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Working Group on Gas (GAS WG)

MEDREG GOOD PRACTICES ON TARIFF METHODOLOGIES CASE STUDIES

MED18-25GA –5.4.2
FINAL REPORT

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Abstract

This document MED18-25GA–5.4.2 “MEDREG good practices on tariffs methodologies case studies” shares good practices and information among MEDREG members regarding the computation of natural gas access tariffs to transmission networks, distribution networks, Liquefied Natural Gas (LNG) Terminals and underground storages. Four different case studies have been collected and explored, specifically Portugal, France, Italy and Turkey.
As a result, the report aims at providing an insight on tariff methodologies in countries that have diverse histories and practices of energy regulation in order to broaden the regulators’ understanding of the systems in other countries and to increase the trust of market players and potential investors interested in these energy markets.

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1. Introduction

The “MEDREG good practices on tariffs methodologies case studies” shares good practices and information among MEDREG members regarding the computation of natural gas access tariffs to transmission networks, distribution networks, Liquefied Natural Gas (LNG) Terminals and underground storages. Four different case studies have been collected and explored, specifically Portugal, France, Italy and Turkey.

The first one is the Portuguese case study which analyzes how transmission tariff systems evolved in Portugal after the implementation of the Third European Energy Package. It especially focuses on how the Portuguese energy regulator approves its tariff methodology according to the EU provisions. Moreover, it deepens the role of tariff systems in ensuring nondiscrimination between domestic and cross border flows, especially considering entry-exit prices for optimal allocation of costs and for the promotion of an efficient use of the gas infrastructure.

The second case relates to the French gas system. It explains how the grid is split between the two main transmission network, namely GRTgaz, which operates 90% of the grid, and TIGF, which is present in the South-West of the country and, in particular, manages the interconnections with Spain. Moreover, it outlines how tariff calculations are different for these two parts, considering that the entry-exit approach is applied to the main lines while the regional networks have a distance-based tariff structure. Finally, it shows the most up to date progresses in the French gas market structure according to the creation and the development of a single market area in the European Union.

The third case analyzes the Italian gas system which describes how tariffs are applied to LNG terminals. Due to its nature of gas net importing country, Italy dispose only of regasification terminals. As a consequence, the case study analyzes how the Italian Regulator ARERA adopted and implemented the methodology to calculate regasification tariffs, including the specific revenues and tariffs derived from additional services to the standard regasification service such as peak shaving service, flexibility services, bundled service regasification and underground storage. Moreover, it is also explored the potential introduction of market mechanisms for LNG capacity allocation instead of priority access and pro-rata mechanisms.

Lastly, the Turkish case study concentrates on the evolution of the regulatory framework enacted to develop natural gas tariffs. As a consequence, it explains basic principles of tariff regulations, deepening the tariff setting process, its composition and its revision considering that transmission and storage tariffs are set by applying the “revenue cap” tariff model, which guarantee the revenue requirement of the facilities. Finally, it gives an overview of the distribution system in Turkey and its development, outlining the methodology to calculate distribution tariffs which are set using the “price cap” method in order to promote a more efficient management of the Distribution System Operators (DSOs).

2. Portugal - Computation of Access Tariffs to Transmission Networks

2.1. Introduction of a decoupled entry-exit tariff system in the Portoguese natural gas sector

The 3rd EU energy package, which entered into force in 2009, defines a number of structural elements for achieving a single European market for gas. A major element is the mandatory entry-exit organization of transmission network access, in the belief that the creation of entry-exit zones is a precondition for the creation of functioning markets in the EU.
To enhance competition through liquid wholesale markets for gas, it is vital that gas can be traded independently of its location in the system, giving network users the freedom to book entry and exit capacity independently, thereby creating gas transport through zones instead of contractual paths. Article 13 of the EC Regulation 715/2009 establishes that “tariffs for network users shall be non-discriminatory and set separately for every entry point into or exit point out of the transmission system” [1]. There is a huge consensus around decoupled entry-exit tariff systems, because they can be more cost reflective, avoid cross subsidies between network users, facilitate gas trade and can provide efficient economic signals for the location of gas injections or off-takes. Decoupled entry-exit tariffs are an important tool to ensure non-discrimination between national and cross border gas flows.
In 2010, the Portuguese Energy Regulator (ERSE) changed the methodology for the calculation of natural gas transmission network tariffs, from a postage stamp to a fully decoupled entry-exit tariff system.
The purpose of this paper is to present the methodology applied to implement a decoupled entry-exit tariff system in the Portuguese natural gas sector that ensures a correct cost allocation of the gas transmission network.
The transmission tariff has a small weight in the final prices, ranging from 2% to 5% depending on the pressure level, but it is very important to define an adequate structure because it has a strong impact on infrastructure investments and on market development.

A. Rational for an entry-exit tariff system

Until 2010 the methodology applied in Portugal to calculate gas transmission network tariffs was the postage stamp methodology, because when transmission tariffs were introduced in Portugal, the transmission system was characterized by dominant flows, almost all gas was hauled in the same direction and so a postage stamp was most likely to be cost reflective. However, with liberalization and the goal of a higher integration of Iberia, where flows may be less predictable, a postage stamp by which a uniform tariff is applied to all points irrespective of their location in the system, will not be cost reflective and may lead to cross subsidies.
When third party access to transmission networks was introduced the preferred tariff methodology adopted by transmission system operators (TSOs) was point-to-point (also known as distance related tariff), by which prices are fixed according to contractual paths, varying with the distance between entries and exits.
The advantages of an entry-exit tariff methodology are fourfold: i) it offers flexibility to shippers and promotes competition because there is not a contractual path defined, i.e., shippers may buy entry into the system without committing to an exit; ii) it is cost reflective, avoids cross subsidies between network users, facilitates gas trade and can provide signals for the location of gas injections, unlike a postage stamp methodology that involve cross subsidies; iii) it is transparent and simple especially if the entry and exit points are grouped into zones so that a limited number of prices are applied; and iv) is a more general methodology which includes

both postage stamp and point to point as particular cases.
Decoupled entry exit tariffs are an important tool to ensure non-discrimination between national and cross border gas flows.

B. EC Directives and Regulations

The importance of transmission tariffs for the completion of the EU internal energy market is such that EC Regulation 715/2009 foresees a network code on rules regarding harmonized transmission tariff structures. The EU Agency for the Cooperation of Energy Regulators (ACER) is working on the framework guidelines on harmonized transmission tariff structure, setting out clear and objective principles for the development of this network code.
EC Regulation 715/2009 of 13 July 2009 states that "To enhance competition through liquid wholesale markets for gas, it is vital that gas can be traded independently of its location in the system. The only way to do this is to give network users the freedom to book entry and exit capacity independently, thereby creating gas transport through zones instead of along contractual paths." Additionally, article 13 states that "Tariffs for network users shall be non-discriminatory and set separately for every entry point into or exit point out of the transmission system. Cost-allocation mechanisms and rate setting methodology regarding entry points and exit points shall be approved by the national regulatory authorities. By 3 September 2011, the Member States shall ensure that, after a transitional period, network charges shall not be calculated on the basis of contract paths." Also, "In order to ensure transparent, objective and non-discriminatory tariffs and facilitate efficient utilization of the gas network, transmission system operators or relevant national authorities shall publish reasonably and sufficiently detailed information on tariff derivation, methodology and structure."
Postage stamps and point-to-point tariffs are not in line with the principles of the single market and therefore are not supported by the EC. Entry-exit tariffs are the chosen model.
As the calculation of entry-exit tariffs always entails some regulatory decision about cost allocation, transparency of tariff setting criteria is crucial, because reduced transparency may consist of a problem, with a certain risk that tariff systems may overweight on transit flows with respect to domestic destinations, or the reverse.

2.2. Entry-exit tariff methodology

The calculation of transmission charges according to an entry exit tariff methodology can be briefly described as follows (Ascari, 2009):

- A snapshot of the gas transmission network is required, where the network is split into entry points, exit points and main pipelines that connect each entry and exit points, together with technical information (distance, diameter, pressure, flow direction);
- A cost index is associated to each pipeline segment, which is calculated as a point to point tariff (it depends mostly on its length and diameter). A decision has to be made on the concept of cost to be used, either average cost or marginal/incremental long run cost;
- Paths must be defined linking each entry point with each exit point and cost index paths are calculated by summing up all cost indexes of pipeline segments included in the path, considering whether they are used in the direction of gas flows or backhaul. A matrix is generated where costs of reaching each exit from each entry point are calculated. Path costs then form a matrix with as many rows as entry points and as many columns as exit points (or exit zones including several delivery points);
- Once costs of all paths have been determined, entry-exit charges are calculated, which are only related to entry points irrespectively of exit, and to exit points

irrespectively of entry. This is achieved by minimizing the sum of the squares of the difference between the sum of entry and exit capacity charges (ETIe and XTIx) for each path and the corresponding actual path cost index (PCI). Negative solutions are not allowed. Formally:

$$\min \sum_{e,x} \left(ETI_e + XTI_x - PCI_{e,x} \right)^2$$

- Subject to: ETIe , XTIx ≥ 0 for each e, x.
  Where: ETI_e is the charge for the entry point e; XTI_x is the charge for the exit point x; and $PCI_{e,x}$ is the cost of the relevant network asset used to flow gas from entry e to exit x.
- Finally, the entry and exit capacity tariffs determined by the previous optimization problem are proportionately increased or reduced so that the allowed revenue is achieved by selling all available entry and exit capacities.

2.3. Transmission tariff structure

The tariff setting process comprises two fundamental steps, the calculation of the allowed revenues for the operators and the definition of the tariff structure that allows for the revenues to be recovered while ensuring that the correct price signals are being transmitted to the network users in order to foster network efficiency. ERSE is in charge of setting the allowed revenues and tariffs, on the basis of TSO operational charges and investments and demand forecasts, according to the rules and methodologies established on the Tariff Code approved by ERSE after a public consultation. Tariffs final approval is preceded by a tariff proposal subject to the non-binding opinion of the tariff council, which is made of representatives of all stakeholders from the natural gas sector.

Gas tariffs structure should be as simple as possible to assure that price signals transmitted to consumers are well understood. Price signals should be stable and coherent, promoting the correct long and short term decisions (investments, load shifting, etc.) by investors and network users and an efficient use of gas. In order to achieve these objectives gas tariff price structure should be based on marginal/incremental costs. Cost reflective pricing also contributes to reducing cross subsidization between network users, thus promoting a better allocation of resources in the economy allowing for improvements in the economic efficiency of the gas system and energy using activities.

For the tariff structure is fundamental to choose the most adequate price variables, according to cost drivers. The price variables applicable to natural gas transmission network are used capacity at entry points, used capacity at exit points, peak time energy at exit points and off-peak time energy at exit points.

The following table discusses the rational for the choice of price variables on transmission networks, how are these variables measured and what costs should these variables reflect.

Price variables	Description	Rational and costs reflected
Used capacity at entry points	Maximum daily flow in the last 12 months, in the transmission network entry point, in kWh/day. The maximum daily value is paid in the twelve following months.	The maximum daily flow determines investments in central and upstream sections of the gas pipeline. Its dimensions is determined by the injection capacity by the users/suppliers.
Used capacity at exit points	Maximum daily flow in the last 12 months, measured in the network delivery point, in kWh/day. The maximum daily value is paid in the twelve following months.	The maximum daily flow determines investments in peripheral sections of the gas pipeline, that include connections to end users and GRMS, shared by a small number of clients. Its dimension is influenced by the maximum capacity required by the clients.
Peak time Energy at exit points	Volume of gas, measured in the network delivery point, in kWh, during peak day.	The flow in peak day periods partially determines investments in central sections of the gas pipeline, shared by a large number of clients. Its dimension is indirectly influenced by the average capacity required in peak days. The capacity expansion of the network is partially justified by the energy that flows in peak days, thus avoiding congestions in those periods.
Off-Peak time Energy at exit points	Volume of gas, measured in the network delivery point, in kWh, during off-peak day.	This variable should reflect the costs that depend on the volume of gas carried in the gas pipeline and processed in the GRMS.

Figure 1. Transmission price variables

It is worth noting that the tariff structure should be capacity based, because capacity, and not the amount of energy, defines the costs of the pipelines. In Portugal capacity recovers 90% of the total allowed revenues.

With the goal of achieving more tariff flexibility, and enabling the access to the gas system of market players with time concentrated uses, the transmission tariff includes two extra tariff options: (i) short duration tariff (on entry and on interconnection exit points) and (ii) low-load-factor tariff (applied on exit points to customers whose consumption has a very low load factor).

In the short duration transmission tariff option, the used capacity price is totally converted to an energy price, applied to the flows in the transmission network, resulting in energy prices (commodity prices) higher than the annual reference energy prices.

In the low-load-factor tariff option, the used capacity price is partially converted to an energy price in peak days periods, applied to the flows in the transmission network.

2.4. Entry-Exit tariff methodology applied to the Portuguese horizontal transmission network

The methodology used in Portugal for the calculation of transmission network access tariffs, namely for the price variable used capacity at entry points is a matrix approach based on the capacity unit costs of every possible path.

To calculate the unit costs of capacity at entry points a methodology for optimal allocation of costs is applied (Hunt, 2008).

A. First step: Simplified model of the horizontal transmission network

The first step in applying the entry-exit methodology is to design a simplified model of the horizontal transmission network (identifying entry points, exit points and pipeline segments'

length). The horizontal transmission network does not include peripheral sections of the gas pipeline, namely connections to consumers and Gas Regulation and Measurement Stations (GRMS) used by a limited number of consumers.
In Portugal there is one balancing zone and the transmission network concerns high pressure gas network, above 20 Bar. Figure 2 presents the Portuguese transmission network.

