APPLYING EQUAL CHARGING TREATMENT WITH GB STORAGE FOR THE PROPORTION OF BOOKINGS ENTRY = EXIT AT THE PHYSICALLY BI-DIRECTIONAL BACTON IP

IUK/BBL

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FINAL REPORT

Prepared by:

Cambridge Economic Policy Associates LLP

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DISCLAIMER

EXECUTIVE SUMMARY

CEPA has been commissioned by IUK and BBL to conduct a study into the impacts of applying equal charging treatment for the proportion of bookings entry = exit at the physically bi-directional Bacton IP as will apply for GB storage under the proposed new national transmission system (NTS) charging regime: UNC Modification 0621 and alternative UNC Modification 0621F.[1]

We evaluated the impact of equal charging treatment by analysing the Bacton interconnectors' historical position in the GB gas market and by using a global gas market model to simulate wholesale market prices and gas flows under a range of future market scenarios and NTS charging regimes.[2] This study finds that:

(1) Bacton IP interconnectors (IUK and BBL) compete directly with the different types of GB storage.

This can be observed from analysis of historical flow patterns and from simulations of future gas years using our market model. Like GB storage, the Bacton interconnectors provide security of supply as well as system flexibility benefits, again demonstrated by our modelling.

(2) Applying equal charging treatment for the proportion of bookings entry = exit at the physically bi-directional Bacton IP as for GB storage would benefit GB consumers.

We find that equal treatment lowers GB wholesale gas prices. Our analysis shows there would also be a further consumer benefit derived from higher GB gas consumption as the sector reacts to lower wholesale prices. Our modelling suggests that this **consumer benefit is substantial, ranging from an estimated £47m to £72m per year under a number of modelled scenarios**.[3]

Lower GB wholesale gas prices will also benefit GB electricity consumers by reducing the production costs of electricity, although we have not sought to quantify this effect except to note that this is likely to increase the benefit to GB energy consumers further.

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[1] Under UNC Modification 0621F, put forward by IUK, the same charging discount applied to GB storage sites would be applied to the proportion of anticipated entry (exit) bookings that equals, over the same gas year, anticipated exit (entry) capacity bookings at a physically bi-directional interconnection point. For any anticipated *net* entry or exit bookings (i.e. bookings that are in excess of forecast capacity bookings in the other direction), no capacity charge discount would be applied.

[2] Our gas market model includes all main entry and exit points to the NTS and accounts for the impact NTS charges may have on shipper and producers dispatch decisions and GB wholesale gas prices.

[3] We note that our modelling study has looked at a single gas year (2022/23). The extent to which our findings would be an enduring (dynamic) benefit for GB consumers may depend on how gas shippers and producers respond to the shift in the market situation that our modelling suggests.

(3) Our modelling shows limited impact on GB storage or UK Continental Shelf (UKCS) producers from applying equal treatment.

Whilst lower GB wholesale prices may benefit GB consumers, this may reduce total shipper/producer revenues from flowing gas to GB, with our market modelling indicating that the largest negative impacts will be on imported gas at St Fergus and, to a much lesser extent, on LNG entry points. However, this estimated revenue loss is lower than the estimated benefits to GB consumers and is also an upper range estimate of the producer impact, given that our analysis does not capture the reduction in gas supply costs for shippers/producers at entry points where gas flows decline, which would mitigate some of the revenue impacts observed.

(4) In light of these findings, equal charging treatment for the proportion of bookings entry = exit at the physically bi-directional Bacton IP would further the interests of GB consumers.

This finding is consistent with the impacts of equal NTS charging treatment that we would expect in theory. The benefits to GB consumers arise from a more efficient way of National Grid Gas Transmission seeking to recover its predominantly sunk cost base under a reformed NTS entry-exit charging regime.

The Bacton IP interconnectors provide access to the large Continental storage capacity. Rather than being a subsidy for the Bacton IP, the proposed equal charging treatment creates a level playing field for access to storage capability.

1. INTRODUCTION

1.1. Context

The National Transmission System (NTS) charging review is considering ways to reform Great Britain's (GB) gas transmission charging methodology to meet the new requirements imposed by European Regulation EU 2017/460 on rules regarding harmonised transmission tariff structures for gas (the TAR NC). [4] The review is also considering broader changes to the GB charging regime to reflect the outcomes of Ofgem's Gas Transmission Charging Review (GTCR) and industry concerns with the current NTS charging methodology.

In GB, changes to the gas transmission charging framework are largely implemented through changes to the Uniform Network Code (UNC). In this context, National Grid Gas Transmission (NGGT) has raised UNC modification proposal 0621[5] which proposes a number of changes to the GB charging methodology including the adoption of a Capacity Weighted Distance (CWD) approach as the new reference price methodology and the application of specific discounts to capacity products at GB storage sites.

Other notable changes to be introduced under the new proposed charging regime include:

- an end to the use of the commodity charge as a revenue recovery charge with revenue shortfalls to be addressed through adjustments to capacity reserve prices; and
- removing discounts on reserve prices for short-term capacity products.

According to UNC0621, a transition period would be implemented between October 2019 and September 2021 during which time some of the features of the current charging regime would be retained. The proposed reforms would be fully implemented from October 2021 (the "enduring regime").

Under the new proposed charging regime, GB storage facilities would receive a discount on capacity charges of 50%. Consistent with the requirements of Article 9.1 of the TAR NC the reasons for the discount include:

- the contribution made by storage to security of supply;
- the supply flexibility provided by storage facilities; and
- avoiding double charging on flows that temporarily exit the transmission system into storage.

[4] Network Code on Harmonised Transmission Tariff Structures for Gas [Commission Regulation (EU) 2017/460] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R0460&from=EN
[5] UNC 0621: Amendments to Gas Transmission Charging Regime: https://www.gasgovernance.co.uk/sites/default/files/ggf/page/2018-04/Modification%200621%20v4.0%20Clean.pdf

Article 9.2 of the TAR NC states that a discount may also be applied "*at entry points from and exit points to infrastructure developed with the purpose of ending the isolation of Member States in respect of their gas transmission systems*".

1.2. Alternative modification proposal

Interconnector UK (IUK) has put forward an alternative modification proposal to UNC0621 (UNC Mod 0621F[6]) which proposes to introduce a similar capacity discount structure for NTS capacity products at Bacton IP as applied for GB storage. This discount would apply only for the proportion of bookings entry = exit on the premise that physically bi-directional interconnectors compete in the same market as GB storage assets, because the Bacton IP interconnectors provide access to Continental Europe storage, and applying discounts to only to one set of assets would distort competition in the market.

IUK has argued that equal treatment is necessary to ensure compliance with Regulation (EC) No 715/2009 Article 13 and TAR NC Article 7(e) which both require that tariffs do not distort cross border trade and that they facilitate competition.

1.3. Terms of reference

CEPA has been commissioned by IUK and BBL Company (BBL) to conduct a study into the impacts of applying the same charging treatment to the proportion of bookings entry =exit at the physically bi-directional Bacton IP as will apply to GB storage under the proposed new GB gas NTS charging regime.

The key questions that we have considered in this study are:

- What is the expected position of the interconnectors' at the physically bi-directional Bacton IP vis-à-vis GB storage and is this supported by observed flows / simulation analysis of the GB gas market?
- What is the potential impact for GB consumers and GB producers/suppliers of adopting an equal NTS charging treatment at the Bacton IP?

1.4. Report structure

The rest of this report is structured as follows:

- Section 2 discusses the modification proposal raised by IUK in more detail.
- Section 3 sets out how we have approached consideration of the questions explored through this study.

[6] UNC 0621F: Amendments to Gas Transmission Charging Regime: https://www.gasgovernance.co.uk/sites/default/files/ggf/page/2018-04/Modification%200621F%20(Version%204.0%2013%20April%202018).pdf

- Section 4 presents our analysis of the position of the Bacton IP interconnectors in the GB gas market.
- Section 5 provides the results of our impact assessment of equal charging treatment.
- Section 6 provides overall conclusions.

2. PROPOSED CHARGING REGIME

The UNC modification proposal 0621F put forward by IUK proposes that specific capacity discounts apply to physically bi-directional interconnection points as well as to storage sites. The objective of this discount is to avoid a market distortion and ensure effective competition in the provision of seasonal flexibility, whether via access to continental storage through physically bidirectional interconnection points, or via GB storage points.

The discounts applied to specific network points are applied to the respective reference prices determined through the Reference Price Methodology to produce a final reserve price for entry or exit capacity products at that network point.

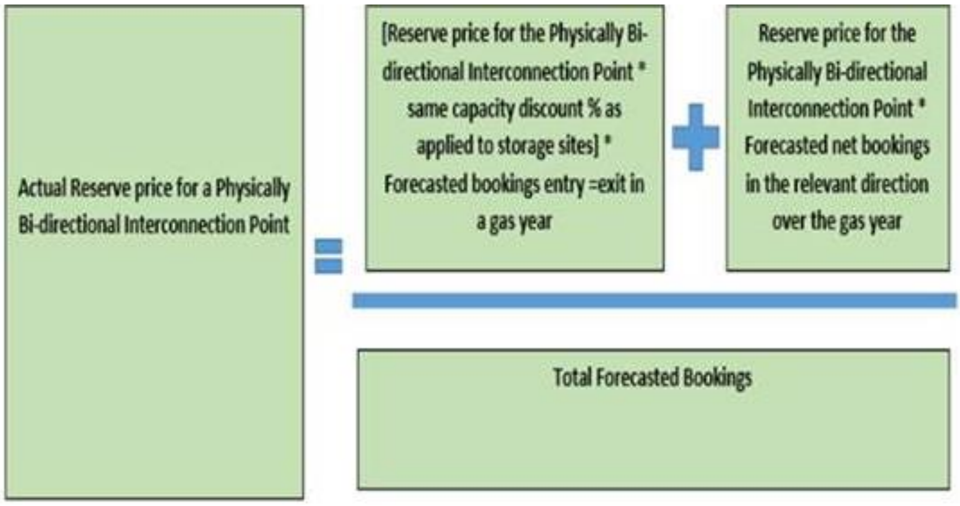
The calculation of capacity reference prices takes into account the revenue shortfall from any discounts which means that reserve prices at other entry or exit points are adjusted to correct for any expected revenue under-recovery. This means that applying a discount to capacity products at Bacton IP results in a redistribution of charges to other entry/exit points.

