INTERNATIONAL EXAMPLES OF GAS INFRASTRUCTURE REGULATION

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Contents

1. Introduction and Summary

The Colombia Energy regulator (the *Comisión de Regulación de Energía y Gas* or CREG) is currently reviewing the regulatory arrangements for the Colombian gas market. Market Analysis, a consultancy, has been asked to advise the CREG on regulatory reforms. We have prepared this report on international experience on regulation of gas infrastructure to inform the work of CREG and Market Analysis.

Regulation and Risk Allocation

We understand one of the important issues for the CREG is the way that different forms of regulation allocate risk between actors in the gas industry. Different regulatory regimes around the world can be broadly categorised into 'revenue cap regulation' and 'price cap regulation'. Under revenue cap regulation, the regulator, as the representative of consumers, approves the investment and guarantees the investors revenue. Users of the gas network bear the risk of the investment. This is the default model of gas infrastructure regulation in Europe. We describe the regulatory regime of National Grid Gas in the UK as a good example of revenue cap regulation.

Under price cap regulation, the regulator sets the price (ideally for the lifetime of the asset) and the investor decides whether to invest or not. The investor bears the risk of under utilisation of the asset. Price cap regulation is rarely applied in Europe, but the Zeebrugge LNG terminal in Belgium has used it. The US regulatory regime looks like price cap regulation, but in reality frequent price reviews mean that the US system is really a hybrid of price cap and revenue cap regulation. In the US, pipeline users bear the long-term risk of pipeline investments. Spain and Italy have also applied hybrid price/revenue cap regimes, in which risk is shared between investors in infrastructure and infrastructure users.

Both the revenue cap and the price cap regimes can give incentives for investment and give efficient outcomes. The person that makes the decision on the investment bears its risk. This should lead to efficient investment. Both a revenue cap and a price cap can be designed so that the expected return for the investor equals the cost of the investment. Therefore there are incentives to invest.

We have also documented the growing trend in Europe to use market information to plan infrastructure decisions. In the UK in 2002 the regulator initiated a system of auctions, whereby gas infrastructure could only be expanded if there was sufficient firm commitment from the market. Shippers sign contracts of up to 14 years before new capacity is built. Throughout the EU the use of open seasons has increased dramatically. Under an open season process, the infrastructure developer invites potential customers to express their interest in buying capacity in a new project. Customers will then sometimes, but not always, sign long-term contracts for use of the infrastructure. Using an open season process to size new infrastructure should reduce the risk of stranding.

We note that unlike most countries in the EU and North America, Colombia does not have a large household gas-load. The absence of a large household gas-load means that the CREG can afford to be more 'hand-offs' with respect to infrastructure planning. A 'hands off' approach is more compatible with price cap regulation than revenue cap regulation.

Moreover, there is a large capacity of hydro generation in Colombia, so that the output of gas-fired power stations in Colombia depends strongly on rainfall, and can vary very substantially from year to year. The variability of output from gas-fired plant and the absence of a steady household gas load mean that it is difficult to forecast demand in Colombia. This is another reason why avoiding a need for approval of gas infrastructure investments by the regulator would be advantageous, and again points to price cap regulation.

We note that switching from a price cap to a revenue cap in effect transfers risk onto consumers for investments they had no part in approving. We see no reason to switch to a revenue cap methodology. A regulatory regime based on a price cap methodology has a number of advantages in Colombia.

Stranded Costs

We understand that stranded cost recovery is an important issue in Colombia. We document a number of cases in the EU and the US where regulators have allowed stranded cost recovery. However, in these cases either the investor is being compensated for a change in the market that was not foreseeable at the time the investment was made, or compensation is required to achieve a fair balance of risk.

To illustrate the latter case, we document the case of two US pipelines that were allowed to increase their rates in response to falling demand for gas transport capacity. We explain that in these cases there were grounds for a rate increase because the US regulatory regime approximates a revenue cap over the long-term. If demand had been much higher than forecast, then pipeline's customers would have brought a rate case and argued for lower tariffs. Denying US pipelines higher rates when demand falls would create an asymmetric risk that pipelines could lose money if demand was less than forecast, but fail to make higher profits if demand exceeded expectations.

When considering stranded costs, the guiding rule is to maintain symmetry, so that investors get their money back in expectation. We understand that if demand rose unexpectedly, the transporter would be allowed to keep the increase in revenues. Therefore, when demand falls the transporter must also bear some of the losses.

Vertical Integration

Allowing gas producers to own pipelines to the national gas transmission system does not, on the face of it, appear to present problems. We explain that in many ways this seems similar to the offshore pipeline regime in the UK, where producers own and share access to pipelines from fields to the national gird under a code of conduct.

A recent investigation by the European Commission concluded that vertical integration between gas suppliers and gas transport networks in the EU has been a major obstacle to the development of competition in the EU gas market. In response to this finding, Europe has recently enacted legislation to strengthen the separation between gas suppliers and gas pipelines. Similar rules have been in place in the US for many years, which explain why the US has a very successful gas market despite vertical integration.

While it is possible to have a competitive gas market with vertical integration between suppliers and pipelines, we would not recommend it. The EU and the US have lived with the situation only because the liberalised gas industry started life vertically integrated, and separation would have been difficult. Starting with a non-vertically integrated industry, it would be a step backward to allow integration between suppliers and pipelines. We note that long term contracts between the shipper and the transporter could achieve similar risk allocation to vertical integration, but without the disadvantages that vertical integration has for competition.

2. Regulation and Risk Allocation

Different models of regulation can allocate risk in different ways. We illustrate this idea by describing two stylised models, which we call 'revenue cap regulation' and 'price cap regulation'. We go onto describe international examples of the application of revenue and price cap regulation, which usually represent blends or 'hybrids' of the two models.

2.1. REVENUE CAP REGULATION – NATIONAL GRID GAS

Revenue cap regulation is the standard model for European Transmission System Operators (TSOs). The regulator allows the pipeline to earn a stream of revenue with a present value equal to the cost of the investment. If gas demand falls, prices will rise to ensure the gas transporter earns back its investment. Accordingly, the consumer bears all the risks of the pipeline investment under pure revenue cap regulation.

