Designing and Structuring the Secondary Market, Short-term Markets and their Management Mechanisms

Task 4 Report

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1. Introduction

The Comisión de Regulación de Energía y Gas (CREG) has retained *Market Analysis* and *The Brattle Group* to advise on the design of secondary markets for the trading of gas and gas transport capacity in Colombia, and their management mechanisms. Our first substantive report addressed Tasks 2 and 3 of the project, introducing the relevant analytical framework and international experience.[1] This second report, responding to Task 4, describes and considers different options for developing secondary and short-term markets for gas and transport capacity in Colombia.

Specifically, Task 4 requires us to identify possible combinations of natural gas physical markets that might be developed in Colombia, and to consider how short-term and secondary markets for gas and transport will interact with primary markets. We are also required to consider the likely participants, the pros and cons of adopting any particular combination of markets, and the role of the government in facilitating the development of, or organizing, these markets.

This report does not make specific recommendations, but rather defines objectives and criteria to assess the pros and cons of the alternatives identified. Following further consultations with the CREG and the industry, a subsequent report (Task 5) will make recommendations on the most appropriate markets and their management mechanisms.

We have organized this report as follows. Section 2 introduces key policy and design objectives for short-term and secondary markets Section 3 describes alternative secondary market designs. Section 4 briefly discusses balancing issues. Section 5 concludes.

2. Policy and Market Design Objectives

A central objective of energy policy is to provide incentives to promote and improve both short-term allocative and productive economic efficiency (i.e. the most efficient use of existing assets, infrastructure and supply sources), and longer term investment and location decisions.

Secondary and short-term markets can help to promote efficiency by facilitating trade between willing market participants (i.e. reducing transactions costs), improving market liquidity, and by providing reliable price signals for both short-term production and consumption as well as for longer-term investment decisions. They can also improve market competitiveness by "levelling the playing field" for smaller traders and new entrants, allowing them to trade with the "market" rather than having to negotiate with large incumbents, guaranteeing them the ability to purchase or sell on the same terms as every other trader in the market.

Alternative secondary market designs can be evaluated by reference to a number of features or attributes which are important for market efficiency, in particular: information provision and transparency; liquidity; market competitiveness; and coordination of purchase of gas and transport capacity. When introducing new market designs it is also important to consider transition and other (e.g. ongoing) costs.

Information: Transparent and open markets facilitate efficient trading by providing information on prices, resource availability and potential trading partners. By making the same information equally available to all market participants, they also help smaller traders and new entrants by relieving them of the burden of information acquisition, which will typically be less costly for larger firms.

Liquidity: A key challenge in the natural gas markets around the world (addressed most successfully in Europe and the United States) has been to achieve sufficient market liquidity. Thin markets make efficient trades more difficult to achieve for participants and

1 "Designing and Structuring the Secondary Market, Short-Term Markets and Their Management Mechanisms, Task 2 & 3 Report," 17 February 2011, Market Analysis (David Harbord and Marco Pagnozzi) and The Brattle Group (Paul Carpenter, Dan Harris and David Robinson).

reduce the reliability of price signals. A liquid market with active trading will provide price signals that better reflect the balance of supply and demand than a market with more limited trading. They also frequently provide reference prices for longer-term contracts.

As we explained in our Task 2&3 report, liquidity increases with the number of traders, the frequency of trading, the narrowness of the buy-sell spread and the range of products. Features which tend to increase liquidity are the standardization of contracts and trading arrangements with good information provision and low transactions costs.

Market competitiveness: Large, or dominant players, in a market can discourage efficient trade and consumption in a number of ways. A dominant gas producer may, for example, impose restrictions in their supply contracts which lock in prices that do not reflect the short-term economic value of the commodity, prevent efficient trading from taking place and discourage efficiency in the day-to-day use of the resource. Pipeline monopolies may impose similar restrictions on the resale of capacity rights. Even when secondary trading is not openly restricted in this way, traders may be reluctant to use markets where prices can be manipulated by dominant companies, acting either independently or collusively. Large firms may use informational advantages obtained from their dominant market positions to discourage secondary trading by smaller players for instance.[2] A key issue in secondary market design and regulation is whether and how to restrict the activities of large or dominant firms in secondary market trading.

Coordination between gas supply and transport: To participate in gas market trading, sellers need to acquire rights to transport gas to the point where it is sold, and buyers require transport capacity rights to take the gas away. Accordingly, there is a crucial link between the availability and management of gas transport capacity, and the liquidity of trading in secondary markets. As discussed in our previous report, liquid secondary markets have developed internationally with both point-to-point transportation contracts (in the USA) and with an entry/exit contracts (in Europe). Simultaneous secondary trading of gas transport capacity may facilitate secondary gas trading in point-to-point systems. In an entry-exit system there is less need to trade capacity since once gas is injected into the system, it is available to all buyers and there is no need to buy capacity that will transport the gas to a specific location in the network. The design of trading arrangements for commodities and transport capacity needs to be consistent and mutually reinforcing.

Transition costs: Changes in market design or regulation potentially create three types of transition costs. First, the tangible costs required for investment in the new market design, for example the creation of new organisations, hardware or IT systems. Second, the costs associated with reallocating rights and obligations under existing long-term contracts, and at the extreme the risk of creating stranded contracts and investments. Third, the possible increase in perceived regulatory risk. Gas production and transmission involve long-term, irreversible investments, the economic value of which are vulnerable to changes in regulatory rules. Rapid or ill-thought out changes in the market rules can result in market participants becoming reluctant to make large new investments, which can increase costs and prices and may reduce security of supply.[3] On the other hand, dominant firms frequently argue for very long transition periods prior to the introduction of market rules or regulations designed to protect consumers, increase competition and curb the exercise of market power.

On-going costs. New market arrangements may imply higher costs, for example if market participants are required to frequently report large amounts of detailed information on their trading activities to the regulator, or to pay for the running of new organisations. Any ongoing costs should obviously be proportional to the ongoing benefits.

Any new market designs for short-term and secondary markets should be evaluated, or assessed, against these general criteria.

2 For example, some Colombian shippers have complained that producers' contracts require them to provide information on their secondary market transactions, potentially placing the producers at a competitive advantage.

3 The recently announced tax increase on North Sea oil producers in the UK has reportedly resulted in the cancellation of a number of investments, for example.

2.1 The Current Situation in Colombia

There are currently no organized markets for secondary or short-term trading of gas or transport capacity in Colombia. Nor are there any organized methods for collecting and disseminating information on such trading activities, which occur on a private, bilateral basis. Nevertheless, a significant amount of secondary market trading does take place, mostly driven by the need for gas-fired power plants to resell gas and transport capacity purchased under firm contracts for the firm energy market. Approximately 45% of Colombia's available gas is purchased by power plants for the firm energy market and is available for resale. Some power companies (such as Colinversiones) sell most of their surplus gas in conditional firm contracts, while others (such as Isagen) sell only 10-15% this way, and the rest in shorter-term transactions.[4] The Bogota distribution company GasNatural told us that it purchases up to 20% of its gas supply requirements in the secondary market from the gas-fired power plants.