Under the proposal put forward by IUK, the calculation of the specific capacity discount applied to the physically bi-directional interconnection points for the period commencing 1st October 2021 onwards (the 'enduring period') will reflect the balance of entry and exit capacity bookings over the same gas year. More specifically, the discounted reserve price applied in any given year would be calculated ex-ante as follows:

- For the proportion of anticipated entry (exit) bookings that equals, over the same gas year, anticipated exit (entry) capacity bookings at a physically bi-directional interconnection point, the same discount as for storage sites will be applied.
- For any anticipated *net* entry or exit bookings (i.e. anticipated capacity bookings that are in excess of forecast capacity bookings in the other direction) over the same gas year, no capacity discount will be applied.
- A weighted capacity reserve price for entry and exit capacity products at physically bi-directional interconnection points will be determined based on the proportion of matched and net capacity bookings.

The calculation is illustrated in Figure 2.1 below.

Figure 2.1: Calculation of discounted reserve price for physically bi-directional IP



Source: [*UNC 0621F: Amendments to Gas Transmission Charging Regime*]

The proposed capacity discount calculation method is designed to accommodate changes in future market fundamentals that would affect the future pattern of flows on the interconnectors. For example, were physical flows on IUK and BBL to become fully unidirectional then the discount would automatically be set to zero. It also means that the actual capacity discount applied at Bacton IP would be equal to that applied for storage sites only if entry and exit capacity bookings at Bacton IP are forecast to perfectly match over the gas year. Where forecast bookings do not perfectly match, the actual capacity discount applied to Bacton IP will be less than the capacity discount applied to storage sites.

For the transitional period (up to October 2021), the IUK proposal envisages applying the same discount as for storage sites for all capacity bookings due to National Grid's proposal to use obligation capacity levels for forecasting purposes in the transition period.

3. APPROACH

As set out in the introduction, the objective of this study has been to consider the position of the interconnectors at the physically bi-directional Bacton IP in the GB gas market, in particular, vis-à-vis GB storage and to determine the impacts on the GB gas market, from the perspective of both consumers and producers, of adopting IUK's equal charging treatment proposal.

We have approached our work by analysing the interconnectors' historical position in the GB gas market and by using a global gas market model to simulate wholesale market prices and gas flows under a range of future market scenarios and NTS charging regimes. As discussed in further detail below, our gas market model includes all main entry and exit points to the NTS and accounts for the impact that NTS charges may have on shippers' and producers' dispatch decisions and on GB wholesale gas prices.

In the rest of this section we present:

- the key features of the global gas market used to simulate future gas market conditions;
- our approach to modelling storage markets; and
- key assumptions and scenarios modelled.

3.1. Global gas market model

We have simulated gas market outcomes under a range of scenarios and charging regimes using our global gas market model.

The model covers all major gas producing and consuming countries in the world. On the *supply side*, the model includes Russia, Norway, Qatar, Australia, Algeria and other producing regions such as North America, Central and South America, Middle East and Central Asia. On the *demand side*, the model covers all existing consuming countries and regions, such as GB, Continental European markets, Russia and other countries of the Former Soviet Union, China, India, North America, Middle East, etc.

The model also covers the entire gas value chain from production regions down to the transmission and wholesale demand level. Therefore, it captures various gas infrastructure assets such as cross-border pipelines, LNG facilities and gas storage facilities. It is an economic and optimisation model and, therefore, does not include some real-world characteristics of gas infrastructure (such as pressure drop in gas pipelines, management of linepack, gas quality limits etc.).

The model represents gas infrastructure assets using two main parameters – physical capacities (e.g. production and pipeline capacities) and the unit cost (marginal cost) for utilising those assets.

Given the inputted cost structure and capacities for these infrastructure assets, the objective of the model is to find a least cost solution to meet daily gas demand in every market specified in the model for the entire modelling time horizon (more than one year). The optimization programme takes into account various physical constraints, such as gas production capacities, transmission network capacities, LNG liquefaction and send-out capacities, storage injection, withdrawal and maximum working volume capacities as well as minimum and maximum daily demand profiles.

The model considers all existing cross border interconnection points in Europe as well as disaggregating European demand regions into individual markets according to their national borders (EU28). This resulted in more than one thousand cross-border pipeline connections (or 'arcs') modelled for Europe only. The physical capacities of these interconnection points were based on ENTSO-G's 2017 capacity map[7], whereas the cost of flowing gas at these interconnection points were taken from ACER's most recent market monitoring report[8] and respective TSOs publications.

For the GB market, the model includes all main entry and exit points to the GB gas transmission network covering all gas supply sources available to the market:

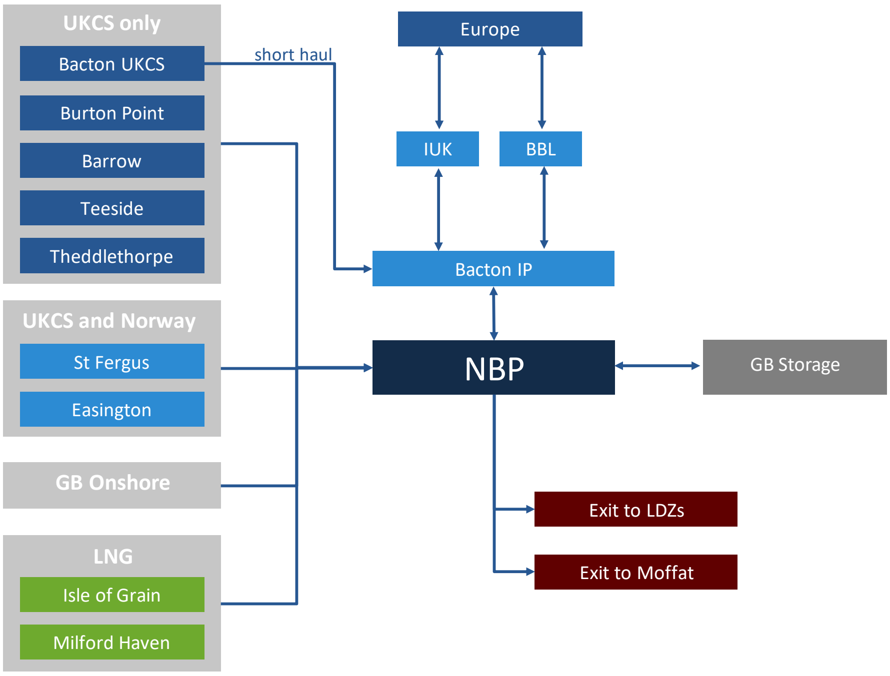
- UKCS-only beach terminals;
- UKCS and Norway flows at Easington & St Fergus NTs entry points;
- LNG terminals;
- GB storage facilities;
- bi-directional interconnection to Europe;
- potential to divert Bacton UKCS gas flows to Bacton IP through the shorthaul option;
- one-directional exit only interconnection to Ireland; and
- domestic consumption.

Figure 3.1 below provides an illustration of the modelled GB gas market and network as represented in our model.

[7] Capacity map version July 2017, available at: https://www.entsog.eu/maps/transmission-capacity-map (accessed April 2018).

[8] ACER/CEER, *Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2016*, October 2017: https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202016%20-%20GAS.pdf

Figure 3.1: Illustration of the modelled GB gas market and network



Source: CEPA

The **outputs from the model** are projections of supply, demand, equilibrium prices[9], cross-border pipeline and LNG flows, storage injection and withdrawal at daily resolution.

3.2. Modelling storage markets

As we noted elsewhere, one of the premises of the study is that interconnectors are in direct competition with other gas infrastructure assets which allow suppliers and shippers to bring gas from one market to another market – in this regard, storage assets are also 'interconnector' facilities which allow gas trading from one market time frame (e.g. summer season) to another time frame (e.g. winter season).

Storage facilities can be differentiated according to their potential to

- temporarily store gas (working volume); and most importantly
- deliver that gas from the storage facility to the market (withdrawal rate).

Usually storage facilities that are very large in terms of storage volume capacity will have a relatively low daily deliverability rate (e.g. long-range storage or seasonal storage) whereas those facilities that have a very high daily maximum withdrawal rate will have relatively limited storage volume capacity (e.g. short-range storage or daily/sub-daily flexible storage). Table 3.1 below shows all existing storage facilities in the GB market – short-range storage facilities will normally have maximum daily deliverability of around 5-10% of total working volume whereas seasonal storage will only have around 1-3%. Table 3.1 also shows total

[9] The notion of *'equilibrium'* prices simply means that prices are determined at the intersection of demand with supply.

storage working capacity and deliverability by storage type for the main markets in North West Europe (NWE).

The model includes all storage facilities in GB; however, storage facilities in Europe were aggregated to a single country-level facility assuming that its daily deliverability is equal to the sum of deliverabilities of all storage sites in a country/market area.

In all future scenarios modelled, the Rough storage facility was assumed to be closed in line with Centrica Storage's announcement in 2017.

Table 3.1: Storage facilities/capacities in GB and North West Europe

Country/market area	Name	Type	Working capacity (mcm)	Peak output (mcm/day)	Peak output as % of working capacity
GB	Aldbrough	Salt cavern	300	40.0	13%
	Hatfield Moors	Depleted gas field	70	2.0	3%
	Holehouse Farm	Salt cavern	50	11.0	22%
	Hill Top Farm	Salt cavern	20	2.1	11%
	Holford	Salt cavern	200	22.0	11%
	Hornsea	Salt cavern	300	18.0	6%
	Humbly Grove	Depleted gas field	300	7.0	2%
	Stublach	Salt cavern	200	15.0	8%
	Total		**1,440**	**117.1**	**8%**
Belgium	**Total**		**680**	**15.0**	**2%**
France		Aquifer	11,015	162	1.5%
		Salt cavern	830	69	8%
	Total		**11,845**	**231**	**2%**
Germany		Depleted gas field	8,924	139	2%
		Salt cavern	14,315	483	3%
		Aquifer	895	30	3%
	Total		**24,134**	**652**	**3%**
Netherlands		Depleted gas field	13,167	232	2%
		Salt cavern	800	36	4.5%
	Total		**13,967**	**268**	**2%**

Source: IEA Natural Gas Information (2017)

As the numbers in the table above show, storage capacity in other neighbouring European markets is much higher than in GB. In this sense, the bi-directional interconnectors at Bacton effectively allow access for the GB market to the large storage capacity in NWE.

