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STUDY ON ELECTRICITY AND GAS MARKETS IN PORTUGAL

Final Report

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CONTENTS

GLOSSARY

bcm	Billion cubic metres (a measure of gas volumes).
CMEC	*Custos para a Manutenção do Equilibrio Contatual.* The planned system of payments to reduce the PPAs.
CNE	*Comisión Nacional de la Energía*, the Spanish regulatory organisation
CPPE	*Companhia Portguesa de Producção de Electricidade*, EDP's generation subsidiary
CTCs	Competition Transition Costs. Payments made to generators in Spain to compensate them for the introduction of deregulation
EDP	*Electridade de Portugal*
EnBW	*Energie Baden-Württemberg*
ERSE	*Entidade Reguladora dos Serviços Energéticos*, the Portuguese Regulator
GDP	*Gas de Portugal*
Eligible customers	Customers who are free to choose from whom they buy their electricity or gas.
GWh	Giga watt hours (10^6 kWh)
IBELM	Iberian Electricity Market (Portuguese Acronym)
MIBEL	Iberian Electricity Market (Spanish Acronym)
NGC	National Grid Company, the UK transmission company, a subsidiary of National Grid Transco
Ofgem	Office of Gas and Electricity Markets, the UK electricity and gas regulator.
PPAs	Power Purchase Agreements
REN	The Portuguese transmission company
SEN	National Electricity System
SEP	Public Electricity System
SENV	The independent system in Portugal
TWh	Terawatt hours (10^9 kWh)

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EXECUTIVE SUMMARY

The Portuguese government has proposed a restructuring of the energy sector in Portugal. Gas transmission would be separated from GALP Energia, and merged with the electricity transmission company REN. Under the framework agreements signed by the Portuguese government and involved parties in February 2004, gas importation, distribution and supply would be controlled jointly by the dominant Portuguese electricity company EDP (51%) and the Italian oil company ENI (49%). The Portuguese Competition Authority asked us to study the gas and electricity markets in Portugal, to examine the proposed merger, and consider remedies that might be applied to mitigate its effects on competition.

Neither the gas nor electricity markets in Portugal can be considered competitive at present. Electricity generation, distribution and supply are dominated by EDP. All elements of the gas market are dominated by GALP Energia. There are plans to increase competition in both markets, by making all customers eligible to choose their electricity and gas suppliers. In addition, the governments of Portugal and Spain have recently agreed that on 20 April 2004, the two electricity markets will be joined into a single Iberian market. Detailed plans for integration of the Portuguese gas market with Spain have not yet been agreed.

There is, however, a severe distortion to the electricity market that under current plans will continue after the integration of the electricity and gas markets. At present, most electricity produced in Portugal is sold on long term power purchase agreements (PPAs). Under these agreements, generators essentially receive payments to cover their fixed costs (capacity payments), and payment to cover their variable costs, when they are instructed to operate. The structure of these contracts makes the cash flows associated with generation very secure.

These contracts are not compatible with a competitive electricity market, and it is planned that they will be replaced. But the planned replacement will essentially have the same economic effect as the existing PPA arrangements. Under the new scheme, generators will receive payments for energy and capacity from the market, and in addition will receive compensation payments for the termination of the PPA contract, known as CMECs. The amount of these CMECs will be calculated so that the generators will essentially receive the amount that they would have received under the old PPA agreements (subject to certain limits). This means that the revenues of operators of plant covered by PPA agreements will not be dependent on the market price of electricity, although it is proposed that there will be a cap on the overall level of payments over the next ten years. There is an analogous

scheme in operation in Spain. While these payment schemes are in operation, there are incentives on incumbents to distort prices.

The precise incentives on the existing market participants will depend on the electricity pool rules, as well as the precise details of the CMEC payments and how they will interact with the pool, and these details have not yet all been finalised. However, it appears to us that the incentives depends on the size of the cap to CMEC payments, and the extent to which exploitation of market power in the future to raise prices will be possible in future.

If the cap on payments is unlikely to be binding (i.e. total CMEC payments will be less than the cap) incumbents have an incentive to keep market prices low, to deter new entry. If total payments over the next ten years are likely to meet the cap limit, and market prices following expiry of CMEC payments is expected to be below current contract prices, then there may be an incentive to distort prices upwards. In addition to the distortion to bidding behaviour, the contracts protect generators from market risk, and this inhibits the development of an active forward market in electricity.

This distortion to competition is the result of past restructuring decisions, and it is often difficult to change these. But the proposed merger provides an opportunity for this severe distortion to competition to be remedied, by imposing conditions on the merger associated with the revision of the PPAs. There may not be another opportunity to do so, or if there is, it may involve unwelcome intervention from Brussels. There is precedent in other European countries of competition authorities using conditions on energy sector mergers to resolve structural problems in markets, and we recommend that serious consideration be given to imposing conditions on the merger to remedy the PPA issue. The aim of this would not be to diminish the value of compensation for the change to the PPAs, but rather to change the structure of payments to remove the relationship with pool prices. One possible remedy could be to require auctioning of generation plant, and using the value of generation plant determined by the auction to determine stranded cost payments to generators. This could then be done in a way that does not distort the electricity market by making payments independent of wholesale prices. An alternative suggested here is to convert the PPA contracts into a Contract for Difference contracts, which could be auctioned, and the revenues from the auctions used to fund CMEC payments. Further work would be necessary to establish the details of appropriate remedies.

We have also examined the direct competitive effects of the restructuring. The separation of gas transmission assets from Galp Energia will facilitate the development of competition,

and is to be welcomed. We also see no specific issues arising from the merger of gas and electricity transmission assets into a single business.

The transfer of control of gas import, distribution, and supply (GDP) to EDP/ENI does raise the following issues:

- it would remove a potentially strong competitor from the electricity supply business in Portugal;
- GDP would have a reduced incentive to develop the gas distribution business; and
- the control of the gas market by GDP could distort the development of competition in the electricity business.

While these effects would be mitigated by the introduction of the Iberian electricity market, and further by the introduction of an Iberian gas market, our analysis indicates that the merger is detrimental to competition under the three different scenarios. It should also be noted that the creation of an Iberian electricity market will not remove the potential for EDP to exploit market power. Following market integration, the interconnectors between Spain and Portugal are likely to remain constrained in specific time periods, and EDP will have a share of 70% of total capacity (including the capacity of the interconnector), which is likely to mean that it will effectively control wholesale electricity prices in those time periods.

We therefore recommend that consideration be given to the following remedies:

- Change the terms of restructuring so that the assets and contracts of GDP are divided into two separate companies. ENI and EDP would then acquire 100% of these smaller independent companies, rather than jointly controlling a larger company which dominates gas supply in Portugal. This would not only create a new competitor in gas supply, but would potentially improve competition in electricity markets;
- In addition, require EDP to sell electricity and gas supply businesses to reduce concentration in energy supply towards pre-restructuring levels;
- Release gas import and interconnect contracts to third parties;
- Limit the construction of new generation plant by dominant generators;
- Impose stricter regulation of gas distribution businesses to ensure that there is no incentive on a dominant energy supplier to distort investment decisions in gas distribution infrastructure; and
- Require retention of gas storage and the LNG terminal within the gas transmission business, and careful regulation of both of these parts of the business.

The proposed restructuring of the energy sector in Portugal does raise serious competition concerns. The suggested remedies, however, could mitigate these concerns, and in addition resolve competition issues associated with the existing market structure and contractual framework, which could speed up the development of competitive energy markets in Portugal.

1. INTRODUCTION

The Portuguese Government announced a plan to restructure its energy sector in April 2003. The main elements of the plan involve:

- The demerger of the state controlled oil and gas business GalpEnergia into three separate parts: oil refining and oil products distribution (Petrogal); gas transmission (Transgás), and gas distribution and supply (Gas de Portugal);
- The merger of the gas transmission business (Transgás) with the Portuguese electricity transmission company (REN); and
- The merger of Gas de Portugal (GDP) with Electricidade de Portugal (EDP).

In addition, it is envisaged that the full liberalisation of the country's energy markets will be brought forward from 2008 to 2004.

Implementation of these plans has required the approval of both GalpEnergia and EDP. The board of GalpEnergia approved the restructuring in 2003, but the decision was disputed by GalpEnergia shareholder ENI. As a result of this, a framework of agreements between the Portuguese government and ENI, and EDP and ENI was signed in February 2004. Under the terms of these agreements, EDP and ENI would jointly control GdP, acquiring stakes of 51% and 49% respectively. Full details of the agreements have not been made public.[1]

Portuguese competition law has now been revised, to bring it in line with EU legislation (law 18/2003 of 11 June 2003), and revision of the legal framework has included the establishment of the Competition Authority as an independent legal entity with investigative and decision powers (Decree law 10 2003 of 18 January 2003). These powers cover the competition aspects of the regulated sectors of the economy. The Competition Authority may be required to make a decision on the proposed restructuring of the energy sector depending on whether the EU or Portuguese authorities are responsible for scrutiny of the proposed restructuring (see Chapter 2 below). If the Portuguese authority has responsibility, it will need to decide in particular, whether to permit the restructuring, and if so, what remedies should be imposed.

[1] Iberdrola, one of the two major Spanish electricity companies published a press release stating that Galp shareholders "are supporting the future acquisition by Iberdrola of natural gas distribution assets from GDP" (Press release of 13 February 2004). Press reports have indicated that it would acquire stakes in Beirigas and Tagusgas, two very small gas distribution/supply companies in Portugal.

In order to inform this decision, it has decided to commission CEPA to undertake a study of the Portuguese electricity and gas markets, in collaboration with a local researcher, Jorge de Sousa in order to:

- provide a summary of the major characteristics of the electricity and gas markets in Portugal;
- identify the major benefits and potential problems emerging from the merger;
- consider a number of scenarios for the sector, with a view to enhancing competition in gas and electricity, under alternative assumptions that the merger does and does not proceed;
- estimate the social benefits and costs of the merger; and
- suggest remedies that could be imposed that would mitigate the negative impact of the mergers.

The merger also provides the Competition Authority with the opportunity to impose remedies that address competition concerns that result from the existing market structure and contractual framework.

The remainder of this report summarises our findings and analysis. It is structured as follows:

- Chapter 2 sets out the relevant parts of merger regulation in Portugal, and the way in which this influences our analysis.
- Chapter 3 summarises the key features of the Portuguese electricity and gas industries, highlighting the similarities and differences to other European countries. In particular, we will highlight the competition concerns that arise irrespective of whether the merger proceeds.
- Chapter 4 discusses in detail the competition problem associated with the Power Purchase Agreements in Portugal
- Chapter 5 discusses other competition issues arising from the merger;
- Chapter 6 sets out potential remedies to mitigate these effects
- Chapter 7 sets out our scenario analysis, which shows the interaction of the effect of merger and remedies and the development of the market;
- Final conclusions are discussed in Chapter 8.

2. COMPETITION LEGISLATION AND THE PROPOSED RESTRUCTURING

EU merger legislation

EU merger legislation from 1 May 2004 will be governed by Council Regulation 139/2004. Mergers subject to an agreement before 1 May 2004 will be governed by the current European legislation, Council Regulation 4064/89.

The size of the companies involved in the merger exceeds the turnover requirements set out in Article 1 of the Regulation. If ENI were not involved, the activities of the merging companies would be primarily within Portugal and so the national authority would have competence.[2] The involvement of ENI means that this is not the case, so the case would be referred to the EU (see Figure 1 below).

Figure 1. International and domestic revenues of companies involved in proposed restructuring

	REN		Transgás		EDP		GDP		ENI	
Revenues (€m)	2001	2002	2001	2002	2001	2002	2001	2002	2001	2002
Global	2,229.8	2,402.6	525.2	535.2	5,650.4	6,381.5	600.3	629.4	48,925	47,922
EU	2,229.8	2,402.6	525.2	535.2	5,281.3	5,391.5	600.3	629.4	35,470	32,247
Portugal	2,229.8	2,402.6	525.2	535.2	4,959.9	5,391.5	600.3	629.4		
Italy									27,244	23,797

Source: Company accounts

Article 9 of the Merger Regulation provides that when a proposed concentration has a community dimension as defined by Article 1, Member States may apply to deal with matter themselves if the proposed concentration only affects that national market. [3] In our view, a very strong case can be made for the Portuguese authorities to deal with this matter. The gas and electricity markets are poorly integrated with those of Spain so the Portuguese market

[2] Under Article 1, if each company achieves at least two-thirds of its EU turnover in one member state the matter is for consideration by the national authorities.

[3] Specifically, Article 9 states that the application requires that either "(a) a concentration threatens to create or to strengthen a dominant position as a result of which effective competition will be significantly impeded on a market within that Member State, which presents all the characteristics of a distinct market, or (b) a concentration affects competition on a market within that Member State, which presents all the characteristics of a distinct market and which does not constitute a substantial part of the common market."

does at present form a distinct market.[4] In the remainder of this report, we have assumed that the Portuguese authority does deal with the matter, although clearly the issues remain the same whether or not the case is referred back to the national authorities.

Portuguese competition legislation

Portuguese competition and merger legislation was revised in 2003, with the entry into force of Law 18/2003 of 11 June 2003. This reformed Portuguese competition law to bring it in line with EU legislation, and the revision has included the establishment of the Competition Authority as an independent legal entity with investigative and decision powers.[5]

The legislation associated with mergers is set out in Article 12 of Law 18/2003. This states that analysis of concentrations (mergers) is to assess their impact on competition, having regard to "the need to preserve and develop effective competition in the Portuguese market, in the interests of the intermediate and final consumer". The law states that the assessment must take account of a number of specific factors:

- The structure of the relevant markets and the existence or absence of competition from undertakings established in such markets or in distinct markets;
- The position of undertakings participating in the relevant market or markets and their economic and financial power, in comparison with their main competitors;
- The potential competition and the existence, in law or in fact, of entry barriers to the market;
- The opportunities for choosing suppliers and users;
- The access of the different undertakings to supplies and markets;
- The structure of existing distribution networks;
- Supply and demand trends for the products and services in question;
- Special or exclusive rights granted by law or attached to the nature of the products traded or services provided;
- The control of essential infrastructure by the undertakings in question and the access opportunities to such infrastructure offered to competing undertakings;

[4] ENI has some gas activities in Spain. It has begun sales of around 1.2bcm of LNG to Iberdrola under a 15 year contract.

[5] Decree Law 10 2003 of 18 January 2003.

- Technical and economic progress provided that it is to the consumer's advantage and does not create an obstacle to competition; and
- The contribution that the concentration makes to the international competitiveness of the Portuguese economy.

The first ten factors above are all relevant to the consideration of the proposed restructuring, and will be addressed in our analysis in this report. In electricity and gas markets, consideration of technical and economic progress is not so relevant, and we will not consider it. The final factor appears to be a catch all that could be used to approve a merger even if there were serious competition issues. It is possible that Article 12.2 (k) could be used to justify the proposed merger, because of the economic and financial strength that the companies would have compared to international peers without such a strong market position in their domestic economy. However, a justification of a merger on these grounds would not be in the interests of Portuguese customers, and we will not consider it further.

The test as to whether a proposed merger can be approved is whether it creates or strengthens a dominant position that results in significant barriers to effective competition in the Portuguese market or a substantial part of it. So as stated, it is not just the creation or strengthening of the dominant position, it is that this will in addition result in significant barriers to effective competition in the Portuguese market.

A proposed merger that satisfies both of these conditions must be prohibited. Of course, as with all competition jurisdictions, conditions (remedies) can be imposed on mergers to mitigate the competition impact of the merger.

