Gas storage and the EU Network Code on Harmonised Transmission Tariff Structures for Gas

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Executive summary

Baringa Partners LLP has been commissioned by Vereniging Gasopslag Nederland, in association with Initiative Erdgasspeicher e.V. and the Gas Storage Operators Group, to produce this report as input to a European Commission (EC) impact assessment considering aspects of a methodology for setting transmission tariffs for storage in the context of the EU 'Network code on Harmonised Transmission Tariff Structures for Gas' (TAR NC).

A number of European gas storage operators and their representatives have major concerns in regard to the current form of the TAR NC in relation to the treatment of gas storage. Key concerns relate to:

- the absence of a 'level playing field' for gas storage facilities operating in different countries, including substantial disparities in levels of transmission tariffs,
- 'double payment' as a result of tariffs paid by storage users arguably recovering the same (historical and/or future) network costs more than once,
- lack of account in tariff setting of the network benefits provided by storage, and
- insufficient regard to the wider societal benefits, such as security of supply, which gas storage facilities provide.

A number of European gas storage operators are concerned that the issues outlined above may lead to underinvestment in new storage facilities and may risk premature closure of existing storage facilities where investment is needed to extend asset lifetimes, and that this could have ramifications for EU consumers in terms of more volatile gas and electricity prices, and may pose more direct security of supply risks in certain areas.

This report suggests an approach to allay these concerns through adopting a methodology for setting transmission tariffs in which network benefits provided by users are directly accounted for alongside costs, together with a set of principles around transparency and stakeholder engagement.

A number of different cost allocation approaches, which reflect historical costs, average costs or long run marginal costs (LRMC), are included as options in the TAR NC. The different methodologies reflect the range of current practices in different Member States. This report focuses on the approach in Great Britain (GB), based on an LRMC methodology. We consider that this approach aligns well with the key principles and rules as set out in Article 13 of Gas Regulation 715/2009.

To calculate cost-reflective tariffs in a transparent manner, a robust model is a necessity. To provide appropriate scrutiny, and the ability for network users to replicate tariffs as well as model different scenarios, the model should be in the public domain.

Experience from GB suggests that such a model can be developed and managed in a practical way, with improvements made over time, as long as the roles of the National Regulatory Authority (NRA) and the Transmission System Operator (TSO) are well defined, and a robust process of stakeholder engagement is put in place. Given the significant information asymmetry between the TSO and the NRA, greater stakeholder engagement is important in supporting the NRA in achieving a more efficient outcome which better protects the interests of consumers.

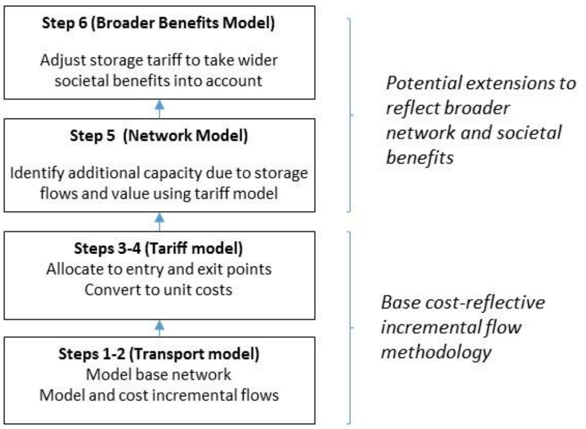
There are a number of broader principles underlying the GB approach which we see as important irrespective of the actual choice of cost allocation methodology, namely:

- requirement on the TSO to develop a tariff model in conjunction with its stakeholders and subject to approval from the NRA,
- requirement on the TSO to make the tariff model and its inputs available to stakeholders and other interested parties,
- requirement on the TSO to actively engage and consult its stakeholders on modelling assumptions, data and scenarios, and
- formalised provisions allowing stakeholders to propose changes to the modelling process and inputs, and for these to be given due consideration.

We also discuss two potential extensions to the GB approach. First, it would be possible to assess whether a specific network-connected asset, such as a storage facility, provides flows that are beneficial to the network, for example by freeing up compressor capacity or creating spare capacity at an entry point. This could be combined with an approach (such as GB's Capacity Trade and Transfer process) that enables this capacity to be priced and used (at least partially) to support alternative network flows. This in turn could allow the potential benefits to be valued and incorporated in a tariff model. Given the underlying assumptions on flows, this might need to come with additional obligations on the connecting asset.

Second, it would be possible to reflect, at least in part, the wider societal benefits that storage provides, including reduced price volatility, increased network flexibility, and improved security of supply. As recently observed by CEER: '(...) until completion of the internal market, it is possible that the value of storage is not appropriately recognised in all markets. In particular, some aspects of storage may be undervalued'. We recognise that storage may not be alone in providing wider benefits, but it does arguably provide a greater range of benefits on a more consistent basis than many other sources. If the market materially undervalues the wider benefits of storage, and there are concerns around the practicality of, or timeframe required for, other harmonised policy interventions, then a mechanism involving an extension to the transmission tariff methodology could be explored as an initial approach to address this. There are a number of existing precedents within Member States which are mentioned throughout the report.

We illustrate the overall approach in a flow chart, a summary version of which is shown below. The steps are shown building upwards to highlight the "bottom up" nature of the approach.



In conclusion, our recommendations (presented in Section 6) are:

- aim to set cost-reflective tariffs based on net costs,
- develop a public domain tariff model,
- ensure robust and transparent data,
- define appropriate roles for NRAs and TSOs, and
- consider recognising broader benefits.

1 Introduction

1.1 Background to this report

Vereniging Gasopslag Nederland (VGN), in association with Initiative Erdgasspeicher e.V. (INES) and the Gas Storage Operators Group (GSOG), have commissioned this report from Baringa as input to a European Commission (EC) impact assessment to consider aspects of a methodology for setting transmission tariffs for storage in the context of the EU 'Network code on Harmonised Transmission Tariff Structures for Gas' (TAR NC)[1], as requested during the Madrid Forum[2].

This report provides:

- a description of high level principles to ensure an economically robust approach to setting gas transmission tariffs considering Long Run Marginal Costs (LRMC) and network benefits of storage,
- an outline of the key Transmission System Operator (TSO) cost drivers and their interaction with storage, considering avoided investment and operating costs,
- a description of a methodology to determine tariffs for storage based on a network modelling approach and tariff model, based on that applied in Great Britain (GB), and
- a summary of the wider benefits of storage that are not directly accounted for through the methodology, but that could be incorporated through an extension to the modelling approach.

1.2 European framework

Historically different member states have adopted different approaches to transmission tariff setting. These different approaches not only make it more complex for network users to run their businesses in different Member States, but could also result in inefficient use and development of the transmission networks.

On 26 December 2014, the European Network of Transmission System Operators for Gas (ENTSOG) published a draft TAR NC. The objective of this code is to improve the efficiency of gas trade and competition, which is in turn a key objective of the Third Package. The aim of harmonising transmission tariff structures, as it clearly appears from the draft TAR NC, is therefore to remove potential distortions through agreeing:

- a set of common parameters, based on economic principles, for all aspects of tariff setting, and
- a common set of requirements on the publication of data relating to each stage of the process.

[1]The public text used for reference concerns the TAR NC as submitted in draft by ENTSOG to ACER for reasoned opinion in December 2014. ACER issued its reasoned opinion in March 2015.
[2]Conclusions Madrid Forum 20-21 April 2015, section 3, p.2

The TAR NC is currently still in its drafting phase. The aim is for it to be formally presented to Member States in Comitology by the end of 2015. Once this process has been finalised and the TAR NC comes into force, member states have 24 months to implement the TAR NC.

Currently the TAR NC allows a number of different cost allocation methodologies, which are based on historical costs, average costs or long run marginal costs (LRMC). These different methodologies reflect the current practices in different Member States. This report focuses on the methodology to set transmission tariffs as used in Great Britain (GB), which uses an LRMC approach. We consider that this methodology aligns well with the key principles and rules as set out in Article 13 of Gas Regulation 715/2009, as users would be given appropriate locational signals and, especially in the presence of an auction regime, TSOs would receive strong investment signals.

We also identify a number of practical pointers as to how to implement the GB approach in other markets. Although we consider that the LRMC approach would be the most efficient starting point, the broader principles and approaches we describe in this report could be used irrespective of the actual choice of cost allocation methodology.

1.3 Treatment of storage facilities

Both ACER and ENTSOG have specifically commented on the setting of tariffs for storage facilities. Article 20 of the TAR NC, as submitted by ENTSOG to ACER in December 2014, addresses the setting of tariffs for storage facilities as follows:

'When the national regulatory authority sets or approves the transmission tariffs for the storage facilities, the following shall be taken into consideration:

(1) the net benefits that the storage facilities may provide to the transmission system;

(2) the need to promote efficient investment in the transmission system;

(3) the need to minimise detrimental effects on cross-border trade.'

Furthermore, Article 21 (3) specifies:

'For the transmission tariffs for the storage facilities, the decision of the national regulatory authority shall contain a detailed explanation of how the requirements of Article 20(1) to (3) have been taken into consideration.'

This approach to setting tariffs for storage facilities explicitly takes into account the benefits which the storage facilities provide to the transmission system. This is also in line with ACER's view[3]:

'The Network Code on Tariffs shall specify that, in setting or approving tariffs for entry and exit points from and to gas storage facilities, NRAs shall consider the following aspects:

[3] ACER (2013), The Framework Guidelines on rules regarding harmonised gas transmission tariff structures for gas, p.27

- *The benefits which storage facilities may provide to the transmission system.*
- *The need to promote efficient investments in networks.*

NRAs shall also minimize any adverse effect on cross-border flows.'

In its Justification document[4], ACER rejects the imposition of harmonised storage discounts on an EU level. INES, VGN and GSOG consider that there are reasonable grounds for setting zero tariffs for storage as the default, but that the principle of recognising net costs (ie costs minus benefits) is the minimum level of harmonisation that could promote efficient investment in the network and to minimise adverse impacts on cross-border trade through cost reflective tariffs.

[4] ACER (2014), Assessment of Policy Options Justification document for Framework Guidelines on rules regarding Harmonised Transmission Tariff structures, ref. ACER-JD-2014-G-01

2 Principles for determining gas transmission tariffs

2.1 General framework

The provision of gas transmission infrastructure services is highly capital intensive and involves assets with long technical asset lives, of 40-50 years. This means that frequently the cost of past investments incurred by the TSO to provide these assets cannot be attributed to individual users. As the NRA will have assessed and approved the past investments, these assets could be regarded as 'shared' assets, and the TSO is allowed a revenue sufficient to earn a regulated return on this asset base.

The question thus arises as to how to design tariffs which enable the TSO to recover its allowed revenue, whilst also ensuring that these tariffs contribute to maximising economic welfare through providing appropriate locational signals to network users.

From a public policy perspective, the objective of economic regulation is to ensure economic efficiency, including:

- least-cost production (productive efficiency),
- best use of scarce outputs (allocative efficiency), and
- optimal investment (dynamic efficiency).

When setting tariffs there may be tensions between enabling the TSO to recover its allowed revenue, ensuring that network users are incentivised to make best use of available capacity, and effectively signalling where and when new investment is needed.

This means that in setting or approving tariffs, the NRA may face a number of trade-offs. This may especially be the case if the network has a large amount of spare capacity. In situations with excess capacity, it would be economically efficient to discount this capacity to ensure its best use. To provide strong locational signals it may therefore be appropriate to set tariffs at Short Run Marginal Costs (SRMC), which may be zero or close to zero. However, this may result in the TSO under-recovering against its allowed revenue. This could then be addressed through an additional tariff to be paid by all network users or certain groups of network users – but this may in turn weaken the locational signals and therefore be less economically efficient.

Similarly, it would be economically efficient to signal the presence of network constraints (and thus the potential need for additional network investment) through higher tariffs or an auction process. This could result in revenue over-recovery. This may be addressed through some form of rebate – but again, this may distort locational signals.

Below, we consider the main principles underlying tariff setting in line with Article 13 of Gas Regulation 715/2009. We present the rationale for each principle and the implications for the network as well as for storage users.

2.2 Cost reflectivity

Rationale

The rationale behind the cost reflectivity principle is to align the incentives of the network users in order to achieve an economically efficient use of existing and new network infrastructure. This is achieved by ensuring that network users take the costs they impose on, and benefits they provide to, the transmission network into account in decisions on where to locate assets and how to schedule flows. Furthermore, in the absence of cost reflective tariffs, effective competition between network users is impeded.

