$162 million in 2002, due to increased prices and sales volume. The average monomic price of energy and power delivered increased 16.7% in 2003, to P$39.9 per MWh from P$34.2 per MWh in 2002. Energy deliveries from this plant increased 4% to 4,918 GWh, from 4,731 GWh in 2002, with a plant factor of 79.1% in 2003 and 73.6% in 2002. The increased sales volume in 2003 was primarily attributable to higher dispatch to the network, due to changes in 2002 to the regulations regarding cost declaration, that benefit the plant s relative competitiveness and permit a more timely and flexible operation. In 2003, the availability factor of the Genelba Power Plant was 96.5%, 1.1% higher than in 2002, as a result of the optimization of starting processes, inspections, maintenance works and the plant s general performance.

In 2003, net sales attributable to HPPL increased P$7 million or 24% to P$36.2 million, from P$29.2 million in 2002. The average monomic sale price of energy and power increased 37.4% to P$32.3 per MWh, from P$23.5 per MWh in 2002, reflecting the overall increase in energy prices discussed above. Energy delivered by HPPL dropped 9.7% to 1,120 GWh, from 1,240 GWh in 2002, due to a lower contribution from incoming river flows, as compared to historic average values. As a result of the application of the Energy Support Price Method and by virtue of the prices recorded in 2003 and 2002, and their future estimates, we recorded P$3 million and P$5 million gains in 2003 and 2002, respectively.

Gross profit: In 2003, our gross profit for this segment increased by P$10 million or 6.3% to P$168 million, from P$158 million in 2002. Our gross profit for this segment in 2003 and 2002 reflects P$74 million and P$108 million, respectively, corresponding to our share of Distrilec s gross profit for these years.

In 2003, without proportional consolidation, our gross profits increased P$59 million or 168.6% to P$94 million, from P$35 million in 2002 (excluding P$15 million corresponding to the gross profits of Conuar/Fae, which we sold in 2002).

Gross profit from generation: In 2003, gross profit for the electricity-generation business increased P$60 million or 193.5% to P$91 million, from P$31 million in 2002. This significant increase is mainly attributable to higher sales prices and lower sales costs as measured in constant pesos given that the nominal cost of gas remained unchanged.

Administrative and selling expenses: In 2003, our administrative and selling expenses for this segment decreased by P$19 million or 20.7% to P$73 million, from P$92 million in 2002. Our administrative and selling expenses for this segment in 2003 and 2002 reflects P$65 million and P$76 million, respectively, corresponding to our share of Distrilec s administrative and selling expenses for these years.

In 2003, without proportional consolidation, our administrative and selling expenses for the generation business dropped P$4 million or 33.3% to P$8 million, from P$12 million in 2002 (excluding P$4 million corresponding to administrative and selling expenses of Conuar/Fae, which we sold in 2002). In nominal terms, these expenses remained unchanged.

Other exploitation income (expense), net: In 2003, our other exploitation income for this segment decreased on a net basis P$6 million or 26% to P$17 million, from P$23 million in 2002. Our net other exploitation income for this segment in 2003 reflects P$5 million corresponding to our share of Distrilec s exploitation income for that year. In 2002 Distrilec did not register significant net other exploitation income.

In 2003, excluding proportional consolidation, our other exploitation income decreased on a net basis by P$1 million or 4.3% to P$22 million, from P$23 million in 2002.

Equity in Earnings of Affiliates and Companies under Joint Control

CIESA/TGS: In 2003, our equity share in the earnings of CIESA (which owns 55.3% of TGS), together with our 7.35% direct interest in TGS, accounted for a P$240 million gain, compared to a P$482 million loss in 2002. Given the significant financial indebtedness of both TGS and CIESA that is denominated in U.S. dollars, the appreciation of the peso in 2003, compared to the depreciation it registered in 2002, had a significant impact on their net results. Additionally, CIESA s exploitation income declined 6.7% in 2003, to P$407 million, as a result of lower revenues for the regulated gas transportation market as a consequence of the pesification of rates. Our results in 2003 include a P$33 million gain in respect of our investment in CIESA, representing the reversal of the P$33 million negative value of our equity in this company as of December 31, 2002.

Sales revenues from the gas transportation segment dropped 20.7% in 2003, to P$422 million. While the committed transportation capacity slightly increased from 61.3 MMm3/d to 61.4 MMm3/d, the drop in revenues results from failure to adjust gas transportation rates due to the delayed start of the tariff negotiation process with the Argentine government and the restatement of income for 2002. Both effects were partially offset by increased revenues from interruptible transportation services, as a result of a rise in the demand for natural gas.

Income from the NGL production and marketing segment increased 23.3% in 2003 to P$428.4 million, as a result of: (i) an increase in domestic sale prices caused by a significant increase in international sale prices, (ii) the renegotiation of certain NGL processing and marketing agreements which had been pesified and were re-indexed to the dollar, and (iii) a 6% increase in sales volumes. These positive factors were partially offset by the effect of the restatement of income for 2002, reflecting the fact that the increase in prices and margins exceeded domestic inflation.

CIESA is presented under the proportional consolidation method in our financial statements as of and for the years ended December 31, 2003 and December 31, 2001 included in this annual report, but not in the financial statements as of and for the year ended December 31, 2002. See Overview. As a result, the financial data discussed above is not directly comparable to the corresponding data appearing in our financial statements.

Distrilec/Edesur: In 2003, our equity interest in the earnings of Distrilec (through which we hold our interest in Edesur) accounted for an P$11 million loss, compared to an P$8 million loss in 2002. In 2003, Distrilec registered a P$17.2 million operating loss, compared to a P$46.8 million operating gain in 2002. This shift reflects the impact of the Public Emergency Law and the pesification of rates. Net sales declined 13.9% in 2003, to P$920.2 million. This decline was mainly attributable to a decrease of approximately 17% (in constant currency) in the average sale price for energy, which was partially offset by a 4.4% increase in the demand for energy. Distrilec s operating loss in 2003 was positively affected by the appreciation of the peso during this year on this company s financial debt.

Distrilec is presented under the proportional consolidation method in our financial statements included in this annual report. See Overview. As a result, the financial data discussed above is not directly comparable to the corresponding data appearing in our financial statements.

Citelec/Transener: In 2003, our equity interest in the earnings of Citelec (through which we hold our interest in Transener) accounted for an P$87 million gain, compared to a P$241 million loss in 2002. This shift resulted primarily from appreciation of the peso in 2003 and its impact on Transener s financial indebtedness. The equity gain from Citelec in 2003 also reflects the reversal of a P$66 million allowance recorded in 2002. In 2003, Citelec s exploitation income declined 39.1% to P$42 million, from P$69 million in 2002, primarily as a result of the pesification of regulated rates. Sales revenues declined 3.7% in 2003, to P$276 million, mainly as a result of the

Argentine government s failure to adjust regulated rates in 2002 and 2003. This effect was offset by the increase in unregulated revenues, primarily attributable to revenues derived from construction of the Yacyretá Ayolas 500 kV High Voltage Transmission Line and other projects in Paraguay.

112

Refinor S.A.: In 2003, our equity interest in the earnings of Refinor accounted for a gain of P$28 million, compared to a gain of P$9 million in 2002. This increase resulted primarily from a 19% rise in fuel marketing margins and, to a lesser extent, the losses attributable to the devaluation of the peso, which had reduced Refinor s earnings for 2002. Refinor s sales increased to P$858 million in 2003, from P$836 million in 2002, reflecting a 10% increase in the volume of gas it processed (to an average of 16.7 million cubic meters per day). This increase in gas volume processed resulted from the launch of operations of the Chango Norte field, which supplied gas to Refinor s gathering and compression system. This increase in gas production was offset by a 6% decrease in the level of oil processed (to 17.6 thousand barrels per day), resulting from reduced availability of crude oil.

Cuyo: In 2003, our equity interest in the earnings of Cuyo accounted for a P$16 million gain, compared to a P$10 million loss in 2002 (which reflects the impact of the peso devaluation in 2002 on Cuyo s U.S. dollar-denominated debt). Cuyo s sales in 2003 totaled P$225 million, compared to P$200 million in 2002, as a result of a 5.9% increase in average sale prices of its products, mainly reflecting the 25% rise in the international prices of polypropylene.

Empresa Boliviana de Refinación (EBR): In 2003, our equity interest in the earnings of EBR accounted for a P$5 million loss, compared to a P$12 million gain in 2002. This drop is mainly attributable to changes introduced in this company s regulatory framework, which resulted in a significant drop in refining margins.

Oleoductos del Valle S.A. (Oldelval): In 2003, our equity interest in the earnings of Oldelval accounted for a P$2 million gain, compared to a P$11 million gain in 2002, mainly due to a 16% decline in sales revenues (to P$102 million) resulting from an increase in the U.S. dollar-denominated rate that Oldelval charges to its customers. Oldelval s operating costs increased due to maintenance work performed to secure reliability of the pumping system. During 2003, oil volumes transported by Oldelval from Allen to Puerto Rosales registered a slight 1.2% drop (to 60 million barrels), reflecting the natural decline of the oil field at the Neuquén basin, and sustained growth of exports to Chile through the Trans-andino Oil Pipeline.

Table of Contents

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Net income: In 2002, we reported a net loss of P$1,579 million, compared to income of P$101 million in 2001. The enactment of the Public Emergency Law, the peso devaluation, the worsening of the current economic and financial crisis in Argentina, in addition to growing uncertainty over its evolution, adversely affected 2002 operations and resulted in significant losses. This resulted in a significant change in the historical evolution of our results. Net income in 2002, without proportional consolidation, was significantly affected by the following factors:

(i) Argentine peso devaluation: The 238% devaluation of the peso in 2002 affected our results in two respects: it caused (i) P$8,030 million in negative exchange differences derived principally from the net borrowing position primarily denominated in U.S. dollars, and (ii) a P$356 million increase in interest related to foreign currency financial debt (from P$477 million in 2001 to P$833 million in 2002). Conversely, remeasurement and translation into Argentine currency of foreign non-monetary assets accounted for a P$1,500 million gain. See Factors Affecting Our Consolidated Results of Operations Economic and Political Developments in Argentina Argentina Peso Devaluation.

(ii) Valuation of our interests in utility companies: Due primarily to the peso devaluation and the pesification of rates, equity in earnings of utility companies dropped P$851 million in 2002. In addition, we recorded a P$66 million impairment charge to write off the book value of Citelec. In 2001, we recorded a P$202 million impairment charge to write off CIESA s acquisition value in excess of the relevant book value. See Factors Affecting Our Consolidated Results of Operations Economic and Political Developments in Argentina Valuation of Our Interests in Utility Companies.

(iii) Impairment of assets: We have recorded a P$63 million impairment allowance for our operations in Ecuador. See Factors Affecting our Consolidated Results of Operations Operations in Ecuador. We also adjusted the book value of assets of certain gas areas in Argentina and equity interest in Hidroneuquén, accounting for P$44 million and P$10 million losses, respectively, in 2002. See Factors Affecting Our Consolidated Results of Operations Economic and Political Developments in Argentina Impairment of Assets. In addition, considering prospects for the evolution of results of operations, we recorded P$19 million and P$103 million impairment charges in 2002 and 2001, respectively, to write off the minimum presumed income tax credit.

(iv) Impairment of Argentine government bonds: Since the Argentine government declared the default on most of its sovereign debt, following a conservative accounting practice, we recorded an impairment charge to write off the book value of our holdings of Argentine External Bills in U.S. dollars, survey rate series 74, accounting for a P$30 million loss in 2002.