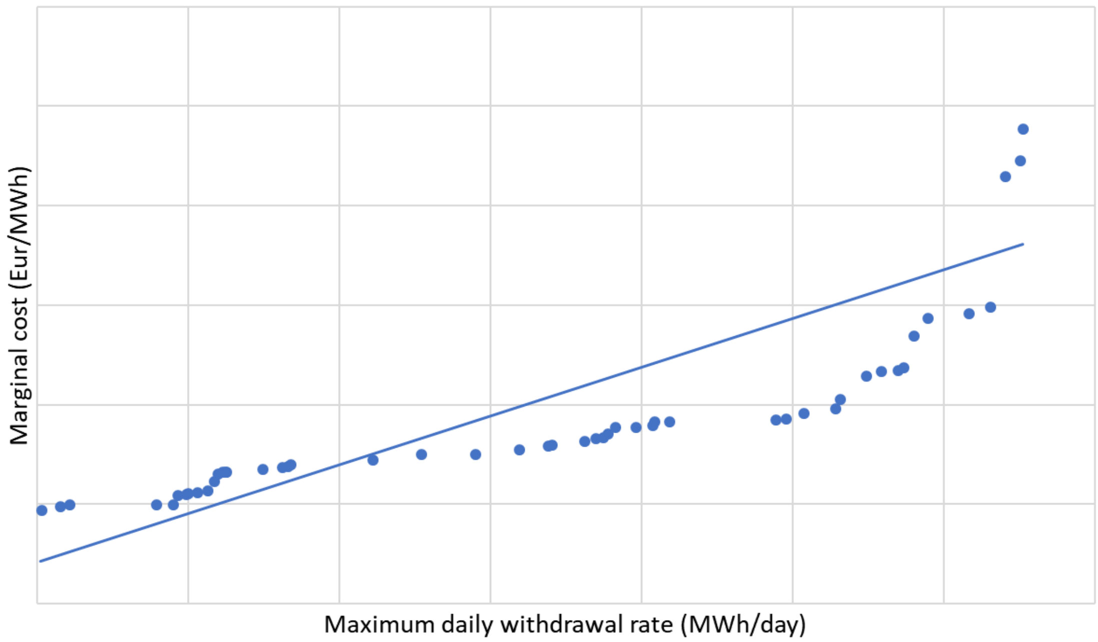
Modelling storage in aggregation at a country level reduces the size of the model and makes the optimisation problem easier to solve.[10] On the other hand it can mean that different cost structures (and thus pricing) of different storage product markets – seasonal flexibility versus daily flexibility – in Europe is neglected.

To ensure we capture the competitive dynamics between interconnectors and all storage types both in the UK and in Europe, we adopted an approach based on building a 'marginal cost curve' for each individual market areas/countries where there are storage facilities of different types (depleted fields, salt caverns and aquifer).

This marginal cost curve is expressed as a linear (increasing) relationship between maximum daily withdrawal rate and costs. The calibration of these marginal cost curves was based on publicly available data gathered from IEA, storage operators, techno-economic literature and other confidential sources.

Figure 3.2 gives an example of an illustrative marginal cost curve for a storage market. The dots on the chart would represent data gathered for individual storage facilities from public and private sources whereas the fitted straight line is the curve used in the model. These marginal cost curves are derived for all European (and global) storage markets.

Figure 3.2: Illustrative example of a storage marginal cost curve



Source: CEPA

[10] This aggregation significantly reduces the size of the model because for some markets in Europe – such as Germany alone, for example, – there are 51 storage sites.

3.3. Key assumptions used in modelling

Demand and supply

The model is run for a future year and so projections of future demand are needed in the model. Expected gas demand for GB is based on projections from National Grid's Future Energy Scenarios[11] whereas demand for all other markets were based on IEA (2017) World Energy Outlook 2017 scenarios.

European gas infrastructure was based on ENTSO-G's 2017 Ten Year Network Development Plan. In particular, new cross-border capacities and LNG regasification capacities in the EU were added in the model based on their final investment decision (FID) status - those projects which took FID as outlined in ENTSO-G's 2017 TYNDP report were added into the model with start time and capacities as reported by these projects. All existing storage sites are aggregated to country level, except for GB, as discussed above. New storage capacities are also taken into account according to their FID status (as reported in ENTSOG's 2017 TYNDP).

The model also takes into account all LNG projects that took FID before 2016, such as those from Australia or USA. All other assumptions are based on publicly available sources such as IEA WEO (2017), US EIA Annual Energy Outlook (2018), UK Oil and Gas Authority, Ministry of Economic Affairs of the Netherlands etc.

Finally, daily gas demand profiles are the average of daily gas demand in the last 5 years and hence the impact of weather on gas demand in future years is assumed to be the average impact witnessed in the last 5 years. The model was run for two years or 730 days starting from 1 January 2022. Since the model determines storage injection and withdrawal profiles based on the cost structure of the assets in the model, together with supply and demand conditions, at the beginning of each model run it was assumed that all storage facilities are half-full, reflecting that 1 January is roughly the mid-point through the winter season.

NTS transmission charges

We used the NGGT CWD model[12] to determine capacity charges at NTS entry and exit points under future charging frameworks. The CWD model produces Reference Prices and, with additional adjustments, determines Reserve Prices for different types of capacity products at each entry and exit point.

Capacity reserve prices under NGGT's UNC Mod 0621 charging proposal have been calculated using the default settings in the NGGT CWD model for the enduring period.

To calculate the discount applied to capacity products at Bacton IP under the alternative UNC 0621F proposal, weighted by net entry-exit bookings, we used the following methodology:

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[11] NGGT, *Future Energy Scenarios 2017*, http://fes.nationalgrid.com/fes-document/

[12] Published model available at: https://www.gasgovernance.co.uk/ntscmf

- We used forecast entry and exit capacity bookings at Bacton IP from National Grid's CWD model. This ensured we are consistent with the way that capacity prices for other NTS points were calculated and also how reserve prices for Bacton IP were calculated for the Base Case scenario.
- For the proportion of forecast entry (exit) bookings that match forecast bookings in the other direction, we assumed a 50% discount. For the residual net entry/exit bookings we assumed a zero % discount.
- We calculated a weighted average discount based on the proportion of balanced and net bookings for each direction (entry and exit).

The weighted average discount obtained through this calculation was applied in the CWD model to obtain capacity reserve prices at Bacton IP.

Given that forecast entry bookings at Bacton IP in the CWD model are higher than forecast exit bookings, there are net forecast bookings (above forecast exit bookings) for which a 0% discount is applied according to the calculation set out above. This resulted in a weighted discount of 39% being applied for entry capacity products. In the exit direction, all forecast bookings are forecast to be matched by entry bookings and therefore, the full 50% discount was applied.

Scenarios modelled

We conducted the market analysis for the gas year October 2022 – September 2023 to capture:

- the impact of the 'enduring' charging regime as set out in the UNC 0621; and
- shifts in the GB demand and supply structure but not too far away in the future to increase uncertainty about the assumptions used.

We ran a number of scenarios to test a range of GB and global market conditions and charging regimes. Each of these scenarios was run against:

(i) a **Base Case** charging option where NGGT's UNC Mod 0621 charging proposals are adopted with **capacity charge discounts applied to GB storage only;** and

(ii) an **equal treatment case** where the proposals in UNC 0621F are adopted such that Bacton IP benefits from the same discount structure as applied to GB storage.

We developed our **Baseline** scenario assumptions based on:

- National Grid's Steady State demand projections for GB;
- IEA's (2017) New Policies Scenario for global demand projections (incl. Europe); and
- a capacity charge discount applied at Bacton IP in the equal treatment case determined based on balance of entry/exit bookings as per the enduring regime proposal in UNC 0621F (see above).

In addition, we also modelled a number of sensitivities around the Baseline scenario:

- **Sensitivity 1** (High Asian Demand) – we assumed a 25% increase in winter gas demand in China, India, Japan and South East Asia which is expected to result in diversion of LNG supplies to those markets.
- **Sensitivity 2** (Low Gas Demand) – we used National Grid's Slow Progression demand projections for GB together with the IEA's Sustainable Development Scenarios for global demand projections. This sensitivity therefore reflects lower gas demand in both GB and global markets.
- **Sensitivity 3** (Full 50% discount) – based on the Baseline scenario demand assumptions but assuming a full 50% discount will be applied in the equal treatment case to reserve prices for both entry and exit at Bacton IP.

The table below summarises the scenarios and sensitivity modelled as part of our work.

Table 3.2: Scenarios and sensitivities modelled

Charging scenarios	Global demand/supply sensitivities		
	Baseline global supply/demand	High Asian demand	Low demand
Base case	Baseline scenario	Sensitivity 1	Sensitivity 2
Equal treatment (enduring period)	Baseline scenario	Sensitivity 1	Sensitivity 2
Equal treatment (50% discount)	Sensitivity 3		

4. INTERCONNECTORS' POSITION IN THE GB GAS MARKET

To determine the role that the interconnectors at the physically bi-directional Bacton IP play in the GB gas market and, in particular, to test the hypothesis that interconnectors compete with storage, we have analysed historical flow patterns and run simulations of future gas years using the gas market model described in the previous section.

We find that the interconnectors compete directly with the different types of GB storage, and, similar to GB storage, the interconnectors provide security of supply as well as system flexibility benefits to GB.