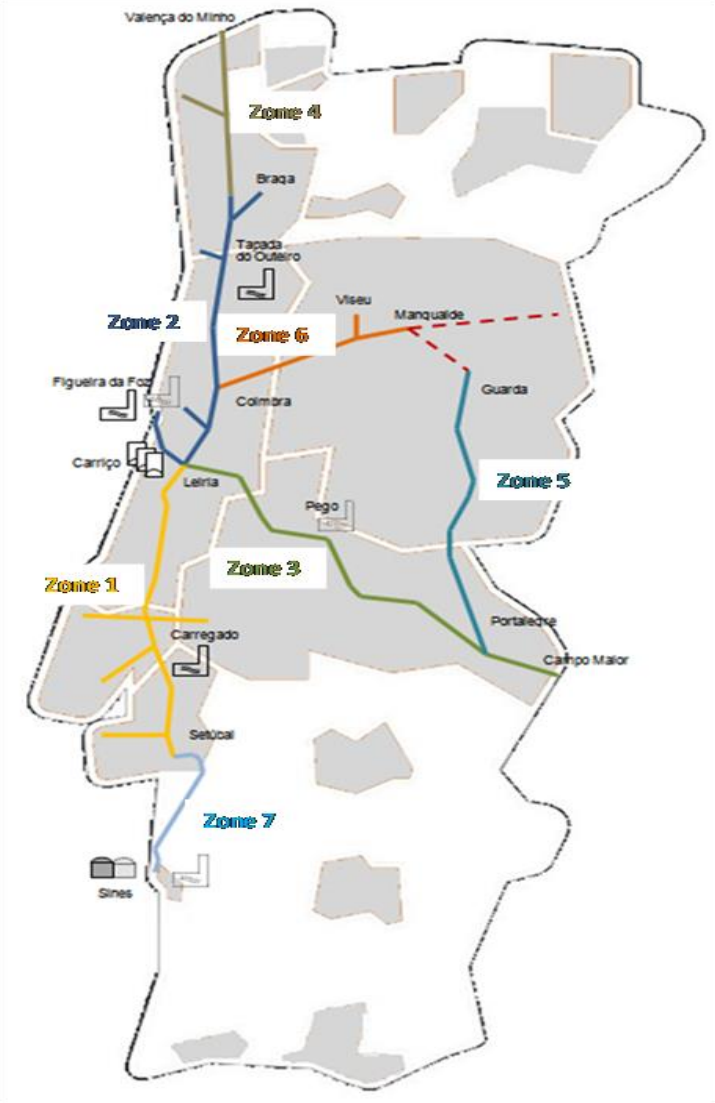


Figure 2. Portuguese gas transmission network

The Portuguese natural gas transmission network has approximately 1200km, with four entry points. The entry points are two international interconnection points (O-Valença do Minho and G-Campo Maior), one LNG Terminal (A-Sines) and one underground storage facility (L). The exit points are the high pressure clients (which include electricity power plants), the LNG terminal and the distribution networks.
The LNG Terminal is also used for balancing, it gives greater flexibility for balancing purposes to shippers. Additionally, it gives more flexibility to small suppliers of LNG to small isolated industrial customers.
The underground storage facility is considered an entry point to the system and not an exit point because physically the exit flows from the grid is always small, investments depend on the exit from the underground facility to the grid.
For the simplified model of the network the exit points are clustered into eight exit zones (Q,

S, U, K, I, N, E, C).

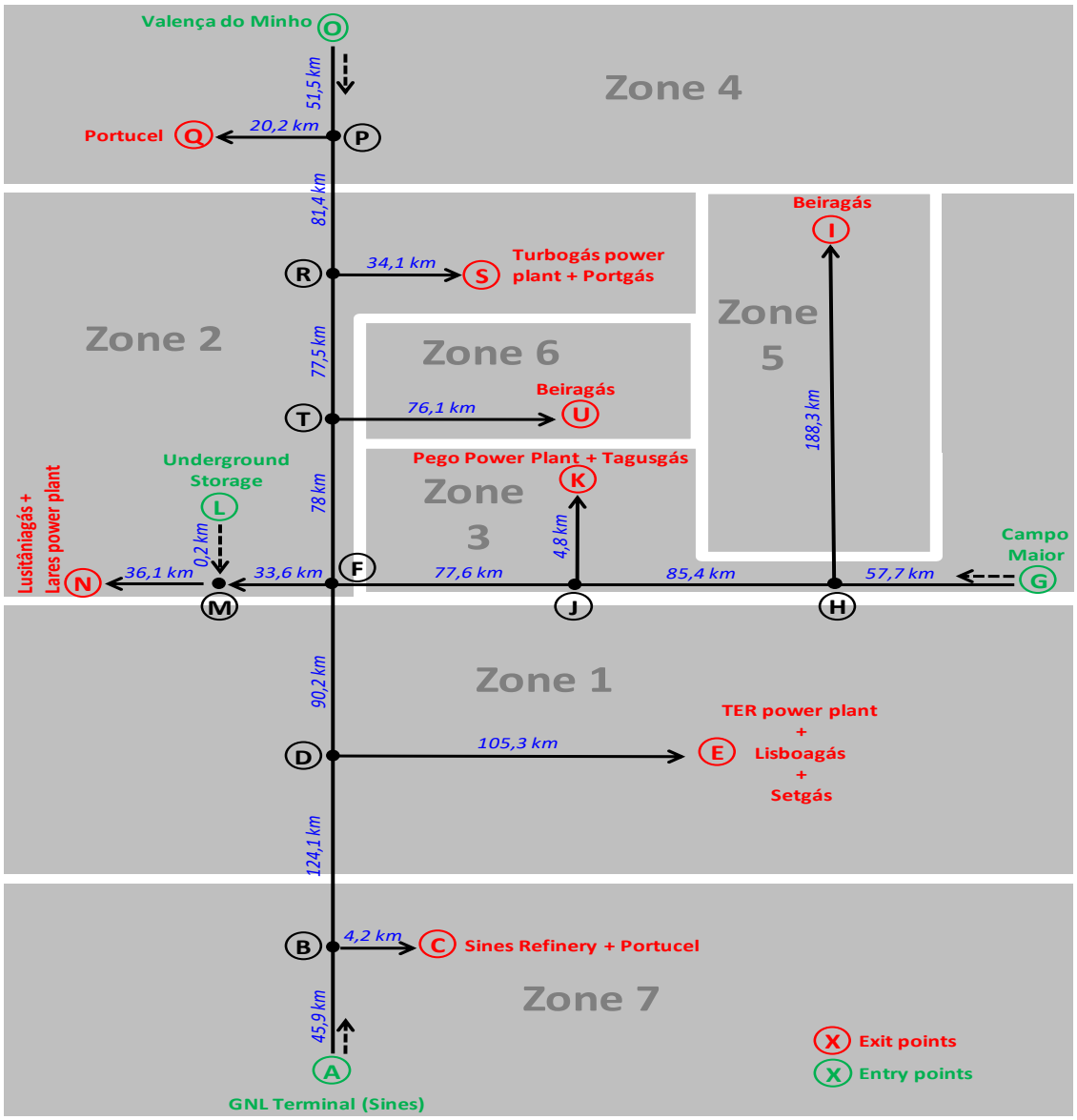


Figure 3. Simplified model of the network

B. Second step: Used capacity at entry points and exit zones

The second step is the characterization of the maximum capacities in the medium term (3 years) in each entry point and exit zone of the simplified model, according to the company's investment and business plan (figure 4).

	Entry points	Capacity MWh/day
A	Sines	192 780
G	Campo Maior	122 000
L	Carriço	6 762
O	Valença do Minho	23 000
	TOTAL	344 542
	Exit zones	**Capacity MWh/day**
C	Refinaria+Cogeração GALP em Sines+Portucel (…)	26 785
E	TER+Carregado+Lisboagas+Setgas+Cog Barreiro	99 424
I	Beiragas (Guarda)	2 178
K	Pego+Tagusgas	41 522
N	Lares+Lusitaniagas+Soporgen+Carriço(ind)+Leirosa	89 891
Q	Portucel	2 390
S	Turbogas+Portgas+Refinaria Petrogal+Air Liquide	80 174
U	Beiragas (Mangualde)	2 178
	TOTAL	344 542

Figure 4. Maximum capacity in the medium term

These maximum capacities are divided by the several sections, resulting in the following matrix (figure 5). The matrix has thus the capacity used in each branch of the network and the contribution associated with each entry point.

Zone	Sections	Capacity (MWh/day)				Flow per section (MWh/day)
		Flow from A	Flow from G	Flow from L	Flow from O	
7	AB	192 780	-	-	-	192 780
7	BC	26 785	-	-	-	26 785
7+1	BD	165 995	-	-	-	165 995
1	DE	99 424	-	-	-	99 424
1	DF	66 571	-	-	-	66 571
3	GH	-	122 000	-	-	122 000
5	HI	-	2 178	-	-	2 178
3	HJ	-	119 822	-	-	119 822
3	JK	-	41 522	-	-	41 522
3	JF	-	78 300	-	-	78 300
2	FM	38 199	44 930	-	-	83 129
2	LM	-	-	6 762	-	6 762
2	MN	38 199	44 930	6 762	-	89 891
2	FT	28 372	33 370	-	-	61 742
6	TU	1 001	1 177	-	-	2 178
2	TR	27 371	32 193	-	-	59 564
4	OP	-	-	-	23 000	23 000
4	PQ	-	-	-	2 390	2 390
2+4	PR	-	-	-	20 610	20 610
2	RS	27 371	32 193	-	20 610	80 174

Figure 5. Maximum capacity in the medium term per section, Mega Watt hour per day

C. Third step: Investments

Then, investments required to meet maximum capacity are identified and annuities are calculated and allocated to each branch of the network, proportionally to its length.
Investments considered are related just to gas pipelines.
The following figure shows the investments made in the past and planed for the future, for a 16 year series. The longer the series the better, the less biased are the results.

Capex €th	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7
1997	205 123	214 607	116 767	22 491	0	931	
1998	7 251	5 592	4 326	21 086	0	574	
1999	322	592	247	5 639	3 210		
2000	386	6 975	38	291		10	226
2001	157	345	44	337	2 019	103	
2002	2 101	468	24	131	282	1 385	
2003	246	691		202	2 548	27 487	47 515
2004	351	873	82	5 362	87	130	818
2005	286	514	730	1 693	81	107	442
2006	212	386	217	295	98	357	207
2007	95						
2008	25	1 935			24	29	1 203
2009	3 475	21 890	1 052	71	16	122	4 433
2010	8 909	7 385	1 652	190	117	103	463
2011	12 465	3 544			29	286	1 698
2012	5 245				0		
Total	246 647	265 798	125 178	57 787	8 511	31 624	57 005

Figure 6. Investments per zone, thousands of euros at current prices

This is the level of investment needed to meet the capacity.
It is worth noting that investments in GRMS are not to be considered in the assets of the horizontal transmission network as they are related to exit points to supply domestic clients in the downstream market. Considering the useful lifetime of these assets of 43 years[1], the companies discount rate of 8% (rate of remuneration fixed by ERSE) and corresponding operational costs of 2,3%[2], we are able to calculate the annuities per zone in figure 7 [4].

	Annuity €th
Zone 1	18 975
Zone 2	20 892
Zone 3	9 838
Zone 4	4 542
Zone 5	669
Zone 6	2 485
Zone 7	4 480
TOTAL	61 882

Figure 7. Annuities per zone, thousands of Euros at current prices

D. Fourth step: Unit cost calculations

Finally the calculation of unit costs is performed and so the unit cost for each possible path (every possible combination of entry point – exit zone) is obtained.
Figure 8 presents the annuity for each gas pipeline section, the maximum daily capacity used and the corresponding annual unit cost obtained. For example, section [BE] total unit cost is given by the sum of the unit cost of the section [BD] and [DE]. The “Total” line represents prices related to contractual paths and they do not favor market freedom. It’s a point-to-point tariff that is adherent to cost, but doesn´t give flexibility to shippers because the path is defined. The unit cost associated with each exit point or zone depend on the entry point and vice versa, i.e., the unit cost associated with each entry point depend on the exit point or

[1] The lifetime of assets is defined on the Portuguese fiscal accounting legislation.
[2] The percentage for the operational costs is based on the actual ratio between operating costs and gross fixed assets (year 2008).

zone. In this situation the cost depends on the contractual path. Figure 9 presents the final results of unit costs for each contractual path in a matrix format.