(v) Association Agreement in San Carlos and Tinaco: P$37 million impairment charge to write off the value of the investments made in such areas. See Factors Affecting Our Consolidated Results of Operations Political and Economic Situation in Venezuela Association Agreement in San Carlos and Tinaco.

(vi) Political and economic crisis in Venezuela: Political and economic unrest, especially the prolonged strike in which PVDSA s workers joined, accounted for a drop in sales from our Venezuelan operations of approximately U.S.$10 million. Considering the uncertainty posed by the prevailing situation in Venezuela, we deemed it prudent to record a P$42 million impairment charge in 2002 to write off the book value of loans granted to partners in Venezuelan joint ventures. Under such loan agreements, we from time to time provide our joint venture partners any cash required to comply with the obligations related to the joint venture s cash flows. The impairment charge was recorded to adjust loan quality to probable recoverable value taking into account that such loans are secured by a pledge as fiduciary bond.

These effects were partially mitigated by:

(i) Effect of inflation: The significant net borrowing position resulted in the recognition of a P$6,210 million gain for exposure to inflation. See Factors Affecting Our Consolidated Results of Operations Economic and Political Developments in Argentina Effects of Inflation.

(ii) Income from divestment of non-core assets: Divestment of non-core assets accounted for a P$78 million net gain in 2002. See Factors Affecting Our Consolidated Results of Operations Divestment of Non-Core Assets. During the 2001 fiscal year, divestment of operations accounted for a P$186 million net gain.

Net sales: In 2002, our net sales decreased by P$64 million or 1.2% to P$5,106 million, from P$5,170 million in 2001. Our net sales for 2002 reflect P$519 million corresponding to our share of Distrilec s net sales for that year. Our net sales for 2001 reflect P$610 million and P$946 million corresponding to our share of the net sales of CIESA and Distrilec, respectively, for that year.

Without proportional consolidation, net sales increased P$973 million or 26.9% to P$4,587 million in 2002, from P$3,614 million in 2001, primarily due to the significant rise in the price of the main commodities that we sell. In the prevailing inflationary scenario in 2002, the price of the main products significantly increased reflecting increased contribution from foreign operations, increased exports and the alignment of domestic prices with export reference prices. In such respect, in 2002 the prices of crude oil, styrene and polystyrene increased 52%, 72% and 37%, respectively. In 2002, sales for the Oil and Gas Exploration and Production business segment increased P$831 million (including a P$300 increase in intercompany sales), and sales for the Petrochemicals and Refining business segments increased P$436 million and P$220 million, respectively. In contrast, sales revenues from the Electricity segment decreased P$116 million.

Gross profit: In 2002, our gross profit decreased by P$1 million or 0.1% to P$1,822 million, from P$1,823 million in 2001. Our gross profit for 2002 reflects P$113 million corresponding to our share of Distrilec s gross profits for that year. Our gross profit for 2001 reflects P$376 million and P$292 million corresponding to our share of the gross profits of CIESA and Distrilec, respectively, for that year.

Without proportional consolidation, gross profit for 2002 increased P$554 million or 48% to P$1,709 million from P$1,155 million in 2001, mainly as a result of increased marketing margins of the main commodities. Oil and Gas Exploration and Production and Petrochemical business segments gross profits increased P$419 million and P$210 million, respectively. Conversely, as a result of restrictions on the increase of energy sales prices in the prevailing inflationary scenario, gross profit for the Electricity business segment dropped by P$62 million.

Administrative and selling expenses: In 2002, our administrative and selling expenses decreased by P$56 million or 8.4% to P$609 million, from P$665 million in 2001. Our administrative and selling expenses for 2002 reflect P$77 million corresponding to our share of Distrilec s administrative and selling expenses for that year. Our administrative and selling expenses for 2001 reflect P$33 million and P$122 million corresponding to our share of the administrative and selling expenses of CIESA and Distrilec, respectively, for that year.

Without proportional consolidation, administrative and selling expenses for 2002 increased P$22 million or 4.3% to P$532 million, mainly as a result of the effect of devaluation on expenses incurred abroad. This impact, however, was mitigated by the implementation of a stringent cost optimization policy.

Exploration expenses: Exploration expenses increased P$17 million or 41.5% to P$58 million in 2002 from P$41 million in 2001.

Other exploitation income (expense), net: In 2002, we recorded other exploitation expenses, net, in the amount of P$28 million, compared to other exploitation income, net, in the amount of P$23 in 2001. Distrilec (which was subject to proportional consolidation in 2002) did not register, on a net basis, any other exploitation expenses in 2002. Our net other exploitation income for 2001 reflects P$3 million corresponding to our share of the net other exploitation income of Distrilec for that year.

In 2002, excluding proportional consolidation, we recorded other exploitation expenses, net, in the amount of P$28 million, compared to other exploitation income, net, in the amount of P$20 million in 2001. Our net other exploitation expenses for 2002 resulted primarily from a P$20 million reduction in income from advisory services related, either directly or indirectly, to utility companies operation, in line with the special situation of these companies, and P$15 million in liabilities for environmental remediation work.

Exploitation income: In 2002, our exploitation income decreased by P$13 million or 1.1% to P$1,127 million, from P$1,140 million in 2001. Our exploitation income for 2002 reflects P$36 million corresponding to our share of Distrilec s exploitation income for that year. Our exploitation income for 2001 reflects P$343 million and P$173 million corresponding to our share of the exploitation income of CIESA and Distrilec, respectively, for that year.

Without proportional consolidation, exploitation income increased P$468 million or 75% to P$1,092 million in 2002 from P$624 million in 2001, mainly as a result of the significant increase in gross profit.

Equity in earnings of affiliates: Equity in earnings of affiliates accounted for a P$638 million loss in 2002 compared to a P$119 million gain in 2001. This significantly increased loss mainly resulted from the decline in earnings of our affiliate utility companies.

Without applying proportional consolidation in 2002, our equity interest in the earnings of affiliates would have registered a net loss of P$647 million, as compared to a net gain of P$204 million in 2001. This shift resulted primarily from a significant reduction in the earnings of our affiliate utility companies. In 2002, these companies registered a loss of P$732 million, compared to a P$119 million gain in 2001. In 2002, our equity interest in the earnings of affiliates was also adversely affected by the following factors:

- the loss of earnings resulting from the sale of our interests in Pecom Agra, from which we had derived a P$17 million gain in 2001; and

- a P$10 million loss from our equity interest in the earnings of Cuyo, compared to a gain of P$4 million in 2001, resulting from the impact of the peso devaluation on Cuyo s dollar-denominated debt.

Conversely, we derived a P$59 million gain from our equity share in the earnings of Cerro Vanguardia, compared to a P$16 million gain in 2001, reflecting the inflow of U.S. dollar-denominated cash flows from this company s operations.

For a discussion of our equity in the earnings of companies over which we exercise joint control in 2002 and the factors that affected these companies results during that year, see Equity in Earnings of Affiliates and Companies under Joint Control.

Financial income (expense) and holding gains (losses): In 2002, our financial expenses and holding losses increased by P$1,254 million or 218.8% to P$1,827 million, from P$573 million in 2001. Our financial expenses and holding losses for 2002 reflect P$168 million corresponding to our share of Distrilec s financial expenses and holding losses for that year. Our financial expenses and holding losses for 2001 reflect P$124 million corresponding to our share of CIESA s financial and holding losses for 2001, and P$2 million corresponding to our share of Distrilec s financial and holding gains for 2001.

Without proportional consolidation, net financial expenses increased P$1,208 million or 267.8% to an expense of P$1,659 million in 2002 from an expense of P$451 million in 2001. Such increased loss is primarily attributable to: (i) a P$8,030 million net exchange loss in 2002, (ii) an increase in net financial costs from P$414 million in 2001 to P$770 million in 2002, (iii) adjustment of liabilities on account of pesification and subsequent application of indexation in the amount of P$54 million, (iv) impairment charge to write off book value of holding of Argentine External Bills in U.S. dollars, survey rate series 74, accounting for a P$30 million loss and (v) a P$470 million loss in 2002 compared to a P$8 million loss in 2001 from derivatives that do not qualify for hedge accounting, reflecting the increase in the future price curve of reference crude oil and the impact of the devaluation of the peso. Such effects were mitigated by a P$1,500 million gain resulting from conversion and translation of foreign non-monetary assets and by a P$6,209 million gain due to exposure to inflation.

Other expenses, net: In 2002, our other expenses increased on a net basis by P$99 million or 112.5% to P$187 million, from P$88 million in 2002. Our net other expenses for 2002 reflect P$9 million corresponding to our share of Distrilec s net other expenses for that year. Our net other expenses for 2001 reflect P$63 million and P$11 million corresponding to our share of the net other expenses of CIESA and Distrilec, respectively, for that year.

Without proportional consolidation, other expenses, net recorded P$178 million and P$14 million losses in 2002 and 2001, respectively. In 2002, losses were primarily attributable to the following: (i) impairment of gas production blocks in the amount of P$44 million, (ii) P$63 million for impairment allowance from our group of assets in Ecuador, (iii) impairment of exploratory investments in the San Carlos areas in the amount of P$37 million, (iv) impairment charge to write off book value of interest in Hidroneuquén in the amount of P$10 million, (v) P$42 million allowance for bad debts related to loans granted to joint venture partners in Venezuela, and (vi) accelerated amortization of financial debt issuance costs in the amount of P$17 million, in the context of the debt refinancing process. Such effects were partially offset by gain from divestment of non-core assets of P$78 million. Losses recorded in the previous fiscal year were mainly attributable to the P$202 million impairment charge to write off the acquisition value of CIESA in excess of the relevant book value and to the P$65 million loss from the sale of Pampa del Castillo-La Guitarra area and of the shareholding in Terminales Marítimas Patagónicas, partially offset by a P$251 million gain derived from a hydrocarbon assets exchange.

Income tax: In 2002, our income tax charge decreased by P$303 million or 78.7% to P$82 million, from P$385 million in 2001. Our income tax charge for 2002 reflects a P$127 million gain corresponding to our share of Distrilec s income tax for that year. Our income tax charge for 2001 reflects P$66 million and P$70 million, corresponding to our share of the income tax of CIESA and Distrilec, respectively, for that year.

Without proportional consolidation, the income tax provision accounted for a P$209 million expense in 2002 compared to a P$249 million expense in 2001. Both years include an impairment charge to write off the minimum presumed income tax credit in the amount of P$19 million and P$104 million, respectively.

Oil and Gas Exploration and Production

Exploitation income: Exploitation income for this segment increased P$327 million or 56.9% to P$902 million in 2002 from P$575 million in 2001. This increase was primarily due to increased sale prices and an increase in margins, as explained below.

Net sales: Net sales for this business segment increased P$831 million or 42.1% to P$2,806 million in 2002 from P$1,975 million in 2001. Excluding intercompany sales, net sales for this segment increased to P$2,033 million or 35.4% from P$1,502 million. This significant rise was attributable to increased sale prices mainly as a result of the peso devaluation during 2002. Crude oil international price slightly increased to U.S.$26.3 per barrel or 1.5% in 2002. As a consequence of the combined effect of such factors, the average price per barrel of oil equivalent increased 52.5% to P$45/per barrel of oil equivalent from P$29.5/per barrel of oil equivalent. Crude oil hedging policy in 2002 and 2001 accounted for an opportunity cost of P$373 million and P$341 million, respectively.