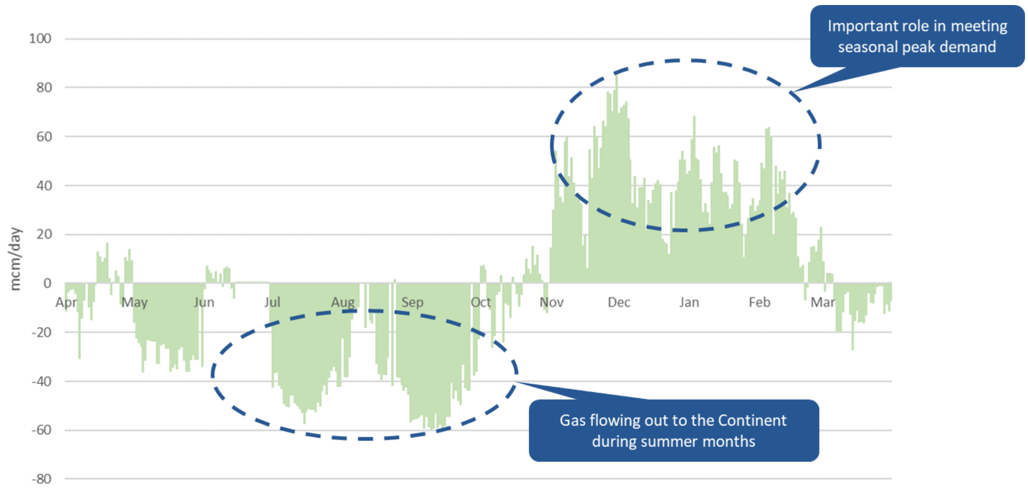
4.1. Analysis of historical flow patterns

Historical gas flow data indicates that the interconnectors at the Bacton IP have in recent years acted as a source of flexibility for the GB gas market. The interconnectors can provide both:

- **Seasonal (or predicable) flexibility -** Related to variations in gas demand, usually on a seasonal or monthly weekly basis, due, for example, to changes in temperature over the course of the year.
- **Short term (or unpredictable) flexibility -** Related to unpredictable variations in gas demand and supply balances (e.g. demand forecast errors, supply interruptions or increasingly short-term demand for gas in the power sector).

Bacton interconnector historical flow patterns show a very similar profile to GB seasonal storage flows as shown in Figure 4.1. Bacton interconnector flows are primarily in the GB export direction during the summer period, with gas injected into continental storage facilities, with interconnector flows into GB primarily occurring during the winter period. This is consistent with a pattern of injecting gas into continental storage facilities during summer and drawing the gas from continental storage as well as upstream flexibility during winter.

Figure 4.1: Historical flow patterns at the Bacton IP



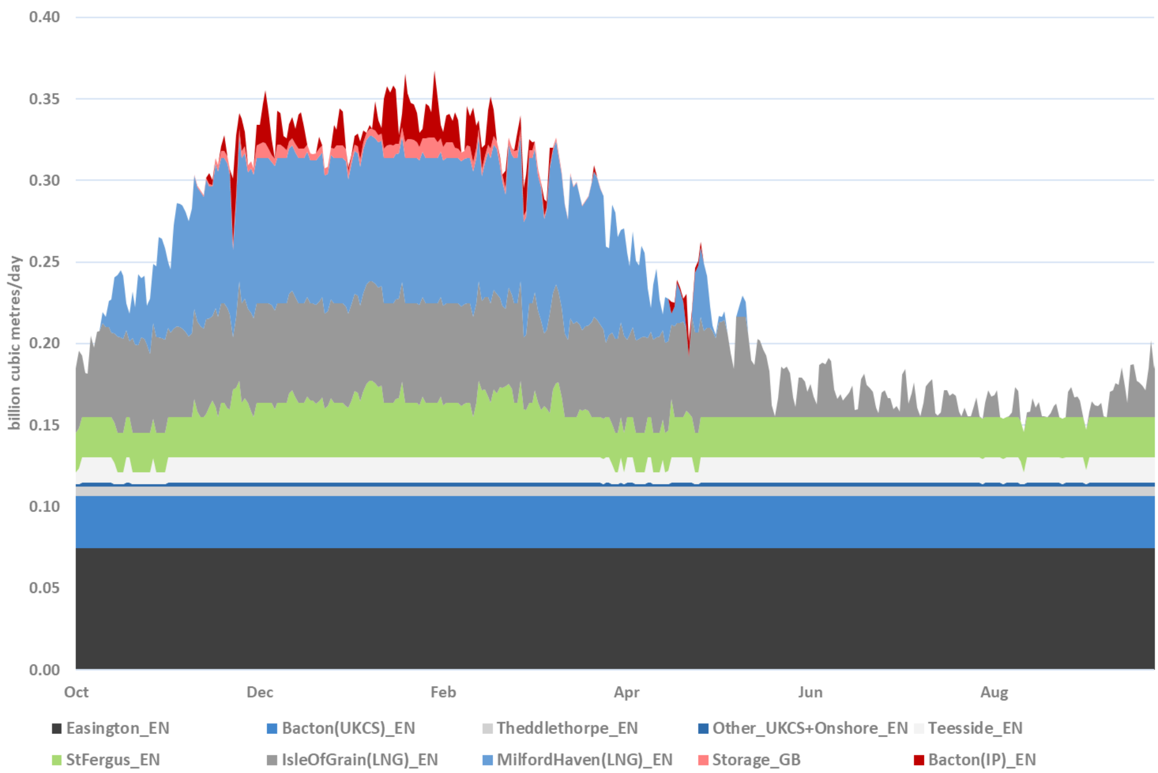
Source: CEPA analysis of National Grid Data Item explorer

As discussed above, as well as seasonal (predictable) flexibility, the interconnectors can also provide short-term (or unpredictable) flexibility related to unpredictable variations in gas demand and supply balances. Provision of these services means that the interconnectors are in competition with other supply infrastructure including short and long-range storage.

4.2. Analysis of simulated flow patterns

Using our gas market model, we simulated gas flows during the gas year October 2022 to September 2023 to determine the future pattern of GB gas supplies and, in particular, to determine the role that the bi-directional interconnectors will play under future market conditions. Figure 4.2 shows daily gas flows into GB by entry point across the entire gas year under our Baseline scenario and assuming that the NGGT charging proposal is implemented.

Figure 4.2: Gas flows into GB by entry point (Baseline scenario)

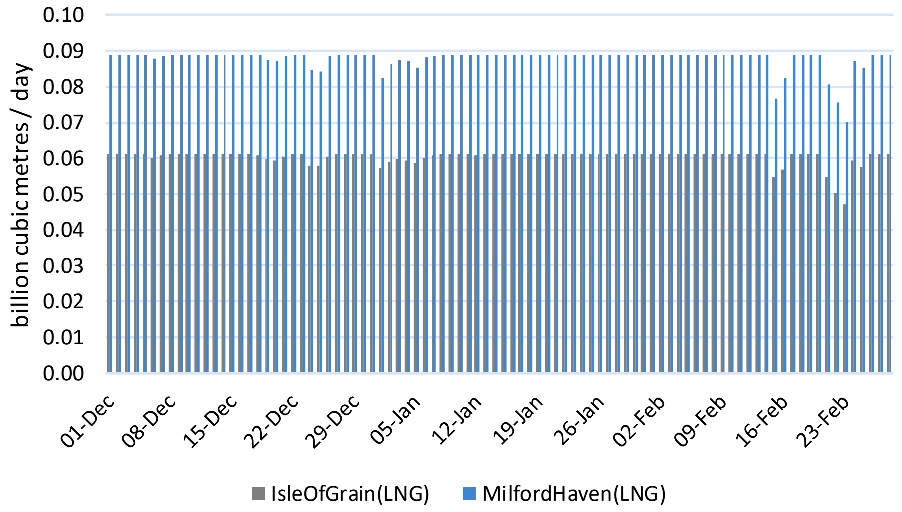


Source: CEPA

The simulated flows suggest that the interconnectors at the Bacton IP help to meet peak demand in the winter season. Most seasonal flexibility is provided by LNG imports, storage and a portion of Norwegian supplies at St Fergus. UKCS and Norwegian flows (particularly at Easington) act as baseload supplies with little seasonal variation. In addition, the interconnectors also serve to meet the need for short-term flexibility with imports at the Bacton IP increasing on days with the highest gas demand. The simulated flows suggest that the interconnectors, together with GB storage facilities, are the main providers of this shorter-term flexibility to the GB market, during winter months.

To better understand the structure of the GB flexibility market, we examined in more detail flows from the main providers of flexibility during the peak winter season. Figure 4.3 shows LNG flows to the GB market during the period December 2022 to February 2023. This shows that while LNG supplies play an important role in providing seasonal flexibility, the GB LNG terminals operate at full capacity almost throughout the entire period. Therefore, the ability of LNG imports to provide additional short-term flexibility is severely restricted.

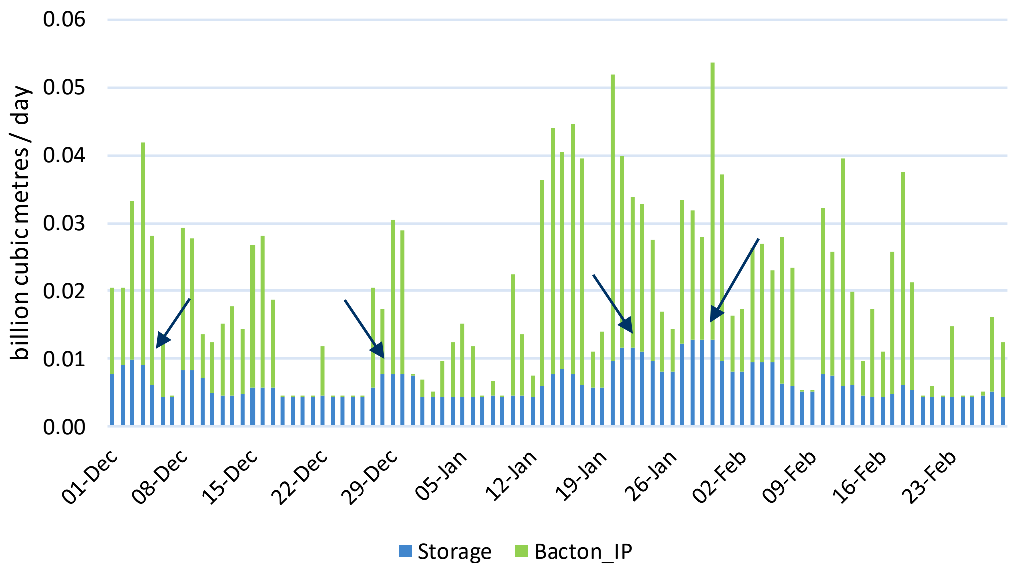
Figure 4.3: LNG imports during winter season (December – February)



Source: CEPA

Figure 4.4 shows GB storage withdrawals and interconnector import flows at Bacton IP during the peak winter season. The variation in interconnector flows is consistent with the behaviour of assets that are used to provide short-term flexibility. It can be observed that on days when interconnector flows are the highest, there also tends to be an increase in storage withdrawals (as indicated by the arrows on the graph).