Zone	Section	Annuity €th (1)	Capacity per section MWh/day (2)	Unit costs €/(KWh/day) (3=1/2)	Unit costs €/(kWh/day)												
					BC	BE	BN	BU	BS	HI	HK	HN	HU	HS	MN	PQ	PS
7	AB	2 250	192 780	**0,0117**													
7	BC	204	26 785	0,0076	0,0076												
7+1	BD	7 665	165 995	0,0462		0,0462	0,0462	0,0462	0,0462								
1	DE	7 181	99 424	0,0722		0,0722											
1	DF	6 156	66 571	0,0925			0,0925	0,0925	0,0925								
3	GH	2 519	122 000	**0,0206**													
5	HI	669	2 178	0,3072						0,3072							
3	HJ	3 725	119 822	0,0311							0,0311	0,0311	0,0311	0,0311			
3	JK	209	41 522	0,0050							0,0050						
3	JF	3 384	78 300	0,0432								0,0432	0,0432	0,0432			
2	FM	2 206	83 129	0,0265			0,0265					0,0265					
2	LM	13	6 762	**0,0019**													
2	MN	2 372	89 891	0,0264			0,0264					0,0264			0,0264		
2	FT	5 128	61 742	0,0830				0,0830	0,0830				0,0830	0,0830			
6	TU	2 485	2 178	1,1413				1,1413					1,1413				
2	TR	5 094	59 564	0,0855					0,0855					0,0855			
4	OP	2 468	23 000	**0,1073**													
4	PQ	971	2 390	0,4061												0,4061	
2+4	PR	4 942	20 610	0,2398													0,2398
2	RS	2 241	80 174	0,0280					0,0280					0,0280			0,0280
				TOTAL	0,0076	0,1184	0,1916	1,3630	0,3352	0,3072	0,0361	0,1272	1,2987	0,2708	0,0264	0,4061	0,2678

Figure 8. Annuities per section, euros per kilowatt hour per day at current prices

System entries	[AB]	[GH]	[LM]	[OP]
	0,0117	0,0206	0,0019	0,1073

		Secondary system entries			
		B	H	M	P
System Exits	C	0,0076			
	E	0,1184			
	I		0,3072		
	K		0,0361		
	N	0,1916	0,1272	0,0264	
	U	1,3630	1,2987		
	Q				0,4061
	S	0,3352	0,2708		0,2678

Figure 9. Annuities per section, euros per kilowatt hour per day

As entry-exit tariffs should be independent from the contractual path, unit capacity costs in each entry point and exit zone, independent of the contractual path, are obtainable through an optimization algorithm. The algorithm adopted minimizes the differences between network charges paid by users under the decoupled entry-exit tariff system and the costs computed for the different entry-exit paths that may be defined. The optimization problem guarantees that the sum of the decoupled entry-exit unit capacity costs are as close as possible to the unit costs for each possible path.

Figure 10 presents the solution to the optimization problem, consisting in the minimization of the square of the sum of the differences mentioned. The prices matrix result from adding the average of each line in figure 9 and multiplying by α (78%), which results from the optimization problem, and the average of each column in figure 9 multiplying by 1-α.

System entries	[AB]	[GH]	[LM]	[OP]
	0,0117	0,0206	0,0019	0,1073

			Secondary system entries			
	Entry points unit cost / Exit zones unitcosts		**0,0550**	**0,0557**	**0,0007**	**0,0184**
			A	G	L	O
Exit zones	**0,0015**	C	0,0565	0,0572	0,0022	0,0199
	0,0231	E	0,0782	0,0788	0,0239	0,0415
	0,0600	I	0,1150	0,1157	0,0607	0,0784
	0,0071	K	0,0621	0,0627	0,0078	0,0255
	0,0675	N	0,1225	0,1231	0,0682	0,0858
	0,5201	U	0,5751	0,5758	0,5208	0,5385
	0,0794	Q	0,1344	0,1350	0,0801	0,0977
	0,1707	S	0,2258	0,2264	0,1715	0,1891

Figure 10. Unit capacity costs by entry point and exit zone, euros per kilowatt hour per day, non-adjusted

In figure 10 the column marked in bold (exit zones unit cost) is the result of the product of the average of each line in figure 9 by the above mentioned α. The line marked in bold (entry points unit cost) is the result of the product of the average of each column by 1-α. Because the unit cost do not allow for the adequate level of revenues given by the unit costs in figure 9, a multiplying factor must be applied, resulting in the prices matrix of figure 11.

System entries	[AB]	[GH]	[LM]	[OP]
	0,0117	0,0206	0,0019	0,1073

			Secondary system entries			
	Entry points unit cost / Exit zones unit costs		**0,072138**	**0,073008**	**0,000944**	**0,024115**
			B	H	M	P
Exit zones	**0,0020**	C	0,0741	0,0750	0,0029	0,0261
	0,0303	E	0,1025	0,1033	0,0313	0,0545
	0,0787	I	0,1508	0,1517	0,0797	0,1028
	0,0093	K	0,0814	0,0823	0,0102	0,0334
	0,0884	N	0,1606	0,1614	0,0894	0,1126
	0,6820	U	0,7541	0,7550	0,6829	0,7061
	0,1041	Q	0,1762	0,1771	0,1050	0,1282
	0,2239	S	0,2960	0,2969	0,2248	0,2480

Figure 11. Unit capacity costs by entry point and exit zone, euros per kilowatt hour per day, adjusted

In figure 12 the final capacity entry prices calculated by the summation of the system primary and secondary entry unit costs are shown in the first row of the table, highlighted in bold. The

capacity exit prices are shown in the first column highlighted also in bold. The resulted added entry and exit prices are shown in the cells inside the table.

			Entry points			
	Entry points unit cost / Exit zones unit costs		0,0838	0,0937	0,0029	0,1314
			A	G	L	O
Exit zones	0,0020	C	0,0858	0,0956	0,0048	0,1334
	0,0303	E	0,1141	0,1240	0,0332	0,1618
	0,0787	I	0,1625	0,1724	0,0816	0,2101
	0,0093	K	0,0931	0,1029	0,0121	0,1407
	0,0884	N	0,1722	0,1821	0,0913	0,2199
	0,6820	U	0,7658	0,7756	0,6849	0,8134
	0,1041	Q	0,1879	0,1977	0,1069	0,2355
	0,2239	S	0,3077	0,3175	0,2268	0,3553

Figure 12. Unit capacity costs by entry point and exit zones, euros per kilowatt hour per day

This methodology reflects the costs and provides the adequate economic price signals for an efficient use of the horizontal transmission network, avoiding discrimination between domestic gas flows and cross border trade.

E. Adopted prices for entry points

As capacity entry prices in points A, G and O were quite similar, ERSE adopted the same price for simplicity reasons. The transmission network entry price from the underground storage is smaller than the previous ones because it is situated in the middle of the transmission network where fewer pipelines are being used.
The prices for the entry points of the Portuguese transmission network presently adopted are depicted in figure 13. They are obtained dividing the entry prices of figure 12 by 12 months.

Used capacity entry points	Capacity prices €/((kWh/day)/month)
(A)	0,008580
(G)	0,008580
(O)	0,008580
(L)	0,000241

Figure 13. Entry prices of the Portuguese transmission network

2.5. Long run average incremental cost of used capacity at exit points to supply domestic clients in the downstream market

The capacity exit prices of the horizontal transmission network were defined in figure 12. Although the presented methodology gives different capacity exit prices for 8 regional zones, a common average value was adopted because the Portuguese law states that access end-user prices have to be uniform throughout the country. An average annual value of 0.090721

€/(kWh/day) is obtained corresponding to a monthly value of 0.007560 €/((kWh/day)/month)
Moreover, GRMS for the downstream market and prices related to connection costs for end-users should be added to the computed capacity in order to calculate the exit prices applicable to deliveries. These deliveries can either be to clients connected directly to the transmission network or to distribution networks. The investment in connections to end users and GRMS represent 26% of the total transmission network investment.
Prices should be as close as possible to the long run marginal costs, which provide the right scarcity signal as they show the cost for the system of expanding the service.
Long run average incremental cost is a more correct designation, since we are not calculating the derivative of a function. The long run average incremental cost of used capacity at exit points corresponds to the additional investment required to meet the increased demand given by the following equation.

$$IncC\,Cap = \frac{\sum_{t=-L}^{t=H-L} \Delta I/(1+d)^t}{\sum_{t=0}^{t=H} \Delta Cap/(1+d)^t}$$

Where IncC Cap is the long run average incremental costs for Capacity; I is the annuity of investment (including the correspondent additional operational costs) required to meet the increase in capacity; Cap is the increase in Capacity; d is the discount rate; H is the number of years; L is the time gap between investment and increase in demand.
Investments include peripheral sections of the gas pipeline, which consist of connections to end users and GRMS, shared by a small number of clients.
The top half of the table in figure 14 presents the annuity level of past and future investments for GRMS and connection to end users considering that the investments are remunerated at 8% and generate operation expenses of 2.3%. On the bottom half of the table is shown the necessary increases in exit capacity in order to meet the demand that generates the investments in the top half. The peripheral network capacity incremental cost is given by the ratio of the present value of the investments annuity and the used capacity.
This incremental capacity cost is only applicable to deliveries to clients directly connected to the transmission network and to distribution networks. Thus, to calculate the exit capacity prices applied for domestic flows one must add the previously exit capacity prices of the horizontal network, presented in figure 12, with the peripheral network incremental capacity cost, presented in figure 14. An average value of 0.015431 €/((kWh/day)/month) is obtained.The access exit tariffs besides having capacity prices calculated in line with the methodology shown present energy prices applied to the energy transported. The methodology adopted on the calculation of these energy prices is shown in [4]. This energy prices are obtained dividing the present value of the operational costs associated to the total investments on the horizontal and peripheral network done in a series of years by the present value of the total annual energy to be transported in the same time period. The operational costs are computed as a percentage (2.3%) of the investments annuity over this period. A value of 0,01329 €/MWh is obtained.

Capex th€		GRMS	Connection to end users	1997	1998	1999	2000	2001	(...)	2009	2010	2011	2012	2013
	1997	44 974	69 616	10 026	10 026	10 026	10 026	10 026		10 026	10 026	10 026	10 026	10 026
	1998	5 513	2 746		723	723	723	723		723	723	723	723	723
	1999	1 730	439			190	190	190		190	190	190	190	190
	2000	4 406	6 865				986	986		986	986	986	986	986
	2001	1 352	302					145		145	145	145	145	145
	2002	3 423	1 030							390	390	390	390	390
	2003	4 171	2 370							572	572	572	572	572
	2004	3 862	5 635							831	831	831	831	831
	2005	2 545	1 604							363	363	363	363	363
	2006	971	470							126	126	126	126	126
	2007	1 125	0							98	98	98	98	98
	2008	12 104	3 113							1 332	1 332	1 332	1 332	1 332
	2009	4 031	29 283							2 915	2 915	2 915	2 915	2 915
	2010	10 515	6 751								1 511	1 511	1 511	1 511
	2011	2 111	1 747									338	338	338
	2012	0	1 966										172	172
	2013	72	0											6
CAPEX				10 026	10 749	10 939	11 925	12 070		18 697	20 208	20 545	20 717	20 724
OPEX	2,3%			231	248	252	275	278		431	465	473	477	477
Total annuity				10 257	10 997	11 191	12 200	12 348		19 127	20 673	21 018	21 194	21 201
Total annuity(present value)				27 896	27 692	26 093	26 338	24 683		20 658	20 673	19 462	18 171	16 830
Used capacity (m3/day)				436 083	3 000 571	9 809 121	9 958 147	11 144 286	(...)	17 038 366	20 534 528	21 505 172	23 144 483	24 373 966
Annual increase in capacity														
	1997			436 083	436 083	436 083	436 083	436 083		436 083	436 083	436 083	436 083	436 083
	1998				2 564 488	2 564 488	2 564 488	2 564 488		2 564 488	2 564 488	2 564 488	2 564 488	2 564 488
	1999					6 808 551	6 808 551	6 808 551		6 808 551	6 808 551	6 808 551	6 808 551	6 808 551
	2000						149 026	149 026		149 026	149 026	149 026	149 026	149 026
	2001							1 186 139		1 186 139	1 186 139	1 186 139	1 186 139	1 186 139
	2002									1 428 873	1 428 873	1 428 873	1 428 873	1 428 873
	2003									1 905 044	1 905 044	1 905 044	1 905 044	1 905 044
	2004									1 842 939	1 842 939	1 842 939	1 842 939	1 842 939
	2005									2 352 522	2 352 522	2 352 522	2 352 522	2 352 522
	2006									-3 204 278	-3 204 278	-3 204 278	-3 204 278	-3 204 278
	2007									485 529	485 529	485 529	485 529	485 529
	2008									110 774	110 774	110 774	110 774	110 774
	2009									972 676	972 676	972 676	972 676	972 676
	2010										3 496 161	3 496 161	3 496 161	3 496 161
	2011											970 645	970 645	970 645
	2012												1 639 311	1 639 311
	2013													1 229 483
	Used capacity(present value)			1 185 983	7 555 948	22 871 330	21 498 893	22 277 479	(...)	18 401 436	20 534 528	19 912 196	19 842 664	19 348 840
Used capacityinc. costs (peripheral sections) (€/(kWh/day)/month)				0,007871										

Figure 14.Used capacity incremental cost at current prices

The energy price applied to peak days is obtained scaling the previously presented energy price so that at least 10% of total payments are recovered through energy prices and the rest 90% through capacity prices. The peak days energy exit price obtained is 0-19989 €/MWh. With this approach a more variable tariff structure is obtained leading to more flexibility in infrastructure use by customers. The off peak days energy exit price is thus equal to the previously presented value of 0.01329 €/MWh.

Whenever prices resulting from applying the present cost methodology don´t allow for the full recovery of the allowed revenues, multiplicative factors should be applied, for each price, in order to assure costs recovery and also to simultaneously reflect the incremental costs structure.

2.6. Results

Applying the Entry-Exit tariff system of the horizontal transmission network and the Long Run Average Incremental Cost Methodology related to investments necessary to supply the domestic downstream market we obtain a tariff structure which we believe will promote a more efficient use of the infrastructures, an efficient allocation of costs, the rational use of the capacity and a harmonized integration with the Spanish market.

The application of a decoupled entry-exit tariff system in Portugal resulted in a tariff structure where prices at the entry point's equal matrix unit costs, recovering 26% of the TSO allowed revenues. The remaining 74% are recovered on exit points to supply the downstream market, with prices based on long run average incremental costs, as shown in figure 15.