There appears to be a clear demand for the creation of more organized markets or trading platforms for gas and transport from both producers and consumers in Colombia. Producers, for instance, have argued for need for more transparent information on market transactions and transport capacity availability, and for improved supply-transportation coordination. Other companies argue for organized and administered short-term and secondary markets, which exclude or limit the participation of the large producers. While there is currently no consensus on the exact market reforms required, most if not all market participants in Colombia appear to believe that their trading opportunities will be improved by greater market transparency and organization of one type or another.

The purpose of the following section is to present a number of 'nested' reform options, or 'market designs', for introducing more transparent and efficient short-term and secondary markets in Colombia. These options or proposals do not contain all of the detail that would be required for their implementation, but are intended to delineate the main alternatives and identify the key changes required for their adoption. Nor at this stage are we attempting to specify how they would be made compatible with existing legislation and regulations, such as the RUT and draft ministerial decree of March 2011.

3. Alternative Market Designs

In this section we describe several alternative approaches to developing more transparent and liquid short-term and secondary markets for gas and transport capacity in Colombia. These are presented as a number of 'nested' reform options, or policy packages, involving increasing degrees of regulatory intervention, organization and changes to the status quo.

The reform options described in this section are:

- Option 1: *Gradual Market Evolution.*
- Option 2: *OTC Trading and Development of Trading Points*
- Option 3: *A Gas Exchange*
- Option 4: *A Single Trading Point or Physical "Hub"*
- Option 5: *Entry-Exit Charges and a Virtual Trading Point*

We describe each of these options in turn.

4 Isagen has recently introduced daily "Subastagas" auctions for 24 hour firm gas and transport contracts.

3.1 Option 1: Gradual Market Evolution

Under this first option, the CREG would not establish any new formal market mechanisms, but rather take steps to promote the growth and development of existing bilateral trading activities. Gas supply or commodity contracts in secondary and short-term markets would be standardized to make bilateral trading more practical and allow fast, low-cost bilateral trades to take place. By standardized contracts, we mean:

- the basic terms and conditions of all contracts would be identical[5]
- there would be a menu of standard contract durations and start dates - for example a within-day gas product, a day-ahead product, week-ahead, month-ahead, quarter-ahead and possibly longer-term contracts

Contracts for a given standard duration and start date would therefore only need to specify the counter parties, the price, the quantity and the delivery point. The products could be specified following consultation with industry, and new standardized products could be introduced over time. However, there would be no product standardization with respect to the delivery point, and gas buyers and sellers would be free *to deliver and receive gas at any point in the network.* Accordingly, gas buyers and sellers would simultaneously need to procure gas transport capacity to either move the gas to the point of sale or transport the gas away from the point of sale. With respect to transport, the existing form of point-to-point capacity contracts would remain.

The Subastagas auctions, or any other bilateral selling arrangement, would continue as today except that the products sold might be standardized. Standardization of the products would likely make the auction more popular as it would be easier to re-sell any gas bought on the secondary or short-term market.

A Market Operator (MO) would be established whose role would be limited to publishing aggregate data on the volumes and prices of secondary market trades in gas.[6] The network code, or other suitable instrument, would require all traders to report to the MO, on a daily basis, details of their secondary market transactions, including the volumes of gas purchased or sold, the counter-parties and the agreed prices. The MO would then publish prices and volumes traded for each type of standardized contract, but not identify individual transactions. The MO might also be made responsible for announcing any market-sensitive news, such as the outage of a pipeline or a production facility, that could affect prices. No other parties would be allowed to announce such news before the MO had done so.

The TSOs would continue to maintain their electronic bulletin boards (BEOs) in which they publish information to facilitate trading in transport capacity. Specifically, information on unsold primary capacity and also on capacity that has been sold but not nominated (if not provided already), and so could be re-sold to third parties on a short-term or interruptible basis. The requirement that shippers notify TSOs of secondary market transactions in transport capacity should be clarified or enforced. TSOs might also then be made responsible for publishing aggregate data on these transactions on their electronic bulletin boards.[7]

The current balancing regime operated by the TSOs would remain as it is, with shippers balancing on each pipeline separately. However, the TSOs should be required to inform

5 These will be determined by the results of the companion study on standardizing contracts by Auctionomics and FTI Consulting.

6 The draft ministerial decree of March 2011, Capitulo 3, appears to provide for the establishment of a market operator (Gestor del Mercado de Gas Natural) with many of the functions or responsibilities we are suggesting here.

7 An alternative would be to have the MO take over these information dissemination functions from the TSOs, which seems to be provided for in the draft ministerial decree of March 2011. The RUT (Reglamento Único de Transporte), established by the Resolution 071 of 1999, contains many of the elements required for both the MO and/or the TSOs to carry out the functions we suggest here. However, our understanding is that not all of the information reporting and dissemination provided for in the RUT has been implemented.

shippers about their balancing positions in as close to real time as possible to enable them to correct any imbalances by trading before the end of the balancing period.

3.2 Option 2: OTC Trading and Development of Trading Points

Option 2 maintains all of the features of Option 1, but introduces regulations designed to encourage the development of more liquid and transparent OTC trading in a number of ways:

1. The delivery points of the contracts would be partially standardized, so that all secondary gas contracts would specify delivery at one of three or four locations where most gas is already traded – for example Ballena, Cusiana, La Creciente, and perhaps Barranca.[8]
2. The MO would be instructed to create a bulletin board where traders could make bids and offers for the standardized gas products. Traders would be able to see the identity of the party offering to sell or bidding to buy gas, the volumes involved, the delivery point, the duration and the price bid or offered. The MO would aggregate and publish on at least a daily basis the prices of the main gas products and the volumes that had been traded.
3. Transport capacity would be sold simultaneously with gas contracts either on the same bulletin board, or on a complementary bulletin board. As above, traders would be able to see the identity of the party offering to sell or buy, the quantities offered, duration and the price bid or offered. The MO would aggregate and publish on a daily basis the prices and the volumes that have been traded.[9]

Any registered shipper that is licensed to transport gas could participate on the OTC markets by using the bulletin boards, or ‘OTC trading platforms’, and market participants would be responsible for making their own checks as to the quality and creditworthiness of their counter parties. Agreed trades would be financially settled directly by the parties involved. [10]

The CREG could stimulate liquidity on the OTC trading platform by mandating a major market player, such as Ecopetrol, to act as a market maker and/or by mandating the sale of specific volumes of gas, e.g. ‘royalty' gas, on the OTC platform. As described in our Tasks 2&3 report, pp. 9-10, the market maker might be obliged to offer to sell a minimum volume of gas at an advertised price every day while simultaneously bidding to buy gas at a lower price. The bid-ask spread of the market maker could be capped to provide strong incentives for market maker to attempt to “bracket” the “real” market price. The market maker could support trading in the main standardized gas contract categories.

There are precedents for regulators requiring a party to act as a market maker to address concerns over market liquidity. For example, in Denmark DONG Energy and Energi Danmark have committed to act as market makers in the electricity market, and there is a mandatory market-maker role in the electricity market of New Zealand. British Gas, the incumbent in the GB gas market, was appointed as a market maker in the earlier years of GB gas market liberalization. Ofgas, the gas sector regulator at the time, fixed the

8 Ballena potentially includes two delivery points – one for the TGI system and another for the Promigas system. An important issue is whether it is feasible to connect the two systems so that a single delivery point is created, facilitating trade between the two networks. Frontier Economics proposed creating two hubs – one at Vasconia and another in Cartagena – which would have the effect of reducing the number of contract delivery points from three or four to two. We discuss the possible creation of single physical hub in Section 3.4 below.