Combined oil and gas sales declined 6.8% to 171.1 thousand barrels of oil equivalent per day in 2002 from 183.6 thousand barrels of oil equivalent per day in 2001. The previous year includes sales attributable to the Pampa del

Castillo La Guitarra area, which was sold in October 2001 and contributed an average production of 7.3 thousand barrels of oil equivalent per day in 2001. Excluding such divestment, the daily sales volume dropped only 2.9%. The significant reduction in the investment plan severely limited operations during 2002. Along these lines, our investments were focused on countries and products with greater possibilities of accelerated cash generation. Our proactive management of operations enabled us to mitigate the effects of the reduction in the investment plan.

117

Table of Contents

Net Sales in Argentina: Net sales of oil and gas in Argentina increased P$383 million or 31.3% to P$1,607 million in the 2002 fiscal year from P$1,224 million in the 2001 fiscal year. Combined oil and gas sales volumes in 2002 decreased 10.1%, to 101.5 thousand barrels of oil equivalent per day in 2002 from 112.9 thousand barrels of oil equivalent per day in 2001.

Sales of crude oil in Argentina increased P$447 million or 45.8% to P$1,423 million from P$976 million as a consequence of the peso devaluation. Average crude oil prices, net of discounts per barrel, increased 62.3% to P$65.4 in 2002 from P$40.3 in 2001. Tax on crude oil exports applied since April 2002 accounted for a P$84 million lower revenue in 2002. Daily oil sales volumes dropped 10% to 59.2 thousand barrels from 65.8 thousand barrels, mainly as a result of the sale of Pampa del Castillo La Guitarra area.

Sales of natural gas in Argentina dropped P$65 million or 26% to P$183 million in 2002 from P$248 million in 2001. In 2002, gas daily sales volumes decreased 10.3% to 253.9 million cubic feet from 282.9 million cubic feet, primarily as a consequence of reduced sales to gas distributors, especially as a result of the application of more stringent credit policies and, to a lesser extent, as a consequence of the reduced demand from thermoelectric generating plants on account of the high water supply levels recorded in 2002. Average gas sales prices dropped to P$1.98 per thousand cubic feet in 2002 from P$2.40 per thousand cubic feet in 2001, in line with the Public Emergency Law provisions that limit the possibility of increasing the price of gas sold in the domestic market, mainly regarding sales agreements entered into with utility companies and with the power thermoelectric generating plants. However, we renegotiated the terms and conditions of certain gas sales agreements, especially those corresponding to exporting clients, and the prices of said agreements were adjusted to meet the new economic conditions.

Net Sales Outside of Argentina: Net sales of oil and gas outside Argentina increased P$448 million or 59.7% to P$1,199 million in 2002 from P$751 million in 2001, mainly as a result of the peso devaluation. In 2002, combined oil and gas sales decreased 1.7% to an average of 69.5 thousand barrels of oil equivalent per day from 70.7 thousand barrels of oil equivalent per day in 2001.

In Venezuela, oil and gas sales increased P$220 million or 45.8% to P$700 million in 2002 from P$480 million in 2001 as a consequence of the peso devaluation. During 2002, average daily oil sales decreased 3.5% to 44.7 thousand barrels compared to 46.3 thousand barrels in 2001 as a result of the field s natural decline and reduced deliveries due to the oil strike during December 2002. In 2002, the average oil price per barrel increased 51% to P$41.9 from P$27.7 in the 2001 fiscal year.

In Bolivia, oil and gas sales increased P$29 million or 34.9% to P$112 million in 2002 from P$83 million in 2001, mainly as a result of the peso devaluation. Combined daily oil and gas sales volumes decreased 6.4% to 7.3 thousand barrels of oil equivalent per day in 2002 from 7.8 thousand barrels of oil equivalent per day in 2001 as a result of reduced gas demand from Brazil.

In Peru, oil and gas sales increased P$174 million or 95.1% to P$359 million in 2002 from P$184 million in 2001. Due to the Argentine peso devaluation, average oil sales prices rose 101% to P$80.4 from P$40 in 2001. In 2002, daily oil sales volumes decreased slightly to 11.3 thousand barrels from 11.6 thousand barrels in 2001, reflecting the field natural decline.

In Ecuador, net sales totaled P$28 million in 2002 and there were no material sales in 2001. Sales in 2002 were attributable to the start-up of production at the Palo Azul field, in Block 18, upon approval of the development plan, which added sales of P$16 million. In addition, management works were performed in the amount of P$12 million.

Gross profit and gross margin: Gross profit for this business segment increased P$419 million or 53.2% to P$1,206 million in 2002 from P$787 million in 2001 as a result of the Argentine peso devaluation. Gross margin increased to 43% in 2002 from 39.9% in 2001. During 2002, we continued to reduce costs by optimizing our operations.

Administrative and selling expenses: Administrative and selling expenses for this business segment increased P$57 million or 34.1% to P$224 million in 2002 from P$167 million in 2001 as a result of the Argentine peso devaluation effect on foreign operations expenses. The ratio of administrative and selling expenses to sales did not suffer significant changes in 2002.

Exploration expenses: Exploration expenses increased P$17 million or 41.5% to P$58 million in 2002 from P$41 million in 2001. During 2002, drilling activities at the Chontayacu well at Block 18 in Ecuador were completed but proved to be unsuccessful. In addition, 238 km of 2-D seismic lines were shot at Block 31. In Argentina and Peru, investments attributable to the Chiripá well in the Santa Cruz II Oeste area and to the Mashansha well at Lot 35 were charged to income, but no reserves were found.

Other exploitation income, net: Other exploitation income recorded a P$22 million loss in 2002 mainly attributable to liabilities for environmental remediation and the sale of fixed assets. In 2001, net exploitation income accounted a P$4 million loss, due mainly to discontinued projects.

Hydrocarbon Marketing and Transportation

Our results for this segment in 2002 do not reflect the proportional consolidation of CIESA. In 2001, CIESA s results are proportionally consolidated. See Overview.

Exploitation income: In 2002, our exploitation income for this segment decreased by P$362 million or 95.7% to P$16 million, from P$378 million in 2001. Our exploitation income for this segment in 2001 reflects P$342 million corresponding to our share of CIESA s exploitation income for that year.

Without proportional consolidation, exploitation income for the hydrocarbon marketing and transportation business segment decreased P$20 million or 55.5% to P$16 million in 2002 compared to P$36 million in 2001.

Our own operations: Due to a reformulation of the liquid processing business, beginning in 2002 the Oil and Gas Exploration and Production business segment has developed the liquid processing business segment. In 2001, sales revenues amounted to P$50 million and exploitation income totaled P$14 million. Excluding the effects from these activities, exploitation income from this segment s operations decreased P$2 million to P$3 million in 2002 from P$5 million in 2001, and sales revenues dropped P$19 million to P$16 million from P$35 million in 2001, mainly due to the deterioration of the price of gas sold in the domestic market and the drop in oil operations, partially offset by improved prices resulting from the Argentine peso devaluation.

Other operating expenses: In relation to advisory services provided to TGS s technical operator, we recorded P$13 million and P$17 million of income in 2002 and 2001, respectively.

Refining

Exploitation income: Exploitation income decreased P$5 million. We did not report exploitation income from this segment in 2002, while in 2001 it totaled a P$5 million gain.

Net sales: Net sales of refinery products, including intersegment sales, increased P$220 million or 27.9% to P$1,008 million in 2002 from P$788 million in 2001, boosted by increased prices and higher export volumes, which partially offset the strong shrinkage in the domestic market. In 2002, the average sales price of diesel oil, gasolines, heavy products, benzene, paraffins, aromatics and asphalts increased 23.1%, 7.3%, 58.5%, 108%, 55.4%, 30.5% and 24.0%, respectively. Total sales volumes remained unchanged compared to 2001. There was, however, a change in the mix of products sold, aiming to prioritize the optimization of margins, as well as in marketing channels. Along these lines, exports increased 171%, capitalizing on the improved competitiveness of Argentine production after the devaluation, while local sales dropped 30% due to the domestic market shrinkage and the lack of profitability.

Taxes on exports applied in April 2002 accounted for P$14 million lower income in 2002.

Table of Contents

During 2002, gasoline and diesel domestic demand dropped 12.5% and 8.4%, respectively. The recession in the Argentine market in addition to the strong tax incidence on final prices of these products had a negative impact on demand. This, in turn, encouraged a strong growth in alternative products such as CNG. Total diesel sales volumes decreased 16.3%, with a 35% decline in the domestic market, offset by a 416% increase in exports to bordering countries, especially to Paraguay. Total gasoline sales volumes dropped 2.7%, reflecting the domestic market behavior.

Aromatics sales volumes rose 3.4% on account of increased exports that rose 144%, mainly to bordering countries and the United States, offset by a 15% drop in the domestic market. Sales volumes of the reformer plant products decreased 5.6% due to reduced local sales (22%), offset by a 503% increase in exports. Sales volumes of paraffinic products increased 34.5% due to the 90% rise in export volumes, mainly to the United States and bordering countries, offset by reduced local sales (20%). Sales volumes of heavy products increased 46.1% due to the 150% increase in volumes exported to the United States and bordering countries, offset by reduced local sales (46%). Asphalts sales volumes dropped 46.4%, with a 60% market shrinkage, and the market share decreased to 17% from 21% in 2001. Sales to the domestic market influenced by the interruption of most public works recorded a 65% drop, offset by exports to Bolivia and Paraguay which increased 194% compared to 2001. We set a new record on asphalt exports.

Gross profit and gross margin: Gross profit for this business segment dropped P$13 million or 16.9% to P$64 million in 2002 from P$77 million in 2001. Gross margin decreased from 9.8% in 2001 to 6.3% in 2002.

In 2002, the refining spread per barrel (average sales price less crude oil cost) decreased to P$18.1 or 22.3% from P$23.3. The average price of crude oil increased to P$78.9 per barrel or 36.8% from P$57 per barrel in 2001, reflecting the impact of the Argentine peso devaluation. The international reference price remained at an average of U.S.$26 per barrel, equivalent to the average recorded in 2001. Express Argentine government initiatives and the gradual drop in the activity level curbed the passing through of increased crude oil costs to sales prices. Sales prices only increased an average of 28%, thus resulting in the aforementioned deterioration of the spread per barrel.

In line with the strategy designed to maximize product contribution margins through the optimization of crude oil volumes processed, mainly by capitalizing on lower refined product export tax rates compared to export tax rates applicable to crude oil, crude oil volumes processed in 2002 averaged 27.1 thousand barrels per day, 6% higher than in 2001.

Administrative and selling expenses: Administrative and selling expenses for this business segment decreased P$11 million or 18.6% to P$48 million in 2002 from P$59 million in 2001, mainly due to the fact that expenses increased significantly below inflation levels.

Other operating expenses: Other operating expenses recorded P$16 million and P$13 million losses in 2002 and 2001, respectively. The under-absorption of fixed costs imposed by the optimization policy of crude oil volumes processed accounted for P$10 million losses in both fiscal years. In addition, P$5 million liabilities for environmental remediation costs were recorded in 2002.

Petrochemicals

Exploitation income: Exploitation income for this business segment increased P$192 million or 325% to P$251 million in 2002 from P$59 million in 2001, primarily due to the significant recovery of marketing margins, especially styrenics margins, and to increased styrene, polystyrene and rubber sales volumes. In addition, the changes in the fertilizers sales mix boosted exploitation income since the sale of products with a higher added value was prioritized.

