ITALIAN REGULATORY AUTHORITY FOR ELECTRICITY AND GAS

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Summary Edition

NATIONAL AND INTERNATIONAL SCENARIOS

EUROPEAN PRICE COMPARISONS

Electricity prices

Using Eurostat statistics, Italian price levels can be evaluated separately for each consumption category on the basis of annual consumption levels, installed power and load factor.

Italian prices are compared with the weighted European average, calculated on the basis of national consumption by volume in 1997 (distinguishing between domestic and industrial users). This enables the Italian price burden to be compared more accurately with levels in the other major European countries since consumption differs considerably from one to another. The comparisons are carried out in euros, using the respective fixed parities (against the euro) to convert prices denominated in the national currencies, or the current exchange rate for countries that have not joined the European Monetary Union.

The Eurostat data for domestic users relate to four types of consumption: 600 kWh, 1,200 kWh, 3,500 kWh and 7,500 kWh per year. The data for July 2001 show that Italian users with low consumption levels, of 600 kWh and 1,200 kWh per year, pay much lower prices (whether gross or net of taxes) that correspond to about half the European average. The opposite holds for users with higher consumption levels: prices in Italy are well above the European average, by about 46% and 53% respectively for consumption levels of 3,500 and 7,500 kWh (including tax). On average, there is a difference of about 17.5% between the weighted European average (based on consumption volumes by country as distributed between the categories under consideration) and the prices applied in Italy (TAB. 1). This corresponds to the price differential paid by the average Italian family with installed power of 3 kW and annual consumption of 2,700 kWh, which covers the majority of domestic users.

The situation is different for industrial users (consumption in places other than homes: industry, tertiary sector and agricultural premises), where data for seven consumption categories are presented, ranging from 50 MWh to 70 GWh per year. With the significant exception of the 50 MWh category, for which the basic tariff for medium-voltage users is applied, Italian prices, both gross and net of taxes, are invariably higher than the European average, with differentials which – unlike the situation that emerged last year – tend to increase as consumption levels rise. The difference is greatest, at over 46%, for the intermediate category, which consumes 2 GWh per year (TAB. 1).

On average, the difference in percentage terms between Italian prices and the weighted European average (based only on consumption volume per country) can be put at about 19% for industrial users (TAB. 3). Net of taxes, the price differential is less marked for lower consumption categories, while for major consumers it is correspondingly higher as a result of the lower incidence of taxes.

Finally, it should be noted that the data for Italy, as shown in the tables, include the tariff component for general system costs, which Eurostat includes among the tax elements of the gross price.

The trend from July 2000 to July 2001

The period from July 2000 to July 2001 saw an upward trend in prices for low consumption categories and a corresponding fall in prices for higher consumption levels. This trend can be attributed in part to the tariff reform introduced by the Authority for Electricity and Gas with effect from 1 January 2000, which has tended to re-balance the overall cost through a gradual recovery of cost responsibility and the progressive absorption of the shortfall between prices and costs for domestic users enjoying special tariff rates.

Against this, there was a sharp fall in prices for industrial users with consumption levels of 50 and 160 kWh per year .

TAB. 1 ELECTRICITY PRICES FOR DOMESTIC USERS IN EUROPEAN COUNTRIES BY CONSUMPTION CATEGORY -
prices in euros/kWh at exchange rates of 1 July 2001

	Annual consumption 600 kWh			Annual consumption 1.200 kWh		
	Gross of taxes	Net of taxes		Gross of taxes	Net of taxes	
Countries	**euro/kWh**	**euro/kWh**	***% var. 00/01***	**euro/kWh**	**euro/kWh**	***% var. 00/01***
Austria	0.161	0.118	*-0.6*	0.155	0.113	*0.0*
Belgium	0.180	0.148	*-1.2*	0.177	0.145	*0.0*
Denmark	0.307	0.158	*0.5*	0.248	0.111	*5.3*
Finland	0.162	0.125	*8.2*	0.116	0.088	*5.5*
France (B)	0.161	0.128	*-0.1*	0.143	0.111	*-0.1*
Germany (B)	0.232	0.184	*-1.9*	0.191	0.149	*-0.3*
Greece	0.079	0.073	*6.6*	0.074	0.069	*6.6*
Holland (B) (D)	0.166	0.159	*7.6*	0.170	0.112	*-3.9*
Ireland	0.155	0.138	*0.0*	0.128	0.114	*0.0*
Italy (A)	**0.091**	**0.083**	***10.6***	**0.095**	**0.086**	***10.1***
Luxembourg	0.225	0.207	*-1.1*	0.169	0.154	*-1.7*
Norway	0.382	0.294	*14.0*	0.228	0.170	*18.6*
Portugal	0.129	0.122	*1.2*	0.148	0.140	*1.3*
Spain	0.134	0.110	*-4.0*	0.134	0.110	*-4.0*
Sweden	0.242	0.160	*15.6*	0.162	0.101	*15.6*
United Kingdom (B)	0.201	0.191	*1.7*	0.157	0.149	*3.3*
weighted Eur average (C)	*0.192*	0.156	*2.3*	*0.158*	*0.125*	*2.6*
Italy: divergence (%age from weighted average)	*-52.7*	*-47.1*		*-40.1*	*-31.5*	

Continues

TAB 1 continued. ELECTRICIY PRICES FOR DOMESTIC USERS IN EUROPEAN COUNTRIES BY CONSUMPTION CATEGORY

prices in euros/kWh at exchange rates of 1 July 2001

Countries	Annual Consumption 3.500 kWh			Annual consumption 7.500 kWh			Weighted average consumption bands net of taxes	
	Gross of taxes	Net of taxes		Gross of taxes	Net of taxes			
	euro/kWh	euro/kWh	*% var. 00/01*	euro/kWh	euro/kWh	*% var. 00/01*	euro/kWh	*% var. 00/01*
Austria	0.132	0.094	*-0.8*	0.133	0.095	*-0.8*	0.101	*-0.6*
Belgium	0.145	0.118	*1.5*	0.137	0.112	*2.3*	0.126	*0.9*
Denmark	0.211	0.081	*13.6*	0.199	0.072	*16.6*	0.096	*8.7*
Finland	0.090	0.067	*3.6*	0.076	0.055	*2.0*	0.077	*4.9*
France (B)	0.115	0.091	*0.0*	0.112	0.089	*0.0*	0.099	*-0.1*
Germany (B)	0.161	0.123	*1.1*	0.148	0.111	*1.3*	0.134	*0.3*
Greece	0.063	0.059	*6.6*	0.072	0.066	*7.2*	0.064	*6.7*
Holland (B) (D)	0.159	0.089	*-2.8*	0.159	0.081	*-4.3*	0.102	*-0.7*
Ireland	0.089	0.079	*0.0*	0.086	0.076	*0.0*	0.093	*0.0*
Italy (A)	**0.196**	**0.155**	***-6.5***	**0.191**	**0.150**	***-0.9***	**0.134**	***-2.8***
Luxembourg	0.126	0.114	*8.5*	0.115	0.104	*2.0*	0.133	*3.5*
Norway	0.127	0.088	*30.1*	0.099	0.066	*40.2*	0.128	*26.1*
Portugal	0.126	0.120	*0.5*	0.112	0.106	*0.4*	0.120	*0.7*
Spain	0.105	0.086	*-4.0*	0.096	0.079	*-4.0*	0.092	*-4.0*
Sweden	0.109	0.063	*15.6*	0.103	0.058	*14.5*	0.083	*-3.6*
United Kingdom (B)	0.114	0.108	*2.6*	0.103	0.098	*1.3*	0.125	*4.7*
weighted European average (C)	*0.134*	*0.104*	*1.2*	*0.125*	*0.096*	*1.8*	*0.114*	*1.7*
Italy: %age divergence from the weighted European average	*46.4*	*49.3*		*52.9*	*56.9*		*17.5*	

(A) Prices include a proportion of system costs (tariff components A2, A3, A4, A6 and UC2) in force at 1 July 2001 (Decision 146 of 27 June 2001);
(B) Arithmetic mean of the prices at various sampling locations;
(C) Weighted average based on the volume of national consumption in 1997;
(D) The variation for the period is calculated on the data for January 2000 (rather than July 2000).

Source: based on Eurostat data.

TAB. 2 ELECTRICITY PRICES FOR INDUSTRIAL USERS IN EUROPEAN COUNTRIES BY CONSUMPTION CATEGORY
prices in euros/kWh at exchange rates of 1 July 2001

	50.000 kWh anno (50 kW, 1.000 h)			**160.000 kWh anno (100 kW, 1.600 h)**			**2 GWh anno (500 kW, 4.000 h)**			**10 GWh anno (2.500 kW, 4.000 h)**		
	Gross of taxes	**Net of taxes**		**Gross of taxes**	**Net of taxes**		**Gross of taxes**	**Net of taxes**		**Gross of taxes**	**Net of taxes**	
Countries	**Euro/kWh**	**euro/kWh**	**var. % 00/01**	**Euro/kWh**	**euro/kWh**	**var. % 00/01**	**euro/kWh**	**euro/kWh**	**var. % 00/01**	**euro/kWh**	**euro/kWh**	**var. % 00/01**
Austria	0.115	0.102	-19.5	0.110	0.094	-9.1						
Belgium	0.129	0.128	-12.7	0.112	0.111	-5.7	0.077	0.077	1.0	0.071	0.070	0.7
Denmark	0.072	0.065	17.2	0.068	0.061	16.6	0.063	0.056	13.8	0.000		
Finland	0.059	0.054	-0.2	0.055	0.051	1.6	0.042	0.038	1.4	0.042	0.038	1.8
France *(B)*	0.088	0.085	-0.2	0.081	0.078	-0.1	0.055	0.055	0.9	0.055	0.055	0.9
Germany *(B)*	0.139	0.133	-1.1	0.111	0.107	0.1	0.072	0.068	1.1	0.067	0.064	0.0
Greece	0.087	0.087	6.6	0.080	0.080	6.6	0.059	0.059	6.6	0.059	0.059	6.6
Holland *(B)*	0.057	0.057	20.5	0.061	0.061	19.1	0.042	0.042	28.2	0.036	0.036	24.2
Ireland	0.126	0.126	0.0	0.109	0.109	0.0	0.066	0.066	0.0	0.062	0.062	-0.1
Italy (A)	**0.100**	**0.086**	**-36.5**	**0.117**	**0.104**	**-7.6**	**0.105**	**0.092**	**7.1**	**0.096**	**0.091**	5.5
Luxembourg	0.126	0.120	-7.8	0.098	0.093	-7.6	0.068	0.064	-7.9	0.046	0.044	-16.1
Norway	0.133	0.106	36.6	0.097	0.084	-19.2	0.066	0.062	-8.5	0.000		
Portugal	0.105	0.105	1.2	0.086	0.086	1.2	0.065	0.065	1.2	0.065	0.065	1.2
Spain	0.103	0.098	0.0	0.072	0.069	-8.4	0.058	0.055	-13.5	0.054	0.051	-13.6
Sweden	0.041	0.041	-15.5	0.039	0.039	-13.1	0.038	0.038	6.4	0.033	0.033	9.8
United Kingdom (C)	0.119	0.112	-4.5	0.110	0.104	0.5	0.069	0.064	-11.2	0.063	0.057	-10.5
Weighted European average (D)	0.105	0.099	-6.4	0.094	*0.089*	*-2.5*	0.067	*0.063*	*-0.3*	0.063	*0.060*	*0.3*
Italy: % divergence from weighted European average	-5.2	*-12.4*		*24.6*	*17.7*		*56.1*	*45.9*		*53.4*	*51.7*	

Continues

TAB. 2 continued ELECTRICITY PRICES FOR INDUSTRIAL USERS IN EUROPEAN COUNTRIES BY CONSUMPTION CATEGORY

prices in euros/kWh at exchange rates of 1 July 2001

	24 GWh anno (4.000 kW, 6.000 h)			50 GWh (10.000 kW, 5.000 h)			70 GWh (10.000 KW, 7.000 h)		
	Gross of taxes	Net of taxes		Gross of taxes	Net of taxes		Gross of taxes	Net of taxes	
Countries	euro/kWh	euro/kWh	var. % 00/01	euro/kWh	euro/kWh	var. % 00/01	euro/kWh	euro/kWh	var. % 00/01
Austria									
Belgium	0.059	0.059	1.7	0.052	0.052	1.9	0.045	0.045	2.8
Denmark									
Finlandia	0.038	0.034	1.9	0.032	0.027	1.8	0.030	0.026	2.2
France *(B)*	0.048	0.048	1.7				0.000		
Germany *(B)*	0.056	0.053	2.0	0.060	0.056	1.5	0.053	0.049	2.7
Greece	0.050	0.050	6.6	0.047	0.047	6.6	0.041	0.041	6.5
Holland *(B)*	0.030	0.030	32.6	0.028	0.028	33.9	0.028	0.028	35.2
Irlanda	0.053	0.053	0.1	0.053	0.053	-0.1	0.049	0.049	0.1
Italy (A)	**0.081**	**0.080**	**5.1**	**0.073**	**0.072**	**3.9**	**0.071**	**0.070**	**11.8**
Luxembourg	0.040	0.038	-11.5	0.042	0.040	-7.9	0.038	0.036	-6.4
Norway	0.000								
Portugal	0.053	0.053	1.0	0.048	0.048	1.2	0.044	0.044	1.2
Spain	0.051	0.049	-8.9	0.050	0.048	-10.5	0.049	0.047	-5.6
Sweden	0.031	0.031	13.5	0.032	0.032	12.5	0.030	0.030	14.9
United Kingdom (C)	0.058	0.052	-11.2	0.056	0.050	-7.8	0.053	0.047	-7.8
Weighted Eur. average (D))	0.054	*0.052*	*2.5*	0.054	*0.052*	*1.3*	*0.050*	*0.048*	*5.0*
Italy: % divergence from Weighted average	50.7	*53.5*		35.2	*40.0*		42.1	*47.5*	

(A) Prices include a proportion of system costs (tariff components A2, A3, A4, A6 and UC2) in force at 1 July 2001 (Decision 146 of 27 June 2001);
(B) Arithmetic mean of the prices at various sampling locations;
(C) Unlike the statistics for the previous semesters, the prices are obtained as an estimte of the national reference values. The break in the historic series of prices lessens the significance of the comparison over time.
(D) The variation for the period is calculated on the data for January 2000 (rather than July 2000).

Source: Based on Eurostat data

TAB. 3 PRICES OF ELECTRICITY FOR INDUSTRIAL USES IN EUROPEAN COUNTRIES. AVERAGE PRICES

1 July 2001; prices in euros/kWh at current exchange rate

Countries	**Arithmetic mean consumption categories** [(A)]	
	euro/kWh	**var. % 00/01**
Austria	0.100	*-16.3*
Belgium	0.084	*-4.5*
Denmark	0.061	*15.6*
Finland	0.041	*1.1*
France [(B)]	0.067	*0.2*
Germany [(B)]	0.083	*0.7*
Greece	0.064	*6.7*
Holland [(B)]	0.043	*28.3*
Ireland	0.081	*0.0*
Italy	**0.092**	***-5.6***
Luxembourg	0.071	*-8.0*
Norway	0.088	*8.0*
Portugal	0.072	*1.2*
Spain	0.064	*-7.2*
Sweden	0.036	*-9.8*
United Kingdom	0.074	*-6.7*
Weighted European average [(C)]	*0.077*	*7.1*
Italy: divergence European average	*18.9*	

(A) The arithmetic mean was calculated on the 9 consumption categories included in the Eurostat survey
(B) Arithmetic mean of prices in various sampling locations
(C) Weighted average based on the volume of national consumption in 1997

Source: based on Eurostat data.

Natural gas prices

In order to obtain comparisons that are homogeneous and up-to-date, as in the case of electricity the international price comparisons for natural gas are based on Eurostat sources. Average price data to 1 July 2001 were obtained by calculating the arithmetic mean of the prices paid by the different Eurostat consumption categories. Italian prices are compared with the weighted European average based on consumption in volume terms in individual countries (distinguishing between civil and industrial uses). This enables price levels to be compared more accurately, given the differences in consumption levels between the different countries. The comparisons are carried out in euro/m^3, converting prices in national currencies using their respective fixed parities against the euro, or the current exchange rate for countries that are not members of the European Monetary Union.

For small domestic customers using gas mainly for cooking purposes, Italian prices gross and net of taxes are among the lowest in Europe (TAB. 4). However, for higher consumption levels the situation changes. The price paid by users with annual consumption of about 2,200 m^3 for gas for heating purposes is higher than in any other European country and about 49% higher than the weighted European average (8% net of taxes). The gap is even greater for users consuming 3,300 m^3, with prices about 53% higher than the weighted average (11% net of taxes). For these last two consumption categories the tax element is over twice the European average.

For industrial users too, the comparison between Italian prices and the European average produces an uneven picture. In general terms, for lower consumption levels, usually small commercial and industrial concerns, prices are among the highest in Europe. The gap between Italian prices and the weighted European average narrows as consumption levels rise (TAB. 5).

In all cases, the tax element of the final price is lower than the European average.

TAB. 4 PRICE OF NATURAL GAS BY CONSUMPTION CATEGORY: DOMESTIC USERS
1 July 2001; heating power kcal/m3= 9,100; prices in euro/ m3 at current exchange rates.

ANNUAL CONSUMPTION	**8.37 GJ (217.62 mc)(A)**			**83.7 GJ (2,176.2 mc)(B)**			**125.6 GJ (3,265.6 mc)(B)**			**Weighted average type of consumption**		
COUNTRIES	**Gross of taxes**	**Net of taxes**	***% var. 01/00***	**Gross of taxes**	**Net of taxes**	***var. % 01/00***	**Gross of taxes**	**Net of taxes**	***var. % 01/00***	**Gross of taxes**	**Net of taxes**	***var. % 01/00***
Austria	0.70	0.54	*24.9*	0.45	0.33	*10.0*	0.44	0.32	*9.3*	0.54	0.41	*16.4*
Belgium	0.73	0.59	*4.3*	0.42	0.34	*6.2*	0.41	0.32	*6.4*	0.56	0.45	*5.1*
Denmark	1.07	0.60	*-54.5*	0.75	0.35	*-59.5*	0.75	0.35	*-56.1*	0.83	0.41	-
France(C)	0.68	0.62	*20.9*	0.41	0.35	*23.2*	0.39	0.34	*23.7*	0.52	0.46	*21.9*
Germany(C)	0.85	0.70	*13.7*	0.50	0.40	*25.3*	0.48	0.37	*27.0*	0.63	0.51	*19.2*
Holland(D)	0.51	0.25	*5.2*	0.42	0.26	*11.7*	0.43	0.25	*11.8*	0.36	0.34	*8.1*
Ireland	0.74	0.66	*-0.4*	0.31	0.28	*0.5*	0.29	0.25	*-0.8*	0.49	0.44	*-0.1*
Italy (C)	**0.57**	**0.47**	***5.0***	**0.67**	**0.40**	***6.1***	**0.67**	**0.39**	***6.1***	**0.62**	**0.42**	***5.7***
Luxembourg	0.58	0.55	*6.3*	0.31	0.29	*12.5*	0.31	0.29	*12.7*	0.43	0.40	*8.8*
Spain	0.69	0.60	*5.8*	0.48	0.41	*6.0*	0.47	0.40	*6.0*	0.56	0.48	*5.9*
Sweden	0.83	0.53	*31.7*	0.64	0.38	*39.8*	0.64	0.38	*44.1*	0.71	0.43	*23.7*
United Kingdom	0.43	0.41	-	0.27	0.26	-	0.26	0.29	-	0.34	0.32	-
Weighted average	**0.60**	**0.58**	***10.6***	**0.45**	**0.37**	***15.1***	**0.44**	**0.35**	***15.6***	**0.51**	**0.44**	***10.9***
Italy: divergence(5)	*-4.4*	*-18.9*	-	*49.6*	*8.2*	-	*53.1*	*10.5*	-	*22.2*	*-4.1*	-

(A) Use for cooking and hot water;
(B) Use for cooking, hot water and central heating;
(C) Arithmetic mean of prices in various localities sampled;
(D) Since 1 January 2001 there has been an interconnection charge on users with consumption of 217.62 m^3. For this reason, prices net of taxes are higher than prices gross of tax.
(E) Percentage divergence from the weighted average.

Source: based on Eurostat data

TAB. 5 PRICE OF NATURAL GAS BY CONSUMPTION CATEGORY: INDUSTRIAL USERS
1 July 2001; heating power kcal/mc= 9,100; prices in euro/mc at current exchange rates.

ANNUAL CONSUMPTION	418.6 GJ (o 10,883.6 mc)(A)			4,186 GJ (o 108,836 mc)(B)			41,860 GJ (o 1,088,360 mc)(C			418,600 GJ (o 10,883,600 mc)(4)			Weighted average consumption categories		
COUNTRIES	**Gross of taxes**	**Net of taxes**	***% var. 01/00***	**Gross of taxes**	**Net of taxes**	***% var. 01/00***	**Gross of taxes**	**Net of taxes**	***% var. 01/00***	**Gross of taxes**	**Net of taxes**	***% var. 01/00***	**Gross of taxes**	**Net of taxes**	***% var. 01/00***
Austria	0.35	0.31	*8.3*	0.31	0.27	*17.0*	0.25	0.21	*22.2*	0.23	0.19	*14.3*	0.27	0.23	*14.6*
Belgium(E)	0.31	0.30	*6.1*	0.24	0.24	*5.9*	0.22	0.22	*10.2*	0.19	0.19	*12.1*	0.22	0.22	*9.3*
Denmark	0.37	0.35	*4.8*	0.35	0.33	*5.0*	0.23	0.21	*-4.9*	0.19	0.16	*-13.7*	0.26	0.24	*-3.1*
Finland	-	-	-	0.34	0.33	*20.4*	0.28	0.26	*28.3*	0.19	0.18	*5.6*	0.20	0.19	*7.8*
France	0.30	0.30	*25.4*	0.26	0.26	*25.7*	0.21	0.20	*8.6*	0.18	0.17	*7.1*	0.22	0.22	*15.0*
Germany(E)	0.37	0.35	*29.5*	0.33	0.31	*26.7*	0.32	0.30	*28.4*	0.27	0.25	*24.4*	0.31	0.29	*27.4*
Holland	0.33	0.23	*12.1*	0.30	0.23	*12.4*	0.21	0.19	*3.1*	-	-	-	0.26	0.21	*8.0*
Ireland	0.27	0.27	*-0.2*	0.22	0.22	*-0.9*	0.18	0.18	*21.9*	-	-	-	0.21	0.21	*8.0*
Italy(E)	**0.37**	**0.36**	***-1.8***	**0.30**	**0.28**	***8.3***	**0.28**	**0.26**	***28.2***	**0.23**	**0.21**	***25.8***	**0.27**	**0.26**	***15.9***
Luxembourg	0.29	0.29	*12.8*	0.27	0.27	*13.8*	0.27	0.27	*14.0*	0.26	0.26	*14.3*	0.27	0.27	*13.9*
Spain	0.32	0.32	*-1.4*	0.19	0.19	*-2.2*	0.18	0.18	*-2.4*	0.17	0.17	*-2.5*	0.20	0.20	*-2.1*
Sweden	0.40	0.32	*24.1*	0.36	0.28	*16.6*	0.33	0.25	*15.5*	0.31	0.21	*14.3*	0.34	0.26	*1.7*
United Kingdom(E)	0.26	0.23	*23.3*	0.24	0.21	*25.7*	0.22	0.20	*42.7*	0.20	0.17	*37.8*	0.22	0.20	*38.7*
Weighted average	**0.34**	**0.31**	***13.8***	**0.30**	**0.27**	***18.6***	**0.258**	**0.24**	***18.8***	**0.225**	**0.209**	***18.2***	**0.26**	**0.24**	***17.5***
Italy: divergence(F)	*9.4*	*15.2*	-	*0.3*	*2.6*	-	*6.6*	*7.1*	-	*0.4*	*1.9*	-	*4.9*	*6.6*	-

(A) without load factor
(B) with load factor of 200 days;
(C) with load factor of 200 days, or 1600 hours;
(D) with load factor of 250 days, or 4000 hours;
(E) arithmetic mean of prices in various survey localities;
(F) percentage divergence from the weighted average.

Source: based on Eurostat data

THE REGULATION OF THE EUROPEAN ELECTRICITY AND GAS MARKET

The Council of European Energy Regulators

The Council of European Energy Regulators (CEER) was set up in March 2000 by initiative of a group of European energy regulators, of which the Authority is one, with the intention of creating a mechanism for cooperation and exchanges of information by European energy regulators and the drafting of common positions for the implementation of single energy market directives. At present CEER members include the regulatory bodies of nearly all the countries of Europe: Austria, Belgium, Denmark, Finland, France, Greece, Great Britain, Ireland, Italy, Luxemburg, Holland, Norway, Northern Ireland, Portugal, Spain and Sweden.

The CEER also provides the national regulatory bodies with a channel for cooperation and consultation with the European Commission and for active participation in the Florence and Madrid Fora, for the Regulation of Electricity and Gas respectively. The CEER also works closely with other European and international institutions such as the European Parliament, the International Energy Agency (IEA), the regulatory authority associations of North America and Latin America, and the countries of Eastern Europe. During the year the CEER established channels for collaboration and technical cooperation with the German energy market regulator (*Bundesministerium für Wirtschaft und Technologie e Bundeskartellamt*).

There have been numerous expressions of interest in the CEER by candidate countries for EU membership. At the 17th CEER meeting, which took place in Budapest on 23 April 2002, it was decided to set up a joint working group with the Eastern European regulatory bodies to tackle the problems arising from the enlargement of the markets.

Initiatives currently under study by the CEER include a training course, in collaboration with DG TREN, for electricity regulators in candidate countries, scheduled for autumn 2002.

Eight CEER meetings were held between April 2001 and April 2002, organised in turn by the various European regulators in their respective countries. One of the most significant results obtained by the CEER in the various activities it carried out over the year was the agreement with the European Union on cross-border electricity tariff-setting. The CEER played an important role in launching and monitoring the temporary mechanism for 2002 and, in collaboration with ETSO (European Transmission System Operators), Eurelectric (the European electricity producers' association) and the European Commission, in drawing up the methodology for a permanent mechanism that will take effect from 2003. At the European Forum on electricity regulation, which took place in Florence in February 2002, the CEER presented a joint document, *A CEER Agenda for Cross Border Tariffication*, which sets out the view of European regulators on this issue, a key one for the development of a truly European single energy market. On a complementary subject, the use of market mechanisms to manage congestions on trans-national networks, the CEER reached a common position during the year, which was presented at the Florence Forum.

In June 2001, the results of the first comparative survey by the CEER of electricity service quality and the regulatory strategies being implemented were presented at a conference organised by the Authority in Milan.

In the natural gas sector, the European regulators worked in close contact with the Joint Working Group set up by the European Forum for the Regulation of Natural Gas, in Madrid. Issues to which the CEER devoted particular attention included the harmonisation of the different tariff structures and the transparency of the data on interconnection capacity; it presented two joint position documents on these issues at the Madrid Forum in February 2002.

Following the European Commission's Communication to the Parliament and Council of December 2001 on the issue of infrastructure in the context of the Energy Infrastructure Initiative, which sees a specific role for European regulators in the definition of strategic infrastructure requirements, the CEER, in collaboration with DG TREN, drew up a joint document setting out solutions to the principal problems that need to be tackled in order to encourage an improved regulatory climate for infrastructure investment and security of supply.

On 6 and 7 December 2001 in Rome, at the 13th meeting of the CEER, the Authority organised the third CEER-NARUC round table on issues that have emerged in the liberalised electricity and gas sectors.

From 4 to 15 March 2002 the first training course for energy regulators organised by CEER took place, with the participation of 13 European regulatory bodies. The aims of the course were to provide the specialist technical, economic and legal skills and expertise needed to design and implement effective regulatory systems in the energy sectors.

The European Fora for the regulation of the electricity and gas markets

The European Fora for the regulation of the electricity and gas markets were set up by initiative of the European Union (in 1998 and 1999 respectively) after the approval of the European Directives for the liberalisation of the energy markets. Their objective is to encourage dialogue between the principal players in the realisation of an effective internal energy market and to reach agreement on how best to deal with the principal barriers to trans-national competition. Participants at the Forum meetings, which are held every six months, in Florence for electricity and in Madrid for gas, include the Commission and the European regulatory bodies, along with representatives of the Member States, network operators, industry and all other actors involved in the liberalisation processes.
Between April 2001 and April 2002 the Authority took part in the meetings of the 7th and 8th European Fora for electricity regulation, which took place in Florence on 7-9 May 2001 and 21-22 February 2002; it also attended the meetings of the 4th and 5th European Fora for gas regulation in Madrid, on 2-3 July 2001 and 7-18 February 2002.

Florence Forum. The CEER, ETSO, the European Commission, the Member States and other interested parties discussed and analysed key strategic issues concerning:

- the completion of the internal electricity market along competitive lines (cross-border tariffication, measures for the allocation of interconnection capacity and the management of congestions, proposed Directives for the completion of the internal market, integration with the mechanisms applied in the EU candidate countries);
- security of supply;
- infrastructure investments, an issue that has become a particularly important element of EU policies in the light of the Californian experience.

Significant progress was made on the first point, especially with regard to cross-border tariffication and related compensation mechanisms between network operators: in February 2002 an agreement was reached in Florence on the entry into force, with effect from 1 March 2002, of a transitional cross-border tariffication mechanism pending the introduction of the definitive mechanism in January 2003. This was discussed during the same meeting, with agreement being reached on the guiding principles. Other issues decided at the meeting were: the creation of a Mixed Commission (European Commission, ETSO, CEER and EU Presidency) to monitor the provisional mechanism and the joint drafting, by September 2002, of a strategy document illustrating the basic criteria for the definitive mechanism and the respective algorithms and calculation models. To complement the cross-border compensation mechanism, agreement was also reached on the need to define common criteria for the structure of transportation tariffs and submit proposals by the end of September 2002, with the aim of introducing these criteria in tandem with the definitive mechanism from January 2003. The monitoring of the mechanisms currently being applied for the allocation of interconnection capacity, introduced further to the Guidelines agreed at the 6th Forum, highlighted the shortcomings involved in applying congestion management systems based on market mechanisms; consequently, the Forum invited CEER and ETSO to examine the procedures with a view to supplementing these Guidelines.
The proposed EU Directives for the acceleration of the liberalisation process were widely supported by the Forum, which also favours the integration within the European single market of the energy markets of the East European EU candidate countries, which since February 2002 have been invited to take part in the meetings of the Forum.
On the question of security of supply the Forum, partly in view of the recommendations contained in the European Commission's Green Paper on security of electricity supply, invited the UCPTE (Union for the Coordination of Electricity Generation and Transmission), Nordel (association of transmission system

operators in the Nordic countries) and other associations of network owners to present binding common standards for network security and reliability for users and operators. This was done in close cooperation with the Commission, the CEER and ETSO, in the light of the meeting of September 2002. The Forum underlined the importance of using the existing infrastructure efficiently in order to ensure a stable and reliable regulatory framework in which to encourage infrastructure investment.