9 An open question is whether the TSOs should post information on their available primary capacity on the MO's trading platform or whether the two types of trading activity should be kept separate. It would appear most sensible for the TSO's to post offers to sell primary transport capacity at regulated prices on the same bulletin board or platform as other traders.

10 Annex 1 describes the information flows and responsibilities of traders, the MO and the TSOs in implementing secondary market transactions.

difference or spread between British Gas's buy and sell offers. Recently, Ofgem (Ofgas's successor and regulator of GB gas and electricity markets) has proposed a Mandatory Market Maker (MMM) role to stimulate liquidity in the GB electricity market. The incumbent electricity supply companies – the so-called Big 6 – would be required to offer volumes for a range of electricity products and Ofgem would approve the bid-offer spreads.[11]

Balancing on the transport networks would be as it is today, with shippers' imbalances being measured on each pipeline on a daily basis. The pipeline operators, not the MO, would be responsible for balancing their own pipelines and administering imbalance charges. However, a more liquid physical market where within-day gas products are traded would make it easier for shippers to resolve their imbalance positions themselves through trading.[12]

An important issue is whether secondary trading using the OTC trading platform would be voluntary or mandatory. If trading on the OTC platform was mandatory, the Subastagas auctions, or any other bilateral selling arrangement outside of the trading platform, would no longer be permitted.[13]

If the OTC market is well-designed, it should be attractive to market participants in its own right, so mandatory participation may be neither necessary or desirable. It could be argued that making the OTC platform mandatory would create a trading platform monopoly that might stifle innovation and service quality improvements. On the other hand, market liquidity and transparency would obviously be increased if all trading occurred on a single platform.

A related issue is the extent to which producers would be allowed to participate by trading on the OTC platform, and if so for which products. Producers might be limited to trading only very short-term products for example, but prohibited from offering longer-term contracts. If a producer such as Ecopetrol is to play the role of "market maker" then obviously some producer participation will be required. The short-term secondary market may also be the obvious place for producers to dispose of any production not sold under longer-term contracts in the primary auctions.[14]

3.3 Option 3: A Gas Exchange

Option 3 is identical to Option 2 as described above, but with the addition of a trading exchange, which may or may not replace the OTC trading platform. Trades at the exchange would be cleared, meaning that a central clearing house would act as the counter party to each trade. For example, when shipper A purchases gas for delivery at Ballena the next day,[15] he will not know who the seller is, but the MO would know that shipper A had a right to withdraw the contracted amount of gas at Ballena the next day. Similarly, the MO will know which sellers have an obligation to deliver a matching volume of gas at Ballena during the same period (see Annex 1). One advantage of this anonymity is that it can help protect commercial confidentiality.

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11 For details see Ofgem, The Retail Market Review - Findings and initial proposals," Supplementary appendices, 21 March 2011, Table 2 p.30.

12 The connection of the two main pipeline networks at Ballena could also potentially facilitate the trading of imbalance positions. For example, a shipper who was long on the TGI gas system could sell to a shipper who was short on the Promigas system, neutralizing the imbalance.

13 An interesting possibility would be adopt the Subastagas auctions as a model for secondary trading, by making the OTC market a series of hourly auctions for example, but with a wider variety of products than are currently traded.

14 See "Designing and Structuring Auctions for Firm and Interruptible Gas Supply Contracts in Colombia: Tasks 1 & 2 Report," 22 April 2011.

15 Again, the products traded on the exchange might need to distinguish two delivery points at Ballena unless and until the two pipeline networks are interconnected.

The MO of the gas system could sub-contract or delegate the running of the exchange to a third party, as many MOs do in the EU. The delegation of the operation of the exchange would add another communication step – as the exchange operator would notify the MO of the net results of trades done for the next day. But it would not change the example given above.

Only members of the exchange could trade, and to become a member applicants would need to reach some minimum credit standard. Traders would also need to post collateral – in the form of cash guarantees – to support the difference between the agreed price of a forward product (e.g. a quarter-ahead contract) and the current market value of that forward product. The requirements for posting collateral would be determined on a daily basis by the MO (or the exchange operator), based on an assessment of current market prices. The exchange could operate in parallel to the OTC trading platform or, if most traders were willing and qualified to trade on the exchange, the OTC platform could be abandoned in place of the exchange.[16]

Trading on the exchange would likely be continuous, but it would also be possible to organize trading in a series hourly auctions. For a brief discussion of continuous trading versus periodic auctions see our Tasks 2&3 report, p. 9.

The exchange would publish the prices and volumes of each of the products traded each day. The same variety of products could be traded on the exchange as on the OTC market, although international experience suggests that initially only shorter-term (e.g. day-ahead and week-ahead) products might be traded. As liquidity on the exchange developed longer-term products could be introduced.

3.4 Option 4: A Single Trading Point or Physical "Hub"

The options described above all involve trading contracts with delivery points at multiple locations, i.e. Ballena (on both the TGI and Promigas systems), Cusiana, La Creciente and Vasconia. As we noted in our Tasks 2&3 report, a main objective of gas market design is to to promote more liquid trading. This could potentially be done by concentrating buying and selling activity at a single location, or trading point, to avoid splitting trading activity over several delivery points. Of key importance is that introducing a single trading point, which can be done either by specifying a single, physical "hub", or by trading gas supply contracts which do not specify a particular location or field, significantly simplifies certain types of "swap" transactions which can increase market efficiency and the gains from trade. We describe two alternative options for doing this here.

3.4.1 A physical hub and 'back-haul' contracts

By a physical hub we mean a particular location in the pipeline network which becomes the 'delivery point' specified in all secondary market gas contracts. The most obvious locations for a physical hub in Colombia would be either Ballena (where gas can be delivered into both of the main pipeline networks), or Vasconia (where the two main branches of the TGI system interconnect). The introduction of a hub immediately raises the issue of how producers at other locations would put their gas there if they are 'downstream' of it. For example, if there was a single hub at Ballena, how would producers at Cusiana sell their gas there?

One solution is to introduce a so-called 'back-haul' capacity product, which would enable a producer to nominate to 'transport' gas against the physical flow of gas – in this example from Cusiana to Ballena.

We illustrate how back haul would work in practice with a simple example. Assume that total interior demand is 10 units, and that 8 units of gas come onshore at Ballena from the Guajira fields (we assume no north coast demand for the purposes of this example). Assume also that the pipeline from Ballena to the interior has a capacity of 8 units. If a

16 See our Task 2&3 report for a more detailed discussion.

producer at Cusiana wants to sell 2 units of gas at Ballena, it will need to purchase 2 units of 'back-haul' capacity on the TGI network from Cusiana to Ballena. 10 units of gas would then be sold at Ballena – the 8 units from Guajira and 2 units of 'back-haul' gas from Cusiana. The interior buyers would then need to buy 10 units of transport capacity from Ballena to the interior. The TGI could sell 10 units of capacity from Ballena to the interior, because it nets off the back-haul nomination of 2 from the north to south demand of 10 – leaving a physical flow from Ballena to inland of 8. Physically of course, only 8 units of gas would flow south from Ballena to the interior, where it would be joined by the additional 2 units of gas from the Cusiana field.