General implications

There is no 'perfect' means to set tariffs in a cost reflective manner, and all approaches will involve some degree of judgment. Given the capital intensive nature of a gas transmission network and the long operational lives of transmission assets it is generally considered most appropriate for tariffs to be set using an LRMC approach. This approach recognises that in the long run, the TSO is able to invest in new network infrastructure in order to meet additional demand or accommodate changing gas flow patterns.

In the short run, the TSO is not able to respond through investment due to long lead times, but is able to make operational changes, for example to the network configuration[5], compressor settings or through using storage facilities for network support (if available). The TSO's SRMC will generally be significantly lower than its LRMC. Thus in practice, setting transmission tariffs at SRMC will result in (significant) under-recovery against allowed revenue.

Implications for storage

When setting transmission tariffs for storage facilities it is important to recognise that, depending on their locations and flow patterns, they may reduce the need for network investment.

Avoided costs

Capacity tariffs are set to recover network investment costs. Some storage facilities may be located relatively close to centres of demand, whereas in most other situations gas has to travel from the border of the network (eg production facilities, interconnectors, LNG terminals). Furthermore, storage would generally be expected to flow at times of high (including peak) demand (and correspondingly high wholesale price). As a result, the TSO may be able to dimension import pipelines[6] to meet a lower net flow at peak times, which could in principle provide significant savings, as demonstrated in the GB context by the GSOG Report[7] on 'UK Gas Transmission System benefits from gas storage'. Through modelling the network infrastructure with and without storage, the potential avoided investment was quantified as being in the range of £218 million to £1,929 million[8] in terms of avoidable capital costs depending on underlying flow scenarios.

[5] For example through the choice of parameters to calculate amount of spare capacity on the network in absence of stable flow patterns.
[6] Import pipelines are pipelines from production terminals, LNG terminals and interconnectors.
[7] Waters Wye Associates (2014), UK gas transmission system benefits from gas storage – an update to the initial report produced in 2007, A report for GSOG
[8] Approximately €255-2260m (based on €/£ exchange rate of 1.17).

No double payment

Furthermore, it is important to ensure that user charges reflect underlying costs in a consistent way, and that there is no 'doubling up' in the way costs are treated. In determining gas transmission tariffs in an entry-exit model, there is no fixed contract path. Entry tariffs give the right to use capacity at a specific entry point to flow gas to a virtual trading point. Exit tariffs give the right to take off gas at a specific exit point which comes from the virtual trading point. If an LRMC approach[9] to tariff setting is adopted then this results in particular reinforcement projects being identified to deal with incremental gas flows, which form the basis for the tariff.

It is important to ensure that the same network reinforcement costs are not identified twice for users of gas storage assets. This needs care because gas storage is not a net source of demand or supply, but shifts consumption from one point in time to another point in time. A storage user may be paying to enter the gas transmission network (first entry tariff), to exit the network (in order to enter the storage facility) (first exit tariff), then (when the gas leaves the storage facility) to re-enter the network (second entry tariff) and finally to exit the network at an offtake point (second exit tariff). If the network model determines costs independently for each element of this chain, then there is a possibility that there may be some overlap in the network costs identified. If this was the case, then such a network user would in aggregate effectively be paying at a level that was not cost-reflective.

There may be some additional network costs which storage imposes on the system, such as the costs of a connecting pipeline, and/or additional compression (for example when filling the site during low demand periods, eg summer), and these costs should be taken into account. (If the storage operator has financed the connecting pipeline then part of these costs will not apply.)

Apart from capacity tariffs, there may be flow related (or commodity) tariffs reflecting the TSO's operating costs. This is the case in GB, and storage has been exempted from the flow related tariffs, as it is viewed as being embedded in the system, and hence flow-related tariffs for storage gas are already considered to have been paid on entering the system at an entry point and exiting the system at an offtake point. This explicit exemption for storage reflects Ofgem's view[10] that there should be no double payment.

Flexibility market

Cost reflective tariffs are a key building block for a well-functioning market. In the flexibility market, gas storage is competing with alternative providers such as LNG. To ensure that this market functions well and can deliver the most efficient outcome, it is important that all types of participants face cost-reflective charges. This includes ensuring that there is no double payment (as discussed above) for storage users compared with other flexibility providers.

[9] Other cost allocation methodologies could also result in double payment, eg the same costs being allocated twice.

[10] Ofgem is the Office of Gas and Electricity Markets, the GB NRA.

2.3 Transparency

Rationale

The rationale behind the transparency principle is to reduce barriers to entry and therefore aid competition. It enables network users to understand how tariffs are set, and facilitates participation in a meaningful dialogue with both the TSO and NRA. It also allows easier comparison between TSOs, for example through benchmarking.

General implications

To increase transparency, it is important that network users have access to a tariff setting model so they can replicate and scrutinise the tariff setting process. This also enables users to model their own scenarios, which enables them to make better decisions based on better information (eg costs of the system and congestion issues) and which also facilitates new entrants. It is important that the inputs to the model are also sufficiently transparent and subject to scrutiny.

When allocating network costs to network users a number of assumptions on demand and supply, entry/exit split, network capability and network costs will have to be made. Different assumptions may have a significant impact on final tariffs for specific groups of users. It is therefore important that network users are involved in determining appropriate modelling assumptions, building credible scenarios and are aware of the model's sensitivity to changes in these assumptions and scenarios. Enhanced stakeholder scrutiny will help the NRA to ensure that only efficient network investment is rewarded.

Due to commercial confidentiality, the TSO may not be able to disclose its cost data in its entirety as this may weaken its procurement position with its suppliers. The NRA has a crucial role to test that the TSO indeed operates in a cost reflective manner and provides good value to its customers. Another important role for the NRA is to ensure that commercial confidentiality is not used by the TSO in a blanket manner to avoid having to publish information to its stakeholders (both current and future).

Implications for storage

Transparent processes, including the processes involving the setting of tariffs, cost assessment and network planning, will enable storage users to make more efficient decisions on how to develop their business or in case of new storage developers on whether, and if so where, to enter the market. In any case, the model assumptions, the input data, and the scenarios that are used, should be consulted on with storage operators as well as other stakeholders.

2.4 Non-discrimination

Rationale

The rationale behind the non-discrimination principle is to ensure fair access to the network for all parties, and to ensure that there is no distortion to competition, thus increasing the efficiency of the outcome resulting in lower costs for consumers.

General implications

It is not considered discriminatory if different network users pay different tariffs as long as these tariffs reflect differences in the underlying net costs. If tariffs are not cost reflective, then users will pay tariffs that are not closely linked to the net costs which they impose on the system. This would be discriminatory, as some users will have to pay for the costs imposed by others. Tariffs which result in cross subsidies provide the wrong signals to users of the system and possibly other stakeholders and result in economically inefficient outcomes.

Implications for storage

The issue of non-discrimination is of particular importance when setting transmission tariffs for storage users. If storage provides benefits to the system through avoided investment and/or reduced operating costs, and if these benefits are not reflected in the tariffs for storage, then storage may cross-subsidise other users. It is therefore important that a tariff methodology recognises the costs imposed *and* the benefits provided to the system by its users in order to avoid different treatment of storage users compared with other network users.

Gas storage is different from all other supply and demand sources as it is not a net source of demand or supply. Rather it shifts net demand from one point in time to another point in time. Storage can be seen as being embedded in the system. Therefore the potential risk of double payment and the issue of avoided costs should be taken into account when setting transmission tariffs for storage. It is nevertheless important to note that this may not necessarily imply that all storage users would receive lower transmission tariffs[11].

2.5 Incentivise efficient investment

Rationale

From an economic efficiency perspective, it is important that investment takes place at the right location and at the right time. Investment in the wrong place on the network may result in stranded assets. If investment takes place too early, it would result in too much spare capacity on the network, resulting underutilised capacity. If investment is too late, then there may have been undue shortage of capacity, higher resulting costs, and potentially under-served demand.

General implications

As TSOs earn a return on their network assets, including new investments, they may have an incentive to 'gold plate' (ie over-invest and/or inefficiently invest in infrastructure assets) resulting in a larger asset base. To prevent this, tariffs should promote efficient new investment and should provide signals, for example through auction prices, to indicate when investment would be efficient.

Tariff methodologies should ensure best use of existing infrastructure (whenever possible and practicable) before encouraging new infrastructure to be built. It would be economically inefficient and thus undesirable, if existing infrastructure is being underutilised due to incorrect tariffs (eg too high a tariff for existing infrastructure compared with new infrastructure). This may need to be taken into account when carrying out network modelling.

[11] There may be scenarios where the injection or withdrawal of storage imposes particular costs, for example compression if injecting on a cold winter day.

Implications for storage

Different approaches to setting storage transmission tariffs could result in price differentials between Member States which may result in inefficient investments in wider network infrastructure. Currently, different Member States have different approaches. This was summarised in a recent EC study which for example showed that storage users in Spain and Denmark receive a 100% transmission tariff discount[12].

Developers may decide not to build new storage in Member States with relatively higher tariffs even if from a network perspective storage is most needed in those markets. This may result in TSOs having to build larger import pipelines capable of meeting peak demand, compared with the case with storage, where pipelines sized for lower net demand may have sufficed. In its recent report[13] the Council of European Energy Regulators (CEER)[14] points out the importance of regulatory arrangements that allow storage to compete on a level playing field with other sources of flexibility, as only in this way can appropriate investment signals be delivered, and efficient, diverse flexibility markets be developed, across Europe.

2.6 System integrity and improvement

Rationale

System integrity refers to the physical and operational capability to maintain and operate a secure and safe gas transmission network. System integrity is integral to ensuring security of supply.

General implications

Any severe network disruptions can cause significant economic losses and hardship. According to ERGEG[15], the January 2009 supply disruption resulted in economic losses in the order of €800-900 million[16]. Bulgaria reported a loss of 9% of its GDP[17].

Implications for storage

Gas storage can deliver additional value to the network through its contribution to system integrity in real time, but also in the short and medium term, for example during a cold spell or severe winter, and through providing insulation from geopolitical risk. Furthermore, in a gas deficit emergency, the

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[12] EC commissioned study: 'Study on the role of gas storage in internal market and in ensuring Security of Supply Presentation of preliminary results to the Madrid Forum', Madrid, 20th April 2015

[13] CEER Final Vision on the Regulatory Arrangements for the Gas Storage Market, May 2015

[14] The Council of European Energy Regulators (CEER) is a voluntary cooperation association of the independent energy regulators of Europe. CEER's work complements (and does not overlap) the work of the Agency for the Cooperation of Energy Regulators (ACER).

[15] "Increased infrastructure investment through regional coordination: Enhancing EU energy security", Walter Boltz, Chair of ERGEG's Gas Working Group at the Regional Initiatives 2009 conference, Brussels, 17 November 2009

[16] Bulgaria: €255 million, Hungary: €70 million, Croatia: €270 million, Serbia: €54 million, and Slovakia: €100 million.

[17] Ofgem (2012), Gas Security of Supply Report, Risks and resilience appendix, p.51

TSO will be able to control storage flows, whereas it is unlikely that the TSO would be able to control LNG imports and/or interconnectors to the same degree, when enforcing rights across borders in such a situation may be effectively impossible. System integrity, including security of supply, can therefore be improved through, amongst other things, ensuring the presence of sufficient domestic storage.

Storage also contributes to greater network flexibility. In the near future, more volatile swings in demand for gas are expected due to the increasing share of intermittent renewable energy sources, such as wind and solar. Fast cycle storage facilities would be well placed to help the network cope with sudden large increases or falls in demand for gas and thus help preserve system integrity.

2.7 Trade-offs

In practice, it will not be possible to align with all these principles to the same degree. Trade-offs will have to be made. For example, to set very accurate cost reflective tariffs may not only be very complicated and therefore less transparent, but they may also result in large price swings from year to year. The GB experience (see chapter 4 and Appendix A) suggests that there is a trade-off between accuracy, and sensitivity to model inputs. This in turn suggests that there is a need to balance more accurate locational signals on the one hand, and transparency and price stability on the other hand. Very precise locational signals may result in tariffs which significantly vary from year to year and are more difficult to understand, making it difficult for network users to operate their business and which may impede efficient investment.