The detailed wording of the test appears to be particularly important in the restructuring case considered here. It appears that a merger that does strengthen a dominant position could be permitted if it does not result in significant barriers to effective competition in the Portuguese market. The merger proposals being analysed here can be allowed to proceed, provided that remedies can be imposed that will allow effective competition to develop.

The counterfactual

Most competition investigations assess whether a merger causes competition problems by a detailed analysis of existing market conditions, as these will provide the most appropriate

guide as to whether a proposed merger will strengthen a dominant market position. But in this particular case, substantial changes to the market environment are expected, including:

- the creation of the Iberian electricity market (MIBEL), with a target date of completion of April 20 2004, with associated major changes in operation of the generation market, and the structure of contracts for the sale of wholesale electricity;
- the potential creation of an Iberian gas market
- an increase in competition to supply for gas and electricity customers, with the proposed increase in the number of customers eligible to choose from whom they buy their electricity;
- the change in the regulatory framework for gas, enacted in 2001, and the transfer of regulatory responsibility to ERSE, which will lead to the creation of new tariff codes;
- the enactment of new legislation at EU level designed to accelerate the development of the internal market for energy;
- the substantial growth in gas demand, partly as a result of increased electricity generation from gas, but also because of demand for gas as a fuel; and
- the completion of an LNG terminal at Sines, increasing the potential imports into the Portuguese gas system.

The combined impact of these developments is uncertain. For example, a number of important elements in the creation of the Iberian electricity market remain to be decided, and these will affect the way in which the market develops. But an assessment of the outcome of these developments is crucial to an assessment of whether the proposed restructuring will be detrimental to competition. These substantial changes mean that many of the standard quantitative techniques used to assess mergers are not appropriate to assess this proposed restructuring.

In our analysis of the proposed restructuring, therefore, we analyse how the gas and electricity markets are likely to develop in Portugal, and in the Iberian Peninsula, with and without the merger, based on different assumptions about the effect of the changes above. This scenario analysis will be the focus of Chapter 7.

Merging companies claim cost savings are achieved through the saving of head office costs, application of best practice, and benefits from coordination of network operations. Because of the different technologies in gas and electricity networks, it is difficult to see how efficient operation is enhanced through mergers. However, the nature of the businesses (both are

capital intensive, subject to similar cost drivers, and are usually subject to similar regulation) means that management skills needed in both are similar. This means that some modest cost savings are likely.

The role of competition authorities in energy market merger cases

In electricity and gas markets, competition policy is only one way in which the future direction of the markets is influenced. The regulatory framework, the way the regulator interprets this, and overall government energy policy, are also crucial elements of the business environment determining markets. But competition policy provides an opportunity for substantial structural change in markets to happen.

Mergers and acquisitions are often about companies wishing to find ways of exploiting market power, as well as to save costs. Approval of mergers can be made conditional on changes to markets that otherwise might be impossible to effect. There is substantial precedent for this.

One of the most notable was in France. In return for being permitted to acquire a stake in the German utility Energie Baden-Württemberg (EnBW), Electricité de France (EdF) was required by the European Commission to auction rights to the output of 6GW of capacity in the French electricity market. Peak load and base load capacity has been sold through a series of auctions. This has substantially improved liquidity in the French electricity market.

An additional case was in Italy. ENEL, the dominant national electricity company wished to buy Infostrada, a telecoms company, and merge it with its mobile phone operations. The Italian competition authority determined that it should sell 5.5GW generation plant, in addition to the 3 generation disposals it was already required to do. It was argued that the acquisition would have strengthened ENEL's dominance of the Italian electricity market, with its ability to increase customer loyalty. Although this decision was eventually quashed, it shows the potential for substantial change to be effected through competition policy.[6]

[6] ENEL appealed the decision, and the Competition Authority decision was annulled. An appeal of this decision to the Supreme Administrative Court upheld conclusions on ENEL's dominant position, but found that the remedies were not proportional to the impact on customers. This was in part based on the new information on the inability of ENEL to link offerings of electricity to telecommunications services that had been part of the reason for the original decision. See Case C4438B, *Autorita' Garante della Concorenza e del Mercato*.

Companies see substantial value in mergers and acquisitions, and competition authorities can use their powers to effect change in energy markets that could not be done without the proposed mergers. The associated remedies can have a substantial effect.

We also examine direct competitive effects from the merger.

3. THE PORTUGUESE ELECTRICITY AND GAS INDUSTRIES

Electricity

Structure

The Portuguese electricity sector is dominated by EDP (Electricidade de Portugal), which is involved in generation, distribution and supply of electricity.

- **Generation** is undertaken by mainly by EDP's subsidiary CPPE (Companhia Portguesa de Producção de Electricidade), which owns and operates 7.4GW, out of a total capacity in Portugal of 9.0GW. Two other companies are involved in generation: Tejo Energia, which owns and operates the 584MW Pego Coal fired power station, and Turbogás, which owns and operates a 990MW CCGT at Tapada. Tejo is in turn owned by an international consortium of electricity companies, including International Power (45%) and Endesa (35%). RWE has a 75% stake in Turbogas, which it is in the process of selling, probably to one of the other Iberian market players.
- **Transmission** is undertaken by Rede Eléctrica Nacional (REN), which owns and operates the high voltage transmission system under a long term concession agreement. The total network length is 6438km, with a transformer capacity of 17667MVA.
- **Distribution** is undertaken by EDP, through its subsidiary EDIS (EDP Distribução de Energia) under 20 year concession agreements.
- **Supply** to customers who are currently unable to choose their supplier is currently undertaken by a subsidiary of EDP. EDP also supplies to "eligible" customers, who can choose their supplier: there is also some new entrant supply.

An important feature of the electricity system is the split between the public electricity system (SEP), and the independent system (SENV). In the public system, a group of power stations sells electricity to the single buyer, which is owned by REN, which sells the energy to the supply business of EDP, which then sells the electricity to customers under the regulated tariff system. In the independent system, customers are eligible to choose from whom they buy their electricity, and for these customers, only the costs of the network are regulated.

Physical information

Portugal is one of the smaller electricity markets in Europe, with a peak demand of around 7GW (it was 7.1GW in 2001, and 6.8GW in 2002). Annual consumption in 2002 was 40.7TWh. Demand growth, however, is expected to increase relatively fast, with REN's projections implying growth of 3.9%, in line with expected growth from other Southern European countries, but above the 1-2% expected in Northern Europe.

Electricity is produced using a mixture of hydro, coal, gas, and fuel oil. Electricity production from hydro in an average year is nearly 10TWh, accounting for around 25% of production, although this can vary significantly. 2002 was considered a very dry year, with production of only 7.3TWh, compared to 13.4TWh in 2001. Hydro is a mixture of run of river and storage plant and accounts in total for 45% of installed capacity.

Coal stations account for 20% of installed capacity. The most important plant is the 1256MW plant at Sines, owned by EDP, which is located on the coast, convenient for international coal imports. The other coal plant is 584MW Pego, owned by a consortium of international electricity companies led by International Power (45%). The Spanish company, Endesa, also has a 35% stake in this plant). Gas currently accounts for 11% of installed capacity, and around 20% of production, produced at the 990MW Turbogás power station, in which RWE has a 75% stake, and EDP 20%, but RWE is in the process of selling its stake.

Electricity flows primarily from North to South, with the size of flows determined by hydrology, with stronger flows (including from Galicia in Spain into Portugal) in wet conditions. This means that in wet conditions there are thermal transmission constraints, which can apply for a significant part of the winter if it is wet. Redespatch of generation is also often needed because of voltage constraints in the south near Lisbon, and expensive fuel oil plant runs at these times.

Legal framework

The main legislation governing the sector was passed in 1995, through a set of decree laws.[7] These established the two systems in Portugal, the public electricity system (SEP), and the independent system (SENV), with power stations within the SEP selling electricity under contract to the "single buyer", and other power stations able to sell to eligible customers (customer able to choose their electricity supplier). It also:

- established a regulatory body to oversee the sector;

[7] In particular, 182/95, 183/95, 184/95, and 185/95 of July 27 1995.

- retained responsibility for planning with the Directorate General of Energy (within the Government);
- required generators within the SEP to have contracts with the "single buyer";
- gave responsibility for transmission network and system operations to a specific entity, with requirement to despatch the system at least cost
- granted licences to distribution companies, with specific areas of operation, and a requirement that tariffs should be non-discriminatory, and a requirement that they should ensure continuing profitability of the companies, and be based on marginal cost principles;
- provided for access to networks for companies within the independent system (SENV); and
- Additional decree laws set out further detailed requirements and obligations for organisations operating in the sector. The 1995 legislation effectively implemented the EU electricity Directive[8], as well as setting out the detailed method of determining tariffs.

The other extremely important part of the legal framework was the set of Power Purchase Agreements (PPAs) which were referred to above. These agreements for the purchase of electricity by companies in the SEP essentially established life of station contracts, with payments for capacity (based on availability), and energy (based on a formula reflecting costs). Further details of these and their impact are set out in Chapter 4. We understand that the capacity payment implied a return on invested capital for the plants of around 8% real.

Regulation

Regulatory functions are split between the government, and the regulatory organisation, ERSE (Entidade Reguladora dos Serviços Energéticos).

The main responsibility of ERSE is for setting tariffs, but it also has other functions including dealing with customer complaints. The government is responsible for identifying needs for system expansion, organising the process of authorising new generation, and for licensing of companies involved in the system.

[8] EU Directive 96/92.

ERSE has set out its approach to tariff regulation in its Tariff Code documents. These set out in detail the formulae for determining revenue for each part of the business, as well as the way in which network tariffs are set, and prices for each class of customer. In particular, for continental Portugal:

- transmission revenues are essentially determined by a formula giving a rate of return on invested capital;
- distribution revenues are determined by a CPI-X style formula, giving an incentive for the company to improve efficiency;
- the supply business is allowed revenue sufficient to cover energy acquisition costs, its own costs, and a rate of return on assets in that business;
- generation costs, from the public electricity system, are essentially passed through to final customers, but there is a mechanism to smooth the variation in costs associated with changing hydrological conditions;
- network prices are allocated to eligible customers in the same way as for non-eligible customers.

The parameters in the formulae are set for three years, with annual revisions of the revenues for inflation. ERSE may in exceptional circumstances revise tariffs between price cap reviews. The current parameters apply for the period 2002-4, with a new period beginning in 2005.

In the early years following the establishment of the new legislation, tariff prices fell, because of a commitment to reduce prices to the EU average by 2000. In the event, prices fell more rapidly than many commentators (and EDP) expected, because EU prices fell faster than expected. EDP's cost cutting has not kept up with this, and as a result, its return on distribution assets has fallen from 18% in 1998, to 6.1% in 2002. It appears that in future, distribution price formula parameters will be set to achieve a target rate of return of 9%[9]

ERSE is independent of government, with its senior members appointed for five year terms, with no reference to government needed for its decisions.

[9] Senior management of EDP indicated this at a presentation to investment analysts in December 2003, based on a discussion with the president of ERSE.

Ownership

The Portuguese government holds significant ownership stakes in the electricity industry:

- The Initial Public Offering of EDP took place in 1996, with subsequent secondary offerings bringing down the Portuguese government's holding to 26.1%. Other shareholders are BCP (5%), Iberdrola (5%), Caixa Geral de Depósitos 4.75%, Brisa (2%) with the remaining 57% being the free float.
- The Portuguese government holds 70% of REN. EDP owns the remaining 30%.

Portuguese market in a European context

All European electricity markets have been undergoing substantial change in recent years, in response to the implementation of European legislation to create an internal market in electricity. Most countries will also need to make further changes to legislation to incorporate new European legislation into national law.[10] Portuguese legislation affecting the sector has evolved and continues to develop to reflect changing EU legislation. Some of the distinctive features of the market, affecting the future development of the market, are set out below.

Structure

France, Italy and Belgium also have a single company dominating the country's electricity industry.

In a country where one company dominates the generation and supply of electricity, it is difficult for competition to develop. Terms of access can allow new entry, but the development of liquid markets in wholesale electricity has been faster in countries where ownership of generation is more dispersed, as is the case in Norway, Sweden, Finland, Germany, and the UK. Large countries with dominant companies have required disposals of generation (ENEL in Italy), or have been forced to impose disposals (EdF in France, which has disposed of virtual capacity). But in Belgium, for example, where generation ownership is dominated by Electrabel, the link with neighbouring countries (Germany, Netherlands, and France) remains the most important source of competition.

[10] Directives 2003/54 and 2003/55 replaced the previous Electricity and Gas directives. These require, inter alia, the establishment of regulatory bodies, and legal unbundling of network activities, as well as enhancement of the definition of eligible customers.

An indication of the concentration of different markets is given by proportion of generation of the largest generating companies. Statistics for these are set out in the table below.

Figure 2 Concentration of EU generation markets

Member State	Market share of three largest generators (%)
Austria	45
Belgium	96
Denmark	78
Finland	45
France	92
Germany	64
Greece	97
Ireland	97
Italy	69
Luxembourg	n.a.
Netherlands	59
Portugal	82
Spain	83
Sweden	90
UK	36

Source: European Commission (2003)

The separation of ownership of transmission from other electricity activities is now an established trend in European countries. Red Electrica in Spain was the first separate transmission entity, followed by National Grid in the UK. Norway, Sweden, Finland, Belgium, and Italy have all created separate transmission entities.

Regulation

All countries in the European Union have now established regulatory organisations to oversee the electricity markets. Germany was the last to this, following the enactment of new European legislation requiring this.

The precise powers and responsibilities of these organisations do differ, though. In Spain, for example, the regulatory organisation makes tariff proposals, but final tariff decisions remain with the government. Regulation is not independent of government. Regulators in Italy, and the UK do have tariff setting powers. The legal framework establishing the Portuguese regulator ensured that it was independent of government.

Capacity

In most European countries, electricity is generated mainly from fossil fuels and nuclear, with a limited role for hydro. The main exceptions to this are in Norway, where nearly all capacity is hydro, Sweden, Spain, and Portugal. There are two main effects of this:

- rainfall is a key determinant of the availability of hydro, and thus the price of electricity. Electricity prices can be more even volatile in these markets, although this volatility is generally seasonal, relating to hydro capacity, rather than the daily volatility observed in other markets.
- a large proportion of hydro usually means that the market for short term energy is more effective, which generally allows the whole electricity market to work more effectively. Availability of hydro means that "balancing services", used for the continual matching of supply and demand, are relatively cheap to provide.

Commercial framework

Portugal is the only country in Europe that used a "single buyer" to purchase electricity for tariff customers.

The dominance of the PPA contracts for the purchase of electricity is also a distinctive feature of the market, which has a significant impact on the future development of the electricity market. This is discussed in detail in Chapter 4.

Gas industry

Structure

Portugal has only very recently developed a natural gas industry. Imports of natural gas from Algeria through the Maghreb pipeline via Morocco and Spain began in 1997. Most of the initial imports were used in the Tapada do Outeiro CCGT, but industrial and domestic demand has grown.

The gas industry in Portugal is dominated by GALP Energia. It was formed in 1999, through the merger of Petrogal (focused on oil) and GDP (focused on gas). It owns shares in all the main gas companies in Portugal, and in particular:

- Transgás is the holder of the concession for importation, transmission, storage, and supply of gas at high pressure. It currently operates a network of some 1458km, and in addition holds stakes in pipelines in Spain which bring the gas to the Portuguese border.
- There are six main Portuguese distribution companies which have concessions to distribute and supply gas in different regions: Lisboagás, Portgás, Lusitâniagás, Setgás, Tagusgás, and Beiragás. In total, these companies have 668,000 customers, and distributed 0.5bcm gas in 2002. Gas de Portugal (GDP) owns the largest stake in all of these companies.[11]

Physical information

In 2001, the total Portuguese consumption of natural gas was some 2.7bcm. Of this, 47% was used for power generation, 8% in cogeneration, 44% in industry and services, and the remaining 5% for domestic use. Most of the imports were from Algeria (2.3 bcm), with the remainder in the form of LNG from Nigeria.

