WHOLESALE GAS COMPETITION IN THE NETHERLANDS AND IMPLICATIONS FOR PHASE III CUSTOMERS

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Executive Summary

Gas distribution companies in the Netherlands currently have legal monopolies to supply households and small commercial establishments. These monopolies are scheduled to expire in 2004, when all customers will become eligible under the third phase of Dutch gas market liberalisation. We have been asked to evaluate the potential development of effective competition in the gas wholesale market and its impact on supply to customers made eligible under Phase III. Our work will enable DTe to anticipate potential problems, and to facilitate successful Phase III liberalisation.

We endorse many of the changes that have taken place in recent years in the Dutch gas industry. The first two phases of liberalisation have been relatively successful. Consumers have switched suppliers with greater frequency in the Netherlands than in other countries. Reforms of the Dutch gas market are proceeding faster than in many Member States, and the planned unbundling of ownership in gas supply and transport constitutes international best practise. Nevertheless, we have identified several characteristics of Phase III customers that may impede the development of effective competition in the wholesale market in the final phase of liberalisation.

In contrast to existing eligible customers, small customers primarily consume L-Gas at a low load factor. However, Gasunie has exclusive access to the main source of L-gas and production swing in the Netherlands – the Groningen field – and to the majority of gas storage in the Netherlands. These resources are essential for serving Phase III customers. Effective competition cannot develop to serve small customers unless other shippers have access to similar resources, or to particular services. We identify four serious problems facing shippers who wish to serve customers who become eligible in Phase III:

1. *Access to quality conversion facilities:* Lacking access to L-gas, competing shippers would require access to GTS quality conversion capacity, which can convert H-gas to L-gas. Existing quality conversion facilities have sufficient capacity to accommodate the Dutch gas market, but most of the capacity is already dedicated to Gasunie.

2. *Access to flexibility services:* serving small customers requires access to storage capacity, line-pack, or flexible production to provide the requisite flexibility. Gasunie controls access to most of these resources. The line-pack and storage capacity that are currently available to other shippers would together suffice to serve only 20% of Phase III consumers, and the storage is subject to commercial terms that would raise practical problems for shippers. Successful competition in the wholesale market for Phase III customers will rely on the sale of additional flexibility services by the Groningen field, but there is no explicit rule ensuring the availability of such services at reasonable prices. The shortfall in flexibility services is unlikely to be met via new build storage, due to the risk of a subsequent price cut in the cost of storage services by NAM.

3. *Access to firm import capacity:* Competing H-Gas suppliers import gas from neighbouring countries, which requires firm transportation capacity on the GTS

system. There is not sufficient firm transportation capacity available to accommodate the surge of H-Gas imports that would be necessary to compete effectively for small customers. Data provided by GTS suggests that at most, there is contractual availability for 2.3 bcm/yr of firm H-Gas imports, which could only serve around 10% of small customers.

4. *Reliability problems:* Households and the other small Phase III consumers demand high reliability. This can present a problem to shippers other than Gasunie. Even if a competing H-Gas supplier obtains the requisite import capacity, quality conversion capacity, and tolerance services, the resulting gas supply would not offer comparable reliability to the Groningen field. We note that this problem could be solved under the proposed amendment of the Dutch Gas Act, which would make GTS responsible for security of supply.

We support the plans to split Gasunie's supply business into two competing companies. However, experience indicates that the presence of two competitors is not sufficient for the development of effective wholesale competition. The problems cited above could severely limit competition by other shippers. In the absence of proactive regulatory measures, small customers are likely to face a Shell/ExxonMobil duopoly that has the incentive and ability to charge excessive prices.[1]

We explore the potential pricing behaviour by Shell and ExxonMobil after full market opening, assuming that they would try to maximise profits. We estimate that the L-Gas price should normally approximate the H-Gas price plus the costs of "switching" from L-Gas to H-Gas. Any higher price would prompt small customers to switch from L-Gas to H-Gas. We estimate that Shell and ExxonMobil would not have financial incentives to reduce prices, unless they faced the prospect of losing more than 40% of the market for small customers to competitors. Competitors simply do not have access to the resources or services necessary to supply such a high portion of the market.

We investigate the likely magnitude of both "supply-side" and "demand-side" switching costs. If we ignore the four serious problems identified above, then a competing H-Gas supplier could theoretically switch to supplying flexible L-Gas by paying for available quality conversion and flexibility services. We call these costs "supply-side" switching costs, and estimate them to be approximately 7-10% of H-Gas prices.

Supply-side switching costs are only relevant if sufficient capacity exists for quality-conversion and flexibility services. In the absence of sufficient capacity, the relevant switching costs would involve a distribution company switching its consumption from L-Gas to H-Gas. The distribution company would have to check and – if required – convert all domestic central heating systems on its network to take H-Gas. We estimate that these "demand-side" switching costs average 9-14% of H-Gas prices. However, we are

[1] Gasunie currently dominates the market for the supply of small customers (more precisely, Gasunie dominates the supply of the Local Distribution Companies that ultimately supply small customers). The Dutch state owns 50% of Gasunie, which allows the government to prevent Gasunie from charging unreasonable prices. The Dutch state will not have the same direct influence over Shell and ExxonMobil.

concerned that distribution companies will have no financial incentive to respond to high prices by converting their networks to H-gas. A further problem is that all customers on a distribution system have to switch quality simultaneously, which could present co-ordination problems. If small customers cannot switch to H-gas, then we see no clear limit on the prices that Shell and ExxonMobil could charge.

Our analysis of switching costs conforms to the analytical approach for defining markets under European competition law. When either consumers or suppliers can switch between two "similar" products, the definition of the market depends on the magnitude of the switching costs. If switching costs are at least 5-10% of total costs, then the relevant products are in separate markets. Our analysis indicates that L-Gas consumed at a low load factor defines a separate market. Further, Gasunie currently satisfies the two criteria for having a dominant position in the supply of this market: Gasunie has a 100% market share of supply (via LDCs), and there are significant barriers to entering the market. In the absence of proactive regulatory measures, ExxonMobil and Shell will inherit a duopoly in this market.

1 Introduction

We begin by describing the Dutch gas supply chain, including the recently proposed restructuring of the 'Gas Gebouw' (Gas Building). We also analyse Dutch gas consumers, discussing the timeframe for market opening and the distinguishing characteristics of different consumers. We also discuss some of the unique features of the Dutch gas supply system, such as the Groningen field's role in providing flexibility.

We identify several serious barriers to shippers who wish to serve customers that consume L-gas at a low load factor. We describe the barriers in detail and, where possible, estimate the maximum portion of the market that competitors could obtain in the face of such barriers.

We then examine the implications of entry barriers for L-gas prices in the Netherlands. We examine the likely pricing incentives of Shell and ExxonMobil, which may be affected by the costs of switching between L-gas and H-gas. We discuss supply-side switching costs and demand-side switching costs separately, and examine the feasibility of distribution networks converting to H-gas in response to excessive gas prices.

We conclude by framing these problems in the context of the European Commission's formal methodology for defining markets and assessing market dominance. We describe the Commission's methodology for market definition, and then apply the methodology to test whether H-gas and L-gas different occupy the same market. We conclude that small consumers of low-load-factor L-gas constitute a separate market, in which Gasunie has a 100% market share. High entry barriers and a high market share combine to give Gasunie a monopoly in the market, which after the proposed restructuring of the Gas Gebouw would become a duopoly between ExxonMobil and Shell.

2 Gas Supply and Demand in the Netherlands

2.1 Background

The Netherlands dominates L-gas production in Europe, producing over 80% of L-gas consumption and exporting approximately 21 bcm/yr. Germany is the only other country to produce significant amounts of L-gas in Europe, producing 10 bcm/yr. German reserves and production are much smaller than in the Netherlands, and Germany does not export significant quantities of L-gas. With L-gas reserves of over 1,260 bcm and a reserves-to-production ratio of approximately 30 years, the Netherlands has a key position in the European L-gas supply chain.

The giant Groningen field accounts for approximately 60% of Dutch L-gas production, with the remaining 40% coming from small fields H-gas that is converted to L-gas.

Table 1: Dutch production, imports and exports for 2000

			H-gas (bcm)	L-gas (bcm)
Dutch Production	[1]	DTe	41	27
Conversion	[2]	[5]+[4]-[1]-[3]	-16.5	16.5
Imports	[3]	DTe	13	0
Exports	[4]	See note	15.7	20.9
Supply to Dutch Customers	[5]	DTe	21.8	22.6

Notes:
General: Cubic metres are at the calorific value of Groningen gas (35.17 MJ/m^3).
[4]: Total export numbers from Gasunie Trade & Supply. For details of exports see Appendix 2.

The production license of the Groningen field is held by NAM as the operator of the field, but controlled by the Groningen Maatschap. The Maatschap is owned 40% by Energie Beheer Nederland (EBN) and 60% by NAM. The Dutch government owns EBN, while NAM is a 50/50 joint venture by Shell and ExxonMobil. Although EBN has a minority share in the Groningen Maatschap, decisions taken by the shareholders must be unanimous, so EBN can block any proposals made by NAM.

In the past, the Groningen Maatschap would provide gas to Gasunie, who would sell the gas on behalf of the Maatschap.[2] This complex relationship was known as the Dutch

[2] Gasunie's maximum profits from gas sales were fixed at a relatively low ceiling (approximately €35 million) while the vast majority of pre-tax profits (approximately €3-4 billion, depending mainly on the severity of the winter) accrued to the Groningen Maatschap. After applying an average tax-rate of some 80%, the Groningen Maatschap would retain net profits of €0.6-0.8 billion, divided among the shareholders.

“Gas Gebouw”, or Gas Building. The old “Gas Gebouw” arrangement is now in the process of being dismantled. Not all the details of the new arrangement have been finalised, but the objective is to restructure the Dutch gas industry to facilitate successful liberalisation.

The restructuring of the Dutch gas market has three main elements. First is the replacement of the old relationship between gas production (NAM) and gas sales (Gasunie). NAM will charge ‘commercial’ prices to downstream wholesale companies, and the old system of profit distribution between NAM and wholesale companies will be abolished.

Second, Gasunie’s supply business will be separated into two separate companies, one owned by Shell and the other by ExxonMobil. The Ministry of Economic Affairs is currently negotiating with Shell and ExxonMobil to allocate Gasunie’s existing gas sales contracts, with the goal of splitting the value of Gasunie’s supply business as evenly as possible. The two new wholesale companies will still have exclusive access to the Groningen field, including the swing capacity that the field can provide. Other shippers will not be able to buy Groningen gas directly from NAM. It is anticipated that the new Shell/ExxonMobil wholesale companies will also take over the current storage contracts between Gasunie and NAM, while the new transport company (see below) may take over the storage contract with BP. The Groningen Maatschap will assume responsibility for implementing the Dutch “small fields” policy, and EBN will become the buyer of last resort for new H-gas fields.

Third, the Dutch government will acquire exclusive control of Gasunie’s gas transportation business.[3] The separation of gas transportation and supply will ensure non-discriminatory access, which is vital to the development of a competitive gas market.

At the time of writing, the Dutch gas industry is in a transition phase. Gasunie has partially unbundled transportation and supply. Gasunie Supply & Trading runs the supply business, while Gastransport Services – GTS – manages the transportation network. However, both businesses remain under common ownership. The Minister of Economic affairs reported to Parliament that the legal unbundling between supply and transport will take place on January 1st 2004, but the ownership unbundling is not expected before January 1st 2005.[4] The Gasunie’s supply business has not yet been split between ExxonMobil and Shell.

[3] In her letter of 8th April 2002 to the Dutch parliament (Tweede Kamer), the Dutch Minister of Economic Affairs states that the Dutch state will take over the property of the transport network under financially neutral terms, and that the corporate governance of Gastransport Services will be brought in line with that of the Dutch electricity transmission company TenneT, which was brought into state ownership after the liberalisation of the electricity industry

[4] Letter of April 8th 2002 and letter of June 11th 2003 from the Dutch Minister of Economic Affairs to the Tweede Kamer.

2.2 Dutch Gas Consumption

We divide Dutch gas consumers into five categories:

- Households– small residential customers and small businesses.
- Large Consumers – medium-sized businesses and small industrial processes.
- Greenhouses– the Netherlands produces a relatively large amount of fruit and vegetables grown under glass in greenhouses. The greenhouses use gas for heating during colder weather.
- Industry – large industrial processes such as steel manufacture that would typically employ more than one shift of workers.
- Power Stations– the Netherlands produces the majority of its electricity from gas-fired generation.

Table 2 summarises the characteristics of the five consumer categories. Below we discuss the distinguishing characteristics of each category in more detail.

Table 2: Characteristics of Dutch gas consumers

Customer Type			Households	Large Consumer	Greenhouses	Industry	Power Stations
Gas Quality	[1]		L-gas	L-gas	L-gas	H-gas	H-gas
Load Factor	[2]	TBG Estimate	Low	Low	Low	High	Medium/High
Served by LDC?	[3]		Yes	Yes	Yes	No	No
Gas Consumption, bcm/y	[4]	See note	14.2	4.4	4	13.2	8.6

Notes:
[4]: Figures for the year 2000, supplied by DTe. All gas volumes are in Groningen equivilant i.e. 35.17 MJ/m^3.

Gas Quality

The Netherlands has two principal types of gas quality, with separate pipelines systems for each. We distinguish between high calorific value gas (H-gas) and low calorific value gas (L-gas). H-gas has a Wobbe Index of around 51.8 MJ/Nm^3, while L-gas has a Wobbe Index of between 43.8 MJ/Nm^3 and 46.5 MJ/Nm^3.

Load Factor

The load factor refers to the profile of gas consumption (or production) over a period of time. The load factor can be defined in a number of ways and is commonly expressed as a number of hours (for annual load factors) or as a percentage. In this report we focus mainly on daily load factors. We calculate the load factor as the average consumption during the period divided by the maximum consumption, expressed as a percentage. A consumer with a high load factor will consume gas at a constant rate throughout the day, whereas a consumer with a low load factor will vary consumption sharply.

LDC Customers

Local Distribution Companies (LDCs) serve smaller customers. Larger customers take gas directly from either the H-gas or L-gas transport network.

Gas Consumption

Household consumption of L-gas can vary substantially depending on the severity of the Dutch winter. Table 2 shows figures for 2000, a relatively mild winter, in which the total Dutch consumption of L-gas was approximately 23 bcm/yr. However, we estimate that the average Dutch L-gas consumption between 1994 and 2000 was between 35 and 40 bcm/yr.[5]

2.3 The Timetable for Liberalisation

The Dutch Gas Act of 2000[6] provides for three phases of market opening (see Table 3). Phase III will make all consumers eligible to choose their gas supplier, although many were already eligible under Phases I and II. We estimate that gas demand from Phase III consumers is between 20 and 25 bcm/yr, which represents about 50% of gas demand in the Netherlands. According to the Gas Act, Phase III implementation should happen on 1st January 2004, but the Minister of Economic Affairs announced in June of this year a delay until July 2004.