Given concerns that the very different tariff regimes which are currently in place across Member States may undermine the most efficient location of storage, and given the security of supply concerns that have been raised in many quarters, it could be argued that a quick improvement could be gained through adopting zero network tariffs for storage across the EU. However, consideration of such an approach would need to take into account that it would not be fully efficient and that there would be cross-subsidisation both between different storage facilities, and between storage facilities and other network users.

Public policy may guide how trade-offs are made. In practice this may mean that different NRAs will make different trade-offs and may prioritise different tariff setting objectives. For example, if a Member State has specific concerns in relation to security of supply, then for that Member State the system integrity principle may be given more weight relative to the cost reflectivity and/or non-discrimination principles.

3 TSO cost drivers and the interaction with storage

The objective of transmission tariff setting is to ensure that tariffs are cost reflective in order to send the appropriate signals to network users on the costs they impose on network operation and development. In this context it is important that there is clarity about cost drivers and the different assumptions in relation to determining costs.

3.1 Main cost drivers

A gas transmission network consists of a large number of primary assets (gas terminals, pipelines, multi-junctions, compressor units, and offtake stations) and secondary assets (which support the primary assets). The network is built to meet peak demand, which is reflected by the length and size of pipelines and compressor capacity on the network. Pipeline costs will mainly depend on the size of the pipeline (diameter), the length of the pipeline and the terrain in which the pipeline needs to be constructed. The costs of compressor stations are likely to be different for gas turbine and electric Variable Speed Drive compressor units and also depend on the size of the compressor stations. The main TSO cost drivers are presented in Table 2. A distinction may be made between supply/demand drivers, equipment and build costs, and operational and maintenance costs.

Table 2 Main TSO cost drivers

Supply/demand drivers	Equipment and build costs	Operational and maintenance
peak demand total energy delivered location supply sources location demand centres changing gas flow patterns	pipeline size pipeline length compressor capacity	emissions regulation asset age asset health

3.2 Network investment

When looking at network investment we can make a distinction between load related expenditure and non-load related expenditure. Load related expenditure (LRE) refers to new investment to:

- deal with changing gas flow patterns on the network, and
- connect new users to the network (eg power stations or storage facilities).

The largest cost drivers are generally load related. Expenditure to deal with changing gas flow patterns may involve modifications to existing compressors, design and installation of new flow control valves, installation of electric drives at compressor stations, etc. Connecting new loads to the network may involve building new pipelines, compressor units, multi-junctions, etc.

Non-load related expenditure (NLRE) refers to expenditure to:

- maintain asset health, eg maintain the condition of primary assets on the transmission network such as terminals, pipelines, multi-junctions, compressor sites and offtake stations, and
- mitigate and abate direct gaseous emissions resulting from the operation of gas turbines required for the operation of compressor stations.

Asset health measures are meant to manage performance, safety, reliability and compliance standards for specific assets. NLRE primarily relates to the secondary assets, where the strategy is to maintain the overall condition of the primary asset group and to minimise disruption to customers by maintaining their reliability, performance and condition. Secondary assets tend to have a high degree of cost variability given design specifications, requirements and equipment innovation.

In addition to capital expenditure, the TSO will also face non-operational capex (non op capex). This is expenditure on capital items other than the operational system, with much shorter asset lives than other capex (eg usually 5 years rather than 40-50 years). Examples of non op capex are IT, telecoms, vehicles such as mobile plant and generators, etc.

3.3 Operating Costs

Operating costs can be divided into controllable and non-controllable costs. The main operating costs (opex) of a TSO will relate to input costs such as labour, electricity and fuel costs.

TSOs, like any other business, will also face other costs, like pension costs, financing costs, legal costs, and insurance. Although these costs may be significant, they are not a direct cost driver and are therefore not further discussed as part of this report.

3.4 Interaction between TSO cost drivers and storage

As previously noted, the provision of gas transmission services is a highly capital intensive business. The main share of a TSO's costs will therefore consist of capex in order to meet peak demand. Other key capex drivers of particular importance in relation to storage are the location of supply sources (production facilities, LNG import terminals, interconnectors) and the location of main centres of demand. Storage facilities may be embedded on the system and may be located close to centres of demand[18], whereas other supply sources may be located at the borders of the gas transmission network. Depending on the location of the storage site and its flow patterns, the TSO may be able to use smaller import pipelines sized for a lower net demand (rather than peak), with the storage facility making up the difference. Recent empirical evidence[19] (see figures 1-3) suggests that storage has made up a significant proportion of European flows on high demand days over the last three years compared for example with LNG imports.

[18] Although not always – for example, storage using depleted offshore fields.

[19] Gas Storage Europe (GSE) presentation at 10th TYNDP Workshop in Athens on 19th and 20th May 2015 (based on ENTSOG data) available on the ENTSOG website

Figure 1 Use of Gas storage in Europe[20], 2013–2014

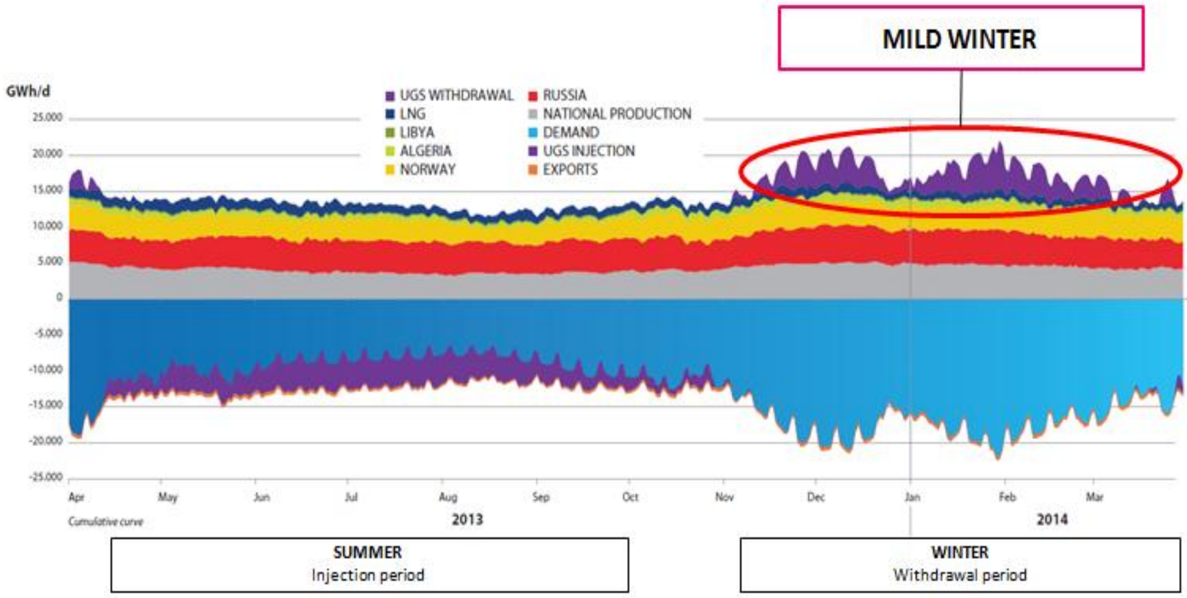
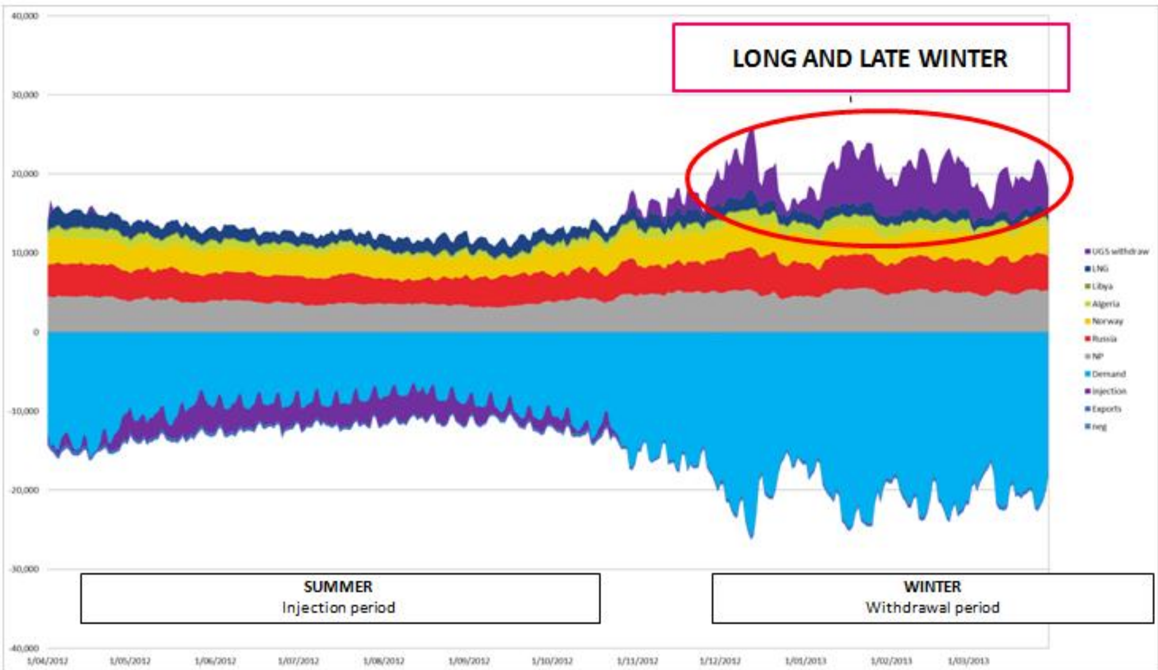
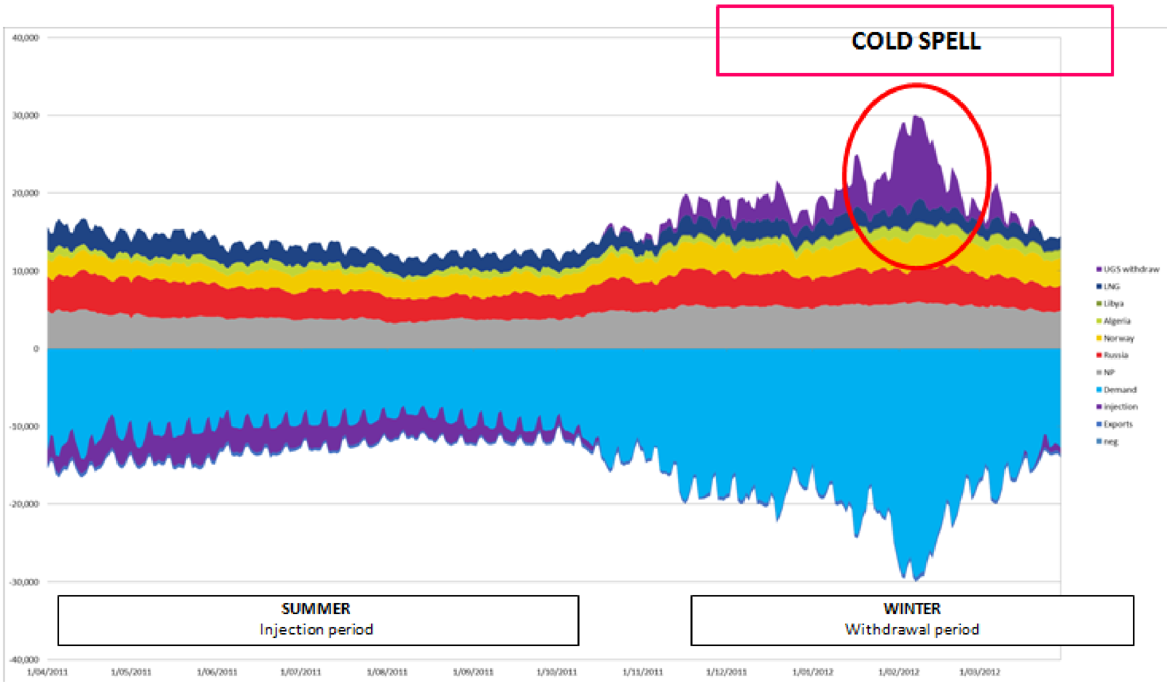


Figure 2 Use of Gas storage 2012–2013 (Long and late winter)



[20] Graphs are based on ENTSOG data and show volumes for the EU-28, Switzerland, Bosnia and FYROM.