Over the next few years, demand is expected to grow rapidly, with projections by Transgás that it will exceed 6bcm by 2010. Most of the increase will be from increased demand for use in new power stations, which will come on stream over this period, but domestic consumption is also projected to rise to nearly 2 bcm, as the gas network extends.

Legal framework

The fundamental legislation for the gas sector was set out in Decree Law 374/89, which established the regime for the importation, storage, transformation, transmission and distribution of natural gas. In particular, market participants in the gas industry are required to have a concession or licence granted by the government, with a maximum term of 40 years. Subsequent laws amended these. Concession agreements set out the investments expected, and other obligations, for example the Transgás concession gives it an obligation to supply the distribution companies.

EU Directive 98/30/CE of 1998 set the conditions for the liberalisation of the gas market, following on from the 1996 Directive for the Electricity market. Portugal was granted a

[11] It also plans to increase these, with an announcement on 27 November 2003 that it has acquired options to buy an addition 46.3% stake in Portgás, exercisable over the next 18 months.

derogation from many of these requirements for ten years, because of the early state of development of the gas industry. Nevertheless, it has passed decree law 14/2001 which has updated the legislation to incorporate the Gas Directive. It provides for third parties to obtain access to the network, but as provided for in the law also allows this to be refused if it would lead to serious economic or financial difficulties for network operators, or prevent them from fulfilling their public service obligations. However, expansion of capacity to accommodate desired transactions is also required. Other rules include the requirement for gas companies to maintain separate accounts for separate gas activities.

Further detailed rules will be required, however, to make the liberalisation effective. These will be established by ERSE, which under Decree Law 97/2002 was transformed into the energy regulator, responsible for both electricity and gas, whereas previously it was responsible only for electricity.

Regulation

At present, prices are proposed by the companies, under conditions set out in their concession agreements, and are approved by the Minister of Economy. They have a fixed and a variable component, with the variable component revised quarterly depending on fuel prices and inflation, and the fixed part is reviewed annually.

Prices are negotiated directly with industrial consumers. Small industrial clients (10,000 cm – 2Mcm) are supplied by distribution companies, but there is no set formula in the concession contracts, with the only restrictions being maximum prices that can be set, and a requirement for no price discrimination.

It is anticipated that liberalisation will take place in 2004, with ERSE creating regulatory codes to effect this. These are likely to take the same form as codes used in electricity.

Ownership

Galp Energia, the dominant gas company, has 7 major shareholders:

- the Portuguese government (34.8%);
- ENI, the Italian oil company (33.3%)

- Iberdrola, the Spanish electricity company (4%);
- EDP (14.3%);
- Caixa Gerald de Depositos (13.5%);
- Setgás and Portgás, Portuguese distribution companies (0.04% each).

While the Portuguese distribution companies all have Galp Energia as a major shareholder (through the subsidiary GDP), numerous other companies have shares including Gas de France, Italgas (the Italian gas company), Enagás (the Spanish gas network company), as well as financial investors.

Gas market in a European context

The distinctive feature of the Portuguese gas market is its very recent (and impressive) development, whereas in most western European countries is a very mature industry. This does influence the commercial framework of the industry. Substantial capital investment was needed to construct the link with the Maghreb pipeline. The cost of this is likely to a large extent, to be met by the gas contract with the Tapado CCGT plant, which is in turn financed by the PPA contract for sale of electricity. The structure of the electricity contract has therefore been important for the financing of the development of the gas industry in Portugal.

It also means that the distribution business is riskier than in other countries, as demand for gas will be determined by the rate of development of the network, as well as choices by customers to switch energy use to gas.

The emergent nature of the market is the reason why the EU allowed a derogation from the full impact of the 1998 gas Directive[12], so there is no competition in the market yet.

The structure of the market is similar to that of many countries, with a dominant gas company in transmission, and participation of other companies in the equity of distribution companies. This is seen, for example, in Spain, and Italy, and in other countries with municipal local utilities.

[12] Article 26 (5) provides that derogations can last for a maximum of 10 years from the date of the introduction of gas into a region.

The regulatory framework for gas is less developed than that for electricity. This has also been a feature of gas regulation in many European countries, where long-term take or pay contracts have been important components of the market, slowing the transition to a more transparent regulatory framework. This is happening now, and will speed up following the passage of the recent package of European legislation with measures to accelerate the development of an internal energy market.

The Iberian energy market

Electricity

The biggest change to the Portuguese electricity market since the restructuring is the expected creation of the Iberian electricity market. This project has been under consideration for many years: in 1998, the governments of Portugal and Spain signed an agreement to cooperate on electricity matters, with a Collaboration Protocol signed in November 2001, which established a start date of January 1 2003.

This was always an ambitious deadline, with significant work needed to harmonise two markets, terms of access, and resolve other regulatory issues. In November 2003, it was agreed by the two governments that the Iberian market would commence on 20 April 2004. A target date for signing detailed agreements setting out how numerous outstanding issues will be resolved has been set for 20 January 2004. In addition, agreements associated with the integration of electricity market operators and the forward markets were made. However, a number of key issues remain to be resolved including:

- market splitting / transmission constraints. There will not be sufficient transmission capacity for the Iberian system to be despatched without transmission constraints at least initially. It is therefore necessary to determine how to deal with this. There are two main options: to set one spot price in the electricity market across Portugal and Spain, and for consumers to pay for the re-despatch; or for the market to split into two (or more) regions with separate prices.
- Arrangements for organising an international balancing market, the market for the organisation of electricity supplied at short notice to allow the continual balancing of supply and demand for electricity in real time. Some system services used in balancing can be applied across national boundaries, others are needed locally. Arrangements for this, and for passing the costs to consumers appropriately will need to be agreed.
- System operation. Day to day system operation will need to be coordinated, and methods to ensure coordination of maintenance of systems will be important.

- Definition of the capacity payment mechanism. It appears to have been decided that there will be a form of capacity payment in the Iberian market, but the structure and basis of this payment has not yet been agreed.
- Governance and legal issues. Formal governance procedures for the market need to be agreed, which will allow representation from organisations in both countries. There is the potential that regulatory and competition issues could arise that span both countries, and it is likely that participants will want a mechanism for dealing with these without appealing to the EU. The market will operate across two different legal systems, and so mechanisms for dealing with this need to be established.

If successful, the project would create a single market with annual production of some 250TWh, with a reduction in concentration in both generation and supply markets, as set out in the table below.

Figure 3 Iberian generation market

	GWh	% National	% IBELM
EDP (CPPE)	24,201	59.5%	9.7%
Turbogas	7,126	17.5%	2.8%
Tejoenergia	4,794	11.8%	1.9%
SENV	497	1.2%	0.2%
Other	4,056	10.0%	1.6%
Total PORTUGAL	***40,674***	***100.0%***	***16.2%***
Endesa	83,648	39.9%	33.4%
Iberdrola	51,658	24.6%	20.6%
Unión Fenosa	24,412	11.6%	9.7%
Hidrocantábrico	14,277	6.8%	5.7%
Viesgo (ENEL)	8,132	3.9%	3.2%
Gas Natural	2,057	1.0%	0.8%
Elcogás	1,938	0.9%	0.8%
Other	23,640	11.3%	9.4%
Total SPAIN	***209,762***	***100.0%***	***83.8%***
Total IBELM	***250,436***		***100.0%***

Source: Company accounts

Figure 4 Iberian supply market

	GWh	% National	% IBELM
EDP	36,427	99.1%	14.9%
SENV (Non-EDP)	314	0.9%	0.1%
Total PORTUGAL	***36,741***	***100.0%***	***15.0%***
Endesa	92,633	44.5%	37.8%
Iberdrola	82,023	39.4%	33.5%
Unión Fenosa	25,384	12.2%	10.4%
HidroCantábrico	8,326	4.0%	3.4%
Total SPAIN	***208,366***	***100.0%***	***85.0%***
Total IBELM	***245,107***		***100.0%***

Source: Company accounts

Will the Iberian markets be effective?

Electricity

Whether or not the Iberian energy market becomes effective has an important impact on the competition issues associated with the proposed energy sector restructuring in Portugal.

If both Iberian energy and gas markets become effective, the merged company would still dominate the Portuguese electricity and gas markets. But the definition of the relevant market, in competition policy terms, would extend beyond national borders. The merger would need to be seen in the context of a larger, international market. In electricity, it would not control the market alone, but would be competing with Endesa, Iberdrola, Unión Fenosa, Enel, and Gas Natural (alongside HidroCantábrico, in which EDP has a 40% stake). Likewise in gas, it would be competing with Spanish gas companies, which include Gas Natural, as well as subsidiaries of the major electricity companies.

Will this happen? There are two issues associated with the formation of effective markets in energy:

- whether the physical infrastructure is sufficient to accommodate the desired flows of energy across boundaries. If an interconnector is constrained for most of the time, two markets will continue.

- whether the commercial and system organisation of the two regions has been sufficiently harmonised to allow active trading across national boundaries.

For electricity, the plans to enhance the transmission systems in both countries are well advanced, with 4 separate initiatives to be completed in 2004/5, and an additional line reinforcement to take place by 2007/8. This will increase interconnection capacity as set out below.

Figure 5 Electricity interconnection capacity (MW)

		2004/5	2007/8
Portugal to Spain	Winter	1390-1545	1750-1945
	Summer	1200-1375	1250-1433
Spain to Portugal	Winter	1000-1225	1543-1855
	Summer	1250-1250	1462-1685

Source: REN/REE

In the context of a system with maximum demand of 7GW, these enhancements appear to be sufficient. A full assessment of the impact of the developments requires extensive system modelling. We understand that analysis by REN and REE indicates that the completion of the above system expansions will be sufficient to mean that system marginal price will be harmonised across both countries for most of the time.

However, until these developments are completed, interconnection capacity is not sufficient, with imports into Portugal dominating the utilisation of the interconnection. This means that EDP will effectively control market prices of electricity until that time.

At this time, key issues associated with the commercial operation of the Iberian market remain to be resolved, and so we cannot comment on whether these are likely to be effective. However, the procedures used to organise the market in Spain have been sensible and are perceived to have worked well, and we would not expect a change to make the market less effective than the Spanish market is.

Thus there is the potential for the Iberian market to become operational in 2004, and to become effective on the completion of sufficient interconnection capacity. However, there is significant work needed to complete the commercial integration of the markets, and while the political will to complete the market may be present, and resolution of key issues may be completed by 20 January 2004, the implementation may take longer than planned.

It should, however, also be noted that the combination of the PPAs and CTCs have a significant impact on the market participants, and the formation of prices in the liberalised market, and we would expect this to continue, unless reformed.

Gas

The Spanish and Portuguese governments have agreed to establish a common Iberian energy market. However, significant progress has only been made to date in electricity, and no concrete plans to harmonise gas markets have been announced. It is possible, however, that initiatives to establish a common gas market could begin following completion of the electricity market in April 2004.

As with electricity, ensuring an effective gas market will involve ensuring that there is sufficient interconnect capacity, as well as the appropriate commercial conditions.

At present, quoted capacity in the connection between Portugal and Spain in the south amounts to some 3.1bcm, although the technical limit may be somewhat higher. In commercial terms, reports on the available capacity to third parties indicate that no capacity is available for use (for example see the report by Laporte & Moselle (2002), which quotes figures by the GTE).

This implies that without further interconnection capacity, it is unlikely that an effective market would develop, unless Spanish producers began to source a proportion of their gas supplies through Portugal from the LNG terminal under construction. Given the expansion of LNG terminals in Spain, and the long term gas contracts associated with these which are necessary to justify this expansion, this may not be straightforward. It is possible that appropriate transmission charge structures for electricity and gas could facilitate this.

4. THE POWER PURCHASE AGREEMENTS (PPAS) AND THEIR PROPOSED REPLACEMENT

The PPAs

At present, most generation capacity of EDP is owned by CPPE, and is subject to long term PPA contracts with the single buyer. These PPAs determine each power station's revenues, and the way in which the stations are operated. In other words, operational control effectively rests with the single buyer, currently owned by REN.

Essentially, revenues for each station comprise:

- energy charges. These are expected to cover the variable cost of operating the station. Specified charges per kWh are therefore set out in the PPA, along with additional items such as start up costs and reserve charges; and

- capacity charges. These are designed to cover the fixed costs of the station. These include the costs of employing the staff, maintaining the station, and providing a return on capital. The return is calculated on the current cost asset value of the station, which will include any investments made in the station which have previously been approved by REN. The capacity charge is also influenced by the availability of the station. If the station exceeds the availability target is specified in the PPA, the fixed charge rises. The reverse would occur should the station's performance fall below the target.

In the case of hydro plant, the variable costs are clearly low. The same structure of charging is adopted, with the fixed charge calculated in the same way. However, the energy charge is modified in order to reflect the additional costs imposed on the system when hydro output is limited. The charge is therefore related to the marginal (thermal) costs on the system at any time, and the hydro output expected from the 50 year average rainfall.

The contracts run for the life of the thermal stations. For most of the fuel oil plants, expiry is before 2010, but for other thermal plants, termination ranges from 2012 to 2023.

These contracts provide CPPE with a high degree of certainty over revenues. However, they are not compatible with the implementation of a competitive wholesale electricity market, and a condition of Protocol for the implementation of the Iberian electricity market is that they will be changed. Under Portuguese electricity legislation, cancellation of the contracts would lead to compensation to CPPE for the net present value of the contract.

Replacing the PPAs with CMECs

The negotiation of the necessary change in the contracts is currently underway. The structure of the proposed change is set out in legislation enacted in 2003, with only the detailed parameters requiring agreement. Power stations would receive payments from the electricity market for energy and capacity (the Iberian electricity market will feature both). In addition, owners of power stations currently subject to PPA agreements receive compensation payments, known as CMECs (*Custos para a Manutenção do Equilibrio Contatual*). Key elements of the CMECs will be:

- the payments will be calculated for each individual power station, and aggregated for each company (clearly this matters only for CPPE)
- the structure of the payments will reflect the amount that would have been received under the existing PPA agreement, reflecting fixed costs (indexed based on changes in costs in the industry) and variable costs (indexed to benchmark fuel costs). Payments will therefore be calculated as the capacity payment (as per the original PPA, adjusted for cost changes) plus the variable plant costs (as per the original PPA), less revenues received from the wholesale electricity market (including the pool price and payments under the capacity mechanism that will be introduced).[13]
- there will be a cap to the value of payments (in present value terms) associated with each power station with a PPA contract.
- as with the PPA agreements, major changes to the operational environment (e.g. relating to the cost of carbon credits) can be passed on to customers. In the PPAs, this would be achieved by appropriate adjustments to fixed and variable payment parameters, and analogous adjustments would be made to the parameters defining the CMEC payments. Wholesale prices would be likely to rise in response to the changes, but the change to the CMEC payment parameters would ensure that profitability of power stations is preserved.
- the CMECs will be paid by customers, as an addition to network charges, overseen by ERSE.
- the recovery of the CMECs will be limited to 2013. This means that additional payments will be made in relation to some of the longer term contracts for power stations.

[13] Under the PPAs, the capacity payment was dependent on target availability. We understand from discussions with staff in the Energy Ministry that this will be translated into CMEC payments, but have not seen details of the mechanism for this. However, EDP has indicated that it expects to be able to operate plant more flexibly under the CMEC system than the PPAs, and in particular can save costs because it will not need to maintain the same level of availability as under the PPAs.