It can reasonably be asked, what is the point of 'pretending' to transport gas north from Cusiana to Ballena and then south from Ballena the interior, when gas is not physically flowing in this way. One advantage is that the back-haul product makes it possible for all gas to be traded at a single location, which avoids splitting trading between multiple locations and reducing market liquidity. Another is that back haul makes it much easier for a party with gas at Cusiana to sell gas to a buyer on the Atlantic coast, by facilitating so-called 'swap' transactions.

Without the back-haul product, a Cusiana producer – or a customer buying gas at Cusiana - that wished to sell some or all of the gas – will find it difficult to sell gas to a customer on the Atlantic coast, for example in Cartagena. A seller at Cusiana could only sell to a buyer in Cartagena by arranging swaps involving one or more other buyers. For example, the seller would need to identify a party in Bogotá that was buying gas at Ballena and then arrange a swap, whereby Cusiana gas is physically delivered to the customer in Bogotá for the price agreed with the seller in Ballena ($4.00 per MBTUD for example). The customer Bogota would then need to sell his gas for delivery in Ballena to the customer in Cartagena at the same price. Finally, a side-payment would need to be arranged between the Cusiana seller and the Cartagena buyer if their agreed price were different (e.g. $3.00 per MBTUD).

Such transactions are clearly complex to arrange, and could involve organizing swaps between many buyers and sellers simultaneously, e.g. selling 100 units of gas to the buyer in Cartagena could involve arranging swap transactions with 4 customers in Bogota, each of which was purchasing 25 units of gas from Ballena. They also require the Bogota customers to purchase transport capacity from Cusiana and to sell Ballena-Bogota capacity, if possible. Such complexity can mean that efficient trades do not occur, for instance when satisfying demand on the North Coast requires that customers in the Interior swap gas from Guajira for gas from Cusiana.

The physical hub and back-haul product simplifies these transactions by effectively having the MO make the swaps on behalf of the buyers and sellers. All transactions are carried out at the Ballena hub at the agreed prices, and there is no need for the parties to the transactions to arrange swaps. The MO will ensure that the physical delivery of the gas matches traders' contractual positions in gas and transport, e.g. from Cusiana to Bogotá and from Ballena to Cartagena.

Defining a single physical hub combined with back-haul products can thus increase liquidity and facilitate efficient transactions. However, it reduces the cost reflectivity of, and is largely inconsistent with, point-to-point gas transport charges. For example, shippers in Bogota who are actually receiving gas from Cusiana need to purchase transport capacity from Ballena, even though their gas is physically travelling a shorter distance.[17] It also raises the issue of how to price back-haul capacity, which does not involve any physical flows and is costless. There is no international consensus on the pricing of back-haul products, and they are typically priced at some arbitrary fraction of forward capacity.[18]

17 Note that the price of transport capacity from Ballena to inland should reduce in the example above, because of backhaul there are now 10 units of capacity for sale, which means the fixed cost of the pipe will be spread over a larger amount of capacity, reducing the unit price.

18 While backhaul may seem like a strange product, its importance in facilitating transactions has been recognised in the EU. The European Commission has begun infringement proceedings against several Member States for failing to offer interruptible reverse flow capacity (backhaul) at all cross-border interconnection points.

Note that in other markets this issue – where sellers have access to only a subset of customers absent a back-haul product – is of less significance. In the EU, capacity is sold under entry exit systems, so that any seller can sell to any buyer without the need to buy additional transport capacity or a back-haul product (see Section 4 of our Tasks 2&3 report). Back-haul products are only needed for gas transactions between separate entry-exit systems. In the US, most producing fields are upstream of demand, unlike in Colombia, where a significant source of gas production – Cusiana – is downstream of a large number of customers on the the Atlantic coast.

3.4.2 Non-location specific products

An arguably simpler way to improve market liquidity and facilitate efficient swap transactions would be for the products traded in an exchange to simply specify quantities, durations and prices, but not a delivery point (a similar idea is presented in Section 5.1. of Designing and Structuring Auctions for Firm and Interruptible Gas Supply Contracts in Colombia: Tasks 1 & 2 Report," 22 April 2011). This is essentially equivalent to specifying a single but "virtual" trading point. This would mean that buyers of gas in the exchange[19] would be forced to commit to purchasing supply contracts before knowing which field the gas was coming from. As in the auctions' proposal, buyers would then be allocated gas *ex post* from different fields and the MO would be responsible for ensuring the feasibility of the allocations. Buyers would subsequently need to ensure they had sufficient transport capacity from each field to the point of consumption.

While this market arrangement may be simpler than introducing physical hubs and back-haul products, and is more consistent with the current point-to-point system of transport tariffs, it also has drawbacks. In particular, it forces buyers to purchase gas contracts prior to knowing what their transport costs will be, and if transport cost differentials from different fields to the point of consumption are significant this may discourage trading. It also potentially forces buyers to rearrange their transport capacity contracts on a frequent (e.g. daily or even hourly) basis which could also discourage trading. However, if the overall proportions of gas received from different fields by particular buyers were reasonably stable or predictable, transport cost and contracting issues may not be such a major impediment.

3.4.3 Some general issues

Allowing for more liquid and efficient trading via swap transactions by adopting either of the two schemes described above, while maintaining 'other things equal' i.e. point-to-point transmission charges and the physical separation of the two main pipeline networks, raises a number of issues. Some of these have already been discussed. For instance, the physical hub/back-haul proposal is largely inconsistent with point-to-point transmission charges and involves shippers and producers in essentially fictional transport capacity purchase arrangements. The non-location specific contracts proposal potentially creates uncertainty over transport costs, and may require shippers to frequently recontract for transport capacity.

Such schemes also raise the possibility that some trades will result in physical constraints being violated, and hence be infeasible. The most relevant such physical constraint would seem to be possibility that shippers on the North Coast will purchase more gas than can physically be provided from the Guajira and La Creciente fields. While unlikely in the immediate future, this may become more of an issue as the production of the Guajira fields declines over time. [20]

An obvious solution to this problem would be to connect the two pipeline networks at Ballena so that gas could physically flow from the interior fields to the north coast, effectively creating a single, interconnected gas market in Colombia. The benefits of doing so should increase over time as Guajira production declines and more gas sources are

19 Since OTC trading is purely bilateral it may be inconsistent with trading non-location specific contracts.

20 Current capacity on the Promigas system is 540 GBTUDs while current production from the two fields exceeds 750 GBTUDs. So at present it is not possible for North Coast consumers to purchase more gas than is available form these fields.

developed in the interior of the country. An alternative is to ensure that the Promigas system never sells more pipeline capacity than the total amount of gas available from the Guajira and La Creciente fields. This will force traders to stay within the overall production constraint automatically, since there is no value in purchasing gas for which transport capacity is not available.

3.5 Option 5: Entry-Exit Charges and a Virtual Trading Point

Encouraging market liquidity and allowing for improved trading opportunities, as in Option 4 above, places strains on the system of point-to-point transmission charges and potentially leads to undesirable complexity and uncertainty. A solution to this would be to replace the existing point-to-point system of gas transport charges with entry-exit (EE) charges. As described in some detail in our Tasks 2&3 report, this means that instead of buying the right to transport gas from point A to point B in the network, shippers purchase the right to inject a certain quantity of gas at point A and, separately, to withdraw a certain quantity at point B. It is the separate purchase of entry and exit capacity that distinguishes this system of gas transport charges from a point-to-point system.