Because the consumer, not the TSO, bears the risk, the energy regulator must approve new investments.[1] Otherwise, the TSO could carry out highly risky investments which prove not to be good value. In effect the regulator is the representative of consumers, and judges if the investment will be useful for them and the risks acceptable. Under revenue cap regulation there is no upside or downside for the transporter. Broadly speaking, the transporter will earn back the cost of its investment, no more and no less.

Some form of revenue cap regulation is applied to all national TSOs in the EU which we are aware of that are subject to price controls.[2] The regulatory regime for National Grid Gas (NGG) in the UK is an interesting example of revenue cap regulation, because GB was the first market in Europe to liberalise and the GB energy regulator is competent and powerful. As a result NGG's regulatory regime is mature and sophisticated, having been through many iterations.

Under the regime Ofgem, the GB energy regulator, estimates allowed annual revenues for NGG for a period of five years. The allowed revenue is calculated based on an allowed return on and depreciation of existing assets, as well as an allowance for investments made over the five year price control. NGG is allowed to recover most of its revenues from capacity charges. This means that in the short term NGG is not exposed to changes in gas demand, since users of the gas

[1] In some countries the Energy Ministry may also have a role in planning or approving pipeline investments.

[2] Some pipelines in the EU operate under rules which pre-date existing legislation and are not subject to price regulation.

network book capacity based on anticipated demand, and pay regardless of how much they actually use the capacity.

NGG applies separate charges for entry capacity (for gas entering the National Transmission System or NTS) and exit capacity (for gas leaving the NTS). NGG sets prices with the aim of recovering about 50% of its allowed Transmission Owner (TO)[3] revenue from entry capacity and 50% from exit capacity. The revenue from exit capacity is relatively predictable, since prices are set in advance and demand is relatively stable. Revenue from entry capacity is much more variable, because NGG sells the capacity by auction. Revenues from entry capacity can exceed the 'target' revenue if bidders exceed the reserve price of fall short of target if entry capacity remains unsold.

NGG applies separate charges for its System Operator (SO) costs, the main element of which is the gas used to run the compressors which move the gas through the system. NGG recover SO costs from a separate SO commodity charge, but since the SO costs depend on the volume of gas moved and the gas price, they can also vary from the forecasts.

NGG addresses overshoots or undershoots in its allowed TO and SO revenue by applying a per MWh charge (a commodity charge) to users of the gas network. Specifically NGG must use best endeavours to ensure that in any year actual revenues are not more than 4% above allowed revenues, and in any two successive years actual revenues over the two years do not exceed the allowed revenues by more than 6% of the allowed revenue in the second year.

NGG can vary the TO commodity charge every six months[4] to ensure that overall its actual revenues meet the allowed revenues. In the event that NGG has earned more than the allowed revenue, it will lower the commodity charge, sometimes to zero, and has a mechanism to refund charges to customers who have bought entry capacity. NGG earns a base rate of interest on under recovered amounts. NGG pays the base interest rate plus 3 percentage points on the any amounts which exceeded its allowed revenue.[5]

NGG's adjustment mechanisms mean that – barring the effect of incentive schemes, discussed below – NGG should always recover its allowed revenue, and faces no risk from changes in demand. Since consumers bear the risk of investments, Ofgem has to assess and approve NGG's planned investments. In the case of entry capacity Ofgem uses entry auctions to assess if there is adequate demand for new capacity. The reserve price of the entry auctions is equal to the cost of expanding capacity. Hence if bids for capacity meet or exceed the reserve price, according to market parties the value of the capacity exceeds its costs, and the investment is efficient. In cases where NGG has made investments that Ofgem does not think were justified

[3] These are the costs associated with owning and maintaining the NTS. The charges for operating the system are discussed separately.

[4] To Commodity charges apply from 1st October and 1st April. NGG can vary SO charges more frequently than this in exceptional circumstances.

[5] For more details of NGG's charging regime see 'General Overview of the Gas Transmission (NTS) Charging Regime' 24 June 2009, available on NGG's website.

by the results of the entry capacity auctions, Ofgem can, and has, prevented NGG from recovering the costs of these investments.[6] We describe the UK entry auctions in more detail below.

NGG also has several incentive schemes, which encourage it to make additional capacity available to the market where operational conditions allow, and to reduce the cost of system operation. If NGG underperforms against its targets under these schemes, it will not recover all of its costs. However, in expectation NGG expects to recover its costs – the risk of a bonus if NGG exceeds its target offsets the risk of a loss if NGG under performs.

2.2. PRICE CAP REGULATION – US, BELGIUM, ITALY, SPAIN, TURKEY AND MEXICO

Price cap regulation is applied in the US, in some instances of European infrastructure development, and more routinely in South America and Latin America. Under price cap regulation the regulator sets a maximum unit price for the service. The price cap is usually based on expected investment costs, a fair rate of return and demand. The goal of the price gap is to prevent the infrastructure owner from charging abusive prices, in the case that the infrastructure is uneconomic to duplicate.[7]

Under price cap regulation the infrastructure developer bears the risk of the investment. If gas demand falls, prices remain fixed and revenues will fall. The transporter will not earn back its investment. But if demand is higher than anticipated, the transporter will earn back more than the cost of its investment.

Because consumers do not bear the risk of investments made under price cap regulation, the energy regulator need not be responsible for approving the investment. The regulator simply presents the tariff, and leaves it to the developer to decide to invest or not. Clearly, the gas transporter faces significantly different revenue streams depending on the demand scenario which materialises. Crucially, the transporter must be allowed to recover more than the cost of its investment in the case of a high demand scenario, to compensate for the risk that it will earn less than its investment in the low demand scenario. That is the expected revenue – being the sum of the revenues under each demand scenario weighted by the probability of the scenario occurring – must equal the investment cost. In expectation, the transporter should recover its investment. This is the 'golden rule' of regulation. In our 2000 report for the European Commission, we referred to this golden rule as the 'Net Present Value (NPV) test – the NPV test requires that a pipeline's

[6] In the 2002 – 2007 price control period, Ofgem disallowed £17 million of transmission capital expenditure at the St Fergus entry point, out of a total expenditure on entry capacity of £475.9 million. See Transmission Price Control Review - Final Proposals, Ofgem, 4 December 2006 p.33.