It should be noted that in other countries where this type of arrangement has been implemented, the additional payments, termed "stranded costs", have been seen by the European Commission as State Aid, for example, the competition transition costs (CTC) payments in Spain.[14]

Impact of CMEC payments on wholesale electricity prices

One of the most important features of the PPA agreements is that the profitability of those power stations subject to the PPAs (which is most of the current installed capacity in Portugal) is essentially invariant to the level of the wholesale electricity prices, and to volumes generated.[15]

With the introduction of the CMECs, generators will receive two types of payments: payments from the pool, and the top up from the CMECs. These payments will ensure that each year, the revenue of power stations which currently have PPAs will be the same in the new wholesale market environment as they would have been with a PPA. While power stations will receive revenue from the wholesale electricity market, the total revenue received will be invariant to the pool price. If the average pool price falls, CMEC payments rise to compensate. If the average pool price rises, CMEC payments would fall.[16]

As a dominant player in the market, EDP will have the opportunity to determine pool prices in Portugal through bidding behaviour, and to influence prices through bidding behaviour in the Iberian market. What is the optimum level of pool prices for EDP, and the other companies subject to PPAs, while the CMEC payments are in force?

The incentives on EDP and other incumbents will depend on the fine detail of the pool rules (yet to be defined in detail for the Iberian market), the precise specification of the payment mechanisms that will replace the CMECs, and the values of individual parameters

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[14] It should also be noted that EDP has stated that it would like the CMECs to have the potential to be securitised. However, in the European Commission decision relating to Spanish CTCs, and the associated guidelines for assessing State Aid, it was indicated that the Commission would look unfavourable on schemes which gave guarantees to payments, which would allow securitisation. In Spain, CTCs did not initially allow securitisation, they were changed to allow it, then changed back in response to the EC decision. An analysis of State Aids and the electricity industry can be found in Mirrlees-Black & Invernizzi (1999).

[15] In most PPA agreements, contract variable costs are slightly larger than actual variable costs, so that profitability does increase slightly with increases in volumes generated. This is likely to be the case with the Portuguese PPAs.

[16] CMEC payments recovered from customers will be based on an expected pool price. If pool prices are different from expectations, there may be a time delay before additional CMEC payments can be collected or returned to customers as necessary, but the adjustment mechanism to achieve this does not affect the economic effect of the CMEC scheme.

in the contracts and their replacement. The treatment of local transmission constraints, and contracts for balancing services may also influence incentives in important ways. Thus it is not possible to provide a full assessment of the incentive effects of the CMEC mechanism at present. However, with this qualification, it does appear that the incentives on the incumbent generators' bidding will depend on two main factors:

- the level of the cap on CMEC payments; and
- expectations of market prices following the exhaustion of the cap on CMEC payments (but prior to 2013).

If the cap on CMEC payments is sufficiently large then they will not be exhausted prior to 2013. This would be the case, for example, if the cap on payments was set to be the NPV of capacity payments under the PPAs. In this case, profits for incumbents are invariant to the pool price. The optimal strategy is therefore to reduce pool prices, so as to deter entry.

If the cap on payments is lower, then the optimal strategy depends on whether it is advantageous to accelerate the time when CMEC payments are exhausted. If it is believed that average prices following expiry of CMECs can be higher than before (including the CMEC payments), because of the exercise of unfettered market power, then it is clearly advantageous for incumbents to attempt to exhaust payments as quickly as possible. In this case, the optimal strategy is to keep prices as low as possible to maximise CMEC payments until they are exhausted, and then to raise prices after.

Alternatively, if it is believed that average prices following expiry of CMECs will be lower than the price prior to the expiry (including the CMEC payments), incumbents will wish to delay the expiry of the CMECs for as long as possible. In this case, it would be advantageous to keep pool prices in the early period as high as is necessary to delay the ending of the CMECs. If the cap is sufficiently large, it will be possible to do this at a price that is below long run marginal cost, so that entry will continue to be deterred. If the cap is not sufficiently large, this price would exceed the entrant cost.

So depending on the level of the cap, and expectation of prices following the expiry of the CMECs, the incumbent might have an incentive to:

- decrease prices to SRMC (if the cap is large, or if market conditions would be attractive following expiry of the CMECs);
- raise prices, but to keep them below new entrant costs (if the cap is smaller, and market conditions following expiry of CMECs are less attractive).
- raise prices to a level above new entrant price (if the cap to CMECs is sufficiently small, and market conditions following expiry of CMECs is less attractive).

Which of these conditions is likely to obtain? Average contract costs under the PPAs are €48/MWh, whereas new entrant costs are around €37/MWh. It seems unlikely that EDP believes it could charge above €48/MWh under conditions of unfettered competition. The direction of the incentive, therefore depends on the levels of the caps to be set in the CMECs. Given that the CMEC payments replace contracts that do effectively guarantee profitability, we would expect that these caps would have to be set relatively high. It is therefore most likely that the incentive on EDP is to keep prices as high as possible, but at a level that deters entry, i.e. at a level just below LRMC.

This is very similar to the overall incentive that is placed on electricity companies in Spain by their CTC payments. These payments "top up" companies' revenues from the wholesale electricity market, to compensate them for the introduction of competition to the market. Further details of this are set out in Annex 4.

Consequences of existence of PPAs/CMECs for the market

The overall consequence of this is that there will be a severe distortion to the Iberian electricity wholesale market, whether or not the merger goes ahead, because revenues for a large proportion of the entire Iberian generation capacity is independent of price. The direction of this incentive is uncertain, as it depends on the structure of the CMEC mechanism, and in particular the cap on payments:

- If the cap is sufficiently large compared to expected payments, there would be an incentive for companies who benefit from PPAs and CTCs to keep the market price of energy in the competitive market low, to deter entry of new capacity. The effect of this would be to preserve the current market structure, with generation capacity controlled by the current incumbents; or
- If the cap is smaller compared to expected payments, it may be in the interest of owners of plant with PPAs to raise prices, whatever the demand / supply situation in the market. This could signal that entry to the market might be appropriate even at times of excess capacity.

This distortion of competition is extremely serious, and probably more serious than the effects of the merger on competition.

5. COMPETITION ISSUES ARISING FROM THE MERGER

Merger of Transgás and REN

The activities of both REN and Transgás can be divided into two types of activities:

- network operations, concerned with the construction, management, and maintenance of the network infrastructure; and
- system operations, concerned with continual oversight of the flows of energy on the networks, including system balancing.

The gas transmission and electricity transmission network activities are both natural monopolies, where it is inefficient for more than one company to be involved in the business within a specific geographical region. Both are now subject to regulation by ERSE. The activities of the two companies do not overlap, and they are not in competition with each other. If these were to be owned by a single company this would not raise any competition concerns.

Similar arguments apply to the system operation activities. The two system operators are responsible for moving different commodities over the two different networks, and to different timescales. Again, there seems to be no reason to prevent these two activities from coming under common ownership.

In addition to its electricity activities, REN is also active in telecoms. These activities appear to make use of assets that are part of the electricity business, which raises regulatory issues, but these activities do not appear to overlap with any Transgás activities.

The increase in competition in the electricity market, and the completion of the Iberian electricity market, and the introduction of competition in the gas market will change the nature of system operation. Management of energy flows will be on behalf of third parties, rather than parts of the same business, and actions will have commercial consequences for those parties. In addition, actions by system operators in the balancing markets may influence prices in the wholesale markets. At the same time, the increase in the use of gas for generation will mean that interaction between the two system operation businesses, as decisions on operation of power stations will affect flows on both networks, and energy companies' contract positions in both markets will interact.

In particular, it will need to be ensured that:

- measures for the protection of the confidentiality of information of parties in balancing markets are effective
- purchases and sales of electricity and gas by the system operators are restricted to be only for specific purposes related to their specific roles.

International precedent

There are two main European competition cases where electricity and gas transmission assets have come under common ownership in recent years: National Grid and Lattice, to form National Grid Transco in the UK, and E.ON and Ruhrgas, in Germany.

In the National Grid/Lattice case, no competition issues were thought to arise by Ofgem, although some additional regulatory requirements were imposed. In the E.ON/Ruhrgas case, clearly the competition issues went far wider than the combination of two transmission businesses: the main requirement imposed was that there should be legal separation, not just accounting separation of the gas transmission business. This is a requirement of the new EU legislation in any case, so provides no additional obligation on E.ON.

Further details of these cases are set out in the Annex.

Demerger of Transgás from GalpEnergia

One of the main problems in the creation of liberalised electricity and gas markets has been providing proper separation of transportation activities from the other market activities. Initial EU legislation to liberalise the gas sector required accounting separation of transmission businesses, but the new legislation passed in 2003 strengthened this to require legal separation. EU legislation has fallen short, though, of requiring full separation of ownership.

Nevertheless, some countries have enacted legislation restricting ownership of gas transmission assets, for example in Spain, the investment in Enagas by market participants is limited to 10%. In other countries, the regulatory framework has meant companies have chosen to demerge gas transmission from other activities, for example SNAM Retegas in Italy from ENI, in Belgium, Fluxys has demerged from Distrigaz, and in the UK Lattice demerged from BG.

Although regulation can provide for effective third party access, separation of ownership substantially improves market participants' confidence in the access regime, and is therefore supportive of the development of a competitive market. This should be strongly welcomed.

Merger of EDP with GALP Energia gas assets

As has been noted above, EDP and the transferring GALP assets are dominant in their respective markets, namely electricity generation, gas imports, gas distribution, gas supply, and electricity distribution and supply. The proposed restructuring does not affect dominance in these markets directly. However, it does have indirect impacts on the following markets:

- electricity generation;
- electricity and gas supply;
- the development of gas distribution networks; and
- potential foreclosure of the gas market.

Electricity generation

GALP currently owns limited electricity generation assets, which are cogeneration plants outside Portugal. Nevertheless, GALP would be a natural competitor to EDP in the generation market in Portugal. In Spain, for example, the dominant gas utility, Gas Natural, is making an aggressive entry into the electricity market with the construction of a number of CCGTs, exploiting its dominant position in gas procurement. Gas companies elsewhere in the world have entered the generation market, with success in particular in markets where they already have gas operations.

The proposed restructuring would remove this potential competitor. However, there are other international gas and electricity companies which are familiar with the Portuguese electricity market, and would be able effectively to construct new plant if this were economically justifiable.

It would be desirable further to increase the level of competition within the Portuguese electricity market. Experience of deregulation in other international markets indicates that introducing competition against one or a small number of incumbent dominant players is very valuable. The nature of electricity markets, though, does mean that market power problems are eliminated once several players have entered. For example, the Dutch market which has around 21GW installed capacity has four main players with roughly equal market shares, but problems of exercise of market power regularly arise. Concentration in the Dutch market is lower than that in many European markets (see Figure 7 and Figure 8 below). In contrast, the UK wholesale electricity market can be considered to be competitive after 2000. However, in the UK, the price/cost margin for generation only fell substantially when the HHI index of concentration of the coal-fired plant fell below 3000 and the HHI of the whole industry fell below 1200, which occurred following the second

wave of plant disposals by major generators and after substantial entry creating surplus capacity (see
Figure 6 below).

Figure 6 UK electricity prices, fuel costs and electricity market concentration, 1990-2003