Under an EE system, a seller can inject gas into the system and sell it to any buyer who has the right to withdraw gas from the system. There is no longer a need to sell gas at a specific physical point in the system, since the transport contracts no longer define where the gas flows. In contrast, under a point-to-point system of capacity contracts, a seller could only sell gas to a counter party that had capacity to transport the gas away from the point of sale. The advantage of an EE system, as explained in more detail in our Tasks 2&3 report, is that the number of counter parties that can buy gas from a seller without having to contract for new transport capacity increases. An EE system therefore connects buyers and sellers at lower transaction costs.

Because trading in EE systems does not take place at a specific point in the transmission network they are often referred to as Virtual Trading Points, or VTPs. Under this system it is not necessary to specify a physical hub in the network where all trade must take place, nor are 'back-haul' contracts required. Gas supply contracts would not need to specify a physical 'delivery point' since buyers do not care where the gas they purchase originates from. All they care about is the cost of purchasing exit capacity at their point of consumption.

An EE system would also resolve the division of the Colombian market discussed above. For example, party A might buy entry capacity at Cusiana on the TGI pipeline system, and sell to a shipper who holds exit capacity at Cartagena on the Promigas system. The MO would then manage the physical flows of gas to implement this transaction, which would be analogous to the swap system described above.

However, in common with the back-haul system, the increased liquidity that an EE system provides could come at the expense of some cost reflectivity in transport charges. There are many ways to set entry and exit charges, but inevitably the total cost of transporting gas from point A to point B will differ from a system of point-to-point contracts. Some market actors may pay more than they did in the past, and others less.

An EE system could be combined with an OTC trading platform and/or a gas exchange. The only difference would be that, rather than multiple physical delivery points being specified in the contracts, 'delivery' would take place at the VTP. All the standardized contracts, whether traded on a platform or an exchange or bilaterally, would specify the delivery point at the VTP.[21]

21 Alternatively, since the VTP is simply a convenient fiction, it is not necessary for contracts to specify a delivery point at all. The VTP and the non-location specific contracts discussed above are equivalent once entry-exit charges have been introduced. The purpose of the VTP is simply to ensure that gas is placed in the system.

Since EE would be a single system or market area, the MO would calculate imbalances across all pipelines. So in other a short position on one pipeline could be offset by a long position on another. The MO, rather than the individual pipelines, would be responsible for administrating the system imbalances and physically balancing the system.

Finally, the same issues concerning violating physical constraints raised in Option 4 arise in Option 5, so we do not discuss them again here.

4. Balancing Mechanisms

There is currently no "market" for imbalances in Colombia. Daily imbalances between gas delivered into a pipeline network and the amount taken out are resolved via bilateral agreements between the shipper and the TSO called "balance agreements". Under these agreements the shipper can either place more gas into the system within a specified time period, or make a cash settlement with the TSO.[22]

In our consultations with the industry, no great dissatisfaction was expressed with the current balancing arrangements. However, as the market grows and secondary and short-term markets develop changes to these arrangements may be warranted. This would involve considering a number of issues with respect to balancing mechanisms:

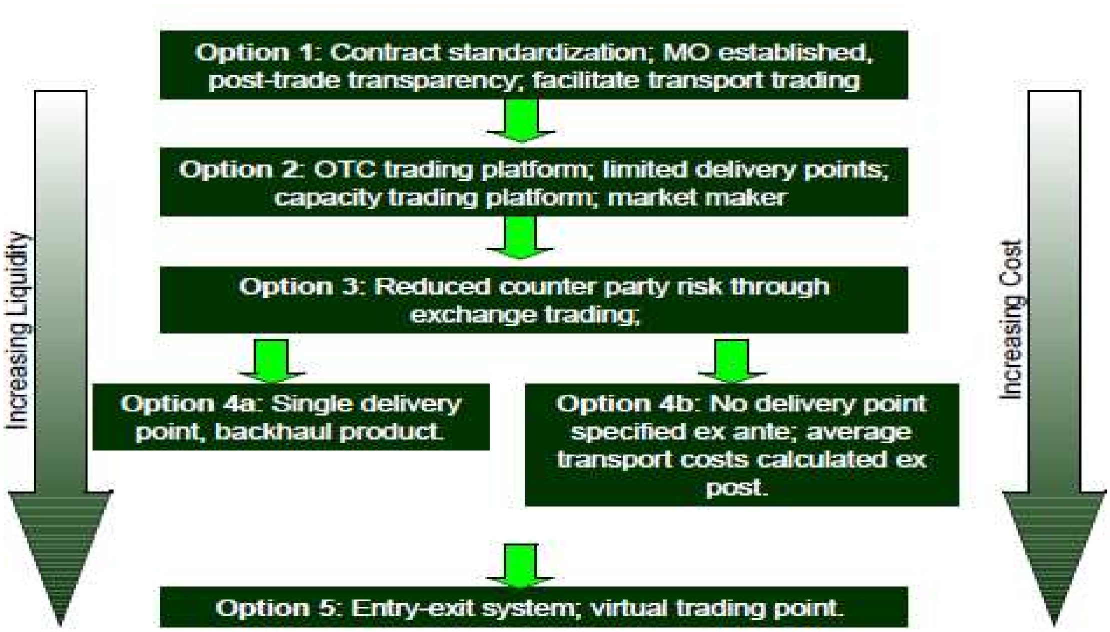
1. What should the objectives and principles of a balancing mechanism be, and what incentives should a balancing mechanism provide for TSOs and agents to efficiently use pipeline networks?
2. Should TSOs procure balancing gas on a separate balancing ('desvios') market, or should they buy gas on the short-term market?
3. How should the TSO allocate balancing costs to shippers?
4. What should the balancing period be and should they be the same for each pipeline network ?

Annex 2 contains a discussion of these issues particularly as they relate to European experience, where there has been considerable debate in recent years. European experience would appear to be more relevant to Colombia where balancing periods are similar than US experience where balancing issues are handled differently.

5. Conclusions

The figure below summarizes the main options we have considered in this section in order of increasing transition costs and market liquidity and competitiveness. Option 1, for instance, introduces relatively few changes to the status quo, while Option 5 requires fairly radical changes to current regulations and market organization.

22 See pp. 61-62 of our Tasks 2&3 report for more details.



As mentioned above, we have not attempted to describe these options in sufficient detail for implementation, but have delineated the main alternatives and identified the key changes that would be required for their adoption. Nor at this stage are we attempting to specify how they would be made compatible with existing legislation and regulations, such as the RUT and draft ministerial decree of March 2011.

Following further consultations with the CREG and the industry, a subsequent report (Task 5) will make recommendations on the most appropriate markets and their management mechanisms. Obviously these recommendations will need to be be coordinated and consistent with the design of the upstream auctions for longer-term gas contracts which is the subject of a companion study.