Figure 3 Use of Gas storage 2011-2012 (Cold spell)



4 GB case study

4.1 Background

National Grid Gas (NGG) is the sole owner and operator of the high pressure gas national transmission system (NTS) in GB. NGG is regulated by Ofgem, which (amongst other things):

- regulates NGG through specifying NGG's duties in the Gas Transporter Licence and monitoring and if necessary enforcing compliance,
- determines the maximum allowed revenue which NGG as Transportation Owner (TO)[21], eg as owner of the gas transmission network, is allowed to earn through the TO price control. NGG as TO decides[22] where, when and how to invest in the system to maintain good asset health, to meet new demand and to increase network flexibility, and
- determines the maximum allowed revenue which NGG is allowed to earn as System Operator (SO) through the SO price control. NGG as SO has the responsibility for day-to-day system operation, including balancing of the system and constraint management.

4.2 GB tariff methodology: high level principles

4.2.1 Allowed Revenue recovery

In the GB approach[23] there are safeguards to ensure that NGG is always able to earn its allowed revenue. Ofgem sets the maximum allowed revenue which NGG is allowed to recover, which reflects efficiently incurred historical costs. NGG can earn more revenue depending on how it performs against its incentives as determined by Ofgem.

4.2.2 Allocation of tariffs

A distinction needs to be made between the allocation of tariffs across network users (ie who has to pay what price for network capacity) which is directly linked to the choice of cost allocation methodology, and the amount of revenue NGG is allowed to recover through capacity tariffs. The tariffs for network users and developers are set using an LRMC approach, through modelling the cost of network reinforcement needed to accommodate additional capacity increments. These modelling outputs form the basis for deciding which network users and developers have to pay higher tariffs and which network users and developers pay lower tariffs. The LRMC approach is therefore used to set *relative* tariffs (eg who has to pay more and who has to pay less), whereas the level of allowed revenue determines the *absolute* level of the tariffs, eg the final prices that are paid.

[21] For regulatory purposes, NGG's activities are split in a transportation part and system operation part.
[22] Subject to its duties as set out in the Gas Transporter Licence (available on the Ofgem website).
[23] This section summarises the GB approach to setting transmission tariffs. More detail can be found in Appendix A.

4.3 NTS Transportation model

The NTS Transportation Model is used to derive the NTS capacity tariffs. Capacity tariffs are set in order to recover the network investment costs. The Transportation Model consists of two parts: the Transport Model and the Tariff Model.

4.3.1 Transport Model

The Transport Model calculates the LRMCs of transporting gas from each entry point (for the purposes of setting NTS Entry Capacity Prices) to a 'reference node'[24] and from the 'reference node' to each relevant offtake (exit) point. This model is an optimisation model that calculates the minimum total network flow distance (in GWh.km) given a set of supply and demand flows.

In order to determine the 'base network', NGG's best estimate of the relevant year's 1 in 20 peak base case supply and demand[25] data is used. To calculate entry prices, supply flows are adjusted to reflect the obligated flow at each entry point (except in the case of UK Continental Shelf (beach) gas[26] where Ten Year Statement data is used). The next step is to derive the shortest total network length to meet this scenario. This is achieved through minimising the total of flow multiplied by distance for a balanced network. This results in the Initial Nodal Marginal Distances from entry points to the 'reference node' and from the 'reference node' to exit points. This forms the base network.

The next step is for the model to calculate the LRMC of transporting an increment[27] of gas from each entry point in turn (for the purposes of setting NTS Entry Capacity Prices) to a 'reference node' and from the 'reference node' to each relevant offtake point. Nodal Incremental Distances are the difference between the Nodal Marginal Distance at the incremental level and the Nodal Marginal Distance at the obligated capacity level (eg base network).

4.3.2 Tariff Model

The Initial Nodal Marginal Distances are adjusted to either maintain an equal split of revenue between entry and exit users where prices are used to set auction reserve prices, or to recover a target level of revenue, where prices are set at administered rates.

[24] A reference node is an arbitrary point on the system chosen to model entry and exit flows. The entry and exit prices are not dependent on the choice of reference node. This is because all Marginal and Incremental Nodal Distances for all entry and all exit points are calculated in relation to the same reference node. What ultimately matters are the *relative* differences in nodal distances.

[25] This refers to the peak day demand that, in a long series of winters, with connected load being held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters, each winter being counted only once.

[26] This reflects the fact that beach gas is declining and the level of obligated capacity would be significantly in excess of forecast flows.

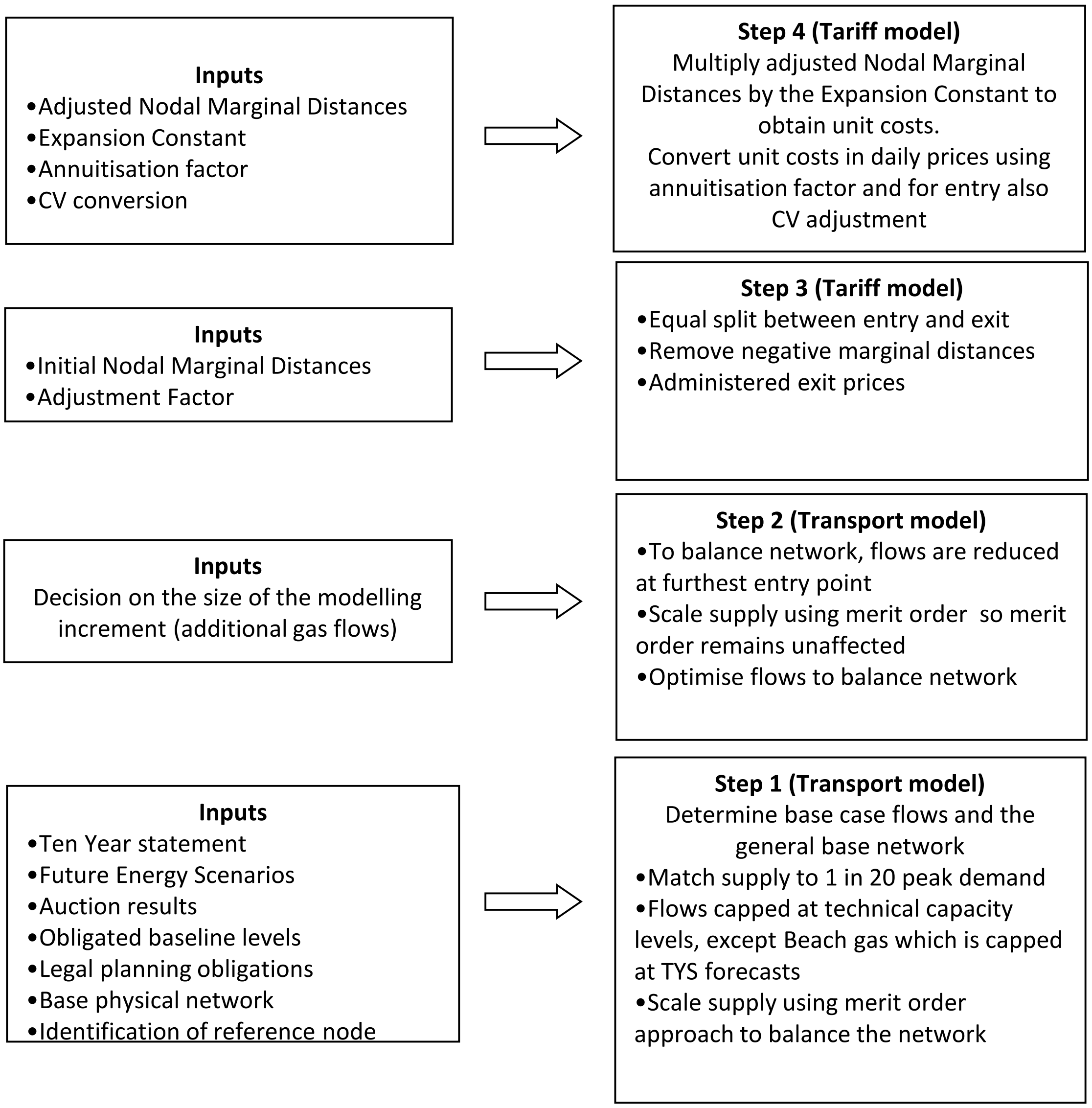
[27] Incremental flow is an additional flow on top of the base case demand/supply scenarios at that specific network point with commensurate flow reduction at the least helpful network point in order to balance the network.

The adjusted Marginal Distances are converted into unit costs (£/GWh) by multiplying by the Expansion Constant. The Expansion Constant[28] is derived as an average cost of the most frequently used pipelines and the cost of compressors necessary to maintain appropriate pressures on the NTS. The Expansion Constant is therefore a proxy for general network costs and does not reflect actual reinforcement costs for a specific entry or exit point. These unit costs can then be converted into daily prices by applying the annuitisation factor (which has been calculated assuming a 45 year asset life, the current allowed rate of return of 6.25% on capital expenditure and 1% operating expenditure allowance) and then dividing by the number of days in the year. For entry prices, an adjustment to reflect the calorific value at the entry point is also applied.

The steps involved in deploying the Transportation Model are shown in figure 4. (Steps are shown from bottom to top to emphasise the 'bottom up' nature of the approach.)

[28] The Expansion Constant, expressed in £/GWhkm, represents the capital cost of the transmission infrastructure investment required to transport 1 GWh over 1 km. Its magnitude is derived from the projected cost of an 85 bar pipeline and compression for a 100km NTS network section.

Figure 4 The Transportation Model: LRMC modelling process



In GB, the LRMC approach is used to allocate an appropriate share of NGG's allowed revenue (predominantly based on historical costs) to each network user. The Transport Model estimates the *relative* differences in costs imposed by different network users (entry as well as exit). The absolute level of the tariff ultimately to be paid by the user depends on NGG's allowed revenue. For entry tariffs, the additional TO commodity tariff makes up for any shortfall against allowed revenue, and exit tariffs are adjusted appropriately.

4.3.3 Simplified model

It is important to note that the Transport Model is a simplified model:

- it does not capture engineering detail (such as physical pipeline sizes and compressor settings),

- spare capacity is not reflected as it is assumed that *any* incremental flow[29] down a pipeline will require network reinforcement at a standard reinforcement cost,
- the Expansion Constant is a proxy for general network costs and does not reflect actual reinforcement costs for a specific entry or exit point, and
- it contains a price floor of 0.0001 p/kWh/day.

The main advantages of this model are:

- no engineering knowledge is required in order to use the model,
- it does not require very detailed technical assumptions (such as compressor settings),
- it enables users to replicate tariff calculations and model other scenarios, and
- it provides locational signals to network users (especially combined with an auction approach).

4.3.4 Role of Ofgem

Ofgem requires NGG to share its tariff setting model with its stakeholders, so stakeholders are not only able to replicate the tariff setting process but also model different scenarios. Stakeholders were consulted in the development of the model. Stakeholders also have to be consulted if NGG wants to make any changes to the model. Ofgem ultimately decides whether to accept or reject any proposed changes. NGG also has obligations to consult on key model inputs, such as demand and supply scenarios.

Ofgem has played a crucial role in ensuring that NGG's approach to setting tariffs has become more transparent, enables stakeholder engagement and scrutiny, and provides more appropriate price signals through ensuring more cost reflective tariffs.

This is, however, an ongoing process. For example, Ofgem[30] has stated that it considers the inclusion of spare capacity in the model to be highly desirable as it would *'provide strong signals to investors about the relative costs of locating new sources of supply or storage at different points on the network'*.

4.4 Capacity transfers

As part of the 2007 Gas Transmission Price Control Review, Ofgem required NGG, in consultation with stakeholders, to develop mechanisms to move unused network capacity to other parts of the network either on a temporary basis (the Capacity Trade and Transfer mechanism) or a permanent basis (the Capacity Substitution mechanism) to ensure best use of existing capacity and to reduce the

[29] The size of an increment is a percentage of the existing technical capacity (eg obligated baseline capacity as determined by Ofgem), therefore the increments used to determine the LRMC are not the same for each network point.