Table 3: Liberalisation of the Dutch gas market

	Gas consumption (mln m3/y)	Date of implementation
Phase I	>10	August 1998
Phase II	1 - 10	January 2002
Phase III	< 1	Mid - 2004

2.4 Characteristics of Phase III Consumers

Phase III will largely affect households and large consumers (medium-sized businesses and small industrial processes). Table 2 illustrates their defining

[5] In 2000, production from the Groningen field was some 19 bcm and household demand for L-gas was some 14 bcm. However, from the mid 1980s typical production levels from Groningen were between 35-40 bcm/year. The difference between 2000 Groningen production and the historical average is due to the mild winter in 2000. Adding on the difference between historical and 2000 Groningen production to the year 2000 L-gas demand gives a more typical level of Dutch L-gas demand.

[6] The Dutch Gas Act implements Directive 98/30 of the European Parliament and the Council of the European Union of 22 June 1998 in respect of Common Rules for the Internal Market in Natural Gas.

characteristics. Unlike Phase I and II customers, they consume mainly L-gas at a varying rate throughout the day. In contrast to some large industrial customers, Phase III customers demand more secure gas supplies.

2.5 Provision of Swing in the Netherlands

Most gas distribution networks have customers whose demand in winter varies significantly over the course of the day. A combination of activities usually meets varying demand: varying the production of gas during the day, injecting or withdrawing gas from storage facilities, or relying on the pipeline's inherent ability to store some gas, which we call "linepack". Most gas systems throughout the world are supplied by remote sources of gas, which makes it expensive to accommodate demand by varying production. Such systems match supply and demand mainly by using local storage facilities and linepack. The Netherlands is unusual in this respect, as it has a very large source of flexible gas supply (the Groningen field) very close to the market. Moreover, the Groningen field is onshore, which reduces the cost of augmenting production capacity. Consequently for the Netherlands, it is cheapest to meet varying gas demand by changing gas production rates from Groningen, rather than building diurnal storage in the distribution system as in the United Kingdom.

The historically low cost of providing swing from Groningen means that Dutch household demand is particularly "peaky", demonstrating a high variation between the peak and average level. For example, most Dutch households do not have a hot water storage tank, because Groningen can provide "swing service" more cheaply than a storage tank.

Over time the pressure of the Groningen field will decline, reducing the maximum capacity of the field and the speed with which production rates can change. The field's ability to provide swing production will therefore decline. This is being addressed, to some extent at least, by the installation of compression facilities on the Groningen field. Groningen's swing capability may be maintained, but will cost more than before.

3 Barriers to Serving Phase III Customers

Many Phase III consumers use L-gas at a highly variable rate throughout the day, and demand secure supplies. We call these customers Low Load Factor (LLF) L-gas customers. Shippers generally find it easy to obtain interruptible supplies of H-gas delivered at a constant rate (High Load Factor H-gas of HLFH-gas). However, serving Phase III customers would require access to:

- Access to a secure source of H-gas – to make L-gas, shippers must also have a supply of H-gas. The supply must be firm to meet the level of security that Phase III customers demand.
- Load Factor Conversion services – the constant (flat) supply of H-gas must be changed to match customer demand throughout the day.
- Quality Conversion Services – the majority of Phase III customers consume L-gas. As we assume that Gasunie will not sell Groningen L-gas to rival shippers, the only alternative is for shippers to use GTS quality conversion services to make L-gas from H-gas.

Obtaining the services listed above *may represent significant barriers for shippers wishing to serve Phase III customers*.

In this section we examine the *quantity* of load factor and quality conversion (collectively termed 'switching services') available to H-gas shippers. We also examine the options for new shippers who wish to ensure the security of their H-gas deliveries. We then calculate the volume of LLFL-gas that H-gas shippers could serve, given the available quantity of switching services.

3.1 Supply of Load Factor Conversion Services

Load Profile

Figure 1 shows our estimated off-take profile for a typical LLFL-gas customer. We derived the profile from data that DTe provided concerning the consumption of a typical LDC serving mainly households and small businesses. Load Factor Conversion (LFC) changes the flow of gas from a constant rate over the day into a varying rate that matches the consumer's off-take profile.

Figure 1: Daily customer off-take profile for switching cost calculations

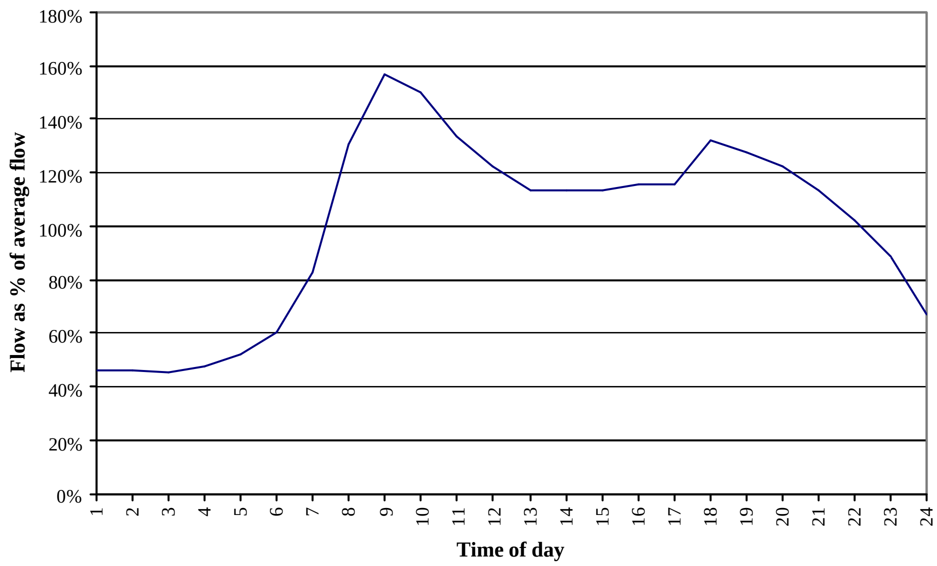
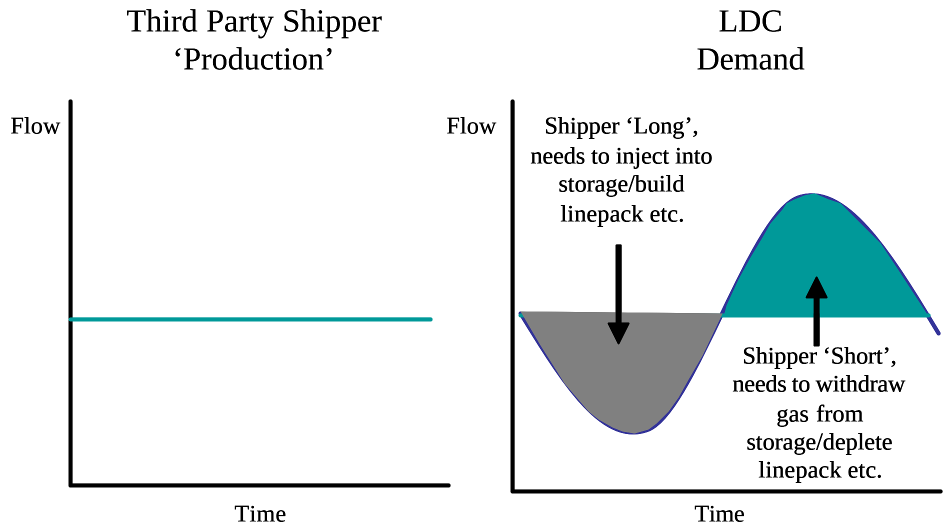


Figure 2 illustrates the need for LFC. In the beginning of the day, demand is falling, so that the shipper has excess gas (the shipper is "long"). In the second part of the day demand exceeds the shipper's delivery rate, so that the shipper is "short" on gas.

Figure 2: Load Factor Conversion



A shipper can avoid the potential problems of long and short positions in four ways:

- Gas storage—the shipper can buy storage capacity that permits the shipper to inject excess gas when demand is low, and to withdraw gas from storage when demand is high.
- Linepack—the TSO usually owns and manage daily linepack. The shipper can sign a contract with the TSO to use the linepack for storage. In the Netherlands, GTS offers

some access to linepack in standard transportation contracts. Linepack use is conceptually identical to gas storage.

- Changes in the rate of gas supply—The shipper could arrange for gas supplies to be delivered to meet demand exactly.

- Changes in the rate of gas demand—In principle some customers could offer to vary their gas demand, to off-set increases and decreases in demand by other customers. For example customer A could offer to increase consumption in the morning when customer B's off-take declines. In the afternoon customer A could reduce consumption when customer B's demand increases. Customer A's flexibility could ensure a flat demand profile for customers A and B combined.

Changes in the rate of gas demand are theoretically possible. For example, households could install hot-water storage tanks that avoid the need to increase gas consumption at the moment that hot water is required. Interruptible contracts for large gas users can help accommodate peak demand by others. According to the IEA, some Dutch power stations have agreements to switch from gas to oil at low temperatures, in effect providing a seasonal swing service. However, in practice changing the rate of gas demand will not provide a significant contribution to accommodating the load profile of LLFL-gas customers.

GTS Bundled Hourly Tolerance

As Box 1 explains, GTS offers shippers a certain amount of hourly tolerance as part of standard transportation contracts. We call this tolerance "bundled" or "free" because shippers pay for it automatically as part of their transportation tariffs, and do not pay extra charges when they actually use the tolerance. GTS does not impose imbalance penalties on hourly imbalances that remain below the amount of bundled tolerance.[7] The bundled tolerance that GTS provided in 2003 would not suffice to serve the off-take profile of a typical LLFL-gas customer. A shipper that relied exclusively on bundled tolerance would face imbalance penalties. However, shippers can trade their bundled tolerance. Any single shipper could hypothetically match the hourly profile of a LLFL-gas customer by purchasing bundled tolerance from other shippers.

[7] GTS allocates the bundled hourly tolerance (expressed in m^3/hour) to shippers in proportion to their hourly gas flows, and measures the tolerance as a percentage. GTS does not distinguish between H-gas and L-gas tolerance, which are interchangeable.

Box 1: GTS balancing requirements

> GTS have a system of so-called 'daily balancing, hourly tolerances.' In brief, GTS requires shippers to balance volume inputs and outputs to within 2% over the gas day. In addition, shippers must match metered inputs and outputs on an *hourly* basis, to within the hourly tolerance prescribed by GTS. The hourly tolerance varies with temperature, going from 13% at temperatures of 0ºC and above, and reducing linearly to 0% at -17ºC. If a shipper exceeds the hourly tolerance they will incur high imbalance charges.

We estimate that GTS provides a total 1.2 million m^3/hour of bundled tolerance (Table 4). This suffices to serve approximately 17 bcm/yr of LLFL-gas. However, as GTS allocates bundled tolerance based on the volume of gas shipped, Gasunie Trade & Supply would receive 1.08 million m^3/hour of the bundled tolerance at the beginning of Phase III, since Gasunie Trade & Supply currently serves the majority of the market. Other shippers would receive the remaining 0.12 million m^3/hour.

Table 4: Supply of GTS bundled tolerance

H-Gas flow in, bcm/y	[1] Table 1	54
H-Gas flow out, bcm/y	[2] Table 1	37.5
L-gas flow in, bcm/y	[3] Table 1	27
L-gas flow out, bcm/y	[4] Table 1	43.5
H-Gas flow in, m3/h	[5] [1]x10^9/8760	6,164,384
H-Gas flow out, m3/h	[6] [2]x10^9/8761	4,280,822
L-gas flow in, m3/h	[7] [3]x10^9/8762	3,082,192
L-gas flow out, m3/h	[8] [4]x10^9/8763	4,965,753
Total GTS L-gas Free Tolerance, m3/h	[9] {[7]+[8]}x0.065	523,116
Total GTS H-gas Free Tolerance, m3/h	[10] {[5]+[6]}x0.066	678,938
Total Free Tolerance, m3/h	[11] [9]+[10]	**1,202,055**

While Gasunie Trade & Supply could sell its bundled tolerance, a refusal to sell could limit the number of LLFL-gas customers that other shippers could serve. Imagine that another shipper obtained a contract to supply a LLFL-gas customer previously supplied by Gasunie Trade & Supply. The shipper would automatically obtain some bundled tolerance in connection with the transportation capacity for the particular customer, but the shipper would still need to buy extra tolerance to avoid imbalance penalties. If Gasunie Trade & Supply refused to sell additional bundled tolerance, then the shipper could only resort to the limited pool of tolerance controlled by other shippers. After exhausting this pool, the shipper would have to explore other resources such as storage. If Gasunie Trade & Supply refused to trade its bundled tolerance capacity, we estimate that other shippers could at most serve around 2.3 bcm/yr of LLFL-gas customers with the remaining bundled tolerance (Table 5).

Table 5: Volume of LLFL-gas that non-Gasunie shippers could serve using free tolerance

Annual consumption of LLFL-gas customer (mln m3/year)	[1]	TBG Example	26.5
Additional tolerance capacity required to serve LLFL-gas customer (m3/hour)	[2]	TBG Calculation	1373
Free tolerance allocated to non-Gasunie shippers (m3/hour)	[3]	TBG Calculation	120,000
Total volume of LLFL-gas that can be served by purchasing non-Gasunie free tolerance (bcm/y)	[4]	([3]/[2])x([1]/1000)	2.3

GTS Flexibility Service

As outlined in section 6.1, GTS currently offers a flexibility service. The service is sold in units of m^3/hour. For example, purchasing 1000 m^3/hour of flexibility service would permit a shipper to incur an imbalance of up to 1000 m^3/hour without incurring imbalance charges. After purchasing the service, shippers can trade their rights to the service in a secondary market either on the GTS bulletin board or elsewhere.

Linepack is the only source of flexibility that GTS currently controls directly. We understand that linepack provides the bundled tolerance described above. To provide the flexibility service, GTS must purchase flexibility from a third party. GTS tenders for such services on an annual basis. Before the tenders, GTS communicates with shippers to assess their demand for flexibility, presumably to prevent GTS from purchasing too much service. We understand that Gasunie Supply & Trading/NAM provides most of the tendered flexibility service from the Groningen field.

GTS has offered flexibility services to shippers for 2004. However, any statements for 2004 might not provide a reliable guide to the future. Most of the customers with highly variable off-take are not yet eligible, so we would expect less shipper demand for flexibility service in 2004 than after Phase III. Offering only a small amount of flexibility services in 2004 may indicate low demand rather than a scarcity of resources.