[7] In theory price cap regulation would not be required if competition for potential customers was possible. A customer facing excessive prices from an infrastructure develop could simply seek an alternative offer. However, most economists would regard gas pipelines as a 'natural monopoly', so that pipe-to-pipe competition would not be efficient.

allowed revenues recover on expectation no more and no less than operating costs, taxes, depreciation and the cost of capital on existing investment.[8]

For price caps to support investment, the regulator must make a very firm commitment to the tariff. Otherwise the investor could fear that, in the event that the high demand scenario materialises, the regulator could be tempted to reduce tariffs to please consumers. In the low demand case, the regulator would not raise tariffs. Without a firm commitment, the investor faces asymmetric risk.

Probably the most widely applied use of price cap regulation is in the US, though in practice the system is really a mix of a short-term price cap and a long-term revenue cap. US pipeline rates or prices are set via a procedure known as a rate case. The regulator[9] sets the tariff based on the pipelines recent capital and operating costs, demand and the pipeline's cost of capital. If demand falls unexpectedly, the pipeline will not recover its costs. Conversely the pipeline has an opportunity to recover more than its costs if demand is higher than was forecasts at the time the regulator set tariffs, and several pipelines in the US do earn very high rates of return. However, either the pipelines, its customers or the regulators can file for a new rate case at any time, if any of these parties feel that rates are too high or too low. Accordingly, if demand did fall unexpectedly, the pipeline would file for a rate case, and appeal for an increase in its tariffs. Hence over the long-term, the pipeline will tend to charge prices which give it sufficient revenue to cover its costs, and any large differences between costs and revenues will be corrected in a rate case. The US regulatory regime is less risky than pure price cap regulation, but more risky than revenue cap regulation, because there is no mechanism to recoup losses incurred before a rate review.

In the US the regulator still has to approve the costs which are allowed into the rate base, to ensure that the pipeline only charges customers for investments which are 'used and useful'. The regulator can disallow investments that are not deemed to be 'used and useful'.

While revenue cap regulation is more normal for gas infrastructure investment in Europe, we have seen some instances of 'pure' price cap regulation. For example in Belgium Fluxys, the Belgian TSO, wanted to expand its LNG import terminal at Zeebrugge. In 2004 Fluxys proposed a long-term maximum price for the terminal's re-gasification service, which the Belgian energy regulator subsequently approved. Fluxys, finding the price cap acceptable, proceeded with the project which came into service in 2007. The terminal's tariffs are set for a period of 20 years (2007 to 2027), including an adjustment mechanism whereby the tariffs increase by 35% of the inflation index. However, there are no adjustment mechanisms to cater for a lower than expected level of demand. If no one wants to book capacity in the Zeebrugge terminal, then Fluxys will not recover its investment costs.

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[8] *The Brattle Group*, 'Methodologies for establishing National and Cross-Border Systems of Pricing of Access to the Gas System in Europe' 17 February 2000.

[9] Strictly speaking the tariff is approved by an Administrative Law Judge.

Italy applies a hybrid of revenue and price cap for LNG-terminal regulatory regime. The regulator sets a price cap for the terminal, but guarantees that the terminal will be allowed to recover at least 80% of its costs over a period of 20 years. The remaining 20% is for the developer's own risk. The Italian regulator adopted this revenue guarantee mechanism in an effort to boost investment in gas infrastructure. The revenue guarantee also applies to LNG terminals which are exempt from regulated tariffs. Clearly, even a guarantee on 80% of revenues could encourage an inefficient level of investment in LNG regasification capacity, with Italian consumers bearing the cost. In an effort to avoid this outcome, the Italian regulator has decided to apply the guarantee to a limited re-gasification capacity.[10] The limit is sufficient to allow two additional LNG terminals in Italy to qualify for the revenue guarantee, though over ten terminal projects are currently at various stages of planning.[11]

Until 2006, Spain also applied a hybrid of revenue and price cap to its LNG terminals regulation. The allowed revenues for LNG terminal were estimated based on an assumed utilisation factor of 75%. If a terminal's actual load factor was less than 75%, then the terminal would recover less than 100% of its costs. Conversely the terminal would recover more than its costs if the load factor was greater than 75%. However, in 2006 the authorities opted to change the regime, arguing that the risk sharing based on the 75% load factor was harming investments. Specifically, the order changing the regulatory regime noted that the pre-2006 regime:

"had a major problem since the recoupment of the investments are only guaranteed if the plants are able to achieve a level of utilization above 75% of its nominal capacity...This factors introduces a level of uncertainty that affects the level of investment and has no logic due to the fact that, because we are dealing with planned regulated activities, the recoupment of the investments must be fully guaranteed."[12]

The new Spanish regime seemed to recognise that either the market is free to make investment decisions and bear the risk, or the regulator approves the investment and the risk is subsequently born by consumers. Apparently the Spanish authorities felt that the pre-2006 regime was an uncomfortable hybrid, with the regulator having to approve investments but with investors still bearing some of the risk. Since the enactment of Order ITC/3994/2006 Spanish LNG terminals have their revenues guaranteed.

With respect to pipelines, we know that Turkey and Mexico have both used a price cap mechanism for their gas distribution companies, though we do not have details of the regimes.

2.3. Conclusions on Price Cap Vs. Revenue Cap Regulation

We recommend a regulatory system that is closer to a price cap regime for Colombia. If designed correctly, both revenue cap and price cap regulation obey the 'golden rule' of regulation

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[10] The limit is 95 million standard cubic metres per day of re-gasification capacity. See Deliberazione 7 July 2008 - ARG/gas 92/08 p7.

[11] Assuming a load factor of 90% and an annual terminal import capacity of 8 bcm/year.

[12] Order ITC/3994/2006.

– that is, in expectation, the investor will earn back the cost of its investment. Both a revenue cap and price cap regulation can meet the NPV test and provide incentives for efficient investment. However, we explain below that price cap regulation has a number of advantages for Colombia in terms of infrastructure planning.

Both the revenue cap and the price cap schemes can give incentives for investment and give efficient outcomes. The person that makes the decision on the investment bears its risk. This should lead to efficient investment. In the case of the revenue cap, the regulator takes the investment decision in its role as a consumer representative.

Both a revenue cap and a price cap can be designed so that they meet the golden rule of the NPV test. The expected return for the investor equals the cost of the investment. Therefore there are incentives to invest.

In Colombia we understand that there have been proposals to move from a system based on a price cap methodology to a revenue cap methodology, where the gas transporters would not bear any risk of changes in gas demand. In our 2000 report for the European Commission, we warned that switching the tariff methodology can create windfall gains and losses for the pipeline company and consumers.[13] Unless adjustments are made to neutralise these windfalls, changing the tariff regime once an investment has been made could lead to inefficient outcomes.