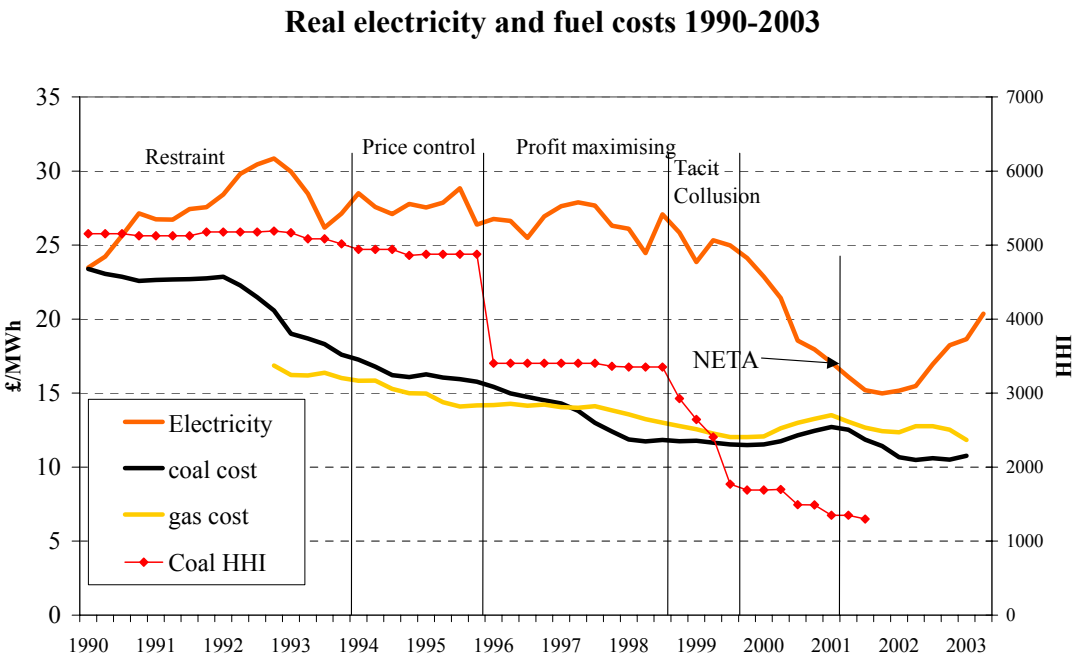


Figure 7 Market share of largest three generators in European countries

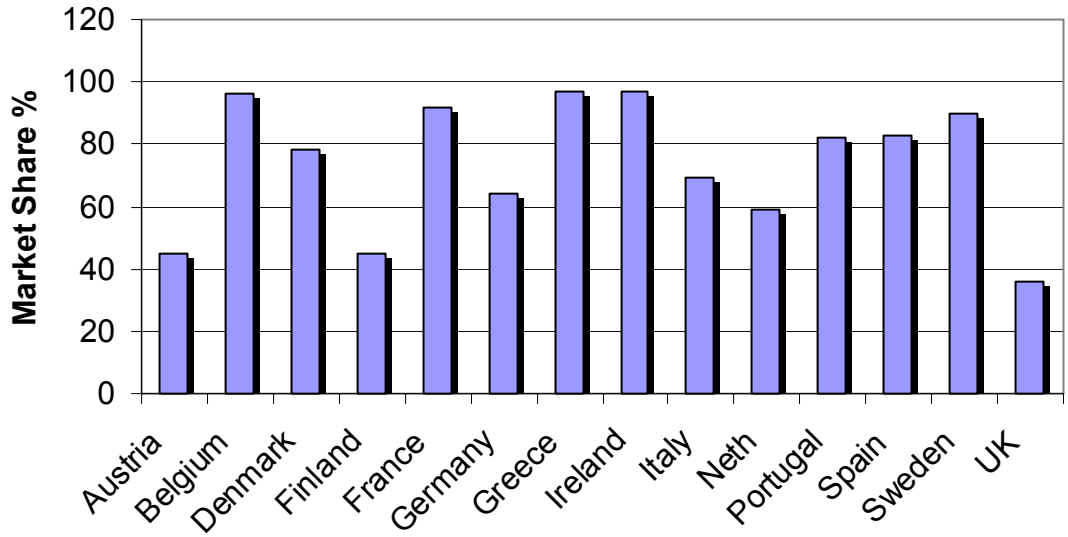
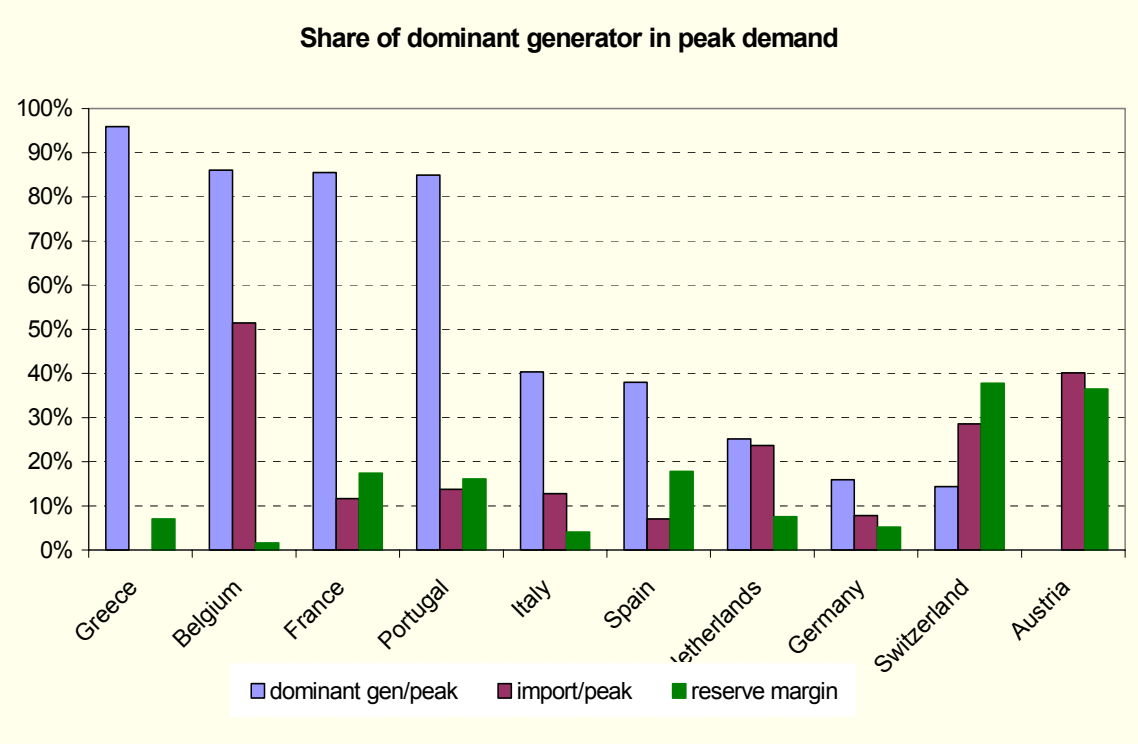


Figure 8 European electricity markets peak demand statistics



The implications of this for Portugal are that fully effective competition is unlikely without radical market restructuring substantially to reduce concentration, which implies that measures to protect customers (such as appropriate long term contracts) and close scrutiny by appropriate authorities will be necessary.

It should be noted that creation of the Iberian market will not overcome the market power problems highlighted here. Imports into Portugal from Spain are restricted by the capacity of the interconnector. EDP will dominate the market behind the interconnector, with a share of approximately 70% (capacity share in Portuguese market including the interconnect capacity). This is the relevant statistic, rather than the market share in the Iberian market as a whole, of approximately 10%.

The energy supply market

The current state of energy supply in Portugal

Only a limited number of large customers are currently able to switch their electricity supplier in Portugal, and enter the "SENV" market. Until 31 December 2001, there was a minimum annual consumption requirement of 9GWh pa. This was reduced on 1 January 2002, when all customers connected to higher voltage networks became eligible.[17] This increased the number of eligible customers to approximately 20,000, accounting for 45% of national electricity consumption. Full liberalisation of the supply market is planned for 2004.

Although a large number of customers are eligible, few decided to switch, as set out in the table below.

Figure 9 Customer switching in Portugal

	2000	2001	2002
No of customers	18	15	460
Consumption (GWh)	227.4	546.7	959.3

Source: ERSE

Most generators are contracted on a long term contract and sell within the public electricity market (SEP), and we understand that there is a penalty if electricity is sold from the SEP into the independent market. This means that there is only a very limited supply of energy available for the independent system, and most of this is imported. This is the most likely reason why few customers have switched in practice.

In gas, the legislation implementing deregulation passed in 2001, but we understand that the necessary network codes and other measures have not yet been defined. These will include rules for non-discriminatory access to networks, as well as pricing.

Experience in other countries

Experience of deregulation of electricity and gas supply in Europe is mixed, as shown in Figure 10 below. This shows that the majority of large eligible customers have made use of their right to switch either by actually switching or through renegotiation of their contract with their existing supplier.

[17] All customers connected to the VHV, HV and MV networks.

Switching in the domestic market is less advanced: most countries have not yet fully liberalised their markets, and in those that have, either the right to switch has only been granted relatively recently, or there are other barriers to switching. For example, in Germany, initially some existing suppliers charged a "switching fee" to prevent customers switching away (this is now illegal).

Figure 10 Electricity and gas market customer switching in European Union countries

	ELECTRICITY				GAS			
Type of customer	Large eligible industrial users		Small commercial / domestic		Large eligible industrial users		Small commercial / domestic	
Customer response*	switch	switch or renegotiate	switch	switch or renegotiate	Switch	switch or renegotiate	switch	switch or renegotiate
Austria	20-30%	unknown	5-10%	unknown	<2%	unknown	not eligible	
Belgium	2-5%	30-50%	not eligible		unknown	unknown	not eligible	
Denmark	>50%4	>80%	not eligible		2-5%	unknown	not eligible	
Finland	unknown	>50%	5-10%	10-20%	not	eligible	not eligible	
France	10-20%	unknown	not eligible		20-30%	unknown	not eligible	
Germany	20-30%	>50%	5-10%	10-20%	<2%5	unknown	<2%	unknown
Greece	nil.	nil.	not eligible		not	eligible	not eligible	
Ireland	10-20%	unknown	not eligible		20-30%	unknown	not eligible	
Italy	>50%	100%	not eligible		10-20%	unknown	2-5%	unknown
Luxembourg	10-20%	>50%	not eligible		5-10%	100%	not eligible	
Netherlands	20-30%	100%	not eligible		30-50%	unknown	not eligible	
Portugal	5-10%	unknown	not eligible		not	eligible	not eligible	
Spain	10-20%	>50%	not eligible		20-30%	unknown	not eligible	
Sweden	unknown	100%	10-20%	>50%	<2%	unknown	not eligible	
UK	>50%	100%	30-50%	n.a.	>50%	unknown	30-50%	>50%

Source: European Commission[18]

*The "switch" columns refer to the proportion of customers who have changed supplier. The "switch or renegotiate" columns refer to these customers, and in addition customers who have used the ability to switch suppliers to negotiate a change to the terms on which they buy energy.

Switching is relatively advanced in the UK market, although the regulator Ofgem remains dissatisfied with the level of switching. Three important points should be noted from this:

- Almost all domestic customers that do switch, move to a "dual fuel" package, supplying both electricity and gas. They may add gas to their existing electricity supply contract, or add electricity to their gas contract, or switch to a new supplier of both, but it is rare for customers to switch one fuel.

[18] Commission staff working paper : Second benchmarking report on the implementation of the internal electricity and gas market. SEC (2003) 448.

- Centrica, the dominant incumbent UK gas supplier, has been very successful at exploiting its customer base, to cross-sell electricity. Of 10.1m customers on dual fuel packages in 2001, Centrica was the supplier of 4.5m of these, and retaining 9m gas-only customers.[19]
- The Scottish companies, ScottishPower and Scottish & Southern Energy, have been more successful at retaining customers than their competitors in England & Wales.

Implications for Portugal

There is no reason to think that if new entrant suppliers are able to buy electricity and gas on the open market, following the implementation of the Iberian market, that large customers won't take advantage of this, despite the experience to date. Spanish companies, for example, do wish to expand into Portugal, and the strategic alliance between Endesa and Sonae to market energy to Portuguese customers, which is already selling 300GWh annually, is one example of this.

In theory, provision of access to networks on a non-discriminatory basis should allow competition in supply to develop to domestic customers as well. But the absence of an obvious alternative major market player makes it seem unlikely that this would happen. Removal of the GDP as a potential competitor to EDP, and vice versa would appear to have a serious impact on competition in this market.

It should, however, be noted that because gas is much less developed than electricity, the impact on the market of the loss of the competitor may be considered to be less severe in the short term than in most countries. Electricity is supplied to 6m customers, whereas the gas distribution network currently reaches only 668,000. However, it should be noted that the potential market is much larger, as there is scope for substantial growth.

Under the current proposed restructuring, GDP will remain a separate legal entity, with both EDP and ENI as shareholders. Clearly, the proposed shareholding structure means that GDP and EDP would not compete. In addition, ENI, a strong company with a strategic interest in the Portuguese gas market, would not be an active competitor with EDP in energy supply, so it appears that competition in energy supply would be worse than under a simple merger between GDP and EDP.

The development of gas distribution networks

In many markets, there is little interaction between electricity and gas distribution networks. As with transmission, these are both network monopolies. Distribution network operators

[19] Lewis-Davies, G. , Mirrlees-Black, & Reehal (2002).

can earn a regulated revenue stream in return for maintaining the assets, and making necessary investments.

But in Portugal, the situation may be different. The gas industry is relatively new in Portugal, and penetration is low compared to many European Union countries. As noted above, there are only around 668,000 customers connected to the gas distribution network, compared to 6m electricity customers. There are, however, plans further to expand the networks, and we understand that existing commitments are for connection of around 880,000 customers.

Why does this matter? If a customer is newly connected to the gas network, it will switch some of its fuel use from electricity to gas. EDP would lose the supply revenue from the customer (but under the tariff code, it would not lose the electricity distribution margin). In exchange, following the merger, it would gain the gas supply margin, but it would have invested in the network to achieve this. In the long term, a return will be earned from the new gas network. But if there is pressure on investment at a group level, the company might limit expansion of the gas network.

There is also a potential detriment to competition in the gas market that could affect those who are already connected to the network. Use of gas usually requires investment in equipment, so demand increases over time as more customers make these investments that allow a switch from gas to electricity (e.g. in central heating systems). Pricing by a company dominant in both markets could deter the development of this demand.

Parts of Spain have low penetration. One of the reasons cited by the CNE in its report on the proposed acquisition of Iberdrola by Gas Natural was its concern over network investment. (See CNE(2003)).

Foreclosure of the gas market

The potential issue arising from the merger is not the dominance in Portuguese gas or electricity markets, but the additional opportunities for abuse of dominance from the linking of the two. There are two competition issues in particular:

- control of the level of gas prices for all companies involved, or potentially involved in electricity generation.
- dominance in parts of the gas market necessary for effective operation in the electricity market.

The first of these refers to the opportunity for the dominant gas company (which is upstream) to raise prices to any company wishing to operate downstream in the electricity

market. It is possible that the gas company could price discriminate, and offer different prices to its own generation company than it does to other market participants, but the competition issue arises whether or not price discrimination occurs. Following the restructuring EDP can choose whether to accrue profits upstream in gas, or downstream in electricity, and arguably it is easier for higher profits to be justified in the gas market rather than the generation portfolio. This action would effectively deter entry from new potential generators in Portugal.[20]

It is possible that Gas Natural in Spain is acting in this way. With its dominance in the gas market in Spain, combined with the aggressive entry into power generation in Spain, indicates that it might expect to exploit its advantage in the gas market.

The second concern relates to the control that the merged company would retain in gas storage, and short term gas markets. Prices in short term markets are extremely volatile, and a dominant player in that market will deter entry by power generators needing access to fuel. It may be possible for them to obtain long term gas contracts at reasonable prices, that are priced in line with others in the region, but the cost of flexibility, or the risk that costs might be high, can make entry unattractive.

Following the restructuring, EDP expects to be able to use flexibility between gas and power markets in Portugal and Spain because it can route gas according to needs in power stations owned by HidroCantrabrico, as well as needs in the Portuguese market, and it values this flexibility at €15-20m pa. Not having this flexibility could cost more than this to a potential new entrant.

If the Iberian gas market becomes fully effective, this problem would be much less serious. Gas, and related markets necessary to use gas, would be available on broadly similar terms to all potential market participants.

System services markets in electricity and gas

In electricity markets, the demand and supply of electricity needs to be matched continuously, and the responsibility for doing this is undertaken by the system operator. Market mechanisms do not (yet) allow the market alone to ensure the stability of electricity systems without intervention. Other functions undertaken by the system operator includes the redespatch of the system to allow the physical transmission system to accommodate energy production, and the restarting of the system following a major system collapse. In

[20] This possibility has been highlighted in network industries in for example Crocioni & Veljanovski (2003).

order to fulfil these roles, the system operator needs to procure services from generators in order to be able to do this.

For the short term "balancing" of the energy market, offers to produce and consume electricity in short timescales can be effective. However, limits to the physical transmission system can lead to local monopolies arising for limited time periods, and the opportunity for companies to raise prices behind transmission constraints.

Despite the expansion to transmission systems in Portugal and Spain to allow the development of the Iberian electricity market, our discussions with REN indicate that transmission constraints will continue to arise within Portugal in specific seasons, times of day, under particular hydrological conditions. It is possible that EDP will be able to exploit these conditions to the disadvantage of customers.

Gas system operators perform a similar role, although instantaneous balancing of the market is not required. Similar opportunities arise for dominant players to exploit local monopoly power under specific system conditions.

6. POTENTIAL REMEDIES

In this chapter, we consider the remedies that might be considered to mitigate the impacts on competition identified above.

The Power Purchase Agreements

The main problem with the proposed definition of "stranded costs" that will replace the PPAs is that the amount of payments depends on the market price of electricity. It is this that causes the distortion in the market, because of the incentives that it places on EDP. The structure of the CTC payments in Spain has the same effect.

Of course, compensation for the termination of the PPAs is necessary. Legal contracts must be honoured. Investors in EDP made their investment decisions on the basis that payments for generation would be made on the basis of the PPA agreements. But stranded cost payments can be structured on a different basis, so that EDP receives the net present value of the PPA contract, but structured differently. This would:

- allow the development of a more competitive electricity market, as the PPA contract structure would no longer distort the behaviour of the electricity market; and
- expose generators to greater risk, and thus facilitated the development of a market in forward electricity contracts.

Defining the value of stranded costs

The value of stranded costs is the net present value of the difference between profits that would be received under the existing contract structure, and those that would be received under a market mechanism. To create a mechanism that makes revenues dependent on wholesale electricity prices means that an *ex ante* estimate of the value of stranded costs is necessary, and a mechanism designed to recover that sum of money.

There are two main ways of calculating the value of generation plant under the new market arrangements:

- "administrative" methods; and
- market based methods.

This value is compared to the value of the plant under the PPA contracts to determine the stranded cost value. So the higher the expected wholesale electricity prices, the higher the value of plant under the new market mechanism, and thus the lower the stranded cost needed to be recovered.

Administrative methods involve the estimation of the future trend in wholesale electricity prices. This requires detailed assumptions about operating conditions of the system, bidding behaviour of generators, as well as numerous other details. Expectations about future electricity prices, and thus the value of CTCs are likely to be very sensitive to the precise assumptions used. This means that public confidence that stranded cost payments are appropriate is likely to be low.

Market based approaches that can be considered, include:

- Auction of power station capacity;
- Auction of rights to capacity for a limited period (virtual ownership); and
- Flotation of part of a generation company subsidiary, while existing owner retains control of the assets.