Annex 1 Examples of Information Flows and Responsibilities

In this annex we explain in more detail the roles and responsibilities of the various market actors. We take the case that:

- There is an onshore receiving terminal at Ballena (the terminal)
- The offshore production must be directed to either the west side of the terminal (Ballena West or BW) or Ballena east (BE). There is no onshore connection to allow the terminal operator to transfer gas from BE to BW or vice versa.
- The pipelines start at a flange somewhere downstream of the terminal.
- The terminal operator is a different entity from the pipeline operators;
- In these examples, the delivery point for all gas trades is at the terminal just upstream of the pipelines – so the terminal is acting as a physical hub;
- Trading takes place day ahead, and at the end of trading nominations are made for the following gas day. All of the examples would also apply if there was within-day gas trading and flows were re-nominated within the gas day, but assuming only day-ahead trading slightly simplifies the explanations.
- The actors in the market are:
    - Gas producers (in this example Ecopetrol), who produce gas and deliver it to the terminal;
    - Traders who buy and sell gas and transport capacity. We refer to these traders as party A, B, C, etc.;
    - The pipeline operators, who are responsible for delivering the nominated gas flows;
    - The Market Operator (MO) who is responsible for co-coordinating trading and balancing at the delivery point or hub, a role we explain in more detail below.

A.1.1 Information flows and responsibilities under Options 1, 2 and 3

The following example applies where there are multiple delivery points, and specifically that BE and BW are separate delivery points.

Example transactions

Ecopetrol has a (long-term) contract with party A for 100 units/day for delivery at the BE terminal (the terminal). Party A sells (day-ahead) 50 units to party B, who re-sells to C etc. At the end of the trading day the gas passes to party Z. Z has the rights for the gas for the following day, which is the delivery day. In this example 100 units of gas arrive at the terminal and 100 units leave.

Information flows

- Party A nominates to the gas producer (Ecopetrol in this example) that it wants 100 units delivered at BE.
- Party A nominates to the pipeline that it wants to transport 50 units of gas (the remainder of the Ecopetrol gas which party A did not sell). We call a request to the pipeline to transport gas a 'flow nomination'.
- Party Z wants to transport its 50 units away from BE, and tells the pipeline it wants to transport 50 units away from BE the following day.

Parties making trades would also notify the MO that they have bought or sold a volume of gas, and the pipelines also report all flow nominations to the MO. The MO would then track all the parties' net trading positions, and in the example above it would see that A has a right to transport 50 units away from the terminal, Z has a right to transport 50 units, and the obligations of all parties B to Y have been extinguished because their trades have netted out. So in this example:

- Ecopetrol would tell the MO that it will deliver 100 units to party A the next day, and A informs that MO that it has bought the 100 units from Ecopetrol.
- Each party B to Z is responsible for informing the MO of the volumes of gas that they have bought and sold for the next day and from which parties. The MO checks that buying and selling notifications match, and resolves any errors/differences.

The MO is also responsible for checking or policing that flow nominations are consistent with the party's position. In the example above, if party A tried to nominate 60 units for transport away from the terminal the MO would see that A has not bought the corresponding amount of gas and would be out of balance – that is, A would be trying to transport away more gas than it has a right to. The MO would ask A to correct its flow nomination, or to buy more gas (assuming there was time to do so).

Moreover:

- The pipeline is responsible for checking that flow nominations match capacity rights held by the nominating party. If nominated capacity exceeds the capacity rights held the nominating party is notified and asked to re-nominate;
- The pipelines then inform the MO of all flow nominations which are consistent with capacity rights held;
- The MO checks that pipeline nominations are consistent with the party's rights and obligations to transport gas.
- Each party is responsible for delivering to the contractual delivery point or transporting away from the contractual delivery point any net volumes of gas that they have agreed to buy or sell.

The transactions and information flows described above would apply to Options 1 and 2. With Option 3, there is now an additional actor in the market, which is the gas exchange operator (GEO). The only modification this makes to the scheme above is that the GEO would inform the MO of the net position of trades done on the exchange for each party. For example, the GEO would inform the MO that it has sold 25 units of gas to party E, and bought 25 units of gas from party F. While the GEO acts as the counter party to all the trades, the GEO's own position always nets out to zero – that is, the volumes of gas that the GEO buys equals the volumes which it sells.

Balancing

It is worth highlighting that under these schemes:

- Parties must be balanced at each side of the terminal (BW and BE), which is to say that they the sum of deliveries to each delivery point plus net gas bought at that delivery point less gas nominated to be transported from that delivery point must equal zero.
- Imbalances would also be calculated for each individual pipeline. In other words, the pipeline operator would ensure that for each party, flows in equalled flows out over the balancing period.

A.1.2 Information flows and responsibilities under Option 4

Under Option 4 (and 5, which we discuss below) there is a single delivery point for all contracts. Under one variant of option 4 the delivery point is a physical hub, and under another variant delivery points are determined ex post. Either option means that, commercially, two parties can trade gas between themselves, even though they will receive the gas on different pipelines which are not physically connected. To enable this to happen, the MO needs to manage the flows between the two pipelines, as described below.

Note that also under options 1,2 and 3 it would also be possible to have a single hub at Ballena, in which case the arrangements described below would apply. However, under options 4 and 5 by definition there is only one hub by definition.

Transactions

As in the previous example, Ecopetrol has a long-term contract with party A for 100 units/day for delivery at the Ballena Terminal (the terminal). However, the contract does not specify if delivery is for Ballena East or West, since now there is only one delivery point. Party A sells (day-ahead) 50 units to party B, who re-sells to C etc. At the end of the trading day 25 units of gas reside with party Y and 25 with party Z.

Information flows

- As in the previous case, all parties notify the MO of their buying and selling trading volumes.
- Party A nominates to Ecopetrol that it wants 100 units delivered at the Ballena terminal.
- Party A nominates to the pipeline that it wants to transport 50 units of gas (what it did not sell of the Ecopetrol gas) into the pipeline connected to Ballena East (the BE pipeline).
- Party Y nominates to the BE pipeline 25 units.
- Party Z nominates to the BW pipeline 25 units.

So in total 25 units of gas are nominated to flow through the BW pipeline and 75 units through the BE pipeline.

The main addition with respect to Options 1, 2 and 3 above is that the MO now tells Ecopetrol which side of the terminal it must deliver its gas. In this example Ecopetrol would deliver 25 units of gas to the BW side of the terminal and 75 units to the BE side of the terminal.

As we mention in the main body of the report, a single hub raises the issue of the physical feasibility of the transactions. However, as long the production from the Guajira is greater than the available capacity of the Atlantic coast pipeline then transactions will be feasible. This could be achieved if the production from the Guajira field is larger than the maximum capacity of the Atlantic coast pipeline or if the capacity sold in the Atlantic coast pipeline is restricted to be no greater than the production available from the Guajira field.

Note that a physical onshore connection between the two pipelines resolves this issue. The MO no longer needs to instruct Ecopetrol on which side of the terminal to deliver gas, since it can instruct the terminal operator to adjust the flows between the pipelines onshore.

Balancing

As before balancing takes place across the hub and across each pipeline. The only difference is now that there is only a single hub on which to balance.

A.1.3 Information flows and responsibilities under Option 5 – Entry-Exit

Under Option 5, we assume that all gas is delivered at the Virtual trading Point or VTP, which is to say that the seller is responsible for buying entry capacity and flowing gas into the system. There would be a single entry point at Ballena, with no distinction between BW and BE. Again, absent an onshore connection, the MO would instruct Ecopetrol on which side of the terminal to deliver gas once all nominations had been finalised.