Switching from a price cap to a revenue cap in effect transfers risk onto consumers for investments they had no part in approving. It would relieve investors of the responsibility for the investment decisions which they have taken. This could encourage people to make poorly considered investments, in the hope that they could transfer the risk onto consumers if the hoped for revenues did not materialise. We see no reason to switch to a revenue cap methodology. A regulatory regime based on a price cap methodology has a number of advantages.

3. The use of market mechanisms for planning infrastructure

A price cap mechanism is compatible with a lower level of central planning that a revenue cap mechanism. With price cap regulation, the regulator can simply offer a maximum price and leave it to firms to see if they would like to invest. Generally market participants are better at planning investments than the regulator. Market participants will tend to have more and better information than the regulator, and the regulator should use this knowledge wherever possible.

The entry capacity auctions in GB are a good example of using information held by market participants to determine demand for infrastructure. In GB a frequent problem used to be that upstream gas producers would demand long-term entry capacity, but that production would then decline leaving assets which were only partially used. The gas producers have the best information regarding how their field is likely to produce over time. Forcing them to commit financially to long-term capacity requests means that the producers must make their best guess as

[13] Loc. Cit. footnote 8, p118. The example we gave referred to switching from straight-line depreciation to economic depreciation, mid-way through the life time of an asset.

to what capacity they really need. The entry auctions reduce the risk of stranded assets. At the time of their introduction (2002), Ofgem said:

> *"Ofgem believes that there is a need for better incentives on Transco [NGG's former name] to invest efficiently in NTS capacity in a timely manner. The longer term auctions being proposed will provide Transco with better information on the market value of capacity. The new incentives will encourage Transco to respond to these signals by investing where it is efficient to do so. This should lead to an NTS that meets customer requirements and facilitates competition, to the ultimate benefit of all customers".*[14]

This example is from a revenue cap regime. The regulator approves new capacity if the present value of commitments exceeds 50% of the cost of the new capacity. With a price cap regime the regulator would not need to take such a view, and could simply leave it to the infrastructure develop to decide how much commitment it needs before investing.

Other regulators in the EU have started to recognise the advantages of reduced central planning and a greater reliance on the market to determine investment needs. The EU's main gas-market legislation – the so-called third Directive – allows for new infrastructure to apply for an exemption from regulated tariffs, if certain conditions are met. An exemption relieves the regulator from having to approve the investment, because it relieves consumers from bearing risk. The transfer of risk from consumers to investors is one of the main motivations for granting exemptions. The Commission's guidelines on implementing exemptions note that "the granting of an exemption by regulators or Member States will be motivated by their desire to protect customers against having to underwrite projects where the ratio of benefits to costs is uncertain and where the cost is particularly high."[15]

For example, the Nabucco pipeline which will carry gas from central Asia to central Europe is one of the EU's flagship gas infrastructure projects. Nabucco has received an exemption for regulated tariffs from most of the Member States through which the line will pass, including Hungary, Romania and Bulgaria. The IGI Poseidon project is another important EU gas pipeline project which has gained an exemption from regulated tariffs. The pipeline will bring gas from Turkey to Greece, Italy and on to other EU Member States. The Bacton-Balgzand Pipeline (BBL) between the Netherlands and the UK has an exemption from regulated tariffs, at least for physical gas flows.[16] Almost all LNG terminals built in the EU since the second gas directive was approved have obtained full or partial exemptions from regulated tariffs.[17]

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[14] Press release R/132 Thursday 7 December 2000.

[15] 'Exemptions from certain Provisions of the Third Party Access Regime', DG Tren, 30.1.2004.

[16] Backhaul gas – that is flow nominations against the physical flow direction of the gas, are not exempt from tariff regulation.

[17] Terminals which have exemptions from regulated tariffs include: Eemshaven LNG Terminal, Liongas Rotterdam, Grain LNG Terminal, Gate Terminal Rotterdam, Brindisi LNG Terminal, Dragon LNG Terminal,

Many regulators and infrastructure developers in the EU are gathering market information via an open season process, similar to the UK's entry capacity auctions. An open season process invites market parties to state how much capacity they would like in a proposed infrastructure project, usually a gas pipeline or LNG project, and at what price. The opens season process is held before a final investment decision in the project is made, and the results of the open season usually play an important role in deciding whether to invest or not. Open seasons can be useful in either helping regulators decide whether to approve an investment, or supporting private investment decisions for projects which are exempt from regulated tariffs. Open seasons could be a useful tool to help the CREG decide which investments are efficient in Colombia.

Recent examples of open seasons processes in the EU are:

- The Nabucco pipeline will hold an open season in 2010. The Nabucco shareholders will have the first right to book up to half the capacity, then all market participants will be invited to bid for the remainder;
- In August 2009 National Grid announced the start of an open season for a fourth phase of import capacity at the Isle of Grain LNG terminal in the UK;
- In July 2009 French energy regulator CRE held an open season to test market interest towards a proposed gas interconnection between France and Spain. The CRE held another open season for a separate pipeline between Spain and France in November 2009. Shippers were able to bid for flows both north-south and south-north in the two lines.
- In 2009 the Austrian Tauern gas pipeline held an open season for 520,000 cubic metres/hour out of a total capacity of 1,300,000 cubic metres/hour. The pipeline will run from Bavaria Germany via Upper Austria to Italy and come on-stream in 2015.
- In July 2009 Dutch gas transporter Gasunie announced that, based on results of an open season, it was considering investing €1 to €2 billion ($1.4 to $2.8 billion) in expanding the capacity of its German gas transport subsidiary Gasunie Deutschland.
- In July 2008 IGI Poseidon held an open season for up to 1 billion cubic meters/year capacity for third parties, out of 8 billion cubic meters/year available.
- In 2008 Belgian and French TSOs Fluxys and GRTGaz respectively held an open season for additional gas transport capacity on the Franco-Belgian border, which would come on stream in 2013. The French energy regulator, CRE said the open season demonstrated strong interest by the market. As a result the CRE approved the investments.[18]
- In June 2007 Swiss energy company EGL launched an open season for 4.5 billion cubic meters/year capacity in the TAP pipeline that will carry gas from the middle-eat under the Adriatic sea to Italy.
- The BBL pipeline launched an open season in May 2007 for expansion of a 3.2 billion cubic meter/year expansion of the line.
- In February 2007 energy utility RWE launched an open season for a new pipeline which will run from Sayda on the Czech border to Aachen on the Belgian border via Werne in western Germany.