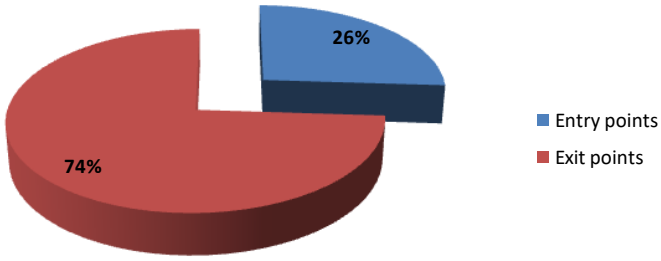


Figure 15. Tariff structure payments between entry and exit points

The methodology presented in this paper is part of the global methodology applied by ERSE on the calculation of the Portuguese transmission network entry-exit access tariff system.

2.7. Conclusions

Directive 2009/72/EC and Regulation (EC) n.715/2009 state that transmission tariff systems shall be based on entry-exit tariff systems in order to foster market development. In line with these provisions the Portuguese Energy Regulator (ERSE) approved new entry-exit transmission tariffs.

To evaluate this entry-exit prices a matrix methodology for optimal allocation of costs related to the horizontal transmission network to entry points and exit zones is adopted.

This tariff system ensures nondiscrimination between domestic flows and cross border flows as stated by European regulation. Final access prices to end-user consumers are obtained adding the costs of network equipment necessary to supply the downstream market. For this purpose a long run average incremental cost methodology is adopted.

With the presented tariff methodology appropriate transmission network entry-exit tariffs are computed promoting an efficient use of the infrastructure and contributing to market enhancement and integration.

3. France - Gas transmission tariff structure and the creation of a single market area

3.1. The gas transmission system

In France, there are 2 transmission system operators, GRTgaz, which operates 90% of the grid, and TIGF, which is present in the South-West of the country and, in particular, manages the interconnections with Spain. The grid is split between the main transmission network, made of the principal pipelines which can, in many cases, be operated in the two directions, and the regional networks which gather one way pipes delivering gas to distribution areas. Tariff calculations are different for these two parts: the entry-exit approach is applied to the main lines while the regional networks have a distance-based tariff structure.

Upstream infrastructures in France

The French gas transmission network, one of the longest in Europe, has 7 terrestrial interconnections with neighbouring countries, a gas pipeline entry point to Norwegian fields in the North Sea, as well as four LNG terminals Fos-Tonkin, Fos-Cavaou, Montoir-de-Bretagne and Dunkirk LNG (of which commissioning is scheduled for September 2016). At the end of 2015, the entry capacity by pipeline to the French network thus amounted to 2,285 GWh/d, and exit capacity to neighbouring countries to 658 GWh/d (figure 22). Once Dunkirk LNG is commissioned, LNG import capacity will rise to 1,330 GWh/d (34 bcm/y), which will put France in third position in Europe, behind Spain (~ 60 bcm/y) and the UK (52.3 bcm/y). France also benefits from major underground storage capacity. It has 16 storage sites, for an overall effective volume of 131.4 TWh (the 3rd largest capacity in Europe), representing approximately 30% of the annual French gas consumption. France therefore has a strong gas system, well integrated with the rest of the European market, with robust diversity of supply.

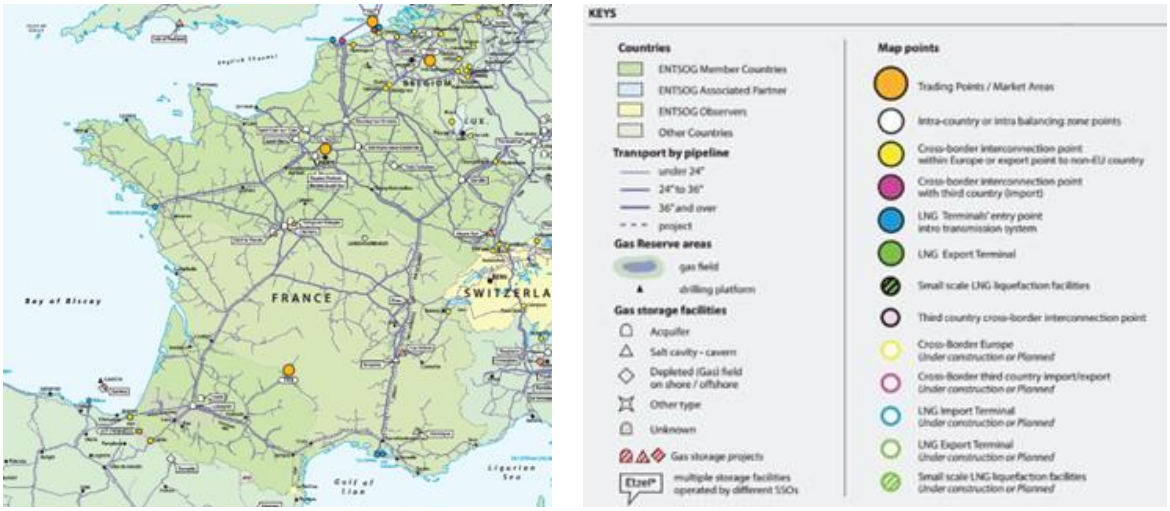


Figure 16. The French gas network (source: ENTSOG)

Capacities and flows at interconnections

The improvement of interconnection capacities and integration with neighbouring countries in general has been a constant concern for the CRE. Thus, in ten years, the entry capacity increased by over 52% and France more than doubled its exit capacity at borders, including the output capacity to Spain and commissioning a new interconnection with Belgium,

Alveringem, which will re-export gas to northern Europe. Significant investments (€ 823 million) to optimize the core French network were also decided upon and will advance the structure of the French market toward a single area in 2018.

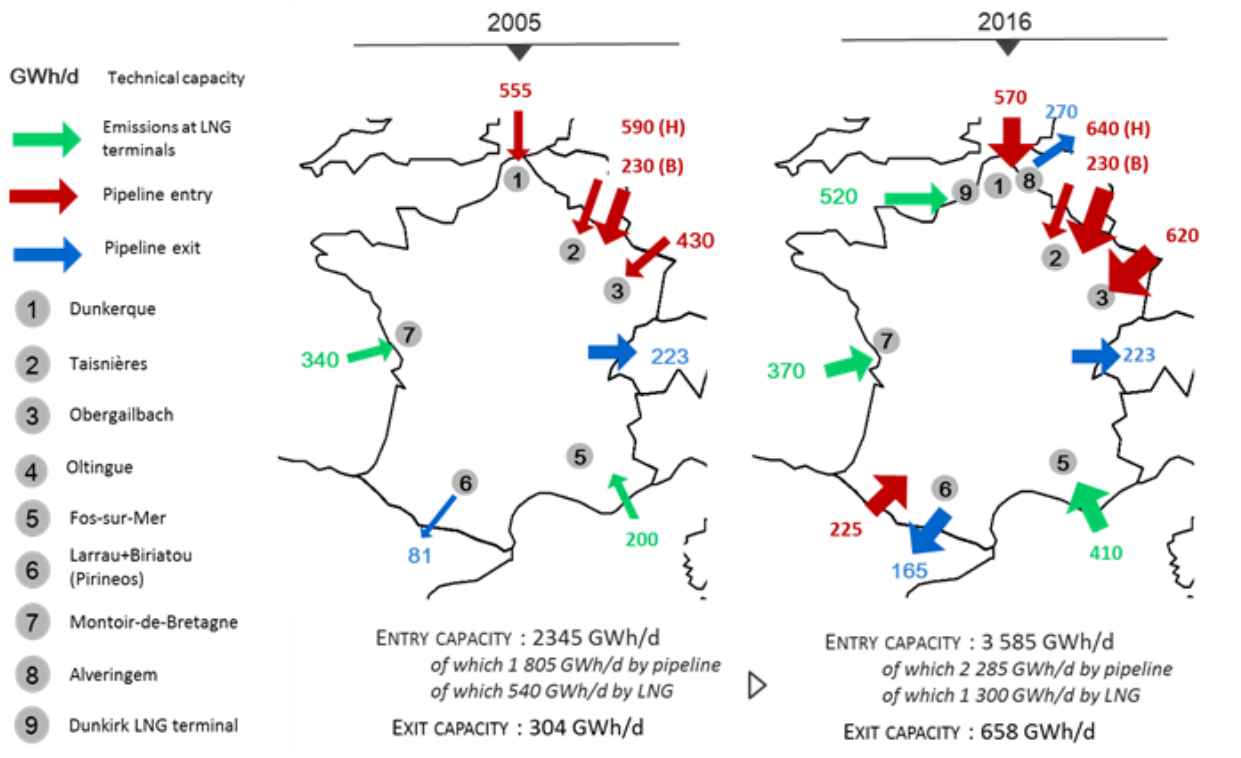


Figure 17. LNG interconnection and entry point, from 2005 to 2016 (source: GRTgaz and TIGF, CRE analysis)

The total gas consumption in France amounted to 480 TWh in 2015, which was one of the warmest years on record. Gas power plants, which consumed 2.6 times more gas than in 2014, compensated the climate's impact on demand, which explains the increase in total gas consumption year on year (+ 2.3%). France's net import balance was brought to 446 TWh (data non-adjusted for climate) in 2015, up 4% compared to 2014 (435 TWh). France has got seven sources of gas imports: Norway, being the main supplier at 40% of total volume, Russia with a coverage of 15% of total volume, the Netherlands, Algeria, Nigeria, Egypt and Trinidad and Tobago. Pipeline imports represented 88% of the total, while, since 2010, the share of LNG has fallen by a factor above two (12% in 2015, as against 26% in 2010 and 2011). This decline was mainly due to the diversion of LNG volumes to Asian markets. Long-term contracts still represent about 80% of imports, but the improved integration of European markets and the development of the British and Dutch liquid hubs, NBP and TTF have led the share of short-term contracts to continuously increase over the past few years.

From the volumes that enter into the French system, a part is re-exported to Italy and Spain. The volumes concerned are part of long term contracts with Norway, but also shorter term transactions on European hubs. Exports to Italy via Switzerland reached about 30 TWh in 2015. France also plays an important role in the operation of the Spanish market, especially when the price of LNG is high. Total exports of gas to Spain were multiplied by 4 between 2010 and 2014 and amounted to 49 TWh. This increase follows investments between France and Spain which raised capacity in both directions to 165 GWh/day. In 2014, French exports amounted to 302 TWh, which represented on average 16% of total gas consumption in Spain.

This situation was largely due to a substitution of pipe gas to LNG when prices were high in Asia; unsurprisingly the decline in LNG prices in the international market led LNG imports to recover in 2015, which translated in a decline of exports to Spain down to 37 TWh. Exports to Spain have to cross all the French transmission network, currently divided into 2 different zones, one at the North (PEG Nord), one at the south of France (TRS). As a result, the North-South link within France has accounted among the most congested points in Europe for the past 5 years since it had to flow all the pipeline gas dedicated to replace LNG either to supply Spain or the South of France. Eliminating this congestion, which led to very high price spreads between the north and the south of France, has thus become a priority for CRE.

3.2. Transmission tariffs are largely compliant with the EU network code project

A network code on tariff structure harmonization is about to be finalized in the European Union. It aims at improving transparency and coherence among the tariff structures in different Member states, in particular to ensure there is no undue discrimination between different kinds of network users. An important focus is on cross subsidies: tariffs should, as much as possible, reflect costs. However, this principle has to cope with others like stimulating competition and promoting stability of tariff levels. France provides a good illustration of the balance between various criteria when implementing the market model promoted by the Third legislative package.

The market model for gas in the EU and its tariff translation

Tariff structure harmonization in Europe and the network codes already adopted (capacity allocation mechanisms, balancing and interoperability) serve market integration through the implementation of a new market design. This model includes entry-exit systems with virtual hubs which are interconnected by bundled capacity products. One of the key issues of tariff structures is thus, within entry/exit zones, to properly allocate costs between transit across the market areas and domestic transportation aimed at supplying local final consumers.
More precisely, in entry-exit zones, network users have to book capacity at entries, where they inject gas into the system, and exits where they take the gas off to their customers. Tariffs at these points should cover the costs of shipping individually and in total. In sum, network users should pay charges in line with costs due to their activities and, when aggregated, cover the total transmission costs, namely the revenue the TSO is allowed to get to cover its expenditures (CAPEX and OPEX) and remuneration.
The European network code on capacity allocation (CAM code) has implemented auctions at interconnections: all capacity bookings should be done through auctions on a single platform per IP. All products of the same kind are auctioned simultaneously within the EU (annual, quarterly, monthly, daily and within-day products). The network code on tariff structure harmonization focuses notably on the determination of reserve prices for these auctions.
France has been among the first countries to implement entry-exit zones in the EU. The CAM code has been implemented in due time with the introduction of auctions at all the interconnection points (cross-border and internal). In many cases, there is few annual capacity offered as a consequence of past reservations resulting notably from open season procedures.

Elements from the draft network code on tariff structure harmonization

Transparency is a priority goal of the project of network code. It includes the publication of cost drivers as well as a clear justification of the calculations behind the tariff levels. Tariff

calculations are also based on assumptions regarding the future usage of infrastructures, the aim being to forecast the revenues to come in order to minimize the potential gap between the allowed TSO revenue and the actual turnover. These gaps are recorded in a regulatory account (Account of regulation of charges and products, CRCP) which is "reconciled" regularly. This approach is in line with practice in France. CRE is responsible for determining gas transmission tariffs; it has provided full transparency about cost drivers and assumptions for many years. Revenue gaps are recorded in the "CRCP" which is generally reconciled when a new tariff is elaborated, every 4 years.