Madrid Forum. During the meeting of the 4th and 5th Fora in Madrid, the CEER, the association of European gas network operators (GTE), the Commission, the Member States and other associations and interested parties discussed and analysed the key strategic issues with respect to:

- the completion of the internal energy market along competitive lines (harmonisation of tariff structures, transparent criteria for available capacity at borders and the management of congestion, technical barriers);
- infrastructure investment;
- technical network inter-operability;
- long-term supply strategies.

The Joint Working Group (which includes representatives of the Commission, CEER, and the Member States, along with industry and GTE representatives) drew up a Strategy Paper that outlines a long-term vision for the creation of an integrated single gas market in Europe. Points worthy of note include the adoption by the Forum of Guidelines for third-party access to gas networks in the European Union in agreement with the network operators, a fundamental step for the development of competition among operators. The Forum also adopted common principles for charges and tariffs for the use of transportation networks, in order to achieve improved coordination and a harmonisation of national tariff structures.

At the invitation of the Forum, the GTE decided to increase the degree of market transparency by publishing the data on available capacity, at least at all cross-border interconnection points on the European gas network. The Forum agreed on the need to move on from the adoption of non-discriminatory rules on the management of congestions and the allocation of capacity in the event of shortages.

The Forum welcomed the creation of a new association, the European Association for the Streamlining of Energy Exchange Gas (EASEE Gas), whose aim is to harmonise measures to deal with the technical obstacles to European network interoperability by defining common technical standards.

On the subject of long-term contracts and security of supply, the Forum called for the definition, where necessary and legally practicable, of a programme that would be compatible with the promotion of competition.

At the invitation of the Forum, the OGP (International Association of Oil and Gas Producers) also carried out a study of the production potential of European and non-European gas supplies in the framework of a single competitive market.

NATIONAL CONTEXT

NATIONAL ECONOMIC AND ENERGY FRAMEWORK

The economic slow-down experienced by all the major industrialised countries in 2001 also affected Italy, where GDP growth fell from 2.9% in 2000 to 1.8%.
The country's energy requirement increased by 1.5%, from 185.3 Mtep in 2000 to 188 Mtep in 2001. In the first ten months of the year the energy requirement stayed fairly close to the previous year's level, and it was mainly as a result of exceptionally harsh weather conditions (in November and December) that the overall demand for energy products rose by 1.5% on an annual basis (Tab 6).
The demand for oil was 0.6% down on the previous year (from 91.4 Mtep to 90.9 Mtep). 4.5% (4.1 Mtep) was covered by national production – 10% less than the 4.6 Mtep produced nationally in 2000, as a result of the gradual depletion of many fields – and 95.5% was covered by imports of crude, semi-processed and derivative oil products. There was no fall-off, however, in refining activity. The fall in demand for oil was caused by a marked reduction in the use of fuel oil for thermoelectric production, a trend that was confirmed in the course of the year.

Natural gas

Natural gas consumption increased by just 0.3%, well below the average increases of around 3.5% seen in previous years. The reduction, which was largely unexpected, is the overall result of the significant fall in the use of gas in industry, which was not offset by the strong increase in use for civil purposes and the slight increase in use for thermoelectric generation. The increase in civil use was largely determined by the adverse weather conditions: while in the first part of the year the mild temperatures resulted in a fall in consumption of about 5%, the cold spell in November and December led to a peak in natural gas usage that was so sharp as to produce a 3.4% increase in consumption, taken annually. In the industrial sector the slow-down in production led to a drop of 2.4% in consumption. The fall in demand had decisive effects on supply trends, with imports falling by 4.6%, the equivalent of about 3.5 billion m^3. The weak growth in demand also influenced national production, which fell from 16.2 to 15.5 billion m^3.

Electricity

The limited increase in the use of natural gas in electricity generation contrasts sharply with the trend in recent years. It was the result of four main factors: the strong increase in electricity imports (from 44.8 TWh in 2000 to 48.9 TWh in 2001); the large amount of hydroelectricity available in the first part of the year; the boost in supplies of electricity from renewable sources; and a further increase in the use of coal in thermoelectric power stations (from 10.3 Mtec to 12.1 Mtec). In 2001, the electricity produced from renewable and similar sources increased by 0.7 TWh with respect to the previous year, a rise that can be attributed to the numerous industrial initiatives launched in recent years and to measures providing tariff-based and other incentives. Further increases are expected as a result of the requirement to supply the network with renewables that was introduced by Art. 11 of Legislative Decree 79 of 16 March 1999 (hereafter Legislative Decree 79/1999).

Operators in the sector

During 2001 the structures of the operators supplying electricity and natural gas underwent significant changes (tab. 7-8-9). The ceilings established by Legislative Decree 164 of 23 May 2000 (hereafter Legislative Decree 164/2000), which took effect on 1 January 2002, obliged Eni S.p.A. to review national supply arrangements.

In 2001, sales by ENI of imported gas of Russian, Norwegian and Dutch origin contributed to the partial diversification of supply and encouraged the emergence of new intermediaries (mainly wholesalers and

distributors' sales companies) that only started operating in the second half or last few months of the year. This process will be taken further with the imminent entry to the national market of foreign operators who will be obtaining their supplies from sources other than ENI.
Among the national operators, one significant development was the creation of companies operating mainly in the supply of gas to customers served by linked distribution companies, in advance of the deadline of 1 January 2002 laid down by Legislative Decree 164/2000.
For the supply of gas in the electricity sector, other groups in addition to Enel S.p.A. have expressly declared their intention to ensure their independence from ENI for natural gas supplies.

TAB. 6 ENERGY BALANCE SHEET 2000-2001 (Mtep)

	Coal and derivatives	Natural gas	Oil	Renewables	Electricity	Total
2001						
Production	0.4	12.8	4.1	13.5	0.0	30.8
Imports	13.2	45.2	108.6	0.5	10.6	178.1
Exports	0.1	0.1	22.3	0.0	0.0	22.5
Change in reserves	-0.3	-0.8	-0.5	0.0	0.0	-1.6
Available supplies for domestic consumption	13.8	58.7	90.9	14.0	10.6	188.0
Energy sector consumption and losses	-1.0	-0.6	-6.2	-0.1	-43.9	-51.8
Transformation to electricity	-8.5	-19.1	-17.4	-12.3	57.3	0.0
Final uses	4.3	39.0	67.3	1.6	24.0	136.2
- industry	*4.1*	*16.3*	*6.9*	*0.3*	*12.0*	*39.6*
- transport	*0.0*	*0.3*	*40.9*	*0.0*	*0.7*	*41.9*
- civil uses	*0.1*	*21.4*	*7.4*	*1.1*	*10.9*	*40.9*
- agriculture	*0.0*	*0.1*	*2.6*	*0.2*	*0.4*	*3.3*
- non-energy uses	*0.1*	*0.9*	*6.7*	*0.0*	*0.0*	*7.7*
- bunkerage	*0.0*	*0.0*	*2.8*	*0.0*	*0.0*	*2.8*
2000						
Production	0.3	13.7	4.6	12.4	0.0	31.0
Imports	13.2	47.4	109.7	0.5	9.9	180.7
Exports	0.1	0.0	21.2	0.0	0.1	21.4
Change in reserves	0.6	2.7	1.7	0.0	0.0	5.0
Available supplies for domestic consumption	12.8	58.4	91.4	12.9	9.8	185.3
Energy sector consumption and losses	-1.3	-0.7	-5.8	-0.1	-43.1	-51.0
Transformation to electricity	-7.2	-18.8	-19.4	-11.3	56.7	0.0
Final uses	4.3	38.9	66.2	1.5	23.4	134.3
- industry	*4.0*	*16.7*	*6.8*	*0.2*	*11.7*	*39.5*
- transport	*0.0*	*0.3*	*40.4*	*0.0*	*0.7*	*41.5*
- civil uses	*0.1*	*20.7*	*7.4*	*1.2*	*10.6*	*39.9*
- agriculture	*0.0*	*0.1*	*2.6*	*0.1*	*0.4*	*3.2*
- non-energy uses	*0.2*	*1.0*	*6.3*	*0.0*	*0.0*	*7.5*
- bunkerage	*0.0*	*0.0*	*2.7*	*0.0*	*0.0*	*2.7*

Source: Report on the economic situation of the country, Rome, 2002.

TAB. 7 GAS BALANCE SHEET (YEAR 2001)
Billions m^3; based on a value of 8.250 kcal/m^3

	Producers			Wholesalers				Distributors				Total
	Eni	**Edison**	**Others**	**Eni**	**Enel**	**Edison**	**Others**	**Eni**	**Enel**	**Edison**	**Others**	
National production	**13,6**	**1,4**	**0,6**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**15,5**
Imports	**0,0**	**0,0**	**0,0**	**44,8**	**6,4**	**2,3**	**1,3**	**0,0**	**0,0**	**0,0**	**0,0**	**54,8**
Direct imports	0,0	0,0	0,0	44,8	6,4	1,8	0,0	0,0	0,0	0,0	0,0	53,0
Eni sales at border	0,0	0,0	0,0	0,0	0,0	0,0	1,2	0,0	0,0	0,0	0,0	1,2
Other Wholesalers	0,0	0,0	0,0	0,0	0,0	0,5	0,1	0,0	0,0	0,0	0,0	0,6
Domestic sales	**0,2**	**0,0**	**0,1**	**13,7**	**6,5**	**2,1**	**1,1**	**7,9**	**1,0**	**0,2**	**22,4**	**55,0**
by Producers												
Eni	*0,0*	*0,0*	*0,1*	*13,6*	*0,0*	*0,0*	*0,0*	*0,0*	*0,0*	*0,0*	*0,0*	***13,7***
Edison	*0,1*	*0,0*	*0,0*	*0,0*	*0,0*	*1,4*	*0,0*	*0,0*	*0,0*	*0,0*	*0,0*	***1,5***
Others	*0,1*	*0,0*	*0,0*	*0,0*	*0,0*	*0,3*	*0,0*	*0,0*	*0,0*	*0,0*	*0,0*	***0,5***
by Wholesalers												
Eni	*0,0*	*0,0*	*0,0*	*0,0*	*6,4*	*0,0*	*0,6*	*7,8*	*0,9*	*0,0*	*20,9*	***36,7***
Enel	*0,0*	*0,0*	*0,0*	*0,0*	*0,0*	*0,0*	*0,2*	*0,0*	*0,0*	*0,0*	*0,0*	***0,2***
Edison	*0,0*	*0,0*	*0,0*	*0,0*	*0,1*	*0,0*	*0,3*	*0,0*	*0,1*	*0,2*	*0,4*	***1,0***
Others	*0,0*	*0,0*	*0,0*	*0,0*	*0,0*	*0,3*	*0,0*	*0,0*	*0,0*	*0,0*	*1,0*	**1,4**
Change in reserves	**-0,1**	**-0,1**	**0,0**	**-1,2**	**0,0**	**0,4**	**-0,2**	**0,0**	**0,0**	**0,0**	**0,0**	**-1,2**
Network consumption and losses	**0,1**	**0,0**	**0,0**	**0,5**	**0,1**	**0,0**	**0,0**	**0,1**	**0,0**	**0,0**	**0,4**	**1,4**
Total resources	**0,1**	**0,0**	**0,1**	**22,5**	**12,5**	**2,9**	**1,2**	**7,7**	**1,0**	**0,2**	**21,9**	**70,1**
Sales and final consumption	**0,1**	**0,0**	**0,1**	**22,5**	**12,5**	**2,9**	**1,2**	**7,7**	**1,0**	**0,2**	**21,9**	**70,1**
Thermoelectric generation	0,1	0,0	0,0	7,3	12,3	1,6	0,5	0,1	0,0	0,0	0,5	**22,5**
Industrial Users	0,0	0,0	0,1	15,2	0,2	1,2	0,7	1,4	0,2	0,0	5,3	**24,3**
Civil users	0,0	0,0	0,0	0,0	0,0	0,0	0,0	6,1	0,8	0,1	16,0	**23,0**
Users	0,0	0,0	0,0	0,0	0,0	0,1	0,0	0,1	0,0	0,0	0,1	**0,3**
Of which												
Captive market	*0,0*	*0,0*	*0,0*	*0,0*	*0,0*	*0,0*	*0,0*	6,3	0,8	0,1	17,7	**24,9**
Free market	*0,1*	0,0	0,1	22,5	12,5	2,9	1,2	1,4	0,2	0,0	4,2	**45,2**

Source: Operators' annual reports and statements

TAB. 8 ELECTRICITY BALANCE SHEET (YEAR 2001)

Values in TWh

	ENEL GROUP	EDISON GROUP (A	ENERGIA GROUP	LOCAL CO.	MINOR CO.	SELF-PRODUCTION	FOREIGN WHOLE-SALERS	CONSOR-TIUMS OF WHOLE-SALERS	OTHER WHOLE-SALERS	CONSOR-TIUMS OF BUYERS	FREE CUSTOMERS	TOTAL
NET NATIONAL PRODUCTION	168,2	30,4	0,0	11,8	35,1	21,1	0,0	0,0	0,0	0,0	0,0	266,5
PUMPING	9,4	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	9,5
IMPORT/EXPORT BALANCE	22,7	0,9	0,9	0,7	0,0	0,0	7,1	2,4	0,9	3,9	8,9	48,4
ENEL CONTRACTS	21,8	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	21,8
GRTN	0,1	0,1	0,0	0,2	0,0	0,0	0,9	0,8	0,8	2,8	6,6	12,1
EUROPEAN TSOS	0,8	0,8	0,9	0,5	0,0	0,0	6,3	1,6	0,2	1,2	2,3	14,5
NET TRANSFERS (B)	31,6	-18,9	2,7	1,9	-30,3	3,3	-1,5	9,1	2,8	-0,2	-0,5	0,0
LOSSES	11,7	2,0	0,1	0,8	2,3	1,4	0,5	0,2	0,1	0,3	0,6	19,6
TOTAL RESOURCES	201,4	10,4	3,5	13,5	2,6	23,0	5,2	11,3	3,6	3,5	7,9	285,8
SALES & FINAL CONSUMPTIONS	201,4	10,4	3,5	13,5	2,6	23,0	5,2	11,3	3,6	3,5	7,9	285,8
OF WHICH CAPTIVE MARKET	174,4	0,0	0,0	10,2	2,6	0,0	0,0	0,0	0,0	0,0	0,0	187,3
FREE MARKET	26,9	10,4	3,5	3,2	0,0	23,0	5,2	11,3	3,6	3,5	7,9	98,5

(A) including Edison, Sondel and Fiat Energia which merged in the Group Nuova Edison in May 2002
(B) Transfers include both CIP 6/92 plants and import capacity

Source: GRTN data and Operators' annual reports

TAB. 9 STRUCTURE OF SALES OF PRINCIPAL WHOLESALERS IN THE ELECTRICITY AND GAS SECTOR IN 2001 [(A)]

Name of wholesaler	Direct sales to final customers	Sales within the group	Sales to Other Wholesalers	Total
Electricity (millions of kWh)				
Enel Trade	26.892	0	213	27.105
Edison Energia	9.771	1.332	0	11.103
Assoenergia	4.515	418	41	4.974
Energia	3.766	13	0	3.779
EGL Italia	3.187	0	158	3.345
AEM Energia/Trading	1.561	618	360	2.539
Dalmine Energie	653	1.592	172	2.418
ASM Energia ambiente	1.687	11	276	1.974
EniPower Trading	1.012	217	646	1.875
Electra Italia	1.434	0	70	1.504
E.On Italia	264	0	1.217	1.482
Centomilacandele	145	684	99	928
Scaligera Energia	634	634	0	0
Others	4.376	2.280	1.657	8.314
TOTAL	**59.987**	**7.167**	**4.909**	**71973**
Gas (millions m^3)				
Eni Gas & Power	14.364	8.651	21.635	44.650
Enel Fti	191	6.036	104	6.330
Edison Gas	712	1.756	894	3.362
Plurigas	183	771	6	960
Aem Trading	179	428	0	608
Enel Trade	199	0	129	328
Estgas	231	65	0	296
Utilità	113	0	11	123
Eos Energia	0	116	7	123
Energia Concordia	0	40	77	116
Blugas	0	68	6	74
Sgr Servizi	0	57	0	57
Dalmine Energie	0	51	1	52
Others	37	0	46	82
TOTAL	**16.209**	**18.039**	**22.916**	**57.161**

(a) Data include resales
Source : Operators annual reports and statements

THE ENERGY POLICY GUIDELINES LAID DOWN BY GOVERNMENT AND PARLIAMENT

The Economic and Financial Planning Document

As envisaged by Law 481 of 14 November 1995, the Economic and Financial Planning Document (DPEF) is the main instrument setting out the guidelines for the activity of the Authority. The Document was approved by Parliament through two resolutions, voted by the Senate and Chamber of Deputies on 31 July 2001 and 1 August 2001 respectively. It covers the subject of energy within the wider context of industrial policy and indicates this sector as a strategic one for the recovery of competitiveness by the national industrial system.
In particular, to enable Italian firms to meet the challenge of international competition the DPEF defines the acceleration of the liberalisation process and the development of competition as priority areas for

action, even if this means going beyond the minimum requirements laid down by the European Union, without prejudice to the principle of reciprocity.
Developments envisaged for the electricity sector include a change in the ownership structure and further development of the national network, and the establishment of the electricity exchange.
For the natural gas sector the DPEF focuses on the management of access to the transportation network and of liquefied natural gas regassification terminals and calls for a simplification of the legislation and the creation of new infrastructure. The Government also undertakes to promote the efficient use of energy resources and the development of renewable sources, not least with a view to reducing Italy's dependence on supplies from abroad.
Decree Law 192 of 25 May containing urgent provisions to safeguard the liberalisation and privatisation processes in specific public utility sectors.
With Law 301 of 20 July 2001 Parliament confirmed Decree Law 192 of 25 May (hereafter Decree Law 192/2001) containing urgent provisions to safeguard the liberalisation and privatisation processes in specific public utility sectors.
Decree Law 192/2001 was issued subsequent to the French electricity company EDF acquiring a share in the equity of the Italian company Montedison S.p.A., which controls Edison S.p.A., an electricity and gas operator. The decree introduces limits to voting rights in resolutions by the assemblies of companies operating in the two sectors, in cases where over 2% of their shares have been acquired by operators controlled directly or indirectly by their respective states and occupying a dominant position in their own national market. The second paragraph of the decree, which envisages the automatic suspension of voting rights in such cases, also precludes the possibility of exercising purchase or subscription rights. Pending the confirmation of the decree, EDF sold part of its holding in Montedison to Fiat S.p.A., transferring the remainder to Italenergia S.p.A., a new company set up with Fiat and other financial and banking operators.

Fact-finding investigation on the situation and prospects in the energy sector

On 9 October 2001 the Chamber's Committee no. 10 on Productive Activities, Commerce and Tourism passed a resolution providing for a *Fact-Finding Investigation on the Situation and Prospects in the Energy Sector*.
The data and conclusions that emerged from the survey underlined the need to up-date Italy's legislative framework and identify possible approaches for the Government to follow in this area and the conditions under which Italian companies in the sector can best prepare themselves for competition on the European market.
The survey, which began on 13 November 2001, was completed on 18 April 2002 with the approval of its concluding document (available from the site www.parlamento.it).
It places a particular focus on drawing up a national energy policy that should be:

- consistent with EU policies on this subject, to underpin the policy guidance framework within which the Authority's technical and administrative supervisory role is set;
- based upon precise strategic choices aimed at the diversification of supply and primary sources, for reasons based on security and the costs of the Italian production system (reduction of the dependence on oil and methane in final uses; promotion of renewable sources, clean use of coal, LNG imports; a specific reflection on the nuclear energy issue);
- in line with the legislative and regulatory requirements for the reform of Title V of the Constitution[1];
- designed with a view to completing the liberalisation process and increasing the efficiency of the domestic market (re-definition, for a set period of time, of the antitrust ceilings on the supply of

[1] Constitutional Law 3 of 18 October 2001, containing Amendments to Title V, part 2 of the Constitution, introduced reforms to the competencies of central and local government in areas that include energy. The new Art. 117 of the Constitution divides responsibility between the two levels of government for legislation regarding the "production, transmission and distribution of energy", leaving only the task of laying down the fundamental principles solely to central government.

electricity and gas; containment of the envisaged stranded cost reimbursements; promotion and facilitation of the construction of new plants and LNG regassification plants; up-grading and development of the national electricity grid; review of the separation of ownership and management laid down by Legislative Decree 79/1999; introduction of the electricity exchange, organised along transparent and non-discriminatory lines and subject to appropriate oversight, after the divestment of the third Gen.Co. by Enel and the entry into operation of the Single Buyer in its role of protecting captive customers; promotion of supply in the distribution sector with an enhanced role for local authority companies);

- fully aware of the need for investment to modernise and develop production capacity and expand the transportation and interconnection infrastructure.

Legislative Decree containing urgent measures to guarantee the security of the national electricity system

On 1 February 2002 the Council of Ministers, acting on a proposal by the Minister for Productive Activities, approved the decree law containing urgent measures to guarantee the security of the national electricity system. The objective of the provision is the realisation in a short timescale of the new generating capacity that is needed to avert the risk, of which the Network Operator has warned, of possible interruptions in the supply of the electricity service in the next few years as a result of insufficient national production capacity. The decree sets forth measures to speed up and simplify the authorisation procedures for the installation, alteration and up-grading of electricity generating stations of over 300 thermal MW, considered as public utility works. The decree law was confirmed by Law 55 of 9 April 2002.

COMPETITION AND REGULATION IN ENERGY SECTORS
MARKET STRUCTURE AND REGULATION IN THE ELECTRICITY SECTOR

GENERATION AND IMPORTS

National Production

According to the provisional data published by the Network Operator, in 2001 gross national production amounted to 279,630 GWh, an increase of 1.1% with respect to 2000.
Net conventional thermoelectric production amounted to 219,204 GWh in 2001 (0.6% down on 2000); hydroelectric production rose by 8.2% (55,091 GWh) and energy from renewable sources by 1.1% (5,335 GWh).
41.2% of conventional thermoelectric production was obtained from natural gas, 45.6% from fuel oil, 14.3% from coal and 6% from gas derivatives and other fuels.
With respect to 2000 there was a significant reduction in the use of fuel oil (-3.8%), a marked increase in the use of coal (+18.1%) and a very slight rise for gas (1.4%).
In 2001 production for consumption, net of the energy destined for producers' own consumption needs (123,127 GWh) and the energy absorbed by pumping (9,434 GWh), amounted to 257,069 GWh, of which about 50,000 GWh from plants selling electricity produced from renewable and assimilated sources under the agreements established by Interministerial Committee on Prices (CIP) provision 6 of 29 April 1992 (hereafter CIP 6/1992).

In 2001 net installed capacity amounted to 76,400 MW, an increase of 800 MW over 2000. However, the data provided by the Network Operator show that only 48,700 MW were available for effective production; to these should be added 6,000 MW of interconnection with neighbouring countries to cover the power requirement of 52,000 MW.
Finally, it should be noted that the Prime Minister's Decree of 4 August 1999 approving the divestment plan drawn up by Enel envisaged that the purchasing companies should undertake to transform the greater part of Gen.Co S.p.A.'s installed thermoelectric capacity to combined cycle technology by the end of 2008. This means that part of Elettrogen and Eurogen's thermoelectric production capacity will be out of commission for some time while the necessary renovation work is carried out.
Within this overall framework, which highlights the risks inherent to a system that does not have sufficient generating capacity, Decree Law 7 of 7 February 2002, confirmed by Law 55 of 9 April 2002, was issued. The aim of this provision is to provide greater impetus and certainty to the procedures for the construction and up-grading of electricity generating stations of over 300 thermal MW.

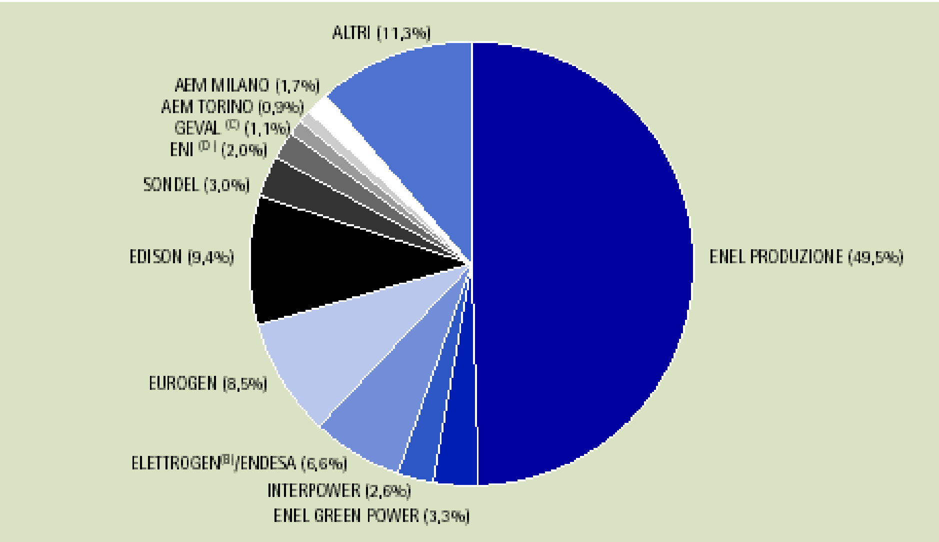
The divestment of Elettrogen, Eurogen and Interpower

In July 2001 the divestment of Elettrogen, to which plants amounting to a net capacity of 5,438 MW had been allocated, including 1,014 MW in hydroelectricity, was concluded. The consortium, composed of Endesa (the main Spanish electricity producer), with a holding of 45.1%, Banco Santander Central Hispanico, with 40%, and Asm Brescia S.p.A with the remaining 15%, won the auction for Elettrogen with a bid of 2,630 million euros[2].
In the same period Enel acquired from Endesa 2,365 MW of generating capacity in Spain, through the purchase of Nuova Viesgo at a price of 1,870 million euros.
March 2002 saw the conclusion of the procedure for the placement of Eurogen, the biggest Gen.Co S.p.A., to which 55 plants had been allocated, 49 of them hydroelectric and 6 thermoelectric, for an overall net capacity of 7,008 MW. Edipower S.p.A., created by Edison S.p.A. (40%), Aem Milano S.p.A. (13.4%), Aem Torino S.p.A. (13.3%) and Atel (13.3%) (in which UniCredito Italiano S.p.A. (10%),

[2] In 2002 Endesa acquired a further 5.7% of Banco Central Hispanico, bringing its controlling stake in Elettrogen to 51%.

Interbanca S.p.A. (5%) and Royal Bank of Scotland (5%) also have holdings), won the auction for Eurogen at a price of 3,700 million euros (including assumed debts).
The divestment process is also under way for Interpower, Enel's third Gen.Co. At the end of April 2002 the notice for expressions of interest in the purchase of the entire share capital of Interpower was published. Interpower has a production capacity of 2,611 MW, of which 2,548 MW are thermoelectric and 63 MW hydroelectric. 98% of Interpower's net production in 2000 was obtained from the 3 thermoelectric plants, while the remaining 2% was hydroelectric.

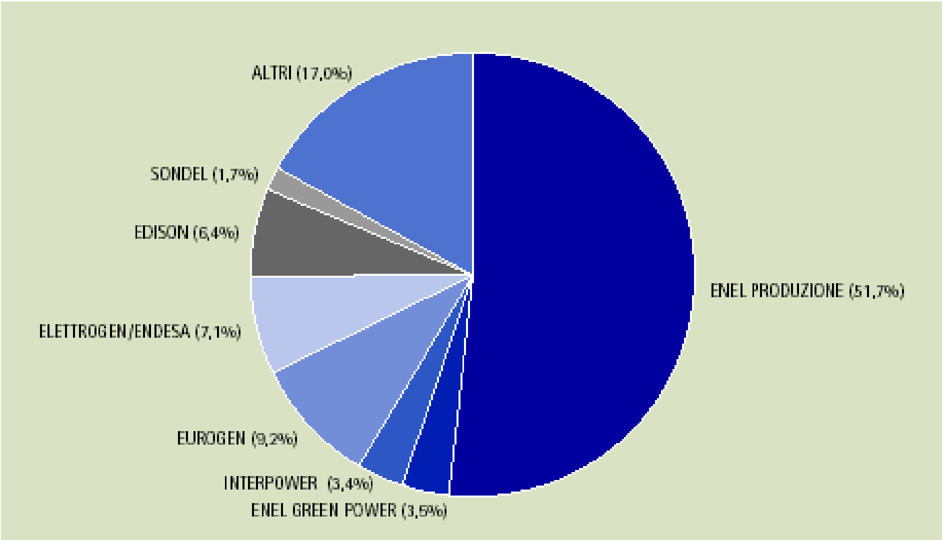
FIG. 1 MARKET SHARES IN THE NET PRODUCTION OF ELECTRICITY [(A)]
Year 2001; percentage composition



(A) Net of production for self-consumption; generation by installations operating under CIP/62 terms is included.
(B)Generation by Elettrogen pre-divestment in 2001 amounted to 11,274 GWh.
(C) Since 1 Jan 2002 Geval has been called CVA.
(D) 38.9% of ENI generation goes to meet the consumption of companies in the group.

Source: Based on data from company reports and GRTN.

FIG. 2 MARKET SHARES IN POWER CAPACITY IN ITALY IN 2001 [(A)]
Hydro- and thermoelectric installed power: percentage composition.



(A) Net of capacity intended for self-consumption
Source: Based on data from company reports and GRTN.