South Hook LNG Terminal, Isle of Grain LNG Terminal and the North Adriatic (Rovigo) LNG Terminal. See http://ec.europa.eu/energy/infrastructure/infrastructure/gas/gas_exemptions_en.htm for details.

[18] See Platts EU Energy January 16 2009 p.24.

- In October 2005 French TSO GRTGaz launched an open season for additional capacity at the Obergailbach entry point in the north-east of France. GRTGaz said that it "needs appropriate market signals for investment".[19]

The European Commission believes that open seasons are a good way of testing market demand. In its guidelines for applying for an exemption from regulated tariffs, the Commission notes that "[m]arket demand is usually tested via so-called Open Season procedures"[20] and goes onto to cite the example of the Nabucco pipeline:

> "In the case of the Nabucco pipeline, for example, the project promoters have committed to the regular testing of market demand by performing open season procedures, thus making available to third parties additional transportation capacity to meet the effective demand."[21]

Open season processes are also common in North American jurisdictions when pipeline operators are seeking to obtain financial support and regulatory clearance for new or expanded capacity. An open season process in which a significant fraction of capacity receives commercial interest from third parties, via long-term contractual commitments that are binding if certain project pre-conditions are met, is usually required by banks and lenders who provide the underlying financial support for the project. At the same time, favourable open-season results provide objective evidence to regulators that the capacity is needed and will not be under-utilised, evidence which is usually required for the assets to be included in the rate base.

3.1 Demand Forecasting and Load

Unlike most countries in the EU and North America, Colombia does not have a large household gas-load. Most demand is from large industrial customers and gas-fired power stations. The absence of a large household gas-load means that the CREG can afford to be more 'hand-offs' with respect to infrastructure planning. A 'hands off' approach is more compatible with price cap regulation than revenue cap regulation.

In contrast, regulators in countries with a large household gas load are compelled to worry about security of supply and take a more active role in planning infrastructure, since a shortage of gas supply would lead to many unhappy voters and political consequences. For example the UK government has recently added security of supply to the energy regulators list of statutory duties.

We understand that there is a market for Compressed Natural Gas (CNG) in Colombia, and that CNG is used by taxi drivers who protest if the fuel is not available due to high gas demand

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[19] GRTGaz Press release.

[20] Commission staff working document on Article 22 of Directive 2003/55/EC concerning common rules for the internal market in natural gas and Article 7 of Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity, Brussels, 6.5.2009, Box 3.

[21] Ibid.

from power stations. However, taxi drivers are a relatively small, if vocal, group. It is not clear that expanding infrastructure to ensure constant gas supplies to the taxi drivers would be efficient.

Household heat-load also provides a steady source of demand. This makes central planning easier. Absent household gas load, it is also more difficult to forecast demand, which is more dependent on the performance of the economy and weather conditions. We understand that gas-fired power stations electricity supply depends drastically on weather and hydrology conditions in Colombia, and usually only run during dry seasons, like the ones that occur during the *El Niño* phenomenon. As a result, the annual percentage of electricity generated by gas-fired plant has varied from 5.43% to 39.46% over the last 10 years. This variation makes gas-demand highly volatile. The relative difficultly in forecasting gas demand in Colombia is another reason why avoiding a need for approval of gas infrastructure investments by the regulator would be advantageous.

4. Stranded Costs

We understand that 'stranded costs' is an important issue in Colombia at present. Gas transporters are apparently asking for compensation because outturn gas demand is less than was forecast, so that the current prices do not give an adequate return on investment.

We sympathise with claims for stranded costs where the risk was not known at the time of the investment. In the EU and the US there are various mechanisms to compensate energy market participants for stranded costs. Claims for stranded costs in the EU relate to changes as a result of market liberalisation in gas and electricity markets, that arguably could not have been foreseen when the investment was made. When the UK gas incumbent, then called British Gas was privatised in 1986 the prospectus claimed that it had an authorisation until 2009 as sole-supplier to about two-thirds of the market by volume. Clearly, this turned out not be the case. British Gas signed a number of long-term contracts in the early 1990s with power stations, which were later 'stranded' by the ability of producers to compete directly with British Gas and a fall in spot gas prices in GB. Until recently Spain had a mechanism in place to compensate privately-owned electricity generation companies that suffered stranded assets as a result of a liberalisation process that was not foreseen at the time the investments were made.

In the case of the claims for stranded assets in Colombia, the risk that demand could fall below the forecast level, and that prices would not fully adjust to compensate for this, was known to investors at the time that the investment decision was made. In such a case, allowing full cost recovery for 'stranded' pipelines would create an asymmetric risk, and violate the NPV test. The expected revenues would be greater than the investment costs.

This is because, assuming a 'symmetric' regulatory regime,[22] if the high demand case had materialised, the transporter would have enjoyed revenues in excess of its costs. But if the low

[22] By a symmetric regulatory regime, we mean a regime in which the higher revenues from a good outcome perfectly offset the lower revenues in a bad outcome, so that in expectation, revenues equal costs.

demand case materialises, the pipe becomes ‘stranded’ and consumers bear the costs. The result is that the downside risk is capped for the investor, and expected revenues exceed the costs. Such a regime would lead to excess investments in risky assets, with consumers bearing the costs.

In North America we have seen examples of ‘stranded’ pipelines filing for increased rates because of a reduction in gas demand. In 2006 Gas Transmission Northwest Corporation (GTN) filed for an increase in rates due to a reduction in demand. The GTN pipeline system extends from British Columbia in Canada to the Oregon-California border in the US. In its filing, GTN stated that:

> “the market in which GTN operates has undergone significant, fundamental changes, including an increase in pipeline capacity into GTN’s major market in California as well as an increase in pipeline capacity out of GTN’s major supply area …[t]he changing competitive landscape has left GTN with substantial unsubscribed capacity as a result of capacity turnback [where shippers do not renew expiring contracts] and shipper defaults, and GTN has been forced to drastically discount the price of capacity to meet competitive demands.”[23]

Since 2001, there had been several expansions of pipeline capacity to California – GTN’s destination market – and this competition had reduced the value of GTN’s capacity. In addition, gas supply in the basin where the GTN pipe originates had flattened out, and was projected to remain flat or decline in the coming years. GTN noted for a substantial amount of time capacity on its pipeline was worthless, since the price of transporting gas on GTN and upstream pipelines exceeded the difference between the price of gas in the supply and market areas. GTN sought to increase rates for the shippers that continued to use the pipeline under long-term contracts, to make up the revenue shortfall.