Net sales: Net sales for this business segment, including intersegment sales, increased P$436 million or 53.3% to P$1,254 million in 2002 from P$818 million in 2001.

Styrene and polystyrene Argentina: Sales of styrene and polystyrene from Argentina increased P$158 million or 54% to P$451 million from P$293 million in 2001 (including exports to Innova in the amount of P$26 million and P$9 million, respectively). Sales prices of styrene, polystyrene and rubber prices increased 72%, 37% and 36%, respectively. Sales volumes recorded a 5% increase, boosted by a 41% increase in exports, which offset the 13% drop in local sales. Styrene sales volumes rose 9%, boosted by a 183% increase of exports, principally to Brazil and Chile, thus confirming our leading position in the styrene market in the Mercosur. Local sales dropped 28% due to the impact of the strong Argentine recession during the year. Polystyrene sales volumes increased 10% due to a 45% record increase in exports, the main destinations being neighboring countries, especially Brazil and Chile, and the United States and Europe, while local sales dropped 12%. Total rubber sales volumes increased approximately 8% boosted by the 15% increase in exports (setting another record for us), mainly to Brazil, Chile and Peru, offset by reduced local sales (6%). Tax on exports applied in April 2002 accounted for a P$6 million income reduction in 2002.

Styrene and polystyrene Brazil: Sales of styrene and polystyrene from Brazil increased P$264 million or 89.6% to P$561 million from P$297 million in 2001, primarily due to the increase in styrene and polystyrene international prices which recorded 88% and 61% increases, respectively, compared to 2001. In addition, Innova s low-cost production, as well as the plant s strategic location and the effective business management, helped extend the client base in Brazil and generate a 25% increase in styrene volumes sales. With a 2.8% rise in the local market share, the increased trading activity allowed us to consolidate our leading position in the Brazilian market. Polystyrene sales volumes were slightly higher than those in 2001. A 188% increase in exports compared to 2001, mainly attributable to the consolidation of commercial relations in South Africa and sales to the United States, favorably offset the 11% drop in local sales. Excluding non-recurrent sales made to co-producers in 2001, the volume sold to our client base registered a 5.7% increase. Overall performance acquires significance within a market characterized by increasing competitive pressures as a result of a substantial increase in the total installed production capacity.

Fertilizers: Net sales increased P$31 million or 13.1% to P$268 million from P$237 million mainly as a result of a 33% price increase on account of the passing through of increased input costs and of the change in the sales mix. Total sales volumes fell 15.4% compared to 2001, in line with the Argentine market shrinkage. In addition, during 2002 we set up a more selective sale strategy aimed at prioritizing the quality of our client portfolio and maximizing marketing margins. Along these lines, sales volumes of products manufactured increased 21%, while resale dropped 58%.

Gross profit and gross margin: Gross profit increased P$210 million or 138.2% to P$362 million in 2002 from P$152 million in 2001. Gross margin on sales increased to 28.9% in 2002 from 18.6% in 2001. In 2002 international and local margins were significantly higher than in 2001, boosted by an increased demand from Asia, in addition to operating problems that affected the performance of plants located in the United States and Europe. Within this scenario, the differential of international prices between crystal polystyrene (South East Asia) and the mix of benzene/ethylene raw materials (U.S. Gulf Coast) increased 64%, and the differential between styrene (U.S. Gulf Coast) and the mix of benzene/ethylene raw materials (U.S. Gulf Coast) increased 330%. In line with the international price trend, polystyrene and styrene marketing spreads increased 27% and 81% in Argentina, and 51% and 129% in Brazil, respectively. In addition, because of the peso devaluation, Argentina s elastomers business gained international competitiveness due to the relative importance of its fixed production costs.

Administrative and selling expenses: Administrative and selling expenses increased P$27 million or 28.7% to P$122 million from P$95 million due to the Argentine peso devaluation effects on Brazilian operations.

Other exploitation income: Other exploitation income recorded P$11 million and P$2 million gains in 2002 and 2001, respectively. Fiscal year 2002 income is attributable to the collection of an insurance compensation for a loss occurred at the ethyl benzene plant and to certain tax credits from operations in Brazil.

Electricity

Our results for this segment in 2002 and 2001 reflect the proportional consolidation of Distrilec. See Overview.

Table of Contents

Exploitation income: In 2002, our exploitation income for this segment decreased by P$198 million or 69% to P$89 million, from P$287 million in 2001. Our exploitation income for this segment in 2002 and 2001 reflects P$32 million and P$149 million, respectively, corresponding to our share of Distrilec s exploitation income for these years.

Without proportional consolidation, income for this business segment dropped P$81 million or 58.7% to P$57 million in 2002 from P$138 million in 2001. Within the current economic context, the Public Emergency Law provisions significantly affected the business segment s margins. In such respect, pesification of tariffs and contracts within an inflation and devaluation scenario adversely affected the business segment s operating performance.

Net Sales: In 2002, our net sales for this segment decreased by P$520 million or 40.4% to P$766 million, from P$1,286 million in 2001. Our net sales for this segment in 2002 and 2001 reflect P$518 million and P$922 million, respectively, corresponding to our share of Distrilec s net sales for these years.

Without proportional consolidation, net sales in the electricity business generally decreased P$116 million or 31.9% to P$248 million from P$364 million. Net sales of electricity generation decreased P$70 million or 26.3% to P$196 million from P$266 million in 2001. Net sales of nuclear fuel elements and other products totaled P$42 million and P$5 million in 2002 and 2001, respectively.

Net Sales from generation: Net sales attributable to the Genelba Power Plant dropped P$40 million or 19.8% to P$162 million in 2002 from P$202 million in 2001 reflecting a drop in energy prices, which was partially offset by increased sales volumes. The average monomic price of energy and power delivered dropped 32.3% accounting for P$34.2 per MWh and P$49.8 per MWh, respectively, mainly due to pesification and a 6% demand shrinkage. In 2002, energy deliveries increased by 18.9% to 4,731 GWh from 3,979 GWh in 2001, with plant factors of 73.6% and 59.8%, respectively. The increased volume was mainly attributable to: (i) non-restriction of fuels during 2002; (ii) higher operating availability; and (iii) higher dispatch to the network, due to a timely and flexible operation and the effects of regulatory changes that improved the Genelba Power Plant s competitiveness. In 2002, Genelba Power Plant operating availability was 95.4%, 3.3% higher than in 2001, as a result of compliance with works scheduled in the technical maintenance program for equipment.

Net sales attributable to HPPL dropped P$19 million or 39.2% to P$29 million in 2002 from P$48 million in 2001 as a consequence of the combined effect of lower sales prices and a slight drop in sales volumes, to 1,240 GWh from 1,313 GWh, determined by the high water levels recorded in 2001. The average monomic price of energy and power delivered dropped 35.6%, accounting for P$23.5 per MWh and P$36.2 per MWh, respectively, mainly due to pesification of prices. On account of the application of the Energy Support Price Method and by virtue of the prices recorded in both fiscal years and their future estimates, we posted P$5 million and P$17 million gains, respectively, in both years.

Gross profit and gross margin: In 2002, our gross profit for this segment decreased by P$222 million or 58.4% to P$158 million, from P$380 million in 2001. Our gross profit for this segment in 2002 and 2001 reflects P$108 million and P$268 million, respectively, corresponding to our share of Distrilec s gross profit for these years.

Without proportional consolidation, gross profit for the generation business dropped P$48 million or 61% to P$31 million in 2002 from P$79 million in 2001. Gross margin declined to 15.8% from 27.9%, mainly as a result of reduced prices of electricity generation on account of the aforementioned provisions of the Public Emergency Law. Gains recorded on account of the application of the support price method for energy generated at HPPL mitigated the significant price drop.

Administrative and selling expenses: In 2002, our administrative and selling expenses for this segment decreased by P$45 million or 32.8% to P$92 million, from P$137 million in 2001. Our administrative and selling expenses for this segment in 2002 and 2001 reflects P$76 million and P$122 million, respectively, corresponding to our share of Distrilec s exploitation income for these years.

122

Table of Contents

Without proportional consolidation, administrative and selling expenses for the electricity generation business increased P$8 million or 100% to P$16 million in 2002 from P$8 million in 2001. This increase mainly derived from allowances for customers bad debts.

Other exploitation income (expense), net: In 2002, our other exploitation income for this segment decreased on a net basis P$21 million or 47.7% to P$23 million, from P$44 million in 2001. In 2002 Distrilec did not register significant net other exploitation income. Our net other exploitation income for this segment in 2001 reflects P$3 million corresponding to our share of Distrilec s exploitation income for that year.

Without proportional consolidation, other exploitation income-net decreased P$18 million or 43.9% to P$23 million from P$41 million, mainly as a consequence of lower advisory services fees rendered to Edesur s technical operator.

Equity in Earnings of Affiliates and Companies under Joint Control

CIESA/TGS: In 2002, our equity share in the earnings of CIESA (which owns 70% of TGS) accounted for a P$482 million loss, compared to a P$51 million gain in 2001. This shift resulted primarily from the effects of the peso devaluation on this company s significant dollar-denominated debt. Additionally, CIESA s net operating profit fell 6.7% in 2002, to P$4.07 million, as a result of reduced revenues in the regulated segment caused by the pesification of utility rates.

Sales revenue for the gas transportation segment dropped approximately 44% in 2002 (in constant pesos), primarily as a result of the pesification of utility rates. These reductions were partially offset by an increase in the amount of contracted firm transportation capacity, which in 2002 increased from 60.7 million cubic meters per day to 6.14 million cubic meters per day, and by greater revenue from interruptible gas transportation services. The increased level of contracted firm transportation capacity is principally the result of a significant expansion of our gas transportation system starting in June 2001.

The revenue derived from the production and sale of NGL in the unregulated segment increased P$111.5 million in 2002, due to an increase in prices and sales volume, which resulted from the devaluation of the peso against U.S. dollar-denominated export prices.

Distrilec/Edesur: In 2002, our equity interest in the earnings of Distrilec (through which we hold our interest in Edesur), accounted for an P$8 million loss, compared to a P$49 million gain in 2001. This reflects the impact of the Public Emergency Law, which caused significant asymmetry between Edesur s revenue flow and its operating costs and expenditures, and the devaluation of the peso on its dollar-denominated debt.

In 2002, Edesur s revenue from sales fell approximately 45.2% (in constant prices) to P$1,068 million, from P$1,950 million in 2001, due to the freezing of rates and a 6% fall in the demand of energy. In 2002, Edesur s costs and expenditures fell 36% (in constant prices), since a large portion of these costs are denominated in pesos.

Distrilec is presented under the proportional consolidation method in our financial statements included in this annual report. See Overview. As a result, the financial data discussed above is not directly comparable to the corresponding data appearing in our financial statements.

Citelec/Transener: In 2002, our equity interest in the earnings of Citelec (interest in Transener) accounted for a loss of P$241 million, compared to a P$19 million gain in 2001. This shift was caused primarily by the effects of the devaluation of the peso on Citelec s U.S. dollar-denominated debt. Our equity share of Citelec s earnings also reflects a P$66 million impairment charge to write off its book value.

Cuyo: In 2002, our equity interest in the earnings of Cuyo accounted for a P$10 million loss, compared to a P$4 million gain in 2001. This shift reflects the impact of the peso devaluation on Cuyo s dollar-denominated debt.