Figure 4.4: GB storage and Bacton IP flows during winter season (December – February)



Source: CEPA

These results suggest that the interconnectors will continue to provide an important source of short-term flexibility to the GB market supplementing (and competing against) the relatively limited storage capacity available in GB.

4.3. Modelling the ICs contribution to security of supply and system flexibility

We used our gas market model to simulate a GB security of supply (SoS) event to determine how the GB market may respond and what the main sources of supply flexibility could be in the future.

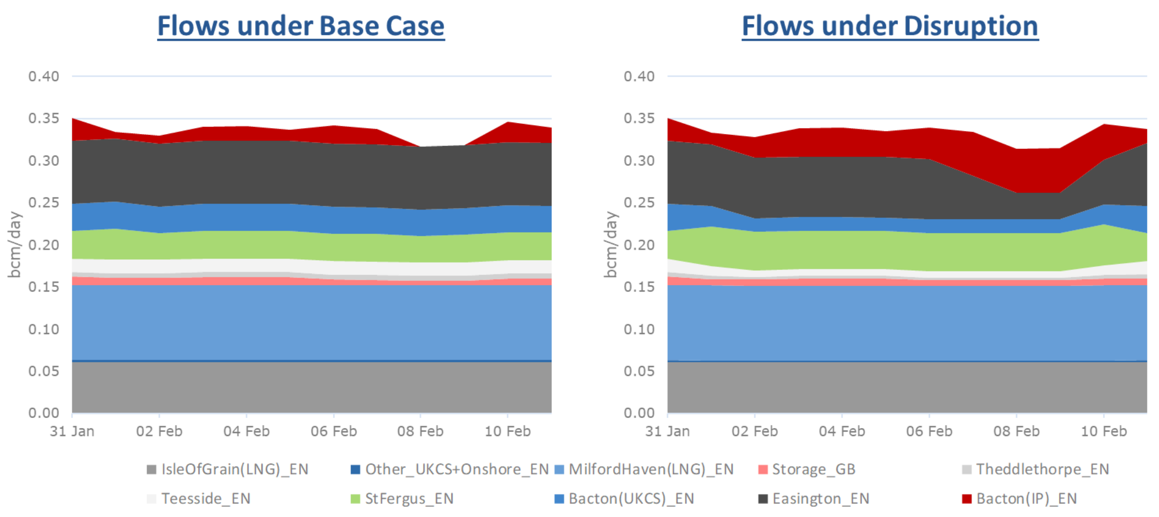
To further test the hypothesis that the Bacton IP interconnectors contribute to system flexibility and SoS we modelled the impact of an unexpected supply-side shock on the GB gas market as follows:

- 10-day disruption (from 01 Feb to 10 Feb 2023) resulting in up to 50% reduction in UKCS supplies; combined with
- 4-day disruption resulting in a loss of up to 44% of Norwegian gas supplies coming in to Easington (07 Feb to 10 Feb 2023).

The supply sources disrupted provide baseload gas supplies to the GB market. By disrupting these sources, we have not affected the supply capacity of flexible supply sources. The SoS scenario chosen mimics events seen in December 2017, when the Forties pipeline closure coupled with maintenance period for Norwegian gas, led to a drop in supplies to the GB market.

Figure 4.5 below shows gas flows at various GB NTS entry points starting from 31st January 2023 (the day before the disruption begins) up to 11th February 2023 (the day after the disruption ends). Flows under the Base Case represent flows in the GB system under normal conditions.

Figure 4.5: Gas flows by entry points under Base Case and Disruption scenarios



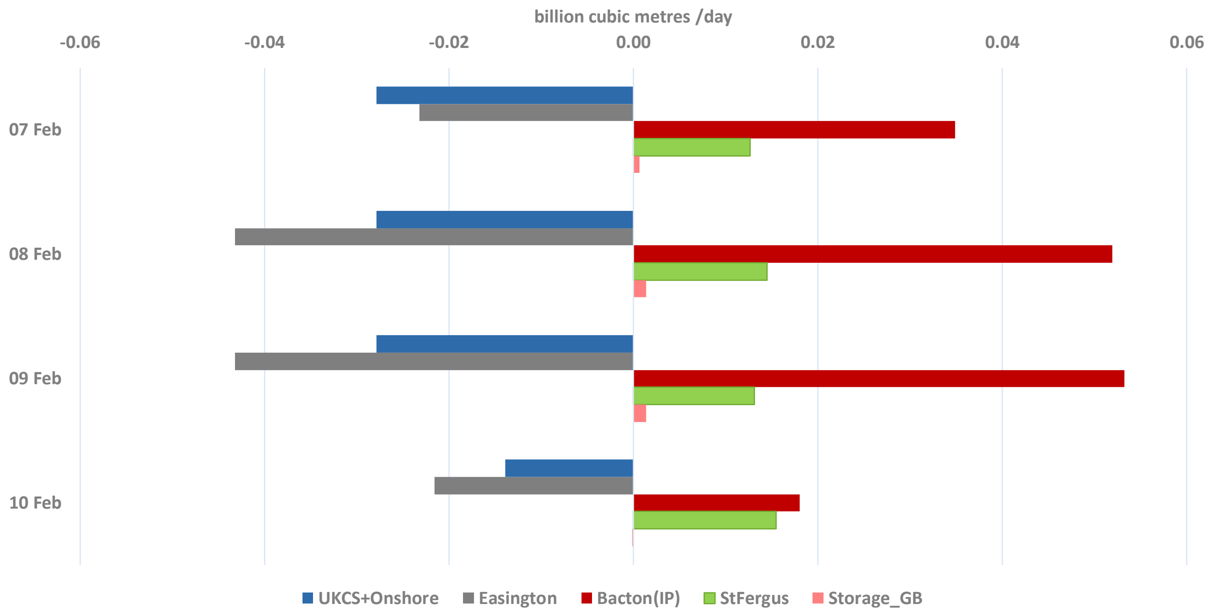
Source: CEPA

Figure 4.6 shows changes in gas flows between the Base Case and the Disruption scenario during the days of highest disruption. The reduction in UKCS and Norwegian gas flows at Easington due to the disruption is mitigated by a significant increase in interconnector imports at Bacton IP as well as an increase in flexible Norwegian supplies at St Fergus and a smaller increase in storage withdrawals.

The main observations are:

- The Bacton IP interconnectors are the main source of additional gas supplies to GB during the disruption period.
- Additional flexibility is provided by Norwegian supplies at St Fergus.
- Storage facilities can provide only limited response due to the unexpected nature of the shock which means shippers cannot optimize storage injections/withdrawals to prepare for the disruption.

Figure 4.6: Changes in daily gas flows on selected days between Base Case and Disruption scenarios



Source: CEPA

Our analysis shows that the Bacton IP interconnectors are the main source of flexibility to GB during the disruption event. The interconnectors compete at the margin of the GB supply – demand balance, together with other sources of flexibility including storage. The simulations confirm that the Bacton interconnectors provide security of supply benefits to the GB gas market.

4.4. Implications

These results suggest that applying equal NTS charging treatment to the physically bi-directional Bacton IP as for GB storage would be consistent with the contribution made by IUK and BBL to system flexibility and to security of supply.

As CEPA's Security of Supply study for BEIS demonstrated[13], the GB system is resilient to almost all significant individual shocks under normal demand conditions, and diversification in supply sources helps improve gas SoS. While there are other sources of system flexibility including LNG, GB storage and flexible Norwegian supplies that contribute to GB SoS, UNC Mod 0621F should be considered seriously by industry and policy makers as a measure to encourage more efficient use of the interconnectors.

One of the key benefits of the Bacton IP (bi-directional) interconnectors is that they provide access for the GB market to the large storage capacity and other sources of flexibility on the Continent at a time when domestic GB flexibility sources are limited, particularly following the recent announcements for Rough. If the TAR NC and specifically the GB NTS charging system, is seeking to encourage storage, then it is important that there is equal treatment for all sources of storage to the GB market, domestic and Continental. Equal charging treatment is consistent with creating a level playing field for competition in these sources of flexibility and, furthermore, encourages increased cross-border market integration.

[13] CEPA (2017): *A review of gas security of supply within Great Britain's gas market – from the present to 2035*, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/652085/gas-security-of-supply-review.pdf

5. IMPACT ASSESSMENT

To determine the impacts on GB consumers and producers of applying equal NTS charging treatment for the proportion of bookings entry = exit at the physically bi-directional Bacton IP as for GB storage, we simulated GB gas market outcomes for a future gas year (October 2022 to September 2023) under the two charging options using our global gas market model: (i) where NGGT's UNC Mod 0621 charging proposals are adopted with **capacity charge discounts applied to GB storage only**; and (ii) an **equal treatment case** where proposals in UNC 0621F are adopted such that the Bacton IP benefits from the same discount structure as applied to GB storage for the proportion of bookings entry = exit.

Based on the modelling simulations we have quantified a range of impacts on both consumers and producers including market prices, consumer surplus and producer/shipper revenues. These impacts are presented in Section 5.1.1. In addition, in Section 5.2, we also discuss further impacts that we have not quantified in our study.

5.1. Quantified impacts

Our analysis shows that under our baseline scenario *and* a range of sensitivities **there are net benefits to GB consumers** from an increase in GB consumer surplus. **This is driven by lower GB wholesale gas prices** which more than offsets the negative impact of higher NTS exit charges at domestic exit points as a result of the Bacton IP capacity discount.

While lower GB wholesale gas prices represent a gain for GB gas consumers they also result in lower overall revenues for GB shippers and producers. Our analysis shows that the main entry supply point sources negatively affected are flexible Norwegian supplies at St Fergus and, to a lesser extent, LNG imports. **Our modelling shows a limited impact on UKCS and storage points (domestic GB supply sources),** which experience a small reduction in revenues due to lower wholesale market prices under the equal treatment charging regime.

5.1.1. Consumer impacts

The main aim of the analysis was to estimate the net GB consumer benefit from the UNC 0621F proposal.