[30] Ofgem decision Modification Proposals to the Gas Transmission Transportation Charging Methodology NTS GCM01 (24 April 2007), p.6

risk of an unnecessarily large (and costly) network[31]. The Capacity Substitution Mechanism aims to achieve better utilisation of the existing network, particularly in response to changes in gas flow patterns. Through this mechanism, unused capacity from one entry point (donor) is moved to another entry point (recipient) on a permanent basis. As the recipient will have indicated the need for extra capacity, this would normally have signalled new investment in the network. However, through capacity substitution the baseline capacity (eg capacity which is technically available) at the donor point is reduced on a permanent basis and capacity at the recipient point is increased on a permanent basis, either with no additional network investment needed or only limited additional investment in the network. This is a more efficient way of creating additional capacity where most needed, because:

- it reduces the risk of stranded assets elsewhere on the network,
- it can address potential capacity constraints (eg need for additional capacity) generally quicker and more cheaply than additional investment.

4.5 GSOG study on system benefits from gas storage

The fact that the GB tariff model is in the public domain and the fact that the approach to tariff setting is more transparent and involves extensive stakeholder engagement, has enabled the Gas Storage Operators Group (GSOG) to estimate the value of storage and devise a method on how the value of storage to the transmission network may be calculated.

The study[32] shows how the presence of storage facilities on the gas transmission network conceptually enables the TSO to avoid network investment. Thanks to the presence and commercial utilisation of storage (eg typically flowing on high demand days) in the right location (eg close to centres of demand), the TSO may be able to avoid costs. The approach in the study consists of three distinct steps:

- examination of the role which storage plays in GB gas supplies on a peak day,
- identification of transmission investments which would be needed to manage peak demand if the current storage sites did not exist, and
- conversion of those identified investments into an annual cost saving.

The model used is the publicly available NGG Transportation Model. In the study it is assumed that the amount of gas which NGG assumes to be delivered through storage to meet peak demand would be delivered through other entry points, instead of storage facilities. Currently in NGG's central scenario the only storage facility assumed to flow to meet peak demand is Rough (GB’s only large scale seasonal storage asset). For the purpose of the study, the merit order as currently used by NGG was changed to enable the modeling of other storage flows to meet high demand. Based on data from 2012-2014, Medium Range Storage (MRS) consistently delivered gas to the NTS on the highest demand days. It may therefore be expected that MRS would deliver supply in more extreme

[31] See Appendix A for a more detailed discussion of the Capacity Trade and Transfer and Capacity Substitution methodologies

[32] Waters Wye Associates (2014), UK gas transmission system benefits from gas storage – an update to the initial report produced in 2007, A report for GSOG

situations, including a 1-in-20 peak demand day. The role of MRS is also reflected in NGG's Winter Outlook report[33].

In the study a number of demand and supply scenarios were used and different ways of using merit order in balancing the network were explored. Even when using the more conservative assumptions, as in the amended base case using a supply substitution method, theoretical capex savings were calculated in the order of £47 million per annum.

As pointed out in the GSOG report[34]:

'Gas storage sites do provide a benefit to the transmission system because on peak days they deliver to the system close to consumer demand, thereby reducing the need for pipe and compression capacity between alternative sources of gas and the demand'.

The report demonstrates the importance of regularly assessing modelling assumptions, scenarios and data to ensure it remains most appropriate. We expect this to be equally relevant for non-GB networks.

4.6 Modelling system benefits of storage: extending the LRMC model

The previous section dealt with the fact that storage may allow a TSO to invest in smaller diameter import pipelines in the presence of storage. The capex savings identified in the GSOG study relate to existing storage and not new incremental storage. However, the findings of the study may be relevant for network planning, for example when dealing with new investment in import pipelines in the presence of storage facilities and when determining appropriate pipeline size.

If we assume that import pipelines were sized to meet 1 in 20 peak demand, then it would not be unreasonable to assume that in the presence of a storage facility close to a centre of demand, and which flows gas on high demand days, that the import pipeline may in fact be larger than necessary. This may increase overall network flexibility, although this may require changes to network configuration. Also, this may result in reduced operating costs in the short term and potentially in reduced current and future network investment costs for example to deal with changing gas flow patterns in the longer term.

As Ofgem[35] has pointed out, *'it is important that the impact of flows which are beneficial to the network and reduce the need for network reinforcement are taken into account in the charge setting process'.*

This raises the issue of how to identify beneficial flows and how to quantify the benefits these flows provide. In order to identify which flows are of particular benefit to the wider network, the GSOG

[33] These reports are published annually in the autumn and provide more up to date forecasts of the anticipated supply for gas for the coming winter based on detailed market analysis and responses received to the Winter Consultation Report.

[34] Waters Wye Associates (2014), UK gas transmission system benefits from gas storage – an update to the initial report produced in 2007, A report for GSOG, p.31

[35] Ofgem decision Modification Proposals to the Gas Transmission Transportation Charging Methodology NTS GCM01 (24 April 2007), p.7

study has provided some pointers through identifying that, in GB, MRS has tended to flow on high demand days (also shown on the European level in figures 1-3 in chapter 3) and may therefore also be expected to flow on a 1 in 20 peak demand day.

If the objective is to set cost reflective tariffs which provide appropriate locational signals to existing and future network users then it is important to assess the network costs and benefits of a *specific* network user. This would firstly involve an assessment of the flow patterns of the user in question (eg does the user always flow in high demand situations) and the network location of the user. The next step would be to use an engineering network model[36] (as used for network planning purposes) to assess whether the current import pipeline/compressor capacity indeed has spare capacity as a result of the beneficial storage flows. Once it has been determined that this is the case, and the level of spare capacity has been determined, then the next step would be to price this capacity. This could be with reference to the capacity price at the entry point. Next, this may be reflected in the level of technical capacity made available at that entry point.

There may be situations that make it unlikely that the additional capacity which has been identified at the entry point as a result of beneficial storage flows will be used at that entry point. This unused capacity could be seen as a temporary or permanently stranded asset. This is currently addressed through the Capacity Trade and Transfer[37] process described above. Using this approach, modelling results will show whether a specific storage facility, due to its flow patterns and its location, benefits the network through freeing up capacity in existing import pipelines and/or compressor stations. If the results show that the entry point has spare capacity as a result of beneficial storage flows then such an entry point could become a capacity donor (eg capacity may be moved from this entry point to another entry point where there is additional demand).

Once it has been determined how much capacity is unused and would be available to be moved thanks to beneficial storage flows and at which exchange rate, the Tariff model may be used to determine the value of this additional capacity, either through using the capacity price at the entry point with the larger pipeline or the capacity price at the new entry point where the capacity may be transferred to. The existing tariff modeling process as presented in Figure 4 could potentially be extended by adding an extra step to identify and quantify potential benefits of a specific storage user:

Inputs

- Storage site close to centre of demand which flows on high demand days (eg MRS)
- Related entry point which may be expected to benefit from storage site through smaller import pipeline or spare capacity in existing pipeline

→

Step 5 (Network Model)

Identify potential benefits provided by storage flows in terms of avoided investment due to smaller import pipeline in case of new entry point or in terms of increased flexibility due to larger than required import pipeline in case of existing entry point using network model and value this additional capacity using tariff model

[36] Information is needed about the actual pipelines and compressor stations to determine available technical capacity with and without beneficial storage flows.

[37] More detail about these methodologies can be found in Appendix A.

As previously explained, the level of benefits provided to the system by a storage facility is likely to depend on its flow patterns (withdrawal as well as injection) and its location (eg whether close to centres of demand). This also means that any benefits which result in tariff discounts may come with additional requirements to ensure that the beneficial flows are provided when needed by the network or the TSO is compensated for additional costs (eg buy back costs). For example, if capacity was to be temporarily transferred from an entry point and this capacity was subsequently needed due to the storage facility not flowing during a high demand period, then the TSO would face additional costs which it may want to claim back from the storage user.

Alternatively, an approach similar to the Constrained LNG approach[38] may be appropriate. The storage user may agree to provide transmission support gas to the network on days of (very) high demand and to keep a minimum inventory level of gas in store so that transmission support gas is available all winter. In exchange for offering transmission support, the network user receives a rebate from NGG, which reflects the saved investment in the pipeline system.

4.7 Lessons learnt

The requirement on NGG to develop, consult on and publish its tariff model has enabled existing and potential future network users to gain a better understanding of how tariffs are set at each entry and exit point, how they may evolve over time, and how sensitive they are to changes in underlying assumptions, data and scenarios.

Ofgem requires that NGG publishes its tariff setting model and actively engages with its stakeholders. This has not only benefited the stakeholders, but also Ofgem in scrutinising NGG's decisions. Arguably, the publication of the GB model has improved economic efficiency through enabling better decision making by stakeholders, NGG and Ofgem. It is reasonable to expect that in future this approach will result in further improvements to the model, underlying assumptions, scenarios and procedures, resulting in further improved levels of economic efficiency.

Simple, transparent model

The model which NGG has developed in consultation with stakeholders, and which has been approved by Ofgem, is a simplified but transparent tariff model. This model does not aim to capture full technical details (such as actual pipeline diameters or compressor settings[39]), but it does enable stakeholders to replicate results and to model their own scenarios. Also, the GB experience shows that it may not always necessary to incorporate a high level of detail in the model and that a simple model may be appropriate.

However, the fact that spare capacity is not included in the model is potentially one of its main weaknesses from an economic perspective. Arguably, this is partially remedied by Ofgem through

[38] Constrained LNG is used to support the system in the case of demand changes in the shorter term, where investment lead times prevent immediate system reinforcement. NGG can decide to use Constrained Services in order to save on pipeline investment, eg as transmission support.
[39] NGG uses a separate model for network engineering analysis.

requiring NGG to facilitate movement of unused capacity to places where it can be utilised through the Capacity Trade and Transfer and Capacity Substitution methodologies[40].

Furthermore, any beneficial flows resulting in operational cost savings cannot be identified by network users. Given that aligning incentives between users and the TSO is important to achieve greater economic efficiency, it seems a logical next step to explore how the model could be used to enable identification and quantification of operational costs savings.

Stakeholder engagement

The GB approach has demonstrated that it is possible to develop a publicly available, simplified tariff model in a relatively short time frame (approximately one year) and in close collaboration with the NRA and stakeholders. The requirement to develop a model in collaboration with stakeholders has led NGG to improve its stakeholder engagement processes. This increased scrutiny has no doubt benefited the development of the model and further increased transparency.

Monitoring and evaluation

It will always remain relevant to monitor and to evaluate the model and its inputs (data, assumptions, scenarios) on a regular basis.

As the recent GSOG study has shown, questions may be asked about the current GB merit order assumptions. Arguably, without the availability of a public tariff model and transparent processes, it would have been much more difficult for stakeholders to fully appreciate the implications of merit order assumptions on their tariffs. It would also be much more difficult to try to make changes to the current processes and/or to persuade Ofgem to consider such changes. It is therefore important that stakeholders not only have access to information but also are given the means to initiate changes if necessary.

Indeed, the GSOG report has resulted in stakeholders currently developing a Uniform Network Code modification[41], which is likely to be submitted to Ofgem in the near future. Ofgem will then determine whether to approve such a modification or not. Stakeholder engagement, involving current and future network users, the TSO and the NRA, is an important part of the GB approach.

[40] See Appendix A
[41]UNC 0517b.

5 Wider benefits of gas storage

5.1 Overview

There are a number of key areas in which gas storage can deliver additional value and where this additional value may not be captured through a tariff methodology based on network costs:

- reduced price volatility,
- greater overall network flexibility, and
- enhanced security of supply.

5.2 Reduced price volatility

Gas storage facilities can deliver value through reducing price volatility for gas suppliers, shippers and most importantly, consumers. As observed by Ofgem[42], although price volatility plays an important role in markets - through signalling shortages - consumers are not well placed to deal with large price spikes and excessive volatility. The presence of gas storage on the network can contribute to more stable prices for consumers. This may be desirable from a public policy point of view.

Gas storage also enables gas suppliers and shippers to better deal with sudden price spikes through hedging against supply and price risk. It can therefore be argued that storage provides insurance against unexpected events, be it a cold spell, severe winter or supply disruptions. Such unexpected events can result in increased demand or reduced supply and result in high market prices in the absence of storage.

5.3 Greater overall network flexibility

Gas storage also delivers value through increasing overall network flexibility to respond to short term variations in demand. This may become more important when dealing with increasing demand volatility. As observed by Ofgem[43], the absence of storage can increase demand volatility across borders as well:

''Since much of Irish gas demand is expected to be met by imports from GB, and Ireland has comparatively little gas storage at present, this could introduce further volatility to the GB system.''