Similarly, in 1997 we are aware of a case where the El Paso Natural gas Company (El Paso) filed to increase its rates as a result of underutilisation of a major gas pipeline. The Federal Energy Regulatory Commission (FERC) noted that “[b]ecause there is a substantial excess of pipeline capacity serving El Paso’s market area (principally California), it is likely that this capacity will not be contracted for by replacement shippers at all, or will be subscribed at less than the maximum tariff rate.”[24] Once again, an increase in competition resulted in the partial stranding of a pipeline, which resulted in an increase in rates for the remaining users who were committed by long-term contract to use the pipeline.

In the case of the GTN and El Paso pipelines, there were grounds for a rate increase. This is because, as we explain above, the US regulatory regime approximates a revenue cap over the long-term. If demand had been much higher than forecast, then GTN’s customers would have brought a rate case and argued for lower tariffs. Denying US pipelines higher rates when demand falls would create an asymmetry and violate the NPV rule.

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[23] Gas Transmission Northwest Corporation Docket No. RP06-, June 30th 2006 pp.1-2. Principals of *The Brattle Group* gave testimony on GTN’s request in this case.

[24] GPM Gas Corporation v El Paso Natural Gas Company 79 FERC ¶61,028 (1997), p.8.

When considering stranded costs, the guiding rule is to maintain symmetry, so that investors get their money back in expectation. We understand that if demand rose unexpectedly, the transporter would be allowed to keep the increase in revenues. Therefore, when demand falls the transporter must also bear some of the losses.

5. Vertical integration

5.1 The Current Situation In Colombia

We understand that the following restrictions on vertical integration currently apply in Colombia:

- Vertical integration of producers and gas transporters is limited to a 25% shareholding of one in the other.
- Distributors may not own more than 25% of transporter companies;
- Distributors and marketers must be integrated, for purposes of supplying the regulated market.
- Companies which were vertically integrated prior to 1994 may remain vertically integrated.

Lines to the National Transport System

Producers could be allowed to build their own gas pipelines to the National Transport System. The risk is that a producer could subsequently deny access to third-parties. The benefits are that:

- The timing of the construction of the new line could fit better with the production of new gas. Accelerated gas development could lower prices and increase security of supply.
- The producer, rather than a third-party transporter, bears the risk of the investment. The producer has the best information regarding the likely production of the field, and is therefore best placed to bear the risk.

The CREG could oblige the producer to offer access to third-parties to his line, if they request it. In many ways the situation is analogous to pipelines for offshore production systems, which are owned by producers. For offshore pipeline systems there are mechanisms in place which allow third-parties to access the line under reasonable terms. For example, in the UK has an Infrastructure Code of Practice (ICOP) a non-statutory industry code which sets out principles and procedures to guide negotiated third-party access to oil and gas infrastructure, including pipelines to shore. The guidelines describe ‘fair and reasonable’ tariffs and terms. If the parties fail to reach an access agreement within 6 months, the matter is referred to the UK Secretary of State and a dispute resolution process begins.[25]

The CREG could encourage industry to adopt a similar set of guidelines, and specify in advance the methodology the CREG would use to set tariffs for third-parties if no settlement is reached. As we understand, given the limited number of production locations in Colombia and their geographic dispersion it could be relatively rare for a third-party to request access to a pipeline leading to the NTS.

5.2 Integration Between Gas Producers And Gas Transporters In The EU

Integration between gas producers and gas transporters – that is, where a gas supply buys all or part of the National Transport System – would be more problematic. Rather than a point-to-point pipe from a specific field to the NTS, ownership of the NTS itself would present a supplier with many more opportunities to prevent rival suppliers from connecting, or to disrupt service for its rivals in a bid to increase its market share or gas prices.

Vertical integration between pipelines and suppliers in the EU has been problematic. The second Gas Directive required pipelines and supply businesses to be legally and functionally separate and produce separate accounts, with the idea being that this would make cross-subsidies easier to detect. However, these measures proved insufficient to prevent pipelines discriminating against non-affiliated supply companies. The European Commission's 2007 sector inquiry identified vertical integration between suppliers and gas transporters as a major obstacle to gas market competition. The Commission's inquiry found that:

> "The operators of the network/infrastructure are suspected of favouring their own affiliates (discrimination). Vertical integration also leads to a situation where operational and investment decisions are not taken in the interest of network/infrastructure operations, but on the basis of the supply interests of the integrated company (including grid connection for competing power plants). This is highly damaging to security of supply."[26]

Subsequent to its inquiry, the Commission has brought specific complaints against GDF Suez and ENI, respectively the vertically integrated French and Italian gas incumbents, for attempting to foreclose markets by restricting access to gas import capacity. GdF Suez has since agreed to reduce its share of long-term import capacity to below 50% by 2014 and remain below 50% for at least 10 years. The case against ENI is ongoing.

As a result of its inquiry, the Commission tried to impose ownership separation, where gas suppliers would not be allowed to exercise control over gas pipelines and vice versa – non-controlling shareholdings would be allowed. This proposal met strong resistance from Member States with vertically integrated incumbents, notably France and Germany. In the end the EU

[25] Code of Practice on Access to Upstream Oil and Gas Infrastructure on the UK Continental Shelf , January 2009. Published by Oil & Gas UK, the trade association of oil and gas producers in the UK.