Imports

In 2001, 15.8% of the demand for electricity, which amounted to 305,446 GWh, was met from imports (48,377 GWh), an increase of 9.1% over 2000 (44,300 GWh).
Interconnection capacity with neighbouring countries – net of capacity used for the performance of long-term import contracts drawn up before 19 February 1997 and transit capacity for the Republic of San Marino, the Vatican State and Corsica – amounted to 1,953 MW for 2002, of which 1,653 on the north-western border (France and Switzerland) and 300 MW on the north-eastern border (Austria and Slovenia). In view of the fact that available capacity was insufficient to meet the demand from operators, as envisaged by Legislative Decree 79/1999 the Authority established the conditions and arrangements under which the available capacity should be allocated. In Decision 301 of 5 December 2001, 600 MW (of which 500 at the north-western border and 100 MW at the Austrian part of the north-eastern border) of the 1,953 MW of available transmission capacity were allocated for a 3-year period (2002-2004) to final customers willing to accept interruptions in supply without notice. 48 such customers were allocated capacity averaging 12.5 MW each. The remaining 1,153 MW available at the north-western border were allocated to 48 operators, with each receiving an average of 24 MW. Transportation capacity over the interconnection with Slovenia, which amounts to 190 MW, was divided among 17 operators, who each received an average of 11.2 MW. The 10 MW of interconnection capacity with Austria were divided amongst 9 operators.

TAB. 10 CONNECTION CAPACITY WITH NEIGHBOURING COUNTRIES FOR 2002
Values in MW - winter

Border	Italy – France	Italy - Switzerland	Italy - Austria	Italy - Slovenia	Total
Existing long-term contracts	1,800	800	-	-	2,600
Capacity allocated to RSM, Vatican, Corsica	147	-	-	-	147
Capacity available to GRTN	653	1,000	110	190	1,953
Capacity for allocation by foreign Operators	-	1,000	110	190	1,300
TOTAL	**2,600**	**2,800**	**220**	**380**	**6,000**
Of which:					
Allocated to interruptible customers	500		100		600
Allocated on annual basis	1,153		10	190	1,353

Renewable sources of electricity

Considerable progress was made in 2001 in the transition from the system of incentives set out in CIP provision 6/92 to the "green certificate" system – in other words, the move from an incentive mechanism based on a pre-defined economic allowance, differentiated by technology, to one in which the incentive is set by market forces.

The incentive mechanism envisaged by Legislative Decree 79/1999 actually took effect on 1 January 2002. It establishes that anyone who produced or imported over 100 MW of electricity from non-renewable sources the previous year is obliged to supply the national grid with 2% of that amount in the form of energy produced from renewable sources, generated in plants that began operating after 1 April 1999.

By 31 May 2002 (in subsequent years the deadline will be 31 March) interested parties were required to present the Network Operator with the certification attesting to the amount they produced and imported in 2001 (net of co-generation, self-consumption and energy produced from renewable sources); in addition, by 31 March 2003 they must be able to demonstrate, through the possession of green certificates, that they have covered the 2% requirement.

These certificates, which are worth 100 MW each, are recognised for the first eight years in operation for plants that came on line after 1 April 1999; they may be attributed to production by plants belonging to the company that is subject to the requirement or to third party producers, sold separately from the electricity actually produced and then exchanged through bilateral contracts or in a special market set up by Gestore del Mercato S.p.A. (the Market Operator).

The new mechanism overlaps with the previous incentive system (CIP 6/92) since the green certificates that can be used to meet the obligation are also issued for plants producing electricity from renewable sources on the basis of CIP 6/92 and which entered into function after 1 April 1999. These certificates, together with the electricity produced, are withdrawn and made out to the Network Operator. This means that there are in fact two types of certificate: the green certificates for plants to which the CIP 6/92 incentives are not applicable, issued in advance or with retro-active effect and made out to private operators, and those for plants to which CIP 6/92 does apply, made out to the Network Operator. While the former may be sold on the market set up by the Market Operator at a free price or through bilateral contracts, the latter must be sold on the same market at the price set by Art. 9 of the ministerial decree of 11 November 1999.

This price is obtained from the difference between the average cost of the incentives granted for power stations operating under CIP 6/92, based on their partial payment communicated by the Equalisation Fund for the Electricity Sector (*Cassa conguaglio per il settore elettrico* – CCSE) and the Network Operator's revenue from the sale of the underlying electricity. It follows that the price of the certificates held by the Network Operator does not depend on market trends in the demand and supply of green certificates, but on adjustments to CIP 6/92 incentives and other factors external to the development of energy produced from renewable sources such as, for example, the arrangements for the sale of CIP 6/92 electricity to the captive market. These are determined by Decision 233 of 13 December 2000 as amended, which implemented the provisions of Art. 4.1 of the Minister of Industry Decree of 21 November 2000.

Since the green certificates held by the Network Operator, the supply of which currently exceeds that of green certificates made out to private operators, are needed to satisfy the demand for green certificates resulting from the 2% requirement, their price will also act as a benchmark for the market in private green certificates.

TAB. 11 SUPPLY OF GREEN CERTIFICATES FROM GRTN

Year	TWh
2002	6.1
2003	7.2
2004	7.4
2005	7.6

Source: Grtn, 2001

TAB. 12 SUPPLY OF GREEN CERTIFICATES FROM PRIVATE PRODUCERS

Type	Operational GWh	Planned GWh	Total GWh
Wind	178.5	1490.30	1668.80
Geothermal	58.6	-	58.6
Hydro	337.48	83.32	460.80
Waste	320.42	121.00	441.42
Solar	0.78	-	0.78
Total	**935.78**	**1694.62**	**2630.40**

Source: Grtn., 2001

The Network Operator publishes a special bulletin[3] containing the data for plants producing electricity from renewable sources, whether already operating or under construction. In addition to these data, the green certificates issued against the partial modernisation of hydroelectric plants should also be taken into consideration, as envisaged by Art. 5 of the decree issued by the Ministry for Productive Activities and the Ministry of the Environment on 18 March 2002. An initial estimate puts the certificates issued subsequent to this amendment to the legislative framework at around 0.7 TWh.

TAB. 13 DEMAND FOR GREEN CERTIFICATES

Year	TWh
2002	4.9
2003	5.1
2004	5.3
2005	5.5

Source: Grtn., 2001

Other incentives for the production of renewable energy

To supplement the green certificates incentive mechanism, funding from carbon tax revenue for 1999 was distributed in 2001. The Environment Ministry decree of 21 May 2001 earmarked 155 billion lire for the regions and the autonomous provinces of Trento and Bolzano as funding for projects involving the use of energy produced from renewable sources (solar and biomass energy) or the promotion of initiatives for the efficient use of energy. A further 50 billion lire (approx. 25 million euros) were

[3] The Network Operator's estimates of the demand for certificates can be consulted on their Internet site at www.grtn.it

earmarked for the co-funding of investments for environmental protection measures involving the use of energy from renewable sources and the rational use of energy.
To meet the objectives of the "10,000 photovoltaic roofs" project promoted by the Ministry for the Environment, 60 billion lire (approx. 31 million euros) were earmarked in 2001 for public and private operators installing small photovoltaic plants (1-20 kW peak). The Authority contributed to this objective through Decision 224 of 31 December 2000, with which it approved the technical and economic arrangements for the exchange of electricity produced by photovoltaic plants with a nominal power of up to 20 kW.

Regulatory framework for the electricity market

In accordance with Art. 5 of Legislative Decree 79/1999, in Decision 97 of 30 April 2001 the Authority submitted its opinion to the Ministry of Industry on the outline regulatory framework for the electricity market as drawn up by the Market Operator. This opinion was, on the whole, favourable, subject to the introduction by the Market Operator of additional elements to ensure that the market mechanisms function correctly and the conditions are satisfied for the supply of the despatching service as defined by the Authority in Decision 95 of 20 April 2001.
Having seen the Authority's opinion, in its Decree of 9 May 2001 the Ministry of Industry approved the rules for the electricity market to organise exchanges through a non-discriminatory auction mechanism. Under these rules, the exchange receives the sale bids from each production plant, draws up a merit order list starting with the lowest, and defines the plants' production programme for the following day. This also minimises the total cost of meeting the demand for electricity on the organised market.
However, even after the Rules for the Electricity Market were approved the legislative framework for the introduction of the bidding system was still not complete, as the rules for implementation, procedures and merit order despatch have still to be set.
In January 2001 the Market Operator sent its proposal regarding the rules for implementation and procedures to the Minister for Productive Activities, who forwarded them to the Authority the following month to formulate an opinion, which was issued in April 2002.
Once the Minister for Productive Activities has approved the Instructions, the Market Operator will be able to draw up the technical provisions for the functioning of the mechanisms, complete with procedural rules.
In the case of merit order despatch, the Network Operator has drawn up a set of rules and submitted them to the Authority for its opinion. Once these two sets of rules – regarding procedures for the functioning of the exchange and merit order despatch – have been defined, some crucial hurdles will still need to be overcome before the electricity market produces the expected benefits.

Even after the planned divestment of Interpower, Enel will continue to hold more than 50% of net installed production capacity in Italy. When the market is launched, the supply structure will therefore be highly concentrated, with evident risks of abuse of dominant position.
Pending the introduction of measures to modify the supply structure and in order to moderate the influence of market power by encouraging competitive supply, the Authority considered in Decision 96 of 30 April 2001 that action should be taken through measures that are essentially regulatory. These include price ceilings, particularly for markets supplying the resources for the despatch service. However, these measures are akin to the administrative setting of market mechanisms and must therefore be used only on a provisional basis.

Interconnection capacity with neighbouring countries

Pending the launch of the electricity market and merit order despatch, the Authority has also taken action on the structure of electricity supply, by defining:

- the conditions for the allocation of transportation capacity over the interconnection between Italy and neighbouring countries (Decision 301/2001);
- the arrangements for the sale on the free market, through competitive procedures, of the electricity produced by plants benefiting from CIP 6/92 incentives (Decision 308 of 21 December 2001).

With regard to transmission capacity over the interconnection, the regulation of electricity exchanges has made it necessary to enter into agreements with the relevant institutional bodies in the countries concerned. After consultation with the regulatory bodies of neighbouring countries, with Decision 301/2001 the Authority introduced the arrangements and conditions for the allocation of transmission capacity over the interconnection between Italy and these countries for 2002; it also provided for the allocation of the same capacity to applicants on a *pro-rata* basis with respect to applications. With Switzerland, Austria and Slovenia transmission capacity was divided 50:50 *a priori*; the agreement with the *Commission de regulation de l'électricité* in France made it possible, on the other hand, to jointly allocate overall transmission capacity at the border with France and the border with Switzerland falling under Italian competence. Responsibility for carrying out the allocation procedure was entrusted to the Network Operator in agreement with the French Transmission Network Operator (*Réseau de transport de l'électricité*).

To encourage the development of a range of electricity suppliers for the national market, in cases where demand exceeds available capacity a limit is envisaged to the share of interconnection capacity that can be allocated to any one operator. This limit has been set at 10% of the available transmission capacity on each interconnection.

Again with the aim of boosting supply and diversifying sources, in its Consultation Paper of 27 February 2002 the Authority proposed a general framework for direct lines (lines that are independent of the national transmission network and can be installed by operators), with particular reference to lines for electricity exchanges with other countries. It also provided some pointers on the formulation of a regulatory framework that would enable the construction and operation of such lines. In this document direct lines are seen as a further means of advancing the integration of the Italian electricity system with the European one, as envisaged by European Directive 96/92/EC, as a means of resolving inadequacies in the existing interconnection network or delays in the construction of new network infrastructure.

Sale of incentivised CIP 6/92 electricity

With regard to the procedures for the sale of electricity withdrawn by the Network Operator pursuant to Art. 3.12 of Legislative Decree 79/1999 to customers on the free market, Decision 308/2001 contains regulations governing the allocation for 2002 and until such time as the bidding system is operational. This sale, provided for by the Ministry for Productive Activities in its decree of 10 December 2001, increases the supply of electricity on the free market and promotes competition. Again to avoid the concentration of production capacity in the hands of a small number of operators, the Authority has proposed that no one operator should be able to apply for more than 20% of the number of bands available for each of the bidding procedures, and no more than 15% of the overall number of bands available for all the bidding procedures.

Wholesale price of electricity for the captive market

With regard to the regulatory system currently in force, in Decision 318 of 27 December 2001 the Authority set the price of wholesale electricity for captive customers for 2002. To avoid making the price-setting mechanism unnecessarily complex pending the introduction of an hourly-based mechanism, the Authority used the same system as in the previous two years. The price is therefore equal to the sum of an element covering fixed electricity production costs for different time bands and a component that is independent of the time bands, to cover variable production costs, which is equal to the allowed unit cost of electricity produced from thermoelectric plants using commercial fossil fuels (paragraph 6.5 of Decision 70 of 11 May 1997).

To set the price of wholesale electricity for 2002, production costs were analysed for plants using conventional fossil fuels; the survey also included the transmission costs envisaged by Art. 16 of the Integrated Text of Authority provisions for the supply of electricity transmission, metering and sales services, as approved in Decision 228/2001 and subsequent amendments. The component covering fixed electricity production costs in the price thus set was substantially in line with the level for 2001.

TAB. 14 PRICE OF WHOLESALE ELECTRICITY FOR 2001 AND 2002
Element to cover fixed costs of electricity production

Time band PG	2001		2002
	Lire/kWh	euro-cents/kWh	euro-cents/kWh
F1(peak hours)	180.1	9.302	9.338
F2 (peak hours)	72.4	3.739	3.755
F3 (medium load hours)	39.3	2.029	2.035
F4 (off peak hours)	0	0	0

In the case of electricity produced by run-of-river installations of up to 3 MW, in Decision 82 of 8 June 1999 (subsequently amended by Decision 56 of 16 March 2000) the Authority had set the price in such a way as to ensure that production costs were covered and an adequate return received. After receiving reports from plant owners and their associations to the effect that there are no features intrinsic to storage or pondage installations of up to 3 MW that would justify differences in treatment, with Decision 62 of 18 April 2002 the Authority brought the prices for the sale of electricity produced by these plants into line with those for run-of-river installations.

Cogeneration

Legislative Decrees 79/1999 and 164/2000 envisage a series of benefits for cogeneration. These include: priority despatch of the electricity produced; exemption from the requirement to supply a quota of electricity produced from renewable sources to which producers and importers of electricity from non-renewable sources with annual production or import levels of over 100 GWh are subject; and recognition of eligible customer status for firms purchasing gas for cogeneration, independently of the level of annual consumption. Art. 2.8 of Legislative Decree 79/1999 also tasks the Authority with drawing up the conditions to be applied for the combined production of electricity and heat to be recognised as cogeneration; it also envisages that these conditions should guarantee a significant saving of electricity with respect to the separate production of the two.
In Decision 42/2002 the Authority set forth the conditions whereby the combined production of electricity and heat is recognised as cogeneration. The definition includes any integrated process for the combined production of electrical or mechanical energy and thermal energy, produced by the section of a combined electricity and heat production plant which, starting with any mix of primary sources and with reference to each calendar year, satisfies two conditions at any one time. The first regards the energy saving achieved by the cogeneration plant with respect to separate production, while the second regards the proportion of thermal energy produced with respect to the total production of electrical and thermal energy.

ELECTRICITY TRANSMISSION AND DESPATCH SERVICES

The national transmission network is made up of 9,782 km of 380 kV circuits (triad lines), 11,980 km of 220 kV circuits (triad lines), which together make 21,762 km, and 20,401 km of 150-132 kV lines (data for 2000). Over 95% of installed power at electricity production sites, about 10% of existing high and very high-voltage final users, and nearly all high-voltage distribution networks are at present connected to the national transmission network.
In view of the structure and characteristics of this network it is not possible to exchange electricity between the different parts of the country under all operating situations and needs. In accordance with Legislative Decree 79/1999 the Network Operator has the sole concession for transmission over the national network and despatching throughout the country. Ownership of the network, however, remains almost exclusively in the hands of the Enel Group.

With regard to interconnection with neighbouring countries, in 2001, following up-grades to some of the lines, the maximum transmission capacity rose from 6,300 MW (January-April 2001) to 6,500 MW (October-December 2001). The connection between Italy and Greece, consisting of 207 km of 400 kV continuous current lines, was completed in 2001 and is scheduled to come on line by the end of summer 2002.

Technical and economic regulatory action on the electricity transmission grid and transportation service

Transportation tariffs: the Integrated Text

In order to standardise the regulations governing the transportation of electricity for the free and captive markets, which were introduced at different times and through different provisions with respect to the liberalisation of the sector that began in March 1999, with Decision 228/2001 the Authority reformed and simplified the regulations governing transmission for eligible customers. At the same time, it grouped together in a single text (the Integrated Text) all the regulatory provisions governing charges for the transmission, metering and sale of electricity on both the free and captive markets. To cover infrastructure costs for the transmission network, the Integrated Text envisages special charges on distribution and production companies, who pay the Network Operator a fee for each kWh entering the grid. The direct charge on producers for the transmission service is negligible and covers only a small part of the costs sustained by the Network Operator for the activities within its remit. This approach is intended to avoid potential distortions, whether of competition between producers or of the balancing price of electricity day-before markets, especially in the light of the introduction of the bidding system

With regard to the charges on distribution companies the Integrated Text envisages that the Network Operator should charge them a specific tariff component (CTR) on the net electricity withdrawn from the national grid and from plants owned by final customers with high-voltage connections.

In the case of electricity produced by plants connected to medium and low-voltage transmission networks, or distributed generation, the Integrated Text introduces a provision allowing producers for part of the avoided cost of transportation over the transmission network.

The cost of the transmission infrastructure weighs most heavily on the owners of portions of the national network, who are also responsible for running and maintenance, and to a much smaller degree on the Network Operator. Therefore the charges for the electricity transmission service, which producers and distribution companies directly connected to the national grid pay to the Network Operator, are transferred to the owners under arrangements envisaged by the standard agreement approved in the Ministry of Industry decree of 22 December 2000.

This agreement envisages that the owners of portions of the national transmission network should pay the Network Operator an annual rent set by the same Network Operator. The annual rents applied to owners are based on the asset costs of the portion of network owned by each, running and maintenance costs and an allowance for technical and economic amortisation.

Technical and economic regulatory action on the despatching service

With Decision 95/2001, the Authority set out the conditions under which the Network Operator should provide the electricity despatching service on a nationwide basis according to merit order criteria. The Decision sets out the arrangements whereby the Network Operator provides the resources needed to maintain the balance between electricity inputs and withdrawals and manage network congestions, and the conditions for the allocation to operators of the rights to use transmission capacity. These envisage the creation of special markets for the supply of reserve production capacity, and resources to solve congestions and ensure that the system is balanced. The management of these markets is entrusted to the Market Operator on the basis of an agreement with the Network Operator as envisaged by Decision 95/2001.

In order to provide operators with a reasonable degree of certainty in the allocation of transmission rights, the country needs to be divided into a limited number of zones defined by the Network Operator and approved by the Authority, and the boundaries of these areas need to be stable over time. For the

electricity exchange's first two years in operation, the Network Operator has been allowed to change the boundaries of these zones, under Authority supervision.
The decision envisages that the right to use transmission capacity between the zones should be allocated in the day-before market, taking transmission constraints into account when determining the input and withdrawal programmes established in that same market. Consequently, in the presence of tight constraints on transmission (congestions), a differential is produced between one zone and another in electricity sale and purchase prices. The unit charge for transmission capacity rights of use as set by the Authority corresponds to the market price differential between the zones where the electricity enters the network and those where it leaves.
On the basis of the conditions set out in Decision 95/2001, the Network Operator has drawn up and submitted to the Authority a set of despatch rules that provides a regulatory framework with which the operator itself will have to comply. The Authority has formulated binding observations on these, which the Network Operator will be required to take into account when it draws up the final rules.

Transitional measures

Pending the introduction of merit order despatch as provided for by the Authority, the reform of transmission charges described above required transitional measures to be introduced to regulate the electricity despatching service to replace those previously laid down by Decision 13 of 18 February 1999.
These regulations (Decisions 317 of 27 December 2001 and 36 of 7 March 2002), which have been in force since early 2002, introduce conditions for the despatching service for free market customers, electricity producers and self-producers. Using simplified mechanisms based on administratively set charges, the aim is to provide operators with economic indicators of the costs their actions impose on the electricity system, the aim being that the system will eventually be based on the economic merit of the resources selected.
Relations between the Network Operator and the operators to which the despatch service is provided are set out in electricity balancing and exchange contracts. To enable the Network Operator to plan the resources needed to maintain the security of the system, operators are required to provide details of their planned input and withdrawal on a weekly basis; the extent of any deviations in actual input and withdrawal levels with respect to those planned are determined *ex post*.
Until a specific market has been set up that determines the cost to the system for each hour (or less) of the resources required to compensate for such unplanned deviations, the charge to the operators responsible (balancing charge) is set administratively[4]. Under the transitional regulations it is possible to charge free customers for the amounts of electricity withdrawn and not injected at a rate that is equal to the price they would have paid if they had remained in the captive market, net of the discount for the component covering the average charge for imbalances. Whether or not this additional charge for the imbalance costs is actually applied depends on the operator's ability to control and predict its load accurately and is therefore an incentive for more accurate planning.

THE MARKET FOR THE SALE OF ELECTRICITY TO ELIGIBLE CUSTOMERS

Over the last year the number of consumers benefiting from the liberalisation of the electricity market has risen by almost 35%, with an increase from 7,780 to 10,581 in the number of withdrawal sites. The

[4] For the evaluation of the differences between the electricity injected and withdrawn by operators in the free market, the Authority has provided for the final balance to be drawn up on a bi-monthly basis; it has also introduced the possibility for exchanges between operators of any differences emerging at the end of each bi-monthly period, if these operators are entitled to buy and sell electricity on the free market. The price of the electricity used at the end of each two months to evaluate the difference between the electricity injected and withdrawn corresponds to the price of wholesale electricity set by the Authority for the captive market, net of the component covering the cost of maintaining the balance between injections and withdrawals.

potential electricity consumption of these sites, with reference to the last statements available, increased by 28% from 97 to 124 TWh.

Taking an overall requirement of 305 TWh in 2001, this corresponds to a degree of market opening of about 41%. The quantities of electricity actually purchased on the free market are, however, considerably lower.

The steepest increase was for final customers belonging to consortia and national companies with more than one offtake point. It must be underlined in this respect that the trend in the various types of eligibility is a reflection not so much of a preference expressed by final costumers as of the different organisational commitment required to attain the eligibility thresholds set by Legislative Decree 79/1999 and of the legislative and regulatory changes of January 2001 and 2002 in conditions for the recognition of eligibility. The increase in the number of final customers with sufficiently high consumption to meet the eligibility requirement without needing to form groups of companies or consortia has been rapid; 75% of final customers who are eligible on their own account had been recognised as such by April 2000. The increase in the number of companies and groups of firms has, however, been slower. In view of the need to organise a large number of operators, the trend in applications from consortia for the recognition of eligible status has been even slower, but still fairly strong.

National multi-site operators (established with effect from January 2002) are at present the most dynamic sector, often growing at the expense of groups of companies and consortia. The characteristics described here are reflected in the trend emerging at the regional level. Here, the significant variability in the degree of market opening can be explained more in terms of concentrations of energy-consuming industries than of a greater or lesser propensity to enter the free market. In regions with a preponderance of high energy-consuming industries (led by Friuli Venezia Giulia, Umbria, Sicily and Sardinia), the granting of eligibility to the biggest plants had already led to a degree of market opening of about 50% or more in 1999; since then, the addition of other smaller plants (often consortium members) has not translated into a significant increase in consumption levels by eligible customers. In other regions with a more evenly distributed industrial structure (such as Trentino Alto Adige, Emilia Romagna, Tuscany and the Marches), the opening of the market (to a large extent resulting from the role played by small companies grouped in consortia) has been much slower, and in most cases accounts for no more than 40% of the overall requirement.

A clear confirmation of this trend can be found in average consumption broken down by withdrawal site, which fell abruptly in almost all regions between 1999 and 2000, and continued to fall when eligibility was granted to a growing number of small firms grouped into consumption consortia.

The lowering of the threshold to 20 GWh with effect from 1 January 2001 has played a part in reducing average consumption, although not to a decisive extent, compared with the effect of the very marked growth in the number of consortium members. In terms of withdrawal sites these companies have increased almost 20-fold over the last year with respect to individual final customers: 1,921 consortium members compared with 104 individual final customers.

TAB. 15 EVOLUTION OF ELIGIBLE CUSTOMERS FROM OCTOBER 1999 TO APRIL 2002

	Oct-99	Apr-00	Apr-01	Apr-02
Eligible customers (number)	**322**	**750**	**1088**	**1388**
Final customer	271	529	604	708
Group	19	58	77	91
Company	15	41	81	103
Consortium	13	97	272	352
Consortium member	4	25	54	86
National multi-site	-	-	-	48
Consumption sites	**656**	**3711**	**7929**	**10581**
Final customer	271	529	604	708
Group	90	429	506	548
Company	36	102	215	335
Consortium	157	2019	5084	6812
Consortium member	102	632	1520	1713
National multi-site	-	-	-	465
Consumption (TWh)	**36.7**	**79.7**	**97.1**	**124.2**
Final customer	30.8	56.1	58.4	69.7
Group	2.8	5.2	8.1	7.4
Company	1.6	2.7	4.4	5.4
Consortium	0.9	9.0	20.2	26.6
Consortium member	0.6	6.7	5.9	10.5
National multi-site	-	-	-	4.6
Consumption by site (GWh)	**56.0**	**21.5**	**12.2**	**11.7**
Final customer	113.8	106.0	96.7	98.4
Group	31.0	12.2	15.9	13.6
Company	45.1	26.9	20.4	16.1
Consortium	5.5	4.4	4.0	3.9
Consortium member	5.9	10.5	3.9	6.1
National multi-site	-	-	-	9.9

There was a considerable boost in eligibility applications towards the end of 2001, with significant effects on the trends for the different types of eligibility. This was caused by the imminent lowering of the eligibility threshold to 9 GWh with effect from 1 January 2002 and the extension of recognition to those final customers with overall consumption of over 40 GWh, taken as the sum of their consumption at various metering points within the geographical area of affiliated companies. The increase in applications was much greater than expected, probably because most customers with consumption of between 9 and 20 GWh/year already had access to the free market through consortia or other forms of aggregation. Many medium-sized companies preferred to wait for the threshold to be reduced to 9 GWh/year rather than turn to purchasing consortia, even on a temporary basis.

From November onwards, about 40% of new applications for eligibility were a direct result of the lowering of the threshold. Less than one third of these referred to sites already granted eligibility as a result of membership of consortia. In a significant number of cases the applications were for changes in eligibility status as a result of company re-groupings. A rapidly growing number of applications received from November onwards concerned the recognition of eligibility, in the form of national multi-sites, of sites previously considered eligible as members of consortia or groups of firms.
Finally, a considerable number of applications concerned moves from one consortium to another. Competition between consortia for final customers, whether new or already members of other consortia, seems to have intensified in 2002, with the consolidation of the most successful consortia.
Applications for recognition increased by about 50-60 offtake points a week on average, to over 300 in December 2001, and stayed at this level throughout January 2002. Factors contributing to this increase included the deadlines for the allocation of import capacity and auctions, as laid down by CIP 6/92. These deadlines resulted in a rush for the recognition of new sites, some of them in the form of consortia.

The entry of new operators to the free market in 2002

The flow of applications only returned to more normal levels towards the end of March 2002. However, other steep rises are expected in 2002, as a result of two new factors: access to the free market by municipal authorities and a further lowering of the threshold, to 100 MW/year[5].

[5] Art. 10 of Law 57 of 5 March 2001 further lowered the eligibility threshold to 100 MW/year “with effect from the ninetieth day from the sale by Enel of not less than 15,000 MW of production capacity”. This reduction considerably increases the potential number of eligible customers, which can be estimated at around 100,000, including a large number of small commercial businesses.

TAB. 16 TREND IN GRANTING OF ELIGIBILITY TO FINAL CUSTOMERS FROM OCTOBER 1999 TO APRIL 2002

	Total Consumption (TWh)				Number of sites				Consumption by site (GWh)				Degree of opening (%)			
	Oct-99	Apr-00	Apr-01	Apr-02	Oct-99	Apr-00	Apr-01	Apr-02	Oct-99	Apr-00	Apr-01	Apr-02	Oct-99	Apr-00	Apr-01	Apr-02
Valle d'Aosta	0.1	0.3	0.3	0.3	1	2	2	3	52.3	148.6	142.9	100.3	7.9	43.9	44.4	45.7
Piedmont	4.6	7.6	9.9	13.7	101	342	915	1,164	45.9	22.3	10.8	11.7	23.8	40.3	50.0	66.3
Lombardy	10.0	21.3	22.9	33.8	211	1,081	2,400	3,195	47.3	19.7	9.5	10.6	22.5	47.7	47.5	67.7
Liguria	0.5	1.0	1.3	1.6	4	55	125	174	119.8	17.9	10.3	9.2	11.1	24.8	31.5	35.8
Veneto	3.9	9.9	10.9	12.7	147	802	1,214	1,536	26.5	12.3	9.0	8,3	19.0	47,6	49,4	54.8
Trentino Alto Adige	0.8	1.2	1.6	1.9	11	126	229	259	73.9	9.6	7.0	7.5	21.2	33.3	42.4	47.7
Friuli Venezia Giulia	2.9	4.1	4.7	4.8	23	213	330	401	125.9	19.3	14.3	12.0	41.8	60.4	66.4	65.2
Emilia Romagna	1.5	4.8	7.1	9.3	36	305	801	1,093	42.3	15.8	8.8	8.5	9.3	29.5	40.8	50.7
Tuscany	3.0	4.6	5.9	7.0	32	243	618	753	92.6	18.7	9.6	9.3	22.1	33.8	42.0	46.9
Marche	0.4	1.2	1.5	1.8	10	132	227	343	44.5	9.0	6.5	5.3	10.6	27.8	31.1	36.4
Umbria	1.9	2.4	2.9	2.9	7	37	117	129	267.8	65.0	24.5	22.1	44.7	56.9	65.3	61.5
Lazio	1.1	2.6	4.9	5.7	17	166	346	476	67.1	15.8	14.0	11.9	9.5	22.1	38.8	41.8
Abruzzi	0.8	1.8	2.1	2.5	10	34	128	199	81.0	51.8	16.7	12.7	18.3	39.2	44.9	50.3
Molise	0.0	0.0	0.1	0.5	-	-	6	48	-	-	15.5	10.5	0.0	0.0	9.9	50.8
Campania	0.9	1.8	2.4	4.9	13	52	133	217	68.5	33.9	17.9	22.6	10.1	20.2	26.8	50.8
Puglia	1.2	3.1	3.9	5.0	12	42	104	218	99.8	72.7	38.0	22.7	11.3	28.3	35.1	41.5
Basilicata	0.2	0.3	0.6	0.9	3	24	57	76	54.1	12.6	10.9	12.1	9.6	17.3	34.8	59.5
Calabria	0.4	1.1	0.9	0.8	3	11	27	37	122.1	99.2	34.1	22.1	13.8	49.6	39.4	32.6
Sicily	1.7	5.7	7.2	7.3	10	34	97	151	167.9	168.7	73.9	48.5	16.7	53.3	62.5	61.1
Sardinia	0.9	4.9	6.0	6.7	5	10	53	109	183.6	494.7	113.6	61.0	11.9	61.6	70.0	76.7
Italy	**36.7**	**79.7**	**97.1**	**124.2**	**656**	**3,711**	**7,929**	**10,581**	**56.0**	**21.5**	**12.2**	**11.7**	**18.6**	**39.5**	**45.5**	**56.6**

The activity of the Authority in the promotion of competition in sales to eligible customers

Allocation of import capacity for 2002

Authority initiatives which contributed to the promotion of competition in sales to eligible customers include the provision for the allocation of transportation capacity on interconnection lines for electricity imports and exports (Decision 301/2001).