The other key change in the EE system is that balancing would not take place on each pipeline, but over the whole system. In other words the MO would check whether, for each party, volumes injected into the system plus net volumes bought at the VTP less gas taken out of the system equalled zero over the balancing period.

Annex 2 Balancing Issues

As we noted in our Task 2&3 report, gas systems require shippers to balance their inputs and outputs over a specified period, at least to within a given tolerance. Imbalances are usually measured over a shipper's portfolio – that is, the sum of all their inputs and withdrawals to and from the system. Any shortfall or excess will usually be sold to the shipper or bought from the shipper by the TSO.

In the early days of gas market liberalisation in the EU, TSOs generally 'punished' imbalances with penal fees. There was little or no opportunity to solve imbalance situations via trading. A recent consultation paper on developing a guideline for EU-wide principles for gas balancing by the European Regulators Group for Electricity and Gas (ERGEG) noted that:

> "In many Member States, network users do not yet have regular information during the balancing period on whether their portfolio is in balance or have access to liquid wholesale markets to trade flexible gas. This impedes new entrants' ability to balance their portfolios and increases their exposure to imbalance charges. …..In many balancing regimes, imbalance charges do not reflect the cost of the TSO balancing the gas networks. This can result in incentives for inefficient behaviour and cross-subsidies between network users which could be considered discriminatory."[23]

It was to address these issues that in 2009 the EU laid out specific requirements for the imbalance rules. The new rules specified that:[24]

1. Balancing rules should reflect genuine system needs and costs, taking into account the resources available to the transmission system operator. Balancing rules should be market-based.
2. The transmission system operator should provide sufficient, well-timed and reliable on-line based information on the balancing status of network users;
3. Imbalance charges should be cost-reflective to the extent possible, whilst providing appropriate incentives on network users to balance their input and off-take of gas;
4. Any calculation methodology for imbalance charges as well as the final tariffs should be made public.

These may be reasonable broad principles to apply to the Colombian gas market, although they leave much open to interpretation. We discuss the key details to be addressed in the case of Colombia below.

A.2.1 Obtaining balancing gas

TSOs need to take actions within the balancing period so as to keep the system in balance. According to the principles above, TSOs should obtain balancing gas in a way that minimizes balancing costs. For example, obtaining balancing gas at above-market prices, and passing these costs through to shippers, should not be allowed. The procurement of balancing gas should be market-based.

23 ERGEG, Gas Balancing In Transmission Systems Framework Guideline Ref: E10-GNM-13-03, 10 March 2011, 1.1. Hereafter referred to as the ERGEG Balancing guidelines.

24 These points are summarised from Article 21 of Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005.

There remains the question of whether TSOs should obtain balancing gas from a dedicated 'balancing platform', where the TSO is the counter party to every trade, or buy gas in the market like any other trader. The ERGEG Balancing guidelines concluded that:

> "Where there is a need for the TSO to procure balancing services, it shall do so on the wholesale market on an equal footing with network users. However, where trading on wholesale markets is limited, it may be appropriate, as an interim step, for the TSO to procure balancing services on a balancing platform, where it acts as the counter party to all trades of flexible gas."[25]

While liquidity may initially be limited in the Colombian market, a separate balancing platform is likely to reduce liquidity further in the short-term market, and this would be undesirable. If balancing is to be market-based, TSOs should either buy gas in the short-term market or tender to provide balancing gas services, with the gas price indexed to short-term market or upstream auction prices.

Shippers should be allowed to trade between themselves within the balancing period so as to resolve their imbalances as far as possible before the end of the balancing period. Such trades can take place on whatever trading platforms are available for gas trading within the imbalance period.

Subject to physical constraints, shippers in one pipeline should be able to trade with shippers in another line. For a example, where possible a shipper who is long on gas in the TGI pipeline should be able to arrange a trade with a shipper using the Promigas pipeline who is short of gas.

A.2.2 Cost allocations and charges

For the purposes of illustration, we will assume a daily balancing period, where the TSO needs to take within-day balancing actions to maintain system balance. We also assume that TSO buys and sells balancing gas in the secondary market.

It is helpful to think of three types of costs:

- The costs of within-day balancing actions. These costs occur even if no one is out of balance at the end of the balancing period.
- The price of gas which the TSO has bought for shippers who are short, or that shippers who are long have sold to the TSO. These costs arise only when shippers are out of balance.
- The costs to any other customers in the event of an extreme imbalance event which causes some users to be disconnected from the system or take less gas than they were entitled to.

The key issues in the balancing system are allocating the costs of the within-day (or more generally within balancing period) charges; and finding cost-reflective prices to use for shippers that are short and long at the end of the balancing period.

With respect to the first issue, the costs of within-day balancing actions need to be measured and paid for. For example, supposing the TSO buys balancing gas in the secondary market, and had to buy gas at the beginning of the day at a price less than it was able to sell the gas at the end of the day, this creates a cost that must be paid by the shippers using the pipeline. Of course, there could also be a profit. These costs and profits should be tracked and ideally made public.

Supposing that all shippers had been out of balance – and created costs – within the day, but all except one shipper (shipper A) was in balance at the end of the day. It would clearly not be fair to allocate all the within day balancing costs to shipper A who was out of balance, when these costs had actually been caused by all the shippers. Rather, the within-day costs should be shared by all the shippers, whether they are in balance at the end of

25 ERGEG Balancing guidelines, 1.4

the day or not. Any attempt to allocate these costs more accurately in effect amounts to a shorter balancing period.

The second cost item essentially involves buying gas from and selling gas to the TSO. For example suppose that shipper A was short of gas at the end of the gas day, in effect it has taken gas that the TSO bought on shipper A's behalf. Shipper A should pay at least the cost of the gas that was bought for it, plus any associated administration costs. In the GB market the Shipper A would simply pay the highest gas price of that day. Presumably this is because it is hard to identify when the gas was bought for the shipper, and so the TSO assumes a 'worse case scenario' that the gas was bought at the most expensive price of the day. Similarly shippers who are long need to be paid for the gas they have given to the TSO, and a price need to be identified for the gas.

As reflected in the objectives, the key point is that the price that short-shippers pay for balancing gas is cost reflective – that is, it reflects the market price of gas at the time the gas was bought, and that the TSO made reasonable efforts to minimize the cost of gas. The price paid for the gas by the short shipper should not be 'penal'. On the other hand, it would be undesirable if shippers in effect contracted out their gas trading to the TSO, deliberately going short and relying on the TSO to buy them gas at the market price. The TSO is not a trading organization, and such actions by shippers would likely create costs that they would not pay for – for example in terms of increased administration and overhead costs. There is also always uncertainty and risk with the pricing of gas. It seems reasonable that the out of balance shipper should bear this risk – rather than all the other shippers. So the TSO should err on the side of charging a little too much rather than too little. In any case the balancing system should be cost-neutral for the TSO, so that any overcharges for gas are eventually recycled to all the shippers.

In Colombia it may take some time for a suitably liquid reference price for balancing gas pricing to develop. While liquidity is developing, the TSOs could base the prices for short and long gas on auctions results, with a spread applied, as in the German market. For example, shippers who were long could be paid 90% of the auction price for their gas, and shippers who were short would pay 110% of the auction price.