Auction methods have a number of advantages over administrative assessments. Administrated methods do involve the use of a number of detailed assumptions that can easily turn out to be incorrect in the event, but to which price expectations are very sensitive. A properly designed auction provides an attractive method of eliciting the value of plant, giving investors the opportunity of judging future market developments, and minimizing the value of stranded cost payments.

An additional auction method, that involves the conversion of PPA contracts into contracts for differences that could be auctioned, is set out below.

An alternative - turning CMECs into Contracts for Differences

CMEC payments replace a contract, with an administrative mechanism. We consider in this section an alternative form of contract that could be used to replace the existing PPA contracts.

A Contract for Differences (CfD) is specified by a strike price, f, and an amount, Q MW. If the pool price is p, and a generator offers q at bid price b, then the generator receives $p.q$ for the quantity q that is accepted by his bid (that is, if $p \geq b$, otherwise he receives zero), and a payment $(f - p)Q$ from the CfD. His (variable) profit if dispatched is $q(p - c) + (f - p)Q$, where c is his short-run marginal cost (SRMC). If $q = Q$, this is $(f - c)Q$ if $p > b$. If $b > p$, his variable profit is just the payment from the CfD, $(f - p)Q$. If he is fully contracted, then the generator has an incentive to bid SRMC. If the generator bids above SRMC (by bidding $b > c$), and as a result is not dispatched (i.e. $b > p > c$), he receives $(f - p)Q$ instead of the larger amount $(f - c)Q$, while if he underbids so that $b < c$ and $b < p < c$, he receives $(f - c)Q$ instead of the larger amount $(f - p)Q$. Thus by not bidding SRMC, the generator risks losing profit, while by bidding SRMC he maximises his net profit, providing in each case that his level of output is equal to the contract cover.

The former English Pool had a number of useful features that might help design a suitable set of CMECs: all plant dispatched received the same pool price, which allowed Contracts for Differences (CfDs), and it paid a capacity payment that depended on the Loss of Load Probability (LoLP) and the Value of Lost Load (VOLL). Plant received a capacity payment equal to V = LoLP x (VOLL – Max(bid price, System Marginal Price)), providing the greatest incentive to be available at times of greatest risk of loss of load.

The question is whether the current PPAs can be translated into CMECs with these desirable properties: full contract coverage, incentive for availability increasing with LoLP, and total generator set profit equal to that under the original PPA. Here is one possible mechanism that may need careful examination to test for possibly perverse incentives.

The original PPA is characterised by $\{A_i, m_i, k_i\}$, that is, the contract pays $A_i + m_i q_i$ per hour that the plant is available and produces q_i (possibly zero) with $q_i \leq k_i$, capacity. This is replaced by a CfD with a strike price m_i for an amount $q_i \leq x_i$, where $x_i \leq k_i$ is the amount bid into the pool. The pool rules are that if $m_i < p$, $q_i = x_i$, and if the plant is marginal (that is, if it is the most expensive plant required to generate), then $p = m_i + V(t)$ the capacity payment at time t), and q_i is set to meet demand. By the definition of the marginal plant, $q_i \leq x_i$. In addition, the plant will receive a capacity payment per hour of $V(t)$ per MW, or $V(t)x_i$. At the end of the year it will receive a CMEC amount $A_i \{\Sigma_t x_i(t)/x^*_i - V(t)k_i\}$, where x^*_i is the target number of MWh/hour expected. That is, the fixed payment depends on availability, x_i, and the capacity payments will cancel out provided the plant is fully available when the LoLP is positive, so that if the plant behaves as expected it will exactly recover its original PPA payment. The total revenue of the generating company will be

$$\Sigma_{i,t} \{(m_i - c_i)q_i(t) + V(t)(x_i(t) - k_i) + A_i x_i(t)/x^*_i\},$$

where $q_i = x_i$ for all inframarginal plant.

A contract market maker can then offer fixed volume CfDs (perhaps profiled) at pre-specified strike prices, perhaps at an auction to determine the payment for these CfDs. The revenue from this auction would reduce the shortfall in the CMEC payments, the balance of which would be recovered from transmission tariffs. This mechanism should have the property of simulating a competitive market, while efficiently signalling entry via the capacity element. It may also have the property that the pool is voluntary, in that generators can choose to contract bilaterally, in which case $x_i \leq k_i - y_i$, where y_i is the bilateral contract that has to be notified to the SO before gate closure. It remains to be checked that this does not create any distortions, although it may not attract much direct contracting. If so, whether that matters is not obvious, given a liquid contract market created by the market maker auctioning off a suitable portfolio of CfDs.

What are the potential advantages and drawbacks of this scheme? First, there is no opportunity to raise the bid price above the PPA energy price, thus eliminating a major source of market power. On the other hand it removes the freedom to bid plant into the pool at a price of the company's choosing. It might be possible to allow the generator to choose the bid price if the contract level could be determined in advance, perhaps by the SO (which would be difficult given the variability of hydro generation). Companies with less than some specified fraction of total capacity (or MWh/year) might be free to choose their bids, and other companies might be able to bid up to the PPA energy amount.

Second, plant is automatically fully contracted. Given that the bids are not chosen by (dominant) generators, this does not itself lead to efficient bidding, but it does enable the PPA to be replicated by the CMEC at least cost.

Third, the amount generated is determined by the SO, subject to the amount offered by the generator. This raises the possibility that it may pay a dominant generator to withhold output and hence raise the system marginal price (or, worse, the LoLP) by bidding $x_i < k_i$. This would have a cost as the generator would have to pay back the capacity payments on the shortfall and that should discourage withholding.

On balance, the proposal replicates almost exactly the original PPAs, but gives little discretion or market freedom to the dominant generator. If the capacity payments are set at an efficient level new firms should be able to enter and compete. The main problem of market power would be deferred until 2013 (or when the capped CMEC payments are exhausted), although the cap of energy prices on bids by dominant firms might usefully be continued. Following the model adopted for limiting market power in British gas entry auctions, the maximum bid could be set at a level which rises as the market concentration falls below an HHI of, say, 2400, e.g. $b \leq m.(\max\{1, \text{HHI}/2400\})$.

State Aids issues

The conversion of the PPA mechanism into CMECs creates payments from customers that have the characteristics of State Aid, which would need approval from the European Commission. Some details of the criteria to be applied by the Commission have been set out in published guidelines, of which further details are set out in Annex 4.

We understand that some of the features of the design of the CMEC mechanism are to be consisted with criteria used by Brussels for approval. In particular, in the past, Brussels has not looked favourable on payment structures that guaranteed that aid would be paid,[21] and it

[21] In particular, the revision to the stranded cost mechanism in Spain, which was later reversed, would have allowed securitisation of stranded cost payments.

can be argued that a scheme of the form set out above would not be consistent with EU requirements.

However, the details of the guidelines do not prohibit mechanisms of this form. We think that a stranded cost mechanism which has been carefully designed to be consistent with the genuine development of competition can be approved by Brussels, even if this is of a different form to stranded cost mechanisms approved so far.

Further work on revision to PPA/CMEC mechanism

Further work would be necessary to establish:

- whether the stranded cost payments for all capacity subject to PPAs should be changed, or whether it could be effective if applied to only a proportion of plant;
- the type of plant for which it would be most appropriate to replace the current PPA incentive structure. Given that hydro is often the marginal plant in Spain and Portugal, it might be appropriate for hydro stations to be included;
- whether EDP would need to sell plant, or whether it could be required to auction the right to the production of plant (as was the case with EDF).
- if rights to production of plant were sold, the term of those rights;
- the method of auctioning any rights sold;
- whether the CfD method suggested above would provide an appropriate alternative to the CMEC mechanism.

Restriction to competition in energy supply

The requirements of the EU "acceleration Directive"

It is a condition of the new EU "acceleration" Directive that distribution system operations will need to be unbundled from other activities, and in particular from supply. Specifically, the Directive requires that distribution system operators are unbundled and independent in terms of "legal form, organisation, and decision making from other activities not related to distribution" (set out in Article 15 of the 2003 Electricity Directive, and Article 13 of the 2003 Gas Directive). In the new Directives (unlike the earlier Directives), distribution explicitly excludes supply activities.

The Directive does not require that distribution and supply business have separate ownership. However, the unbundling provisions do require that distribution is effectively separately operated from supply, and further that any legal instruments (contracts, concessions) are structured so that the two business are independent. We interpret the conditions on independence to mean that the distribution and supply businesses could (and

ideally would) be separately owned. If the measures to separate the business are not sufficient to allow separate ownership, we think that would indicate that the terms of the Directive have not been met.

It is likely that changes to concession agreements would be necessary to accommodate this separation, and to ensure that there is no discrimination between the supply business of the incumbent and other supply businesses. These changes would need to allow continuation of public service obligations such as the obligation to supply customers, and it may be necessary for the distribution concession holder to have the right to assign obligations to other parties (so for example an obligation to be a supplier of last resort could be passed to either the incumbent supplier or an alternative).

Making these legal changes to the concession agreements of companies may not be straightforward. But they are condition of the Directive, and must be implemented whether or not the merger proceeds.

Portugal is an "emergent market" under the terms of the Directive, as imports of natural gas began in 1997. It is therefore permitted (but not obliged) to derogate from the unbundling provisions set out in Article 13 of the Directive until 2007 (ten years after the first imports of gas). This exemption does not apply to electricity, and the combined electricity distribution supply company will definitely be required fully to apply the provisions of the Directive.

Suggested remedies

The restriction to competition would occur because EDP would control all electricity supply in Portugal as well as effectively controlling gas supply through the stake in GDP.

A simple way to improve competition in energy supply, over and above the terms of the Directives discussed above, would be for the parties to change the terms of the proposed merger so that new independent gas companies are created. Rather than EDP and ENI jointly controlling GDP, the assets of GDP could be divided, with gas distribution supply companies and associated contracts transferred into new companies. ENI, EDP, and potentially other companies would buy stakes in these individual gas companies. Additional restrictions on EDP's total energy supply activities as described above would also be made. This would have the advantage of providing each company with unhindered ability and incentive to compete more vigorously in the gas markets. By removing any obstacles to ENI's freedom of action in its gas business, it would encourage more competition in the electricity market through ENI's entry via gas-fired generation plant.

If GDP and EDP buy separate gas companies, there would still be greater concentration in energy supply than there is at present. In order further to mitigate the impact of the merger over and above the requirements of the Directive, we suggest that EDP would be required to sell electricity and/or gas supply business activities to new owners. The size of required business sales should offset the increase in concentration as a result of the restructuring. We therefore suggest that electricity and/or gas supply businesses serving up to the number of gas customers acquired by EDP are sold. It would be preferable if the sale of supply businesses allowed an additional new entrant to supply both electricity and gas supply customers.

Restrictions on market share in supply markets have been considered in some markets as a way of encouraging the development of competition. We think it would be difficult to specify such a restriction in a way that would not be counterproductive to the development of competition. In particular, the incumbent would be partially removed from the supply market with active customers. We think that scrutiny of market participants with swift and effective response to unfair competitive tactics would be more appropriate.

Restriction of expansion of gas distribution

There are a number of possible remedies for this:

- Regulatory. Impose stricter regulation of investment plans required by concession agreements, including decisions on the appropriateness of expansion of the network, and financial penalties for failure to meet targets.
- Asset disposal. Require disposal of at least one of the major gas distribution networks.

The problem with the regulatory intervention remedy is that the company will control the information available to the regulator, and may make it difficult for an independent judgement to be made about whether further network expansion is warranted. Asset disposal of one of the networks would allow an alternative source of information on the merits of network expansion, from a company which may have a vested interest in expansion, and it is therefore to be preferred. Splitting GDP into independent companies owned separately by ENI and EDP, as discussed above in the discussion of energy supply would have the desired effect.

Gas market foreclosure

The key here is not only for gas to be available in Portugal to potential entrants to the generation market in Portugal, but also for flexibility in short term markets, and between gas markets in Spain and Portugal to become available to third parties.

The following remedies would mitigate the competition concerns:

- Gas release. The transfer of a sufficient volume of gas contracts at the interconnector at Badajoz to third parties (the merged company should be able to meet current obligations using gas supplied at the LNG terminal).
- Storage. Storage assets should not be transferred to EDP. In addition it may be appropriate for the price of storage to be regulated in the short term until an appropriate level of competition develops.
- LNG terminal. Regulations for the terms of access to the new LNG terminal need to ensure non-discrimination. Again, it may be necessary to regulate these for a limited period.

The reason for releasing gas supplies at the Badojoz interconnector is to enable active trade to take place across it. At present, the supplies are controlled by GALP Energia, and granting access across it by the release of gas supplies would facilitate the participation in the market by third parties.

The most appropriate way for gas release to be organised is likely to be through auctions. These would need to be designed carefully to avoid manipulation. Ideally the design should involve auctions of contracts for different terms and delivery periods. A one time auction could prevent the development of active trading in contracts, so we recommend that auctions should occur on a regular basis (which also allows the precise design to respond to market circumstances).

There may be destination clauses in existing gas contracts that are difficult to renegotiate. Even if this is the case, it should be possible to negotiate financial contracts that give the same effect as actual gas release, and facilitate trading by third parties.

We understand that the direct counterparty for the gas contract with Turbogas is REN, which is also the counterparty to the PPA contract. The structure of the combined contracts means that Turbogas bears limited commercial risk, as fuel purchase costs are passed through to electricity customers under the PPA. Under the present contractual arrangements for electricity purchase, it is appropriate for the electricity and gas contracts to have the same counterparty. With the ending of the PPA agreements, commercial arrangements will change substantially. Without further clarity about the fine detail of what will replace PPA contracts, and the structure of the CMEC payments, it is not possible to make concrete recommendations for the gas contract.

In addition to measures to facilitate competition in the gas market, it would be appropriate to consider measures that would facilitate competition in electricity generation. As noted above, concentration in the Portuguese market is already high, and the restructuring does not change this, although it does remove a potential competitor. We suggest that to prevent further enhancement of market dominance, a measure is introduced to limit the expansion of market participants which already have a large market share (e.g. a company with a market share greater than 40% would need to give reasons why it should be allowed to build plant in Portugal). There are alternative ways of giving this legal effect for this type of measure.

It should be noted that control of the gas market would give the expanded EDP the opportunity to extract economic rents upstream in the gas market whether or not it builds any new plant, and scrutiny of prices in the different wholesale markets will be needed to establish whether this is occurring.

Potential market abuse

An effective way to deter market abuse is:

- to set up an effective mechanism for identifying it; and
- a mechanism to punish it should it be detected.

This means that an organisation needs to be given responsibility for monitoring market developments, including pricing, and with the powers to obtain information from market participants so that full investigations can be swiftly undertaken when there are allegations of abuse.

A number of countries have created such organisations, either as part of the energy regulator, or the competition authority. (e.g. the Netherlands, and the UK).

7. SCENARIOS

The impact of the proposed restructuring on the electricity and gas markets in Portugal is complicated by the uncertainty associated with future market developments. In particular, it has been agreed that the Iberian electricity market will be established in April 2004, but it is unclear whether this will be a true market.

In this chapter, we make an assessment of the impact of the proposed restructuring on the basis of three different assumptions about market developments:

- assuming the status quo, i.e. the Iberian electricity market is not effective[22];
- the Iberian electricity market is implemented and effective, but the Iberian gas market is not;
- both the Iberian gas and electricity markets are implemented and effective.

We also assume four different assumptions regarding the proposed restructuring:

- that it does not proceed (i.e. the status quo);
- that it proceeds, with no remedies; and
- that it proceeds, with the minor remedies set out in the previous chapter; and
- that it proceeds, with the resolution of the PPA issue.