Economists typically measure consumer benefit by referring to changes in consumer surplus. **Consumer surplus** represents the difference between the amount consumers are willing to pay for gas and what they actually pay (i.e. the market price):

Total consumer surplus = GB gas demand x (Willingness to pay – market price)

We estimated consumer surplus by taking into account changes in:

- wholesale gas prices;
- gas consumption as a response to changes in market prices; and

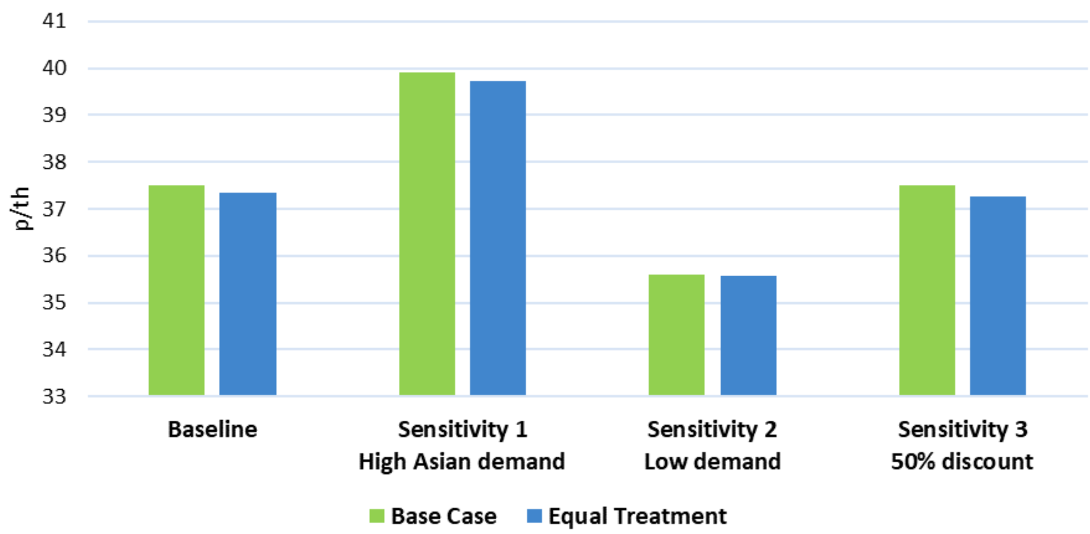
- exit capacity charges at domestic exit points as a result of redistribution of NTS charges.

Impact on wholesale gas market prices

Across all four scenarios considered in our quantitative impact assessment, the adoption of an equal treatment charging regime results in a decline in GB wholesale gas prices. As presented in Figure 5.1, the reduction in the average annual GB gas market price varies across scenarios, for example:

- equal treatment for the proportion of bookings entry = exit reduces GB wholesale gas prices by 0.4% per year in the Baseline scenario;
- equal treatment reduces GB wholesale gas prices by 0.6% if the full 50% discount is applied on both entry and exit at the Bacton IP; and
- equal treatment reduces GB wholesale prices by 0.1% under the Low demand sensitivity.

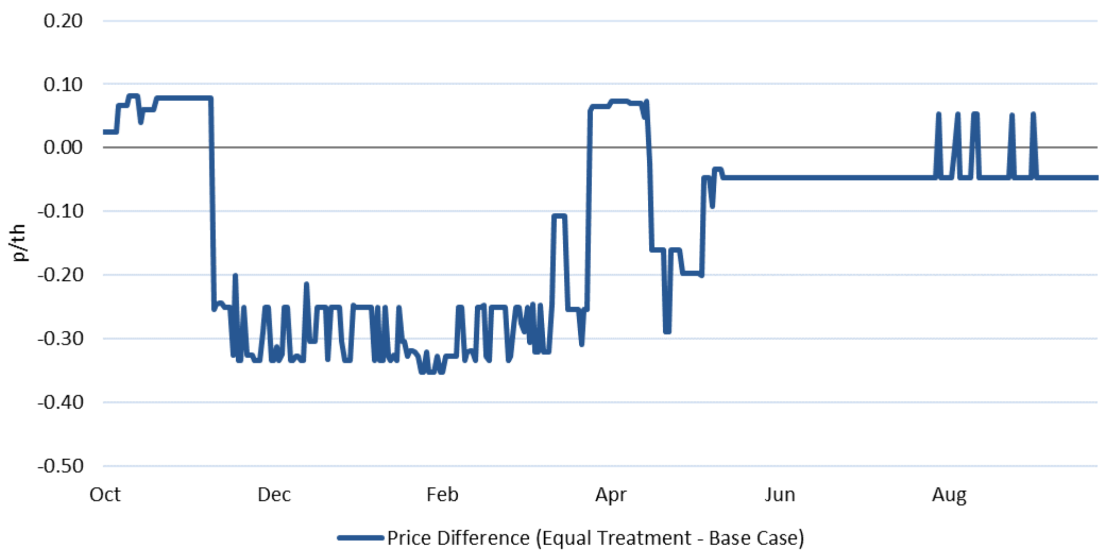
Figure 5.1: Average annual GB gas market prices under Base Case and Equal Treatment charging regimes



Source: CEPA

When evaluating the magnitude of the reduction in GB wholesale gas prices over the course of the gas year, it can be seen that the impact of the equal treatment charging regime on wholesale prices is greatest during the winter season – driven by the reduction in the cost of importing gas from the Continent as a result of the discount applied at Bacton IP. This effect is presented in Figure 5.2, which shows that the difference in GB wholesale gas prices between Equal Treatment and the Base Case is highest in the December to March period. This is also when the greatest benefits to GB consumers occur as winter gas demand (predominantly used for space heating) is substantially higher and more 'valuable' for consumers than summer season demand. Figure 5.2 presents the effect in the Baseline scenario, but the same seasonal pattern is evident in all of the sensitivities modelled.

Figure 5.2: Change in daily GB gas market prices under Equal Treatment relative to the Base Case charging regime[14]



Source: CEPA

As discussed in the next section, the reduction in prices is the main driver of the change in the estimated consumer benefit from the adoption of an equal charging regime.

Consumer benefit

Changes in consumer surplus are a function of: (i) price changes and (ii) consumption changes in the modelling which may result from the adoption of an equal treatment charging regime.

As shown above, there is a change in wholesale prices under the equal treatment charging regime. The change in prices also leads to a change in gas consumption estimated using the price elasticity of demand. Each of these changes, therefore, contribute to the change in consumer surplus estimated in our model. Specifically:

- annual average GB wholesale gas prices decline;
- GB wholesale gas consumption increases;
- network exit charges at domestic exit points marginally increase.

The reduction in wholesale gas prices and the increase in consumption both have a positive impact on consumer surplus. The marginal increase in network exit charges at domestic exit points has a negative impact on consumer surplus, as it increases the total cost of gas delivered to final consumers. However, the magnitude of this increase in network exit charges

[14] Negative values represent a decrease in price and thus a consumer benefit.

is significantly smaller than the reduction in wholesale prices, such that the overall impact on consumer benefit of equal treatment is positive in all scenarios modelled.[15]

Table 5.1 presents the net change in annual consumer benefit between the Base Case and the Equal Treatment case in all four scenarios.

Table 5.1: Net change in consumer benefit from the adoption of equal treatment (£m/year)

Scenario	Net change in consumer benefit (£m/year)
Baseline scenario	£47.8m
Sensitivity 1 - High Asian demand	£59.2m
Sensitivity 2 – Low demand	£4.4m
Sensitivity 3 – Full 50% discount	£71.8m

Source: CEPA

The magnitude of the change in consumer benefit is sensitive to the scenario. **In the Baseline scenario, consumer surplus increases by £47.8 million. The benefit is appreciably greater if a full 50% discount is applied, amounting to £71.8 million.** Under a low demand scenario, the impact is considerably smaller, although it remains positive.

It should be noted that the consumer benefits estimated above refer only to direct impacts on GB gas consumers and do not capture a range of wider potential economic impacts, including the impact of lower gas prices on the electricity market which would, most likely, further increase the consumer benefit. The overall impact on consumer welfare of an equal treatment charging regime would depend importantly on these effects, and while the quantitative impact of these consumer effects was not estimated in our modelling, we discuss some of these impacts in Section 5.2.

5.1.2. Gas market impacts

In addition to the consumer benefit, we have also quantified the impact of Equal Treatment on producers and shippers across our modelled scenarios. In order to estimate the impact of the equal treatment charging regime, we consider the difference in *revenue for gas flows* at different entry points when comparing equal treatment with the Base Case. Differences in revenue are calculated on the basis of changes in:

- GB wholesale prices;
- transmission charges; and
- the volume of gas supplied.

We calculate the revenue impact using the following formula:

[15] Exit charges at NTS exit points other than Bacton IP increase by less than 2% on average due to the redistribution of charges. We note that exit capacity charges represent a relatively small portion of the total cost of gas for final consumers.

Shipper revenue impact = Δ [Volume of gas supplied x (Market price – entry NTS charges)]

The revenue calculation assumes the price received by a shipper for supplying gas to NBP using a specific entry point is equal to the GB wholesale gas market price minus the NTS entry charges that the shipper incurs at the respective entry point. Changes in revenue are calculated for each NTS entry point under both the Base Case and the Equal Treatment charging options.

In addition to the impact on producers and shippers, we consider the impact of Equal Treatment on revenue at storage sites. In the case of storage, we calculated the profitability over the gas year as the spread between the cost of storage injection (market price + NTS exit capacity charge) and the revenue earned from selling gas back to the market (market price - NTS entry capacity charge).