Greater overall network flexibility is likely to become more important given the increasing role of intermittent renewables in power generation. As observed by the GB Department of Energy and Climate Change (DECC)[44]:

''Flexible gas supply infrastructure, including gas storage and volumes held at LNG regasification terminals, will become increasingly important as volatility increases.''

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[42] Ofgem (2012), Gas Security of Supply Report, Ofgem report to UK Government
[43] Ofgem (2012), Gas Security of Supply Report, Risks and resilience appendix, p.8
[44] DECC (2014), Gas Generation Strategy, Cm 8407, p.51

Storage is already relied on to deal with network balancing issues due to gas demand changing during the day, varying demand during day and night, during peak periods, sudden cold spells and to deal with the seasonal profile of demand. The presence of storage significantly increases overall network flexibility as demand-supply imbalances can be quickly addressed, from within-day to seasonal timeframes. Although financial market tools can be used to manage the risk of gas imbalances, the availability and cost of such tools will depend on the underlying physical system: ultimately the TSO has to ensure physical system integrity. Storage is a flexibility tool that can be physically guaranteed.

5.4 Enhanced security of supply

One of the main aims of the European Commission, European Governments, NRAs, TSOs and stakeholders is to ensure a safe and secure gas network with adequate levels of security of supply.

This is currently a very significant issue for Europe, given its heavy and increasing reliance on gas imports. In the last ten years, there have been two significant supply interruptions in Europe, in 2006 and 2009. Both crises resulted from Russia cutting off gas supplies to Ukraine. During the 2006 crisis, pressure drops of up to 30% were reported by a number of European countries[45]. Hungary was reported to have lost up to 40% of its Russian supplies; Austrian, Slovakian and Romanian supplies were said to be down by one third, France 25-30% and Poland by 14%[46]. No customers were affected, but this was in part due to the mild weather and in part due to the industrial and commercial customers not operating over the New Year period. The situation was more severe during the next crisis in 2009. This crisis was a landmark gas and energy security event. The dispute resulted in 20% of Europe's gas being cut off for two weeks in the middle of winter. As pointed out by the Oxford Institute for Energy Studies[47]:

'The surprise, indeed the shock, was that both sides allowed the dispute to escalate from disagreements about debts, prices, and transit tariffs to the point where supplies to Europe were completely cut off; and then allowed this situation to continue for two weeks in the middle of winter, with serious adverse humanitarian consequences for (especially) south-east European countries.'

As a result of this crisis, Bulgaria was forced to reduce supply to households during a very cold winter. This caused severe hardship. Bulgaria suffered an estimated 9% loss in GDP[48]. In Moldova businesses and households were totally cut off from gas supplies[49].

In October 2014, the European Commission published a series of 'stress tests' on 38 European countries to assess the impact of any prolonged disruption of Russia's gas supply. The conclusion of the report[50] was that a prolonged Russian supply disruption could leave private households 'out in

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[45]Austria, France, Germany, Hungary, Italy, Poland and Slovakia

[46]Stern (2006), The Russian-Ukrainian gas crisis of January 2006, Oxford: Oxford Institute for Energy Studies, p.8 and 9

[47]Pirani, Stern, Yafimava (2009), The Russia-Ukrainian gas dispute of January 2009: a comprehensive assessment, Oxford: Oxford Institute for Energy Studies, p.60 and p.61

[48]Ofgem (2012) Gas Security of Supply Report – Risks and Resilience appendix

[49]Pirani, Stern, Yafimava (2009), The Russia-Ukrainian gas dispute of January 2009: a comprehensive assessment, Oxford: Oxford Institute for Energy Studies, p.4

[50] European Commission (2014), Gas stress test: Cooperation is key to cope with supply interruption, Brussels: European Commission

the cold'. Finland, Estonia and the non-EU Balkan states of Serbia, Bosnia-Hercegovina and Macedonia, would be affected most and miss at least 60% of the gas they need. However, the report also points out that co-operation through optimised infrastructure use and relative burden-sharing, would significantly reduce the impact on customers.

Gas storage can help mitigate the impact of such events. One of the characteristics of domestic storage facilities is that they enable supplies to be physically available in large quantities on the gas transmission network, typically close to demand. This gas is not subject to geopolitical risk and therefore remains available to the market and likely to be used in the event of international circumstances that could reduce the availability of imported gas.

5.5 Storage and alternatives

Storage is not alone in providing wider benefits, but as summarised in Table 1, it does arguably provide a greater range on a more consistent basis than alternatives, other than domestic production which is of course limited based on the location of resources.

Table 1 Value contributions for example technologies over time

	Within day (system integrity)	Short term (eg 5 day cold spell)	Medium term (eg severe winter)	Long term (eg 3-6 month international crisis)
Domestic production	Some production fields developed to provide very short term response	Has a degree of flexibility to change output when needed	Has a degree of flexibility to change output when needed	Ongoing supply controllable in an emergency
Gas storage facilities	Highly flexible for network balancing purposes	Highly flexible on short term basis	Flexible to change output when needed	Dependent on scale of storage and level of gas in store
LNG import	Dependent on level of LNG in tanks at terminals, and locations of ships	Dependent on level of LNG in tanks at terminals, and locations of ships	Dependent on global market	Dependent on global market and extent of crisis
Demand-side response (industrial customers and power stations)	Potential provider dependent on underlying demand profile	Demand response typically short term only	Demand response typically short term only	Demand response typically short term only
Flexibility via interconnections	Dependent on flexibility in neighbouring market	Dependent on neighbouring markets	Dependent on neighbouring markets	Dependent on neighbouring markets and extent of crisis

● Suitable ● Suitable under conditions ● Not suitable

5.6 Potential role of transmission tariffs

It is important that policy makers and regulators carefully consider whether the wider benefits of storage are fully reflected in the market, and if not, what means may be appropriate to correct this. Not reflecting the wider benefits of storage could contribute to underinvestment in new facilities and pose a risk that existing facilities could close where investment is needed to extend asset lifetimes, thus potentially increasing the risks of excessive price volatility, and the severity of any security of supply shocks for EU citizens.

If the market materially undervalues the wider benefits of storage, and there are concerns around the practicality of, or timeframe required for, other harmonised policy interventions, then a mechanism involving an extension to the transmission tariff methodology could be an initial approach to address this. An appropriate and transparent methodology would be required to quantify this, for example, modelling network risks associated with gas shortages where a key supply source is interrupted (amongst other scenarios), in order to assess both the probability and the impact of such an event. This could result in putting a value on being able to avoid or mitigate the consequences.

Were it concluded that the market does not reflect the full value of storage, and alternative interventions are not appropriate, it would be possible to add an additional step to the GB LRMC tariff setting model (presented in figure 7 in section 4.3.2), in order to reflect wider societal benefits of gas storage into the tariff setting model:

Inputs

- Value of improved security of supply
- Value of greater price stability
- Value of greater network flexibility

→

Step 6

Adjust storage tariff to take wider societal benefits into account

In a number of Member States, storage users are receiving discounts for a number of different reasons, which may include the reflection of avoided costs, avoiding double payment, improving network flexibility, and the reflection of their contribution to increased security of supply.

In Germany, this issue of wider benefits has been recognised through providing a 50% discount for storage users, not only to avoid double payment but also to recognise the system as well as wider benefits of gas storage (eg increased security of supply, greater flexibility and its role in network balancing)[51].

In 2012, the Austrian Regulator E-Control[52] commissioned KEMA to assess the principal options for designing an entry-exit tariff system in line with the EU and national legal framework and to provide recommendations for its implementation in Austria. E-Control followed KEMA's recommendations for (shallow) connection charges to take into account those costs arising from the connection of storage facilities and variable costs related to the transportation of gas to and from storage. KEMA concluded in their study for the Austrian Regulator that storage capacities in Austria are able and used to cover peak demand in the local distribution system without transporting gas over long distances. Without these storage capacities more entry capacity to the market area would be necessary to cover high demand in the local demand areas in winter time.

[51] Bundesnetzagentur (March 2015), Beschluss In dem Verwaltungsverfahren nach § 29 Abs. 1 EnWG i. V. m. §§ 13 Abs. 2 S. 4 GasNEV, 15 Abs. 2 bis 7 GasNEV, 30 Abs. 2 Nr. 7 GasNEV, 50 Abs. 1 Nr. 4 GasNZV

[52] EndberichtGrundsätze der Entry-Exit-TarifierungIm Auftrag von: Energie-Control Austria, erstellt durch: KEMA Consulting GmbH, Bonn, Mai 2012

6 Conclusions

6.1 Aim to set cost-reflective tariffs based on net costs

The aim of the TAR NC is to harmonise gas transmission tariff structures across Member States. This is supported by Article 13 of Gas Regulation 715/2009. The ultimate objective is to agree an economically robust approach to setting transmission tariffs for network users which does not distort cross-border flows.

Cost reflective transmission tariffs should provide investment signals and therefore contribute to system integrity, facilitate efficient gas trade and competition, avoid cross-subsidies and reduce the risk of cross border trade distortions. Therefore, any material benefits which a user provides to the network (for example through avoided investment costs or reduced compression costs or increased technical capacity) should also be taken into account when setting the tariffs for that user.

In summary, to achieve cost reflective transmission tariffs:

- tariffs should ideally be set using a LRMC approach,
- tariffs should be set separately for each entry and each exit point,
- tariffs should be based on a publicly available tariff model,
- if the location and flow patterns of certain users result in avoided investment costs/reduced operational costs/increased network capacity then these network benefits should be reflected through lower tariffs[53],
- capacity tariffs should reflect network investment costs, whereas flow related (commodity) tariffs should reflect operating costs, and
- sensitivity analysis should be carried out when modelling tariffs to ensure that underlying assumptions and scenarios are and remain appropriate.

6.2 Develop a public domain tariff model

TSOs should be required to develop, in consultation with stakeholders, a public tariff model which could be used by any party, including potential new entrants, to understand how tariffs are set and how they may evolve over time.

It may be appropriate to consider a model similar to the GB model to quickly advance harmonised transmission tariff structures and provide an initial improvement to cost reflectivity in the approach.

As for any model, it will be important to conduct regular reviews, so any legacy decisions are not locked in and to enable improvement over time. For example, it may be desirable for the GB model to be further developed over time through inclusion of spare capacity and it may be possible to adopt less risk averse modelling assumptions in relation to balancing the network (for example the current assumption to use the least beneficial alternate supply flow when balancing the network).

[53] As pointed out by CEER: 'Transportation tariffs should consider the benefits and costs that storage facilities provide to the overall system', May 2015, p.28

6.3 Ensure robust and transparent data

In order to set tariffs using a tariff model, all inputs should be sufficiently robust. Given the significant information asymmetry between the TSO on the one hand and the NRA and stakeholders on the other hand, transparency is very important. Greater transparency is likely to reduce the risk of incorrect assumptions, problematic data and inappropriate scenarios through the scrutiny of stakeholders.

Data types required and to be made public include:

- supply and demand data (historical and forecasts),
- network capability (of each entry and each exit point),
- technical data (Calorific Value, pipeline data),
- cost data (network costs, operational costs),
- booking data (auction data),
- financial data (cost of capital, annuitisation factor),
- allowed revenue (as determined by the NRA),
- modelling assumptions (eg network balancing, merit order etc.), and
- demand and supply scenarios to enable sensitivity testing and stress testing.

6.4 Define role for NRAs

The NRA plays a key role in ensuring an appropriate tariff setting methodology and process. Given that the TSO will generally be able to earn its allowed revenue, it faces little in the way of commercial incentives in ensuring that tariffs are indeed cost reflective and in line with the other key principles aimed at maximising welfare. This puts the onus on the NRA to ensure that the TSO puts a robust methodology and process in place.

In GB, Ofgem requires NGG to engage extensively with stakeholders (which also involves providing stakeholders with appropriate information), as this increases scrutiny and therefore an economic efficient outcome is more likely to be achieved.