Regarding tariff calculation, the model chosen within the network code and applied by France is "capacity based", as opposed to "commodity based". That means that network users only pay for the amount of capacity they book in the system, the unit being €/MWh/day. These levies are supposed to cover all the TSOs' costs. Commodity charges (proportional to the energy flowed) are allowed but within a narrow scope, mainly to cover some variable costs (fuel for compression for example).

Regarding price levels for different kinds of capacity products, a principle of "multipliers" for short term products has been agreed. It consists in allowing short term products to be more expensive than long term ones to promote long term capacity reservations. Quarterly, monthly and daily capacity products can be up to 50% more expensive than annual products (for a comparable duration). This approach has been implemented in France, with multipliers of 1.3 for quarterly products and 1.5 for monthly and daily products.

Cost allocation methodology

Tariff methodologies in the EU consist in securing cost recovery for TSOs. These costs have to be translated into tariffs via a cost-allocation methodology. The network code drafters have been looking for a compromise between distance-based tariffs and some postage stamps, which consist in identical tariffs for all the users. Indeed, the entry-exit concept does not allow pure distance-based tariffs in case of meshed networks, thus there is an unavoidable gap between actual tariffs and individual costs (which cannot be determined). In addition, spreading costs among the network users independently from their geographical location helps developing competition by reducing tariff differences among shippers according to where they bring gas into the system. Economic signals promoting an efficient use of the network have also been taken into consideration. Another aspect is the split between entries and exits, namely the share of the total costs to be collected at entries and at exits. Even though it leaves some flexibility to NRAs, the network code proposes a reference entry-exit split of 50/50. In France, on the main network, this split is approximately 40 % on entries and 60 % on exits.

The network code proposes a reference methodology named "capacity weighted distance" (CWD). The CWD method consists in calculating tariff levels proportionally to the capacity offered and the average distance to exits (for entries) or from entries (for exits). NRAs have the possibility either to apply it or to develop an alternative one but, in that case, should compare their method to the results they would have got from the application of CWD. NRAs can also equalize tariffs at points of a same category as a "secondary adjustment". In France, the new tariff structure currently prepared by the CRE is based on the application of the CWD methodology in order to properly reflect the domestic and transit costs in tariffs at cross-border interconnections. Domestic exits on the main network are equalized: the same exit fee is applied.

3.3. Structure of Gas transmission tariffs

In France, transmission tariffs for natural gas apply the same way to cross border and domestic flows. The French tariff transmission system is based on a full entry-exit capacity separately bookable, with no restriction. There is one virtual hub per market area.
The distinction between the main transmission grid (high pressure) and regional networks (medium pressure) is reflected in the tariff structure. On the main transmission grid, the entry/exit model is applied while, on regional networks, a distance based approach is followed. In the following developments, we will focus on the main grid.

Tariff structure on the main transmission grid

The costs of the network (CAPEX and OPEX) are allocated to the tariffs applied at entry and exit points. The French system includes a distinction between the costs necessary for the reinforcement of the core part of the main transmission grid and those necessary for the creation of additional capacity at interconnection points. The costs of the core part of the main transmission grid are shared among all entry and exit points.
Concerning the development of new capacity at interconnection points or for the connection of new LNG terminals, generally long term bookings are required from future users to decide on the investment. Investment decision is made under the condition that a certain amount of investment costs are covered by long term commitments taken by shippers. The full coverage of costs usually requires increasing tariffs.
Each exit zone of the TSO main network is defined by the set of delivery points attached to it. For all of the exit zones of a TSO, the charge applicable to the domestic exit capacity is equalized. There is a discount proximity charge for shippers supplying consumers located close to some entry points (Taisnières B, Taisnières H, Dunkerque and Obergailbach). Tariffs at cross-border entry capacities are equalized as well. In this way, gas supplies from every source (Germany, Belgium, Norway, Spain) benefit from a level playing field. The same equalization principle applies to the entry capacities from LNG terminals.

The treatment of underground storage

Underground storage facilities are key to the security of supply of France. There are 15 facilities spread over the country which account for a capacity of about 100 days of average consumption. Gas is injected in summer and withdrawn in winter, when demand is high. Storage contributes to optimizing the management of the transmission network in France and, thus, the principle is that entry and exit tariffs at storages should not be identical to other points, but lower. Actually, a discount is applied at storages to avoid “double payments” from users, reflect savings in terms of transmission system development and stimulate the use of storages by users to support security of supply.

3.4. New issues relating to the creation of a single market area

The evolution of the market design in France

In France, the design of balancing zones has reflected constraints in the transmission system: the existence of several entry-exit areas in France is due to the technical and physical limitations in the transfer of gas between one area’s entry point and another’s exit point. The CRE has soon promoted the reduction of the number of market areas in France, moving towards three zones as from 1 January 2009 by eliminating several congestions on the main lines in the northern half of the country. In July 2012, the CRE has set out a roadmap for reducing the number of market places with the objective to have, by 2018, a single market

area for the whole country (PEG or “point d’échange gaz”), namely the “PEG France”. This project involves the elimination of the congestion on the North-South axis, which requires significant investments in the French transmission network.

Towards a single trading region in France

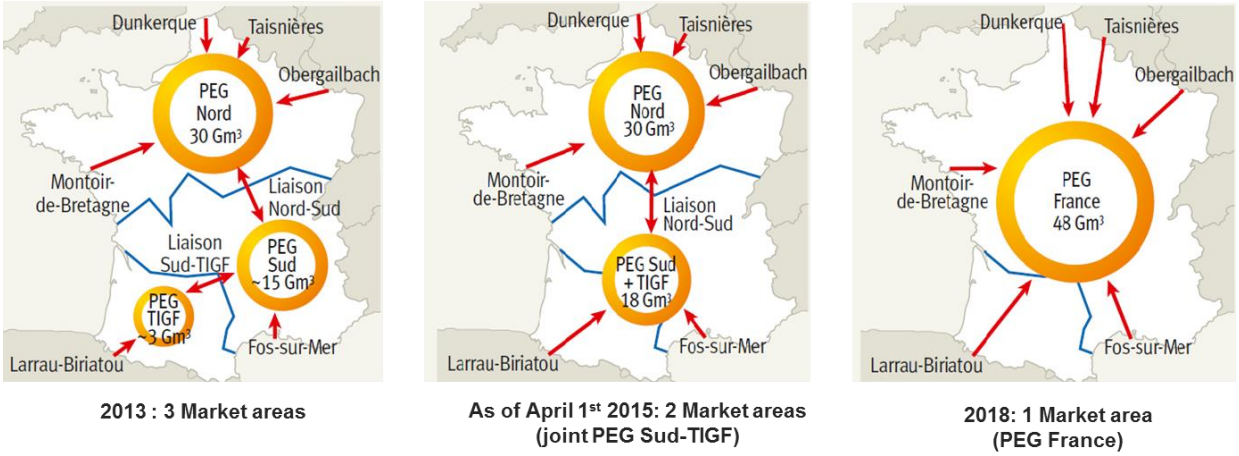


Figure 18. Towards a single trading region in France (source: CRE)

Creating a single market area involves high investment costs and the suppression of an internal interconnection point where some revenues are collected from shippers. In terms of tariffs, CRE thus has to re-design the structure to get the required revenues from the other entry and exit points of the French system while correctly reflecting the value of transmission services provided by TSOs.

A gradual decision process

From 1 January 2009 to 2013, the French gas market was composed of three marketplaces known as Points d'échange de gaz (title transfer points – PEGs): the PEG Nord and PEG Sud in GRTgaz's system and the TIGF PEG in TIGF's system. CRE undertook to reduce the number of marketplaces in France in order to improve the functioning of wholesale and retail gas markets for end customers.
In the first half of 2012, CRE consulted widely on the future of the French gas market. At the end of this consultation, it defined the roadmap towards the creation of a single marketplace in France (deliberations dated 19 July 2012 and 13 December 2012):

- 1 April 2013: merger of the Nord H and Nord B balancing zones;
- 1 April 2015:creation of a single PEG for the GRTgaz south and TIGF balancing zones (known as Trading Region South or TRS);
- 2018: goal to create a single marketplace in France, following the commissioning of new pipelines by GRTgaz and TIGF.

The first two steps have been achieved. All that remains to complete is the merger of the PEG Nord and the new TRS. In the current situation, a large portion of needs in the south of France (TRS) is supplied by liquefied natural gas (LNG) imported via LNG terminals located on the Mediterranean coast.
Between 2012 and 2015, the significant increase in Asian demand, linked in particular to the aftermath of the Fukushima accident, led to an increase in LNG prices in global markets. LNG players, producers and importers, therefore redirected LNG shipments towards these higher-paid markets, to the detriment of European markets. This situation led to an increase in the cost of supply of the south of France, which resulted in price spreads between the PEG Nord

and PEG Sud. In winter 2013-2014, these price spreads increased considerably, exceeding €10/MWh for several weeks in December 2013 and January 2014.
These price conditions in the south negatively affected the competitiveness of industrial customers, in particular, gas-intensive customers. They could also hamper the opening up of markets to other client segments and create difficulties ahead of the abolition of regulated tariffs for the sale of gas for companies consuming over 30,000 kWh of gas per year and for regional authorities. CRE ordered a consultancy study in 2013 to perform a cost/benefit analysis of the investments and/or flow commitments necessary for the creation of a single marketplace in France by 2018 based on entry/exit capacity decided at the time.
The Val de Saône (GRTgaz) and Gascogne-Midi (TIGF) projects were identified as the solution with the most favourable cost-benefit ratio. The expected costs of these projects were respectively estimated at around € 650 million and € 173 million. On the basis of these elements and after a public consultation, CRE decided the creation of a single marketplace by 2018.

Required tariff adjustments

Once completed, this merger will require an adjustment of the transmission tariff structure. The interconnection (Liaison Nord-Sud) between the PEG Nord and the TRS will disappear and the income currently collected there will have to be got from other entry and exit points in the transmission system. This structural adjustment shall maintain a fair cost sharing between domestic users and transit towards Italy or Spain.
CRE had envisaged that the tariffs borne by users of the transit system (Dunkerque-Pirineos and Dunkerque-Oltingue roads) would remain constant over the next tariff period (ART6). All gas supplies from France to Spain are sourced in the north of France and the shippers flowing gas to Spain have currently to pay the tariff charge at the Liaison Nord-South (€208.04/MWh/d/year) to reach the Spanish border. Once the merger completed, a portion of this charge will have to be shifted to the exit capacity to Spain (Pirineos PIR) in order to keep reflecting the cost of transit.

Solution considered in the public consultation of 27 July 2016

The correlation between the level of the tariff charges and the distance covered by gas is one of the key principles of the European draft network code on the harmonisation of gas transmission tariff structures. In conjunction with GRTgaz and TIGF, CRE carried out analyses to ensure the ATRT tariffs would comply with the principles stated in the draft network code, which should enter into effect during the ATRT6 tariff period. CRE calculated the unit tariffs (per kilometre), in the ATRT5 tariffs, based on the distances covered according to the type of flow:

Flow	Entry	Exit	Distance (km)	Unit tariff (€/MWh/d/year/km)
Transit to Spain	Dunkerque PIR	Pirineos PIR	1,045	0.78
Transit to Italy	Dunkerque PIR	Oltingue PIR	731	0.70
Domestic consumption	Entry PIR/PITTM/PITS	Exit to regional network	Between 200 and 350	[0.6 – 1.1][3]

Figure 19. Two directions for the development of the ATRT6 tariff structure

This data highlights two directions for the development of the ATRT6 tariff structure:

[3] The average distance covered for domestic consumption varies, according to modelling, by approximately 200 km to roughly 350 km.

- on the one hand, the transit unit tariffs are within the range of unit tariffs calculated for domestic customers; therefore, CRE does not intend to re-balance transit and domestic consumption;
- on the other hand, if the charge at the North-South link were fully deferred to the PIR Pirineos, unit tariffs borne for transit to Spain (€0.78/MWh/d/year/km) would be higher than that of transit to Italy (€0.7/MWh/d/year/km).

CRE currently envisages to re-align the unit cost of transit to Spain with that of Italy when the charge at the North-South link is eliminated. CRE therefore forecasts an increase in the charge to Spain by roughly €120/MWh/d/year, to be compared to the €208.04/MWh/d/year currently received at the North-South link. The rest of the loss due to the elimination of the charge at the North-South link would be covered by other GRTgaz's tariff charges.

4. Italy - Computation of Access Tariffs to LNG Terminals

4.1. Regasification

In Italy there are three LNG regasification terminals operating with a total regasification capacity of about 15.5 bcm/y, corresponding to import capacity of about 46 mcm/d. These terminals are the Panigaglia terminal in Liguria, the Porto Levante LNG offshore terminal near Rovigo (Veneto) and FSRU offshore terminal in Tuscany:

- The Panigaglia LNG regasification terminal is operated by GNL Italia. Panigaglia has a regasification capacity of 3.5 bcm/y and a send-out capacity of about 11 mcm/d. Its storage capacity is 100,000 m3. The terminal can receive vessels with maximum load of 70 000 m3.
- Porto Levante LNG offshore terminal (also named Rovigo) is operated by Terminale GNL Adriatico. With 8 bcm/y of regasification capacity and a send out of about 21 mcm/d, it is the largest Italian regasification terminal. The terminal's storage capacity is 250,000 m3 and can receive tankers with payloads ranging from 65,000 to 152,000 m3.
- The third terminal is a Floating Storage Regasification Unit (FSRU) named Toscana, a LNG carrier converted into a floating regasification terminal with a maximum authorized regasification capacity of 3.75 bcm/y and a send out of 15 mcm/d. The terminal's storage capacity is 134,500 m3 and it can receive vessels with load up to 180,000 m3. The terminal is operated by OLT Offshore LNG Toscana.