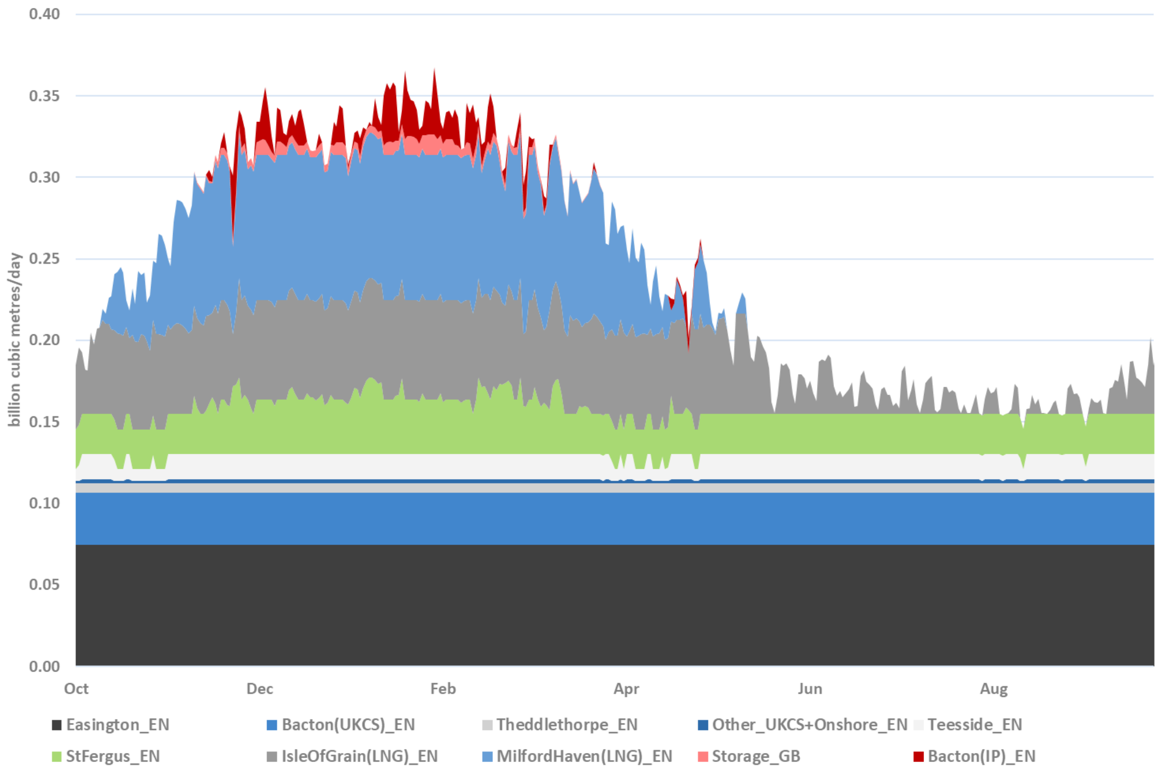
Impact on gas flows

Figure 5.3 and Figure 5.4 below show gas flows into the GB market across the entire gas year (2022/23) modelled under the Base Case and Equal Treatment charging regimes. A comparison of the two figures shows that the NTS charging regime has an impact on the pattern of gas flows to the GB market.

As already discussed in Section 4.2, under the *Base Case*, the interconnectors at Bacton IP play a role in helping to meet peak demand in the winter season. Other supply sources such as LNG imports, storage and a portion of Norwegian supplies at St Fergus also provide seasonal flexibility. UKCS and Norwegian flows (particularly at Easington) act as baseload supplies with little seasonal variation. In addition, the interconnectors also serve to meet the need for short-term flexibility with imports at Bacton IP increasing on days with the highest gas demand.

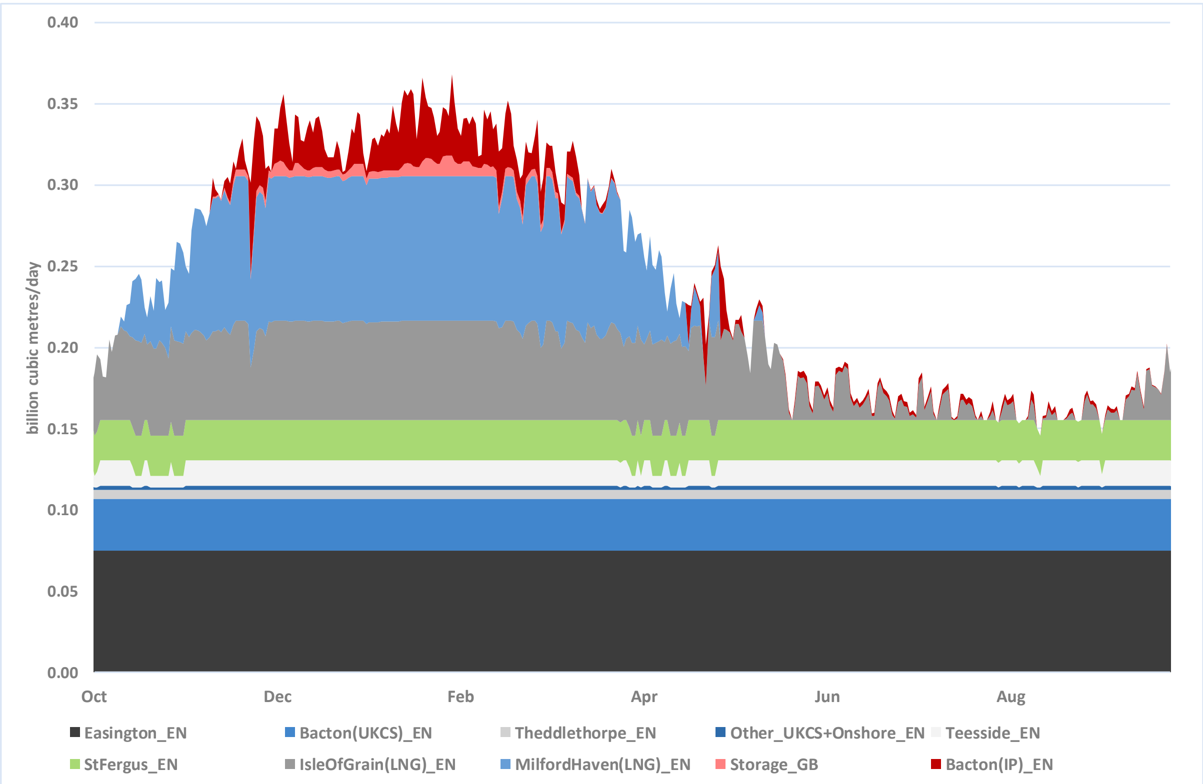
In contrast, under the *Equal Treatment* charging regime, import flows at Bacton IP increase, particularly during the winter months. There is also less seasonal and daily variation in LNG and St Fergus gas flows.

Figure 5.3: Gas flows into GB by entry point – Base Case charging regime (Baseline scenario)



Source: CEPA

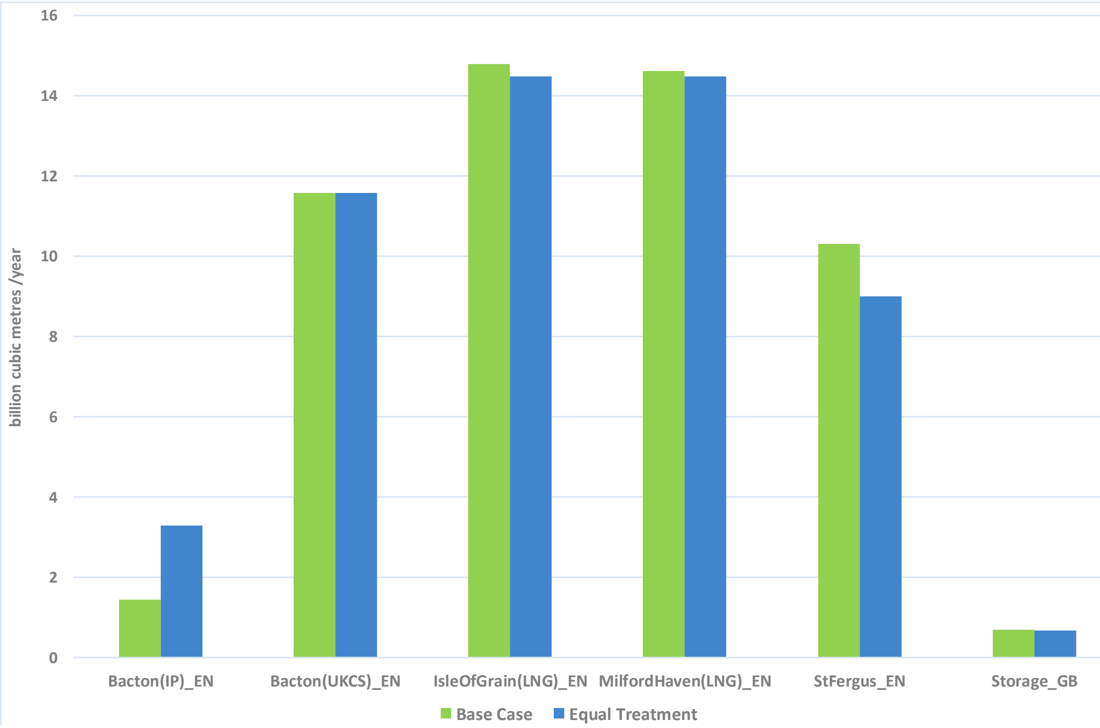
Figure 5.4: Gas flows into GB by entry point – Equal Treatment charging regime (Baseline scenario)



Source: CEPA

The impact of the NTS charging regime is further illustrated in Figure 5.5 which shows aggregate annual flows at the main GB supply points under both our Base Case and Equal Treatment charging regime cases. The Equal Treatment charging regime results in increased import flows at Bacton IP. Much of this increase in inflows has a displacement effect on gas inflows from other shippers and producers. Specifically, there is a reduction in St Fergus supplies and LNG imports. Gas flows at entry points not included in the figure below (e.g. Easington) are unchanged under the two charging regimes. Aggregate storage flows also remain very stable. The figure presents the impact on flows in the Baseline scenario, however, a similar pattern applies across all sensitivities modelled.

Figure 5.5: Annual gas flows – Baseline



Source: CEPA

Producer/shipper impacts

Given the impact of equal treatment on GB wholesale gas prices, entry and exit charges, and gas flows to the GB market, we have estimated the impact that the Equal Treatment charging regime would have on revenues earned by producers/shippers operating at each NTS entry points. We note that the estimated impacts refer to shipper/producer revenues from selling gas to the market and not revenues earned by owners of infrastructure assets used to supply gas to the market.

It is also important to note that we do not estimate changes in actual producer/shipper profitability or producer surplus as this would have to take account of changes in the cost of supplying gas to the market as well as market revenues. Since the quantity of gas supplied at each entry point is affected by the introduction of equal treatment, it would be reasonable to expect that the total costs for producers and shippers would also change which would mitigate some of the revenue impacts observed. A full consideration of producer surplus would need to capture the impact on costs.