In drawing up the rules for electricity imports in cases of low interconnection capacity, the Authority's aim was to maximise Italian eligible customers' contractual power with respect to foreign operators, given the fact that average European prices for electricity are significantly lower than Italian prices.

The arrangements for the allocation of capacity on the north-western border, which amounts to 1,800 MW (net of long-term contracts for the captive market), were agreed by the Italian Energy Authority and the French *Commission de Régulation de l'Electricité*. The agreement between the two Authorities created the first electricity free trade area in Europe. The usual direct agreements between companies and network operators have been replaced by reliable, transparent rules applied under equal conditions to all operators concerned (traders, wholesalers and free customers).

The allocation arrangements envisage a primary pro-rata distribution in bands of over 3 MW, on the basis of applications received by the network operator, and the creation of a monthly and weekly secondary market for supply adjustments. Spot supplies, and any new capacity becoming available in the course of the year, will be handled on the secondary market. To avoid speculation or attempts to snap up scarce, freely allocated resources, only final customers and operators already connected to them may take part in the pro-rata allocation and secondary market.
With Decision 301/2001, the available capacity bands for interconnection with neighbouring countries were allocated on both the eastern and western borders. About 31% of the 1,953 MW available overall were assigned for a three-year period (2002-2005) to 48 final costumers agreeing to unannounced interruptions, with the remaining 69% allocated on an annual basis to 74 operators.

Sale on the free market of electricity produced from renewable sources

For 2002 the Authority has defined the competitive procedures for the sale on the free market of incentivised electricity produced from renewable and assimilated sources. As was the case for 2001, the allocation mechanism consists of three separate auctions: the first is reserved for eligible final customers subject to unannounced interruptions in supply; the second for customers subject to interruption with notice; and the third is open to all. The auctions start from a base price set by ministerial decree. The results of the bids for annually assigned production capacity (up to 4,500 MW allocated continuously) were as follows:

- the production capacity reserved for final customers willing to accept unannounced interruptions amounting to 500 MW was allocated at an average price of around 0.01243 euros/kWh, to which should be added 67.6% of the CT parameter as last up-dated by the Authority;
- 820 MW of the 1,500 MW of production capacity reserved for final customers agreeing to interruptions with notice were allocated at an average price of 0.01493 euros/kWh, to which should be added 67.6% of the CT parameter as last up-dated by the Authority;
- of the remaining production capacity available on an annual basis, 2,290 MW were allocated at an average price of 0.02427 euros/kWh and the remaining 890 MW at an average price of 0.02428 euros /kWh, to which should be added 67.6% of the CT parameter as last up-dated by the Authority.

The Network Operator, to which producers sell electricity at incentivised prices, also organises the auctions. None of the participants may acquire more than 20% of the electricity available at each auction, or over 15% of the electricity available overall. In the wake of the complaint submitted by Enel, the Regional Administrative Court (TAR) of Lombardy partly suspended the mechanism set out above. To provide operators with the necessary degree of certainty concerning actual availability in 2002, the Authority decided not to appeal against the TAR ruling; it also raised the ceiling on overall purchases by any one operator over the three auctions, two of which have already been completed, from 15 to 20%. The same limit is envisaged for the secondary market.

TAB. 17 PRICE OF INCENTIVISED ELECTRICITY PRODUCED FROM RENEWABLE AND ASSIMILATED SOURCES 2001

	Electricity GWh	**Price** Lire/kWh	**Price** Eurocents/kWh
Interruptible without notice	4,322	77.6	4.007
Interruptible with notice	3,848	80.8	4.173
Others	26,132	105.4	5.443
Total Free market	**34,303**	**99.1**	**5.118**
Sales to Captive market	**20,200**	**130.2**	**6.724**
Average sales price to free and eligible market	**54,503**	**110.6**	**5.712**

DISTRIBUTION AND SALE TO THE CAPTIVE MARKET

The local distribution monopoly and the market supplying captive customers

Rationalisation and development of distribution along pluralistic lines

Under the terms of Legislative Decree 79/1999 only one distribution concession should be issued for each municipality (with the exception of the provisions set forth in Art. 16 of the same decree regarding the autonomous regions and provinces). Distribution companies in which local authorities have holdings may ask Enel to sell or transfer distribution branches in municipalities where they serve at least 20% of users.

In 2001 and the early months of 2002, 44 companies supplying 67 municipalities applied for distribution concessions from the Ministry of Industry. Further concessions have still to be issued to municipalities distributing electricity under special economic terms and to Enel itself.

The divestment by Enel Distribuzione S.p.A. of portions of the distribution network in municipalities such as Rome, Turin, Trieste and Parma, which cover over one million final customers, has also been completed.

In other municipalities, such as Sondrio and Imola, Enel Distribuzione has already reached agreement (and will soon be signing the contract) for the sale of its portion of the distribution network. A similar anegotiation, covering over 500,000 final customers, has still to be concluded for other municipalities, including Milan, Verona, Modena, Vicenza, Sanremo, Trani, Terni, Vercelli and Gorizia. Pursuant to Art. 9.4 of Legislative Decree 79/1999, the transfer should have been completed by 31 March 2001; in some cases, however, the parties have failed to reach agreement on the sale and have resorted to arbitration.

Again in 2001 and the early months of 2002, Enel Distribuzione in its turn acquired distribution undertakings that account to date for less than 10,000 final customers.

Economic regulation of distribution

The transportation service for final customers

The Integrated Text, which simplified the rules governing transportation services, envisages a mechanism for final customers, similar to the one set forth in Decision 204 (repealed) of 29 December 1999, regulating supply to captive customers. The Authority therefore defined the tariff constraints within which distributors have a degree of flexibility to propose their own tariff options. Distributors have until 15 November 2001 to submit their basic and special tariff options for the transportation service for 2002, to be applied to users from 1 January of that year. Decision 322/2001 contained the results of the Authority's evaluation of the proposed tariff options for the basic and special transportation services, and rejected any options that were not compatible with the Integrated Text. The Decision also envisaged a tariff system to be applied to operators for the period 1 January 2002 to 31 December 2002 for contractual categories other than domestic users, for whom no basic tariff options were in force at 1 January 2002 for the transportation service.

Overall, the Authority evaluated basic transportation tariff options submitted by 174 distributors and special options submitted by 39 distributors. The approved options were published on the Authority's Internet site.

Connection to electricity networks

Within the framework of the universal service guarantees, the Authority began work on reforming the rules governing connections, with particular reference to access to networks with compulsory third-party connection. The first step was Decision 50/2002, which sets out the conditions governing the connection service to electricity transmission or distribution networks with nominal voltage of over 1 kV. In this context, and in view of the objective of promoting competition and efficiency, the Authority introduced more flexible arrangements for the definition of the rights and duties of network users (both final customers and generators) and operators. In particular, network users will have the option of applying for connection to the local distribution network rather than the national transmission network, taking any technical restrictions into due account. For this purpose the distributor and Network Operator will propose their own connection formula to each user, along with the respective technical and pricing conditions, leaving it up to users to choose whichever solution they find most attractive. It is worth noting that, regardless of this new degree of flexibility, distributors and the Network Operator are still required to connect users to the electricity network if they so request.

Economic regulation of sales to captive customers

Sales to non-domestic captive customers

With regard to the conditions governing sales to captive customers with contracts other than those envisaged for low-voltage domestic users, the Integrated Text included a component to cover the costs of purchasing and selling electricity, known as the CCA component. Set directly by the Authority, this is up-dated on a bi-monthly basis and, for final customers with appropriate meters, is divided into hourly bands. For other customers it is not differentiated. Distributors therefore have the option of providing "further" tariff options for the sales service, which their customers can choose as an alternative to the CCA component. For 2002, 11 distributors submitted additional options. The Authority reviewed and published the options meeting with approval in Decision 322/2001 and posted them on its Internet site.

The sales service for domestic customers

In the case of captive customers with low-voltage domestic contracts, the system envisaged by the Integrated Text provides greater protection than for customers as a whole. In accordance with the system introduced by Decision 204/1999, the Authority sets administered tariffs which each distributor is required to offer its domestic customers. These are designed to cover the costs of the transportation, purchase and sale of electricity to low-voltage domestic customers. Distributors have the option of offering their domestic users "further" tariff options, with different features from the obligatory tariffs, which they consider to be more in keeping with their clients' needs.
The administered tariffs set by the Authority envisage:

- tariff D2, applied to contracts for homes (where the customer is normally resident) with reserved power of no more than 3 kW;
- tariff D3, applied to contracts for homes (where the customer is normally resident) with reserved power of more than 3 kW and to contracts for homes in which the customer is not normally resident;
- a standard tariff, D1, for all customers with low-voltage domestic contracts, which is due to come into force in 2003.

For 2002, the levels of tariffs D2 and D3 were set in Decision 316/2001. These levels are provisional and take into account the fact that the tariff adjustments envisaged as part of the process of gradually bringing tariffs D2 and D3 into line with tariff D1 would have resulted in increases for domestic customers with effect from 1 January 2002.
These increases would also have affected economically disadvantaged customers, for whom the special conditions envisaged in the new tariff structure have still to be defined.

Transportation service on the distribution networks and the sales service to distribution firms

In addition to regulating electricity transportation and sales services to final customers the Integrated Text also introduces specific rules to regulate the provision of transportation services to distribution companies and electricity producers. These include the charges to be paid by electricity distributors and producers for transportation over the national transmission and distribution networks.
The Integrated Text also incorporates the regulations envisaged by Decision 205/1999 concerning the arrangements for the supply of electricity to captive customers. Consequently, the Authority has set the

fees for the sales service to distribution companies until such time as the Single Buyer S.p.A. begins operating. Any distribution company buying electricity is required to pay the wholesale price for whichever quantity is intended for its captive customers. The wholesale price for electricity for 2002 was set in Authority Decision 308/2001.

Annual adjustments of parameters and constraints

In Decision 163/2001 the Authority up-dated for 2002 the tariff constraint parameters (components of TV1 tariff options) and tariff D1 for the transmission, distribution and sale of electricity, using the price cap method as envisaged by Decision 204/1999.
The value of each tariff component was adjusted by applying to its value for the previous year both the inflation rate as calculated from June 2000 to May 2001, 2.8%, and the annual rate of reduction of allowed fixed unit costs, which for the first regulatory period (2001-2003) was 4%. The variations in allowed transmission costs resulting from changes in the legislative framework, and in allowed costs for distribution on the medium and low-voltage networks as a result of improvements in service quality, were also taken into consideration for adjustment purposes.

Bi-monthly adjustments

From the first bi-monthly period of 2001 to the equivalent period in 2002 the allowed unit cost of fuel (Vt) pursuant to Art. 6, paragraph 6.8, of Decision 70/1997 as amended and supplemented by subsequent Decisions, fell from 44.081 lire/Mcal (0.02277 euros/Mcal) to 31.871 lire/Mcal (0.01646 euros/Mcal). This reflects the fall in fuel prices in US dollars on the international markets and the revaluation of the euro against the dollar. Over the period under consideration the fiscal component of the allowed unit cost of fuel remained unchanged. The rates of excise duty on mineral oils and taxes on coal consumption as set by the Prime Minister’s Decree of 15 January 1999 did not change in 2001. in view of the greater efficiency of the country’s thermoelectric generating plants, when the tariff adjustment was made for the first bi-monthly period in 2001 the average consumption index (Rt) was reduced to 2,260 kcal/kWh. As a result of the changes in Vt and Rt, the allowed cost for electricity produced by thermoelectric plants using commercial fossil fuels (Ct) fell from 99.623 lire/kWh (0.05145 euros/kWh) in the first two months of 2001 to 72.042 lire/kWh (0.03720 euros/kWh) in the first two months of 2002.
During the period under review the Authority also adjusted the rates of tariff components A and UC, with the result that tariff components A2, A3 and A6 were increased. These are used to finance, respectively, the account for the funding of residual nuclear activity, the account for new plants using renewable and assimilated sources and the account for the reimbursement to production and distribution companies of the costs sustained for the generation of electricity in the transition stage.
In the fourth bi-monthly period of 2001 the Authority increased tariff component A2 by 0.4 lire/kWh (0.0002 euros/kWh) in order to generate the revenue needed to cover the cost of dismantling decommissioned nuclear generating stations, the closure of the nuclear fuel cycle and related activities.
In 2001 the average rate of tariff component A3 rose by about 7 lire/kWh (0.003 euros/kWh) as a result of variations involving more than one bi-monthly period. This was a consequence of the increased revenue requirement resulting from the transfer by Enel to the Network Operators of rights and obligations relating to the purchase of electricity (produced by other national operators), and of the bidding procedures envisaged by the Ministerial Decree of 21 November 2000.
Another factor contributing to the increases in tariff component A3 was the reduction in the value of parameter Ct; this led to a reduction in the revenue from the provisions compensating for the greater value of the electricity produced by hydroelectric and geothermoelectric plants. In the third bi-monthly period of 2001, the Authority increased tariff component A6 by about 1.8 lire/kWh (0.0009 euros/kWh) following the entry into force of the Decree issued on 17 April 2001 by the Minister of Industry, acting in concert with the Minister for the Treasury, excluding hydroelectric and geothermoelectric plants with a nominal power greater than or equal to 3 MW, which are not entitled to the special terms.

Tariff component UC2, which finances the account compensating for the greater value of electricity during the transition stage, was eliminated, since the funding requirement for the additional revenue component pursuant to Art. 6 of Decision 205/99 no longer applies. This component had already been cancelled with effect from the first bi-monthly period of 2001 as the requirement was covered by the revenue from the "hydroelectric yield".

TAB. 18 BI-MONTHLY VARIATIONS IN ELECTRICITY TARIFF COMPONENTS
Average national rates for A and UC components [(A)]

Authority Decision	Effective from	Ct[(B)] Lire/kWh	A2 Lire/kWh	A3 Lire/kWh	A5 Lire/kWh	A6 Lire/kWh	UC4 Lire/kWh	Ct[(B)] euro-cents/kWh	A2 euro-cents/kWh	A3 euro-cents/kWh	A5 euro-cents/kWh	A6 euro-cents/kWh	UC4 euro-cents/kWh
244/00	1 Jan 2001	99.62	0.6	4.8	0.6	0.9	-	5.145	0.031	0.248	0.031	0.046	-
27/01	1 March 2001	95.96	0.6	9.6	0.6	0.9	-	4.956	0.031	0.496	0.031	0.046	-
90/01	1 May 2001	83.55	0.6	11.4	0.6	2.7	-	4.315	0.031	0.589	0.031	0.139	-
146/01	1 July 2001	83.55	1.0	11.4	0.6	2.7	-	4.315	0.052	0.589	0.031	0.139	-
189/01	1 Sept 2001	83.55	1.0	11.4	0.6	2.7	-	4.315	0.052	0.589	0.031	0.139	-
242/01	1 Nov 2001	79.19	1.0	15.5	0.6	2.7	-	4.090	0.052	0.891	0.031	0.139	-
319/01	1 Jan 2002	72.03	1.0	14.5	0.6	2.7	0.5	3.720	0.052	0.749	0.031	0.139	0.026
24/02	1 March 2002	68.04	1.0	18.5	0.6	2.7	0.5	3.514	0.052	0.955	0.031	0.139	0.026
69/02	1 May 2002	70.50	1.0	18.5	0.6	2.7	0.5	3.641	0.052	0.955	0.031	0.139	0.026

(A) The national average rates were determined by including the consumption of all final customers, including those eligible for special consumption tariffs in accordance with part IV of the Integrated Text. Consequently, component A4, which results from the exemption of special categories from the payment of system costs, cannot be shown in the table. Component UC2 was eliminated as a result of Decision 244 of 29 December 2000.
(B) Trend in the allowed variable unit cost of electricity produced by thermoelectric installations using commercial fossil fuels.

TAB. 19 TARIFF COMPONENTS A AND UC

User category	A2	A3	A4	A5	A6	UC4
	Euro-cents/offtake points/year					
Low-voltage domestic	-	-	-	-	-	-
Low-voltage public lighting	-	-	-	-	-	-
Low-voltage with power < 1.5 kW	-	-	-	-	-	-
Low-voltage with power > 1.5 kW	371.85	4,469.37	-	366.68	-	-
Medium-voltage public lighting	-	-	-	-	-	-
Others, medium-voltage	371.85	3,718.79	-	366.68	-	-
High and very high-voltage	371.85	4,689.96	-	366.68	-	-
	Euro-cents/kWh					
Low-voltage domestic	0.08	0.83	0.11	0.05	0.15	0.04
Low-voltage public lighting	0.05	0.98	0.21	0.03	0.15	-
Low-voltage with power < 1.5 kW	0.08	0.83	0.21	0.05	0.15	0.03
Low-voltage with power > 1.5 kW	0.04	1.03	0.21	0.02	0.15	0.03
Medium-voltage public lighting(3)	0.04	0.82	0.21	0.02	0.15	-
Others, medium-voltage(3)	0.04	0.88	0.21	0.02	0.15	0.02
High and very high-voltage(3)	0.04	0.84	0.21	0.02	0.15	0.01
	Euro-cents/kWh					
Primary aluminium	0.04	0.84	-	0.02	-	-
Ferrovie dello Stato Spa (1)	0.04	0.84	0.21	0.02	0.15	-
Ferrovie dello Stato Spa, Società Terni Spa and related (2)	-	-	-	-	-	-
Franchise holders (4), coastal municipalities	-	-	-	-	-	-

(1) For quantities of electricity for traction in excess of those envisaged by Art. 4.2 of Presidential Decree 730/1963.
(2) Within the quantitative limits envisaged respectively by Art. 4.2 of Presidential Decree 730/63 and by Art. 6 of Presidential Decree 1165/1963.
(3) For monthly consumption in excess of 8 GWh, components A2, A3, A4, A5 and A6 are eliminated.
(4) Users whose water supply has been diminished or interrupted by the construction of a hydroelectric power plant, to whom a special tariff system applies.

SYSTEM COSTS

Legislative Decree 79/1999 envisages that the general costs of the electricity system should be set through one or more decrees issued by the Minister for Productive Activities in concert with the Treasury Minister on the basis of Authority proposals. Following this procedure, the Decree issued by the Ministries of Industry and the Treasury on 26 January 2000, which takes into account the Authority proposal submitted formally to the Government in Decision 138/1999, lists the following general costs:

- reimbursement to production and distribution companies of the non-recoverable part of the costs sustained for the generation of electricity following the implementation of European Directive 96/92/EC (stranded costs);
- compensation for the greater value, resulting from the implementation of European Directive 96/92/EC, of electricity produced by hydroelectric and geothermoelectric plants which at 19 February 1997 were owned by or at the disposal of production-distribution companies (known as the “hydroelectric yield”);
- costs relating to the dismantling of decommissioned nuclear power stations, the closure of the nuclear fuel cycle and related activities (nuclear costs);
- costs related to research and development with a view to technological innovation of general interest to the electricity system;
- application of favourable tariff conditions for the supply of electricity, envisaged by the provisions of Art. 2.2.4 of Decision 70/1999 and by the Minister of Industry decree of 19 December 1995.

Finally, the general costs also include part of the costs arising from the tasks entrusted to the Network Operator by Art. 3.12 of Legislative Decree 79/1999. These include:

- electricity withdrawals by the Network Operator as a result of the transfer of the rights and obligations previously falling to Enel with regard to the purchase of electricity produced by other national operators, in accordance with the Ministerial Decree of 21 November 2000;
- the withdrawal of electricity governed by Art. 22.3 of Law 9/1999 and offered by producers at prices set by the Authority;
- electricity withdrawals by the Network Operator in connection with the production governed by Title IV b) of CIP 6/92 (production-distribution companies).

Incentives for renewable and assimilated sources

The provisions contained in the Ministry of Industry Decree of 21 November 2000 change the arrangements for the determination of the greater cost of producing electricity from renewable and assimilated sources and the way this cost is divided between the operators withdrawing the electricity and final consumers.
The higher cost, to which CIP 6/92 incentives apply, is funded through a special account in the *Cassa Conguaglio* Equalisation Fund for the electricity sector. This in turn is financed by tariff component A3 and the revenue from the "hydroelectric yield" envisaged by the Ministry of Industry Decree of 26 January 2000. Allocation through a bidding procedure has resulted in a price that is lower than the wholesale price of electricity for the captive market.

Funding arrangements

General costs are funded by "A" Tariff Components, which are set by the Authority. These adjust the charges for the electricity transportation service over networks with obligatory third party access. The Integrated Text currently envisages the following tariff components:

- tariff component A2, covering costs connected with the dismantling of decommissioned nuclear power stations, the closure of the nuclear fuel cycle and related activities;
- tariff component A3, covering costs sustained by the Network Operator pursuant to Art. 3.12 of Legislative Decree 79/1999;
- tariff component A4, for the equalisation of the subsidies replacing the special tariff systems;
- tariff component A5, covering system research costs;
- tariff component A6, to reimburse production-distribution companies for costs sustained in electricity production during the transition;
- tariff component A7, covering the greater value of electricity produced by hydroelectric and geothermoelectric plants.

The revenue from the application of these components is managed through the *Cassa Conguaglio* Equalisation Fund. Transportation companies pay the sums deriving from the application of the "A" tariff components at set intervals in accordance with the electricity transportation service provided over the bi-monthly period in question.

METERING

The electricity metering service is currently regulated, on a transitional basis, by Articles 28 to 33 of the Integrated Text. During this period the Authority felt that this service to final customers should continue to be provided by the transportation company, as the operator providing customers with tariff options. Additionally, to ensure that the changeover from the sole provider system to one in which a range of operators will be providing metering services is sufficiently gradual, the Authority opted to cover costs through a specific component in the transportation charge, and to introduce transitional provisions to

ensure continuity and reliability in the provision of this service. The aim was to identify the operators responsible for the different parts of the metering service, which is divided into installation and maintenance services and the reading and noting of electricity levels. This was done by establishing .
that the operator responsible for the installation and maintenance of the meters is:

- for withdrawal points, the operator providing the electricity transportation service for final customers withdrawing electricity from these points;
- for injection points for electricity production plants, the owner of the plant;
- for interconnection points with the national transmission network, the distribution company on whose network the points are located;
- for interconnection points between one distribution network and another, the distribution company selling electricity through these points;

and the operator responsible for reading and recording electricity levels is:

- for withdrawal points, the operator of the electricity transportation service for final customers withdrawing electricity from these points;
- for injection points located on a network with compulsory third party connection, the operator managing the network in question;
- for interconnection points with the national transmission network, the distribution company on whose network these points are located;
- for interconnection points between one distribution network and another, the distribution company selling electricity through these points.

ADMINISTRATIVE AND ACCOUNTING UNBUNDLING OF VERTICALLY INTEGRATED ELECTRICITY COMPANIES

With Decision 310/2001 the Authority carried out a partial review of the directives for administrative and accounting unbundling envisaged by Decision 61/1999. The review was carried out with the aim of:

- bringing these arrangements into line with the changed structural and regulatory context;
- harmonising the directives for operators in the electricity sector with those for operators in the gas sector;
- simplifying some of the obligations envisaged by Decision 61/1999.

These directives concern electricity operators who may already be up and running, such as electricity producers, self-producers, the Network Operator, distributors, and sellers to the free and captive markets, and operators who are not yet fully operational, such as the Market Operator and Single Buyer. An exemption is envisaged for small operators.
The need to adapt to the changed structural and regulatory framework required a redefinition of the activities carried out and a change in the way the information is broken down, revenue items in particular. The list of activities was extended to include metering, which may well develop along more competitive lines as it is not a naturally monopolistic activity.
As for simplification, firms were given more flexibility in the organisation of their accounts and specific rules were introduced for smaller electricity companies.

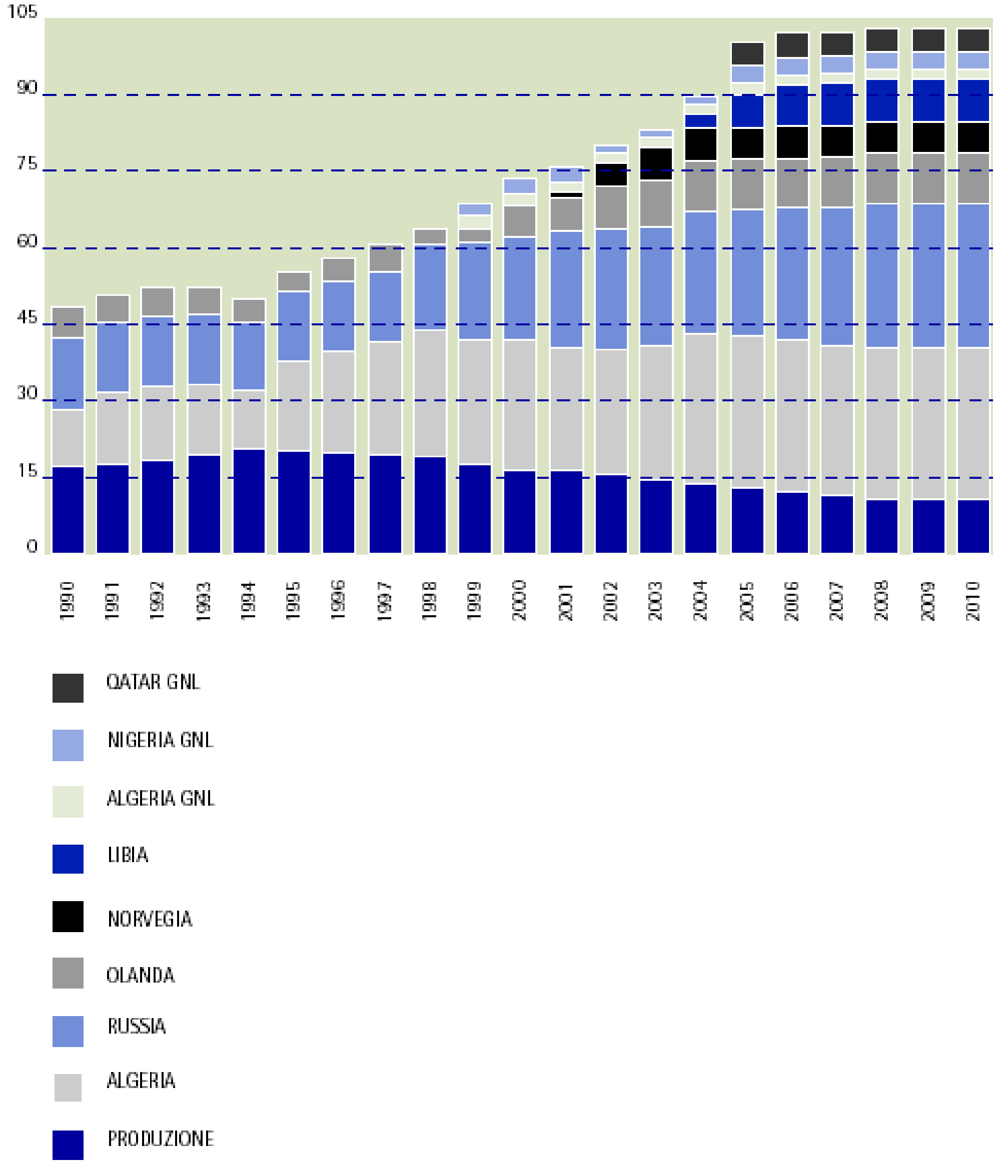
MARKET STRUCTURE AND REGULATION IN THE GAS SECTOR

STRUCTURE OF THE MARKET FOR PRODUCTION AND SUPPLY

The market for natural gas is made up of two segments: national production and imports. National production covers about 24% of the annual requirement and is falling, in absolute and relative terms, with respect to needs. There is one dominant operator in this first segment, ENI, which in 2001 accounted for 88% of total production. The second operator, Edison S.p.A., produces much of the remaining gas, with 12% of total production. Proved overall reserves amount to about 215 Gm^3, the equivalent of 13 years' production at current levels. The input from the Val D'Agri fields, developed by the Eni-Enterprise Oil Italiana consortium after complex negotiations with the local and regional authorities, will slow – but not stop – the decline. Potential production from other fields, such as those identified in the upper Adriatic (with proved reserves amounting to about 29 Gm^3), would further slow the reduction in the share of the overall requirement that is covered by national production. However, extraction is not yet possible because of concerns over the environmental impact of extraction operations.
The second segment, imports, covers most of the country's requirement (just under 80%) and is increasing in both absolute and relative terms. Imports are expected to cover 88% of the total requirement by 2005, and 90% by 2010.

FIG. 3 TREND IN PRODUCTION AND IMPORTS OF NATURAL GAS IN ITALY FROM 1990 TO 2010

Projection based on contracts drawn up by 2001.