In 2002, Cuyo registered an operating gain of P$16 million, compared to a P$13 million gain in 2001, as a result of a 59.9% increase in the profit margin for sales of prolipropoline (which was consistent with the increase in the sale margins for this product in international markets), as well as a 5.3% increase in its sales volume (resulting from a 113% increase in Cuyo s exports).

Empresa Boliviana de Refinación: In 2002, our equity interest in the earnings of EBR accounted for a P$5 million loss, compared to a $12 million gain in 2001, due to the significant decline in refining margins caused by regulatory changes.

Refinor: In 2002, our equity interest in the earnings of Refinor accounted for a P$9 million gain, compared to a P$6 million gain in 2001. This increase was primarily caused by the growth of export prices, 59% for diesel oil and 86% for gasoline, which in part mitigated the increased costs of raw materials that mainly affected local profit margins. In 2002, local prices for LPG, diesel oil and gasoline increased 8.8%, 13.4% and 9.2%, respectively. Refinor s sales volumes in the local market increased 14.5% for LPG, 2.8% for diesel oil and 12.6% for gasoline.

CRITICAL ACCOUNTING POLICIES

This operating financial review and prospects is based upon our financial statements, which have been prepared in accordance with accounting principles generally accepted in Argentina. The preparation of financial statements in accordance with GAAP requires our management to make estimates that affect the reported amounts of our assets and liabilities. Our actual results could differ from those estimated if our estimates or assumptions prove to be incorrect.

We believe the following represents our critical accounting policies. Our accounting policies are more fully described in notes 2 and 4 to our financial statements.

Estimated oil and gas reserves. Estimates of oil and gas reserves have been prepared in accordance with Rule 4-10 of Regulation S-X. The choice of method or combination of methods employed in the analysis of each reservoir was determined by the stage of development, quality and reliability of basic data, and production history.

Reserve engineering is a subjective process of estimation of hydrocarbon accumulation, which cannot be accurately measured, and the reserve estimation depends on the quality of available information and the interpretation and judgment of the engineers and geologists. Therefore, the reserves estimations, as well as future production profiles, are often different from the quantities of hydrocarbons which are finally recovered. The accuracy of such estimations depends, in general, on the assumptions on which they are based.

Successful efforts method of accounting. Under this method, exploration costs, excluding the costs of exploratory wells, are charged to expenses as incurred. Drilling costs of exploratory wells, including stratigraphic test wells, are capitalized pending determination of whether proved reserves exist which justify commercial development. If such reserves are not found, the drilling costs are charged to exploratory expenses for the period. Drilling costs of productive wells and of dry holes drilled for development of oil and gas reserves are capitalized.

Hedging and other derivatives. We use various derivative financial instruments such as options, swaps and others, mainly to mitigate the impact of changes in crude oil prices and interest rates.

Changes in the accounting measurement of derivative financial instruments designated as cash flow hedge, which have been determined as effective hedge, are recognized under Transitory differences Measurement of derivative financial instruments determined as effective hedge, and any other change is recognized under financial income (expense) for the year. Changes in the accounting measurement of derivative financial instruments recognized under Transitory differences Measurement of derivative financial instruments determined as effective hedge are subsequently reclassified to income (loss) for the year or years in which the hedged item affects such results.

A hedge is considered to be effective when at its inception, as well as during its life, its changes offset from eighty to one hundred and twenty five percent the opposite changes of the hedged item. In this respect, we exclude the specific component attributable to the time-value of an option when measuring the effectiveness of instruments that qualify for hedge accounting.

Hedge accounting ceases for the future upon occurrence of any of the following events: (a) the hedge instrument has matured or has been settled; (b) the hedge transaction is no longer effective; or (c) the projected transaction does not have a high likelihood of occurrence. Should that be the case, the income (loss) arising from the hedge instrument that would have been allocated to Transitory differences Measurement of derivative financial instruments determined as effective hedge should remain there until the committed or projected transactions occur, in the case of (a) and (b), and are charged to income in the case of (c).

Inflation accounting. Due to the new inflationary environment in Argentina in 2002, and the conditions created by the Public Emergency Law, the CPCECABA approved on March 6, 2002 Resolution MD No. 3/2002 applicable to financial statements for fiscal years or interim periods ending on or after March 31, 2002. Resolution MD No. 3/2002 required the reinstatement of the adjustment-for-inflation method of accounting in financial statements, which provides that all recorded amounts be restated by changes in the general purchasing power through August 31, 1995, as well as those arising between that date and December 31, 2001 stated in currency as of December 31, 2001.

On July 16, 2002, the Argentine government issued Decree No. 1,269/02, instructing the CNV and other regulatory authorities to issue the necessary regulations for the delivery to such authorities of balance sheets or financial statements prepared in constant currency. On July 25, 2002, under Resolution No. 415/02, the CNV reinstated the requirement to submit financial statements in constant currency. As the inflation rate stabilized in 2003, on March 25 of this year, Decree No. 664/03 rescinded the requirement that financial statements be prepared in constant currency. On April 8, 2003, the CNV issued Resolution No. 441/03 discontinuing inflation accounting as of March 1, 2003. On October 1, 2003, the CPCECABA also discontinued inflation accounting.

In accordance with the above, our financial statements for the fiscal years ended December 31, 2002 and 2001 were restated in constant pesos as of February 28, 2003 based on changes in the Argentine wholesale price index published by the INDEC. This price index does not reflect any specific variation in the price of products and services sold by us, and therefore, variations in gains (losses) for both periods include positive or negative price variations that may be higher or lower than the general price variation or price variations for the products or services sold by us. After March 1, 2003, in accordance with the accounting standards described above, we no longer apply adjusting-for-inflation accounting.

Impairment of long-lived assets. We record impairment losses on long-lived assets used in operations when events and circumstances indicate that the assets might be impaired and the undiscounted cash flows estimated to be generated by those assets are less than the carrying amount of those items. Our cash flow estimates are based on historical results adjusted to reflect our best estimate of future market and operating conditions. Our estimates of fair values used to determine the resulting impairment loss, if any, represent our best estimate based on forecasted cash flows, industry trends and reference to market rates and transactions.

Contingencies. Certain conditions may exist as of the date of the financial statements, which may result in a loss to us, but which will only be resolved when one or more future events occur or fail to occur. We assessed contingent liabilities based on the opinion of our legal counsel and the available evidence. If the assessment of a contingency indicates that it is probable that a loss has been incurred and the amount can be estimated, liability is accrued. If the assessment indicates that a potential loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the possibility of occurrence, is disclosed in a note to the financial statements. Loss contingencies considered remote are not disclosed unless they involve guarantees, in which case the nature of the guarantee is disclosed.

Income tax. We estimate income tax on an individual basis under the deferred tax method. The deferred tax balance as of the end of each period has been determined on the basis of the temporary differences generated in certain items that have a different accounting and tax treatment.

To book such differences, we use the liability method, which establishes the determination of net deferred tax assets and liabilities on the basis of temporary differences determined between the accounting measurement of assets and liabilities and the related tax measurement. Temporary differences determine the balance of tax assets and liabilities where its future reversal decreases or increases the taxes determined. In the event there are unused tax loss carry-forwards that may be offset against future taxable income, we will recognize a deferred tax asset, only to the extent that recovery of such asset is probable.

Deferred tax assets and liabilities have been valued at their nominal value, as established by CNV s General Resolution No. 434. The professional accounting standards effective in the city of Buenos Aires require that such nominal value be discounted at a current rate estimated as of each year-end.

Foreign currency translation. We apply the following method for the translation of financial statements of foreign subsidiaries, affiliates, divisions and joint ventures.

Foreign currency denominated transactions are first remeasured into U.S. dollars (functional currency for such transactions) before they are translated into Argentine pesos. Gain (loss) from remeasurement is charged to income in the Financial income (expense) and holding gains (losses) account. The translation effect arising from the translation of the financial statements into Argentine pesos is recorded in the Transitory differences foreign currency translation account.

The above also applies to exchange differences arising from liabilities in foreign currency assumed to hedge the net investment in the foreign entity.

The magnitude of the remeasurement gain (loss) and the translation effect is dependent upon movements in the exchange rates of the respective foreign currencies to the U.S. dollar (to remeasure) and upon movements in the exchange rates from U.S. dollars to Argentine pesos (to translate), respectively.

Change in Accounting Standards

The FACPCE Technical Resolutions Nos. 16, 17, 18, 19, and 20, approved as amended by the CPCECABA and adopted by the CNV through its General Resolution No. 434, became effective on January 1, 2003. These new technical resolutions are a consequence of the process whereby Argentine professional accounting standards are being made consistent with the international accounting standards issued by the International Accounting Standards Committee, or IASC; in addition, they provide clarification for certain issues which had not been provided for in past regulations.

The primary changes included in the technical resolutions that have resulted in significant effects on our financial statements, are: (i) the introduction of guidelines regarding the recognition, measurement, and disclosure of derivatives and hedging transactions; (ii) the amendment of the method used to translate the financial statements of foreign subsidiaries stated in foreign currency; (iii) the mandatory requirement to apply the deferred tax method to recognize income tax; (iv) measurement of asset and liability amounts on discounted bases; (v) changes in the frequency and method of comparison of assets with the recoverable values thereof; (vi) the incorporation of guidelines to assess whether certain transactions including financial instruments, irrevocable capital contributions and preferred stock, among others, should be classified as liabilities or shareholders equity; (vii) the incorporation of new disclosure requirements including proportional consolidation of companies under joint control, change in the disclosure of direct sales revenues, information by segment, earnings (losses) per share, and the comparative information to be disclosed.

In addition, we amended the method used to recognize future estimated abandonment costs in oil and gas areas. Consistent with U.S. Statement of Financial Accounting Standards (SFAS) No. 143 guidelines, such costs, discounted at a rate estimated upon initial measurement, are capitalized together with the assets from which they originate and are depreciated using the production units method. In addition, a liability is recognized on such account at the estimated value of the amounts payable discounted at a rate estimated in its initial measurement.

As established in the new accounting standards, there are certain transition regulations enabling us to prospectively apply the valuation and disclosure method incorporated thereto. The transition standards applied by us, affecting the comparability of the financial statements, are:

(i) the new methods for translating the financial statements of foreign subsidiaries stated in foreign currency were not applied retroactively; and

(ii) the beginning balances resulting from the recognition, measurement, and booking of financial instruments qualified as effective hedge were not corrected.

LIQUIDITY AND CAPITAL RESOURCES

The discussion below regarding our liquidity and capital resources relates to Petrobras Energía and its consolidated controlled subsidiaries. Beginning in 2003, in accordance with Argentine GAAP, we are required to consolidate proportionally the results and financial conditions of companies that we control jointly with other persons. The discussion below generally excludes these jointly controlled companies, and as a result may not be directly comparable to amounts reflected in the financial statements included in this annual report. CIESA and Distrilec, the two companies that are consolidated proportionally in our financial statements, are principally engaged, through TGS and Edesur, respectively, in regulated energy businesses in Argentina and have been significantly affected by the Argentine crisis and the enactment of the Public Emergency Law. Of these companies, CIESA and TGS are currently in default on their financial indebtedness. There are significant uncertainties regarding the ability of CIESA and TGS to continue operating as going concern. We are under no obligation to financially support CIESA, TGS and Distrilec and do not currently intend to do so. We did not receive any dividends from the companies in 2003 or 2002. Our management analyzes our results and financial condition separately from the results and financial conditions of these companies, and we believe presenting our financial information without proportional consolidation with respect to these companies is useful to investors in evaluating our financial condition and results of operations. See " Overview.