[26] DG Comp, Energy Sector Inquiry, pp. 7-8.

adopted a compromise solution of Independent Transmission Operators (ITOs) to solve the issues identified in the sector inquiry. The ITO concept involves much stricter separation rules than were previously in force. Some of the most significant new rules specify that:[27]

- The ITO must be able to make investment decisions independently of any affiliated supply business. The ITO should be able to raise its own funds for investments, or ‘contract out’ the construction of new infrastructure to third-parties. The ITO should comply with a 10-year network development plan approved by the regulator;
- Decisions regarding the appointment and renewal, working conditions (including remuneration), and termination of the term of office, of the persons responsible for the management and/or members of the administrative bodies of the ITO shall be taken by a Supervisory Body;
- The regulator must approve the identity of, and the conditions governing the term, the duration and the termination of office of the persons nominated as managers of the ITO.
- The regulatory authority may object if doubts arise as to the independence of a nominated person responsible. Te regulator may also object in the case of premature termination of a term of office, if doubts exist regarding the justification of such premature termination.
- Persons working for the ITO cannot have worked for the affiliated supply company for at least three years;
- Having left the ITO, managers cannot work for the affiliated supply company for at least four years;
- The remuneration of the staff of the ITO shall not depend on activities or results of the affiliated supply subsidiary.

The new rules – which must be transposed into national law by March 2012 – should address the two main problems with vertical integration in the EU: deliberate underinvestment by the pipeline company to favour supply affiliates; and control over pipeline affiliates by the supply affiliate or its parent through pay structure and staff transfers.

It remains to be seen if the use of ITOs and the new rules will be successful in the EU. However, there are grounds for optimism. Many of the rules are similar to those found in the US, which has a very successful and competitive gas market, even though there is vertical integration between suppliers and gas pipelines. The success of the US gas market despite vertical integration, is due to strict rules on how the pipelines handle the capacity of the affiliated supplier and its rivals.

5.3 Integration Between Gas Producers And Gas Transporters In Colombia

Colombia could allow vertical integration between suppliers/producers and gas transporters, and adopt similar non-discrimination rules to the US and the EU. However, we would not

[27] More details of the rules can be found in the so-called third-gas Directive, Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC.

recommend this. The rules are costly to implement and monitor, and there is no compelling argument to move from an unbundled structure to a market with vertical integration between suppliers and the NTS, or parts of it.

Both the US and the EU have allowed ‘controlled’ vertical integration because the industry in many countries in the EU and States in the US was vertically integrated to begin with. Unbundling the industry in the EU would have involved complex issues regarding property and investor rights. Accordingly, a compromise solution was reached.

This does not mean that an industry that is unbundled to begin with should become vertically integrated. Most economists would agree that keeping the network part of the business separate is the best structure. In a 2007 paper, we noted that no one who believes in competition has identified a compelling synergy between the ownership of transmission infrastructure and the ownership of supply activities.[28]

Long term contracts between the shipper and the transporter could achieve similar risk allocation to vertical integration, but without the disadvantages that vertical integration has for competition. Under a long-term contract, the producer/supplier could fix the amount it pays for gas transportation capacity. The producer would bear the volume risk. If production volumes fell below what was anticipated, the producer would pay a relatively high unit transport cost per unit of gas transported.

As we understand it, under the current scheme the transporter bears some of the volume risk. The transporter must make demand scenarios with associated probabilities. If a low demand scenario materialises, the transporter will not recover the full investment costs. Some of the main risks for gas transport in Colombia are the changes in production from gas fields, and changes in gas flows because of new fields coming on line. The producer is in the best position to assess both these risks. The producer has access to technical information on the field’s production characteristics which indicate how the field will decline. Most producers should have a detailed model of the reservoir which predicts future production rates. Similarly, a party active in upstream gas production is in the best position to judge the likelihood of other new gas fields coming on stream.

In some industries it is difficult to create contracts which cover all risks and eventualities. In these cases vertical integration may be the best response. This is not the case in the gas industry. It is possible to write long-term contracts for gas transportation which cover all the material issues that could arise.

The producer could share some of the risks with customers. As we noted above, in Colombia the majority of demand is from large users – industrial processes and power stations. These kind of large sophisticated buyers are in a position to be able to sign long-term contracts for gas, which include a commitment to pay for the transport capacity. The willingness of producers or gas users

[28] See ‘The Costs of Moving to a Perfect World: Forced Ownership Unbundling in the Natural Gas and Electricity Sectors’ by Carlos Lapuerta, *The Brattle Group*, September 2007. Presented at the Fordham anti trust conference in New York, 2007.

to sign long-term contracts to support new pipeline investment is a strong signal the investment is worthwhile. It avoids the regulator having to make a decision as to the validity of the investment.

Appendix: Long term entry capacity auctions in Great Britain

Long term auctions of entry capacity were introduced in Great Britain (GB) to provide stronger incentives for efficient investment in the national transmission system (NTS). It should be noted, however, that the information from long term auctions has not completely replaced more traditional forecasting methods for capacity expansions, rather it is used to refine them.

The idea of long term auctions was first raised in May 2000 and the proposals were given legal force as part of the set of licence changes required to implement Transco's five year price control from April 2002. From the outset the intention was to reduce the risk of stranded investments in the NTS. For example (and as quoted earlier), when the GB regulator Ofgem confirmed its intention to introduce long term auctions in December 2002, the Deputy Director General said:

> *"Ofgem believes that there is a need for better incentives on Transco to invest efficiently in NTS capacity in a timely manner. The longer term auctions being proposed will provide Transco with better information on the market value of capacity. The new incentives will encourage Transco to respond to these signals by investing where it is efficient to do so. This should lead to an NTS that meets customer requirements and facilitates competition, to the ultimate benefit of all customers".*[29]

The introduction of long term auctions was felt to be particularly timely as it was becoming increasingly difficult for Transco to forecast where gas was likely to enter the NTS in the future and yet different flow patterns implied very different investment requirements. For example, inflows in Scotland (St Fergus) would necessitate far greater investment that additional inflows in the east of England e.g. Bacton. Consequently, being able to take account of long term capacity commitments was seen as an important safeguard against stranded investments.

Under this system, Transco (now NGG) has to have received strong market signals, in the form of long-term commitments, before it builds new entry capacity. This requirement significantly reduces the risk that Transco will build capacity that becomes stranded. Moreover, if it does build capacity that is stranded, the system significantly reduces the exposure of British consumers:[30] Ofgem can (and has) used information from long-term auctions to decide that certain investments should not be guaranteed a return, because of the lack of supporting commitments from shippers. For example, in the 2002-2007 price control period, Ofgem did not allow £17 million of transmission capital expenditure undertaken by Transco at the St Fergus

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[29] Press release R/132 Thursday 7 December 2000.