Under the current regulatory regime, GTS cannot realistically commit to provide specific amounts of flexibility service in future years. GTS depends almost entirely on Gasunie Supply & Trading/NAM to supply flexibility services. Even if GTS offered sufficient flexibility in one year to meet shipper demand, the service might be withdrawn the following year. It is not clear how shippers could acquire sufficient flexibility in the absence of the GTS service.

Gas Storage

Table 6 indicates the total amount of storage services offered by NAM (at the Grijpskerk UGS) and BP (at the Alkmaar UGS) to shippers other than Gasunie Trade & Supply.[8] It is anticipated that the new Shell/ExxonMobil wholesale companies will take

[8] For further details of Dutch storage capacity see DTe's Guidelines for Gas Storage 2003, 30th August 2002.

over the NAM storage contracts, with GTS taking over the BP storage contract. NAM has L-gas storage physically available at the Norg location. However, NAM does not currently offer this storage to shippers other than Gasunie Trade & Supply.

To provide daily load-factor conversion using gas storage would require injection and production capacity, and working volume. Our calculations indicate that the offered amount of injection capacity constrains the total amount of load-factor conversion that storage can provide. The injection capacity offered by NAM and BP could provide load-factor conversion for up to 1.7 bcm/yr. Our estimate may be excessive, as we ignore the restrictions that NAM and BP apply to storage services.

Table 6: Dutch storage capacity constructed and offered in 2003

			Grijpskerk (NAM, H-gas)	Norg (NAM, L-gas)	Alkmaar (BP, L-gas)	Total
Production Capacity						
Constructed, million m^3/d	[1]	See Note	65.0	53.0	36.0	154.0
For sale, million m^3/d	[2]	See Note	8.2	0.0	2.5	10.6
Fraction for sale, %	[3]	[2]/[1]	13%	0%	7%	7%
Injection Capacity						
Constructed, million m^3/d	[4]	See Note	12.0	24.0	4.5	40.5
For sale, million m^3/d	[5]	See Note	1.8	0.0	0.2	2.1
Fraction for sale, %	[6]	[5]/[4]	15%	0%	5%	5%

Notes:
General: All gas volumes are in Groningen equivalent i.e. 35.17 MJ/m^3.
[1]: Constructed production capacity from GTS Gas Capacity Plan 2002.
[4]: Grijpskerk and Alkmaar constructed injection capacity from BET report "Technical Study Gas Storage" 16/05/2001. Norg injection capacity estimated by TBG.
[2],[5]: Websites of storage operators; www.alkmaargasstorage.nl, www.nam.nl

We note that in theory, gas storage in neighbouring countries could provide load-factor conversion services for the Dutch market. In practise this is difficult due to the time required for the gas to travel from the foreign storage to the GTS entry point. The European Commission notes that "the economic radius for pore storage is less than 200 kilometres."[9] However D-gas – a German gas company – is developing a storage facility near Bunde-Oude, near the Dutch-German border. According to D-gas and some market participants this will give some extra flexibility for the Dutch gas market in the future. We do not yet know the technical details of the proposed D-gas storage.

[9] Commission Decision of 29.09.1999 declaring a concentration compatible with the common market and the EEA Agreement (Case No IV/M.1383 – Exxon/Mobil).

Production Swap

Although small onshore fields can provide seasonal swing, Groningen is the only production field capable of providing any significant amount of daily load-factor conversion. Gasunie Trade & Supply currently has exclusive access to the Groningen field, including the field's swing capability, and we expect that the new Shell and ExxonMobil wholesale companies will inherit this exclusive access.[10] Gasunie Trade & Supply does not currently offer a "production swap" service, as described in this report. Consequently, none of the Groningen field's swing capability is available to other shippers, except indirectly through the purchase of the GTS flexibility service.

Other Sources

We are unaware of any other significant sources of daily load-factor conversion that exist at this moment.

3.2 Supply of Quality Conversion

Switching Gas Quality

Shippers can supply L-gas by first purchasing H-gas, and then paying for quality conversion. Quality conversion (QC) usually involves either adding nitrogen to the H-gas to lower its calorific value, or blending the H-gas with large volumes of L-gas.

Shippers can also buy L-gas from Gasunie, instead of purchasing QC services. However, buying L-gas from Gasunie would not introduce competition to L-gas *production*. Gasunie would remain the monopoly supplier of L-gas, and could charge a monopoly price. In contrast, QC services permit shippers in theory to offer lower prices than Gasunie in the L-gas market, forcing Gasunie to reduce the price of L-gas. Potential competition relies on a sufficiently low H-gas price, and on QC services being inexpensive and abundant. QC services are essential for placing real competitive pressure on L-gas prices.

Consumers can also switch from L-gas to H-gas by modifying their gas burner equipment and/or reducing the delivery pressure. An LDC could theoretically switch to H-gas by first connecting the distribution system to the H-gas transmission network, and by then reducing the delivery pressure of the gas after ensuring that all connected customers had central heating systems and boilers compatible with H-gas. Some large industrial consumers may independently be able to invest in new H-gas pipelines that would connect them to the Dutch H-gas network, although this clearly would not be practical for smaller users or households.

Quality Conversion Capacity

We estimate that GTS has approximately 430,000 m^3/h of nitrogen generation capacity, which is enough to generate over 16 bcm/yr of L-gas assuming a load factor of

[10] According to DTe, this was also proposed by the Minister of Economic Affairs in spring 2002.

70%. However, the majority of this capacity is committed to Gasunie Trade & Supply on a long-term basis. GTS offers the remaining quality conversion capacity on a first-come-first-served basis. GTS does not disclose the total amount of quality conversion capacity that is available. We therefore cannot predict how much L-gas other shippers could generate, but we suspect that the volume is small relative to the size of the L-gas market.

In addition to the GTS quality-conversion capacity, one LDC in the Netherlands (Delta) has built a QC facility. The facility can produce 0.5 bcm/yr of L-gas. Note that the Delta quality conversion facility can only serve customers on the Delta distribution network, and could not be used by shippers to serve customers in other parts of the country.

3.3 Import Capacity and Gas Supplies

In addition to purchasing switching services, a shipper must obtain gas supplies to serve LLFL-gas customers. A shipper can either purchase gas from a shipper or producer within the Netherlands, or can import gas from other countries. Both methods of securing H-gas face problems.

Much of the H-gas produced within the Netherlands has been committed to Gasunie Trade & Supply through long-term contracts. NAM, which produces between 75-80% of Dutch gas and has rights to the vast majority of exploration areas, has historically sold exclusively to Gasunie Trade & Supply. New gas fields in the Netherlands are developing only slowly.

In the absence of access to indigenous Dutch gas, the shipper must import gas. GTS has disclosed the transport capacity available for imports from 1st January 2003 to 30th April 2004.[11] Extrapolating to the remainder of 2004, we estimate that available firm transport capacity would suffice to import approximately 2.3 bcm of H-gas in 2004, via Zelzate and the Ruhrgas and Wingas connections at Oude Stantenzijl (Appendix 2 provides details). The available capacity represents only 10% of the physical capacity at these import points. Our calculations indicate that the available firm import capacity can serve no more than approximately 10% of the LLFL-gas market.

H-gas can also be “imported” via backhaul in a direction that opposes the physical flow of export gas (counter flow). However, backhaul transportation service is not as reliable as direct import capacity.[12] In principle, the quantity of exports provides the only limit to the volume of gas that can be “imported” via backhaul routes. Gasunie exports approximately 16 bcm/yr, making it theoretically possible to import an equivalent amount of backhaul gas. However, the majority of LLFL-gas customers have stringent security of supply requirements (see discussion on back-up services below), which raises doubts

[11] Available from www.gastransport.nl

[12] Reverse flow is not possible at these ‘backhaul’ import locations. Hence the import of gas physically takes place by reducing the flow of export gas. However, once the export flow has reached zero, no import would be possible, hence the interruptible nature of backhauls imports.

about the ability of shippers to attract LLFL-gas customers with interruptible import capacity.

In principle it would also be possible to import L-gas from Germany, although we understand that the quantity of L-gas for sale there is limited. We do not consider German L-gas to be a significant source of supply for the Dutch LLFL-gas market.

The limited amount of available firm import capacity need not impede competition in the Netherlands. Imagine a situation where shipper A imports gas to serve a Dutch customer, who then decides to switch to shipper B. Assume the absence of spare import capacity. By losing the customer, shipper A would also lose the need to hold the import capacity. This import capacity should become available to shipper B. Alternatively, shipper A might initially serve the customer with Dutch gas. In this case one of two things could happen. Upon losing the customer to shipper B, shipper A could curtail the purchase of gas from the Dutch producer, making the capacity available for shipper B. Alternatively, imagine that shipper A (or the producer) decided to export the "spare" gas that the customer previously consumed. Exporting gas would make more import capacity available for shipper B. The need to acquire import or production capacity would not impede competition in any of these cases.

However, in reality new shippers will likely face problems acquiring import capacity or uncommitted gas production. For example, the incumbent shipper could refuse to relinquish import capacity to entrants. Implementing "automatic resale" rules can overcome this problem. We use the term "automatic resale" to describe a policy that permits the new shipper to acquire any entry or exit capacity that the previous shipper would no longer need after losing the customer, in exchange for appropriate compensation.[13] One could also imagine automatic resale rules for gas production, which would require a producer to offer gas to the new shipper, under the same price and delivery conditions that applied to the customer's previous shipper. However, no automatic resale rules, either for entry capacity or production, currently exist in the Netherlands.[14]

Competitors to Gasunie currently import H-gas into the Netherlands. Competitors bought and sold approximately 8 bcm of gas in 2000. However, we see several difficulties in obtaining *more* H-gas to serve Phase III customers: insufficient additional import capacity, the absence of uncommitted domestic gas supplies, and the absence of automatic resale rules.

[13] We initially developed the concept of automatic resale rules in our work for the European Commission: "Convergence of Non-Discriminatory Tariff and Congestion Management Systems in the European Gas Sector", *The Brattle Group*, September 2002, pp. 67-72. The report can be downloaded from http://europa.eu.int/comm/energy/library/ madrid6/brattlestudy.pdf. We propose that the TSO serve as an intermediary for handling the payments that would compensate the previous shipper for released capacity.

[14] We refer only to the absence of explicit rules. The principles of competition law can require a dominant shipper to release unneeded capacity to competitors, but we offer no opinion on Dutch competition law.

3.4 Back-up Services

A distinguishing feature of the LLFL-gas market is the predominance of household consumers and greenhouses. For various reasons these consumers demand a high level of security of supply. In contrast, some industrial customers who have already switched to new shippers can accept occasional interruptions in exchange for lower gas prices.

A customer can continue to consume gas after the shipper has experienced an interruption to its supplies. The GTS transportation system addresses this possibility with imbalance rules. However, GTS has no explicit legal obligation to continue supplying customers if their shippers are out of balance. To assure household customers of continued supply, a shipper would likely require a "back-up contract" with someone else who could continue delivering gas if the shipper experienced a disruption to its primary gas source. Without a back-up contract that guarantees delivery, we are concerned that a shipper will face difficulties attracting LLFL-gas customers.

We understand that back-up contracts can be negotiated at gas trading hubs such as Zeebrugge. However, importers have a limited ability to provide such back-up contracts, and are unlikely to assure security for much of the LLFL-gas market. Only the Groningen field can provide suitably robust and plentiful back-up service. The field has the ability to increase production quickly, has spare capacity and has a high level of redundancy built into its production facilities.[15] However, Gasunie Trade & Supply has no inherent financial incentive to offer "Groningen" back-up contracts to competitors. We conclude that difficulties in obtaining back-up service can represent a significant barrier to competition for LLFL-gas customers.

We note that this problem may be solved by legislation currently proposed in the Dutch parliament. A proposed amendment to the Dutch Gas Act would assign GTS responsibility for security of supply. One interpretation of the law could be that it prevents GTS from interrupting customers even when their suppliers experience disruptions. This interpretation would eliminate potential concerns of LLFL-gas customers with switching to new shippers. This interpretation could also facilitate the use of interruptible import contracts to serve the LLFL-gas market, largely overcoming the problem of insufficient firm import capacity. Of course, we do not urge any interpretation of the proposed amendment that would oblige GTS or NAM to provide security without appropriate compensation. We recommend compensating the providers of back-up services reasonably, which can happen with reasonable balancing rules.

3.5 Demand for Switching Services

The size of the LLFL-gas market drives the demand for switching services. In this report we define the LLFL-gas market as those consumers with a load factor less than or equal to the profile shown in Figure 1. To estimate the size of the LLFL-gas market precisely, we would require detailed information concerning the off-take profile of the

[15] The Groningen System (the field plus the underground gas storages) was designed so that at most it would fail to meet demand only once in 50 years. In practise it has never failed to meet demand.

typical household, greenhouse and large user listed in Table 2. In the absence of this information, we assume that all households and greenhouses, and half of the large users in Table 2 qualify for the LLFL-gas market. This assumption implies a size of 20 bcm/yr for the LLFL-gas market in 2000. As we note elsewhere, households and greenhouses consume different amounts of gas depending on the severity of the Dutch winter, and therefore the size of the LLFL-gas market can vary.

3.6 Summary

We have identified the services that shippers would need to serve newly eligible Phase III customers, consuming L-gas at a variable rate throughout the day. Although we do not have numerical estimates concerning the amount of each load-factor and QC service available, we have reason to anticipate a significant shortage of switching services compared to potential demand. Currently available linepack and storage together suffice to serve 4 bcm/yr of LLFL-gas, which represents only 20% of the LLFL-gas market. Successful competition would rely on the availability of significant flexibility services at reasonable prices. The most likely source of flexibility is Groningen, but there is no explicit rule requiring Groningen to provide such services. Rules would also be required to ensure the availability of sufficient QC services. Table 7 summarises the supply of switching services.

Our estimate in Table 7 is conservative because we perform the calculation based on an average off-take profile over the year. Considering winter days of peak demand could reduce our estimates. Peak demand is most likely to occur on cold days, when GTS reduces the amount of bundled hourly tolerance to 0%. We also note that Gasunie Trade & Supply controls the vast majority of switching services, and would maximise profits by withholding these services from other shippers.

A shortage of switching services would limit competition in the wholesale market, possibly raising the price of LLFL-gas. These price increases would be passed onto Phase III customers. Prices will ultimately depend on the quantity of switching services available, their price, and the L-gas pricing policies of the new Shell and ExxonMobil wholesale companies. We discuss possible L-gas pricing policies in the next section.

In a well-functioning market, high prices for flexibility and quality conversion services should prompt market entry and new build. However, the current Dutch market presents significant risks for the construction of new storage or quality-conversion facilities. There is no *physical* shortage of flexibility or quality conversion. Rather, *there is a shortage of services available to non-Gasunie shippers*. A potential storage developer could therefore face the risk of an adverse response by NAM. NAM could temporarily increase access to its existing facilities at reduced prices, which could bankrupt the new entrant. Building new capacity is risky in the absence of a physical shortage, and more so in a market where one company controls the majority of existing capacity.