Panigaglia and FSRU Toscana terminals are completely regulated, while Rovigo is partially exempted from Third Party Access (TPA) for 80% of its regasification capacity.

4.2. Regasification tariff

The Law 481/1995 set the general principles on tariffs providing that tariff system shall be stable, transparent, promote competition and efficiency, and balance the economic and financial objectives of companies with general social goals, environmental protection and efficient use of resources. Tariffs also should be defined according to the price cap methodology.
Legislative decrees 164/00 and 93/11 define LNG regasification tariff principles providing that it is guaranteed a fair return on capital and incentivized the investment in LNG regasification capacity.
According to the Law, the Italian Regulator (ARERA) has adopted the above mentioned principles with its resolutions and has defined the methodology to calculate the allowed revenues that represent the maximum allowed revenues for regasification activity. These revenues must guarantee the coverage of operating costs and capital (defined as depreciation and return on net invested capital).

Regulatory Asset Base (RAB)

ARERA has determined the value of the RAB as follows:

- the value of assets, including those under development, corresponds to the real term (revalued) historical cost, after deducting the corresponding depreciation fund computed applying useful lives;

- revaluation is done through the Gross Investment Deflator Index (GID)[4];
- RAB is calculated deducting adjustments such as the lump sum paid on pensionable retirement (TFR), and the present value of public grants for infrastructure developments.

The net working capital is parametric, and equals to 0.8% of the gross invested capital, deducting adjustments. The RAB is updated on a yearly basis taking into account GID variations, new investments/divestitures, depreciation, and changes in public grants.
The Italian Regulator determines the rate of return of RAB as a weighted average of the rate equity return and debt capital (Weighted Average Cost of Capital WACC), according to the following formula, which takes into account the fact that taxes paid are applied to nominal revenues:

Where:
$$WACC(real, pre\,tax) = \frac{\left[1+\left(\frac{Ke}{(1-T)} * \frac{E}{(E+D)} + Kd * \frac{(1-tc)}{(1-T)} * \frac{D}{(E+D)}\right)\right]}{1+rpi} - 1$$

Ke is rate of return on equity calculated applying the Capital Asset Pricing Model (CAPM) as follows: $Ke = r_f + ERP * \beta_{levered}$
Kd is the cost of debt calculated as follows: $Kd = r_f + DRP.$

In the table below, the parameters used to calculate the WACC for the current (fourth) regulatory period are reported. In particular:

- The risk free variable is calculated as the average of the ten year "BTP benchmark" bond yield (the return an investor realizes on a bond);
- The debt/equity ratio is based on financial structure of regulated companies in the gas sector;
- The beta parameter takes into account a higher risk than the one associated with the transport of gas.

For this regulatory period the return on capital is equal to 7.3%.

4th period WACC parameters		
D/E	Debt/Equity ratio	**0,8**
r_f	Risk free rate	**4,53%**
DRP	Debt Risk Premium	**0,45%**
Kd	Return on debt	**4,98%**
$\beta_{levered}$	Systematic risk	**0,829**
ERP	Equity Risk Premium	**4%**
T	Tax rate	**35,7%**
tc	Tax shield	**27,5%**
rpi	Inflation rate	**1,8%**
$WACC_{real,\ pre\text{-}tax}$	Return on capital	**7,3%**

Figure 20. 4th period WACC parameters

[4] GID is detected by Italian National Institute of Statistics (ISTAT) and it allows to obtain a congruent monetary revaluation of historic investments made in the activities of regasification.

The regulatory framework provided an extra WACC to compensate for regulatory lag. A 1% WACC increase is granted to new investments from 2014 to counterbalance negative effects of the time lag between the year revenues are recovered through tariffs (y) and the one which allowed revenues refer to (y-2).WACC for 2016-17 is updated considering the April 2014 – March 2015 average of the ten year "BTP benchmark" bond yield.
Investments in new strategic LNG terminals, or in new capacity (at least +30%) for existing terminals, can benefit from a 2% WACC increase granted for 16 years. Strategic terminals are those identified by the Italian Ministry of Economic Development, according to legislative decree n. 93/11, article 3, within the framework of the National Energy Strategy Document (SEN).

Depreciation of assets

The table below reports the regulatory life of regasification assets. The yearly allowance for asset depreciation is the ratio between each asset gross present value and the corresponding regulatory life.

Asset	Regulatory life (years)
Buildings	40
Pipelines	50
LNG regasification facilities	25
LNG offshore regasification facilities	25*
IT	5
Other tangible assets	10
Intangible assets	5
Meters	20
Gas	Not depreciated
Land	Not depreciated

* Can be reduced down to 20 years for offshore terminals, provided the operator can prove - based on an independent 3rd party assessment - the shorter useful life

Figure 21. Regulatory life of regasification asset.

OPEX

According to Law 481/1995, the Italian Regulator applies to OPEX the price cap methodology. At the beginning of each regulatory period the allowed OPEX ($RLco_t$) are aligned to the actual OPEX, deducting:

- a profit sharing amount, if efficiency targets have been met;
- an update of allowed OPEX in previous regulatory period, if efficiency targets have not been met.

All OPEX related to standard operations are eligible in tariff, while others are normally excluded from allowed costs (e.g. rental costs, reserves, non-mandatory insurances, financial costs, no recurring costs). Allowed OPEX are company specific and based on each operator's actual data.
OPEX are yearly updated as follows:

$$RLco_t = RLco_{t-1}(1 + RPI_{t-1} - X + Y)$$

Where:
$RLco_{t-1}$ are the OPEX of the previous period;

RPI_{t-1} is the inflation rate;
X is the required efficiency gain, which is company-specific;
Y reflects additional costs due to extraordinary events such as modifications of the regulatory framework or variations in public service obligations.

If the LNG regasification company has been more efficient than what it was required by the X-factor, the allowed revenues for the next regulatory period are aligned to actual OPEX plus a decreasing share (over an 8 year time) of half the efficiency gains obtained during the previous period. Efficiency gains are defined as the difference between allowed OPEX and actual costs based on the last available final statement.
Costs due to losses and fuel-gas of LNG regasification chain are provided in kind by terminal's users.

Revenues compensation mechanism

In Italy, a revenue compensation mechanism is in place to ensure capital cost recovery in case of missing capacity allocation. The revenue compensation mechanism is applied to terminals which obtained the right before 2014 and strategic terminals as defined according to legislative decree 93/11.

The amount of revenue compensation for year *t*, FC_t, is calculated with following formula:

$$FC_t = max(\alpha * RL_t - REF_t ; 0)$$

Where:

RL_t is the allowed revenue for year *t*;

α is the level of revenue covered by revenue compensation mechanism, equal to:

- 64% for terminals which obtained the right before 2014
- a value determined by AEEGSI, on a case-by-case basis, for strategic terminals;

REF_t is the effective revenue for year *t* from regasification service tariff.

For terminals that opt out from the Third Party Access (TPA) exemption regime, according to ARERA resolution 272/2013/R/gas, the amount of revenue compensation does not take into account investment incentives ($RL_{incentive}$), as follows:

$$FC_t = max(\alpha *(RL_t - RL_{incentive}) - REF_t ; 0)$$

Tariff structure

The tariff applied to users for regasification services has a capacity-only charge, in order to reflect structure of the service provided. In fact, most part of the regasification costs are fixed costs, while variable costs like losses and fuel-gas of LNG regasification chain, beared by the terminal users. Regasification services requires that users delivers LNG to terminals and withdraw regasified gas at the entry point of the national transmission network. The annual tariff is calculated as follows:

$$TL = (Cqs + Crs) * Qs$$

Where:

TL is tariff for annual regasification service;

Cqs is regasification capacity charge (€/LNG cm/year) calculated as ratio between allowed revenues (RL_t) and terminal regasification capacity;

Crs is decommissioning cost charge (€/LNG cm/year) calculated as ratio between

revenues to cover decommissioning cost and terminal regasification capacity;

Qs is regasification capacity booked at terminal (LNG cm/year).

4.3. Additional regasification services

In recent years other services were introduced in addition to the standard regasification services, such as peak shaving service, flexibility services and bundled service regasification and underground storage. Specific revenues and tariff have been defined for additional regasification services, considering the underlying costs.

Peak shaving service

The Italian Ministry of Economic Development has provided the introduction of peak shaving service with Decree of October 18, 2013.
Peak shaving service covers the emergency needs of the gas system at peak time during winter. The LNG is unloaded and stored in the terminal to be available in a short time if necessary. If the LNG is used during the winter the shipper receive a defined price, if not it receives the gas back in April. The costs of the services are covered by the gas system (i.e. the final customer).
The shipper pays the transport and regasification fees and receives from the system the price established in the auction. In the auction the offer with the lower price wins. The Ministry set the maximum price that can be accepted on a proposal from the ARERA.
The maximum price also takes into account the cost/opportunity for a user to supply gas to immobilize into the tanks of LNG terminals and is used in case of system crisis.

Flexibility services

With the Resolution 502/2013/R/gas, the Italian Regulator has introduced criteria concerning the offer of the flexibility service (change redelivery program on users' request) and the temporary storage service by LNG regasification terminals.
The goals of the Resolution 502/2013/R/gas are to increase liquidity and gas market competitiveness in Italy; increase availability balancing resources and their flexibility and finally improve the gas system security.
The service is offered taking into account that LNG terminal have to propose flexibility services fee aligned to incremental costs, regasification costs and transport costs. Revenues from fees application in order of priority go to: (1) recover LNG terminal incremental cost; (2) reduce revenue compensation if greater than zero (FCt > 0); (3) users of services (pro-quota).
Following is reported the case of Rovigo terminal on how it implemented flexibility service and temporary storage service.
Rovigo LNG terminal could offer to its users on the day (D) the possibility to increase/decrease the gas quantities to be redelivered on the next day (D+1). The tariff for flexibility service (FS) is calculated as follows:

$$FS = CSS + CAS + CRF$$

Where:

CSS is fee for the subscription of the services and depends on the subscription period chosen by the user (annual, semiannual, monthly)

CAS is fee for service activation

CRF: is fee for redelivery

The Rovigo LNG terminal could also offer to its users on the day (D) the possibility to keep

temporarily into the terminal tanks an LNG quantity to be subsequently redelivered. The tariff for temporary storage service (TSS) is calculated as follows:

$$TSS = CSS + CAS + CBO + CRF$$

Where:

CSS, CAS e CRF are the same as the flexibility service and CBO is fee for boil-off.

Bundled service regasification and underground storage

The Italian Ministry of Economic Development has established with Decree of February 25, 2016 that 1 bcm of UGS capacity should be left available to industrial customers first who want to use this capacity to receive LNG. The measure has the purpose to optimize the use of the regasification capacity of the national LNG terminals, increase the liquidity of market and at the same time to limit the impact of these infrastructure costs for the system;
With resolution 77/2016/R/gas, the Italian Regulator has defined the mechanism for the allocation of the bundled capacity for regasification and underground storage in line with the provisions of the Ministerial Decree. The Resolution 77/2016/R/gas also defines the reserve price for auction that should keep into account:

- The winter/summer spread of the forward price for gas at TTF or PSV;
- The winter/summer difference among tariffs' charges for gas injected into the network;
- The charges associated to the allocation and the use of storage capacity (i.e. transmission charges at the entry/exit point for the UGS; injection and withdrawal charges; charges for purely storage activity);
- The charges for the allocation and the use of LNG capacity (i.e. transmission charges at the LNG entry point, charges to recover losses and consumption of the client).

In any case the allocation price for bundled capacity for regasification and underground storage couldn't be less than the auction allocation price for storage capacity.

4.4. Market mechanisms for LNG capacity allocation

With Consultation 714/2016/R/gas, the Italian Regulator has prospected the introduction of market mechanisms for LNG capacity allocation instead of current mechanisms (priority access and pro-rata).
Also in this case, as previously seen for bundled service regasification and underground storage, Regulator's target are to make regasification capacity more attractive for the market so that is possible to maximize use of regasification plants ensuring more liquidity for market and security for the gas system as well as minimize charges for the gas system (i.e. revenue compensation).
The Consultation 714/2016/R/gas concerns in particular the identification of the most efficient auction procedure, the criteria to define reserve prices and the management of auction revenues.
About auction procedures, the Italian Regulator has suggested to adopt the same auction mechanisms currently provided for allocation of interconnection capacity and to align it with network code on capacity allocation mechanisms (CAM) foresee by Commission Regulation EU No 984/2013; therefore it proposes to adopt:

- Ascending clock and marginal price for allocation of long-term capacity products (more unloading);
- Pay as bid for allocation of short-term capacity products (one unloading)

- On the reserve prices AEEGSI has prospected to adopt a reserve price:
- Based on the regasification tariff for capacity ≥ 1 year (more unloading);
- Based on forward price indexes for capacity < 1 year (but not spot, more unloading)
- Equal to zero for spot capacity (one unloading).

About management of auction revenues, the Italian Regulator has suggested that for LNG terminal with revenue compensation greater than zero (FCt > 0), the auction revenues go to reduce it (FCt).