NRAs may want to:

- ensure that the tariff methodology adopted by the TSO is indeed cost reflective and not only takes the costs which users impose on the system into account, but also benefits which users bring to the system, for example in terms of avoided investment costs/increased network flexibility/reduced operating costs,
- require the TSO to publish its tariff model, developed in conjunction with stakeholders, which enables stakeholders to replicate tariffs and examine different scenarios,
- ensure that stakeholders have access to key model inputs, such as underlying data, assumptions and scenarios and that commercial confidentiality is not inappropriately used as a reason to refuse to provide information to stakeholders,
- ensure an appropriate network balancing approach which does not result in an unrealistically large network,
- ensure that stakeholders are involved on an ongoing basis in the tariff setting process, including the development of the methodology, decisions on underlying assumptions and use of data and scenarios,
- ensure a stakeholder engagement process through which stakeholders are able to propose changes to the tariff model, assumptions and/or data inputs,
- place an obligation on the TSO to keep the tariff methodology, tariff model and inputs in the form of data, assumptions and scenarios under regular review, and
- provide stakeholders with the option to ask the NRA to review key TSO decisions if the stakeholders believe these decisions to be inappropriate.

From an economic perspective, we consider it desirable to examine the level of network benefits provided by storage facilities which are located close to centres of demand and have beneficial flow patterns and are thus likely to provide network benefits. Such a process would need to be driven by the NRA, given that the TSO may have an incentive to build a larger network (eg overinvest) in order to increase its allowed revenue. We consider that through a network modelling approach combined with a tariff model the benefits provided by an individual storage facility could be identified and quantified. This may provide a transparent, non-discriminatory and cost reflective way to address the network benefits provided by a storage user through the tariff setting process.

6.5 Define role for TSOs

Given that only the TSO has all necessary information to set tariffs in line with the requirements set out in the Gas Regulation 715/2009 and given the significant information asymmetry between the TSO and NRA and the TSO and its stakeholders, we consider that the following checklist may be a good starting point for the TSO's role in tariff setting:

- develop a simple but transparent tariff setting model, which is shared with stakeholders and enables stakeholders to replicate the tariff setting process, and model different scenarios,
- consult stakeholders on modelling assumptions (such as approach to network balancing including merit order) and data inputs (such as forecast demand and supply scenarios),
- keep the tariff model, assumptions and data inputs under regular review,

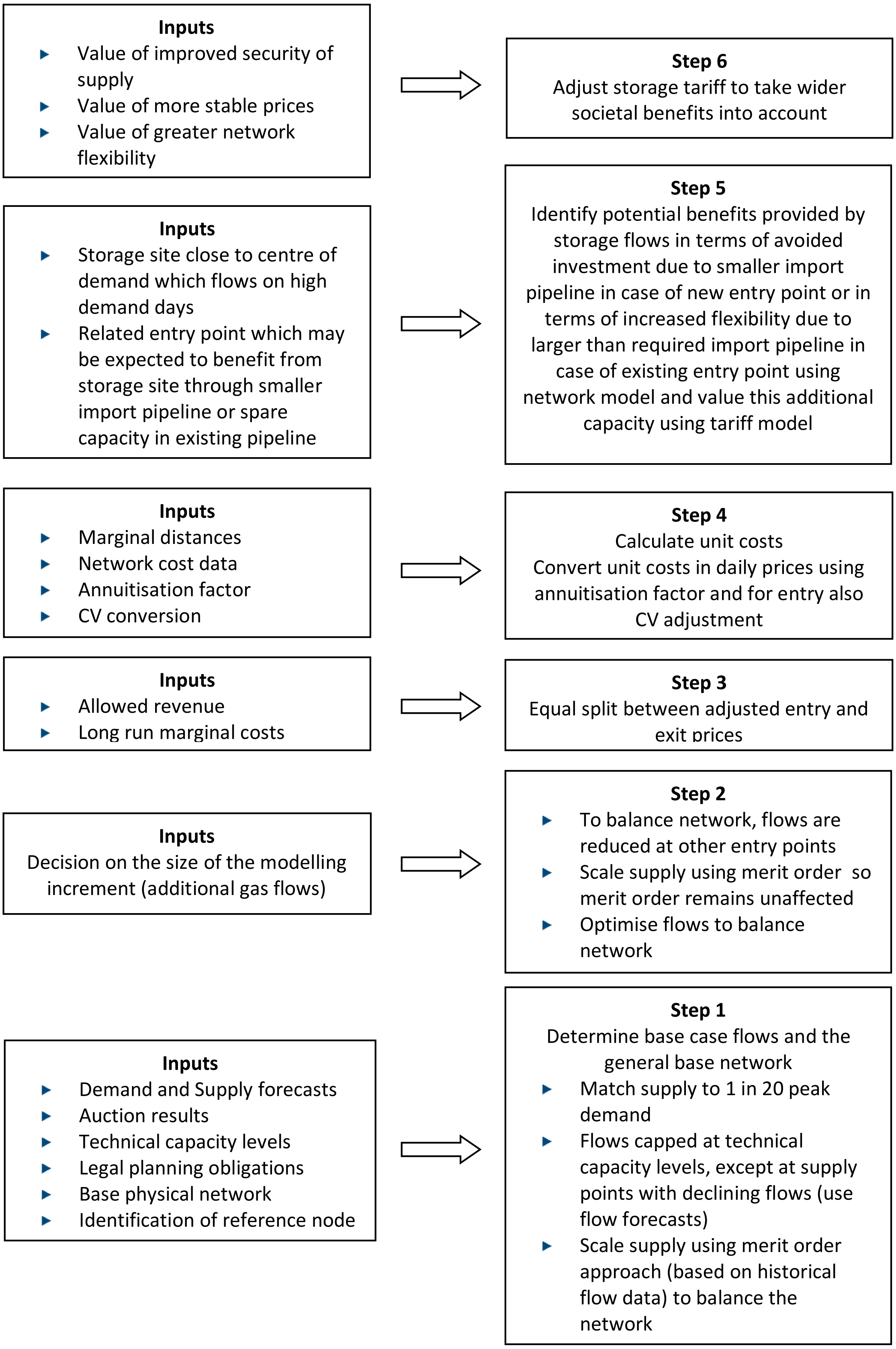
- either the tariff model or a network model should be used to identify and quantify the benefits which users may provide to the system and take these benefits, for example in the form of increased flexibility and/or avoided costs in terms of network investment and/or compression, into account in the setting of tariffs.

The tariff model should:

- strike the right balance between cost reflectivity and transparency, ensuring accessibility whilst providing appropriate locational signals,
- be able to produce tariffs which are not unduly volatile from year to year as a result of minor changes in assumptions and/or data inputs as this would reduce transparency and undermine efficient investment signals, thus potentially damaging system integrity and improvement,
- ideally reflect spare capacity through lower tariffs to ensure best use of existing assets or if this is not possible, be supplemented with a mechanism to move unused capacity from a specific entry or exit point to another entry or exit point where there is excess demand, if efficient to do so,
- if so determined by policy-makers (as discussed below), take into account wider societal benefits.

Figure 5 shows the steps involved in setting tariffs based on the GB approach with potential additional stages to take account (if appropriate) of the additional network and societal benefits provided by gas storage facilities.

Figure 5 LRMC modelling process including benefits of storage



6.6 Consider recognising broader benefits

There are a number of wider benefits which storage facilities provide, such as reducing volatility, providing greater overall network flexibility and increasing security of supply. Security of supply has increasingly been an area of concern and focus for regulators and policy makers. A recent CEER report[54], produced in response to concerns about the low levels of gas in store following the 2013 winter, states that *'Storage plays an important role in delivering Security of Supply for European consumers'.*

As these benefits are not solely associated with network investment or operational costs, they are not fully captured within an LRMC-type methodology. These may also not be fully valued in the market, and if so it may be important from a public policy perspective to intervene to ensure these are recognised. If other potential harmonised mechanisms were shown to be impractical, then tariff methodology could provide one initial means of doing so. We have noted in this report a number of existing precedents within Member States. As pointed out by CEER, *'(...) until completion of the internal market through the 3rd Package, it is possible that the value of storage is not appropriately recognised in all markets. In particular, some aspects of storage may be undervalued'.* The report recommends that *'transportation tariffs should consider the benefits and costs that storage facilities provide to the overall system'*.

[54] CEER Final Vision on the Regulatory Arrangements for the Gas Storage Market, May 2015

Appendix A GB approach to setting transmission tariffs

In this appendix we provide more detailed information about the GB regulatory regime and GB approach to setting transmission tariffs.

A.1 Transmission tariffs determined to recover allowed revenue[55]

NGG is subject to revenue cap regulation and has to aim to collect its maximum allowed NTS TO revenue through entry and exit capacity tariffs. NGG's TO allowed revenue is based on efficiently incurred (eg approved by Ofgem as part of price control reviews) historical investment costs. The NTS SO allowed revenue is based on an Ofgem estimate of an efficient level of operating costs and is collected largely by means of a commodity charge levied on entry and exit flows.

A.1.1 Capacity tariffs

Capacity tariffs are set in order to recover the network investment costs. They are payable when a right to flow gas is purchased, with payment due irrespective of whether or not the right is exercised. Although the obligation to pay for capacity remains with the primary purchaser, all types of entry capacity can be traded between network users. The Transportation Model is used in deriving the capacity tariffs.

Long-Run Marginal Costs

The processes to determine capacity tariffs for new and existing network users and revenue drivers for NGG to provide new network capacity have been de-linked. This enables the annual resetting of capacity tariffs using a LRMC approach to provide better locational signals to network users and developers. It also preserves the price control incentive properties on NGG as it enables the setting of revenue drivers for a longer period, resulting in higher powered incentives.

Capacity tariffs

The tariffs calculated through the transportation model (eg combination of the transport and tariff models) are used to set the reserve prices for all the entry capacity auctions and administered tariffs plus reserve prices for the pay as bid auctions for exit (exit has a combination of administered tariffs and pay as bid auctions). Entry tariffs are payable when a *right* to flow gas is purchased, with payment due irrespective of whether or not the right is exercised. The actual price paid by network users for GB entry capacity depends on the outcome of the auctions. In the case of capacity constraints the actual price could be in excess of the reserve price.
In the past, NGG over-recovered in the auctions due to capacity constraints and network users received rebates. As the network is now increasingly unconstrained, network users tend to buy entry

[55] The Uniform Network Code sets out how NGG has to set tariffs and can be found on http://www.gasgovernance.co.uk/sites/default/files/TPD%20Section%20Y%20-%20Charging%20Methodologies_22.pdf

capacity in the short term auctions[56] at discounted prices resulting in significant under-recoveries against NGG's allowed revenue, thus resulting in a positive TO commodity charge which all network users (except for flows into and out of storage) have to pay and which is flow based.

A.1.2 Commodity tariffs

Commodity tariffs consist of tariffs per unit of gas allocated to network users at NTS entry and exit points. These tariffs are linked to actual flows. The SO commodity tariffs are set so NGG is able to recover its allowed SO revenue. The TO commodity charge is set to enable NGG to recover its allowed TO revenue in case of a capacity tariff shortfall (for example, auctions have resulted in lower than anticipated revenue due to capacity being purchased at discounted prices).

Storage

Gas storage users do not pay TO and SO commodity tariffs on gas flows at storage facilities, other than on the amount of gas utilised as part of the operation (storage 'own use' gas). Own use gas is the difference between the quantity that is injected into storage and the quantity that is available for withdrawal back into the system. Own use gas is subject to both the TO and SO commodity tariffs.

A.1.3 Approach to network balancing when calculating the LRMC

Arguably, one of the most critical network assumptions when determining LRMC is how to balance the network within the model. Very simplistically, if you want to add more gas, you will need to take gas elsewhere on the network away to maintain a balance. This can be done in two different ways in the model:

- through putting less gas on at other entry points to make space for the new increment, referred to as ‘substitution of supply’, or
- to increase the gas taken off the system at the exit side (demand side). This implicitly assumes that if you add more gas onto the system, customers will also start using more, which will require a larger network (eg more and/or bigger pipelines). This is referred to as ‘load absorption’.

In practice, a gas transmission network is of course more complex due to the need for compression. However, the network balancing basics are similar. The choice is:

- to keep the network the *same size* when you model an additional increment of gas (for example when setting LRMC or modelling new entry flows for a new entry point); or
- to assume that when you put more gas on the network, the demand for gas will also increase, which results in the network becoming *larger* (eg more and/or larger pipelines, compression etc.).

The resulting tariffs will be very sensitive to this key modelling assumption. Clearly, if you assume that demand increases when adding an additional increment of gas, potential network reinforcement costs will typically be much higher and the resulting tariffs will therefore also be considerably higher.