Table 7: Supply of switching services for 2003

	Comment	Volume of LLFL-gas that can be generated (bcm/y)
Load Factor Conversion		
Free GTS Tolerance	Provided largely by linepack, which is under the control of GTS.	2.3
GTS Tolerance Capacity	GTS must buy this tolerance capacity from Gasunie, who could in principal decide not to offer any for sale.	Unknown
Storage	In practise this number should be heavily discounted, due to the difficulty of using storage for hourly balancing.	1.7
Quality Conversion		
GTS QC Capacity offered	The majority of quality conversion capacity is contracted to Gasunie Trade & Supply.	Unknown
Delta QC	This capacity can only be used in the local Delta region.	0.5

4 L-Gas Pricing After Phase III

4.1 The Pricing Policy of EZ[16]

The Minister for Economic Affairs currently has the authority to approve the prices that the Groningen Maatschap charges to downstream gas wholesalers.[17] The Dutch government can also influence prices via its shareholding in the Groningen Maatschap (held via EBN). EBN can veto any price proposals made by NAM. Current government authority can prevent Gasunie from charging excessive prices to households.

Prices will become an issue after dismantling the old relationship between the Groningen Maatschap and Gasunie. The prices charged by the Maatschap have tax implications. If the Maatschap charges Shell and ExxonMobil low prices, then the Maatschap will record low profits, while in the absence of effective competition these low prices would allow Shell and ExxonMobil to earn high profits.[18] The transfer of profits from the Maatschap to Shell and ExxonMobil could seriously reduce the government's tax revenues, since the Maatschap faces a much higher tax rate than Shell and ExxonMobil. The Ministry of Economic Affairs has natural incentives to prefer prices that would maintain an equitable share of the profits between the Dutch taxpayer and the shareholders of Shell and ExxonMobil.

There are no plans to regulate the prices of the new Shell/ExxonMobil wholesale companies. Price controls might not be necessary in the presence of sufficient competition from H-Gas. However, we find the prospect of vigorous competition between the two new wholesale companies unlikely. We have not yet discussed these issues with the Ministry.

4.2 Gasunie's Pricing Policy

Gasunie has traditionally set gas prices according to the "market value" principle, which means by reference to the prices of alternative fuels available to particular sets of customers. For example, Gasunie set the gas price for households to approximate the cost of gas oil, on a €cents/MJ basis. Gasunie uses fuel oil as the reference price for slightly larger gas consumers.

We note that in the past Gasunie *could* have priced its gas as the market value *plus* the cost of switching to the alternative fuel, and not lost any customers. This strategy would

[16] Much of this subsection is based on information provided by the Dutch Ministry of Economic Affairs.

[17] The production licence for Groningen gives the Minister this authority.

[18] If Shell and ExxonMobil competed actively with each other, then low prices from Maatschap would translate into low prices for consumers, and the profits of Shell and ExxonMobil would not be affected. We explain this possibility in a separate section below.

have maximised profits. However, the Dutch government has had authority over prices, and the Dutch State clearly has other objectives than maximising profits.

The Dutch State will not have a shareholding in either of the Shell and ExxonMobil supply companies that will inherit the Gasunie supply business. Under purely private ownership, the Shell and ExxonMobil companies will have natural incentives to maximise profits. In the absence of intervention to address the barriers that we identified above, the new profit-maximising policy could *increase* gas prices for consumers.

4.3 Possible Future Pricing Policies

Competition between Shell and ExxonMobil?

When deciding on the price of LLFL-gas in a fully liberalised Dutch gas market, Shell and ExxonMobil could decide to compete vigorously with one another. If this scenario materialised, all the potential problems envisaged in this report would be avoided. L-gas prices would fall, and the identified shortage of switching services would be irrelevant.[19]

However, we see several grounds for concern that competition between the two new wholesale companies would not be sufficient. First, the old Gasunie contracts may not be divided between the two new wholesale companies in a way that encourages competition. For example, if ExxonMobil inherits all of the Gasunie contracts related to the supply of LLFL-gas, and Shell inherits the contracts that only relate to export markets, then the two companies might not compete to sell L-gas in the Netherlands. Second, the two wholesalers might prefer not to compete for each other's customers. An explicit agreement not to compete would be illegal, but the companies might naturally refrain from competing in the absence of an explicit agreement. Shell and ExxonMobil have a long history of co-operation in the European gas industry, and are joint shareholders in NAM. In addition, the staff of the new wholesale companies will know each other well, having previously worked for the same company. The two companies would be selling their products in relatively mature markets, and the products are not highly differentiated. Economists recognise that all these factors support an equilibrium in which companies with high market shares prefer to charge high prices rather than compete vigorously.

Pricing in the absence of competition

Assuming an absence of competition between Shell and ExxonMobil yields interesting results. The two companies might find it attractive to offer L-gas at a price that *exceeds* the sum of the H-gas price and the cost of switching services. We call this the

[19] In principle, competition would force the LLFL-gas price to approach the transfer price at which NAM sells gas to Shell and ExxonMobil. A sufficiently low transfer price could permit Shell and ExxonMobil to sell at a lower retail price than all potential entrants. Consider a transfer price of 8 €cents/m^3 for LLFL-gas between NAM and Shell/ExxonMobil. If the HLFH-gas price is 10 €cents/m^3 and switching costs to LLFL-gas are 0.83 €cents/m^3 (Route 1 in section 6.1 below), then H-Gas shippers cannot offer LLFL-gas for less than 10.83 €cents/m^3. Shell and ExxonMobil could offer LLFL-gas at any price down to 8 €cents/m^3. H-gas shippers would no longer see any potential profit from the purchase of switching services, no matter how low the cost. The cost of switching services would become irrelevant.

"high price" policy, which would create room for other shippers to sell L-gas profitably, taking some business from Shell and ExxonMobil. Alternatively, Shell and ExxonMobil could price the L-gas at *just below* the price of H-gas plus the cost of switching services. We call this the "low price" policy.[20]

The attractiveness of the high-price policy depends on the volume of LLFL-gas sales that Shell and ExxonMobil might lose to other shippers. This in turn depends on the quantity of switching services available. If a large quantity of switching services were available, Shell/ExxonMobil might find that the high-price policy threatens an excessive loss of market share. Limitations to the quantity of switching services could make the high-price policy extremely attractive.

Logically there must be a critical amount of switching services, which if exceeded would make the low-price policy more attractive than the high-price policy. The critical amount depends on a number of factors, and is hard to calculate accurately. However, in Appendix 3 we develop a simple market model, which indicates that the critical amount of switching services could be between 8 and 10 bcm/yr. The current amount of switching services is insufficient to support these volumes. We conclude that Shell and ExxonMobil would likely find the high-price policy more attractive.

We also note that in the absence of government intervention, Shell and ExxonMobil would control *the supply of load-factor conversion services*. Therefore the quantity of switching services mentioned above is not exogenous. As the model in Appendix 3 demonstrates, Shell and ExxonMobil will always make more profit by using switching services themselves, as opposed to offering the services to others. Shell and ExxonMobil would not rationally offer sufficient switching services to make the low-price policy more attractive.

What would the price be under the high-price policy? In principle, Shell and ExxonMobil could not sell LLFL-gas at a higher price than the price of HLFH-gas plus the demand-side switching cost, without the risk of losing customers. In section 6.2 we estimate these costs at between 9 and 14% of the HLFH-gas price, but we also conclude that the price of LLFL-gas could exceed this level because we see several practical obstacles to customer switching. Shell and ExxonMobil would have incentives to charge higher LLFL-gas prices, constrained only by political pressure and the threat of intervention by regulatory and competition authorities.

We have considered the possibility of an additional pricing strategy: "predatory pricing". Predatory pricing describes a strategy where Shell and ExxonMobil would initially charge very low prices to discourage competitors, and then switch to charging high prices after eliminating competitors from the market. Predatory pricing could possibly permit ExxonMobil and Shell to sustain the high-price policy without sacrificing market share to competitors. We do not find it necessary to explore predatory pricing in detail. Even if predatory pricing were likely, it would not yield different policy implications than the possibility of the high-price strategy considered in isolation.

[20] The low-price policy could still be profitable depending on the NAM sales price.

5 Market Definition

We wish to determine if different gas products in the Netherlands represent separate markets. Markets must be defined appropriately before conducting any meaningful discussion of potential market power abuse or competitive problems.

5.1 The SSNIP Test

To define the relevant markets, we apply the "small but significant and non-transitory increase in price" (SSNIP) test:[21]

> The question to be answered is whether the parties' customers would switch to readily available substitutes or to suppliers located elsewhere in response to a hypothetical small (in the range 5 % to 10 %) but permanent relative price increase in the products and areas being considered. If substitution were enough to make the price increase unprofitable because of the resulting loss of sales, additional substitutes and areas are included in the relevant market. This would be done until the set of products and geographical areas is such that small, permanent increases in relative prices would be profitable.

We apply the SSNIP test as follows: Imagine two different products, A and B. Many producers compete to make and sell product A at a competitive price. The SSNIP test addresses the following question: if the producers of A merged to form a single company, could they profitably and sustainably raise the price of A by 5-10% above the competitive price?

If a price rise of 5-10% caused many consumers to switch from product A to B, then the price increase would be unprofitable. In this case, the SSNIP test logic would imply that product A and product B are close substitutes, and occupy the same market. However, if relatively few consumers switched from A to B following a price increase, we would conclude that the two products were not close substitutes, and that product A represented a separate market.

By how much could the price of A rise without causing consumers to switch to B? Imagine that consumers faced costs in switching to B. We refer to such costs as the "demand-side switching costs", because consumers incur the costs, and consumers demand the products. The switching costs help determine the potential increase in the price of A. If the competitive price of B was 10, and switching to B cost 2, then a hypothetical merger of all the producers of A could not raise the price above 12. At any price higher than 12, consumers would pay the switching cost and use the alternative product.[22]

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[21] Paragraph 17 of the *Commission Notice on the definition of relevant market for the purposes of Community competition law,* Official Journal C 372, 09/12/1997, pp.5–13.

[22] Note that we assume that consumer demand is inelastic, at least to the extent that the loss of sales before customers switch to the alternative product is negligible.

Imagine that the competitive price for A was 8. After the hypothetical merger, the single producer of A could raise the price of to 12, which represents an increase of 50% (12 – 8 = 4, and 4/8 = 50%). The SSNIP test would therefore classify product A in a separate market from B. Table 8 summarises the calculation.

Table 8: Example SSNIP calculation

Pre-merger price of A	[1]		8
Price of B	[2]		10
Cost of switching from A to B	[3]		2
Maximum price of A, post-merger	[4]	[2]+[3]	12
Maximum price increase of A, post-merger	[5]	[4]-[1]	4
Maximum percentage price increase of A, post-merger	[6]	[5]/[1]	50%

The SSNIP test is summarised in Equation 1, where P_B is the price of product B, S is the cost for consumers to switch from A to B, and $P_{A,C}$ is the competitive price of A.

Equation 1: SSNIP test

$$\frac{P_B + S - P_{A,C}}{P_{A,C}} \geq 5 - 10\%$$

The discussion above only considers that consumers may switch products. However, perhaps a producer of B could profitably switch to making A, if the price of A were high enough. Switching to A may cause the producer to incur a cost: the "supply-side switching cost". The SSNIP test is conceptually identical whether we imagine consumers or producers switching from A to B.[23] However, the supply-side and demand-side switching costs may differ. Proper competitive analysis should consider the lowest switching cost, whether it is associated with the demand-side or supply-side of the market.

5.2 Product Selection

To apply the SSNIP test, we first select some gas "products" which plausibly substitute for each other. We focus on two defining characteristics of a gas product: its calorific value and its load factor at the customer delivery point.

[23] The Commission acknowledges the potential use of supply-side switching costs in competition analyses: "supply-side substitutability may also be taken into account when defining markets in those situations in which its effects are equivalent to those of demand substitution in terms of effectiveness and immediacy." (Paragraph 20 of the Commission notice cited at 21). Economists would use slightly different language when analysing supply-side switching costs. If the producers of B could switch to producing A at less than 5%-10% above the competitive price for A, then economists might still say that B and A represent different markets, but would agree that a competitive analysis of A must include the *producers* of B.

In the Exxon-Mobil merger,[24] the European Commission looked at calorific value as a factor that potentially defined separate markets. The Commission noted that L-gas and H-gas might constitute separate markets in the Netherlands, but decided that making a distinction was not "necessary for the purpose of this case".[25] The Commission defined L-gas as having a Wobbe Index of "up to 13 kWh/m³ [46.8 MJ/ m³]." GTS defines four different gas qualities: 43.8 MJ/m³, 44.39 MJ/m³, 46.51 MJ/m³ and 51.98 MJ/m³. We follow the Commission's definition in our analysis.

In section 2 we noted that LDCs supply households, who consume gas at a relatively low load factor. The Commission also notes that "[l]ocal distribution companies buy from the wholesale companies the swing and other related services. The Commission therefore agrees with the parties that local distribution constitutes a distinct product market." We examine load factor as the second defining characteristic of a gas product.

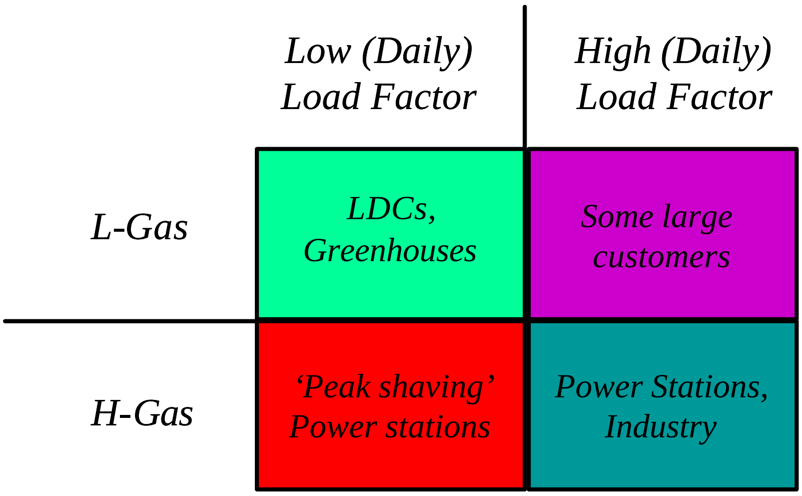
We distinguish between "seasonal swing" and "daily swing". Seasonal swing involves storing gas (or curtailing deliveries) in the summer and withdrawing from storage (or increasing gas production) in the winter. Daily swing describes similar behaviour during the gas day: reducing deliveries to consumers during hours of low demand, and increasing deliveries during peak hours. Conversations with shippers in the Netherlands have confirmed that the supply of seasonal swing is greater than daily swing. Producers outside the Netherlands can provide seasonal swing, but daily swing can only be provided locally. It would not be feasible for a Norwegian gas producer to adjust production to match hourly consumption in the Netherlands. The inherently local nature of daily swing limits its supply, which tends to raise prices. We conclude that the degree of daily swing will more likely define separate markets. We therefore focus on daily load factors.