5. Turkey - Natural Gas Tariffs

5.1. Legal Background and Evolution of the Regulatory Environment

After the enactment of the Natural Gas Market Law (NGML) No: 4646 in 2001, one of the first By-laws published by the Energy Market Regulatory Authority was By-law on Natural Gas Tariffs, which included the regulations on transmission, distribution, storage including the LNG facilities and FSRUs, and wholesale tariffs. Since the NGML does not define import, export, storage, regasification and sales of LNG and CNG as separate activities but together with relevant activities for pipeline gas and classifies LNG terminals as storage facilities, all the aforementioned LNG and CNG activities were carried out under similar licenses and subject to the similar regulations as the relevant pipeline activities.

After the debut of the private importers in 2007 as a result of the gas release tenders in 2005, wholesale tariffs including LNG sales were liberalized as of the start of 2008 by a Board Decision, in line with the relevant article of the NGML that dictates that the wholesale tariffs shall be set freely between the parties provided that a competitive wholesale market is established. Since that date, all tariffs of private wholesalers including the importers are set by negotiations between the parties, whereas tariffs of the incumbent BOTAS are set by the "Cost-Based Pricing Mechanism" governed by the High Planning Council, in order to avoid predatory pricing.

The tariffs of the LNG and CNG transmission activities, which were not differentiated regarding the licensing and tariff regulations by the Law, were liberated as of the start of 2015, making the CNG sector fully liberated.

Tariffs of LNG terminals including FSRUs were also regulated under the same principles with the underground storage facilities until the end of 2017, when the BOTAS Dortyol FSRU, the second FSRU and the fourth LNG facility of the Turkish network, was operable. The LNG tariffs were liberalized as of the start of 2018, in line with the NGML articles dictating that the storage tariffs including LNG facilities should be freely set between the parties provided that there's sufficient capacity, and the Board Decision confirming that the increased capacities of the existing capacities and the additional capacity added by the new infrastructure suffices to meet the demand towards LNG regasification services.

Currently, the tariffs that are regulated in line with the NGML and the By-law on Natural Gas Tariffs, and set by Board decisions before the start of every tariff period, are as follows:

- Transmission tariffs: the pipeline transmission tariffs of the incumbent BOTAS Transmission;
- Distribution tariffs: service and connection tariffs of the 58 DSOs for which the tender period, during which the service fees are fixed, is finished;
- Storage tariffs: tariff of the underground storage facility to which TPA is granted and capacity reservations are possible at the moment, BOTAS Silivri Underground Storage Facility.

Although the legislative basis for the regulated tariffs are common and unified, there are differences in the basics set by the methodologies published separately for the activities and the related Board Decisions.

5.2. Basics of the Tariff Regulations

All tariffs set for the natural gas market activities, with the exception of distribution tariffs, are set by applying the "revenue cap" tariff model, guaranteeing the revenue requirement of the facilities. The distribution tariffs are set by using the "price cap" method in order to promote

more efficient management of the DSOs.

5.2.1. Tariff setting process

The process of setting tariffs in Natural Gas Markets is rather unified among all regulated tariffs of the Turkish natural gas market.

- Information and documents that will form the basis for the tariffs are requested from the license holders.
- Tariff proposals are submitted by the license holders, including the financial and technical information about the operations.
- The tariff proposals and financial tables of the license holders are reviewed by the tariffs department.
- Additional data are requested from the firms if necessary, and meetings are held to clarify the probable issues.
- Data exchange is made with the natural gas department about the operations of the firm, regarding the realization of the investments, efficiency, performance and the service quality of the firms.
- Tariffs of the firm are submitted to the Board to be approved.
- The board approves/determines the tariffs.

During all steps of the tariff setting and approval process carried out by the Tariffs Department of the Energy Market Regulatory Authority, license holders are obliged to provide all relevant information with legal proofs to the Authority, even if they are not included in the first set of regular documents requested from the firm.

5.2.2. Tariff and Depreciation Periods

Tariff periods for the different activities vary between the market activities and the facilities. The tariff period for the transmission activity has been set as 3 years by a Board Decision in December 2010, the currently the third period of three-year tariffs, which will end in 2019, is applied to the TSO. The length of the tariff period is 1 to 10 years for underground storage facilities, whereas currently the new periods are not set for the existing facilities. The length of the period was decided to be between 3 to 10 years for the LNG facilities and FSRUs while the tariffs for these facilities were regulated, and the length for the first FSRU facility was set as 7 years before the liberalization of the tariffs. Tariff periods for the DSOs are 5 years, and the period starts as of the end of the 8 year period following the tender for the distribution region, during which the lowest prices given by the winning firms in the bidding process are applied.

Depreciation periods of the activities also vary between facilities. The periods for all activities are different than the accounting values, and considerably shorter than the technical lives of the facilities in order to incentivize the investments. For storage facilities, the length of depreciation period is between 12 and 22 years. While the tariffs were regulated, the periods could vary between 5 and 22 years, and was set as 9 years for the Etki FSRU. The length of depreciation periods for tariffs of all DSOs are set as 22 years by the Board Decision dated October 2011.

5.2.3. Components of the Natural Gas Tariffs

Tariffs of all activities in the natural gas market are calculated by the same principles and consist of the same components with slight variations. Main components that are taken into account while calculating the natural gas tariffs are as follows:

- **Capital expenditures** for the infrastructure related to the licensed activity;
- **Investment adjustments** for the investments that were not included in the initial investment plan;
- **Operational expenditures** regulated by perspectives of necessity and efficiency;
- **Revenue corrections** resulting from volume risk or other unforeseeable factors;
- **Working capital expenses** calculated by applying the "Real Reasonable Rate of Return" to the 1/12 of the annual regulated operational expenditures.

Although the revenue requirements of the license holders are calculated by applying the Weighted Average Cost of Capital to the capital expenditures for all market activities, there are variations in the applications. For the transmission system and underground facilities as well as the FSRUs and LNG terminals when their tariffs were regulated, reasonable return on line pack and cushion gas is also included in the revenue requirements of the firms, in order to compensate for the opportunity cost of holding the gas in the facilities.
Similarly, a minimum WACC limit of 10% is applied to the tariffs of some market activities in order to support these facilities that are important for security of supply and promote new investments in these areas. Although the lower limit is applied to only storage tariffs at the moment, tariffs of LNG terminals and FSRUs also had the same limit until the liberalization of the tariffs.
Transmission tariffs consist of two separate types of fees, namely Capacity Fees and Service Fees. For calculation of the Capacity Fees, Entry-Exit methodology is utilized. There are 14 entry points to the system, currently all Turkish natural gas network is defined as a single exit zone, with the Kipi interconnection point to Greece being the second exit point.

5.2.4. Tariff Revisions

Tariffs can be revised in case of:

- Investment adjustments, for the investments that were not forecasted initially but decided by the Board as necessary or were included in the initial calculations but not realized.
- Unexpected, unforeseeable and unavoidable conditions such as force majeure, macroeconomic developments or changes in the legal environment.
- Non-Controllable OPEX components.

5.3. Distribution Tariffs

5.3.1. History of Natural Gas Distribution in Turkey

At the date the NGML was enacted, there were 7 DSOs active in Turkish natural gas market, supplying gas to the subscribers in 6 provinces of Turkey. These firms, called as "existing firms" in Turkish natural gas market legislation, are as follows:

- EGO (renamed as Baskentgaz for privatization) Natural Gas Distribution JSC in Ankara;
- IGDAS Istanbul Natural Gas Distribution JSC in Istanbul;
- AGDAS Adapazari Natural Gas Distribution JSC in Sakarya;
- IZGAZ Izmit Natural Gas Distribution JSC in Koceli;
- Bahcesehir Natural Gas Distribution JSC in İstanbul;
- Bursa Natural Gas Distribution JSC in Bursa;

- ESGAZ Eskisehir Natural Gas Distribution JSC in Eskisehir.

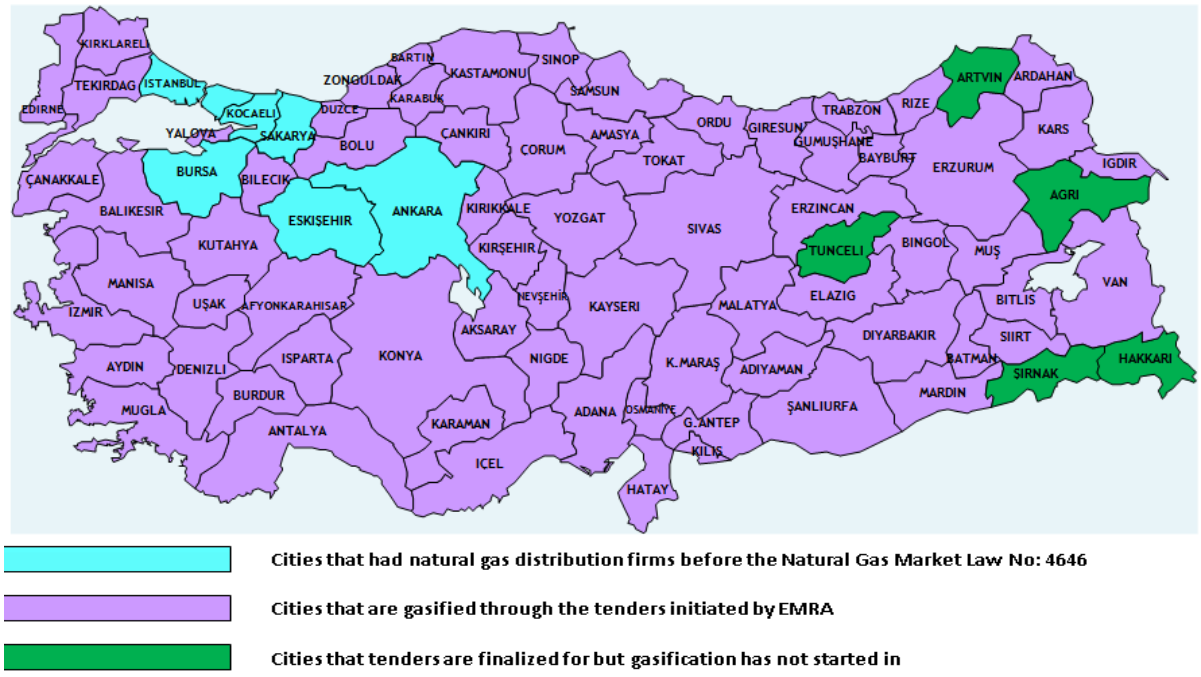


Figure 22. Natural Gas Distribution as of 2017

Starting from 2003, as a result of the intensive tendering and licensing process carried out by EMRA, the number of licensed DSOs has reached 72 and 76 of the 81 provinces of Turkey were supplied with natural gas as of the year 2017. The fees resulting from the tendering processes carried out by open auctions during which the applicants decreased the unit service and connection fees to win, are in force during the first 8 years of the 30 year license period of the winning firm. The tariffs of the DSOs that are granted licensed by the tenders (called as “tendered firms”), are regulated by the Tariffs Department of EMRA after the end of the 8 year periods.

With the exception of Baskentgaz and IGDAS, of which the tariffs were fixed by the relevant laws regarding the privatization of these DSOs, tariffs of all of the “existing firms” are regulated.

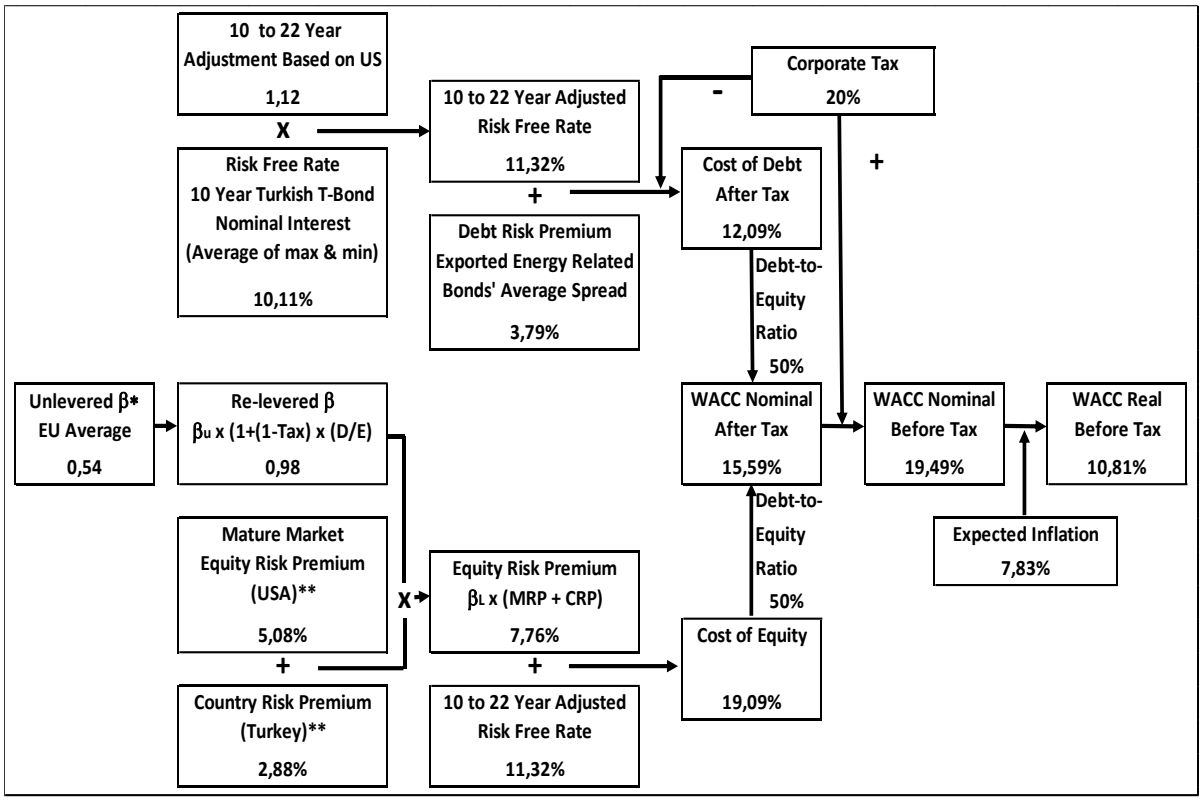
5.3.2. Calculation of Distribution Tariffs

Calculation of the Revenue Requirement

In the same manner as the tariffs for other market activities, the distribution tariffs are set by applying the reasonable rate of return calculated by using the weighted average cost of capital to the regulatory asset base of the firm. Capital Asset Pricing Model is used for determining the Required Rate of Return.

$$RR_t = \left[(RAB_t + OA_t) * RWACC\right] + D_t + \left(OC_t - OR_t\right) + WCE_t$$

RRt :	Revenue requirement for the year t
RABt:	Regulatory asset base of year t
OAt:	Other assets (5% of RAB)
RWACC:	Reel WACC before tax
Dt:	Depreciation calculated for the year t
OCt:	Operational costs calculated for the year t (part of OPEX)
ORt:	Other revenues forecast for the year t (part of OPEX)
WCEt:	Working Capital Expenses for the year t (part of OPEX)



* https://www.boe.ca.gov/proptaxes/pdf/2016capratestudy.pdf
** http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ctryprem.html

Figure 23. Steps of WACC Calculation Process

The steps of the WACC calculation for the distribution tariffs are shown in the diagram above. Although the debt-to-equity ratios of all the DSOs differ greatly, a ratio of 50%-50% debt-to-equity ratio is taken as a basis for the calculations in order to incentivize the firms to be more efficient. As a result of this approach, efficient firms financing their operations mostly by debts get higher profits, and the firms which have higher financial costs as a result of working mostly on equities are forced to be more efficient.