[56] For short term auctions, reserve prices are scaled down. The level of discounts in the shorter term auctions is currently being reviewed due to the significant revenue underrecovery against Ofgem allowed revenue.

This raises the question whether such an assumption is plausible. Given that the GB network is mature, and if anything, demand for gas may be expected to decrease rather than increase in the future, the assumption that demand will increase if you put more gas on the network would not be appropriate.

In the Transport Model flows are therefore balanced through substitution of supply. When an additional increment of gas is added in order to model LRMC (eg the cost of transporting an additional increment of gas on the network), supply (eg entry) flows are reduced elsewhere on the network to ensure that supply equals demand. The method to reduce flows elsewhere on the network is referred to as the 'merit order'.

Merit order

In order to balance the network the aggregate supply flow is adjusted to ensure that the values for supply and demand are equal (eg substitution of supply approach). The merit order sets out in which way supply flows are used to balance the network. In practice this means that some entry supplies are always assumed to flow, whereas others are only assumed to flow to meet higher levels of demand. The merit order used by NGG is based on its Ten Year Statement.

Supplies are divided into six different groups and are reduced in accordance with the merit order approach. This currently implies that supplies are being reduced in the following order to the point at which supplies equal the forecast demand:

- short range Storage Facilities;
- mid range Storage Facilities;
- LNG Importation Facilities;
- long range Storage Facilities;
- pipeline interconnectors; and
- beach terminals (UK Continental Shelf).

The merit order reflects views on which supplies are more likely to flow at peak than others, which supplies may be displaced by other sources of gas (supply balancing) and the range associated with maximum and minimum likely anticipated flows for each supply. These rankings may vary from one supply scenario to another.

A.1.4 Assumptions

In deriving tariffs using the Transport Model, a number of assumptions are made, such as:

- demand and supply assumptions, eg 1 in 20 peak day demand,
- merit order assumptions,
- technical capacity at each entry and exit point (eg Ofgem determined baselines as set out in NGG's licence),
- Single Expansion Constant as a proxy for network investment costs,
- minimum entry and exit capacity tariff (eg price floor of 0.0001 pence per kWh per day), and
- 50:50 entry/exit split.

A.1.5 Data

The Transport Model requires a set of inputs which are consistent with the costs incurred in making capacity available on the NTS:

- nodal supply and demand data (GWh)
  - Demand data in relation to each NTS Exit Point as the lesser of:
    - NGG's forecast 1-in-20 peak day demand at that Exit Point or
    - the aggregate of the Baseline Capacity and incremental Capacity in respect of that Exit Point,
  - Supply data at NTS Entry Points,
  - Technical data, eg transmission pipelines between each node (measured in km) and calculated by reference to existing pipelines and new pipelines expected to be operational on or before the start of the Gas Year under analysis, and
  - Identification of a reference node.
- the nodal supply data is derived from the supply/demand data presented in the most recent Ten Year Statement for each Gas Year for which prices are being determined (central scenario is currently the 'Gone Green Scenario')and physical capability,
- the supply figures at storage facilities and/or pipeline interconnectors may be set at a level that is less than or equal to the expected entry point capability,
- baseline NTS Entry Capacity (measure of technical capacity as determined by Ofgem and set out in NGG's licence) plus capacity substitution,
- auction bookings, and
- cost data, eg expansion constant to proxy capital costs of investing in network to transport 1 GWh over a distance of 1 km.

A.1.6 Scenarios

As part of the tariff setting process, a number of different scenarios are considered, which also enables sensitivity testing to changes in demand and supply.

- Ten Year Statements (TYS) - The TYS details NGG's latest supply and demand scenarios, proposed system reinforcement projects and investment plans, and actual flows seen on the NTS in recent years. It takes into account information received from the long term entry capacity auctions and incremental entry capacity release process, the long term exit capacity bookings made by Distribution Network Operators (DNOs) and the exit capacity requirements of network users. The TYS is published in line with NGG's Licence requirements and UNC obligations,
- Future Energy Scenarios (FES) -These are long term future energy scenarios which in part inform the TYS,
- Sensitivity analysis - In order to test how robust the model is, a number of other scenarios are applied. For example, an assessment may be made for the potential for gas that can be delivered to interconnected markets to be delivered elsewhere and the implications for the GB network,

- Winter Outlook reports - These reports are published annually in the autumn and provide more up-to-date forecasts of the anticipated supply for gas for the coming winter based on detailed market analysis and responses received to the Winter Consultation Report.

A.1.7 Assumptions

The Tariff Model also contains a number of assumptions, such as:

- 50:50 entry:exit split in order that 50% of the allowed revenue is recovered from entry and 50% from exit users,
- Single expansion constant as a proxy for network investment costs,
- 45 year asset life,
- allowed rate of return of 6.25% on capex, and
- 1% operating expenditure allowance.

A.1.8 Data

The Tariff Model requires the following data inputs:

- Marginal costs of supply (output from Transport Model),
- Marginal costs of demand (output from Transport Model),
- Cost data, eg Expansion Constant to proxy capital costs of investing in network to transport 1 GWh over a distance of 1 km,
- Financial data: cost of capital, inflation rate, etc. and
- Allowed revenue as determined by Ofgem

A.2 Spare capacity and capacity constraints

The Transportation model does not include spare capacity which is already present on the (physical) network. This could result in inefficient investment decisions, eg investment in new capacity resulting in a larger network than necessary. Ofgem has therefore in its various decisions made clear that it would expect NGG to address the spare capacity issue in an appropriate manner.

In addition, Ofgem requires that NGG in collaboration with its stakeholders develops and regularly reviews methodologies to move unused capacity from one entry point to another entry point, where it is efficient to do so, in response to demand signals[57]. These mechanisms are called the Capacity Trade and Transfer Mechanism for dealing with a temporary move of capacity and the Capacity Substitution Mechanism for a permanent move of network capacity.

[57] As set out in Special Condition 9A of NGG's Gas Transporter Licence (available on Ofgem's website)

A.2.1 Capacity trade and transfer

NGG has in consultation with stakeholders developed a capacity Trade and Transfer Methodology for a temporary move of capacity between network points which has been approved by Ofgem[58]. In this section we describe the methodology for entry points only as this is more relevant in the context of storage tariffs.

The objectives of the capacity trade and transfer methodology are to:

- ensure that entry capacity transfer/trade is effected in a manner consistent with NGG's duties under the Gas Act and which makes efficient and economical use of the NTS,
- ensure that entry capacity transfer/trade is effected in a manner which is compatible with the physical capability of the NTS,
- avoid material increases in cost (including entry capacity constraint management costs) that are reasonably expected to be incurred as a result of facilitating entry capacity transfer/trade, and
- so far as is consistent with the above three points, to facilitate effective competition between relevant shippers and suppliers.

NGG's methodology, which can be found on its website, sets out the process by which unsold obligated capacity from one entry point can be used to satisfy demand for firm capacity at another entry point (transfer) and the process of transferring sold firm capacity from one entry point to satisfy demand for firm capacity at another entry point (trade). This process applies to capacity within investment lead times as demand for additional capacity cannot be met by investment on the system within such timescales. There is a Rolling Monthly Transaction period for the Trade/Transfer process.

Network Analysis

NGG will undertake network analysis to determine what capacity Exchange Rate would be required to either enable a trade or a transfer from a donor entry point to a recipient entry point through assessing the flow patterns that can be accommodated without increasing the risk of capacity constraint management actions being needed. If in this manner capacity can be moved in an efficient way using an appropriate Exchange Rate then this would result in a temporary move of capacity from the donor entry point to the recipient entry point (for the period of one day or for one month).

Exchange Rates

The determination of a capacity Exchange Rate is based on fixed supply and demand scenarios against which potential Transfer and Trades will be assessed. Analysis is undertaken on a point by point basis. An Exchange Rate will be determined for the movement of capacity across entry points

[58] Available on http://www2.nationalgrid.com/uk/industry-information/gas-capacity-methodologies/entry-capacity-transfer-and-trade-methodology-statement/

where there is a beneficial relationship between them i.e. reduction in obligations at one entry point would allow more capacity to be released at another entry point without causing system constraints or breaching existing commitments.

The Exchange Rate is calculated as follows:

$$\frac{Reduction\ in\ Obligated\ Entry\ Capacity\ at\ Donor\ entry\ point}{Increase\ in\ Obligated\ Entry\ Capacity\ at\ Recipient\ entry\ point}$$

If necessary, capacity from several donors may be used to satisfy one Recipient entry point's bid (or group of bids). In that case multiple donor Exchange Rates will be determined.

Acceptable Exchange Rates are dependent upon previously accepted Transfer and Trades. Therefore, in order to maximise potential Exchange Rates the methodology assumes that a sequence for assessing Recipient entry points (and the Transfer / Trade quantity) has been established prior to calculating Exchange Rates.

A.2.2 Capacity substitution

As part of the 2007 Transmission Price Control Review settlement, Ofgem required NGG to develop a Capacity Substitution Methodology for a permanent move of capacity between points, both for entry and for exit, in consultation with stakeholders and subject to being approved by Ofgem. The objective of capacity substitution is to minimise investment that would otherwise be required to satisfy demand for incremental obligated entry capacity as signalled through the long-term entry capacity auctions. NGG has developed both an Entry and Exit Capacity Substitution Methodology. In this section, we summarise the Entry Capacity Substitution Methodology.

Network Analysis

This methodology sets out the process in order to substitute unsold baseline capacity from one or more entry point(s) to allow release of incremental (eg additional) capacity at another entry point. Where an incremental signal has been received through the long term entry capacity auctions, NGG will undertake network analysis to determine what Exchange Rate would be required to satisfy the incremental capacity request without the need for investment through assessing the flow patterns that can be accommodated without increasing the risk of capacity constraint management actions being needed. If in this manner incremental capacity can be obtained in an efficient way using an appropriate Exchange Rate then this would result in a permanent substitution of capacity.

In order to assess whether capacity substitution can take place, NGG uses its engineering model to review the physical capability of the recipient entry point's local infrastructure in line with the criteria set out in the Transmission Planning Code which forms the basis for NGG's network development decisions. For example, if there are physical limits on the maximum flows which could be achieved at that entry point, no capacity substitution resulting in flows above this physical maximum will be allowed. Based on network modeling, NGG has grouped donor entry points in zones where entry points use common sections of NTS infrastructure and consequently are deemed to be 'interactive' in terms of utilizing network capability. Basically the donor entry points within a zone are interactive with the recipient entry point. NGG publishes lists with entry points grouped in zones in the appendix of its Entry Capacity Substitution Methodology Statement[59].

Exchange rates

If there is a suitable donor entry point in the same zone as the recipient entry point, then a within zone donor will be considered before an out of zone donor is considered. In practice, substitution will take place through reducing the capacity at the most favourable donor entry point and increasing the capacity at the recipient entry point. The most favourable entry point will be the entry point with the lowest Exchange Rate, as this will achieve the most efficient outcome (eg the least aggregate loss of capacity). NGG calculates the Exchange Rate for each donor – recipient entry point pairing based on a network model (not the Transportation model) and only if the Exchange Rate is 3:1 or less is the substitution is permitted. This means that if network analysis indicates that more than 3 units of capacity are required from a donor entry point in order to create 1 unit of capacity at the recipient entry point the substitution will be rejected.

When two or more donor entry points have equal Exchange Rates, then the nearest donor entry point based on pipeline distance to the recipient entry point will be selected. Also, in order to meet demand for incremental capacity at a recipient entry point, more than one donor entry point may be used if necessary.

Capacity retainers

Network users will be able to exclude capacity at potential donor entry point from being treated as Substitutable Capacity without having to buy or be allocated the capacity. To do this network users are able to take out a 'retainer'. A retainer reserves capacity at an entry point for any network user to obtain at a later date through either the long term entry capacity auctions or the annual monthly entry capacity auctions. A NTS Entry Capacity Retention Charge applies to any retainer agreement. If retained capacity is subsequently booked at the entry point where the retainer was taken out, the charge may be refunded. However, if the retained capacity is not obtained at a later date then the retention charge will not be refunded.

[59] This statement is prepared by NGG in consultation with stakeholders and has to be approved by Ofgem. The current statement as well as review and consultation documents can be found on NGG's website: http://www2.nationalgrid.com/uk/industry-information/gas-capacity-methodologies/entry-capacity-substitution-methodology-statement/ The Exit Capacity Substitution Methodology can also be found on NGG's website.