At entry points where annual gas flows do not change, it can be assumed that total supply costs would also remain the same under the Equal Treatment. In this case, any revenue impact would be the result solely of changes in wholesale gas prices and network charges, and the revenue impact of Equal Treatment would fully capture the impact of equal treatment on producer surplus.

However, in the case of producers/shippers whose level of supply is impacted by Equal Treatment in our model – including flows through the Bacton interconnectors, Norwegian gas supplies through St Fergus and LNG supplies – the revenue impact is also driven by the change in total gas flows. In this case, costs can also be assumed to be different, and our estimate of the revenue impact would only provide a partial view of the full producer welfare impact of an equal treatment charging regime.

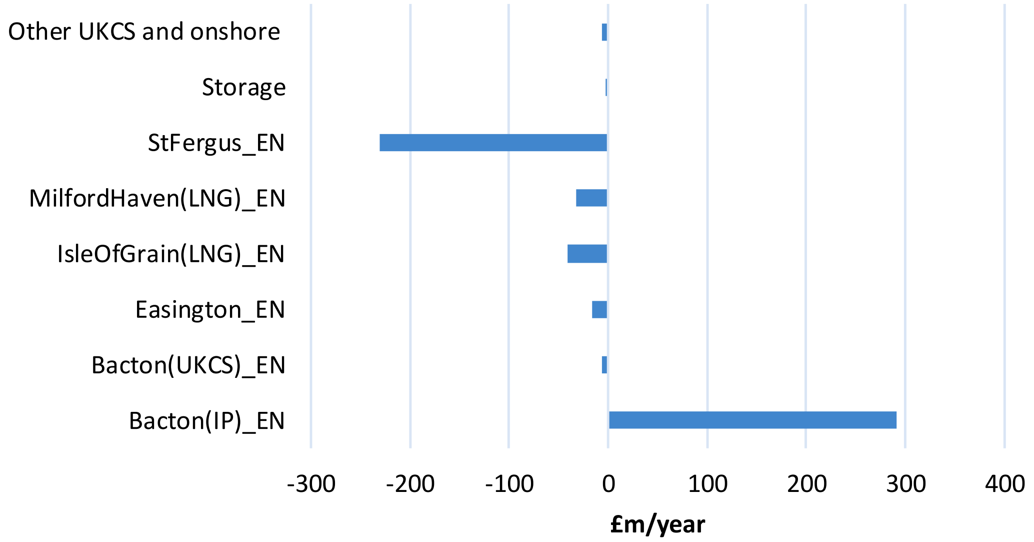
As a consequence, our adopted quantification measure of producer/shipper impacts from the Equal Treatment charging regime is a simplification of the producer welfare changes compared to the Baseline scenario.

As noted above, the revenue impact of Equal Treatment depends on:

- the reduction in average annual GB wholesale gas prices under Equal Treatment, which has a negative effect on gas producer and shipper revenue;
- changes to NTS charges, which, with the exception of Bacton IP, increase at every entry point and exert an additional negative effect on gas producer and shipper revenue; and
- changes to the volumes of gas supplied: in the case of LNG and Norwegian, gas supply falls, with a negative impact on revenue; in the case of Bacton IP, supply increases, with a positive impact on revenue.

The combined effect of these changes in prices, charges and volumes is summarised in Figure 5.6 for the Baseline scenario.

Figure 5.6: Change in the annual value of gas flowing through NTS entry points in the Baseline scenario



Source: CEPA

As the chart shows:

- The value of the gas flowing across the Bacton IP (and the revenue earned by shippers/producers selling that gas to the market) increases significantly under Equal Treatment, by £291 million/year as a result of lower charges and increased gas flows (more than doubling the estimated gas market revenues under the Base Case charging regime).
- Norwegian flexible supplies at St Fergus experience the greatest decline in estimated revenue, due to lower market prices and reduced gas flows. Shipper/producer revenues at St Fergus experience a decline of £246.6 million/year (representing 17% of estimated annual revenues) while the annual value of gas supplied at LNG import entry points drops by an estimated £73.3 million/year (representing a reduction of 1.6% in estimated annual revenues relative to the Base Case charging regime).
- There is a negative but relatively small estimated revenue impact on shippers/producers at UKCS-only entry points and storage points due to lower market prices and redistribution of NTS charges. Shipper/producer revenues earned at UKCS-only entry points fall by £12.2 million/year, while shipper revenues at storage points fall by £2.1 million/year. This represents a fall in estimated market revenues for shippers/producers at UKCS entry points and GB storage facilities of approximately 0.5%.

It is important to note that most of the impact at St Fergus and Easington refers to Norwegian gas supplies, which account for the vast majority of flows at those entry points, but it also includes a smaller impact on UKCS flows at those entry points.

We should also note that the revenue impacts estimated refer to gas flows to the GB market only and do not represent the impact on the overall revenues of producers/shippers. This is particularly important to consider in the case of Norwegian and LNG gas flows which have the optionality to flow to other markets. For example, while we observe an expected reduction in Norwegian flows at St Fergus which is reflected in a fall in revenues at that entry point, the modelling results show that aggregate production levels for Norway remain the same under the two charging regimes.

Table 5.2 presents the estimated revenue impact for shippers/producers at different NTS entry point categories under all scenarios modelled. Whereas the magnitude of revenue changes is different in the other three sensitivities modelled the overall pattern of impacts is consistent across all scenarios: revenues earned by shippers at entry points for Norwegian gas experience the largest fall under the Equal Treatment charging regime, while increased import flows through the interconnectors drive higher market revenues for shippers and producers flowing gas at Bacton IP. Given the fact that this is a revenue impact only rather than a full producer surplus impact, the revenue impact figures presented in the table are not directly comparable to the change in estimated GB consumer benefit.

Table 5.2: Net change in revenue (£m/year) from introduction of an equal treatment charging regime,

Net change (£m/year)	UKCS only entry points	Storage points	Continental supplies Bacton IP	St Fergus + Easington (NCS/UKCS)*	LNG entry points	Total Producer revenue impact
Baseline scenario	- 12.2	- 2.1	291	- 246.6	- 73.3	- 43.2
Sensitivity 1: High Asian demand	- 18.2	- 3.6	370.7	- 258.7	- 139.9	- 49.8
Sensitivity 2: Low demand	- 6.1	0.7	43.2	- 36.5	- 17.7	- 16.5
Sensitivity 3: Full 50% discount	- 17.6	- 2.3	348.8	- 256.0	-134.9	- 62.0

Source: CEPA

5.2. Qualitative impact assessment

Apart from the impacts we have quantified in the previous section, there are a range of impacts that we have not attempted or was not possible to quantify as part of this study.

The most obvious of these is the impact in the electricity market. Gas-fired generation is often the marginal source of generation and thus sets the price in the electricity market. Therefore, **lower wholesale gas prices under the equal charging treatment are likely to result in lower electricity prices and an increase in consumer surplus in the electricity sector**. Lower wholesale gas prices may also result in:

- increased utilisation of gas-fired power plants due to lower gas prices; and

- potential impacts on CO_2 emissions if gas-fired power plants displace other sources of power generation.

6. CONCLUSIONS

This study has evaluated the impact on the GB gas market of applying equal charging treatment with GB storage for the proportion of bookings entry = exit at the physically bi-directional Bacton IPs. It has considered historical flow patterns and used a global gas market model to simulate wholesale market prices and gas flows under a range of future market scenarios and NTS charging regimes. The key findings are as follows.

(i) Bacton IP interconnectors (IUK and BBL) compete directly with different types of GB storage.

Our analysis of historical flow patterns suggests that the interconnectors at the physically bi-directional Bacton IP are used in a similar way to storage facilities, providing system flexibility and contributing to security of supply. Our gas market modelling has shown that the interconnectors are likely to play the same role in the GB gas market in the future. These observations suggest that applying equal NTS charging treatment for the proportion of bookings entry = exit at the physically bi-directional Bacton IP as for GB storage would be consistent with the contribution made by IUK and BBL to system flexibility and to security of supply.

(ii) Applying equal charging treatment with GB storage for the proportion of bookings entry = exit at the physically bi-directional Bacton IP would benefit GB consumers.

In addition, we find that applying equal charging treatment for the proportion of bookings entry = exit at the physically bi-directional Bacton IP as for GB storage would bring net benefits to GB consumers by lowering GB wholesale gas prices. Our modelling suggests that this **consumer benefit could be substantial, ranging from an estimated £47m to £72m per year under a number of modelled scenarios**. In addition, equal charging treatment may also have a wider social benefit of higher GB gas demand which arises from the power generation sector reacting to lower wholesale gas prices. Lower GB wholesale gas prices may also benefit GB electricity consumers by reducing the production costs of electricity. Although we have not sought to quantify this effect, this would likely increase the estimated benefit to GB energy consumers further.

(iii) Our modelling shows limited impact on GB storage or UKCS producers from applying equal treatment.

The analysis demonstrates that while equal charging impacts could have GB consumer benefits, there will also be distributional impacts on producers/shippers. However, this estimated revenue loss is lower than the estimated benefits to GB consumers and is also an upper range estimate of the producer impact, given that our analysis does not capture the reduction in gas supply costs for shippers/producers at entry points where gas flows decline, which would mitigate some of the revenue impacts observed. There is a limited impact on UKCS producers and GB storage.

(iv) In light of these findings, equal charging treatment with GB Storage for the proportion of bookings entry = exit at the physically bi-directional Bacton IP would further the interests of GB consumers.

Our modelling study has looked at a single gas year (2022-23). The extent to which the findings from our modelling would create an enduring (dynamic) benefit for GB consumers may depend on how suppliers/shippers in practice respond to this shift in profitability. This is not an effect we have explored through our modelling. However, the modelled outcome in 2022-23 is what might be expected from more effective competition in the provision of flexibility to the GB market. Equal charging treatment – by providing more cost-effective access to storage and other sources of supply flexibility from the Continent – helps to increase competition at the margin in the GB market which drives the wholesale price reduction observed. This finding is consistent with the impacts of equal NTS charging treatment of the interconnectors we would expect in theory. The benefits to GB consumers arise from a more efficient way of NGGT seeking to recover its predominantly sunk cost base under a reformed NTS entry-exit charging regime.

Rather than being a subsidy for the Bacton IP, UNC Mod 0621F ensures **a level playing field for flexibility infrastructure that offers access to either GB or Continental gas storage capacity.**