[30] As we explain in greater detail later on, Ofgem will only approve incremental capacity expenditure if at least 50% of the costs are covered by user commitments in the form of long term purchases of entry capacity. Consequently, such investments can only be partially stranded and hence consumers bear only some of the risk.

entry point to be included in its regulated asset base for the next price control.[31] This is equivalent to 3.6% of the total allowed capital expenditure on entry points. The basis for this decision was a lack of market signals of a need for additional capacity at this entry point, as indicated by the results of long-term entry capacity auctions.

At high level, the system works as follows.

1. Transco agrees with the regulator a minimum "baseline" amount of entry capacity that will be available at each entry point throughout the period of the auction.
2. Each year, it then holds an auction, or "open season" process, where it asks shippers to commit to buying capacity at each entry point, for dates up to sixteen years in the future, at pre-specified prices.[32]
3. It builds new capacity if the total commitments it receives from shippers for that capacity, out to the sixteen year time horizon, have a present value greater than 50% of the costs of that new capacity.

How much long term capacity is made available is determined from the interaction of:

- the long term auctions (which define the demand for capacity);
- the price control process (which defines the minimum – baseline – level of capacity that has to be made available and the price that can be charged for increments of capacity at each entry point); and
- the application of the "incremental entry capacity release" (IECR release) methodology (which determines what level of capacity has to be made available on the basis of the demand signals coming from the auctions – the "obligated incremental capacity").

Below, we describe each of these elements.

Long term auctions

The system currently works as follows:

1. The long term auctions (for quarterly strips of capacity) run from two calendar years (CY) after the auction is held for 14 years (i.e., from CY+2 to CY+16). For example, in the September 2008 auction, the period for which capacity was made available was April 2010 (CY+2) to Mar 2025 (CY+16). No incremental capacity has to be released before 42 months after the auction date i.e. for the September 2008 auction, incremental capacity release only has to be considered from April 2012.
2. In advance of the auction, NGG[33] publishes the level of capacity available at different prices for each entry point, starting from the baseline level it is required

[31] Transmission Price Control Review - Final Proposals, Ofgem, 4 December 2006 p.33. Capital expenditure of £475.9 million is Transco's load-related entry capacity capex between 2002 and 2006 inclusive. Although £19 million was disallowed, £2 million of this disallowance was due to inefficient contracting strategy. Since entry auctions were not responsible for identifying this inefficiency we do not include the £2 million in our estimate above.

[32] The price depends on the entry point and the total amount of capacity that NGG guarantees to make available.

[33] Transco is now known as National Grid Gas NTS.

to make available (see below). These pairs of prices and capacities are known as "price steps" and there can be up to 22 price steps for each entry point. The price steps must show an increase in both capacity and demand between each step. The capacity above the baseline included in the auction must equal the smaller of 150% of the baseline capacity and the obligated incremental capacity determined by the application of the incremental entry capacity release methodology.

3. Shippers submit a matrix specifying how much capacity they would be willing to purchase at each price level for each quarter and entry point. Bids for capacity must decrease with increasing price i.e. the combination of a bid for 30 GWh at a price of 0.02 p/GWh/day and one for 35 GWh at 0.03 p/GWh/day cannot be accepted.
4. The clearing price for each quarter/entry point combination is determined from the price step at which the demand for capacity is first less than or equal to the baseline level of capacity.
5. The results of the auction are published and shippers are allowed to revise their bids. This process is repeated up to 10 times: it will stop earlier if the clearing prices for four or less quarter/entry point combinations have not changed between one round and the next.

Incremental Entry Capacity Release (IECR) Methodology

NGG NTS is obliged to publish a statement explaining how it will determine whether or not to release incremental entry capacity. This statement has to be approved by Ofgem.[34]

The methodology is best illustrated by an example. Consider the situation shown in **Table 1** below. The top half of the table shows the capacity and price steps associated with the auction at a particular entry point, together with the bids submitted for capacity at each price level. The first step in the methodology is to identify the first quarter in which demand matches or exceeds supply (available capacity) at a price step. The IEC test level is set by the capacity above the baseline for which this test is met. In the example, the test level is 30 GWh (130-100 GWh) at price step 3 in Q3. This determines the maximum capacity to be release in this iteration.

Table 1: Example of the IEC release methodology

Price step	Available capacity (GWh)	Price (p/kWh/day)	Estimated project cost (£m)	Demand = bids submitted (GWh) Q1	Q2	Q3	Q4	Q5	Q9	Q34
5	150	0.06	20	90	95	120	120	110	100	100
4	140	0.05	16	90	95	120	120	110	100	100
3	130	0.04	12	90	95	130	130	120	100	100
2	120	0.03	8	90	95	135	135	120	110	100
1	110	0.02	4	90	95	140	135	130	120	100
Baseline	100	0.01	0	90	95	145	140	131	131	100
Capacity to release (GWh)				0	0	30	30	30	20	0
Clearing price (p/kWh/day)						0.04	0.04	0.02	0.02	0
Incremental revenue (£m)						1.09	1.09	0.55	0.36	0.00

Choose lowest step where demand <= test level

Find 1st quarter where demand >= available capacity for a price step

[34] The current methodology statement can be found on the National Grid website at www.nationalgrid.com/uk/Gas/Charges/statements/.

For the subsequent 31 quarters i.e. out to Q34, the capacity to release is determined from the lowest price step where the demand is less than or equal to the test level. Thus, in the example, the trigger price step in Q5 is step 1 (30 GWh). The capacity assumed to be released is shown in the bottom half of the table.

The incremental revenue associated with releasing this capacity is determined by multiplying the clearing price i.e. the price for the chosen step, in each quarter by the capacity that would be released. In our example, the clearing price (also shown in the bottom half of the table) is 0.04 p/GWh/day for Q3 and Q4 and 0.02 p/GWh/day for Q5 and Q9. The net present value of these revenues is then compared to the estimated cost for releasing the capacity. In our example, this is £12m because the capacity release starts at the third price step. If the NPV of the incremental revenue exceeds 50% of the projected costs i.e. £6m then the capacity has to be released.

If the NPV test is failed, then the process is repeated taking the maximum capacity to be released from the preceding price step i.e. 20 GWh at step 2. If the NPV test is failed for all the price steps in a particular quarter, the analysis moves on to start at the next quarter e.g. 30 GWh at step 3 in Q4. The process is repeated until all the steps of each quarter have been tested.