We conclude that four different gas products could plausibly substitute for each other (Figure 3): High-Load-Factor H-gas (HLFH-gas), Low-Load-Factor H-gas (LLFH-gas), High-Load-Factor L-gas (HLFL-gas) and Low-Load-Factor L-gas product (LLFL-gas). In Appendix 4 we provide the rationale for excluding other sources of energy such as electricity or fuel oil from the market definition.

[24] Commission Decision of 29.09.1999 declaring a concentration compatible with the common market and the EEA Agreement (Case No IV/M.1383 – Exxon/Mobil).

[25] The Commission found that L-gas and H-gas formed part of the *same* market in *Germany*, but the Commission did not feel compelled to reach the same conclusion in the Netherlands. The Commission did not disclose sufficient information concerning its analysis of switching costs in Germany to permit a full evaluation.

Figure 3: Gas products



5.3 Switching Between Products

A relatively diverse number of independent companies can supply HLFH-gas to the Netherlands. The supply of HLFH-gas is potentially competitive. In contrast, NAM and Gasunie dominate the supply of LLFL-gas.

Box 2: LLFL-gas and 'phase III consumers'

We differentiate between a LLFL-gas product and a HLFH-gas product, because the latter is served by a relatively diverse group of producers and the former is served mainly by NAM/Gasunie. We note that the purpose of this report is to determine if, following the third and final phase of market opening, there will be effective competition to supply the newly eligible 'phase III customers.' However, phase III customers consist largely of households and greenhouses, that consume L-gas at a low load factor *i.e.* they consume the LLFL-gas product as we define it. Clearly there is a large degree of overlap between newly eligible phase III customers and consumers of LLFL-gas. Therefore, determining if LLFL-gas defines a separate market, and whether one company has a dominant position in that market, will be crucial in determining the degree of competition to supply phase III customers.

If HLFH-gas and LLFL-gas were part of the same market, then the diversity of HLFH-gas producers could prevent NAM and Gasunie from exercising market power. NAM and Gasunie could not successfully raise the price of LLFL-gas much above HLFH-gas levels, because consumers would switch products. We conclude that it is important to determine whether HLFH-gas and LLFL-gas are part of the same market.

We examine both supply-side and demand-side switching costs to determine whether HLFH-gas and LLFL-gas are part of the same market. The supply-side switching costs involve the possibility of shippers converting HLFH-gas to LLFL-gas. Demand-side switching costs involve the possibility of consumers switching from LLFL-gas to HLFH-gas, if NAM and Gasunie try to exercise market power. We define markets based on the lowest switching costs.

5.4 Applying the SSNIP Test to Natural Gas

The SSNIP test requires estimates of competitive prices for different products. If several independent companies compete to make the product, then the prevailing market price would likely represent a competitive price. In the absence of independent competitors, the prevailing price may not be competitive. Proper application of the SSNIP test should consider what the LLFL-gas price would be if there were many competing suppliers.[26]

We see good reasons to believe that the *short-term* competitive price for LLFL-gas would be less than its current market price. First, we understand that the cost of production from the Groningen field is relatively low because it is onshore, which tends to reduce extraction costs, and which also eliminates the need for expensive offshore pipelines. The location of the field in the Netherlands eliminates the need for transit pipes. Economists acknowledge that competitive prices for scarce resources need not track marginal operating costs perfectly, but also depend on the expected duration of the resource. However, we do not consider this factor significant for the present analysis. The Groningen field is expected to last for several more decades, consistent with estimates of the gas resources available to Europe as a whole. The relative marginal cost advantage at Groningen should therefore reflect a lower competitive price. Finally, the current price for LLFL-gas may exceed the short-term competitive price because the HLFH-gas market itself is not perfectly competitive. Even if LLFL-gas and HLFH-gas form part of the same market, imperfect competition in the market could still permit the current LLFL-gas price to exceed competitive levels.

Nevertheless, we make the conservative and simplifying assumption that the competitive price of LLFL-gas is equal to the market price of HLFH-gas: we effectively set P_B equal to $P_{A,C}$ in Equation 1, which yields Equation 2, where S is the (demand or supply side) cost of switching between HLFH-gas and LLFL-gas and P is the market price for HLFH-gas. Put simply, in this context the SSNIP test requires that *if the cost of switching between LLFL-gas and HLFH-gas is greater than 5-10% of the HLFH-gas price, then LLFL-gas defines a separate market.*

Equation 2: SSNIP test for LLFL-gas and HLFH-gas

$$\frac{S}{P} \geq 5-10\%$$

In the following section we estimate demand-side and supply-side switching costs as a percentage of the HLFH-gas price.

[26] Paragraph 19 of the Commission notice cited at 21.

6 Switching Cost Estimates

In this section we calculate supply-side and demand-side switching costs. We first estimate switching costs based on the advertised tariffs for load-factor and quality-conversion services. We then consider the likely price of switching in the secondary market, given the anticipated scarcity of switching services. In line with the European Commission's market definition methodology, we do not consider the long-run switching costs of building new blending facilities or investing in new sources of flexibility such as storage.[27]

6.1 Supply-Side Switching

We estimate the costs of Load-Factor Conversion and Quality Conversion for a shipper who wishes to deliver LLFL gas with a Wobbe Index of 12.33 kWh/Nm^3. We use the demand profile shown in Figure 1, which involves a load factor of 64%. The shipper injects H-gas with a Wobbe Index of 14.44 kWh/Nm^3 at a constant hourly rate. Switching costs consist of Load-Factor Conversion services to avoid incurring imbalance penalties (see Box 1),[28] and Quality Conversion services. We assume that the (adjusted) ambient temperature exceeds 0ºC, so that shippers can enjoy the full 13% of GTS bundled hourly tolerance before incurring imbalance penalties.

Equation 2 above shows that the HLFH-gas price is an input to the SSNIP test. We test the sensitivity of market definition to alternative HLFH-gas prices. We estimate switching costs as a percentage of the gas price using two price scenarios produced from a recent independent forecast.[29] The "high" price is US$ 3/MMBtu (€c 12.15/Nm^3 H-gas), and the "low" price is US$ 2/MMBtu (€c 8.1/Nm^3 H-gas). We identify four possible ways of converting HLFH-gas to LLFL-gas. Below we discuss the switching costs associated with these conversion "routes".

[27] The Commission notes that appropriate market definitions should only consider the switching costs of suppliers who can "switch production to the relevant products and market them in the short term without incurring significant additional costs or risks in response to small and permanent changes in relative prices." The Commission defines the short term as "a period that does not entail a significant adjustment of existing tangible and intangible assets… [when] supply-side substitutability would entail the need to adjust significantly existing tangible and intangible assets, additional investments, strategic decisions or time delays, it will not be considered at the stage of market definition." *Commission Notice on the definition of relevant market for the purposes of Community competition law,* Official Journal C 372, 09/12/1997.

[28] Due to the level of GTS imbalance charges, with perfect foresight about demand it is always cheaper to buy some form of flexibility services rather than pay imbalance charges.

[29] See Jonathan Stern, Royal Institute of International Affairs, "Traditionalists versus the New Economy: Competing Agendas for European Gas Markets to 2020". The prices used cover a range of scenarios for European gas prices.

Route 1: GTS Flexibility Service and "Peaky" QC

Route 1 involves the purchase of GTS flexibility service and "peaky" QC, by which we mean the use of QC at a low load factor. We estimate the costs based on the tariffs published in "Transmission service Agreement 2003-2" (Model 11, November 2002). Table 9 summarises the results.

Table 9: Switching costs for route 1

	Cost, €	As % of H-gas price		Cost
		Low price	High Price	€cents/m3
Annual QC Cost	85,603	4.0%	2.7%	0.32
Annual LF Conversion Cost	135,898	6.3%	4.3%	0.51
Total Cost	221,500	10.3%	7.0%	0.83

Route 2: H-gas Storage and "Peaky" QC

Under this route, a shipper avoids imbalances by injecting H-gas into storage at periods of low demand, and withdrawing during peak hours. The shipper purchases storage in the Grijpskerk facility, paying the advertised price for the offered bundle of injection, withdrawal, and storage capacity.[30] This route presents additional gas transport costs, as the shipper must pay to transport gas to and from the storage site. We account for these extra transport costs using GTS's entry and exit tariffs at Grijpskerk. The shipper purchases QC as in Route 1. Table 10 summarises the results for Route 2.

Table 10: Switching costs for Route 2

	Cost, €	As % of H-gas price		Cost
		Low price	High Price	€cents/m3
Annual QC Cost, €	85,603	4.0%	2.7%	0.32
Annual LF Conversion Cost, €	473,506	22.0%	14.9%	1.78
Total Cost	559,109	26.0%	17.6%	2.11

In practice shippers would face several problems using Grijpskerk for daily load factor conversion. A "minimum flow" requirement makes the injection and withdrawal service unreliable. If the net injections or withdrawals do not meet certain thresholds, then NAM will either reject or adjust shipper nominations, exposing shippers to the risk of incurring imbalance penalties.[31]

[30] Tariffs are taken from NAM's "Standard Long Gas Storage Services Agreement [sic]" between NAM and a shipper. The contract details can be found at http://www.nam.nl

[31] For further details on storage service issues, see "Access to Storage in the Netherlands", May 2002, *The Brattle Group*.

Route 3: L-gas Storage and Flat QC

This route is identical to Route 2 described above, except that the shipper converts H-gas to L-gas *before* storage. Converting the H-gas prior to storage would permit the use of QC service at a higher load factor, which is 11% cheaper. However, the switching costs for Route 3 are actually higher than for Route 2, because the storage in Route 3 is more expensive. BP Amoco's Alkmaar storage is the only L-gas storage in the Netherlands that currently offers capacity to shippers other than Gasunie.[32] Alkmaar's injection capacity is relatively small in relation to its withdrawal and storage capacity. When purchasing the required injection capacity, shippers must also buy relatively large amounts of withdrawal and storage capacity. This makes the Alkmaar storage expensive for load factor conversion. Table 8 shows the result of the switching cost calculation.[33]

Table 11: Switching costs for Route 3

	Cost, €	As % of H-gas price		Cost
		Low price	High Price	€cents/m3
Annual QC Cost, €	75,999	3.5%	2.4%	0.29
Annual LF Conversion Cost, €	1,052,445	49.0%	33.0%	3.97
Total Cost	1,128,444	52.5%	35.4%	4.25

Route 4: Production Swap and QC

In principle a shipper could buy flexibility from another shipper who has access to flexible production, such as Gasunie. The shipper could import gas at a constant rate at Zelzate, but pay Gasunie to reduce nominations for domestic Dutch gas production during periods of low demand, to offset the shipper's excess deliveries at Zelzate. Similarly, Gasunie would request increased production during peak demand hours to supplement the Zelzate deliveries. The shipper would deliver all of the *volume* used by the customer, but Gasunie would provide the *swing*. In Appendix 1 we discuss production swaps in more detail.

A transaction between Duke Energy and Gasunie demonstrates the feasibility of this route.[34] However, Gasunie does not advertise tariffs for a "production swap" service, and Gasunie has no financial incentive to offer significant quantities of such a service. If Gasunie offered such a service at a lower cost than the cheapest alternative Route (Route 1), then Gasunie would only facilitate the loss of its sales to Phase III consumers. We therefore assume that the price of Route 4 would at least match the cost of Route 1.

[32] NAM operates L-gas storage at Norg, but no capacity is currently offered to non-Gasunie shippers.

[33] We use the 2002 Alkmaar tariffs as the basis for our calculation. See http://www.alkmaargasstorage.nl for details of the storage contract.

[34] Duke had a minority share in a producing field. Duke gave Gasunie control of the field in return for load factor conversion services.

6.2 Demand-Side Switching

We calculate the demand-side switching cost for a "typical" LDC. Total switching costs include the cost of changing the distribution system from L-gas to H-gas, and the cost of Load Factor Conversion. Although in principle consumers on the LDC's network could modify their off-take profile, in practise it would be cheaper for the LDC to buy Load Factor Conversion services in exactly the same way as shippers.

Quality Conversion

On the demand side, the cost of converting H-gas has two distinct elements. The first element is the cost of connecting the distribution network to the nearest point on the H-gas network. The second element is the cost of modifying burner equipment to accommodate the new gas quality. We understand that H-gas is readily available to LDCs in the Netherlands, so we ignore the cost of laying new pipes to connect with the H-gas network. We only consider the need to inspect and, if required, modify the equipment in the home of every LDC customer.

We do not have precise numbers on how many domestic Dutch boilers are compatible with H-gas. However, even if we supposed that the majority of consumers have boilers that are compatible with both H-gas and L-gas this would not lead to a significant reduction in switching costs. As the LDC does not know which of its customers have H-gas compatible boilers, it must still inspect the equipment in every consumer's home before switching to H-gas. Failing to modify an old boiler to accept H-gas could have serious safety consequences. Only an inspection can determine which consumers have modern boilers and which do not. This inspection requirement (and not the cost of converting some boilers to H-gas) is the main source of switching cost. Hence even if only 1% of boilers were incompatible with H-gas, but the LDC did not know which 1%, significant switching costs would still be incurred due to the inspection programme. Prior to the inspection, an LDC might also need to incur significant costs training technicians.

An LDC will incur different switching costs for households, small business and industrial customers. However, DTe estimates that over 90% of the switching costs for a typical LDC will relate to households. We therefore ignore the slightly lower switching costs for industrial and business users.

We have obtained estimates of household switching costs from the European Commission,[35] from the costs that Fluxys (the Belgian gas transportation company) incurred in its most recent switching campaign in the 1980s, and from DTe based on a technical study by an engineering consultant. It is hard to quantify the switching costs per customer, and the estimates therefore vary significantly. Table 12 summarises the cost of converting to H-gas, both per household and per €cents/m^3. The calculation in €cents/m^3 allocates the switching costs among each cubic metre of household gas consumption over twenty-five years, using a discount rate that reflects the financial risk to the LDC of deferring recovery over time.

[35] See footnote 24.