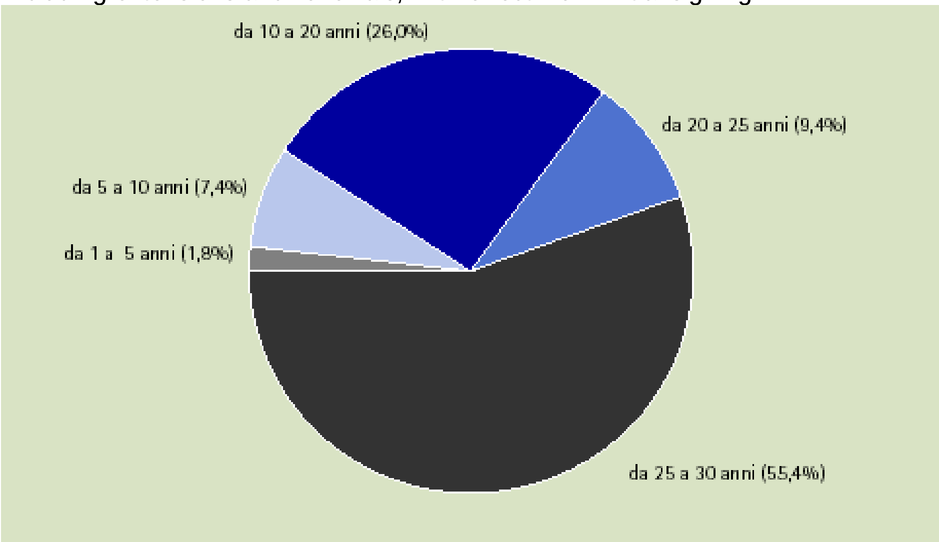
Source: from data submitted to Authority pursuant to Legislative Decree 164/2000.

In the case of imports the ENI Group is again the dominant operator, with about 85% of the total in 2001. Starting from 2002, injections of gas (produced nationally or imported) to the national network will be regulated in accordance with the ceiling established for the period 2002-2010 by Legislative Decree 164/2000 (75% in 2002, falling by 2% each year until 2010). Under long-term contracts to operators such as Plurigas S.p.A., Dalmine Energie S.p.A. and Energia S.p.A., the ENI Group has sold part of the gas it would otherwise have imported from Holland and Norway: delivery takes place upstream of the entry point at Passo Gries. ENI has also reached an agreement with Edison and Promgas to sell gas of Russian origin to Edison under a long-term contract: in this case, delivery takes place upstream of the Tarvisio entry point.
The second importer after ENI is Enel S.p.A., with about 11% of imports in 2001.

In 2003 and 2004 imports of gas from Libya will begin (Eni will deliver the gas to Gas de France, Energia and Edison, immediately upstream of the Gela entry point), while in 2005 Edison is due to begin importing liquefied natural gas (LNG) from Qatar, with the construction of a regassification terminal in the upper Adriatic. Import contracts signed to date will satisfy expected requirements until 2010. Most of these contracts are multi-annual; in 2001 they accounted for about 98% of imported volumes (of this share, about 80% concerns contracts drawn up before the entry into force of Legislative Decree 164/2000).

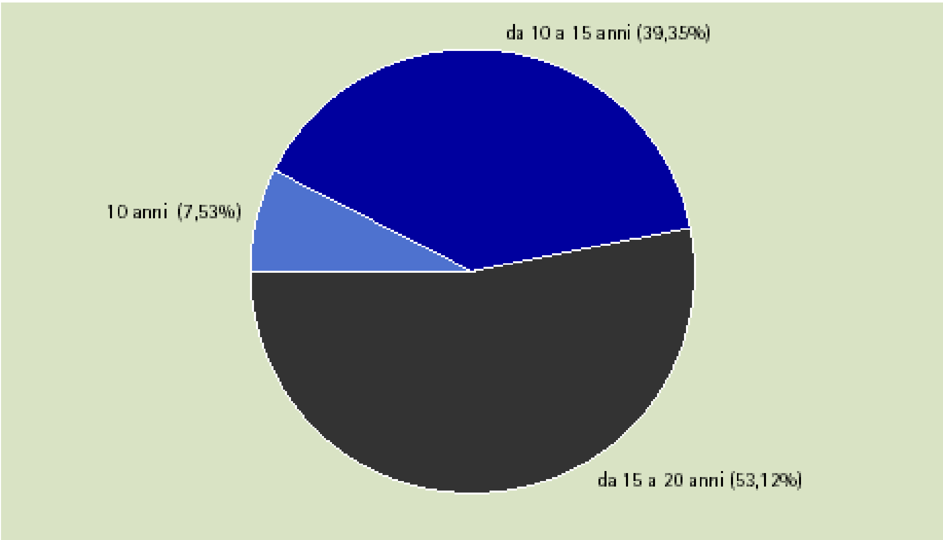
FIG. 4 STRUCTURE OF LONG-TERM CONTRACTS IN FORCE IN 2002, ON BASIS OF ENTIRE DURATION

Including extensions and renewals, with effect from initial signing



In volume terms, annual contracts are of modest importance, as are spot contracts. The latter, however, are of considerable importance in terms of opening the market to new operators who have difficulty gaining multi-annual, as opposed to shorter-term, access to import pipelines on foreign territory.

FIG. 5 STRUCTURE OF LONG-TERM CONTRACTS IN FORCE IN 2002, ON BASIS OF REMAINING DURATION



Nearly all (93%) imported gas is transported by pipeline to entry points in Italy. The transportation rights paid by importers on foreign pipelines serving the national gas system go mainly to companies in the Eni Group, which was responsible for constructing and funding the infrastructure in question.
6.5% of the gas imported in 2001 was transported by sea, in the liquid state, and regassified at the Panigaglia plant by Snam Rete Gas S.p.A. Most was imported by Eni and Enel, with Edison accounting for a small share.

TRANSPORTATION AND STORAGE

Structure of monopoly and organisation of transportation, storage and regassification terminals

Transportation

For reasons of economies of scale, it would not be either efficient or feasible to duplicate the Snam Rete Gas S.p.A. network. Snam owns 96% of the transportation capacity in Italy, in terms of invested capital. The network of the second operator, Edison T&S S.p.A., is geographically complementary to that of Snam Rete Gas, especially in the Abruzzi, Molise and Lazio regions.
The section of pipeline passing under the territorial waters of the Canale di Sicilia is also part of the national system. This is owned by Transmediterranean Pipeline Co. Ltd. (TMPC, an Italian-Algerian company in which Sonatrach and Eni hold equal stakes).
Access to Italy's transportation networks is regulated in accordance with Legislative Decree 164/2000. Tariffs, access criteria and the obligations to be met by the transportation companies are set by the Authority.
Legislative Decree 164/2000 also defined the national network of gas pipelines, which is made up of import pipelines, connections to storage facilities and the principal inter-regional pipelines. For this network, defined and up-dated by ministerial decree, access has been regulated since October 2001 along entry-exit lines.
In the thermal year 2001-2002, continuous transportation capacity at entry points corresponding to interconnections with foreign import pipelines amounted to about 94% of the technically available capacity. More specifically, near-saturation was reached for imports from the North, with greater capacity available for imports from the South. The LNG regassification plant at Panigaglia has reached saturation point.

TAB. 20 CONTINUOUS TRANSPORTATION CAPACITY IN ITALY
Millions of standard cubic metres per day, unless otherwise indicated

Continuous capacity	Technical	Allocated	Available	Percentage allocated/allocatable
Passo Gries	43.0	42.6	0.4	99
Tarvisio	74.0	74.0	0.0	100
Panigaglia (GNL)	11.4	11.4	0.0	100
Mazara Del Vallo	88.0	74.4	13.6	85
Total	**216.4**	**202.4**	**14.0**	**94**

In 2001 the transportation networks in the national system were extended by almost 2% in terms of length (the average rate of increase envisaged by Snam Rete Gas for the period 2000-2005 is 1.25%).

Work is currently being carried out to up-grade the pipeline carrying imports from Russia. The interference caused by these works resulted in a reduction of about 12% in the technical capacity available at Tarvisio between March 2002 and the start of the next thermal year (October 2002). The backbone for imports from Northern Europe is nearing completion and up-grading work is under way for new imports from Libya.
In 2001 both Snam Rete Gas and Edison T&S were hived off from their respective vertically integrated groups (Eni and Edison), in compliance with the provisions of Legislative Decree 164/2000 concerning the unbundling of activities in the gas sector.
40.24% of the shares of Snam Rete Gas were floated at the end of 2001, with Eni continuing to own the remaining stake.
In the 2001-2002 thermal year, 24 users (producers, wholesalers and final customers) obtained access to the Snam Rete Gas transportation network; of these, 6 have also signed transportation contracts with the Edison T&S network.

Storage

The Italian storage system consists of depleted fields. The storage sites currently in operation are managed by Stoccaggi Gas Italia S.p.A. (Stogit), a company set up in 2001 by the Eni Group, after hiving off its storage branch, and Edison T&S.
Stogit manages 8 storage facilities, seven of which in the Valle Padana (the concessions at Brugherio, Cortemaggiore, Ripalta, Sergnano, Settala, Minerbio and Tresigallo), and one in central Italy (Fiume Treste concession). For 2001-2003 the total operational reserve of working gas amounts to about 16 Gm^3, with daily producibility of nearly 280 Mm^3.
Edison T&S has two storage facilities (Cellino, in Abruzzo, and Collalto, in the Veneto), with an active reserve of about 263 Mm^3 and daily producibility in conditions of maximum capability (currently being expanded) of about 2 Mm^3/day.
The Ministry for Productive Activities has granted Stogit the concessions for the conversion to storage of the fields at Alfonsine and Fiume Treste, for which, according to initial estimates, the overall operational reserve is expected to increase by a further 2.4 Gm^3. In addition, Eni has recently been given the concession for the conversion of the field at Bordolano (and is in the process of transferring the concession to Stogit).
The current situation of the market for the storage of natural gas is a legacy from the vertically integrated situation that preceded the liberalisation introduced by Legislative Decree 164/2000. In order to encourage competition, the Decree envisages that some fields now nearing depletion should be used for storage and assigned through competitive procedures to operators interested in taking over their management. Pursuant to the Decree issued by the Ministry of Productive Activities on 27 March 2001, concerning the criteria for the conversion to storage of fields at an advanced stage of exploitation, the owners of exploitation concessions provided the Ministry of Productive Activities with the necessary information on mainland fields to establish whether these were technically and economically suitable for conversion to storage.
The Ministry published the list of fields selected for conversion, with relevant data and the storage capacity programme, in the *Bollettino ufficiale degli idrocarburi e della geotermia* of 31 October 2001. Of the 12 projects examined, the six fields deemed to be suitable, all of them on the mainland, are: Cornegliano, Cotignola, Portocannone, San Potito, Serra Pizzuta and Ravenna Terra. The procedure for the allocation of the concessions is currently under way.
Compared with the transportation infrastructure, the storage infrastructure has fewer monopolistic features. The modulation functions performed by storage services can also be achieved through actions to influence demand (interruptibility) or recourse to other fuels. In addition, peak supply can be replaced, at least in part, through flexible import contracts. In the thermal year 2001-2002 the instruments adopted were the interruption of supply, where included in the sales contract (without reaching the maximum levels envisaged), and the maximisation of imports (to the extent envisaged by the supply contracts, again without reaching the maximum levels).

The Authority sets the tariffs, criteria, access priorities and obligations that storage companies are required to respect. For other a-cyclical modulation functions, the storage facilities can already be considered to be operating in competition with other services.

Regassification terminals

In the Italian context, the control exerted by the Eni Group over transportation pipelines on foreign territory means that regassification terminals are needed if competition is to develop in the downstream segments of the market. In accordance with Legislative Decree 164/2000, access to these facilities is regulated. The only regassification terminal in Italy at present is the one at Panigaglia, which is run by Snam Rete Gas; its entire capacity is currently taken up by import contracts drawn up before 10 August 1998.

New terminals that are part of integrated long-term supply projects and make use of liquefaction plants and tanker ships are being planned: Edison, with a terminal in the upper Adriatic with capacity of 6 Gm^3/year; British Gas, with a terminal at Brindisi with initial capacity of 4 Gm^3/year; Enel, with three terminals at Taranto, Vado and Muggia; and LNG Terminal (a company in the Falck Group), with a terminal on the Calabrian coast with capacity of 8 Gm^3/year rising to 12 Gm^3/year; plus an off-shore plant (to be built in Calabria or Tuscany).

For these new terminals the problem arises of reconciling the need to encourage investment with the need to guarantee third party access to what, in this transitional stage in the development of competition, must still be considered as essential infrastructure.

Economic and technical regulation of the transportation network, storage and regassification terminals

In 2001 and the first quarter of 2002, the Authority's work in the gas sector focused on the completion of the tariff interventions regarding the transportation, despatching and storage of natural gas; the use of LNG terminals and storage facilities; and the fine-tuning of the rules for access to the gas system, as established by the decree transposing the European Directive on the internal market for natural gas.

In the transportation and storage phases the questions remaining to be defined are: the commercialisation tariff for customers connected to high-pressure pipelines and the criteria for the Network and Storage Codes, for which the Authority has already completed the consultation process.

Transportation tariffs: constraints and reference criteria

With Decision 120/2001, the Authority set out the criteria for the determination of the transportation and despatching tariffs for natural gas, both for the use of LNG terminals (pursuant to Art. 2.12 d) and e) of Law 481/1995 and Articles 18.6 and 23.2, 23.3 and 23.5 of Legislative Decree 164/2000). The Authority's provision defines the criteria under which natural gas transportation and despatching companies that are already up and running (Snam S.p.A., Edison Gas S.p.A., Tmpc and Sgm S.p.A) and those still to enter the market calculate tariffs for transportation and the use of LNG terminals and adopt minimum rules for access to the system.

For the first thermal year of the regulatory period (which lasts four years), the Authority also determines the criteria for the calculation of allowed tariff revenue for each company.

The Authority considered that the allowed tariff revenue should be determined on an individual basis since the differences in size and operating conditions between one company and another would have made it difficult to adopt standardised criteria. This approach also makes it possible to establish a degree of consistency, by means such as tariffs reflecting cost differences, in those few zones with networks operated by more than one company, or where new LNG terminals are planned.

Considerations of non-discrimination between one company and another mean that common criteria must inevitably be adopted in determining the invested capital and its rate of return, amortisation and allowed operational costs.

The allowed revenue is the income considered to be congruent for the activity in question and the tariff proposals formulated by operators, under the technical and economic conditions in force at the

beginning of the regulatory period. The proposals are subsequently submitted to the Authority for approval.
The reference revenue is based on the cost elements for transportation and regassification activities, in such a way as to ensure that both operating and capital costs are covered, including a suitable return on invested capital in accordance with Art. 23.2 of Legislative Decree 164/2000.
The costs recognised by Authority Decision 120/2001 are:

- the cost of the net invested capital, which is equal to the value of the Regulatory Asset Base (RAB)[6] multiplied by a return of 7.94% per year gross of taxes;
- amortisation, calculated using the economic lifespan of the assets according to the standards used in the principal European countries, based on a period of 40 years for gas pipelines, 20 years for compression facilities, 25 years for LNG terminals, 50 years for buildings and 10 years for other fixed assets;
- operating costs, the costs actually sustained by the transportation companies in 2000 for staff, consumption material, compression and injection, services provided by third parties and set-asides other than amortisation.

The reference revenue is determined for each year of the regulatory period. This includes the revenue for the network as it stands at the beginning of the period and any investment made during the lifespan of the plant, taking into account any corrective factors and the revenue from system balancing costs. On the basis of the reference revenue companies calculate and propose their transportation tariff components using the entry-exit method. These provide a simpler solution than a “point-to-point” tariff, which is economically unjustified and difficult to set objectively in a tightly meshed network such as Italy’s.
Since Decree 164/2000 also indicates the distance between the entry and exit points as a tariff criterion, the Authority’s provision calculates unit transportation costs on a point-to-point basis.
The transportation tariffs for the regional network are the same throughout the country and are correlated to capacity at delivery points, with proportional distance-based reductions for re-delivery points in municipalities less than 15 km from the national pipeline network.
The ratio of capacity charges to volume charges for volume transported is 70:30. The latter component is intended to encourage a more entrepreneurial approach by transportation companies (which are guaranteed higher revenues/volume) and at the same time to reduce the risk of under-use of pipelines.
The adjustment mechanisms for allowed revenue refer to both capacity and volume and envisage an increase corresponding to the inflation rate for the previous calendar year, plus a reduction corresponding to a productivity rate set for the entire regulatory period. This amounts to 2% and 4.5% respectively for capacity and volume. The mechanism used for capacity imposes a revenue cap since it determines total revenue independently of the volumes transported. The mechanism for volume imposes a price cap per volume transported, which consequently influences revenue.
Incentives are envisaged for new investment, the aim being to develop transportation activity in view of the expected 3-5% annual increase in gas consumption over the next decade, and the development of new uses as a result of technological innovation.
The tariff structure envisages incentives for new infrastructure investment; these include higher charges for 6 years against investment actually carried out and exemption from the pre-set productivity improvement requirements.
Tariff discounts are envisaged for operators other than transportation companies who decide to fund projects to up-grade plants and networks in stretches in which they have an interest.

[6] The RAB is determined using the *Current Cost Accounting* (CCA) method, which is based on the historic costs of the assets listed at 31 December 2000, revalued according to the fixed investment deflator, net of technical economic depreciation and of the unsecured funding paid by government departments for transportation services.

Tariff for the use of regassification plants

For the definition of the tariff for the use of regassification plants for LNG transported on tanker ships, the same calculation method as used for transportation tariffs has been followed, using an expected return on investments of 9.15%.
The rate of return is higher for regassification than for transportation because the former involves a higher risk. For the same reason, and to encourage the construction of new regassification plants in Italy, the price cap has been reduced by 2%.

Transitional arrangements for network access

When it defined the criteria for the setting of tariffs, the Authority also set out the transitional arrangements for access to the service. Pending a more precise definition in the network codes, these guarantee access under equitable and non-discriminatory conditions, prevent abuse of dominant position in the allocation of capacity and encourage the development of competition. More specifically, features such as capacity allocation and system balancing charges were also put forward. These arrangements will stay in force until the network codes are issued and, in the case of allocation, until 30 September 2002 at the latest. The definition of provisional rules also makes it possible to monitor the application of the same and obtain useful pointers in view of the transition to the definitive regime.
Bearing in mind the difficulties encountered in the introduction of the new tariff system and a series of problems noted by users in the *Access Conditions* published by Snam Rete Gas in November 2001, the Authority set up an informal working group to draw up useful pointers for future provisions regarding any problem issues. These include system balancing charges and the publication of capacity allocation data within the context of the provisions pursuant to Articles 20.2 and 24.5 of Legislative Decree 164/2000 and Authority Decisions 146 and 150 of 3 August 2000. The working group has already achieved some interesting results on the topics under consideration, such as: the setting up by Snam Rete Gas of a “notice board” to encourage the secondary capacity market; the improvement for users of some contractual conditions regarding access (penalties for imbalances and exceeding capacity) for the thermal year 2001-2002, the suspension of some penalties until 21 December 2001 and the introduction from this date of new charges that are more advantageous to users.

Transportation tariffs: values applied

With Decision 193/2001, the Authority approved the transportation tariffs for methane gas on the national gas pipelines and regional networks, and the regassification tariffs submitted by operators for LNG treated at the Panigaglia plant.
The decision identifies the entry points (national borders, deposits and storage) and exit points from the national network and enables individual operators to calculate the overall cost of transportation from withdrawal point to consumption point.
There are 16 entry points in the national network, of which 3 for interconnection with foreign import pipelines (Mazara del Vallo, Passo Gries and Tarvisio); one for the Panigaglia regassification plant; ten for the main national production fields (North Western, North Eastern, Rubicone, Falconara-Fano, Pineto, San Salvo, Candela, Monte Alpi, Crotone and Gagliano); and two corresponding to storage facilities (Eni and Edison Gas). The exit points, linking the national network to the regional networks, refer to the following 17 regional zones: Friuli Venezia Giulia, Trentino Alto Adige-Veneto, Eastern Lombardy, Western Lombardy, Northern Piedmont, Southern Piedmont and Liguria, Emilia Romagna-Liguria, Basso Veneto, Tuscany-Lazio, Romagna, Umbria-Marche, Marche-Abruzzo, Lazio, Basilicata-Puglia, Campania, Calabria and Sicily.
The following criteria have been defined for transportation over the national network:

- CV, a volume charge (in euros/GJ);
- Cpe, a capacity charge (in euros/Sm^3/day) for each of the 16 entry points;
- Cpu, a capacity charge (in euro/Sm^3/day) for each of the 17 exit points.

And for transportation over the regional network:

- CRr, a single capacity charge (in euros/Sm^3/day) for all re-delivery points for each transportation company; discounts are envisaged for distances of less than 15 km;
- CF, a fixed charge (in euros/re-delivery point) for the gas pipeline network.

"Interruptible" charges are envisaged, with reductions of 8% for Snam Rete Gas and 4% for Edison Gas. A regassification tariff has also been introduced, for the use of the Snam Rete Gas terminal at Panigaglia.

TAB. 21 TRANSMISSION AND DESPATCHING TARIFFS
Thermal year 2001-2002

Variable unit charge CV (euro/GJ)		0.176549		
National network capacity unit charges (euro/Sm^3/g)				
CPe		**CPu**		
Mazara del Vallo	3.032460	Friuli-Venezia Giulia	A	0.841763
Passo Gries	0.338364	Trentino-Alto Adige-Veneto	B	0.986886
Tarvisio	0.857216	East Lombardy	C	1.076087
Panigaglia	0.613272	West Lombardy	D	1.276102
North-Western	0.077469	North PIedmont	E1	1.535033
North-Eastern	0.104647	South Piedmont and Liguria	E2	1.276102
Rubicone	0.077469	Emilia and Liguria	F	0.986886
Falconara-Fano	0.494016	Basso Veneto	G	0.862372
Pineto	0.720943	Tuscany and Lazio	H	0.858547
San Salvo	0.559849	Romagna	I	0.697670
Candela	0.633425	Umbria and Marche	L	0.569331
Monte Alpi	0.905488	Marche and Abruzzo	M	0.524838
Crotone	2.026530	Lazio	N	0.659117
Gagliano	2.174299	Basilicata and Puglia	O	0.735951
		Campania	P	0.521476
Eni-Edison Gas Storage	0.174442	Calabria	Q	0.446735
		Sicily	R	0.157519
Unit regional network capacity charges (euro/Smc/g)				
Edison Gas and Sgm	1.801000			
Rete Gas Italia	1.312991			
CF fixed charge (euro / re-delivery point)		1° level	2° level	3° level
Edison Gas e Sgm (1)		31.00	2,141.30	5,183.70
Rete Gas Italia (2)		3,098.70	7,746.80	17,570.60
Tariff for interruptible service				
Edison Gas e Sgm		CRr reduction by 4%, for 5-day interruptions, with 48 hours notice		
Rete Gas Italia		reduction by 8% of Cpe+Cpu+CRr, for 5-day interruptions, with 3-day notice		

(A) The definition of the levels is based on 2 parameters: annual consumption at re-delivery point and type of metering.
(B) The definition of the levels is based on 4 parameters: cubic metres withdrawn, type of metering, type of metering equipment, method of obtaining metering data.

TAB. 22 REGASSIFICATION TARIFF FOR THE USE OF THE RETE GAS ITALIA TERMINAL AT PANIGAGLIA
Thermal year 2001/2002

Unit charges	Units of measurement	Value
associated with the quantities of LNG unloaded	euro/liquid m^3	3.622390
associated with contractual berthings	euro/number of berthings in a year	16,271.491063
variable for energy associated volumes regassified	euro/GJ	0.064330
Losses	per m^3 regassified	2%

Storage tariff: constraints and criteria

With Decision 26/2002 the Authority established the criteria for the definition of natural gas storage tariffs. On the basis of these tariffs Stogit, a member of the Eni Group, calculates and submits for Authority approval the storage tariffs coming into force at the beginning of the thermal year. The Authority has based the tariff criteria on the costs of the service. These tariffs, plus a weighted average real rate of return of 8.33%, determine the revenue allowed for storage companies using them as a starting point to set their own tariffs. The tariffs, which remain in force for four years, are subject to a price cap that takes into account inflation and a productivity recovery of 2.75% per year.
In keeping with the most advanced practice in the sector, the tariff structure consists of two fixed elements, one based on the annual capacity used (space occupied in the reservoir) and one based on maximum capacity demand for one day in the year, plus a variable element based on the quantities entering and leaving the field.
Operators with storage fields that are not yet fully operational (e.g. Edison T&S) or who are developing new fields, are free to set their own tariffs or ask for the tariffs set by the Authority to be applied. The Authority's decision to leave operators free to define their own tariffs was prompted by the need to encourage new operators to enter the Italian market. These operators will be able to put flexible arrangements in place to manage the services they provide in the start-up phase, during which costs are generally higher. The decision also establishes temporary access conditions that open the way to the liberalisation of storage services and enable operators to build up the necessary experience to draw up a storage code that responds to the real needs of the market. In the meantime, all new storage service contracts will be monitored by the Authority, which may require any clauses that do not comply with the need to ensure transparency and freedom of access under equal conditions to be amended.

Storage tariffs in force until 2006

In accordance with Decision 26/2002, Stogit sent the Authority its tariff proposals for the thermal year 2002-2003. However, the proposals were rejected as they did not comply with the criteria laid down in the Decision. Consequently, and to provide users with a clear framework in time for the new thermal year, in Decision 49/2002 the Authority has laid down the new unit charges that make up the storage tariff. These will remain in force until 2006.

TAB. 23 UNIT STORAGE CHARGES INCLUDED IN TARIFF

Charges	Unit of measurement	Value
Unit charge for space	euro/GJ/year	0.257
Unit charge for peak daily availability	euro/GJ/year	10.160
Unit charge injection and delivery	euro/GJ	0.092
Unit charge for making available gas held by company for strategic storage	euro/GJ/year	0.163

The tariff introduced by the Authority replaces the one provisionally self-defined by Stogit and will remain in force until 2006.

Consultation on the allocation of LNG regassification capacity

LNG regassification is subject to requirements of equal treatment and non-discrimination of users, as envisaged by Legislative Decree 164/2000 and Authority provisions pursuant to Art. 24 of the same Decree.

On 4 February 2002 the Authority published a consultation document setting out the proposed criteria for the allocation of new LNG regassification capacity. This illustrates the criteria and proposals for the use of new capacity obtained by constructing new plants or up-grading and/or modernising existing ones.

The Authority's document contains a proposal to earmark part of the regassification capacity to provide priority access for the operators financing the construction of the plant under negotiated economic conditions. This reserve would be subject to the normal conditions governing regulated access.

The document suggests that this special rights system should apply for a set period of time under a temporary derogation from the general regulatory framework which has liberalised access to the national gas system infrastructure. This period would last for 15/18 years at most, during the first 5 of which the priority access would apply to up to 80-90% of new regassification capacity. The reserve would be reduced over time and gradually phased out altogether, until such time as the plants were fully accessible under free market conditions. The Authority's proposals also cover the up-grading and modernisation of existing plants providing new capacity in order to extend the reserve to access and use by third parties.

The aim of the provision is to provide greater economic certainty for operators and encourage the construction of plants that will help diversify the country's sources of energy supply by enabling gas to be brought in by sea.

Consultation on Storage Codes

In March 2002 the Authority published a consultation document setting out the *Criteria and priorities for drawing up Storage Codes, conditions for access to storage facilities and obligations on operators*. The document presents to interested parties the Authority's proposals regarding arrangements for access to and use of the storage service (the structure of the service, the order of precedence for allocation in the event of demand exceeding supply, and balancing arrangements).

The Authority's proposals envisage the co-existence of services offered on the basis of regulated or negotiated access. The consultation document contains proposals on priority access, the criteria to be used in drawing up the Storage Codes, and the obligations on operators providing this service. Priority access means the order of precedence for the allocation of storage services to those requesting them, not least in situations of scarce capacity.[7] Under the order of precedence proposed by the Authority, operators with responsibility for ensuring the security of the gas system have a priority right to the modulation storage service: these are transportation and gas companies required, directly or indirectly, to provide modulation and balancing services in accordance with Legislative Decree 164/2000. Next come other eligible customers, whether Italian or from other EU Member States, and finally, eligible customers and gas companies from non-EU member states, on condition that any reciprocity conditions are satisfied where so requested. If there is insufficient available capacity to meet demand, the document proposes that allocation should be based on criteria that as far as possible will encourage greater long-term efficiency in the storage service. The proposed allocation arrangements are: public auction, *pro quota* allocation, and first-come-first-served allocation.

The Storage Code, understood as a code containing rules and arrangements for the management and running of the storage system, is a new departure for the Italian regulatory system. According to the Authority's proposals the Code, drawn up by the storage companies themselves, should meet the following requirements:

- completeness;
- clarity (the Code, an instrument of commercial law of considerable length and complexity, should be accompanied by explanatory documents to ensure that it can be easily understood, even by non-specialists);
- flexibility, which means that the Code should also include arrangements and rules enabling it to be up-dated.

In consideration of the characteristics of the storage service, and taking as a model the format already proposed for the Network Code in the relevant consultation document, the Authority has proposed an index that would be common to all the Storage Codes, the chapters and sections of which mainly cover:

- informational requirements (information for the Authority and third parties) to be satisfied by storage companies;
- operational requirements, which mainly concern the conditions for access and use of the system.

A procedure is envisaged for up-dating the Code, which will be drawn up by storage companies and submitted to the Authority for approval.

After the codes have been approved and adopted, an introductory period is envisaged, with six-monthly checks so that the arrangements and rules that will be in place once the codes are fully up and running can be applied gradually at the outset. This will be coordinated with the introduction of the Transportation and Distribution Network Codes and the LNG Codes. In this respect the procedure for up-dating the Code can also act as an efficient means of monitoring its application.

During the initial regulatory period, the supply and use of the storage service will refer to the companies' total stocks, taken as a single node, as envisaged by the tariff system set out in Decision 26/2002.

The consultation document also envisages the possibility, after this initial regulatory period, of a gradual transition from the integrated storage system to one divided into nodes, formed by stores that are similar in geographical or technical terms (following the French model); and finally to a system where the services also regard single stores (following the British model).

[7] Under the terms of Legislative Decree 164/2000 available storage is intended on a priority basis to meet the requirements for the exploitation of gas deposits on national territory (mineral storage). The available storage is reserved for strategic stores, to which importers from non-EU Member States can contribute, according to shares and arrangements set by the Ministry for Productive Activities (Strategic Storage). The remaining storage is allocated to the modulation service in its various forms, seasonal and peak seasonal, daily and hourly (modulation storage).