For each of the twelve combinations of assumptions, we make an assessment of the future development of:

- the electricity wholesale market;
- the electricity supply market; and
- the gas supply market.

Assessing the impact on the wholesale electricity market

In wholesale electricity markets, as in other markets, costs are, of course, one of the most important determinants of prices. When the market is in equilibrium, the revenue of power stations can be expected to reflect the long run marginal cost (LRMC) of installing new capacity. In most markets in Europe, the marginal plant is a gas-fired CCGT for base load, or an OCGT for peak.

[22] Although it might be implemented

In the short term, though, prices can be significantly different from LRMC. In a competitive unregulated wholesale electricity market, the different between price and LRMC mainly reflects reserve margins, the amount of excess capacity available for generation that is not needed. When there is substantial excess capacity, prices are close to short run marginal cost (SRMC), and when capacity is short, electricity trades at a premium to LRMC, which can be substantial. Prices then act as a signal to market participants to close excess capacity, or to enter a market respectively.

But costs and reserve margins are not the only determinants of prices. Four other factors are also crucial:

- the market power of existing market participants. This can lead to lower or higher prices. Low wholesale prices can be used to deter new entry (provided the company can secure more favourable prices from existing contracts), while prices higher than SRMC are likely with excess capacity, when there is no risk of encouraging entry;
- barriers to entry, combined with market power. Vertical integration into transmission combined with the ability to raise transmission tariffs and lower wholesale prices, can deter entry, as can vertical integration into supply. Transmission constraints can isolate local demand pockets and allow the sustained exercise of market power if there is no obvious local shortage of capacity and hence little incentive for new entrants to build capacity behind the transmission constraint,
- explicit incentives placed on market participants by the regulatory framework. This can include the contracts for purchasing, power, and regulations concerning the price at which suppliers can buy power; and
- other incentives. Companies may believe that regulatory intervention will be prompted if prices exceed a certain level, and their behaviour in the wholesale electricity market may be designed to ensure this.

The importance of these factors in determining prices has two important implications.

First, lowering wholesale prices is not an appropriate test of whether the market arrangements are appropriate. A market structure that produces lower wholesale prices when it is not appropriate can reduce welfare over the longer term, as it prevents prices from signalling when entry or exit should occur. The test is rather whether the arrangements allow prices to properly reflect the costs and reserve margin on the system.

Second, a detailed quantitative model of future prices is unlikely to be helpful in determining the impact of structural changes to the market. It is of course possible to construct a quantitative model of price determination, using estimates of costs of all power stations in Portugal and Spain, and by modelling demand and production. There are standard packages such as PowerSym which will determine the least cost dispatch and compute the system

marginal cost for each hour of a week (an extended period of time is required to capture constraints on ramp rates, cool down time, and the fixed costs of start-up). Commercial software is extremely expensive, and although there are non-commercial models available, they still require expensive data collection, programming, and validation. Such models are best suited to computing competitive prices.

In a market like Portugal, final prices are not simply determined by costs, but by the strategic action of market participants in the wholesale markets. Modelling the exercise of market power is one of the more challenging tasks facing analysts, and all approaches adopted to date have various limitations. The most fundamental problem is that under a wide range of conditions, if individual generators bid into the wholesale market to maximise their profits, without colluding, and responding to the perceived actions of their competitors, then there are a whole continuum of possible imperfectly competitive equilibria.

The problem becomes more difficult if, as is the case in practice, generators sign contracts with consumers, for this reduces their exposure to and interest in the wholesale spot price. The higher the contract coverage, the more competitively generators will be tempted to bid in the wholesale spot market. However, the contract price must bear some relationship to the predicted spot price if both buyers and sellers are willing to hold both contracts and to buy or sell spot. Properly speaking, the equilibrium spot and contract price depend on each other and should be solved for simultaneously. There are at present no commercially available models that can do this, and theoretical models can only do it by assuming that contract prices are entirely determined by the conditions of entry, which requires no barriers to entry.

Some analysts choose particular assumptions to simplify the problem. One common assumption is that each generator assumes that the outputs of its competitors are not influenced by its own choice of output (the Nash-Cournot assumption), although there are delicate problems in modelling imports and exports over interconnectors that can significantly influence the result. Recently a group of modellers compared the results of their differing solution techniques for modelling the results of integrating the Benelux markets, using the same data for power station costs in neighbouring countries and the same data for interconnection capacity, all using Nash-Cournot models. The results differed depending on how trading across interconnectors was modelled, and also suggested implausibly high prices. That was because the Nash-Cournot assumption tends to overstate market power when there is spare capacity, and it also assumes that there are no threats of regulatory action in the face of unreasonably high prices – potentially high enough to constitute an abuse of dominant position.

In markets with dominant players, such as Portugal and Spain, the outcome of these models will therefore depend largely on the assumptions made about strategic behaviour of players

in the context of regulatory action and threats of it. Estimates of prices will depend directly on these assumptions, rather than the underlying costs of electricity generation. For the purpose of assessing the impact of structural changes, therefore, we focus on a qualitative assessment.

So what is the likely development of prices in the Portuguese market, and/or the Iberian market, and what would the impact of restructuring with and without remedies be?

Under the status quo, the current market arrangements give an incentive for the dominant incumbent player to ensure that prices are low. There are two reasons for this. First, the PPA agreements and their proposed replacement give EDP an incentive to keep wholesale prices below LRMC, to deter entry (see Chapter 4 above for further details of this). Second, its dominance in the market means that prices significantly above LRMC would be expected to lead to regulatory action, so it would probably keep prices low to prevent this. In the short term, the contract arrangements provide protection to customers from the dominance of EDP. But in the longer term, the arrangements serve to preserve the dominance of EDP. Prices are unlikely to rise to signal the need for new capacity, deterring third parties from market entry. In addition, at times of excess capacity, market dominance of EDP could ensure that prices would not fall. It is likely, though, that GALP Energia, even with EDP's 14.3% shareholding, would attempt to enter the electricity market, as Gas Natural has in Spain. This would give potentially one small market participant exposed to market prices.

What changes if the Portuguese electricity market, and possibly the gas market, is integrated with the Spanish market? This means that during those periods where there is no transmission constraint between the two markets, prices will be determined conditions in both countries. This means that prices in Portugal will be set by a well functioning market mechanism. Market participants, including new entrants, would have the opportunity actively to trade energy, and it is likely that there would be sufficient liquidity in the market to do this. This is clearly an improvement on the status quo. Spanish wholesale electricity prices are not, however, freely determined because of the regulatory mechanism of the CTCs. Overall, this provides an incentive for prices to be set below marginal cost at present. A likely scenario for wholesale prices is that on average they will be just below LRMC in the short term, deterring entry. At some time in the future, when there is little need for new capacity, and when the companies benefit financially from higher electricity wholesale prices because a sufficiently large part of the market is exposed to wholesale prices rather than CTCs or CMECs, prices will rise. Because there are only a limited number of players in the Iberian market, and it is these companies which own the new capacity, competitive forces would not be able to force prices down.

Against this background, what would the impact of the restructuring be?

If the Iberian markets have not integrated, or that integration is not effective for either commercial or physical reasons, the impact on competition is serious. No domestic or international player is likely to enter the generation market. In the short term, customers would receive the protection afforded by the PPAs / CMEC mechanism. But a competitive energy market would be unlikely to appear for at least 10 years, until after the expiry of the CMEC mechanism.

It can be argued that integration of the Iberian energy markets mitigates the impact of the restructuring. And it does. But against the counterfactual of what the integration of the market would do without the restructuring, it is harmful. First, it reduces the total number of market participants in the energy market. At present, these comprise Endesa, Iberdrola, Unión Fenosa, EDP/HidroCantabrico, Viesgo/ENEL, Gas Natural, and GALP Energia. Combining EDP/HidroCantabrico with GALP Energia reduces competition in both electricity and gas markets. Second, one of the two major gas importers (GALP Energia and Gas Natural) would be controlled by an electricity company, potentially foreclosing the gas market in a region of the market, making entry less likely. In the short term, the integration of these two market participants would be unlikely to have any significant impact on prices, or the market. It is the longer term impact that is of concern, and the way that it makes it more certain that an oligopoly of a few players will dominate the Iberian energy market, providing little opportunity for new entry in the near term, and exploiting customers through higher prices in the longer term.

The proposed remedies would provide mitigation against the increased control of the market from the restructuring. In respect of the energy wholesale markets, the "minor" remedies identified would mainly improve the prospects for gas competition in Portugal, by creating a new independent company that is able to compete effectively in gas supply, and further ensuring that other third parties would have the opportunity to be involved in the market (rather than just the legal right that will be granted by legislation). This would prevent gas market foreclosure by an electricity company which also has effective control of the Portuguese gas industry.

This would also provide better opportunities for entry into both the Portuguese electricity and gas markets. Indeed, the new independent gas company may find it attractive to enter the Portuguese electricity market, and sell electricity in both Portugal and have an option to sell electricity in Spain.

Without the "major" remedy, though, of resolution of the PPA/CMEC issue, distortion to wholesale electricity prices would continue, and could still deter entry into wholesale electricity generation. If a significant proportion of electricity generators benefit from higher wholesale electricity prices, it is more likely that prices will reflect long run marginal cost. This will encourage appropriate entry. This would raise wholesale electricity prices in the

short term, but over the medium term would facilitate the development of effective competition. This would clearly be more effective if gas and electricity markets in Portugal and Spain are integrated.

Summary impact of scenarios

A summary of the likely impact is set out in Figure 11, which is based on the discussion of the future development of markets, and impact of mitigating remedies set out earlier in the report.

Our qualitative assessment of the scenarios, compared to the status quo, is set out in Figure 12.

Figure 11 Development of scenarios

	No Iberian energy market	**Iberian electricity market implemented and effective, no Iberian gas market**	**Iberian electricity and gas markets implemented and effective**
Status Quo			
Electricity wholesale market	Remains dominated by EDP. Short/medium term protection afforded by PPAs.	Active trade in electricity in Portugal, more effective wholesale market. But lack of effective access to gas market makes new entry less likely.	Active trade in electricity in Portugal, and effective wholesale market. Opening of gas market makes entry into generation more likely.
Electricity supply market	Limited change of suppliers by customers	Active market for industrial customers, with foreign suppliers able to source large quantities of electricity from Spain. Some competition in retail market from gas suppliers.	Active market for industrial customers, with foreign suppliers able to source large quantities of electricity from Spain. Some competition in retail market from gas suppliers.
Gas supply market	Limited change of suppliers by customers	Limited development of effective competition.	Active market for industrial customers, with foreign suppliers able to source sufficient quantities of gas from Spain. Some competition in retail market from electricity supplier.
Restructuring, no remedies			
Electricity wholesale market	Little change from Status Quo. Separation of gas network assets improves new entrant access to gas, but this effect offset by combination of electricity and gas assets.	The separation of the gas infrastructure assets is positive, but offset by the effect of the integration of gas and electricity assets in EDP.	The separation of the gas infrastructure assets is positive, but offset by the effect of the integration of gas and electricity assets in EDP.
Electricity supply market	Removal of domestic competitor negative impact on potential for competition.	Active competition in industrial market.. Limited competition in retail market.	Active competition in industrial market.. Limited competition in retail market.
Gas supply market	Removal of domestic competitor negative impact on the potential for competition.	Limited competition in both industrial and retail market.	Active competition in industrial market. Limited competition in retail market.

Figure 11 continued

	No Iberian energy market	**Iberian electricity market implemented and effective, no Iberian gas market**	**Iberian electricity and gas markets implemented and effective**
Restructuring, plus minor remedies			
Electricity wholesale market	Better access to gas market means entry more likely.	Impact of link between EDP electricity and gas assets mitigated by improved domestic competitive environment for gas.	Impact of link between EDP electricity and gas assets mitigated by improved domestic competitive environment, and competition from Spain.
Electricity supply market	Local competitors (possibly foreign owned) given opportunity to compete, new gas competitor likely to compete.	Active competition in industrial market, and potential for competition in retail market in particular from newly established gas companies.	Active competition in industrial market, and potential for competition in retail market in particular from newly established gas companies.
Gas supply market	New competitor established, and other competitors (possibly foreign owned) given opportunity to compete.	New competitor established, which can compete in both industrial and retail market.	Active competition in industrial market, and competitor established to compete in retail market. Further competitors may also enter.
Restructuring, plus minor remedies, plus resolution of PPAs			
Electricity wholesale market	Market prices determined by competition	Market prices determined by competition, with impact on Spanish market	Market prices determined by competition, entry decisions made on basis of more appropriate gas prices
Electricity supply market	Market pricing improves entry conditions in supply	Market pricing improves entry conditions in supply	Market pricing improves entry conditions in supply
Gas supply market	Improved gas-electricity arbitrage likely to enhance gas trading and supply	Improved gas-electricity arbitrage likely to enhance gas trading and supply	Improved gas-electricity arbitrage likely to enhance gas trading and supply

Source: CEPA

Figure 12 Assessment of scenarios

	No Iberian energy market	**Iberian electricity market implemented and effective, no Iberian gas market**	**Iberian electricity and gas markets implemented and effective**
Status Quo			
Electricity wholesale market	0	+	++
Electricity supply market	0	+	++
Gas supply market	0	0	++
Restructuring, no remedies			
Electricity wholesale market	–	0	+
Electricity supply market	–	+ industrial – domestic / small commercial	+ industrial – domestic / small commercial
Gas supply market	–	–	–/0
Restructuring, plus minor remedies			
Electricity wholesale market	0	+	+
Electricity supply market	0/+	+ industrial 0/+ domestic / small commercial	+ industrial 0/+ domestic / small commercial
Gas supply market	+	+ industrial + domestic / small commercial	+ industrial + domestic / small commercial
Restructuring, plus PPA resolution, plus minor remedies			
Electricity wholesale market	++	++	++
Electricity supply market	+	++industrial + domestic / small commercial	++ industrial + domestic / small commercial
Gas supply market	+	+ industrial + domestic / small commercial	++ industrial 0/+ domestic / small commercial
Key: 0: Neutral, compared to Status Quo; +, positive compared to Status Quo; - negative compared to Status Quo			

Source: CEPA

It can be seen from this analysis that the impact of the combination of the restructuring and the implementation of the Iberian gas and electricity markets does lead to more effective competitive electricity and gas markets in Portugal. Compared to the status quo without restructuring, there is likely to be an active competitive energy supply market to large consumers, and electricity and gas wholesale markets will be more liquid than at present. However, the table also shows that the restructuring without remedies has a negative impact keeping the assumption about the development of the Iberian energy markets constant. The

suggested remedies do improve the competitive environment, mitigating the impact of the proposed restructuring.

8. CONCLUSIONS

The structure and business environment for the Portuguese energy markets have a number of characteristics distinguishing them from other European energy markets. Like some other countries, electricity and gas markets are dominated by large companies, which remain partially owned by the state. In these markets, the idea of merging these companies, even with significant remedies, would be difficult to contemplate.

The analysis here, however, shows that:

- while there is a negative impact from restructuring, there are remedies that can mitigate these;
- the development of an effective Iberian energy market would further mitigate the competition issues raised by the restructuring.

In particular, the restructuring provides the opportunity for the resolution of the competition issues associated with the PPA contracts that substantially distort competition in the Portuguese market, and under current plans will effectively remain. We recommend that serious consideration be given to imposing a condition on the restructuring that would change the structure of the stranded cost payments.