Of course, it could be that some shippers are long, and other are short, but in aggregate at the end of the balancing period there is no imbalance. According to the system above the TSO would be making a 'profit' of 10% of the auction price on the imbalance volumes. While this is true, we note that a) with enough information regarding their imbalances, shippers have an incentive to trade with each other to resolve the imbalances and b) the profit would in any case be recycled to all shippers eventually.

We understand that the final event, which where there are damages to final customers, is very rare and has only happened once in Colombia. The damages in these cases should be determined on a case-by-case basis in consultation with the CREG, but should nevertheless remain cost reflective.

A.2.3 The balancing period

The balancing period is the period within which the off-take of an amount of natural gas must be offset by every network user by means of the injection of the same amount of natural gas into the transmission system. At the end of the balancing period, any excess or shortfall of gas is 'cashed out' – that is to say, there is financial settlement whereby the TSO buys gas from shippers that are long and sells gas to shippers that are short. After cash out, the shippers' imbalance position is re-set to zero.

The balancing period has been the subject to much debate within the EU, and much less debate in the US. This is because US balancing periods are typically very long – one month is typical – and this does not represent an issue for shippers. In some EU networks, on the other hand, shippers must balance their inputs and outputs every hour. Many shippers find it very difficult to balance on an hourly basis, and combined with penal imbalance charges, such balancing regimes have impeded market entry in the past.[26]

This debate is typically cast as a technical issue – that the system 'needs' to be balanced every hour or day. But the choice of balancing period actually represents similar trade offs between cost reflectivity and liquidity that we discussed in our first report with respect to the definition of capacity rights.

Many gas systems require balancing on an hourly basis. The salient question is, should the system be made as cost reflective as possible, even if this inhibits market entry and hence liquidity and competition? Or should some cross-subsidization be allowed in the interests of making the market an easier place in which to operate, especially for smaller shippers, and we let the TSO do more of the work of balancing?

To illustrate the issue, we consider two situations. In one, we have hourly balancing. The TSO sells all of the available linepack (gas stored within the pipeline that can be used as gas storage) to shippers as a balancing product, and shippers must balance their inputs and outputs every hour. The TSO does not need to do much in this situation, since shippers will balance the pipeline themselves through trading, use of gas storage etc. Each shipper will bear the costs of balancing its own injection and withdrawal profiles.

In the second situation we have daily balancing. This means that as long as shippers are in balance over a 24 hour period they will not need to pay any imbalance charges. In this situation shipper A could inject gas at a constant rate of 100 units/hour, withdraw at 200 units/hour for the first 12 hours and then nothing for the second 12 hours. In many systems the TSO would need to take balancing actions to manage such a profile, but there would be no charge for it in this regime. The costs of the balancing actions would then typically shared among all shippers, even those that had injected and withdrawn gas at a constant rate thereby not creating any balancing costs. This example illustrates why there is some cross-subsidy with longer balancing periods.

Germany recently moved from hourly balancing to daily balancing precisely to make the market easier for smaller shippers to operate in. A recent paper noted that

> "[t]he change in the balancing regime [from hourly to daily] will accelerate the development of competition…..This should induce local distribution companies to opt out of the remaining "all inclusive" procurement contracts and develop more complex procurement portfolios. The Day-Ahead trading market should become more liquid because of the opportunity which it gives for portfolio balancing. Supply to most final customers, in particular residential customers, becomes much easier."[27]

The degree to which cross-subsidization takes place is a technical issue. If, with daily balancing the TSO does not need to take many within-day balancing actions, then there will be little cross-subsidy. This could be the case if the pipeline system had a large amount of linepack. If on the other hand a system requires constant attention to keep it balanced on an hourly basis, then a daily balancing period could create much larger cross-subsidies.

The ERGEG Balancing guidelines recommended a daily balancing period, but noted that the trade off above:

> "where the cost of during the gas day balancing actions is high, this could lead to undue 'smearing' of these costs across all network users. In those circumstances, to ensure that the balancing regime is market based, i.e. it encourages shippers to balance their portfolios rather than leaving it to the TSO, it may be appropriate to impose these costs at the network users who cause them. As such, certain

26 An issue we do not discuss here is whether it is necessary to define a balancing period at all, or as in the recently introduced Dutch system to allow shippers to remain out of balance until the system operator is required to take action. See our Task 2&3 report, p. 31.

27 Lohmann, Heiko The German Gas Market post 2005: Development of Real Competition, Oxford Institute for Energy Studies, September 2009, NG 33, p.84.

obligations may need to be placed on network users to maintain a particular balance during the gas day."

However, ERGEG also recommended that national regulatory authorities approve that within-day balancing action on behalf of shippers is really required. In other words, in the EU the burden of proof is now clearly on the TSO to show that within-day balancing is required, rather than shippers having to prove that it is not.

A.2.4 Harmonizing the balancing period in Colombia?

In Colombia, the Promigas and TGI pipelines seem to have balancing periods of different durations and tolerances and apply different rules. One issue is whether these will lead to any inefficiencies or undesirable behavior.

As explained above, the choice of balancing period is not primarily a technical issue, but rather a trade off between cost reflectivity and encouraging market entry and liquidity in the market. Therefore it seems appropriate that the CREG should ultimately be responsible for setting the balancing period, as it is best placed to judge the trade offs.

The same trade-off between cost-reflectivity and easing market entry should be applied to all pipelines. Balancing periods between pipelines should only differ if there are genuine technical reasons why one pipeline requires more frequent and costly balancing actions than another, so that a shorter balancing period is justified.

Differences in balancing periods or tolerances between the two pipelines may affect behavior. For example, rather than have an imbalance on Pipeline 1, which has a shorter imbalance period, a shipper that was short could 'borrow' gas from a shipper on Pipeline 2 with a longer balancing period. This would have three effects. First, we would expect to almost never see shippers out of balance on Pipeline 1, since they could borrow or park gas on the other pipeline. Second, shippers holding capacity on Pipeline 2 would probably charge for such a 'park and loan' service. This could imply that some of the value of the Pipeline 2's longer balancing period would accrue to the shippers using the pipeline. Third, we would expect to see larger imbalances on Pipeline 2 as shippers use the longer balancing period to balance shippers on Pipeline 1. This could lead to an increase in balancing costs for Pipeline 2. Since these costs would be shared, shippers on Pipeline 2 would have an incentive to get as much 'park and loan' business from Pipeline 1 shippers as possible. The difference in balancing periods could thus increase the overall costs of balancing compared to a situation in which the balancing periods were the same on both pipelines.[28]

One could ask why has this issue not arisen already? One reason why it might arise in future is that making it easier to trade, and to trade between pipelines, will also facilitate the arbitrage of balancing periods between the two pipelines.

Based on the discussion above, in the absence of compelling reasons for different balancing periods they should probably be harmonized. If there are good reasons, CREG should be mindful of the way in which difference in balancing periods could distort trading, and keep the balancing periods under review.

28 A shipper on Pipeline 2 cannot charge more for the park and loan service than the Pipeline 1 shipper would pay for being out of balance. Ultimately each Pipeline 2 shipper might pay more for its share of the increased balancing costs than it makes from the park and loan service. But each individual shipper has no incentive to stop selling the service, as the gains are private but the costs are shared.