Table 12: Quality conversion cost estimates for households

Source of Switching Cost	[1]		European Commission	Fluxys	DTe
Cost of switching per Household (€)	[2]		60	118	944
Switching Cost (€cents/m3)	[3]	TBG	0.32	0.62	4.63
High Gas Price (€cents/Nm3)	[4]		12.15	12.15	12.15
Low Gas Price (€cents/Nm3)	[5]		8.10	8.10	8.10
Switching Cost as a percentage of a high gas price	[6]	[3]/[4]x100	2.6%	5.1%	38.1%
Switching Cost as a percentage of a low gas price	[7]	[3]/[5]x100	4.0%	7.7%	57.2%

Notes:

[4],[5]: Price assumptions are from a paper by Jonathan Stern of The Royal Institute of International Affairs entitled "Traditionalists versus the New Economy: Competing Agendas for European Gas Markets to 2020".

The cost of switching provided by DTe is significantly greater than both the Commission's estimate and the Fluxys estimate. Without evaluating the details of each estimate in more detail, we cannot account for the differences. We rely on the middle estimate provided by Fluxys, but note that the true costs of switching could be much higher.

Load Factor Conversion

We assume that the LDC would buy the cheapest Load Factor Conversion service on offer, which is the GTS flexibility service examined under Route 1. The costs of Load Factor Conversion are therefore identical to those for Route 1. Table 13 summarises the total costs of demand-side switching.

Table 13: Demand-side switching costs for an LDC

	Cost, €	As % of H-gas price		Cost
		Low price	High Price	€cents/m3
Annual QC Cost	164,538	7.7%	5.2%	0.62
Annual LF Conversion Cost	135,898	6.3%	4.3%	0.51
Total Cost	300,436	14.0%	9.4%	1.13

Incentives for system conversion

When considering demand-side switching costs, it is important to understand that *small L-gas customers on the distribution grid cannot independently decide to change from L-gas to H-gas*. Only the distribution grid operator (the LDC) can take the decision to change the system to H-gas. The authority of the LDC presents two key problems.

First, *the LDC has no financial incentive to respond to "high" L-gas prices by converting the system to H-gas*. Following full liberalisation of the gas market, LDCs will operate the distribution systems, while shippers sell gas to end consumers. Each LDC's income will derive from regulated commodity and capacity tariffs levied on shippers for using the distribution system. Whether or not the gas passing through the distribution system is "expensive" or "cheap" makes little difference to the LDC's income.[36] If the gas were very expensive, consumers might curtail demand (or even leave the network), which could reduce the LDC's revenues. However, this possibility is not likely to present significant financial consequences for the LDC, because consumer gas demand is relatively insensitive to price. In any case, the LDC might later be permitted to increase distribution tariffs to compensate for the reduced volumes, weakening the switching incentives further. In theory the regulator could order an LDC to switch to H-gas, but the Dutch Gas Act does not give DTe explicit authority on this issue.

The second problem involves *potential disagreements among LDC customers*. Even if a majority of LDC customers supported a conversion to H-gas, a minority might prefer to continue consuming L-gas. These customers may have secured supplies of L-gas for several months or years. The conversion might disrupt their supplies, prompting the customers to oppose the switch or demand compensation from the LDC. Potential disagreements could prevent or delay switching, or raise the switching costs.

Recall the purpose of our analysis: to assess the ability of a theoretical monopolist to increase prices without losing customers to H-gas. The problems outlined above could permit the price of LLFL-gas to exceed the cost of HLFH-gas plus the switching costs in Table 13. Therefore *the demand-side switching costs in Table 13 might significantly understate any distinction between the markets for HLFH-gas and LLFL-gas*.

6.3 Summary

Table 14 summarises the supply-side and demand-side switching costs for the various routes analysed.

Table 14: Summary of switching costs

	Switching cost as % of H-gas Price		
	Low gas price	High gas price	Cost (€cents/m3)
Supply-Side Switching			
Route 1	10%	7%	0.83
Route 2	18%	26%	2.11
Route 3	52%	35%	4.25
Route 4	10%	7%	0.83
Demand-Side Switching			
Route 1	14%	9%	1.13

[36] Even if the LDC retains a gas supply business, switching to H-gas would not likely increase profits, since a switch would raise the prospect of competition with other suppliers.

6.4 Conclusions on Market Definition

We estimate the minimum switching costs as 8.3 €cents/m^3, or between 7.0-10% of the HLFH-gas price. This level of switching cost is sufficiently high that *LLFL-gas defines a separate market*, according to the SSNIP test criteria. However, our estimates are conservative, because they neglect the effect that the shortage of switching services could have on price. A shortage of switching services could cause their prices to exceed significantly the levels that we use above. We anticipate a significant shortage of switching services after Phase III liberalisation.

7 Market Structure

After establishing that HLFH-gas and LLFL-gas represent different markets, we can now assess the question of market dominance. Competition law defines a dominant position as:[37]

> A position of economic strength enjoyed by an undertaking which enables it to prevent effective competition being maintained on the relevant market by giving it the power to behave to an appreciable extent independently of its competitors, customers and ultimately of consumers.

The two key tests for market dominance involve examining market concentration and barriers to entry.[38] For a firm to hold a dominant position it must have a large market share and the barriers to entry must be relatively high. The latter point is conceptually important—even a very large market share might not create a dominant position in the absence of entry barriers, because potential competition from entrants could restrain an incumbent's behaviour.

To determine market concentration in the LLFL-gas market, we need to answer the questions: which consumers are part of the LLFL-gas market, and who supplies them? Under the terms of the Dutch Gas Act, LDCs must buy the gas used to supply non-eligible customers from Gasunie. When Phase III liberalisation occurs, Gasunie will (via LDCs) initially supply 100% of the market– although customers will have the freedom to change supplier. In Box 2 (p. 28) we cite a large degree of overlap between Phase III customers and LLFL-gas consumption. Some LLFL-gas customers may already have become eligible under Phase II. Some Phase III customers may not consume LLFL-gas. Without more detailed information, we cannot quantify exactly the number of LLFL-gas consumers who will be eligible under Phase III. However, we estimate that the number of such consumers is large such that Gasunie's share of the LLFL-gas market is between 90% and 100%.

We have already identified several significant barriers to entry, which will limit the ability of new shippers to take market share from Gasunie. The shortage of switching services would itself limit the amount of the LLFL-gas market that other shippers can supply. Obtaining gas supplies and back-up contracts represent further barriers to entry. Given Gasunie Trade & Supply's high market share and the significant barriers to entry, we conclude that *Gasunie Trade & Supply has a dominant position in the LLFL-gas market*. After splitting Gasunie Trade & Supply into two separate companies, ExxonMobil and Shell will have a position of *collective dominance* in the LLFL-gas market, unless measures are taken to reduce entry barriers significantly.

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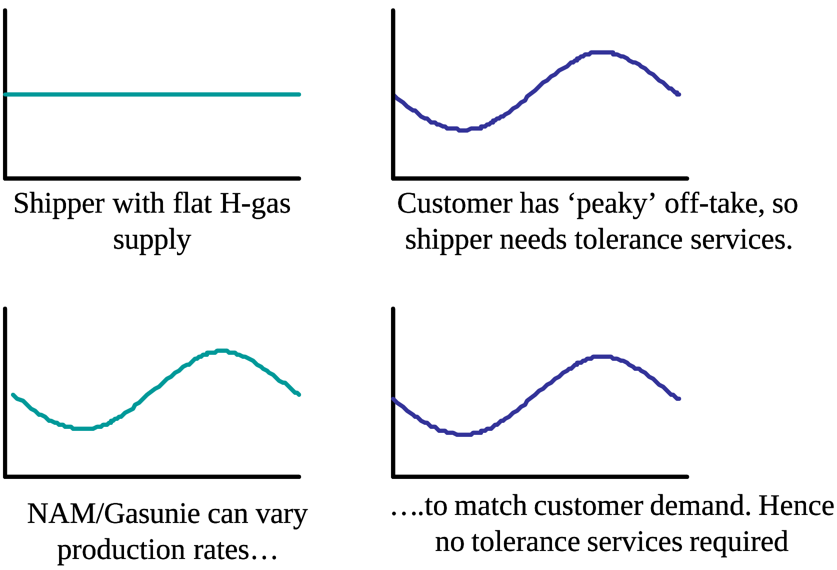
[37] Case 27/76 *United Brands v Commission* [1978] ECR 207.

[38] See Faull, J. and A. Nikpay, "The EC Law of Competition", Oxford University Press 1999, pp.124-136 for a detailed discussion of these tests and related matters.

Appendix 1: Production Swap Example

In section 6.1 we referred to a production swap, whereby a shipper delivers gas to Gasunie at a constant rate and Gasunie delivers the gas at a variable rate to the shipper's customer. Figure 4 illustrates the need for such a service. The shipper has access to only a flat source of gas, whereas the customer is using gas at a varying rate over the day, creating a peaky off-take profile. In contrast, NAM/Gasunie has access to the Groningen field, which can vary production rates to match customer demand. This is often referred to as 'swing' production.

Figure 4: The need for swing production

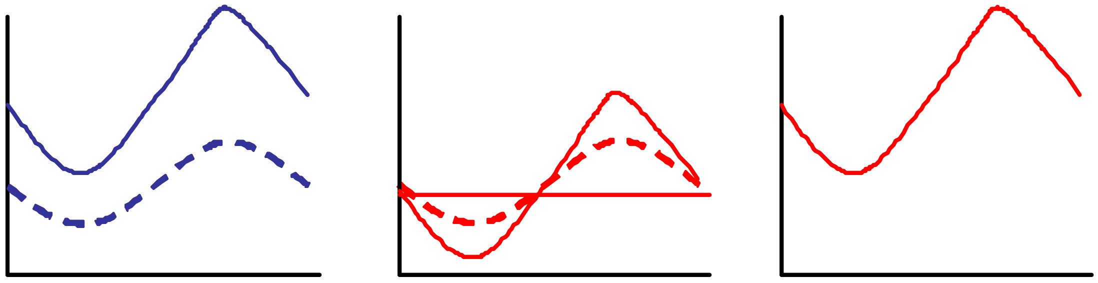


It would be possible for NAM/Gasunie to market its ability to vary production rates as a service to the shipper with a flat delivery profile. Such a service is illustrated in Figure 5, and could work as follows. NAM/Gasunie takes on the responsibility of delivering gas to the shipper's customer, so that the level of demand that NAM/Gasunie serves is in effect doubled. This is illustrated on the left hand drawing of Figure 5, where the dashed line represents NAM/Gasunie's original demand, and the solid line represents the demand that NAM/Gasunie must serve after the production swap has taken place.

The shipper delivers its flat supply of gas to NAM/Gasunie, who uses it to help serve customer demand. However, NAM/Gasunie adjusts production to make up the difference between the shipper's flat supply of gas and the (now doubled) customer demand *i.e.* NAM/Gasunie act as a swing producer. The middle of Figure 5 illustrates this process. The solid curvy line represents NAM/Gasunie's production, and the dashed curvy line represents what NAM/Gasunie's production was before the production swap. Note that, after the production swap, NAM/Gasunie' production has become much more variable *i.e.* they are producing at a lower load factor. This is because at the beginning of the gas day, the shipper is delivering too much gas to the market, relative to his customers needs. Consequently NAM/Gasunie must reduce their production to compensate. Later in the gas day, the shipper is under-delivering, and NAM/Gasunie must increase production to make up the difference. Hence NAM/Gasunie production is reduced at the beginning of the day

– relative to the situation without the production swap – and increased at the end of the day. The composite production profile, made up of the shippers flat delivery of gas and NAM/Gasunie's swing production profile, is illustrated on the right hand side of Figure 5, and exactly matches demand.

Figure 5: Selling production swing



Gasunie 'adopts' shippers customer. Demand is now x2.

Gasunie takes shippers flat L-gas, and varies its gas production…

...in order to create a total production profile which matches demand.

Note that NAM/Gasunie have not increased their *volume* of gas production, as the shipper still delivers all the gas volume that his customers consume. However, NAM/Gasunie do produce at a lower load factor, and this could incur additional production costs.

Appendix 2: Calculation Details and Data

Table 15 contains a detailed summary of the cost of profiling demand by four different routes.

Table 15: Detailed summary of switching costs

Input Data					
Annual Gas Volume Sold, mcm	[1]	26.5			
GTS Gas Price, €cents/m3 (low)	[2]	8.1			
GTS Gas Price, €cents/m3 (high)	[3]	12.0			
Annual value of gas sold (low), €	[4]	2,149,611			
Annual value of gas sold (high), €	[5]	3,184,609			
			As % of H-gas price		Cost
		Cost, €	High	Low	€cents/m3
		[A]	[B]	[C]	[D]
Route 1: GTS Tolerance Service and					
Annual QC Cost	[6]	85,603	4.0%	2.7%	0.32
Annual LF Conversion Cost	[7]	135,898	6.3%	4.3%	0.51
Total Cost	[8]	221,500	10.3%	7.0%	0.83
Route 2: H-gas Storage and 'Peaky'					
Annual QC Cost, €	[9]	85,603	4.0%	2.7%	0.32
Annual LF Conversion Cost, €	[10]	473,506	22.0%	14.9%	1.78
Total Cost	[11]	559,109	26.0%	17.6%	2.11
Route 3: L-gas storage and Flat QC					
Annual QC Cost, €	[12]	75,999	3.5%	2.4%	0.29
Annual LF Conversion Cost, €	[13]	1,052,445	49.0%	33.0%	3.97
Total Cost	[14]	1,128,444	52.5%	35.4%	4.25
Route 4: Buy swing, flat QC					
Annual QC Cost, €	[15]	75,999	3.5%	2.4%	0.29
Annual LF Conversion Cost, €	[16]	145,501	6.8%	4.6%	0.55
Total Cost	[17]	221,500	10.3%	7.0%	0.83
Demand Side: LDCs					
Annual QC Cost	[18]	164,538	7.7%	5.2%	0.62
Annual LF Conversion Cost	[19]	135,898	6.3%	4.3%	0.51
Total Cost	[20]	300,436	14.0%	9.4%	1.13

Notes:
[A][6],[9]: Table - Quality Conversion Cost with Profiled Conversion
[A][12],[15]: Table - Quality Conversion Cost with Flat Conversion
[A][7],[19]: Table - GTS Balancing Costs
[A][10]: Table - H-Gas Storage Costs
[A][13]: Table - L-Gas Storage Costs
[A][16]: [7]+[6]-[15]
[A][18]: [1]x10000x.62
[A][8],[11],[14],[17],[20]: [A]n-1 + [A]n-2
[B]: [A]/[4]
[C]: [A]/[5]
[D]: [A]/([1]x10000)

Table 16 details how we calculated the cost of quality conversion when the amount being converted varies. Table 17 details the same calculation, but with a flat quality conversion rate.