The ability of Argentine companies to access bank loans and capital markets over the last few years has been affected by the economic recession and political instability in Argentina. The size and complexity of the Argentine crisis by the end of 2001 significantly affected the liquidity, creditworthiness and profitability of most Argentine companies and severely limited their ability to access foreign and Argentine financial markets in the near and medium term. In light of Argentina s default on its sovereign debt, it is expected that these difficulties will persist for at least the next few years.

Our goal is to consistently maintain high levels of liquidity as a way to reduce financial risks and provide flexibility to overcome the difficult conditions and high volatility of Argentine financial markets and of emerging capital markets as a whole.

In 2002, as a consequence of the Argentine government s default on most of its financial obligations, the restrictions imposed by the government on bank withdrawals and transfers abroad, the deepening recession and an unprecedented political instability, our liquidity was materially affected. The crisis limited our ability to renew short-term lines of credit and the current portion of medium- and long-term financings at maturity. The difficulties in accessing medium- and long-term borrowings resulted in a significant shortening of medium-term maturities of our debt. For further details see Financing Activities and Description of Indebtedness.

In addition, the change in the economic financial equation of the utility companies (see Economic and Political Developments in Argentina Valuation of Our Interests in Utility Companies) also affected our liquidity. In 2001, we received cash dividends from our related companies in the amount of P$65 million, P$52 million of which we received directly or indirectly from TGS, Edesur and Citelec. During 2002 and 2003, we received no dividends from any related utility company.

In order to secure compliance with financial commitments and at the same time support our growth strategy, since 2002 we have implemented a financial management plan that prioritizes the strict monitoring of liquidity levels. Along these lines, an action plan was implemented in 2002 which mainly focused on the refinancing of a substantial portion of our financial debt (see " Financing Activities and Description of Indebtedness) and the significant reduction in our investment plan (see Factors Affecting Our Consolidated Results of Operations Decline in Historical Capital Expenditures). The refinancing plan executed during 2002 extended the debt maturity profile of our debt from 2 to 3.9 years. We believe that the success of our refinancing

Table of Contents

plan evidences the confidence in our business prospects that is held by investors and local and international financial institutions.

In the medium-term, we will seek to gradually reduce our level of indebtedness, in order to optimize our debt to capital ratio. We expect to accomplish this, in part, by generally limiting the level of our investments to cash generated internally and funds obtained from project financings, giving priority to projects with better potential of generating profits on an accelerated basis.

Thus far, we have had success in the implementation of this policy, as evidenced by the following developments:

during 2003, we registered an 89% growth in our operating cash flow (excluding companies under joint control);

Petrobras Energía and its subsidiaries under sole control have paid all of the financial obligations that have come due, while registering an 8% decline in their average annual indebtedness in 2003 as compared to 2002; and

during 2003, we increased our capital expenditures as compared to 2002.

Additionally, with the issuance in October 2003 of U.S.$100 million aggregate principal amount of our Series R notes, we became the first company to place an issuance, which was not in connection with a debt restructuring, in the international markets following the Argentine government s default. The proceeds from this issuance were used to repay short-term liabilities, resulting in an extension of the average life of our outstanding debt and an improvement of our debt profile.

Cash

The table below reflects our cash and cash equivalents at December 31, 2003, 2002 and 2001 and the net cash provided by (used in) operations, investing activities and financing activities during 2003, 2002 and 2001 under the proportional consolidation method as is required by Argentine GAAP beginning in 2003, as compared to such data excluding the proportional consolidation of the companies under joint control. See Overview.

	With Proportional Consolidation			**Without Proportional Consolidation**		
	2003	**2002**	**2001**	**2003**	**2002**	**2001**
Cash and cash equivalents at beginning of period[1]	725	1,333	565	693	1,256	565
Additions (deductions) of cash and cash equivalents from proportional interest in CIESA at beginning of period	103	(64)	71			
Net cash provided by operations	1,353	710	1,725	1,003	532	1,459
Net cash used in investing activities	(915)	(182)	(1,924)	(857)	(114)	(1,592)
Net cash provided by (used in) financing activities	(251)	(1,827)	896	(206)	(1,754)	824
Devaluation and inflation effects on cash	(88)	755		(88)	773	

Cash and cash equivalents at end of period	927	725	1,333	545	693	1,256

(1) For 2003 and 2001, this amount does not include cash and cash equivalents from our proportional interest in CIESA.

As of December 31, 2003, cash and cash equivalents, excluding the proportional consolidation of companies under joint control, totaled P$545 million, compared to P$693 million as of December 31, 2002 and P$1,256 million as of December 31, 2001. The inability to access capital markets during 2002 resulted in a significant drop in our liquidity level. As explained above, we have since then instituted a financial plan that strictly monitors liquidity levels. The reduction in our liquidity level in 2003 is in line with the increase in our net investment levels during 2003 as compared to 2002.

Our goal is to maintain excess cash primarily in U.S. dollars.

Table of Contents

Operating Activities

Net cash from operations, excluding the proportional consolidation of companies under joint control, was P$1,003 million, P$532 million and P$1,459 million for 2003, 2002 and 2001, respectively.

In 2003, net cash from operations increased P$471 million, mainly due to the increase in the WTI, which contributed to the increase in margins for the refining and the oil and gas exploration and production segments, a decrease in interest expense and a reduction in losses attributable to derivatives instruments used to hedge the price of crude oil.

In 2002, net cash from operations decreased P$927 million mainly due to: (i) an increase in net financial expenses on account of the Argentine peso devaluation, (ii) the inclusion in 2001 of a P$244 million inflow from the assignment to international financial institutions of a portion of the fees we will receive from PDVSA for the exploitation of the Oritupano Leona area, (iii) increased cash operating requirements, especially on account of the regularization of payments to suppliers in Venezuela, and (iv) a significant drop in dividends received from related companies, in line with the crisis affecting utility companies. These factors were partially offset by the dollar-denominated flow from foreign operations and by increased marketing margins in pesos from Argentine operations, resulting from higher local sales prices and increasing exports.

In 2003 and 2002, we made advanced payments of P$442 million and P$311 million, respectively, to meet the collateral requirements of our hedging operations, due to increased WTI future prices (see Item 11. Quantitative and Qualitative Disclosures About Market Risk). In these years, we also made payments of P$51 million and P$149 million, respectively, as collateral in connection with letters of credit that guarantee our investment commitments in Ecuador.

Investing Activities

Cash used in investing activities, excluding the proportional consolidation of companies under joint control, was P$857 million in 2003, P$114 million in 2002 and P$1,592 million in 2001.

Capital expenditures totaled P$778 million in 2003, P$732 million in 2002 and P$1,756 million in 2001.

Capital expenditures made in the Oil and Gas Exploration and Production business segments totaled P$696 million in 2003, P$596 million in 2002 and P$1,580 million in 2001. Investments during these last three years have generally focused on enhancing production and reservoirs through development drilling, secondary recovery and workover activities, as well as infrastructure projects. Capital expenditures in 2002 and 2003 were primarily focused on maintaining production and maximizing cash flow, giving priority to countries and products having greater potential to contribute to our business. In particular, during 2003, we undertook important infrastructure projects, particularly outside of Argentina, aimed at increasing the yield and operating capacity of our fields, allowing us to increase production volumes with higher efficiency. During 2003, 206 wells were drilled (compared to 142 wells in 2002), 185 of which are located in Argentina, and 288 units were repaired (compared to 231 in 2002), 159 of which were located in Argentina.

Capital expenditures in the Refining and Petrochemicals business segments totaled P$57 million in 2003, P$86 million in 2002 and P$59 million in 2001. Our capital expenditures in these segments during 2003 were mainly directed at maintaining efficient operating conditions at the plants. In 2002, we acquired a 19% additional interest in EBR, for P$60 million. In addition, during 2002 we invested P$26 million, primarily in the development of the commercial network.

In the Hydrocarbon Marketing and Transportation business segment, during 2003 we made capital contributions to OCP in the amount of P$11 million, while in 2002, we were required to disburse P$39 million to maintain letters of credit that secure our investment commitments in connection with OCP.

Capital expenditures made outside of Argentina accounted for approximately 62% of the capital expenditures budget for the 2003-2001 period, totaling P$2,033 million. These figures reflect our long-term strategy to grow as an integrated energy company in Latin America.

Significant sources of cash were generated by the sale of non-strategic equity and fixed assets during 2002 and 2001. These sales generated P$593 million in 2002 and P$226 million in 2001. In 2002, we sold our interest in Cerro Vanguardia and our forestry and agricultural business assets. In 2001, we sold our interest in the Pampa del Castillo La Guitarra area and in Terminales Marítimas Patagónicas. See Item 4. Information About Us Business Overview Discontinued Investments for more information on our recent divestitures. During 2003, we received approximately P$20 million from the sale of oil blocks.

In 2003, our net investments increased P$619 million, or 445%, reflecting Argentina s economic recovery during this year and the improvements to our operating cash flows and liquidity levels. Our capital expenditure program has been concentrated in the Oil and Gas Exploration and Production business segment.

Financing Activities

Net cash provided by (used in) financing activities, excluding the proportional consolidation of companies under joint control, totaled P$(206) million in 2003, P$(1,754) million in 2002 and P$824 million in 2001.

In 2003, we paid off long-term liabilities in the amount of P$629 million. These included Series E, J and L notes, which were repaid at maturity, for an aggregate amount of P$421 million (U.S.$166 million). In addition, during 2003, we repaid bank loans and long-term lines of credit in an aggregate amount of P$208 million.

In 2002, long-term liabilities in the amount of P$1,724 million were paid or cancelled, including:

Fifth Series of notes in an aggregate amount of P$841 million (U.S.$177 million), issued under the U.S.$1.2 billion global note program, which were paid in March 2002;

financial debt with an aggregate principal amount of approximately P$553 million (U.S.$144 million), which was cancelled pursuant to the terms and conditions of the exchange offers launched to refinance our overall debt; and

outstanding notes in aggregate principal amount of P$86 million (U.S.$22 million) issued under PASA S.A. s global note program (later absorbed by us), which were repaid at maturity.

In 2001, we paid P$1,047 million in principal amount of financial debt, P$659 million of which was applied to pay off a U.S.$300 million syndicated loan due December 2001 and P$357 million to pay off, principally, lines of credit for foreign trade operations.

During 2002 we designed and completed an overall refinancing of a substantial portion of our financial debt. The main purpose of refinancing was to align principal payments in line with expectations regarding cash flow to be provided by operations, and to establish a manageable debt maturity schedule. In August 2002 we issued corporate notes with a face value of U.S.$845 million in connection with an exchange offer. Simultaneously, and in line with the conditions of the offer, we repaid U.S.$70 million of notes. In October 2002, we refinanced financial liabilities in an aggregate amount of approximately U.S.$849 million, through the issue of new corporate notes in an amount of approximately U.S.$600 million and other medium-term credit instruments in the amount of approximately U.S.$249 million. We simultaneously paid off debt in the amount of U.S.$74 million. The credit instruments issued under this refinancing plan replaced short-term letters of credit, previously used as performance bonds. These new credit instruments comply with our financial obligations related to (i) our hedge agreements of crude oil prices at

U.S.$50 million, and (ii) our capital contribution commitments to OCP (including our commercial obligations under the ship or pay agreement with OCP and OCP s financial obligations of U.S.$199 million). Long-term letters of credit issued under these credit facilities are due on an annual basis, but may be automatically extended for successive annual terms until (i) December 2005 for the letters of credit related to the crude oil derivative agreements, or (ii) October 2007 for obligations related to OCP. If these letters of credit are not renewed on their respective maturity dates, they must be disbursed, and thereafter, they will constitute new loans for us. These refinancings significantly improved our debt maturity profile, extending debt life from 2 to 3.9 years.