DISTRIBUTION AND SALES IN THE FREE AND CAPTIVE MARKETS

In 2001 and the first quarter of 2002 the Authority's activity regarding the sale and distribution of gas focused on the regulation of the rights of eligible customers to withdraw from contracts, the implementation of the tariff reform for distribution and supply to customers on the captive market, and the rules for the administrative and accounting unbundling of companies operating at all stages in the gas industry. Aspects still to be defined are the Distribution Codes, modulation obligations, the standard service contract, the informational obligations of gas companies vis-à-vis other operators in the sector and energy efficiency initiatives (on which a public consultation process is under way).

Structure of the market and regulation of distribution and sales activities for the free and captive markets

The free market for gas, calculated using data from 1999, accounts for about 64% of the total and is made up of approximately 3,200 industrial customers connected to the Snam-Edison-SGM networks (with total annual consumption of 17 billion cubic metres); 6,148 industrial and hospital customers connected to distribution networks (consumption of 6 billion cubic metres); about 1,680 civil customers, mainly large condominiums (consumption of about 800 million cubic metres); 25 electricity generators (consumption of about 19 billion cubic metres) and 750 distribution companies (consumption of about 29 billion cubic metres supplying the captive market).

Right of withdrawal for eligible customers

With Decision 184 of 9 August 2001 the Authority issued a directive giving major gas consumers, or eligible customers, the right to withdraw from existing contracts and change supplier.
On the basis of Legislative Decree 164/2000 eligible customers are those consuming more than 200,000 cubic metres of gas per year. The directive concerns both the sale and delivery of gas and, unless other express agreements by both parties are in place, requires suppliers to give their customers the option of withdrawing from existing or future contracts giving no more than six months notice in the case of long-term contracts.
Before this provision was applied, the withdrawal option was not generally available, a fact which greatly limited the possibility for the approximately 11,880 gas customers entitled to obtain their supplies on the free market to take advantage of the opportunities offered by other suppliers. The Authority's intervention, which was prompted by numerous complaints from customers, is intended to promote competition and accelerate the liberalisation process.

The implementation of the tariff reform for customers in the captive market

The new tariff system set out in Authority Decision 237/2000 for gas distribution and supply to customers in the captive market came into effect on 1 January 2001.
In view of the important changes this entailed, Decision 237/2000 provided for a transitional period to allow a gradual changeover to the new system. Up to 30 June 2001, companies applied the same tariff structures to customers as were in force at 31 December 2000, with tariff levels changing in accordance with the provisions of Art. 18 of Decision 237/2000, and adjusted through the bi-monthly up-dates introduced by Decision 52 of 22 April 1999. From 1 July 2001 Decision 237/2000 introduced tariff options differentiated by consumption band rather than gas usage.
The Authority organised the collection, through channels such as its Internet site, of the necessary data to monitor the tariffs for the first six months of 2001 and the tariff options for the thermal year 2001-2002.
The checks carried out by the Authority covered:

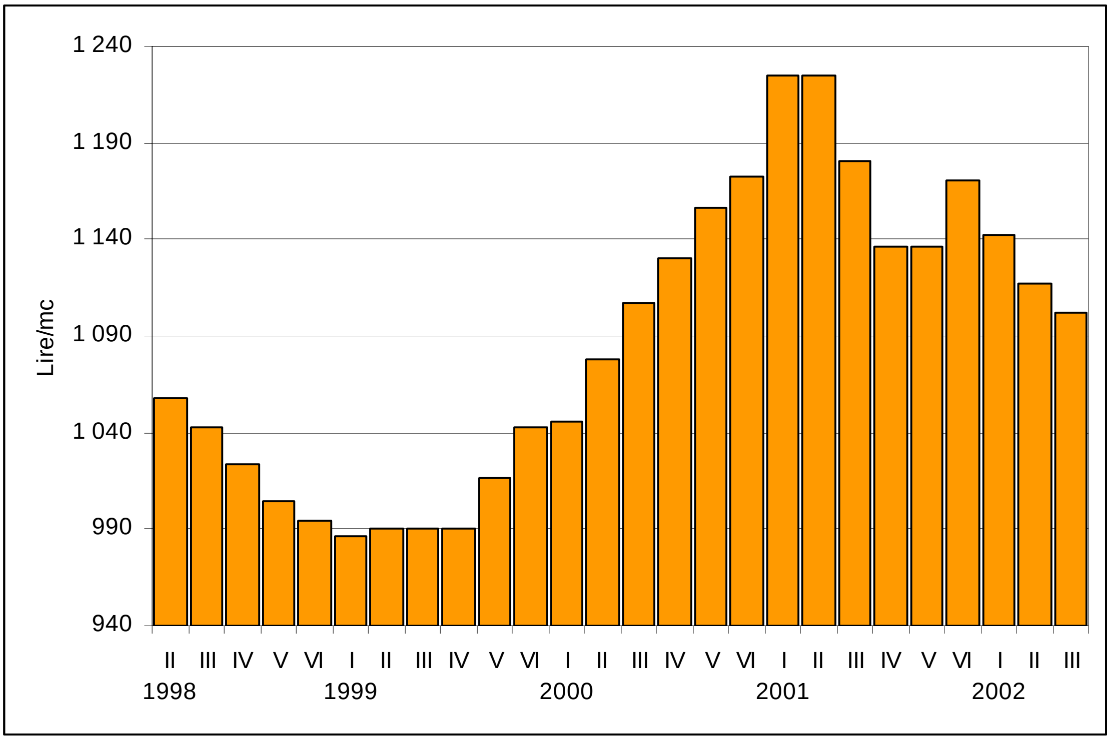
- the setting of revenue constraints for each geographical area served (about 6,000);
- the definition of tariffs for each tariff zone (about 2,300) for the first six months of 2001;
- the compatibility of the basic tariff options in each tariff zone with the revenue constraints.

An analysis of the data submitted by 716 companies revealed a high number of errors in the calculation of the tariffs and tariff options, as well as discrepancies in the data itself.
It should be noted that in 2001 the tariff reform was only implemented in part. Some distributors (including Italgas and some municipal companies) appealed against the reform to the Regional Administrative Court (TAR) and decided not to apply it pending the decision by the Council of State, to which the Authority appealed after the Lombardy TAR had ruled in favour of the complainants. It should also be underlined that most of the complaints to the TAR took issue only with the part of Decision 237/2000 that uses a parametric method to evaluate the capital invested by companies. The TAR rulings recognised the overall validity of the parametric method, but pointed out that since the companies were able to provide concrete data, the Authority evaluations should refer to these.

Bi-monthly adjustments

As a consequence of the tariff reform, the system of bi-monthly tariff adjustments had to be modified. Authority Decision 52/1999, concerning the indexation of tariffs to the raw material, was amended by Authority Decision 135 of 21 June 2001, in consideration of the fact that the new tariffs are correlated to the actual heating power, and to the altitude and climatic conditions of the geographical area in question.
After an increase in the first bi-monthly period of 2001, the rest of the year saw a constant series of reductions as a result of the fall in prices on the international oil markets. The fall in gas prices was, however, partly counterbalanced by exchange rate movements: in 2001 the euro depreciated by 3% against the dollar, going from an average rate of 0.92 dollars to the euro in 2000, to 0.89 in 2001.
At the same time, with effect from 1 November 2001 duties on gas supplies, which had been reduced in 2000, returned to the values set by the Prime Minister's Decree of 15 January 1999.

FIG. 6 AVERAGE TARIFF OF NATURAL GAS GROSS OF TAXES
Lire/m^3



Note: the figures for March and May 2002 have been changed from euro/m^3 to Lire/ m^3 for reasons of comparability

GAS PRICES AND TARIFFS DURING THE TRANSITION

Tariff components and effects of variations on the system

As a result of the favourable trend in international prices for oil products, half-way through 2001 there were two significant reductions in the price of natural gas for Italian households (which includes the gas used for heating, cooking and the production of hot water) as recorded by the National Statistics Institute (ISTAT), with the index falling by about 2% in May and July. After a period of relative stability in the autumn, the price of gas rose again in November, by 2.3%.

As TAB. . 24 shows, one effect of this trend, and of the fact that the values of the index were high in early 2001, is that taken as a yearly average the price of gas rose by 7.3% with respect to 2000.

Prices rose in general in 2001, bringing the inflation rate for the economy as a whole to 2.8%. Measured in real terms, therefore, the rise in the price of gas was actually less marked, at 4.4%.

The break-down of the national average gas tariff net of taxes shows how the fall over the year can be attributed almost entirely to the sharp dip in the fuel cost component. In 2001 the impact of this component on the total tariff net of taxes was reduced by almost ten percentage points, going from 48% in the first bi-monthly period to 39% in the sixth. Over the same period the weight of the component covering distribution costs fell by almost half a percentage point, as the result of Authority provisions.

TAB. 24 MONTHLY INDICES OF GAS PRICES FOR DOMESTIC USE

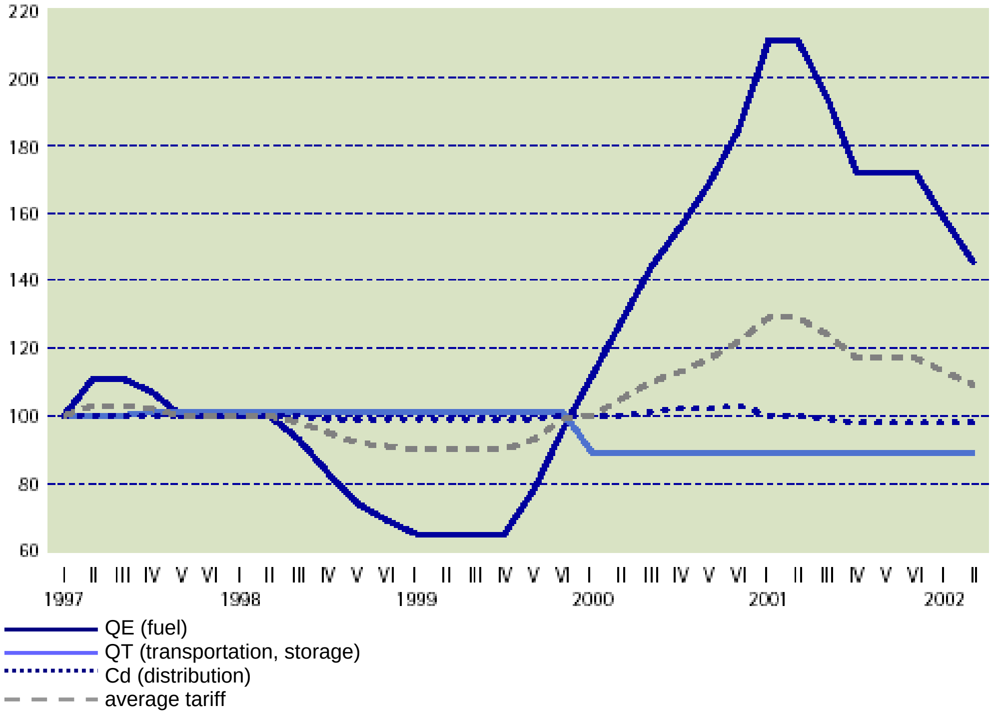
1999-2000; index 1995=100 and percentage variations

MONTHS	2000				2001			
	Nominal price	*var. %*	Real price(A)	*var. %*	Nominal price	*var. %*	Real price(A)	*var. %*
JANUARY	112.0	*6.1*	100.7	*3.8*	129.2	15.4	112.7	*11.9*
FEBRUARY	112.2	*5.9*	100.5	*3.5*	129.8	15.7	112.9	*12.3*
MARCH	115.3	*8.8*	103.0	*6.1*	130.1	12.8	112.9	*9.6*
APRIL	115.0	*8.6*	102.7	*6.2*	130.2	13.2	112.6	*9.7*
MAY	117.9	*11.2*	104.9	*8.7*	127.5	8.1	110.0	*4.9*
JUNE	118.0	*11.4*	104.6	*8.5*	127.3	7.9	109.6	*4.7*
JULY	120.1	*13.3*	106.4	*10.5*	125.1	4.2	107.7	*1.2*
AUGUST	120.1	*13.1*	106.3	*10.3*	124.9	4.0	107.5	*1.1*
SEPTEMBER	122.9	*13.1*	108.5	*10.1*	124.8	1.5	107.3	*-1.1*
OCTOBER	121.8	*11.7*	107.2	*8.9*	124.8	2.5	107.1	*-0.1*
NOVEMBER	125.1	*12.4*	109.7	*9.3*	127.7	2.1	109.4	*-0.3*
DECEMBER	125.2	*12.4*	109.7	*9.3*	128.0	2.2	109.6	*-0.1*
YEARLY AVERAGE	**118.8**	***10.7***	**105.4**	***7.9***	**127.5**	**7.3**	**109.9**	***4.4***

(A) Relation between elementary gas index and general index multiplied by 100.
Source: based on Istat data

FIG. 7 COMPONENTS OF THE AVERAGE NATIONAL GAS TARIFF NET OF TAXES

Index values 1st bi-monthly period 1997 = 100



Source: Authority estimates

Distribution tariffs in regional capitals

At the end of 2000, with Decision 237/2000, the Authority defined the reform of the tariffs for the distribution and supply of gas to captive customers, which entered into force on 1 July 2001.
Before this date the tariffs for civil uses of natural gas distributed over urban networks were differentiated by consumption type, size of user and geographical location. More precisely, in the tariff system in force to 1 July 2001, tariffs T1 (set at four different levels on the basis of consumption in the areas served) and T4 (using countrywide standard levels) were defined at the national level. Tariffs T2 and T3, on the other hand, were set freely by distribution companies, with due respect for constraints of cost-revenue consistency. Decision 237/2000 established that from 1 July 2001 tariffs T1, T2, T3 and T4, differentiated according to use, would be substituted by tariffs divided by consumption level. The new tariff scheme has not yet been applied in full, however, as some distribution companies, which took the question to the courts and are still awaiting the outcome, are still following the previous tariff structure. These include Italgas, which distributes gas to many regional capitals.
There have been no changes on the fiscal side, however, to reflect the abolition of use-based categories: as things stand at present these are still used for the application of duties (consumption tax and regional surtax) and VAT. In 2001 the levels of taxes on gas, were the same as under the previous system.
On 25 March 2002, on the basis of the Finance Law for 2002 (Art. 14 of Law 488/2001), the Ministry for the Economy and Finance issued a provision by effect of which the duty on methane for fuel for civil uses in Northern and Central Italy (i.e. excluding the areas of Southern Italy set out in Presidential

Decree 218/1978) was reduced by the rates shown in TAB. 25. The reduction applies retroactively from 1 January 2001 and remains in force until December 2002.

TAB. 25 TAXES ON GAS
Lire/m^3 (unless otherwise specified) and percentage rates in force in 2001 and 2002

TARIFF	T1	T2		T3(2)	T4
USE	Cooking and hot water	Individual heating		Centralised heating, craft and commerce	Industrial uses
CONSUMPTION		<250 m3/y	>250 m3/y		
CONSUMPTION TAX					
From 1 January to 31 October 2001					
NORMAL	56.99	124.62	307.51	307.51	24.2
EX-SOUTHERN FUND REGIONS	46.78	46.78	212.46	212.46	24.2
From 1 November 2001 to 31 December 2001					
NORMAL	86.84	152.68	335.57	335.57	24.2
EX-SOUTHERN FUND REGIONS	74.84	74.84	240.52	240.52	24.2
From 1 January 2002 to 31 December 2002					
NORMAL					
values in Euro/m3	0.04	0.04	0.17	0.17	0.012498
Corresponding to Lire/m3	77.45	77.45	329.57	329.57	24.2
EX-SOUTHERN FUND REGIONS					
values in Euro/m3	0.038652	0.038652	0.124218	0.124218	0.012498
Corresponding to Lire/m3	74.84	74.84	240.52	240.52	24.2
REGIONAL SURTAX(A)					
PIEDMONT	36.22	50	50	50	12.1
LOMBARDY(B)	10	30	35	35	10
VENETO	10	38.5	50	50	12.1
LIGURIA(C)	36.22	50	50	50	12.1
EMILIA ROMAGNA	36.22	60	60	60	12.1
TUSCANY	36.22	50	50	50	12.1
UMBRIA	10	10	10	10	10
MARCHE	30	30	30	30	12.1
LAZIO	36.22(D)	60(D)	60	60	12.1
ABRUZZO	30.475	30.475	50	50	12.1
MOLISE	10	10	10	10	10
CAMPANIA	30.475	30.475	50	50	12.1
PUGLIA	30.475	30.475	50	50	12.1
BASILICATA	30.475	30.475	50	50	12.1
CALABRIA	30.475	30.475	50	50	12.1
VAT RATE (%)	**10**	**20**	**20**	**20**	**20**

(A) The Special Statute regions have set the regional surtax at zero.
(B) Reduced rate of 10 l/m^3 for municipalities belonging to climatic band “F”
(C) Reduced rate of 30 l/m^3 for municipalities belonging to climatic band “E” and 20 l/m^3 for band “F”.
(D) Reduced rate of 30.475 for regions covered by the ex-Southern Italy Fund (Abruzzo, Molise, Campania, Puglia, Basilicata, Calabria, Sicily and Sardinia; the provinces of Frosinone and Latina; some municipalities in Rome province that are part of the Latina land reclamation district; municipalities in the province of Rieti included in the ex-Cittaducale district; some municipalities in Ascoli Piceno province that are part of the Tronto reclamation district; the islands of Elba, Giglio and Capraia.

Most of the cities in which the new tariff structure has been applied are regional capitals in Central and Southern Italy. Cities in which Decision 237/2000 has not been applied are mainly large regional capitals, including Rome, Milan, Naples and Turin.

A comparison of annual expenditure shows wide regional differences, if we take expenditure net of taxes, and even wider differences taking expenditure gross of taxes. These account on average for 40% of the overall cost, which in turn varies greatly from one regional capital to another. The fiscal component varies from 31% in Palermo to 46% in Bologna, with an average value of 33% in 2000.

In 2001 consumers spent an average 708 euros net of taxes and 1,187 euros including tax on 1,900 cubic metres for individual heating use. The average price per cubic metre was 0.37 euros net of tax or 0.62 euros including tax.

Taking the net values, the lowest price was recorded at l'Aquila (0.31 euros/m^3), while the highest was in Palermo (0.49 euros/m^3). In 6 of the 17 regional capitals taken into consideration, the price was less than 0.35 euros/m^3, and in 8 it was less than 0.40 euros/m^3.

If we take the values including tax, the city with the lowest price was again l'Aquila (0.53 euros/m^3), while the highest price was recorded in Naples (0.73 euros/m^3).

The addition of taxes to the tariff has a significant effect on the relative positions of the cities, measured on the basis of the cost of the gas service. In 7 of the 17 regional capitals (Potenza, Campobasso, Perugia, Ancona, Aosta, Bari and Trieste) the relative position moves up (which means that the service becomes relatively cheaper).

These cities are either situated in the part of the country that used to be covered by the *Cassa del Mezzogiorno* fund for Southern Italy, in which a lower rate of consumption tax is applied, or in special statute regions where there is no regional surtax.

PUBLIC SERVICE OBLIGATIONS, QUALITY AND CONSUMER PROTECTION

THE ELECTRICITY SECTOR

Quality indicators in the electricity service

With regard to the continuity of the electricity distribution service, two Decisions came into effect on 1 January 2000 concerning the arrangements for recording interruptions (Decision 128/1999) and the economic regulation of long unannounced interruptions (Decision 202/1999). With regard to commercial quality, speed in providing services requested by users and regularity in sales activities (for example the reading and billing of consumption), five specific standards with their own refund arrangements as defined by Decision 201/1999 came into effect on 1 July 2000. The obligations apply to operators who at 31 December 1999 served more than 5,000 low-voltage users. The standards and compensation rates set out in Decision 201/1999 replace the previous standards defined by operators in their Service Charters, which differed from one area of the country to another and envisaged compensation only at users' request.
The data supplied by operators on the implementation of the new commercial quality regulations in the second half of 2000 show that:

- the introduction of specific standards defined by the Authority, which are more exacting than those set by operators in their Service Charters, did not result in an increase in the incidence of non-performance. This suggests that the previous standards had been on the cautious side. One operator, AEM Torino S.p.A., introduced specific standards that are more advantageous to low-voltage customers: the company set a maximum of 6 working days to supply the estimate for simple works and 5 working days to carry out the works, while the Authority standard is 15 days for both services;
- the introduction of the new system extended the guarantees to medium-voltage users, who were not previously covered by any guarantee in the Service Charters. For this category of users Enel Distribuzione and Valdis (an electricity distribution company covering Val d'Aosta and now called Deval) introduced specific standards that improve upon those set by the Authority (maximum of 5 working days for connection and disconnection of supply, compared with 10 and 7 working days respectively as set by the Authority).

TAB. 26 SUMMARY OF SPECIFIC STANDARDS FOR MEDIUM-VOLTAGE CUSTOMERS ENEL GROUP (ENEL + DEVAL), 2ND SEMESTER 2000

Service(A)	No. Requests/Year	Authority Standard	Unit Of Measurement	% Off Standard	Actual Time
Connection	5,768	10 days	Working days	0.12	1.21
Disconnection	1,698	7 days	Working days	0.06	1.04
Re-Connection for Arrears	656	1 day	Days (excl holidays)	0.45	0.34

(A) The services shown in the table refer to 91,991 medium-voltage final customers.
Source: As declared by operators to Authority

TAB. 27 SUMMARY OF SPECIFIC STANDARDS FOR MEDIUM-VOLTAGE CUSTOMERS - LOCAL ELECTRICITY COMPANIES WITH MORE THAN 5,000 FINAL CUSTOMERS, 2ND SEMESTER 2000

Service(A)	No. Requests/Year	Authority Standard	Unit Of Measurement	% Off Standard	Actual Time
Connection	107	10 days	Working days	3.42	4.00
Disconnection	121	7 days	Working days	0.00	1.28
Re-Connection for arrears	10	1 day	Days (excl holidays)	0.00	0.77

(A) The services shown in the table refer to 4,032 medium-voltage final customers.
Source: As declared by operators to Authority

TAB. 28 SUMMARY OF OVER ALL STANDARDS FOR LOW-VOLTAGE CUSTOMERS: ENEL GROUP (ENEL + DEVAL), 2ND SEMESTER 2000

Service	No. Requests/Year	Authority Standard	Unit Of Measurement	% Respecting Authority Standard	% Improving On Authority Standard	Actual Time	% Actually Respecting
Estimate for complex works	71,274	40	Working Days	85	87	12.36	99.74
Execution complex works	35,068	60	Working Days	85	87	14.94	99.52
Billing corrections	8,862	15	Working Days	90	92	4.91	97.62
Meter inspections	2,506	10	Working Days	90	92	6.65	97.44
Voltage checks	1,004	10	Working Days	90	92	6.12	98.21
Replies to complaints	27,448	20	Working Days	90	92	8.25	98.36

(A) The services shown in the table refer to 29,709,670 low-voltage final customers.
Source: As declared by operators to Authority

TAB. 29 SUMMARY OF OVER ALL STANDARDS FOR MEDIUM-VOLTAGE CUSTOMERS: ENEL GROUP (ENEL + DEVAL), 2ND SEMESTER 2000

Service	No. Requests/Year	Authority Standard	Unit Of Measurement	% Respecting Authority Standard	% Improving on Authority Standard	Actual Time	% Actually Respecting
Estimate for complex works	3,345	40	Working Days	80	82	14.66	98.87
Execution complex works	583	60	Working Days	80	82	13.56	99.65
Billing corrections	7	15	Working Days	95	97	6.29	100.00
Meter inspections	28	10	Working Days	95	97	4.64	100.00
Voltage checks	11	10	Working Days	95	97	5.36	100.00
Replies to complaints	1,855	20	Working Days	95	97	8.20	98.75

(A) The services shown in the table refer to 91,991 medium-voltage final customers.
Source: As declared by operators to Authority

TAB. 30 SUMMARY OF SPECIFIC STANDARDS FOR LOW-VOLTAGE CUSTOMERS, 2ND SEMESTER 2000

Company	Final Customers	Service	Standard Set	No. Requests/Year	% Off Standard	Actual Time
AEM – Torino	248,712	Punctuality personal appointments	2 hours	277	3.36	7.34
AMSP - Seregno (MI)	20,082	Execution simple works with connection	15 working days	55	0.00	4.20
ENEL Distribuzione and Deval	29,709,670	Execution pre-accepted simple works	15 working days	13,301	0.39	4.93

Source: As declared by operators to Authority

TAB. 31 SUMMARY OF SPECIFIC STANDARDS FOR MEDIUM-VOLTAGE CUSTOMERS, 2ND SEMESTER 2000

Company	Final Customers	Service	Standard Set	No. Requests/Year	% Off Standard	Actual Time
AEM – Torino	311	Estimate for execution of complex works	20 working days	0	–	–
AEM – Torino	311	Availability outcome of meter inspections	5 working days	0	–	
AEM – Torino	311	Voltage checks	1 working day	0	–	–
AEM – Torino	311	Replies to written complaints or requests for information	10 working days	2	0.00	5.00
AEM – Torino	311	Punctuality personal appointments	2 hours	0	–	–

Source: As declared by operators to Authority

TAB. 32 REFUNDS FOR FAILURE TO MEET SPECIFIC COMMERCIAL QUALITY STANDARDS. GENERAL SUMMARY, 2ND SEMESTER 2000

Company	No. Refunds	Refunds Paid (Millions Of Lire)
GROUP ENEL (Enel Distribuzione and Deval)	2,599	232,750
LOCAL ELECTRICITY COMPANIES with more than 5,000 final customers	2,172	193,156
TOTAL	4,771	425,906

Source: As declared by operators to Authority

TAB. 33 REFUNDS FOR FAILURE TO MEET SPECIFIC COMMERCIAL QUALITY STANDARDS. GENERAL SUMMARY PER SERVICE, 2ND SEMESTER 2000

Indicator	Gruppo Enel		Operators > 5,000 Users		Total	
	No. Refunds	Refunds Paid (Millions Of Lire)	No. Refunds	Refunds paid (millions of lire)	No. refunds	Refunds paid (millions of lire)
Estimates simple works	219	16.150	307	30,550	526	46.700
Connection	246	19.400	215	33,760	461	53.160
Execution of simple works	188	14.600	18	2.446	206	17.046
Disconnection	90	6.850	1,552	114,150	1,642	121.000
Re-connection for arrears	1,815	172.650	71	5,950	1,886	178.600
Execution of pre-accepted simple works (A)	–	–	0	0.000	0	0.000
Execution of pre-accepted simple works (A)	41	3.100			41	3.100
Punctuality personal appointments (A)	–	–	- 9	6,300	9	6.300
Availability outcome meter inspections (A)	–	–	- 0	0.000	0	0.000
Estimate execution						
Replies complaints info requests (A)	–	–	0	0.000	0	0.000
Voltage checks (A)	–	–	0	0.000	0	0.000
TOTAL	**2,599**	**232.750**	**2,172**	**193.156**	**4,771**	**425.906**

(A) Further specific standards defined by operator.
Source: As declared by operators to Authority

Regulation and monitoring of service quality in the supply of electricity

Investigations: Individual proceedings against Enel Distribuzione

The formal investigation into Enel Distribuzione that was opened on 13 December 2000 through Authority Decision 225 was completed in 2001. Enel was found to have provided incorrect information on the duration and number of interruptions in the electricity service in Campania, Calabria and Sicily in 1998 and 1999. During the investigation Enel Distribuzione submitted a defence brief and service continuity data for 2000; these show that in the three regions the continuity data for 1998 and 1999 substantially under-estimated interruptions. The misleading data concern a geographical area that includes 22.6% of all low-voltage customers supplied by Enel Distribuzione in 1999, or around 21% of low-voltage users at the national level. In absolute terms the low-voltage customers at 31 December 1999 numbered 1.17 million in Calabria region, 2.37 million in Campania and 2.79 million in Sicily.
The specific nature of service continuity in the three regions made the situation worse. Overall, a comparison with the data for 2000 led the Authority to estimate that in 1999 the situation was over 80% more serious than implied by the data submitted.

The Authority recognised in part the extenuating circumstances cited by Enel Distribuzione, including the non-intentional nature of the occurrence, the action taken to remove the causes of the misreporting and the absence of any previous penalties against Enel Distribuzione. In Decision 99 of 3 May 2001 the Authority decided to fine the company 90 billion lire.
At the same time the Authority opened a second procedure against Enel Distribuzione, with the aim of setting new continuity performance targets for the three regions, given that the levels set by Decision 144 of 3 August 2000 had been based on incorrect information.
Following the submission of technical briefs and a series of hearings, Authority Decision 166 of 19 July 2001 concluded the procedure for setting new performance targets for Campania, Calabria and Sicily. The new annual improvement goals were gauged in such a way as to enable them to meet the final target for 2004; however, on the basis of information emerging during the procedure the Authority changed the initial proposal to make the investment effort required more gradual and therefore easier to achieve. The new targets will require Enel Distribuzione to accelerate its service quality improvement effort in Campania, Calabria and Sicily. An average improvement of 60% with respect to the starting level of 2000 is required for the three regions by the end of the period 2001-2003, compared with 40% for Southern Italy on the basis of the old data and an average level of 32% for the country as a whole.

Investigations: the implementation of service continuity regulation

Ordinarily, the Authority carries out technical checks on the service continuity data rovided by distribution companies in order to establish whether operators have respected the interruption-recording requirements arising from Decision 128/1999, and whether the data can be used in regulating electricity service continuity (Decision 202/1999). During the checks carried out in 2001 on service continuity data for 2000, attention focused on three aspects:

- the accuracy of the data on interruptions recorded by operators;
- the precision of the service continuity data provided by operators;
- documentary evidence of *force majeure* and external causes, since interruptions arising from these causes can be excluded from the calculation of the benchmark indicator used to ascertain whether the performance targets have been achieved.

To this end the Authority drew up three indices for the evaluation of the results of the technical checks and, in Decision 178 of 1 August 2001, defined the criteria for the evaluation of the results of the technical checks and the determination, in the event of negative results, of the “presumed value” of the benchmark indicator used for the regulation of service continuity.