Table 16: Quality Conversion Cost with Profiled Conversion

Degree of Conversion			
H-gas Wobbe Q-in, MJ/Nm3	GTS	[1]	52
L-gas Wobbe Q-out, MJ/Nm3	GTS	[2]	44
Wobbe Delta, MJ/Nm3	[1]-[2]	[3]	7.6
Conversion Requirements			
Mean Flow (m3/hr)	*[Table: Required Flow]*	[4]	3,029
Max Flow (m3/hr)	*[Table: Required Flow]*	[5]	4,749
Quality Conversion Capacity (mj/hr)	(([4]+[5])/2)x[3]	[6]	29,557
Day/Year Capacity Charge			
QC Capacity Tariif, €/MJ/h	GTS	[7]	1.47
Annual QC Capacity Cost, €	[6]x[7]	[8]	43,449
Quantity Charge			
QC Quantity, m3	[4]x24	[9]	72,708
QC Quantity, MJ	[3]x[9]	[10]	552,581
QC Quantity Tariff, €cents/MJ	GTS	[11]	0.02
Daily QC Quantity Cost, €	([11]/100)x[10]	[12]	115
Annual QC Rates Summary			
Annual QC Quantity Cost, €	[12]x365	[13]	42,154
Total Annual QC Cost, €	[8]+[13]	[14]	85,603

Table 17: Quality Conversion Cost with Flat Conversion

Degree of Conversion			
H-gas Wobbe Q-in, MJ/Nm3	GTS	[1]	52
L-gas Wobbe Q-out, MJ/Nm3	GTS	[2]	44
Wobbe Delta, MJ/Nm3	[1]-[2]	[3]	7.6
Conversion Requirements		[4]	
Hourly Gas Flow (Nm3)	*[Table: Required Flow]*	[5]	3,029
QC Capacity, MJ/h	[5]x[3]	[6]	23,024
Day/Year Capacity Charge			
QC Capacity Tariif, €/MJ/h	GTS	[7]	1.5
Annual QC Capacity Cost, €	[6]x[7]	[8]	33,846
Quantity Charge			
QC Quantity (Nm3)	[4]x24	[9]	72,708
QC Quantity, MJ	[3]x[9]	[10]	552,581
QC Quantity Tariff, €cents/MJ	GTS	[11]	0.021
Daily QC Quantity Cost, €	([11]/100)x[10]	[12]	115
Annual QC Rates Summary			
Annual QC Quantity Cost, €	[12]x365	[13]	42,154
Total Annual QC Cost, €	[8]+[13]	[14]	75,999

Table 19 describes the costs involved with purchasing balancing services from GTS. Table 20 describes the costs involved with purchasing H-gas storage.

Table 18: Tariff calculations

Short Service Tariffs			
Injection Capacity, GJ/h	BP	[1]	30
Injection Capacity, m3/h	[1]x1000/35.17	[2]	853
Bundle Price, €/y	GTS	[3]	580,000
Injection Cost €/m3/h	[3]/[2]	[4]	680
Demand for Injection			
Mean Flow	*[Table: Required Flow]*	[5]	3,029
Min Flow	*[Table: Required Flow]*	[6]	1,386
Max Injection	[5]-[6]	[7]	1,644
Free Tolerance	([5]+[6])*0.065	[8]	287
Max Injection Rate	[7]-[8]	[9]	1,357
Entry/Exit Charges			
Entry Tariff, €/m3/h/y	GTS	[10]	16.8
Exit Tariff, €/m3/h/y	GTS	[11]	16.5
Exit Capacity Booked, m3/h	*[Table: Required Flow]*	[12]	3029.5
Entry Capacity Booked, m3/h	*[Table: Required Flow]*	[13]	4748.7
Totals			
Cost of storage (€/yr)	[9]x[4]	[14]	922,507
Cost of Entry/Exit (€/y)	[10]x[13]+[11]x[12]	[15]	129,938
Total	[14]+[15]	[16]	1,052,445

Table 18 describes the tariff calculations used as an input for Table 19.

Table 19: GTS Balancing Costs

Offtake Data			
Min Offtake (Nm3/hr)	*[Table: Required Flow]*	[1]	1,386
Mean Offtake (Nm3/hr)	*[Table: Required Flow]*	[2]	3,029
Max Offtake (Nm3/hr)	*[Table: Required Flow]*	[3]	4,749
Imbalance at Min Offtake			
Imbalance (Nm3)	[2]-[1]	[4]	1,644
Imbalance including margin (Nm3)	[3]x1.01	[5]	1,660
Tolerance (Nm3)	0/065x([1]+[2])	[6]	287
Imbalance Capacity Required (Nm3)	[5]-[6]	[7]	1,373
Imbalance at Max Offtake			
Imbalance (Nm3)	[3]-[2]	[8]	1,719
Imbalance including margin (Nm3)	[7]x1.01	[9]	1,736
Tolerance (Nm3)	0/065x([2]+[3])	[10]	506
Imbalance Capacity Required (Nm3)	[9]-[10]	[11]	1,231
Max Imbalance			
Max Imbalance (Nm3)	Max ([7],[11])	[12]	1,373
Imbalance Capacity Costs			
Balancing Cost	([12]x65)/365	[13]	245
Extra Transport Cost			
Annual Tariff	*[Table: Cap. & Tariffs]*	[14]	46,642
Annual Tariff per day, €	[14]/365	[15]	128
Total LF Conversion Cost			
Daily Cost, €	[13]-[15]	[16]	372
Annual Cost, €	[16]x365	[17]	135,898

Table 20: H-Gas Storage Costs

Short Service Tariffs			
Injection Capacity, GJ/h	NAM	[1]	67
Injection Capacity, m3/h	[1]x1000/35.17	[2]	1,905
Bundle Price, €/y	GTS	[3]	510,000
Injection Cost €/m3/h	[3]/[2]	[4]	268
Demand for Injection			
Mean Flow	*[Table: Required Flow]*	[5]	3,029
Min Flow	*[Table: Required Flow]*	[6]	1,386
Max Injection	[5]-[6]	[7]	1,644
Free Tolerance	([5]+[6])*0.065	[8]	287
Max Injection Rate	[7]-[8]	[9]	1,357
Entry/Exit Charges			
Entry Tariff, €/m3/h/y	GTS	[10]	14.1
Exit Tariff, €/m3/h/y	GTS	[11]	14.3
Exit Capacity Booked, m3/h	*[Table: Required Flow]*	[12]	3029.5
Entry Capacity Booked, m3/h	*[Table: Required Flow]*	[13]	4748.7
Totals			
Cost of storage (€/yr)	[9]x[4]	[14]	363,211
Cost of Entry/Exit (€/y)	[10]x[13]+[11]x[12]	[15]	110,296
Total	[14]+[15]	[16]	473,506

Table 21: L-Gas Storage Costs

Short Service Tariffs			
Injection Capacity, GJ/h	BP	[1]	30
Injection Capacity, m3/h	[1]x1000/35.17	[2]	853
Bundle Price, €/y	GTS	[3]	580,000
Injection Cost €/m3/h	[3]/[2]	[4]	680
Demand for Injection			
Mean Flow	*[Table: Required Flow]*	[5]	3,029
Min Flow	*[Table: Required Flow]*	[6]	1,386
Max Injection	[5]-[6]	[7]	1,644
Free Tolerance	([5]+[6])*0.065	[8]	287
Max Injection Rate	[7]-[8]	[9]	1,357
Entry/Exit Charges			
Entry Tariff, €/m3/h/y	GTS	[10]	16.8
Exit Tariff, €/m3/h/y	GTS	[11]	16.5
Exit Capacity Booked, m3/h	*[Table: Required Flow]*	[12]	3029.5
Entry Capacity Booked, m3/h	*[Table: Required Flow]*	[13]	4748.7
Totals			
Cost of storage (€/yr)	[9]x[4]	[14]	922,507
Cost of Entry/Exit (€/y)	[10]x[13]+[11]x[12]	[15]	129,938
Total	[14]+[15]	[16]	1,052,445

Table 22: Capacity and Tariffs

Capacity Demand			
Exit Capacity with Flat load, m3/h	[1]	*[Table: Required Flow]*	3,029
Exit Capacity with LLF, m3/h	[2]	*[Table: Required Flow]*	4,749
Incremental Exit Capacity, m3/h	[3]	[2]-[1]	1,719
Tariff Calculation			
Exit Tariff, €/m3/h	[4]	GTS	27.13
Annual Exit Tariff, €	[5]	[4]x[3]	46,642

Table 23 details the minimum, maximum, and mean hourly flows for a representative Median Day. The day chosen was 28th May 1999.

Table 23: Required Flow

Min Hourly Flow (m3)	[1]	1,386
Max Hourly Flow (m3)	[2]	4,749
Mean Hourly Flow (m3)	[3]	3,029

Appendix 3: Simple Market Model

In section 4.3, we describe a high price and a low price policy that Shell/ExxonMobil could implement. In this appendix we develop a simple economic model to determine how much of the Low Load Factor (LLF) L-gas market Shell/ExxonMobil would be prepared to lose before changing from the high price to the low price policy.

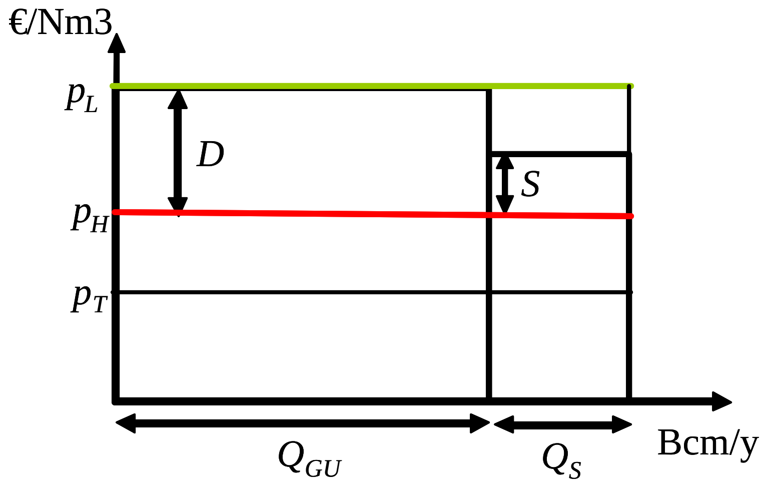
Model assumptions

Shell/ExxonMobil is the gas wholesaler, and NAM is the gas producer with control of the Groningen field. NAM sells exclusively to Shell/ExxonMobil. Shell/ExxonMobil has sufficient L-gas and swing capacity to serve the entire market. In contrast, the scarcity of quality conversion and load-factor conversion services limit the scope for entry by H-gas shippers.

NAM sells gas to Shell and ExxonMobil at a uniform transfer price, *i.e.* there are no volume discounts. We assume that the Ministry of Economic Affairs imposes the transfer price exogenously on Shell/ExxonMobil. We ignore any motivations arising from cross shareholding issues. Shell and ExxonMobil have a shareholding in NAM, but we assume that they do not consider the effect of their actions on NAM's profits. We also assume that Shell and ExxonMobil do not compete with one another to sell gas, and act as a single company to maximise profits. We treat the price for HLFH-gas as exogenous, and we assume that the H-gas price remains fixed. The LLFL-gas product is homogenous.

The model assumes that Shell and ExxonMobil abandon the "market value" pricing principle, and instead price to maximise profits based on the degree of market entry by other shippers. Figure 6 illustrates the model, with the x-axis representing the volume of gas sold in bcm/y, and the y-axis measuring gas prices and switching cost in €cents/m^3.

Figure 6: Market Model



The variables in the model are:

D – the demand-side switching price (€cents/m^3)
S – the supply-side switching cost (€cents/m^3)

Q_{GU} – the volume of gas sold by Shell/ExxonMobil (m^3/y).
Q_S – the volume of gas sold by other shippers (m^3/y).
Q_T – the total size of the LLFL-gas market (m^3/y) ($Q_{GU} + Q_S$).
Q_S^* – the critical volume of gas sold by other shippers (m^3/y).
p_H – the HLFH-gas price (€cents/m^3).
P_L – the LLFL-gas price (€cents/m^3).
p_T – the transfer price between NAM and Shell/ExxonMobil(€cents/m^3).

The 'critical' supply of switching services

Shell/ExxonMobil can either pursue a high-price or a low-price policy. Under the high-price policy, Shell/ExxonMobil charges a price equal to p_H, plus (just less than) the demand-side switching price, D. Shell/ExxonMobil could not charge more than this for L-gas, without customers switching to H-gas. However, we note that D may in fact be well above each individual's *cost* of demand-side switching, because local distribution companies lack financial incentives to switch the network to a different gas quality when it may be cost-effective, and because customer switching presents co-ordination problems. Equation 3 gives the LLFL-gas price under Shell/ExxonMobil's high-price policy, where e represents a very small number. Equation 4 gives Shell/ExxonMobil's profit under the high-price policy.

Equation 3: LLFL-gas price under Shell/ExxonMobil's high price policy

$$p_L = p_H + D - e$$

Equation 4: Shell/ExxonMobil profit under the high price policy

$$Q_{GU}\left(p_H + D - p_T\right)$$

Shell/ExxonMobil's profits attract other shippers into the LLFL-gas market. Initially they pay price S for switching services to convert their H-gas to LLFL-gas, and sell this gas for (just less than) the Shell/ExxonMobil price. These other shippers must sell at a slightly lower price than Shell/ExxonMobil to gain market share. However, a scarcity of switching services limits the size of the LLFL-gas market that they can serve to Q_S. Note that a secondary-market would raise the price of switching services to just below D. The profits of other shippers will decline to zero (except for "rents" caused by access to switching services at lower prices than D), and entry will stop.

Equation 5

$$p_T < p_H + S$$

If the condition in Equation 5 is met, which we assume to be the case, it would be possible for Shell/ExxonMobil to sell profitably at a lower price than all other shippers, and capture the entire market, by charging a price equal to the HLFH-gas price plus (just less than) the cost of supply-side switching S. We call this the low-price policy. Equation 6 gives the price under the low-price policy. From here on, we set e equal to zero.

Equation 6: LLFL-gas price under Shell/ExxonMobil's low-price policy

$$p_L = p_H + S - e$$

Under the low-price policy, Shell/ExxonMobil captures the entire market, and hence Q_{GU} is equal to Q_T. Equation 7 indicates Shell/ExxonMobil's profit.

Equation 7: Shell/ExxonMobil profit under the low-price policy

$$Q_T\left(p_H + S - p_T\right)$$

We also assume that total demand is fixed, and note that:

Equation 8

$$Q_T = Q_{GU} + Q_S$$

We take the case that Shell/ExxonMobil starts with a 100% share of the market. If so, then clearly Shell/ExxonMobil's profits under the high-price policy will be higher than under the low-price policy, and Shell/ExxonMobil will initially pursue the high-price policy.