Cash provided by long-term financing totaled P$591 million in 2003, P$124 million in 2002 and P$1,011 million in 2001, as described below:

Our long-term financing in 2003 included the following:

In October 2003, we issued Class R medium-term notes for an aggregate principal amount of P$286 million (U.S.$100 million).

In December 2003, our subsidiary Petrobras Energía Venezuela S.A., or PEV S.A., received P$206 million corresponding to the first disbursement of U.S.$76 million under a U.S.$105 million loan agreement between PEV S.A. and International Finance Corporation. The financing facility consists of loans with terms of up to nine years to be used in the investment plan for developing our oil reserves in Venezuela. As of the date of this annual report, we have received the whole outstanding amount.

In August 2003, our wholly-owned subsidiary Petrobras Energía del Perú S.A. received a first disbursement of P$87 million (U.S.$30 million) under a U.S.$40 million loan entered into with Banco de Crédito del Perú and Interbank to finance its investment plan for developing our oil reserves in Peru. As of the date of this annual report, we have received the whole outstanding amount.

In 2002, we issued Class E notes in the amount of P$124 million (U.S.$35 million), which were repaid at maturity in March 2003.

In 2001, we issued Class C notes in the amount of P$483 million (U.S.$220 million), due 2005. The Class C notes accrued interest at LIBOR plus 2.5% in the first year, 2.75% in the second year and will accrue interest at LIBOR plus 3% for the third and fourth years. Under this particular financing arrangement, in the event that currency transferability restrictions are imposed by the government of Argentina and we are unable to make debt service payments in cash offshore, we will make debt service payments in crude oil. If payment is made in kind, the volume delivered to the holders of the Class C notes will be priced at the WTI spot price at the time, with the guaranteed minimum price for such oil set at U.S.$15 per barrel. In connection with the contingent requirement to deliver crude oil, we entered into an Oil Marketing and Delivery Agreement dated July 17, 2001 between Petrobras Energía as Issuer and Deutsche Bank AG, London Branch, as Oil Purchaser; and a Crude Oil Purchase and Delivery Contract dated July 17, 2001 among Petrobras Energía, as Issuer, Deutsche Bank AG, London Branch, as Oil Purchaser and Bankers Trust Company as Oil Agent and Administrative Agent. These agreements provide that, in the event of a payment being made in oil, the crude oil would be purchased by the Oil Purchaser from the Oil Agent on the terms and conditions and at a market-related price set out in those agreements.

In addition, in 2001, cash provided by foreign lines of credit amounted to P$287 million; cash provided by foreign trade financing totaled P$163 million, and cash from the last tranche of the loan granted by the IFC to Innova amounted to P$78 million.

Net cash used to pay short-term financing totaled P$168 million in 2003 and P$94 million in 2002. The combination of the Argentine and Venezuelan crises limited our ability to renew short-term lines of credit at maturity. Conversely, during 2001, cash provided by short-term financing amounted to P$1,025 million, mainly attributable to short-term notes issued in November 2001 in the amount of P$344 million (U.S.$156.5 million) and short-term bank loans, including loans related to trade financing.

Description of Indebtedness

All of our financial debt and a significant portion of the debt of our principal affiliates is denominated in U.S. dollars.

Table of Contents

As of December 31, 2003, our total indebtedness, excluding the proportional consolidation of companies under joint control, was P$6,063 million, P$5,009 million of which was long-term indebtedness. As of such date, our short-term indebtedness totaled P$1,054 million, P$919 million of which represents the current portion of long-term obligations and P$135 million of which is short-term indebtedness with financial institutions under loan agreements or promissory notes. In addition, our consolidated financial statements include debt of P$2,239, principally debt that is in default, owed by our affiliates under joint control. See Factors Affecting Our Consolidated Results of Operations Impact on our Investments in Utility Companies.

The following is our debt maturity profile, excluding the proportional consolidation of companies under joint control, expressed both in millions of pesos and millions of U.S. dollars as of December 31, 2003:

Maturity	1 year	2 years	3 years	4 years	5 years	6 or more years
Millions of Pesos	P$1,054	P$971	P$480	P$1,284	P$48	P$2,226
Millions of U.S. dollars	U.S.$358	U.S.$330	U.S.$163	U.S.$437	U.S.$16	U.S.$757

Our long-term debt primarily consists of corporate notes. Our remaining long-term debt is mainly related to bank loans obtained by foreign subsidiaries and import credit lines used to finance the construction of the Genelba Power Plant and Innova plant.

Petrobras Energía maintains a five-year corporate global note program, or the Global Program, for a principal amount at any time outstanding of U.S.$2.5 billion or its equivalent in any currency, which was due to expire in May 2003, but was extended for five additional years. As of May 31, 2004, notes in an aggregate principal amount of U.S.$1,724 million were outstanding under this program. Notes under the program are not subject to acceleration in the event our credit ratings are downgraded.

As of May 31, 2004, notes outstanding under the Global Program were:

Class B, in an aggregate principal amount of U.S.$5 million notes, payable in a single installment in May 2006, at a 9% fixed annual rate;

Class C, for U.S.$220 million, with the final maturity in July 2005, to be amortized in quarterly installments beginning in 2004. Class C notes accrue interest at LIBOR plus 2.50% for the first year, 2.75% for the second year, and 3% for the third and fourth years. As of May 31, 2004, the total amount outstanding was U.S.$157 million; Petrobras Energía has called a bondholder s meeting to be held on July 30, 2004 in order to ratify Petrobras Energía s interpretation of the prepayment provisions of these notes, so that partial prepayment may be applied to one or more installments of principal as determined by Petrobras Energía;

Class F, in an aggregate principal amount of U.S.$64.4 million maturing in August 2005, at a 7.875% annual rate;

Class G, in an aggregate principal amount of U.S.$250 million maturing in January 2007, at a 9% annual rate;

Class H, in an aggregate principal amount of U.S.$181.5 million maturing in May 2009, at a 9% annual rate;

Class I, in an aggregate principal amount of U.S.$349.2 million maturing in July 2010, at an 8.125% annual rate;

Class K, in an aggregate principal amount of U.S.$286.3 million, amortized in quarterly installments from January 2004 and with final maturity date in October 2007, accruing interest at three month LIBOR plus 4% per annum. As of May 31, 2004, the total amount outstanding was U.S.$260 million;

Class M, in an aggregate principal amount of U.S.$181.8 million, amortized in quarterly installments from January 2004 and with final maturity date in October 2007, accruing interest at three month LIBOR plus 4.75% per annum. As of May 31, 2004, the total amount outstanding was U.S.$165 million;

Class N, in an aggregate principal amount of U.S.$97 million, with principal amortized in two installments, the first equivalent to 9.9099% of face value settled on the day of issuance and the remainder due in June 2011, accruing interest at six-month LIBOR plus 1% (issued in January 2003). As of May 31, 2004, the total amount outstanding was U.S.$ 87 million;

Class Q, in an aggregate principal amount of U.S.$4.0 million, with principal amortized in two installments, the first equivalent to 10% of face value on the date of issuance, April 25, 2003; and the balance in April 2008. These bonds accrue interest at 5.625%. As of May 31, 2004, the total amount outstanding was U.S.$3.6 million; and

Class R, in an aggregate principal amount of U.S.$200 million, with final maturity in October 2013, accruing interest at a 9.375% annual rate (issued in U.S.$100 million tranches in October 2003 and in April 2004).

In addition, Petrobras Energía has a U.S.$1.2 billion global medium-term note program. In June 1998, the right to issue new notes under this program expired. On December 31, 2003, two series of notes remained outstanding under this program. One of the series was paid in January 2004, and the other, with an aggregate principal amount of U.S.$32.6 million, matures in July 2007, accruing interest at 8.125%.

Covenants

Class F, G, H, I, N, Q and R notes include cross default covenants, whereby the trustee, as instructed by the noteholders representing at least 25% of the related outstanding capital, shall declare all the amounts owed due and payable, if any debt of ours or our significant subsidiaries is not paid at maturity, provided that those due and unpaid amounts exceed the higher of U.S.$25 million or 1% of our shareholders equity at that time, and that the default has not been cured within 30 days after we have been served notice of the default.

Class K and M notes include cross default covenants, whereby the trustee, as instructed by the noteholders representing at least the majority of the respective outstanding capital, shall declare all of the amounts owed due and payable, if any debt of ours or our significant subsidiaries is not paid at the maturity date, provided that those due and unpaid amounts exceed the higher of U.S.$15 million or 1% of our shareholders equity at the time.

Class C notes, as well as certain loan agreements, include cross default covenants, whereby the trustee or the creditor bank, as appropriate, shall declare all the amounts owed as due and payable, if any of our debt is not paid at maturity, provided that those due and unpaid amounts exceed U.S.$10 million or 1% of our shareholders equity at the time.

For so long as the Class K and M notes and medium-term credit instruments remain outstanding, we will be subject to certain restrictions and must comply with certain covenants as described below:

(i) Restrictions on capital expenditures: We shall not make any capital expenditure, including the amount of debt incurred in relation thereto, in excess of U.S.$450 million in 2004, U.S.$425 million in 2005 and U.S.$475 million in 2006 and 2007, which limits shall be increased under certain circumstances.

(ii) Restrictions on the incurrence of additional debt: We shall not incur any financial debt as long as, after giving effect to the issuance and application of the proceeds thereof, the ratio of: (A) consolidated financial debt, to (B) consolidated EBITDA (defined as gross profit less administrative, selling and exploration expenses, plus depreciation and amortization, dividends and advisory services collected) exceeds 3.5. This restriction is not applicable to subordinated debt, project financings and refinancings.

(iii) Compliance with certain ratio tests: We must comply with certain financial ratio tests including (A) consolidated financial debt (excluding subordinated debt) to consolidated EBITDA, which

133

shall not be greater than 3.5 to 1.0 in 2004 and 3.0 to 1.0 from 2005 through 2007, and (B) EBITDA to interest expense, which shall not be lower than 3.0 to 1.0 from 2004 through 2007.

(iv) Restrictions on the amount of short-term debt: At any time, our short-term financial debt shall not exceed an amount equal to U.S.$650 million.

(v) Mandatory prepayments: Within 120 days from the end of each fiscal year, we must use up to 50% of our excess cash to redeem on a pro rata basis the Series K and M notes and the medium-term credit instruments. In addition, proceeds from sales of assets (other than those that constitute the business purpose) not reinvested within approximately one year, and 50% of the proceeds from new debt, must be used to make mandatory prepayments.

(vi) Limitation on liens.

(vii) Restrictions on the payment of dividends.

These restrictions and covenants may have a negative effect on our ability to implement our investment plan or obtain additional financing and may negatively affect our results of operations.

Future Capital Requirements

Our 2004 budget provides for a continued recovery in the level of our investments, as we expect to continue moving beyond the economic crisis that gripped Argentina in 2002. We expect the level of our investment to gradually increase to our historical levels. Increased investments are crucial to our future growth objectives.