Indices and criteria for the evaluation of the results of the technical checks on service continuity (Decision 178/2001)

The Authority set up three indices for the evaluation of the results of the technical checks on service continuity:

a) the accuracy index, which is intended to provide an estimate of the completeness and accuracy of the records taken by operators of interruptions originating on the MV network. It is built up by classifying the interruptions on the basis of errors found in the records and allocating a differentiated weighting according to the gravity of these errors. The highest weighting is applied for failure to record an interruption and the lowest for records with errors of 1 minute more or less in the start time and between 1 and 10 minutes in the end-time of the interruption. Intermediate weightings are attributed to other types of incomplete or inexact records. In cases where there is more than one type of incompleteness or inaccuracy in the record of an interruption, the record is classified on the basis of the most serious of these. The accuracy index ranges from 0 (total inaccuracy) to 100% (maximum accuracy).

b) the precision index, which is intended to provide an estimate of the overall value of the benchmark indicator the operator has submitted to the Authority, for recordings taken by the operator. Since errors in the recording of data can be compensated for, the precision index uses a different algebraic sign to note errors falling short of or exceeding the true value. The precision index is calculated only on long unannounced interruptions recorded by the operator on the MV network, by comparing the correctly calculated interruption-time for the sample examined with the duration measured by the operator. A precision index rating of 0% indicates maximum accuracy.

c) The correctness index, which is intended to ascertain whether interruptions have been correctly attributed to force majeure, external causes, or the national/high voltage grid. These interruptions are excluded from the economic treatment of unannounced interruptions. The correctness index ranges from 0 to 100, with 0 indicating totally incorrect attribution of force majeure and external causes and 100% indicating maximum correctness in the attribution of the causes and origins cited for the interruptions.

To evaluate the outcome of the service continuity checks, the Authority has established that all three indices must provide adequate values if the data for the area covered by the checks are to be considered as valid. The evaluation criterion is based on a "tolerance" band for each of the three indices, and on whether or not the values for these indices fall within this band in the areas covered by the check, as indicated below:

- *over 90% for the accuracy index;*
- *between –3% and +3% for the precision index;*
- *value higher than a threshold set, for each area covered by the check, in such a way that the results satisfy the following condition: the percentage weighting of interruptions incorrectly excluded from the economic treatment of the interruptions must not be greater than 3% of the benchmark indicator for the area in question, as declared by the operator.*

In the event that, following sample checks on the service continuity data provided by operators, the Authority establishes that these data have not been recorded properly, the Authority itself defines the presumed benchmark value for the area in question.

The checks on the service continuity data are carried out in the operators' remote checking centres; each centre generally covers more than one area, and therefore more than one set of continuity data. In the course of 2001, 10 Enel remote checking centres were checked (distributed evenly between North, Centre and South) and 4 remote checking centres run by local distribution companies (Aem Milano

S.p.A., Aem Torino, Asm Brescia S.p.A. and Acea Roma, S.p.A.). Overall, sample checks were carried out on about 20% of the geographical areas.

Decision 27 of 28 February 2002 is the first of the annual decisions envisaged under the new system of incentives and penalties defined by the Authority that entered into force on 1 January 2002 for Enel and the main local distribution companies, and which will gradually be extended to the other local distributors.

The first effects of this new system suggest a significant improvement in service continuity in 2000 and 2001. In the 17 regions served by Enel for which data are also available for 1999, the average improvement from 1999 to 2001 is 31% for the average number of interruptions per customer; 26% for the total accumulated duration (minutes lost per customer, for all causes); and 49% for the net accumulated duration (minutes lost per customer, only for interruptions for which the distribution company is responsible).

In the three regions served by Enel for which valid data for 1999 are not available (Campania, Calabria and Sicily) and for which more rigorous continuity improvement requirements have been drawn up with effect from 2001, there was a considerable improvement between 2000 and 2001 in terms of minutes lost per customer. From 1999 to 2000, on the other hand, there was an increase in announced interruptions in Enel regions, presumably as a result of the introduction of recording obligations (Decision 128/1999) that were not in force in 1999. In the cities served by local distribution companies, announced interruptions did not increase to the same extent and in 2001 were at the same level as in 2000.

TAB. 34 LONG UNANNOUNCED INTERRUPTIONS SUMMARY ENEL GROUP
Average number and duration per client; whole country (A).

Region	2000			2001		
	Average no. interruptions	Total accumulated duration	Net accumulated duration	Average no. interruptions	Total accumulated duration	Net overall duration
PIEDMONT	3.5	213	108	2.7	127	99
VALLE D'AOSTA	3.5	688	72	1.8	83	59
LIGURIA	4.0	154	105	2.5	89	77
LOMBARDY	1.8	91	61	3.5	95	51
TRENTINO ALTO ADIGE	5.3	373	220	2.7	143	76
VENETO	2.6	127	91	1.8	119	77
FRIULI VENEZIA GIULIA	2.4	120	89	3.5	68	58
EMILIA ROMAGNA	2.0	101	75	2.2	122	65
TUSCANY	4.3	193	157	3.3	120	100
MARCHE	2.8	126	101	2.5	102	82
UMBRIA	3.2	169	148	2.3	95	81
LAZIO	4.4	231	198	4.1	179	146
ABRUZZO	3.5	197	161	3.4	181	112
MOLISE	3.1	171	138	4.0	162	141
CAMPANIA	5.1	259	223	4.9	236	163
PUGLIA	4.0	310	249	3.6	258	175
BASILICATA	4.3	304	275	4.9	435	308
CALABRIA	9.9	535	333	8.2	327	257
SICILY	6.0	362	284	5.8	311	179
SARDINIA	6.9	368	309	7.4	486	210
NORTH	2.6	139	85	2.3	109	69
CENTRE	4.0	197	165	3.3	133	110
SOUTH	5.7	330	259	5.3	291	183
SOUTH(E)	4.6	294	242	4.5	302	177
ITALY	3.9	218	162	3.6	181	118
ITALY(E)	3.3	179	132	2.9	151	97

(A) Average weighted value of continuity levels in areas of high, medium and low concentration.
(B) Minutes lost per customer, unannounced interruptions for any cause.
(C) Minutes lost per customer; only unannounced interruptions for which distributor responsible.
(D) Where necessary, the presumed values set by the Authority in Decision 27/02 have been used for those areas where technical inspections have given a negative outcome.
(E) Excluding Calabria, Campania and Sicily; data from comparison with 1999.

Source: As declared by operators to Authority

TAB. 35 LONG UNANNOUNCED INTERRUPTIONS SUMMARY LOCAL ELECTRICITY COMPANIES WITH MORE THAN 100,000 FINAL CUSTOMERS (A)
Average number and length of interruptions by customers; whole country (A)

Region	2000			2001		
	Average no. interruptions	**Total accumulated duration (C)**	**Net accumulated duration (C)(D)**	**Average no. interruptions**	**Total accumulated duration (B)**	**Net overall duration (B)**
ACEA – Roma	2.7	127	88	2.6	98	73
AEM – Milano	1.5	66	37	1.9	60	35
AEM – Torino	2.4	108	62	2.3	51	36
ACEGAS - Trieste	1.7	55	41	1.3	43	34
ASM – Brescia	0.9	26	24	1.3	41	33
AEC - Bolzano	2.3	103	ND	3.5	66	31
META - Modena	0.5	13	11	1.2	40	37

(A) Average weighted value of continuity levels in areas of high, medium and low concentration.
(B) Minutes lost per customer, unannounced interruptions for any cause.
(C) Minutes lost per customer; only unannounced interruptions for which distributor responsible.
(D) Where necessary, the presumed values set by the Authority in Decision 27/02 have been used for those areas where technical inspections have given a negative outcome.

Source: As declared by operators to Authority

TAB. 36 LONG INTERRUPTIONS WITH NOTICE SUMMARY GRUPPO ENEL
Average number and length of interruptions by customers; whole country (A)

Region	2000		2001	
	AVERAGE N0. INTERRUPTIONS	TOTAL ACCUMULATED DURATION (B)	AVERAGE N0. INTERRUPTIONS	TOTAL ACCUMULATED DURATION (B)
PIEDMONT	0.6	61	0.5	62
VALLE D'AOSTA	2.0	241	1.3	158
LIGURIA	0.3	39	0.2	29
LOMBARDY	0.4	46	0.5	53
TRENTINO ALTO ADIGE	0.8	85	0.8	84
VENETO	1.0	142	0.9	124
FRIULI VENEZIA GIULIA	0.8	76	0.8	116
EMILIA ROMAGNA	0.8	102	0.6	89
TUSCANY	0.9	126	0.8	108
MARCHE	1.1	149	1.1	154
UMBRIA	1.7	201	2.1	225
LAZIO	1.1	197	1.6	291
ABRUZZO	1.5	258	1.6	257
MOLISE	1.4	275	1.3	240
CAMPANIA	0.4	70	0.4	82
PUGLIA	0.7	106	0.7	117
BASILICATA	1.4	216	1.3	215
CALABRIA	1.6	365	1.6	344
SICILY	1.4	262	1.3	282
SARDINIA	0.9	175	0.8	167
NORTH	0.6	78	0.6	75
CENTRE	1.1	163	1.2	184
SOUTH	1.0	188	1.0	194
ITALY	0.9	134	0.8	138

(A) Average weighted value of continuity levels in areas of high, medium and low concentration.
(B) Minutes lost per customer, unannounced interruptions for any cause.

Source: As declared by operators to Authority

TAB. 37 LONG INTERRUPTIONS WITH NOTICE SUMMARY LOCAL ELECTRICITY COMPANIES WITH MORE THAN 100,000 FINAL CUSTOMERS
Average number and length of interruptions by customers; whole country (A)

Company	2000		2001	
	Average N0. Interruptions	Total Accumulated Duration (B)	Average N0. Interruptions	Total Accumulated Duration (B)
ACEA – Roma	0.1	9	0.2	20
AEM – Milano	1.2	82	1.0	63
AEM – Torino	0.2	17	0.2	16
ACEGAS - Trieste	0.2	22	0.3	26
ASM – Brescia	0.5	23	0.3	17
AEC Bolzano	0.5	39	0.6	56
META – Modena	0.3	17	0.3	18

(A) Average weighted value of continuity levels in areas of high, medium and low concentration.
(B) Minutes lost per customer, unannounced interruptions for any cause.

Source: As declared by operators to Authority

For each of the 230 zones the incentives or penalties applied to distributors are set in relation to their continuity improvement targets on the basis of a moving bi-annual average. For 1999-2000 the average improvement target was 11% with respect to the 1998-1999 value. The system uses average bi-annual values for the overall duration of interruptions to ensure greater stability since the effects of meteorological events on service continuity data vary over time.
Interruptions attributable to *force majeure* or third parties are excluded. The system envisages incentives for geographical areas that improve by more than the target level, and penalties for areas failing to meet the target. For areas coming close to their objective (give or take 5%) no penalties or incentives are envisaged.
In 2000, 57 areas reached their target improvement levels, 79 exceeded them, and 75 fell short. Finally, in 19 zones the continuity levels are already in line with European standards, in which case the requirement is to maintain the level already achieved.

International comparison of regulatory strategies for service quality

In 2001 the international comparison of regulatory strategies for service quality carried out by a CEER working group coordinated by a representative of the Italian regulatory Authority was completed. The final report: *Quality of electricity supply: initial benchmarking on actual levels, standards and regulatory strategies* was published in April 2001 and discussed at a CEER seminar in Milan on 8 June 2001 with representatives of over 20 European nations and international experts. The report is available on the Authority's Internet site. The international comparison made it possible to assess the aims and instruments applied in the regulation of service quality in the different countries taking part in the working group (Holland, Italy, Norway, Portugal, Spain and United Kingdom).
In terms of commercial quality, the regulatory approach is largely similar across countries. Commercial quality is regulated through general and specific standards linked to refund mechanisms when the standards are not respected. Differences are found with respect to which services are subject to specific standards and which to general standards, and to the procedures for obtaining refunds (on application or automatically). The amount of the automatic refunds also varies from one country to another. The actual levels, standards and regulatory mechanisms for service continuity are more uneven. There are still significant differences in definitions and above all in data-recording methods, which makes it difficult to compare continuity levels. The working group has launched a comparative exercise on this front that is still on-going; the differences in quality levels recorded can be attributed in part to differing levels of

service reliability, and in part to exogenous factors such as population density, geographical and relief features, and the structure of the network.

THE GAS SECTOR

In 2001 work continued on the collection of data on the quality of the service provided to final customers under the rules set out in the Service Charters, in order to assess their adoption and implementation by operators.

With effect from 1 January 2001, with the entry into force of Decision 47/2000, the Authority introduced new commercial quality regulations which substitute the previous general reference framework set out by the Service Charter for the gas sector. Decision 47/2000 was partly amended by Decision 334 of 28 December 2001, which takes into account the company separation imposed on the major operators with effect from 1 January 2002 by Legislative Decree 164/2000.

In the course of 2001 contacts continued between the Authority and the technical bodies and associations in the sector in order to complete the regulations required for the full implementation, from 1 January 2002, of Decision 236/2000 regulating the security and continuity of the gas distribution service.

Gas service quality indicators

In 2001 the Authority carried out the fifth annual survey of gas service quality. This included, for the last time, a check on whether the commercial standards declared by operators in their Service Charters were being respected and, using the data provided by operators, also included security and service continuity, with an evaluation of the quality levels achieved in 2000.

At 31 December 2000, 516 operators declared they had adopted the Service Charters. The percentage of gas service customers whose operator had adopted a Charter remained substantially unchanged for 2000, taking into account the increase in final customers in the sector; this amounts to about 93% of all users, for a total of 15 million customers. Those operators who do not yet have Service Charters in place are mainly small operators with less than 10,000 customers.

TAB. 38 DEGREE OF ADOPTION OF SERVICE CHARTER

OPERATORS AND CUSTOMERS	LARGE OPERATORS	MEDIUM OPERATORS	SMALL OPERATORS	TOTAL
NUMBER OF SERVICE CHARTERS ADOPTED				
1997	20	155	326	501
1998	21	157	353	531
1999	21	144	332	497
2000	22	148	346	516
CUSTOMERS OF OPERATORS WHO HAVE ADOPTED SERVICE CHARTER (millions)				
1997	9.0	3.9	1.1	14.0
1998	9.4	4.3	1.2	14.9
1999	9.6	4.2	1.1	14.9
2000	9.7	4.2	1.1	15.0

Large operators: operators with more than 100,000 customers.
Medium operators: operators with between 10,000 and 100,000 customers.
Small operators: operators with less than 10,000 customers.

Source: As declared by operators to Authority

Overall, the findings of previous years appear to be confirmed for 2000:

- standards differ, both for large operators and, to a more marked degree, for medium- and small-sized concerns;
- the percentage of non-standard cases is relatively low for all services, especially among small operators;
- on average there is a gap between actual levels and the maximum levels declared by operators in their Service Charters;
- most big operators have checked on whether they are respecting the specific standards, especially with regard to estimates, the installation of complete plants, and the connection and disconnection of supply.

TAB. 39 SUMMARY SPECIFIC STANDARDS: LARGE OPERATORS

Service	Cases 2000 (A)	Standard 2000 Days			Off Standard (E) %		Actual Days (F)	
		AVERAGE (B)	MINIMUM (C)	MAXIMUM (D)	2000	1999	2000	1999
Estimates	168,128	18.5	10	60	1.7	2.2	7.5	8.1
Aerial line connections	63,643	22.3	60	2.0	3.0		10.6	10.8
Full installations	37,439	34.6	15	90	5.5	3.6	17.5	22.0
Connections and reconnections	507,053	7.3	3	15	0.4	0.8	2.9	3.7
Disconnections	260,376	7.2	3	10	1.3	0.7	3.2	4.0
Replies written enquiries	3,129	27.4	15	30	5.2	4.8	12.6	12.7
Replies complaints	7,986	22.9	20	30	15.2	5.3	14.5	7.8
Billing corrections	387,907	11.4	7	80	1.0	0.3	17.2	2.4
Re-connection late paying customers	12,831	3.5	1	7	2.4	0.0	1.6	1.1
Meter inspections	2,973	7.6	5	20	2.8	1.7	5.6	4.6
Pressure checks	1,137	4.1	2	20	0.6	0.7	0.9	2.4
Planned suspensions (G)	22,046	10.1	6	72	0.0	0.0	3.3	1.7
Rapid response (H)	114,468	60.4	0	120	8.3	4.5	40.5	25.0

Cases: total number requests for the services indicated.
(B) Average value standard: weighted average value of the standards for the services indicated.
(C) Minimum value standard: minimum value for the standards declared.
(D) Maximum value standard: maximum value for the standards declared.
(E) Percentage off standard: percentage of cases where longer time elapsed before service was provided for causes for which operator responsible.
(F) Actual: weighted average value of actual time taken.
(G) Time measured in hours
(H) Time measured in minutes.

Source: As declared by operators to Authority

TAB. 40 SUMMARY SPECIFIC STANDARDS: MEDIUM OPERATORS

Service	Cases 2000 (A)	Standard 2000 Days			Off Standard (E) %		Actual Days (F)	
		AVERAGE (B)	MINIMUM (C)	MAXIMUM (D)	2000	1999	2000	1999
Estimates	100,552	22.7	3	60	1.2	0.9	10.0	11.1
Aerial Line	33,990	30.8	0	90	0.7	0.8	14.2	18.9
Full installations	53,037	43.1	4	90	1.8	1.9	23.6	26.2
Connections and re-connections	185,640	7.3	1	20	1.3	0.9	3.2	3.7
Disconnections	125,171	6.2	2	30	1.1	0.8	3.1	3.2
Replies Written enquiries	7,190	24.3	8	40	4.8	3.9	18.1	18.1
Replies complaints	2,542	25.6	8	40	6.4	3.3	17.4	18.0
Billing corrections	32,319	14.9	1	90	1.5	2.5	6.6	18.1
Re-connection late-paying customers	10,170	3.6	0	60	0.3	0.0	1.5	1.4
Meter checks	2,715	8.6	1	90	2.5	7.4	5.0	10.9
Pressure checks	2,349	4.1	1	20	0.3	1.1	1.8	2.4
Planned suspensions	4,152	21.2	1	48	0.0	0.4	4.8	7.6
Rapid response H)	27,339	57.0	20	180	1.3	2.9	32.8	43.7

Cases: total number requests for the services indicated.
(B) Average value standard: weighted average value of the standards for the services indicated.
(C) Minimum value standard: minimum value for the standards declared.
(D) Maximum value standard: maximum value for the standards declared.
(E) Percentage off standard: percentage of cases where longer time elapsed before service was provided for causes for which operator responsible.
(F) Actual: weighted average value of actual time taken.
(G)Time measured in hours
(H)Time measured in minutes.

Source: As declared by operators to Authority

TAB. 41 SUMMARY SPECIFIC STANDARDS: SMALL OPERATORS

Service	Cases 2000 (A)	Standard 2000 Days			Off Standard (E) %		Actual Days (F)	
		AVERAGE (B)	MINIMUM (C)	MAXIMUM (D)	2000	1999	2000	1999
Estimates	32,080	20.3	1	50	0.5	0.8	8.3	9.0
Aerial line connections	15,294	22.2	2	60	0.5	1.6	12.4	14.1
Full installations	21,581	41.0	3	90	0.8	1.9	20.9	24.1
Connections and re-connections	47,645	7.5	1	20	0.2	0.3	2.8	8.0
Disconnections	30,709	6.2	1	375	0.4	0.5	2.9	2.9
Replies written enquiries	1,961	25.9	3	0	0.5	0.5	12.4	14.8
Replies complaints	711	24.8	2	30	2.3	1.4	9.3	14.5
Billing corrections	8,056	14.1	1	90	0.4	0.2	6.8	6.6
Re-connection late-paying cutomers	2,313	4.3	1	30	0.7	0.0	1.7	1.5
Meter checks	1,894	11.2	1	60	0.3	0.8	4.2	3.5
Pressure checks	1,594	5.2	1	30	0.2	0.3	2.7	2.7
Planned suspensions	517	14.3	4	48	0.0	0.7	4.8	4.3
Rapid response (H)	7,676	60.9	15	180	0.8	0.6	26.5	29.6

Cases: total number requests for the services indicated.
(B) Average value standard: weighted average value of the standards for the services indicated.
(C) Minimum value standard: minimum value for the standards declared.
(D) Maximum value standard: maximum value for the standards declared.
(E) Percentage off standard: percentage of cases where longer time elapsed before service was provided for causes for which operator responsible.
(F) Actual: weighted average value of actual time taken.
(G) Time measured in hours
(H) Time measured in minutes.

Source: As declared by operators to Authority

Refunds to customers

The general reference framework of the Service Charter for the gas sector envisages that operators should set at least 4 specific quality standards, failure to respect which entails a refund for the customer in question.
For 2000 there was a marked increase, from 1,640 to 3,709, of refunds to customers, nearly all of which automatic; much of this increase was produced by Italgas S.p.A., which made 497 refunds in 1999 and 2,241 in 2000, and by Napoletana Gas, with 867 refunds in 1999 and 1,306 in 2000.
Compared with 1999, there was an increase in the number of cases where operators, especially large operators, failed to respect the standards subject to refund. This increase may be the result of more accurate measurement and monitoring of the quality provided to final customers.

TAB. 42 REFUNDS TO CUSTOMERS

Cases	Large Operators (A)	Medium Operators (B)	Small Operators (C)	Total 2000	Total 1999
Cases of failure to respect standards (D) subject to refund - causes for which operators responsible	10,394	3,923	318	14,635	11,212
Number of customer requests for refunds	10	16	1	27	256
Number of refunds paid	3,567	131	11	3,709	1,640
Of which automatic refunds	3,560	116	11	3,687	1,479
Total Amount Refunds Paid Millions Of Lire	211.3	11.1	1.1	223.5	134.3

Large operators: operators with more than 100,000 customers.
Medium operators: operators with between 10,000 and 100,000 customers.
Small operators: operators with less than 10,000 customers.
Standard: maximum time, measured in calendar days, declared in the Service Charters in force for the year under consideration, to provide the customer with the service requested.

Source: As declared by operators to Authority

TAB. 43 TREND IN NUMBER OF CASES OF FAILURE TO RESPECT STANDARDS SUBJECT TO REFUND

Cases of failure to respect standards (D) subject to refund - causes for which operators responsible	Large Operators (A)	Medium Operators (B)	Small Operators (C)	Total
1997	10,707	3,172	386	14,265
1998	8,814	2,880	672	12,366
1999	6,943	3,984	285	11,212
2000	10,394	3,923	318	14,635

Large operators: operators with more than 100,000 customers.
Medium operators: operators with between 10,000 and 100,000 customers.
Small operators: operators with less than 10,000 customers.
Standard: maximum time, measured in calendar days, declared in the Service Charters in force for the year under consideration, to provide the customer with the service requested.

Source: As declared by operators to Authority

The survey of gas service quality also examined, as aspects of the rapid intervention service, the percentage of medium- and low-pressure network inspected and gas odourisation.

The rapid intervention service

The rapid intervention service in response to third party calls is an important way of dealing rapidly with potentially dangerous situations before they develop into full-blown incidents.
A wide range of values emerged with respect to the average call frequency, with some very low values, such as those for Aem S.p.A. in Milan, Società Gas Rimini and Asco Piave, and others well above the average, such as Consiag-Prato, Fiorentina Gas and Amg-Palermo. However, this difference can be explained by the differences in the definitions of rapid intervention, types of installation, or the state of the installations resulting from higher or lower frequency of inspections of the underground network, or the type of material and age of the distribution networks.

TAB. 44 RAPID RESPONSE: LARGE OPERATORS

Operators	2000						1999	
	Customers (A)	**Cases Every 1000 Customers**	**Cases (B)**	**Standard (Minutes) (C)**	**Off Standard % (D)**	**Actual (Minutes) (E)**	**Off Standard % (D)**	**Actual (Minutes) (E)**
ITALGAS	4,541,681	14.6	66,098	60	3.8	35.0	9.5	35.4
CAMUZZI – GAZOMETRI	862,332	18.6	15,998	60	0.0	28.1	0.0	26.2
AEM – MILANO	820,625	2.5	2,075	60	0.0	21.8	0.0	22.5
NAPOLETANA GAS	570,644	15.2	8,663	60	5.1	81.0	5.0	67.0
SEABO – BOLOGNA	350,137	0.4	129	120	5.4	51.0	N/A	N/A
ITALCOGIM	342,065	10.3	3,512	45	1.6	20.2	0.2	20.1
AMGA – GENOVA	316,446	N/A	N/A	N/A	N/A	N/A	0.0	87.0
FIORENTINA GAS	300,722	23.6	7,094	60	9.1	36.0	29.2	74.0
AGAC – REGGIO EMILIA	180,663	5.7	1,031	120	N/A	60.0(E)	N/A	60.0(E)
SICILY GAS	168,569	20.9	3,519	60	0.9	22.4	3.6	30.3
ASM – BRESCIA	151,220	14.4	2,179	N/A	N/A	52.9(E)	N/A	20.6(E)
SOGEGAS	148,229	13.1	1,939	60	2.2	24.8	80.9	27.2
CONSIAG – PRATO	145,804	N/A	N/A	N/A	N/A	N/A	N/A	N/A
AGES – PISA	137,181	12.5	1,710	N/A	N/A	35.2(E)	N/A	30.0(E)
SOCIETÀ GAS RIMINI	127,133	2.9	368	60	0.8	20.0	6.6	21.0
ASCO – PIAVE	126,581	4.2	534	120	13.4	91.0	9.7	53.0
AMAG – PADOVA	123,441	2.8	350	120	0.0	60.0	N/A	N/A
AGSM – VERONA	122,881	5.8	708	N/A	N/A	62.0(E)	N/A	56.0(E)
META – MODENA	117,312	5.7	665	60	0.0	N/A	0.0(E)	N/A
ACEGAS – TRIESTE	113,109	15.8	1,791	60	N/A	43.3(E)	N/A	40.0(E)
AMG – PALERMO	110,667	15.6	1,725	120	23.5	99.4	11.7	55.6
AGAS	101,804	8.6	875	60	0.1	29.3	0.3(E)	30.2(E)

(A) Number of customers: number of customers at 31 December of the year under consideration.
(B) Number of cases: number of requests received from customers during 2000 for the service under consideration.
(C) Standard: Maximum time declared in the Service Charters (expressed in minutes).
(D) Percentage off standard: percentage of requests not responded to in maximum declared time.
(E) Actual: actual time for execution of requested service achieved during the year, calculated as weighted average on number of cases and measured in minutes.
(F) Time of arrival at place of call for rapid response: the time, expressed in minutes, between the call from the customer and the arrival of the rapid response team at the place of call.
However, some operators interpret the concept of rapid response differently and define the time of arrival at the place of the call in a different manner.

Network inspections to identify gas leaks

The inspection of the network to identify gas leaks is one of the most important safety aspects of the gas distribution infrastructure. To evaluate progress on the quantity of network inspected, the data were grouped according to the type of network (medium and low pressure) and for each of the three groups of operators (large, medium and small). Over the last year there was an increase of about 1% in the percentage of low-pressure network inspected, compared with a reduction of 7% for the medium-pressure networks (44% of the network inspected compared with 51% the previous year).
This reduction can be attributed mainly to Italgas, which in 1999 reduced the quantity of medium-pressure network inspected with respect to the previous year.
The survey showed that 200 medium-pressure operators and 196 low-pressure operators, covering about 10% of the customers served, did not inspect any stretches of the network. These data confirm the marked divergence in the choices made by operators, and the different degrees of protection provided for the public (TAB. 47).

TAB. 45 NETWORK INSPECTED: LOW PRESSURE

Operators	Customers (D)	Extent Of Network In Km (E)	Metres Of Network/ Customer	Extent Of Network Inspected Km	Network Inspected 2000 %	Network Inspected 1999 %
Large (A)	9,979,246	62,842	6.3	21,518	*34.2*	*38(F)*
Medium (B)	3,537,001	34,274	9.7	10,756	*31.4*	*27*
Small(C)	1,130,195	13,363	11.8	5,217	*39.0*	*31*
Total	14,646,442	110,479	7.5	37,491	*33.9*	33

Large operators: operators with more than 100,000 customers.
Medium operators: operators with between 10,000 and 100,000 customers.
Small operators: operators with less than 10,000 customers.
Number of customers: number of customers at 31 December of the year under consideration.
Total metres of network existing at 31 December 1999 against number of customers at 31 December 2000.
For the comparison between 2000 and the previous year the percentage of network inspected in 1999, including Meta-Modena and Agas, was re-calculated.

Source: As declared by operators to Authority

Gas odourisation

With regard to gas odourisation, operators were evaluated on the basis of the average level of odourisation of the gas distributed and the type of odorising agent used. The odourisation levels were examined separately for THT (main component tetrahydrothiophene) and TBM (main component tertiary-butyl-mercaptan), which are the main agents used by operators to give the gas its characteristic odour. This makes it possible to smell the presence of gas, which in itself is odourless, in the air before it reaches dangerous levels, with the risk of explosion. In several of its operational zones Italgas uses both types of odorising agent.
An examination of the data shows that there are 10 operators using THT, serving about 18,000 customers, and 13 operators using TBM, serving about 84,000 customers, who were not able to indicate the quantities of odorising agent introduced to the gas distributed.

TAB. 46 NETWORK INSPECTED: MEDIUM PRESSURE

Operators	Customers (D)	Extent Network In Km (E)	Metres Of Network/Customer	Extent Of Network Inspected Km	Network Inspected 2000 %	Network Inspected 1999 %
Large (A)	9,798,583	34,709	3.5	16,628	*47.9*	*48(F)*
Medium (B)	3,634,506	20,650	5.7	8,297	*40.2*	*37*
Small(C)	1,159,069	9,874	8.5	4,527	*45.8*	*43*
Total	14,592,158	65,233	4.5	29,452	*45.1*	44

Large operators: operators with more than 100,000 customers.
Medium operators: operators with between 10,000 and 100,000 customers.
Small operators: operators with less than 10,000 customers.
Number of customers: number of customers at 31 December of the year under consideration.
Total metres of network existing at 31 December 1999 against number of customers at 31 December 2000.
For the comparison between 2000 and the previous year the percentage of network inspected in 1999, including Meta-Modena and Agas, was re-calculated. Acag-Reggio Emilia was not included in the calculation of the values in the table as it did not provide the necessary data.