Increasing the available capacity of switching services will increase the volume of LLFL-gas sold by other shippers, causing Shell/ExxonMobil to lose more market share. Shell/ExxonMobil's profits will decrease. Eventually, the sales of other shippers will be so large that Shell/ExxonMobil's profits from the high-price policy no longer exceed the profits of the low- price policy. If other shippers increase market share further, Shell/ExxonMobil will find it more profitable to reduce prices and capture the entire market. We denote the volume of non-Shell/ExxonMobil sales at which this happens by Q_S^* (the critical volume of gas sold by non-Shell/ExxonMobil shippers).

We can find the value of Q_S^* by setting Equation 4 equal to Equation 7, and substituting in Equation 8 to eliminate Q_{GU}. Rearranging and solving for Q_S^* we get Equation 9.

Equation 9: Critical volume of gas sold by non-Shell/ExxonMobil shippers

$$Q_S^* = Q_T\left[1 - \frac{\left(p_H + S - p_T\right)}{\left(p_H + D - p_T\right)}\right]$$

In Table 24 we give an illustrative calculation using Equation 9, and conclude that – in this model – other shippers would need to supply at least 10 bcm/y of LLFL-gas before Shell/ExxonMobil switched to the low-price policy. In other words, there should be sufficient switching services to permit other shippers to produce 10 bcm/y LLFL-gas, to prevent Shell/ExxonMobil from pursuing the high-price policy.

Table 24: Example calculation of the critical volume sold by non-Shell/ExxonMobil shippers

H-gas price (€cents/m3)	[1]	See note	10
Transfer price (€/cents/m3)	[2]	See note	8
Demand-side switching cost, % of H-gas price	[3]	See note	30%
Demand-side switching price (€cents/m3)	[4]	[3]x[1]	3
Supply side switching cost (€cents/m3)	[5]	TBG	0.83
Market size (bcm/y)	[6]	TBG	23
Critical volume of sales by non-Gasunie shippers (bcm/y)	[7]	See note	**10**
Critical market share of non-Gasunie shippers (%)	[12]	[7]/[6]	43%

Notes:
[1]: Average of high and low gas price assumed in the main
[2]: Estimate based on information from former Gasunie employees.
[3]: The degree to which Gasunie could increase the L-gas price above the H-gas price without prompting consumers to switch will in practise be limited by political/regulatory pressure. The number used I based on TBG experience of German L-gas prices.
[7]: [6]x{1-{[1]+[5]-[2]}/{[1]+[3]-[2]}}

In addition the model helps illustrate some interesting points described below.

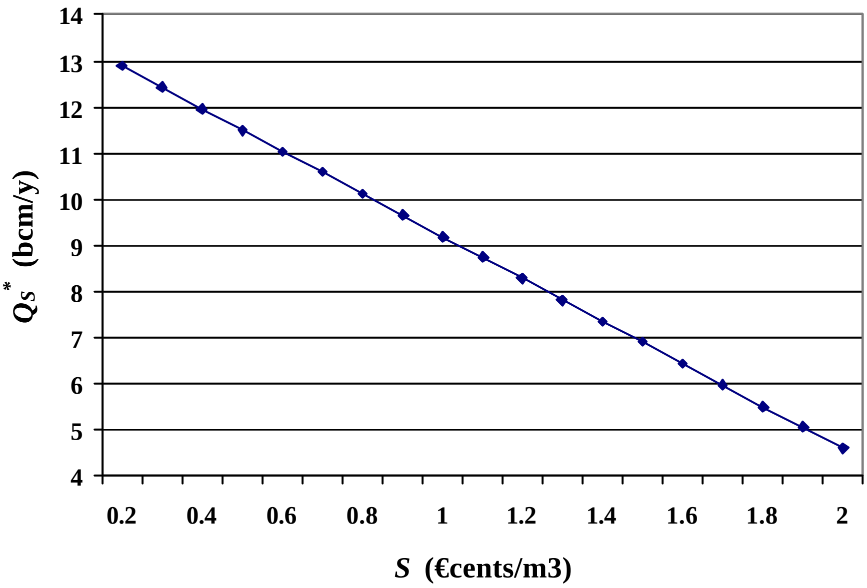
Shell/ExxonMobil's incentive to sell 'productions swaps'

As long as the HLFH-gas price (p_H) exceeds the transfer price (p_T), Shell/ExxonMobil will always make more profit by using NAM's swing and L-gas, rather than selling the swing and L-gas to other shippers via a production swap. Even if Shell/ExxonMobil could provide switching services at zero cost, the maximum profit from the sale of switching services would be equal to the demand-side switching price *D*. However, if Shell/ExxonMobil use the switching services themselves, they can make a profit of p_H minus p_T plus *D*, which is greater than *D*. Hence Shell/ExxonMobil will not willingly sell production swap services to other shippers.

The optimal price of switching services

The model illustrates a trade-off between a low final price of LLFL-gas and the capacity of switching services necessary to prompt a low-price policy. The trade-off arises because a low cost of switching services (S)makes the low-price policy relatively unattractive to Shell/ExxonMobil, as (from Equation 7) profit under the low-price policy is reduced. Therefore Shell/ExxonMobil is prepared to tolerate a higher loss of market share before switching to the low-price policy. Figure 7 illustrates the trade-off (using the input values in Table 24).

Figure 7: Supply-side switching price trade-off



However, reducing S will reduce the final price of LLFL-gas, once sufficient switching-services capacity has become available, because in the model the LLFL-gas price under Shell/ExxonMobil's low price policy is given by p_H plus S.

The role of the transfer price

Reducing the transfer price reduces the capacity of switching services that must become available to prompt a low-price policy. Figure 8 illustrates the profits under the low-price and high-price policies with a *high* transfer price. There is a relatively large percentage difference in profit between the two polices. Using the values in Table 24, the high-price policy profits are 53% larger than the low-price policy.

Figure 9 illustrates the profits under the low-price and high-price policies with a *low* transfer price. Now there is a relatively small percentage difference in profit between the two polices. Assuming a transfer price of 3 €cents/m^3 the high-price policy profits are only 11% larger than the low-price policy. The percentage difference in profit between the two polices has been reduced relative to the high-transfer-price case. With a low transfer price, the area between p_H and p_T line is much larger in Figure 9 than in Figure 8.

Consequently, only a relatively small loss of market share is required to make the high-price policy unattractive relative to the low-price policy. Hence with a low transfer price Shell/ExxonMobil tolerates a smaller loss of market share before reducing prices.

Figure 8: Profits with a high transfer price

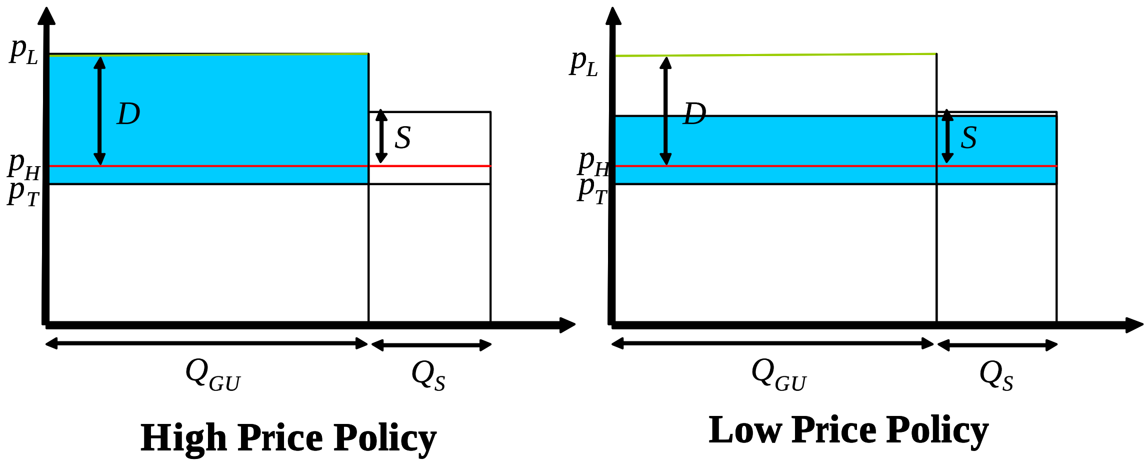
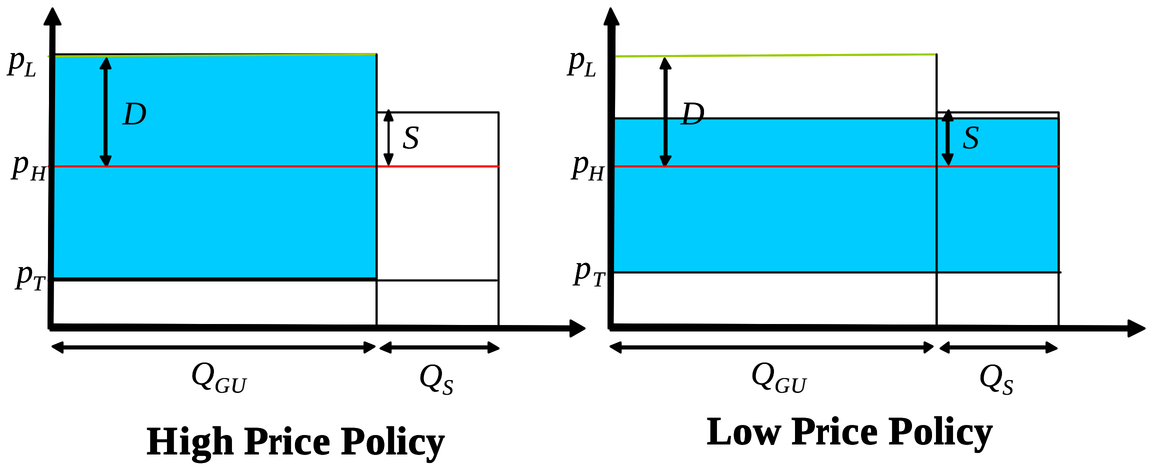


Figure 9: Profits with a low transfer price



Appendix 4: Potential Inter-Fuel Competition

Natural gas competes on a limited basis with electricity, coal, oil, nuclear and renewable sources of energy. This competition is generally relevant only over a time-frame that encompasses the typical life of the relevant capital. For example, gas may compete with coal as an energy source when a power company considers constructing a new generating unit. Once the unit has been built, changing from one fuel type to another involves considerable expense in altering boilers, in the opportunity cost of plant downtime, and in logistical arrangements. Fuel conversion may also be prohibited by environmental regulations. The various impediments to fuel conversion impede competition among alternative fuels for the roughly thirty to fifty years of a power plant's useful life. Some competition among fuels may arise as different types of power plants compete for despatch on a daily basis. However, long-term contracts for electric power can limit the extent of such competition.

At the retail consumer level, two fuels compete when a choice is made between a gas-fired or oil-fired heating system. Once the purchase has been made, the heating system is likely to remain in use for many years, and cannot economically be converted.[39] The Commission has already recognised a similar principle in various decisions relating to gas and district heating.[40] Competition occurs when a heating method is chosen; there is little subsequent competition between different energy sources.[41]

For these reasons, the European Commission has found that *gas constitutes a distinct market from other fuels*.[42] In addition, authorities in Germany,[43] the United Kingdom,[44]

[39] The fact that retail customers have essentially no ability to switch fuels once a decision to purchase equipment dedicated to a single fuel source is made has explicitly been recognized by the German antitrust authorities. See Decision of March 23, 1984, Energieversorgung Schwaben - Technische Werke Stuttgart, B8-822000-U-91/83, WuW-Entscheidungssammlung, BKartA 2157.

[40] See, e.g. *Neste/Ivo,* Case No. IV/M931, Decision of 2 June 1998 and *Gaz de France/BEWAG/ GASAG,* Case IV/M.1402, Decision of 20 January 1999.

[41] Unless there is a radical change such as a renovation or replacement. *See, Neste/Ivo, supra* at para. 14.

[42] Commission Decision of 29.09.1999 declaring a concentration compatible with the common market and the EEA Agreement (Case No IV/M.1383 – Exxon/Mobil). See also, Decision of 1 September 1994, *Tractebel Distrigas* II IV, M.493; Decision of March 17, 1998, IV/M.1107 - EDFI/ESTAG; WuW-Entscheidungssammlung EU-V 48 (EU-V 49 in particular); Decision of May 5, 1994, IV/M.417 - VIAG/Bayernwerk, WuW-Entscheidungssammlung EV 2139 (EV 2141 in particular).

[43] See Decision of March 23, 1984, Energieversorgung Schwaben - Technische Werke Stuttgart, B8-822000-U-91/83, WuW-Entscheidungssammlung, BKartA 2157 (BKartA 2158 in particular)("As long as a customer has not made a decision about a fuel source for meeting heating demand, suppliers of various forms of energy face competition from alternative energy sources since the consumer, when making a choice, will reasonably consider the primary fuel to be used once heating equipment is installed. But once the consumer has chosen gas as the heat source, he can procure the needed energy for heating only in the gas market. Other energy sources are no longer viable substitutes").

the United States,[45] Australia[46] and New Zealand[47] have also generally chosen to regard natural gas as a separate product for competitive analysis.

[44] Monopolies and Mergers Commission, *Gas – A report on the matter of the existence of a monopoly situation in the supply in Great Britain of gas through pipes to persons other than tariff customers* (October 1988) and Monopolies and Mergers Commission, *British Gas plc – Volumes 1 and 2 of reports under the Gas Act 1986 on the conveyance and storage of gas and the fixing of tariffs for the supply of gas by British Gas plc* (August 1993) at 95 ("We accept that gas forms part of the wider energy market and that over a period of years it is possible for most users of gas to switch to alternatives if they are dissatisfied. Where users have alternative fuel-burning facilities installed, this switch is relatively easily made…However, other users, once they have made their choice of gas as a fuel, have less flexibility in switching…In a substantial part of the firm gas market, we consider that there is at most only limited competition from other fuel suppliers").

[45] *City of Chanute, Kansas v. Williams Natural Gas Co*., 1988-1 Trade Cas. 67,977 (D. Kan. 1988); *Consolidated Gas Co. of Florida v. City Gas Co. of Florida, Inc.*, 665 F. Supp. 1493 (S.D. Fla. 1987).

[46] Australian Competition Tribunal, *Review of ACCC Determination revoking Authorisation No A90424 (AGL Cooper Basin Natural Gas Supply Arrangements)*, No VI of 1996 (14 October 1997) ("We find that there are three product markets of relevance…The first is natural gas, extending at the margin to encompass, at times, alternative and complementary energy sources, particularly electricity.")

[47] *Shell Petroleum Mining Co., Ltd. and Todd Petroleum Mining Co., Ltd. vs. Kapuni Gas Contracts, Ltd, and Natural Gas Corp. of New Zealand,* High Court of New Zealand (Auckland, 3 Feb. 1997) ("The Commerce Commission in a number of decision has held that the appropriate market is not an 'all energy' market… We conclude that the relevant markets in this case are the wholesale and retail natural gas markets.")