Our 2004 budget contemplates investments totaling approximately U.S.$350 million, which will be directed primarily towards the Oil and Gas Production and Exploration segment, with a strong emphasis on our operations in Argentina and Venezuela. We currently expect to conduct significant well-drilling campaigns in 2004, particularly at mature fields in Argentina, with the goal of maintaining production levels. In addition, we currently expect to make investments in infrastructure projects, with the goal of increasing the yield of our reserves, improving oil treatment quality and increasing secondary recovery.

Our investments in the Refining and Petrochemicals segments will focus on optimizing efficiency levels. Moreover, we expect to continue expanding the retail commercial network, while taking advantage of the synergies provided by the Petrobras brand. With respect to our fertilizers business, we currently expect to launch construction works of a new thiosulphate plant.

We currently expect that our investment requirements, financial debt payment obligations and working capital will be financed by cash from operations, and, to a lesser extent, new debt financings.

We can offer no assurance that we will be able to make the level of investments discussed above, since our level of investments will depend on a variety of factors, many of which are beyond our control. These include the future price evolution of the commodities we sell, the outcome of the renegotiation of utility rates, the renegotiation of concession contracts of the privatized companies, the behavior of energy demand in Argentina and in regional markets, the existence and competitive impact of alternative projects, government regulation, the economic situation prevailing in Argentina and the Mercosur region, the availability of financing and the evolution of the peso exchange rate.

OFF-BALANCE SHEET TRANSACTIONS

Other than the transactions described below, we do not have any off-balance sheet arrangements required to be disclosed by Item 5 of Form 20-F.

OCP Investment s Letters of Credit

To secure our commercial obligations under the ship or pay contract with OCP and OCP s financial obligations, we have obtained letters of credit for a total amount of approximately U.S.$224 million. Of this amount, U.S.$199 million must be secured by cash collateral. As of December 31, 2003 we had deposited U.S.$55 million of this cash collateral. We must deposit the balance of this cash collateral on a yearly basis according to the following schedule:

(in millions of U.S.$)	2004	2005	2006	2007	Total
	32	38	37	37	144

These letters of credit must remain in place until our OCP investment obligations and commitments expire or are terminated. We are required to renew or replace these letters of credit as they mature. Otherwise, we will be required to repay the amounts due in cash at maturity, which will have a material adverse effect on our cash flows.

Derivative Financial Instruments

We have commitments under derivative financial instruments. For a discussion of these additional commitments see Item 11. Quantitative and Qualitative Disclosure About Market Risk. As of December 31, 2003 the fair value of our outstanding oil derivative financial instruments represented accounts payable to counterparties in the amount of U.S.$185 million. In connection therewith, as of that date we had standby letters of credit in place in favor of these counterparties with total commitments of U.S.$31 million and cash collaterals amounting to U.S.$136 million.

Oritupano Leona Revenues Assignment

In December 2001, we assigned to an international lending institution U.S.$120 million in future capital fees to be collected from PDVSA under our operating agreement for the Oritupano Leona area. Capital fees assigned are payable by PDVSA in twelve quarterly, equal and consecutive installments starting February 2002. This transaction, net of the discount calculated at LIBOR plus 2.75%, provided us cash in the amount of U.S.$110 million. In order to guarantee to the lending institution that PDVSA will meet its obligations under this operating agreement, we assigned an additional U.S.$10 million of future capital fees to such institution. Should PDVSA not settle any amount payable on this account by the due date and such noncompliance stems from any commercial challenge or claim that PDVSA may have with respect to our billings for investments made, we are required to either assign to the lending institution additional capital fees in an amount equivalent to the amount being challenged, or pay amounts due in cash. This assignment does not release the members of the consortium from the obligations under the operating agreement for the area.

Table of Contents

CONTRACTUAL OBLIGATIONS

The following table summarizes certain contractual obligations as of December 31, 2003. The table does not include accounts payable or pension liabilities.

	Payments due by period (in millions of pesos)				
	Total	**Less than 1 Year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Debt Obligations	6,063	1,054	1,451	1,332	2,226
Significant Operating Lease Obligations	2	1	1		
Purchase Obligations:					
Ship or pay agreement with OCP (1)	3,298	220	440	440	2,198
Long term service agreement	141	25	54	62	
Gas transportation agreement with TGS (2)	300	30	60	60	150
Ethylene (3)	550	50	100	100	300
Benzene (4)	1,233	112	224	224	673
Total	11,587	1,492	2,330	2,218	5,547

(1) Estimated price P$7.53 per bbl.(5)

(2) Estimated price P$0.025 million per MMm3.(5)

(3) Estimated price U.S.$555 per ton.(5) Contractual prices are in dollars. Peso amounts translated using exchange rate as of December 31, 2003.

(4) Estimated price U.S.$451 per ton.(5) Contractual prices are in dollars. Peso amounts translated using exchange rate as of December 31, 2003.

(5) Our obligations under these agreements are determined by volume, and prices are generally determined by formula based on future market prices of the goods or services under each contract. In addition, the estimated prices used to calculate the monetary equivalent of these purchase obligations are based on current market prices as of December 31, 2003 and may not reflect actual future prices of these commodities. Accordingly, the peso amounts provided in this table with respect to these obligations are provided for illustrative purposes only.

The following table sets forth volume information with regard to our commitments under commercial contracts for which a fixed price has been agreed, for the years indicated below, as of December 31, 2003.

	Obligations by period				
	Total	**Less than 1 Year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**

Purchase Obligations					
Ship or pay agreement with OCP (in millions of bbls)	438	29	58	58	293
Gas transportation agreement with TGS (in MMm3)	11,873	1,199	2,398	2,398	5,878
Ethylene (in thousands of tons)	337	31	61	61	184
Benzene (in thousands of tons)	930	85	169	169	507
Sales Obligations					
Natural gas (in MMm3)	18,854	2,609	3,451	2,730	10,064
Styrene (in thousands of tons)	56	39	16	1	
Electric power (in MWh)	329,115	329,115			

Long Term Service Agreement. We have entered into a long term service agreement for the maintenance and repair of the Genelba Power Plant.

OCP Oil Transportation Agreement. Regarding the future exploitation of Blocks 18 and 31, we have executed an agreement with OCP whereby it has obtained an oil transportation capacity of 80,000 bbls/d for a term of 15 years as from commencement of OCP operations. We, as well as the remaining producers, shall pay a ship or pay fee that will cover, among other items, OCP s operating costs and financial services.

Innova Supply Agreements. Benzene and ethylene feedstock, necessary for Innova operations, are supplied by Copesul, a Brazilian company, pursuant to a long-term contract that expires in 2014.

Table of Contents

Gas Transportation Agreements. We have entered into various gas firm transportation agreements with TGS to provide gas transportation services to our Genelba Power Plant.

Exploration Commitments. Regarding the exploration and development of our oil and gas fields, we have minimum investment commitments amounting to U.S.$7 million through 2005.

U.S. GAAP RECONCILIATION

We had net income under U.S. GAAP of P$100 million in 2003, as compared to net losses of P$1,554 million in 2002 and P$2,266 million in 2001. Under Argentine GAAP, we reported net income of P$381 million in 2003 and P$101 million in 2001, as compared to a net loss of P$1,579 million in 2002.

There are several differences between Argentine GAAP and U.S. GAAP that significantly affect our net income and stockholders equity. The most significant differences in their effect on 2003 net income related to foreign currency translation adjustments, the depreciation of property, plant and equipment, the accounting for derivative instruments and deferred income taxes. See note 23 to our financial statements. Neither the effects of inflation accounting nor the proportional consolidation of Distrilec, a company under joint control, under Argentine GAAP have been reversed in the reconciliation to U.S. GAAP. The proporational consolidation of CIESA, another company under joint control, in 2001 and 2003 under Argentine GAAP has been reversed in the reconciliation to U.S. GAAP.

RECONCILIATION TABLES

The following tables reconciliate our results for the years ended December 31, 2001, 2002 and 2003 with proportional consolidation as required by new changes to Argentine GAAP to our results as adjusted to reflect the elimination of proportional consolidation:

	For the Year Ended December 31, 2003			
	With Proportional Consolidation	CIESA[1]	Distrilec[2]	Without Proportional Consolidation
Net sales	5,494	(432)	(447)	4,615
Costs of sales	(3,386)	200	373	(2,813)
Gross profit	2,108	(232)	(74)	1,802
Administrative and selling expenses	(559)	30	65	(464)
Exploration expenses	(196)			(196)
Other exploitation income (loss) net	(121)	12	5	(104)
Exploitation income	1,232	(190)	(4)	1,038
Equity in earnings of affiliates	163	221	(11)	373
	(417)	(124)	(28)	(569)

Financial income (expense) and holding gains (losses)				
Other expenses, net	(421)	1	13	(407)
Income (loss) before income tax and minority interest in subsidiaries	557	(92)	(30)	435
Income tax provision	(18)	(58)	29	(47)
Minority interest in subsidiaries	(158)	150	1	(7)
Net income (loss)	381			381

(1) The results of CIESA are proportionally consolidated in our Hydrocarbon segment.

(2) The results of Distrilec are proportionally consolidated in our Electricity segment.

	For the Year Ended December 31, 2002			
	With Proportional Consolidation	CIESA[(1)]	Distrilec[(2)]	Without Proportional Consolidation
Net sales	5,106		(519)	4,587
Costs of sales	(3,284)		406	(2,878)
		—		
Gross profit	1,822		(113)	1,709
Administrative and selling expenses	(609)		77	(532)
Exploration expenses	(58)			(58)
Other exploitation income (loss) net	(28)			(28)
		—		
Exploitation income	1,127		(36)	1,091
Equity in earnings of affiliates	(638)		(9)	(647)
Financial income (expense) and holding gains (losses)	(1,827)		168	(1,659)
Other expenses, net	(187)		9	(178)
		—		
Income (loss) before income tax and minority interest in subsidiaries	(1,525)		132	(1,393)
Income tax provision	(82)		(127)	(209)
Minority interest in subsidiaries	28		(5)	23
		—		
Net income (loss)	(1,579)			(1,579)

(1) For the 2002 fiscal year we did not proportionately consolidate on a line by line basis the assets, liabilities, earnings and cash flow of CIESA, since, as of December 31, 2002 our equity interest in such company had a P$33 million negative value.

(2) The results of Distrilec are proportionally consolidated in our Electricity segment.

	For the Year Ended December 31, 2001			
	With Proportional Consolidation	CIESA[(1)]	Distrilec[(2)]	Without Proportional Consolidation
Net sales	5,170	(610)	(946)	3,614
Costs of sales	(3,347)	234	654	(2,459)

Gross profit	1,823	(376)	(292)	1,155
Administrative and selling expenses	(665)	33	122	(510)
Exploration expenses	(41)			(41)
Other exploitation income (loss) net	23		(3)	20
Exploitation income	1,140	(343)	(173)	624
Equity in earnings of affiliates	119	36	49	204
Financial income (expense) and holding gains (losses)	(573)	124	(2)	(451)
Other expenses, net	(88)	63	11	(14)
Income (loss) before income tax and minority interest in subsidiaries	598	(120)	(115)	363
Income tax provision	(385)	66	70	(249)
Minority interest in subsidiaries	(112)	54	45	(13)
Net income (loss)	101			101

(1) The results of CIESA are proportionally consolidated in our Hydrocarbon segment.

(2) The results of Distrilec are proportionally consolidated in our Electricity segment.

Table of Contents

Item 6. DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

DIRECTORS AND SENIOR MANAGEMENT

Board of Directors