Source: As declared by operators to Authority

TAB. 47 GAS ODOURISATION (A) : LARGE OPERATORS

Operator	Customers (D)	Total Gas Purchased M^3	Type Of Odorising Agent (B)	Total Odorising Agent Introduced Kg	Average Degree Of Odourisation 2000(C) Mg/ M^3	Average Degree Of Odourisation 1999 Mg/M^3
ITALGAS.	1,431,919	1,402,220,448	THT	47,420	33.8	37.2
ITALGAS	211,823	238,611,971	TBM	3,893	16.3	18.5
ITALGAS	3,370,954	5,393,036,610	THT+TBM	101,860	18.9	30.0
CAMUZZI – GAZOMETRI	862,332	1,435,760,724	TBM	29,976	20.9	19.0
AEM – MILANO	820,625	1,020,248,974	TBM	20,316	19.9	21.5
NAPOLETANA GAS	570,644	427,413,947	THT	20,000	46.8	38.3
SEABO – BOLOGNA	350,137	748,657,786	THT	27,299	36.5	36.5
ITALCOGIM	342,065	387,215,585	TBM	4,756	12.3	11.6
AMGA – GENOVA	316,446	358,801,892	THT	11,482	32.0	32.0
FIORENTINA GAS	300,722	527,851,000	THT	35,441	67.1	62.5
AGAC – REGGIO EMILIA	180,663	525,051,781	THT	16,842	32.1	30.7
SICILYNA GAS	168,569	142,541,295	TBM	1,293	9.1	10.6
ASM – BRESCIA	151,220	333,494,662	THT	12,467	37.4	38.2
SOGEGAS	148,229	286,787,918	TBM	3,011	10.5	9.5
CONSIAG – PRATO	145,804	324,392,619	THT	9,334	28.8	32.4
AGES – PISA	137,181	266,754,701	THT	8,002	30.0	24.8
SOCIETÀ GAS RIMINI	127,133	255,089,058	TBM	4,800	18.8	16.3
ASCO – PIAVE	126,581	371,883,853	THT	7,245	19.5	19.6
AMAG – PADOVA	123,441	296,741,654	THT	11,420	38.5	32.9
AGSM – VERONA	122,881	299,793,436	TBM	4,311	14.4	20.7
META – MODENA	117,312	284,363,388	THT	6,182	21.7	19.1
ACEGAS – TRIESTE	113,109	136,199,882	THT	4,961	36.4	42.7
AMG – PALERMO	110,667	53,602,896	TBM	681	12.7	12.4
AGAS	101,804	205,480,341	TBM	2,068	10.1	10.9

(A) Odourisation: process by which a normally odourless gas is made odorous and therefore recognisable.
(B) Odorising agent: substance added to the gas to make it odorous and therefore recognisable.
(C) Degree of odourisation: the quantity of odorising agent present in each unit of volume of gas distributed, measured in milligrams per cubic metre under standard conditions (mg/m^3)
(D) Number of customers: number of customers active at 31 December 2000.

Source: As declared by operators to Authority

Regulation and quality control of the gas supply service

New commercial quality regulation

With Decision 47/2000 the Authority introduced new countrywide commercial quality standards that are obligatory for all operators with more than 5,000 low-pressure customers. These national standards replace the standards defined by the operators themselves in their service charters, which had produced considerable differences in the treatment of customers from one area of the country to another.
The new standards are both specific, and subject to automatic customer refunds when standards are not met for causes that can be attributed to the operator, and general. In order to implement Decision 236/2000 in full, in 2001 contacts continued between the Authority and the various bodies working in the sector to draw up technical rules and Guidelines that will enable uniform arrangements to be introduced for all distributors for the performance of important safety and continuity activities. By 31 December 2003, the Authority will check on the implementation of the security and continuity regulations, using the data submitted by distributors. On the basis of this assessment, the Authority can extend the regulations to distributors who were initially exempted, identify further safety and continuity indicators and amend the service obligations or introduce new ones.

Regulation and consumer protection

Contractual conditions for the supply of the gas service: the aims of the new regulatory arrangements

In 2001 the Authority issued a directive on the contractual conditions for the sale of the gas service (Decision 229 of 18 October 2001). The directive is addressed to operators selling natural or other types of gas over networks.
Directive 229/2001 introduced similar contractual conditions for the sale of gas as those previously applied to the electricity service through Decision 200/1999. In order to provide a minimum level of protection in the liberalised market also, Decision 229/2001 envisages that the contractual guarantees identified by the Authority must also be offered to customers in the free market. In this way, in view also of the fact that from 2003 all customers will be considered eligible, customers presented with different tariff proposals will be able to agree with the operator on the conditions that match their interests most closely, while also being fully informed of the conditions which the Authority considers as minimum guarantees.
Operators selling gas can also offer different contractual conditions from those outlined by the Authority, but only if these are more advantageous to customers. These conditions cannot involve additional costs for customers choosing basic tariff options, and must not create discrimination between customers.
The contractual conditions for the sales service, which in view of their particular importance to final customers the Authority considered should be regulated, are:

- frequency of meter readings;
- frequency and arrangements for billing and paying;
- penalties for late or non-payment;
- conditions, arrangements and duration of suspensions of supply by operators;
- payment by instalments of charges owed by customers;
- forms of guarantee;
- arrangements for complaints.

For customers with average consumption of up to 5,000 m^3 per year the deposit has been replaced by the direct debit system.
The provisions of Directive 229/01 were initially intended to take effect in March 2002; in response to a request by the principal associations representing gas operators, with Decision 21/2002 the Authority postponed implementation to 2 May and 1 July 2002.

The conversion into euros of the unit charges for tariffs and their presentation in bills

Council Regulation (EC) 1103 of 17 June 1997 containing provisions relating to the introduction of the euro included rules for rounding, leaving Member States the option of introducing any other national "rounding practice, convention or national provisions providing a higher degree of accuracy for intermediate computations".
Art. 4 of Legislative Decree 213/1998, containing provisions for the introduction of the euro at the national level, envisages that with effect from 1 January 1999, when a sum in lire contained in laws already in force, including those setting tariffs or administered or other set prices, has to be converted into euros, the sum converted should have at least:

- five decimal figures for sums originally expressed in units of lire;
- four decimal figures for sums originally expressed in tens of lire;
- three decimal figures for sums originally expressed in hundreds of lire;
- two decimal figures for sums originally expressed in thousands of lire.

In Decision 136/2001 the Authority recommended that, independently of the criterion set out in paragraph 1 of Legislative Decree 213/1998, electricity and gas distribution and sales operators should always use six decimal figures when converting into euros unit costs in lire relating to tariffs, administered or set prices (as envisaged by the current rules or by rules no longer in force but applied for corrections or adjustment payments).
The Authority calculated that by using 6 decimal points for any unit charge and extending the criteria proposed by Art. 4 of Legislative Decree 213/98, any discrepancies with respect to the starting value in lire resulting from the changeover from lire to euros and the subsequent re-conversion into lire would be insignificant or non-existent (around 0.001 lire).
Decision 136/01 also envisaged that the intermediate calculations should be carried out using unit charges converted to 6 decimal figures, while individual sums for payment or for accounting purposes should be expressed and used in euros to 2 decimal figures.

ENERGY EFFICIENCY IN FINAL USES, ENERGY SAVINGS AND THE DEVELOPMENT OF RENEWABLE SOURCES

Italy's commitments under the Kyoto Protocol, together with concerns over the possible environmental consequences of the opening of the energy markets to competition, have helped focus attention on the role of energy efficiency in final uses as a means of containing greenhouse gas emissions.
As for the efficient use of resources, Art. 9.1 of Legislative Decree 79/2001 and Art. 16.4 of Legislative Decree 164/2000 envisage that obligations regarding electricity and natural gas distribution services should include a requirement to pursue energy efficiency in final uses on the basis of quantitative targets to be defined in a subsequent ministerial decree. The decrees issued by the Ministry of Industry in concert with the Ministry of the Environment on 24 April 2001 were a response to this provision.

The ministerial decrees of 24 April 2001.

The targets

The decrees of 24 April 2001 set annual national targets for the containment of primary energy consumption for the period 2002-2006. At least half of these targets must be pursued through actions to reduce consumption in final uses of electricity and natural gas.

TAB. 48 NATIONAL QUANTITATIVE TARGETS

Year	Objective (Mtep/Year)	
	Electricity Distribution	Gas Distribution
2002	0.10	0.10
2003	0.50	0.40
2004	0.90	0.70
2005	1.20	1.00
2006	1.60	1.30

At present only distributors and distribution companies supplying at least 100,000 final customers at 31 December 2001 (about 30 in number) are subject to the obligations laid down by the two decrees.
For individual distributors, not less than 50% of the annual target must be met through actions to reduce energy consumption. Distributors are also required to respect informational obligations vis-à-vis the regions or autonomous provinces, and to coordinate their initiatives to meet their specific targets, taking into account any regional and local energy/environmental planning provisions.
To guarantee a certain degree of graduality in the launch of the mechanism, with sole regard to 2002 distributors may include energy savings produced by projects carried out in 2001, as long as these were covered by agreements with the public administration and subject to Authority approval. Moreover, any shortfalls in the energy saving with respect to the objective can be made up in the two subsequent years (2003 and 2004) without incurring any penalty.

Eligible projects

The energy-saving targets must be met through actions or "projects" whose results, in terms of primary energy, are assessed using Guidelines drawn up and published by the Authority, taking into account the opinions of the regions and autonomous provinces and further to consultation with the interested parties.
The types of initiative typically eligible for the purposes of the objectives set by the legislator are listed in Annex 1 to both the decrees. Projects designed to improve the energy efficiency of electricity generating plants are expressly excluded[8]. Each project should generate a primary energy saving for up to five years[9].
The projects can be realised directly by distributors, companies controlled by them, or third party companies operating in the energy services sector (independently or on behalf of distributors).

Energy efficiency certificates

Each year the Authority has to evaluate and certify the energy savings obtained by each project. This is done by issuing "*Titoli di efficienza energetica*" or TEEs (Energy Efficiency Certificates), the value of which is expressed in terms of primary energy savings (TEPs).
TEEs can be exchanged by operators through bilateral contacts or on the certificates market which is to be set up by the Market Operator along with the operational rules for the market itself, in agreement with the Authority.
The possibility of exchanging TEEs will enable distributors for whom projects to achieve savings in final uses would entail high marginal costs to purchase energy-saving certificates (instead of actually carrying out the projects) from those operators who incur relatively low marginal costs to achieve savings, and who will find it advantageous to sell their certificates on the market. The development of the TEEs market is therefore of fundamental importance in containing the overall costs sustained by distributors

[8] With the exception of photovoltaic plants of less than 20 kW.
[9] Specific certification arrangements are also envisaged for products, equipment or components of plants used in the projects or the use of which has been promoted.

and third party companies operating in the energy services sector (*Energy Services Companies* or ESCOs) in order to meet the quantitative targets set by the decrees.

Checks and penalties

To check that the projects are indeed being carried out in compliance with the criteria laid down in the decrees and in its own Guidelines, the Authority carries out specific checks, including spot checks.
The Authority will also carry out annual checks, based on the TEEs sent in by distributors for the previous year, to ascertain whether the quantitative targets assigned by the decrees to individual distributors are being met. Distributors failing to meet the targets are subject to penalties defined and applied by the Authority.

Recovery of costs

The decrees include the possibility for any part of the costs sustained by distributors to carry out projects designed to meet their quantitative targets, that is not covered by other resources, to be funded through the electricity and gas transportation tariffs according to criteria set by the Authority.
These criteria should also take into account any increases or reductions in profits connected with higher or lower sales of electricity/gas as a result of the projects.

Consultation document

In April 2002 the Authority published a consultation document containing proposals for the implementation of the ministerial decrees of 24 April 2001.

Criteria for the preparation, execution, evaluation and monitoring of energy-saving projects

The Authority proposed that operators who can carry out energy efficiency projects should take steps to obtain any authorisations and permits required by the current legislation and then the relative technical documentation, which may be requested in the event of spot checks. The Authority also proposed that a minimum scope should be envisaged for projects to meet the targets set by the decrees. The arrangements for carrying out the projects should not create obstacles to the development of competition or discriminate between one type of customer and another.

Evaluation of savings

Three approaches are proposed for the evaluation of the savings achieved by the projects:

- standardised evaluations
- engineered evaluations;
- final evaluation based on the energy monitoring plans approved after first checking compliance with the decrees and Guidelines, in accordance with Art. 4.5 of the decrees.

Standardised evaluation methods are defined for each type of intervention that can be repeated on a large scale and which make it possible to establish the average saving that can be obtained for each physical unit of reference (high efficiency equipment already or due to be installed), given certain conditions.
Engineered evaluation methods are based on an algorithm estimating the primary energy savings, the results of which depend on the final values not just of installed units but also of usage parameters.
Final evaluation methods, based on energy monitoring plans, apply to types of projects for which evaluation methods defined by the Authority are not available (standardised or engineered).
The Authority proposes that in these cases a preliminary assessment should be made of whether the monitoring plan complies with the decrees and Guidelines in accordance with Art. 5.7 of the decrees. In all cases, the Authority has established that the energy saving needs to be achieved while providing

equal energy services to users. For the standardised and engineered evaluations the Authority will indicate the benchmark technologies with respect to which the savings achieved by each single project are to be assessed. For projects for which standardised evaluation formats are available the Authority will also define:

- corrective coefficients for non-additional savings, which enable the gross savings arising from the project to be separated out from any savings achieved by users taking part because it is economically advantageous for them to do so, but who would have made similar consumption choices in any case;
- corrective coefficients for delivery methods other than direct installation of high efficiency equipment (for example, sale without installation);
- size of project in terms of minimum number of physical units (for example, number of sets of equipment installed).

In order to consider the impact of technical and behavioural factors on the continuation over time of the savings achieved by these projects, the Authority proposed that for the four years following the introduction of the initiative, year-on-year savings of between 95% and 100% should be considered, depending on the type of intervention (for example, active and passive projects). All the coefficients and parameters used to define the unit energy-saving values attributable to the different types of project would be subject to on-going checks and adjustments by the Authority. The continuation of the savings over the five-year lifespan of the projects would be measured directly, while the minimum project size would be set by the Authority in terms of energy units. For all projects accompanied by information, training, awareness-raising and promotional campaigns, the Authority would attribute a standard value *a priori* to the potential incremental benefits of these measures; this would be set following the consultation process and would be differentiated by type of intervention. For those information, promotion and awareness-raising campaigns that constitute projects in themselves, the Authority proposes that the final evaluation method should be used.

Criteria for the partial tariff cover of the costs sustained in carrying out the projects

The Authority has proposed that a cost-recovery mechanism should be included in the tariff for any costs distributors sustain to meet the quantitative targets that are not covered by other resources. Recognition will be based on standard parameters promoting efficiency in the realisation of energy-saving projects.
The standard parameter will consist of the average allowed cost per unit of energy saved, expressed in euros/tep; it will also refer to the average avoided purchase cost of that unit of energy, to the environmental cost avoided by saving that unit of energy, to that part of the cost of carrying out the projects that will have to be covered from other resources, and finally, to estimates of the average cost of energy saving for certain types of project.
To encourage reductions in final consumption, the Authority has proposed that recognition should be limited to savings of primary energy through projects to reduce electricity or gas consumption, to whichever extent is required to meet the targets set for individual distributors.
As far as any increases or reductions in profits arising from higher or lower sales of electricity/gas as a result of the projects are concerned, the Authority considers that by effect of the tariff structures of the electricity transportation and natural gas distribution service, defined respectively by Decisions 228/2001 and 237/2000, these profits and losses will be considered as null.

Levies

Tariff allowances for distributors are funded through tariff levies calculated by the Authority. The mechanism and procedure proposed by the Authority is that the levy should be based on the variable part (€cents/kWh or €cents/m^3). After ascertaining that the distributors have met their specific targets, the Authority would determine the allowed cost for each distributor for projects actually carried out and for any energy certificates purchased on the market, until the specific annual target assigned to the distributor by the decrees has been met. The levy is based on the costs actually recognised as having been sustained by the distributors.

Energy efficiency certificates: beneficiaries.

In order to encourage access to the TEE market by as many operators as possible, the Authority proposes that distributors not subject to obligations should also be entitled to certificates and that the ordinary minimum requirements for companies should also hold for ESCOs.

Energy efficiency certificates: types of certificate.

In accordance with the decrees it is proposed that the Authority should issue three types of certificate corresponding to the distributors' different targets:

- Type 1, attesting to the achievement of primary energy savings through the reduction of electricity consumption;
- Type 2, attesting to the achievement of primary energy savings through the reduction of natural gas consumption;
- Type 3, attesting to the achievement of primary energy savings through the reduction of consumption of other fossil fuels.

Under the proposal, the certificates would have a lifespan of five years from the date of issue. In this way distributors can carry over any excess certificates with respect to their one-year objective to help them meet their targets in the four subsequent years. This provides a degree of flexibility and helps limit certificate price volatility.

Assessment of whether targets have been met and penalties for failure to do so: amount of the penalty.

The Authority proposes that a penalty should be set for failure to meet the targets (euro/tep not saved) and that the unit value should be equal to whichever is highest between a parameter to be defined after the consultation process, and the average market value of the TEEs in the year when the target was not met, multiplied by a coefficient that is higher than one. These reference values can be adjusted.

In order to ensure that the penalty mechanism is in keeping with the general thrust of the decrees, the Authority also proposes that the penalties for failure to meet the overall annual target assigned to each distributor should be differentiated from the penalty for failure to meet at least 50% of the target through reductions in final consumption of distributed energy. To take into account the fact that the achievement of primary energy-saving objectives also depends on the way customers respond to proposals formulated by distributors and ESCOs, the Authority proposes that, at least in the initial years of implementation, the ratio of total savings achieved to overall target should be taken into consideration when penalties are issued. In the event that this ratio is lower than 1, any penalties applied to distributors who do not meet their specific target could be reduced in proportion to the shortfall with respect to the overall target.

Assessment of whether targets have been met and penalties for failure to do so: arrangements for imposition.

The penalty can be imposed in a lump sum, or by reducing the total allowed costs by an amount equal to the penalty. Finally, the Authority can impose penalties pursuant to Art. 2.20 c) and d) of Law 481/1995, for failure to respect its provisions, including the Guidelines, or for submitting incorrect information and data.

RELATIONS WITH OTHER GOVERNMENT DEPARTMENTS

The Authority co-ordinates and liaises with other institutional bodies and is called upon to express opinions, submit observations and reports, and present briefs on issues falling within its remit.
In June 2001, in view of the entry into force of the tariff reform for gas distribution, the Authority submitted observations and proposals to the Government on the taxation of the supply of methane and other types of gas distributed over urban networks (consumption taxes, regional surtaxes and value-added taxes). The Authority pointed out to the Government the timely and urgent need to amend the tax legislation to bring it into line with. the objectives of market liberalisation and with the new tariff order. This, based on consumption bands, brought together the previous range of tariffs where different rates were applied on the basis of types of use.
In July 2001 the Authority sent the Government a report regarding the Ministry of Industry decree of 7 May 2001 setting out strategic and operational guidelines for Sogin S.p.A. (Società gestione impianti nucleari). The objective was to highlight some discrepancies in the decree with respect to the tariff system for the electricity sector, which could have produced significant increases in costs to final customers in the free and captive markets. The Authority recommended that the ministerial decree should be amended in order to avoid increasing the fiscal element of tariffs and prices.
In September 2001 the Authority submitted a report to the Government on the European Commission's proposal to the Parliament and Council of Ministers to adopt regulations governing conditions for access to the networks for cross-border exchanges of electricity. The regulation recommends an increase in these exchanges and, by defining instruments to remove technical and economic barriers to them, the encouragement of competition in the internal market. The Authority underlined the fact that the elimination of existing obstacles and the harmonisation of the different countries' regulatory systems in an integrated European system was a necessary condition for the creation of a liberalised single European market. To this end suggestions were advanced to introduce an appropriate degree of reciprocity to the regulation, regarding the compensatory mechanisms for transit flows, the criteria to ensure balanced network access arrangements and the terms and conditions for the allocation of transportation capacity on the interconnections.
In October 2001 the Authority submitted an opinion to the Ministry for Productive Activities on the outline ministerial decree on the charges to apply to owners of concessions for the exploitation of gas fields for storage. The Authority expressed its approval and presented its observations on the criteria for the evaluation of installations and the gas still to be extracted.
As envisaged by one of its Decisions, the Antitrust Authority asked the Authority for its opinion on a list of plants submitted by Enel S.p.A. The question was whether or not these plants were suitable for divestment, a necessary condition for approval of the acquisition of Infostrada S.p.A. On 3 October 2001 the Authority gave a negative response, having ascertained that the plants in question were not included in the "key" category, as required.
On 30 October the Authority presented a favourable opinion to the Ministry for Productive Activities on the annual up-grading of the national gas pipeline network with specific reference to the plans to construct new infrastructure linked with the national network.
In November 2001, as part of the Fact-finding Investigation on the situation and prospects of the energy sector, the Authority attended a hearing by the Productive Activities Committee of the Chamber of Deputies. On this same occasion it submitted a brief describing the state and prospects of the electricity and gas sectors.
In December 2001, the Authority sent an analysis to the Committee set up by the Ministry for the Public Administration to rationalise the regulatory role of the independent authorities and agencies.
On 2 February 2002, the Authority attended a hearing of the Presidency of the Senate Industry Committee as part of the discussion on the annual "simplification" law, which envisaged delegated powers for the Government to carry out a legislative review of the electricity and gas sectors, including a review of the Authority's institutive law. During the hearing a brief was handed over illustrating the role

and tasks performed by the Authority in its first years of activity and providing an overview of the on-going liberalisation processes.
On 13 March 2002, the Authority sent a report to Government and Parliament on the bill confirming Legislative Decree 7 of 7 February 2002. This envisaged special provisions to facilitate the construction of new electricity plants and guarantee the security of the national electricity system. The Authority expressed its agreement with the general objectives of the provision, which it considered an essential step in putting the liberalisation process onto a firmer and surer footing, and called for its rapid approval. At the same time it pointed out to the Government and Parliament certain additional articles, particularly regarding stranded costs and the remuneration of the electricity distribution networks, which appeared to be in contrast with the general objectives of liberalisation and the promotion of competition, and the need to reduce electricity costs for final users.

Summary of the brief submitted by the Authority for Electricity and Gas for the Fact-finding Investigation on the situation and prospects of the energy sector, 13 November 2001.

Demand and supply of electricity.

Network energy systems in Italy are characterised by higher costs than in the rest of Europe: this weakens the competitive position of businesses, for which electricity is a significant cost factor. The answer to the problem lies in liberalisation and the promotion of competition.
Customers in the free market are already able to buy electricity at much better prices than their counterparts in the captive market.
The trend in the tariff indicates the course followed since the Authority began operating in the first half of 1997. The electricity tariff has risen by 7% with respect to that period: a rise that is lower than inflation, and modest if we take into account the very real oil shock of the last few years, which was worsened by the euro's loss of ground with respect to the dollar.
Customers eligible to purchase electricity on the free market have more than doubled in just over a year and represent 40% of total demand. This percentage will rise to about 60% when the eligibility threshold falls to 100,000 kWh per year, three years after the completion of the envisaged divestments of plants by Enel. Then the small and medium-sized companies that are such a characteristic feature of Italy's industrial fabric will enter the free market, to which some already have access through purchasing consortia. The desirability of an opening of the electricity market that is consistent with the arrangements already decided for the gas market, in which all customers will be free with effect from 1 January 2003, should be evaluated, not least to avoid imbalances between the two sectors and markets and to encourage economies of scale and rationalisation initiatives.
The expansion in potential demand on the free market has not so far been matched by a comparable development of supply.
At present the supply of electricity is characterised by a high degree of concentration, which is destined to continue over the medium term: contributory factors include the long timescale for the divestment of Enel power stations and the construction of new plants for generation and interconnection with abroad. The principal operator will continue to hold a dominant position in the domestic production market, even after the divestment of plants of 15,000 MW, as envisaged by Legislative Decree 79/1999, is complete. Moreover, a large part of the installations being divested will need to be radically modernised, and will therefore be out of service for not less than two years. With respect to overall supply, including imports, the Enel group seems set to maintain a share of around 50% in the long-term.
The shortfall in interconnection capacity with neighbouring countries means that the prices of imported electricity are approaching the average prices for the Italian market, creating unearned revenue for sellers. When setting the criteria for the allocation of import capacity the Authority seeks to comply with the task entrusted to it by law, of protecting Italian consumers, respecting conditions of impartiality and seeking to establish relations of cooperation with the regulatory bodies of neighbouring countries. The

objective is to manage the interconnection in an orderly way, so as to avoid undue revenue for sellers and eliminate potential shortcomings in the infrastructure.

Transmission network and electricity market

In recent years the management of the network by the National Transmission Network Operator (GRTN S.p.A.) has brought to light a large number of problems, especially regarding the implementation of necessary and urgent rationalisation initiatives to remove internal congestion, increase the capacity for interchanges with other countries and connect up new installations. The possibility of bringing the ownership and management of the national transmission network together again under a single neutral business operator with no interests in the production, distribution and sale of electricity, as is the case in nearly all European countries, should therefore be evaluated.

With regard to the market, the Electricity Market Operator (GME S.p.A.) has been set up and its governing rules defined by the Ministry of Industry; the Authority has played a part in this process in order to bring together in a single framework the electricity exchange, the bilateral trading market, and the role of the Single Buyer (Acquirente unico S.p.A.). The opening of the exchange could be hindered by the highly concentrated supply structure and by imbalances on the information side. The Authority is aware of the problem and intends to oversee developments in the market and where necessary use appropriate economic and administrative instruments to avoid distortions arising.

The natural gas sector

Gas prices and tariffs too, net and gross of taxes, are higher than average European prices: the difference is particularly high for industrial users, compared with those countries where the market is, or is being, liberalised. The high tax burden emphasises this gap.

Structural factors, such as easier access to sources of supply and climatic differences that influence the efficiency of distribution, can explain some the differences; the rest can be explained by the lack of competitive pressures in the gas market in Italy.

Since the beginning of 1997 the average national tariff has increased by about 17% as a result of the trend in the international price of natural gas, which reached a peak in the early months of this year.

The increase in the costs of the raw material was in part counterbalanced by the reduction in the transportation and storage elements (over 11%) and in the distribution cost, as a result of the Authority's tariff reform.

In May 2001 the Authority set out the criteria with which companies already operating in the transportation and despatching of natural gas and those wishing to enter the market should calculate tariffs for transportation and despatching on the national and regional gas pipeline networks. The provision completes the tariff system for transportation over the high, medium and low-pressure networks, and creates the conditions for the renegotiation of existing wheeling contracts drawn up directly by the parties. The unbundling of the network of high pressure pipelines, owned by Eni, is a positive step towards liberalisation. Entrusting the network to a quoted company poses the problem of the definition of rules to run the national gas system and govern the network in such a way that the new company is transparent and neutral. The Authority intends to encourage interested operators to ensure that appropriate rules are put in place.

The gas market today is far from competitive: the introduction of a number of suppliers who are able to create true competition in the supply of gas will help guarantee national energy security, greater integration of the European gas system, closer economic interdependence with producer countries and diversification of zones of origin. To ensure the development of competitive supply, obstacles and obstructions of a political, ownership and contractual nature need to be overcome. The construction of new infrastructure also needs to be promoted, starting with regassification terminals for liquefied natural gas, with a concerted approach by the Authorities, including at the local level. In this dynamic context it is in the country's interest for the gas market to be liberalised as quickly as possible, without prejudice to the conditions of reciprocity envisaged by the European Directives and Treaties.

Service quality

In a phase of liberalisation in which company administrators, private or public, act with economic results as their main objective, there is no guarantee that their conduct will be designed to achieve adequate levels of service quality. The Authority's efforts have made it possible to increase the range of consumer-protection instruments available and to bring Italy's position more into line with that of the principal European countries. In Italy, the average national data regarding interruptions experienced by low-pressure users of the dominant operator conceal marked disparities between the north and south of the country. For this reason, the Authority has decided to set up a system of obligatory service quality levels with appropriate penalties and incentives, which is comparable with the systems regulators are introducing in other countries of the European Union.

Conclusions

Liberalisation offers great development opportunities for companies that were formerly monopolistic. It is necessary for this re-positioning to proceed without obstructing and delaying the development of competitors on the national market, so that the benefits of competition are able to rapidly compensate domestic and industrial consumers for the costs borne during the transition. Under conditions of competitive parity, it is to be hoped that foreign companies will enter the Italian market, providing a competitive stimulus that is capable of weakening the privileged positions that still penalise our energy system. Conditions of true reciprocity will need to be respected: the definition of reciprocity contained in the European Directives is not sufficient in itself, as it only regards consumers' right to choose and equal conditions amongst operators. The protection of competition cannot be delayed until such time as the European markets are competitive and integrated: it is during this transition phase that the need is most urgent for all existing and new companies to confront each other on an equal footing.

RESOURCES AND FINANCIAL MANAGEMENT

The financial management of the Authority, governed by its accounting rules, is based on the annual budget projection. The final balance sheet for the 2001 financial year, with coincides with the calendar year, was approved with Decision 83/2002.

The running of the Authority is not a burden on the Government budget. It is covered by operators, who contribute through annual payments of no more than 1/1000 of their revenues for the last financial year, determined through a provision by the Ministry of Finance. The levy paid by operators in 2000 was entered in the accounts for the 2001 financial year, at a rate of 0.6/1000. Payments in 2001, which the Authority enters in its accounts as the levy for the 2002 financial year, were at a lower rate of 0.5/1000; this reduction was partly the result of a detailed survey that, by identifying all regulated operators, increased the number of contributors and enabled the amount of the levy to be lowered.

The financial revenue, which was composed almost entirely of the above contribution by gas and electricity operators, amounted to 35.30 billion lire, net of self-balancing items, and exceeded committed expenditure of 28.91 billion lire, again net of self-balancing items. This generated an administrative surplus of 7.12 billion lire net of the variations generated by expired revenue and expenditure arrears (735 million lire).

In terms of outlays, costs for staff and the running of the institutional offices amounted to about 15.64 billion lire. Salaries for members of the Authority, which the Prime Minister's Decree of 13 May 1998 pegged to the pay levels of the President and Judges of the Constitutional Court, did not change in 2001 with respect to the provisions laid down by decree no. 11473 of the President of the Constitutional Court on 11 March 1999. Personnel costs, amounting to 13.62 billion lire, are the most significant item of Authority spending.