Risk Free Rates that will be a basis for both Cost off Debt and Cost of Equity calculations are calculated by taking the average of maximum and minimum of nominal interests of 10 Year Turkish T-bonds. The Risk Free Rate is then adjusted to 22 years, which is the depreciation period of the distribution investments, by the adjustment ratio obtained by comparing the average yields of 10 year bonds and long term bonds in US. Debt Risk Premium, which is the average spread of the Turkish energy related bonds that are exported, is added up to the Risk Free Rate, and the Cost of Debt After Tax is calculated taking into account the Corporate tax.

Average of selected EU countries is used in Cost of Equity calculations for the unlevered β[5], for lack of a calculated value for the Turkish natural gas market. Re-levered β is also calculated by a ratio of 50%-50% Debt-to-equity ratio, taking into account the 20% Corporate Tax. For calculating the Equity Risk Premium re-levered beta is multiplied by the Country Equity Premium[6] , and the 10 to 22 year adjusted Risk Free Rate is added up to this ratio in order to calculate the Cost of Equity.

For calculating the Nominal WACC after Tax, the aforementioned 50%-50% debt-to-equity

[5] https://www.boe.ca.gov/proptaxes/pdf/2016capratestudy.pdf
[6] http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ctryprem.html

ratio is applied to the Cost of Debt and Cost of Equity. Nominal WACC before Tax is calculated by the adding the Corporate Tax, and the Real WACC before Tax is calculated by taking into account the Consumer Price Index inflation.

Evaluation and Calculation of Operational Expenditures

Principles of evaluation of the operational expenditures of the DSOs are as follows:

- Only OPEX that are required to operate distribution activities are taken into account.
- OPEX increase that cannot be rationalized is not accepted.
- Efficiency targets are applied OPEX.
- A percentage OPEX is added to support Research and Development activities.

The expenditures that are not crucial for the safe and efficient operation of the DSOs, such as expenses for lawsuits and legal counselling, advertisement costs, costs of sponsorships and representation expenditures are not taken into account in operational expenditure calculations. The main principles of the OPEX evaluation is similar for all market activities, with the addition of the R&D funds for the DSOs.

After the calculation of Regulated Operational Expenditures, the fees and fines collected by the DSO that shall be classified under the “other revenues” component are subtracted from these value in order to find the “Operational Expenditures Basis to Tariff Calculations”. The fees collected by the DSOs and discounted from the Operational Expenditures as items of the “other revenues” component are as follows:

- Meter closing-opening fee;
- The control fee for the inspection of indoor installations;
- Certification fees;
- Illegal gas consumption fines;
- Revenues from regulated assets;
- Other revenues generated through distribution activity.

		Natural Gas Cost	Service Fee	VAT	SCT	Total
2016	Household	0,8485 (25,40 cents)	0,1156 (3,46 cents)	0,1777 (5,32 cents)	0,023 (0,69 cents)	1,1647 (34,87 cents)
I. Half-Year	Industry	0,7597 (22,75 cents)	0,041 (1,23 cents)	0,1483 (4,44 cents)	0,023 (0,69 cents)	0,9719 (29,10 cents)
2016	Household	0,806 (24,13 cents)	0,1263 (3,78 cents)	0,172 (5,15 cents)	0,023 (0,69 cents)	1,1272 (33,75 cents)
II. Half-Year	Industry	0,7276 (21,78 cents)	0,0374 (1,12 cents)	0,1419 (4,25 cents)	0,023 (0,69 cents)	0,93 (27,84 cents)

*1 EUR = 3,34 TRY (2016 Average,) Central Bank of Turkey,

Figure 24. Average End-User Prices in 2016 (TRY per Sm3)

5.3.2.3 Example Case on Distribution Tariffs

Board Decision on the 2nd Tariff Period of the Gondor Gas Distribution JSC*

ARTICLE 1- (1) For the tariff calculations of the firm, the Regulatory Asset Base for the start of 2017 is determined as **100.003.636 TRY** (19,92 million EUR).
ARTICLE 2- (1) The forecasted network investment caps for the firm during the tariff period are as follows:

	2017	2018	2019	2020	2021
Investment Cap (TRY)	35.053.792 (6,99 million €)	35.294.765 (7,03 million €)	35.508.298 (7,07 million €)	35.694.389 (7,11 million €)	35.853.040 (7,14 million €)

*1 EUR = 5,02 TRY, Central Bank of Turkey, 10 April 2018

ARTICLE 3- (1) Calculations for the retail tariffs of the firm are done using the data included in the appendix.
(2) Service fees that will be applied by the firm shall not exceed the upper limits for January 2017, posted in the following table divided by the consumption groups.

	Annual Consumption	Service Fee (TRY/Sm^3)
Group 1	**0-100.000 Sm^3**	0,237722 (4,735 cents/Sm^3)
Group 2	**100.001-1.000.000 Sm^3**	0,159664 (3,181 cents/Sm^3)
Group 3	**1.000.001-10.000.000 Sm^3**	0,085154 (1,696 cents/Sm^3)
Group 4	**10.000.001-100.000.000 Sm^3**	0,047308 (0,942 cents/Sm^3)
Group 5	**100.000.001 Sm^3 and above**	0,011827 (0,236 cents/Sm^3)

(3) Monthly update of the upper limits for January 2017 in the Sub-article 2 of this Decision shall be made according to the Article 26 of the Tariff Methodology.
(4) The service fees applied to the eligible customers by the firm shall not exceed the upper limit for the service fees for the relevant consumption group in the relevant month.
(5) The retail prices applied to the customers that the firm supplies natural gas shall not exceed the wholesale price the distribution firm buys the gas for, plus the upper limit for the service fees for the relevant consumption group in the relevant month.

ARTICLE 4- (1) Value Added Tax is not included in the fees determined in accordance with this decision.

Calculation of the Revenue Requirement	2017	2018	2019	2020	2021
Asset Base at the Start of the Tariff Period	100.003.636	100.230.744	100.230.579	100.003.140	99.548.430
Planned Investment	5.000.000	5.000.000	5.000.000	5.000.000	5.000.000
Depreciation	4.772.893	5.000.165	5.227.438	5.454.711	5.681.983
Asset Base at the End of the Tariff Period	100.230.744	100.230.579	100.003.140	99.548.430	98.866.446
Average Regulated Asset Base (Ave. RAB)	100.117.190	100.230.661	100.116.860	99.775.785	99.207.438
WACC	12,85%	12,85%	12,85%	12,85%	12,85%
WACC$_{adj}$	12,074%	12,074%	12,074%	12,074%	12,074%
Return	12.088.150	12.101.850	12.088.110	12.046.928	11.978.306
CAPEX Component	16.861.04	17.102.01	17.315.54	17.501.63	17.660.2

	2	5	8	9	90
$OPEX_R$	20.000.000	20.000.000	20.000.000	20.000.000	20.000.000
Other Revenues related for dist. act.	2.000.000	2.000.000	2.000.000	2.000.000	2.000.000
Operational Expenditures Basis to Tariff Calculations	18.000.000	18.000.000	18.000.000	18.000.000	18.000.000
Working Capital Expenses	192.750	192.750	192.750	192.750	192.750
OPEX component	18.192.750	18.192.750	18.192.750	18.192.750	18.192.750
Annual Revenue Requirement	**35.053.792**	**35.294.765**	**35.508.298**	**35.694.389**	**35.853.040**

As of 01/01/2017	Revenue Requirement	Consumption Forecasts for 2017-2021 Period	Distribution Charge
0 - 100.000	118.860.870	500.000.000	0,237722
100.001 - 1.000.000	15.966.386	100.000.000	0,159664
1.000.001 - 10.000.000	10.644.257	125.000.000	0,085154
10.000.001 - 100.000.000	14.192.343	300.000.000	0,047308
100.000.001 and above	17.740.428	1.500.000.000	0,011827
Total	**177.404.284**	**2.525.000.000**	

Tariff tables filled by the license holders: http://www.epdk.org.tr/TR/Dokumanlar/TDB/Dogalgaz/Dagitim
Manual on filling the tariff tables: http://www.epdk.org.tr/TR/Dokuman/7753
Board decisions on tariffs: http://www.epdk.org.tr/TR/Dokumanlar/TDB/Dogalgaz/KurulKararlari

6. Final Remarks

Among all of the instruments utilized in regulation of the energy infrastructures, setting of tariffs may be the one that demonstrates most clearly the lack of perfect regulations or absolute truths, apart from the broadly accepted principles of regulation for setting a fair and reasonable rate of return. It is generally accepted that tariffs are one of the most important regulatory instruments for managing the risk of operation of energy infrastructures for both system users and operators and guaranteeing a sustainable service as well as a reliable investment environment. Therefore, it can be deduced that, tariff methodologies employed in a market should let average market operators survive, award more efficient operators for their efforts by sharing the benefits of the increased efficiency, and incentivise less efficient ones to increase their efficiencies, as well as letting the system users access the services by paying fair prices.

In these study, four cases of good practice have been analyzed. While the case studies on Portugal and France transmission systems explain the progresses made in these countries towards the goals of compliance with the EU provisions and establishing of the single European energy market, the case studies on tariffs of LNG terminals in Italy and the DSOs in Turkey detail the three steps of the process such as calculation of the WACC and evaluation of the operational expenses.

Although there are no universal rights and wrongs or perfect practices regarding the tariff-setting process, it can be seen from the case studies presented in this paper that some common methods are widely adopted by the countries that aim to proceed towards a common goal. All good practices give utmost importance to compliance with EU codes and regulations, taking European Tariffs Network Code as a basis, if not fully comply with it. Discrimination among the parties in setting of the tariffs of the infrastructures that are open to third party access is granted. Cost reflectiveness of the tariffs is another common norm, which is aimed at by all good practices, jointly with the concerns about the security of supply and sustainability which shall not be sacrificed for lower costs.

In setting of the tariffs of the main transmission lines, both good practices, namely Portugal and France, use the Entry-Exit system, which allows the optimal allocation of costs, promotes efficiency, provides necessary price signals for new investment decisions and is compatible with the capacity allocation mechanisms implemented by the EU Network Code on Capacity Allocation Mechanisms. Tailor-made solutions made necessary by the characteristics of the national natural gas networks in both cases demonstrate the challenges and the different ways they can be coped with towards the single internal European energy market goal. The comprehensive methodology adopted by Portugal guarantees the maximum efficiency in utilization of the interconnection points considering the priorities of the system, while the French regulators aims at a more market approach at these points.

By examining the case studies on the Italian LNG tariffs and Turkish DSOs, it can be seen that both regulators use the Capital Asset Pricing Model for calculation of the expected return of equities and the WACC to calculate the reasonable rate of return. In both cases, regulators use “price cap” methodology in order to promote efficiency of the system operators. The tariffs aim at sharing the benefits from the increased efficiency of the system between the operator and the system users by applying efficiency targets to the operational expenses. As a result, the cases provided represent good examples of maintaining the balance between the sustainability of the infrastructure operators and the fair tariffs that are cost reflective and transparent.

Finally, it can be deduced that all good practices presented in this study have a common goal

of setting as efficient and transparent tariffs, without sacrificing the other pillars of energy regulation such as security of supply, sustainability, service quality and innovation. Increasing the level of information exchange regarding the tariffs in energy markets shall contribute to not only the regulators' understanding of the systems in other countries, but also level of trust of the market players and the potential investors interested in these energy markets. Hopefully, this study will reach its goal of providing an insight on tariff methodologies, by giving examples of transparent and comprehensible tariff methodologies from selected MEDREG countries that have diverse histories and practices of energy regulation.

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