Consideration should be given to imposing conditions including:

- changing the terms of the merger so that GDP assets and contracts are divided into separate independent companies, which are transferred to ENI and EDP;
- requiring EDP in addition to sell additional gas and electricity supply businesses to reduce concentration in energy supply to pre-restructuring levels;
- the release of gas import and interconnect contracts to third parties;
- limiting the construction of new power stations by dominant generators;
- strict regulation of gas distribution businesses, to prevent distortion of investment incentives in gas distribution by the dominant electricity supplier; and
- retention of gas storage within the gas transmission business, and careful regulation of gas storage and LNG terminal.

ANNEX 1 – SUMMARY OF RELEVANT INTERNATIONAL COMPETITION CASES

National Grid and Transco

In April 2002, National Grid and Lattice announced their intention to merge.

National Grid is responsible for the ownership and operation of the transmission system in England and Wales, and it is also system operator, responsible for the operation of the balancing market, and ensures that generation and demand for electricity are continuously balanced. In addition, it operates interconnectors (with France and Scotland), is involved with gas trading through ownership of EnMO, as well as significant electricity transmission and gas and electricity distribution assets in the North East USA.

Lattice, through its subsidiary Transco, was responsible for gas transmission and gas distribution in the United Kingdom, and for gas balancing in the UK trading system for gas. It also owned and operated 5 LNG storage facilities in the UK, as well as a gas connection service. Lattice was formed following the demerger of BG group in 2000.

Ofgem has a non-statutory role in the application of UK and European merger controls in respect of transactions that arise in the gas and electricity systems in Great Britain, providing confidential advice to the Director General of Fair Trading. Following a consultation exercise, Ofgem provided this advice in May 2002. The merger was cleared by the Secretary of State for Trade and Industry on 2 July 2002, after which Ofgem undertook analysis of regulatory issues arising from the merger.

Ofgem's final advice to the DGFT was not published, but in the consultation paper on this issue stated that: "in relation to the ownership and development of electricity and gas transmission and gas distribution networks it is Ofgem's initial view that NGC and Transco are not in direct competition with each other given that the networks deliver substantially different products" (Ofgem 2002).

With respect to system operation, it was considered that the two companies do perform similar roles, albeit for different products. Given the increasing links between gas and electricity markets in real time, Ofgem could see advantages from the improved communication between the two system operators which could result from the merger.

Respondents to the consultation paper in general agreed with Ofgem's conclusions. They did, however, raise issues concerning the interaction of the gas and electricity system

operator roles. In particular, it was noted that the merged company would have additional information that could be used not only to the benefit of customers, through improved coordination of for example scheduling of maintenance, but could also be used to influence prices in the balancing markets, to the advantage of the merged company.[23] These and other issues were addressed by Ofgem in the analysis and response to regulatory issues, which followed approval of the merger.

Ofgem decided to:

- restrict the licensed businesses of NGC and Transco, so that none could buy or sell gas or electricity except in the specific role of system operator. However, Ofgem did permit the merged company to continue to own generation plant, provided it was of small scale, connected to distribution networks rather than transmission networks, and is environmentally beneficial.[24]
- impose restrictions on the information that could be passed from National Grid's subsidiary EnMo, which operates the on the day commodity market in gas.
- to bring financial ring-fencing provisions for NGC and Transco into line with each other, and into line with those of distribution network operators. This involved appropriate conditions in licences of the regulated companies on issues including credit ratings, permitted activities, and indebtedness. Provisions were also included in licences to allow companies within the merged company to provide services to the regulated companies, and for NGC and Transco to provide services to each other.

Ofgem considered that further concerns about system operation could be handled under existing regulatory provisions.

E.ON and Ruhrgas

E.ON is a German-based energy group, formed in 2000 from the merger of VEBA and VIAG. In the past, both companies were industrial conglomerates, dominated by energy, but the non-energy assets have now been sold or are up for sale. It has a significant share in the German generation market with installed capacity of 27.7GW, it owns and operates transmission networks in northern Germany and Bavaria, as well as distribution/supply companies. It has other energy assets in the Nordic region, Eastern Europe, the UK (Powergen) and US (LG&E).

[23] Raised, for example in the comments by Innogy, and British Gas. These responses are available at www.ofgem.gov.uk.

[24] For some of the CHP assets of Lattice, therefore, time limited consents were granted.

Ruhrgas is the largest of the gas transmission companies in Germany, and through contracts controlled virtually all gas delivered to regional and municipal gas companies, giving it a market share of almost 60%. It also has ownership stakes in gas distribution companies, as well as international gas interests. Prior to the acquisition by E.ON, it had a complex ownership structure, including shareholdings by major international oil companies.

The approval of the proposed acquisition was somewhat tortuous. The Bundeskartellamt prohibited the merger in January 2002. E.ON applied for a *Ministererlaubnis* (Ministerial permit) to overturn this decision, as provided for in German merger legislation. A report by the Monopolkommission disapproved of the merger on competition grounds. Nevertheless, a the *Ministererlaubnis* was granted in May 2002, with remedies including auctioning of gas contracts, sale of stakes in municipal companies, and legal separation of gas transmission assets. Opponents of the merger obtained an injunction preventing the merger completing, on the grounds that *Ministererlaubnis* had not been properly obtained. A new *Ministererlaubnis* was sought and granted in September 2002, with slightly stricter conditions, including requirements to dispose of additional companies, and an increase in the volume of gas release. This was also challenged by other market participants in the gas and electricity markets. On 31 January 2003, an out of court settlement was reached with 9 companies who had objected to the merger and were involved with court proceedings.

Gas Natural and Iberdrola

Gas Natural dominates the Spanish gas market, and Iberdrola is one of the major Spanish utilities. In February 2003, Gas Natural made a hostile takeover bid for Iberdrola, for €15.3bn. Under Spanish legislation, the bid was subject to the approval of the Spanish energy regulatory organisation, the Comisión Nacional de la Energía (CNE).

In order to gain regulatory approval, Gas Natural offered to make a number of asset disposals. These included:

- liquid shareholdings in related companies to a value of €2.2bn;
- power stations, including 2.4MW of partially constructed CCGT power stations and the associated gas contracts with annual volumes of 3bcm;
- Iberdrola's gas contracts, with volumes of 5.5bcm annually
- a reduction in its stake in Enagas, the Spanish gas transmission company
- to sell gas distribution assets associated with 750,000 customers, to reduce its national market share to no more than 70%.

The aim of these was clearly to reduce the newly merged company's dominance in gas and electricity markets, and to reduce the possibility that the company could exercise control of the wholesale electricity price through control of the gas price.

The CNE did not approve the proposed merger (CNE 2003). The reasons for this were:

- there was a risk that the acquisition and associated divestment plan would jeopardise the quality improvement plans in both Iberdrola and Gas Natural
- there was a risk that cross subsidies between regulated activities and non-regulated activities would occur
- there was a possibility of unbalanced expansion of network activities in the two regulated businesses.

There are also reports that competition authorities were concerned about the horizontal effects of the merger.

ANNEX 2: CLAIMED ADVANTAGES OF THE MERGERS

EDP-GDP

EDP has provided two main reasons for the proposed merger with GDP:

- cost savings; and
- strategic benefits.

In terms of cost savings, it is claiming that the merger would allow it to save between €16 - €25m pa. The source of these savings is set out below.

Figure 13 Estimated cost savings from merger of EDP and GDP

Item	Estimated Annual savings €m
Coordination of the supply of gas and electricity	7-9
Network costs (capex and opex)	4-6
Administration	2-4
Customer services and commercial activities	2-4
IT	1-2
Total	16 – 25

Source: *EDP*

These are relatively modest savings, in the context of the current EDP group, which in 2002 had sales of €6381m, and operating costs of €4898m.

The strategic arguments concern the reduction of risk, by securing the source of supply for a major fuel in power generation, as well as perceived attractive characteristics of the Iberian gas market, as there are likely to be only a few market participants which may have significant market power. Other factors include the existence of destination clauses in gas contracts, giving an advantage to companies with a portfolio of contracts, and the limited flexibility in take-or-pay gas contracts, compared to the increased flexibility needed in the operation of CCGTs.[25]

EDP sees tangible benefits from the flexibility that owning the gas contracts would give them. Through its 40% interest in Hidrocantábrico, which in turn owns Gas Asturias and

[25] These arguments are set out in a presentation to investment analysts made in London on 2 December 2003.

Naturcorp, it sells 2bcm of gas each year in Spain, and will also own and operate CCGT plant. Changes to schedules in either Portugal and Spain can be accommodated more economically once EDP has control of the gas import contract. EDP estimates that the value of this flexibility would be between €15-20m each year. The ability to make these savings is exactly what the creation of a common Iberian energy market is intended to achieve.

Transgas - REN

We have no information on the claimed advantages of the merger of the transmission businesses.

The two types of transmission business do use different technologies, and so there is limited direct overlap between the two businesses. The approach to management of the two businesses, however, is similar: both are capital intensive, require active asset management, and are subject to similar regulatory frameworks. This means that there can be advantages in the application of best practice between the two businesses. Indeed, following the merger of National Grid and Transco in the UK, the merged company has combined the management of many gas and electricity assets.

An additional advantage of combining the two businesses is that coordination of investment and maintenance, where this is important, can be achieved more readily.

ANNEX 3. COMPETITION TRANSITION COSTS IN SPAIN

The introduction of CTCs in Spain

The broad framework for the deregulation of the Spanish electricity sector was agreed in 1996 in the form of a Protocol, and translated into law in 1997. As part of the move to market-based pricing in generation, it was expected that prices would fall. In order to compensate the utilities for this loss of revenue, it was agreed that they would receive compensation payments known as Competition Transition Costs (CTCs). The rational for this is that investments were made by utilities under a previous regulatory regime, which would have provided a reasonable return on any investments made, and the change in the regulatory framework therefore required compensation. In the US, this type of payment has become known as "stranded costs".

These payments are substantial. Under the original legislation, these payments would have amounted to some Pta 1,989bn (€12bn), payable over a maximum ten year period. This has subsequently been reduced to €10.5bn.

The structure of CTC payments

The structure of the payments is as follows:

- The government determines the overall level of the tariff, determining revenues to be collected from non-eligible customers and the network fees from eligible customers;
- the regulatory framework determines the revenues for transmission, distribution, and supply to tariff customers, extra payments to the island systems, and payments due to other organisations from the tariff (including the costs of the regulatory body). Wholesale market revenues are calculated and added to these.
- CTCs for the industry are the residual payment, calculated as the difference between allowed revenue, and the allowed costs (regulated revenues plus wholesale market revenues). A part of the payment is allocated to companies on the basis of production using indigenous coal. The remainder is allocated to companies according to fixed percentages.

Additional features of the payments are:

- payments will not be made after 2010
- the present value of CTCs is limited, so it is possible that payments will be exhausted prior to 2010

- if average pool prices rise above Pta 6/kWh (€36.06/MWh), the additional revenue is deducted from the total value of CTCs that can be paid.

The structure of payments has not always been the same. In 1999, the structure of payments was modified so that a part of CTCs was collected by a 4.5% surcharge to the tariff. This was subsequently modified in February 2001, which made all the payments by difference again. This was associated with an EU investigation into stranded cost payments (see Annex 4).

If pool prices rise sufficiently high, it is possible that the revenue to be collected from customer is insufficient to cover CTC payments. This happened in 2001, and led to the "tariff deficit". Legislation passed in late 2002 allowed companies to recover this tariff deficit beginning with the 2003 tariff.

Under normal market conditions, the underlying mechanism provides an overall incentives on incumbents as a group for prices to be around €36/MWh on average. The allocation of CTCs by fixed percentages, though, does mean that individual companies benefit from increasing market share, and this provides further downward pressure on prices.

Despite these incentives, prices in 2002 were higher than this, averaging €38/MWh, excluding capacity payments because of poor hydrology. This is because companies that receive a relatively low share of stranded cost payments can still benefit from higher prices, and in times when hydrology is low, this effect dominates. In 2003, wholesale prices averaged €30/MWh, excluding capacity payments. Effective reserve margins in Spain at times of peak demand, excluding hydro and wind capacity which is not available at those times, have been low, and prices have not been as high as would normally be expected.

Comparison of Spanish CTCs and Portuguese CMECs

There are a number of similarities between CTCs and CMECs:

- They make up the difference between the market price for electricity and a reference price.
- There is a cap to total payments that can be made.
- The payments are of limited duration.
- The cost of the payments is met by customers through a surcharge to the tariff.

The main differences between the payment systems are:

- The CMECs replace PPA contracts, and therefore the mechanism to replace the contracts can be designed to replace the economic effect or value of those contracts. The CTCs in contrast replaced a "regulatory compact", under which utilities in Spain had a legitimate expectation about the returns that they could expect to earn under

the "Stable Legal Framework" that was in operation prior to the introduction of competition in 1997.

- We understand that the CMECs attach to individual power stations, although they will be calculated for each company in aggregate. In contrast, the CTC payments allocate revenues to companies in proportions that were agreed at the time of the establishment of the mechanism.
- We understand that the CMECs will be surcharge on the tariff, whereas in Spain the CTC payments have been calculated as the residual difference between the tariff and other items. While this may not appear to make much difference, in practice it has meant that under the Spanish system "tariff deficits" can arise, under which tariffs do not necessarily collect all revenues to which companies are entitled.

This means that some of the detailed incentive properties of the CTCs noted above may not occur with the CMECs. However, the broad distortion to competitive pricing that we see in Spain under the CTCs is also likely to happen in Portugal. The contractual nature of the PPAs which are to be converted into CMECs means that the size of the CMEC payments, and the need to make them, are easier to justify under EU State Aids legislation (see Annex 4).

ANNEX 4. STATE AID AND CMEC PAYMENTS

The replacement of the PPAs by CMEC payments gives rise to a potential State Aid issue. Although these payments will replace existing agreements, they will:

- confer an advantage on firms;
- is granted by the state (or if by the regulator ERSE is granted using powers conferred on it by the state);
- is selective, favouring certain firms.

Under Article 87 (ex 92) of the EU Treaty, these payments should therefore be treated as State Aids. These payments will, therefore, require EU approval, as has been the case with other stranded cost payments in the electricity sector.

Payments of this type of State Aid have been approved in the past by the Commission, and associated with decisions on approval of stranded costs of other countries, a set of guidelines was published setting out its methodology for considering such cases.[26]

The justification for approving these payments is:

> the distortion of competition that results from aid paid to facilitate the transition for electricity undertakings from a largely closed market to one that has been partially liberalised cannot be contrary to the common interest where it is limited in time and effects, since liberalisation of the electricity market is in the general interest of the common market in accordance with Articles 2 and 2(1)(t) of the EC Treaty and supplements moves to establish the internal market. ….the Commission takes the view that aid designed to offset stranded costs normally qualifies for the derogation under Article 87(3) (c) if it facilitates the development of certain economic activities without adversely affecting trading conditions to an extent contrary to the common interest.

Criteria to be satisfied by stranded cost schemes include:

- the costs must be clearly identified and determined;
- the arrangements for paying aid should take account of the future developments in competition;
- the degressive nature of aid will be viewed favourably;
- the maximum amount of aid payable should be specified in advance;

The nature of the PPAs means that the aid is well-defined. Schemes like the CMEC scheme (e.g. the Spanish CTCs) have been approved, so it is possible that CMEC scheme as identified in the text could also be approved. However, the text of the Commission Communication states that "the financing arrangements must not have the effect of

[26] Commission Communication relating to the methodology for analysing State aid linked to stranded costs. 26 July 2001.

deterring outside undertakings or new players from entering certain national or regional markets". Given the significant impact that the PPA scheme has on the market, alternatives which do not distort competition might be approved more readily by the Commission.

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