MAY 2015

IED Investments: Ofgem Submission

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Introduction

This document sets out National Grid Gas Transmission's plan for compliance of our National Transmission System (NTS) compressor units with the Industrial Emissions Directive (IED). Our plan has been developed in conjunction with our stakeholders and we would like to thank them for all their time and commitment throughout this process.

In May 2014, we commenced the engagement process to develop a compressor strategy that delivers a network with the capabilities to meet stakeholders' needs at an acceptable cost, whilst compliant with the requirements of the IED. Stakeholders have played a key role in the development of this plan by working with us to help us understand what is of the upmost importance to them in the development of the NTS compressor strategy.

The process of stakeholder engagement we have undertaken has been different to anything we have done before and has been welcomed by stakeholders. We have used a range of different methods including commissioning a video to clearly explain the legislation and its impact on us, developing a scorecard which enabled stakeholders to tell us what is most important to them and creating an innovative tool which provides a user friendly front end to our network analysis tool.

This plan has changed significantly since our RIIO-T1 submission by making much more use of the available derogations within the legislation. This has been informed and supported by stakeholders and enables us to maintain adaptability to future legislation.

In this document we show how the available options for compliance at each affected site have been considered, how we have responded to stakeholder feedback and how we have reached the recommended options.

This document builds on our written stakeholder consultation documents and amends the *IED Investments: Proposals Consultation* to respond to stakeholder feedback to that consultation and provide updated information where applicable.

As an appendix to this document we have included the costs associated to this programme of work, these are based on, where appropriate, unit costs agreed during RIIO-T1 and detailed reports from external engineering consultancy firms.

Mark Ripley
Director, UK Regulation
National Grid

Executive summary

The EU has agreed targets and directives that determine how we should control emissions from industrial activity. The IED is the biggest change to environmental legislation in over a decade, with implications for everyone who relies on the NTS.

The IED impacts our operations heavily. It has two principle elements that affect our compressor fleet, the Large Combustion Plant (LCP) directive and the Integrated Pollution Prevention and Control (IPPC) requirements. On our network, we have 64 gas driven compressor units at 24 sites. In terms of the LCP directive, 17 of these units do not comply with the requirements so we have to decide on a unit by unit basis what to do. In addition to this there is upcoming legislation, the Medium Combustion Plant (MCP) directive, which we anticipate will affect a further 26 of our compressors which we may have to make compliant by 2025. With this in mind, the main options we are considering at the sites affected by the IED are[1]:

- Retain the unit(s) under Limited Life Derogation – which means they will cease operation on 31st December 2023, or after 17,500 hours, whichever is sooner
- Retain the unit(s) under an Emergency Use Derogation – which means retain the units beyond 2023 but we cannot run them for more than 500 hours per year from 2016
- Replace the unit(s) at a site, either with like for like or with different network capability

[1] The options discussed within this document have been evaluated in accordance with our duties as a gas transporter and other statutory obligations relating to safety and environmental matters and our obligation to plan and operate the system in an economic and efficient manner.

Where the chosen option is not to replace units, the capacity that we make available to customers and the costs of taking constraining actions need to be factored into RIIO-T2; for example through reductions in obligated capacity (baseline) levels or an increase to the cost target for the constraint management incentive scheme that would apply in RIIO-T2 (this is the incentive scheme to manage situations where we are unable to meet our capacity obligations).

Against the backdrop of these options, stakeholders have helped us to build the Gas Network Development scorecard to identify the network capability criteria that is most important to them. Following stakeholder feedback we built upon our analysis included in the *IED Investments: Initial Consultation* document to include a detailed commentary to explain our reasoning as well as a recommended option for each site in the *IED Investments: Proposals Consultation*. This evolved following stakeholder feedback that we should, where practicable, prioritise the use of the derogations available; to enable us to keep our options open with the uncertainty around the upcoming legislation.

With regard to the IPPC requirements, we have an overarching strategy as agreed with the Environment Agency (EA) and the Scottish Environment Protection Agency (SEPA) which allows us to review our compressors as a fleet on an annual basis, targeting sites emitting high levels of NO_x to maximise the environmental return. This process is managed through the Network Review which culminates in an annual report. In alignment with this strategy, we are currently undertaking work at five sites and are now proposing three further sites as part of an IPPC Phase 4 programme.

Under RIIO-T1, we received an up-front allowance to create an integrated and cost efficient plan setting out how we will ensure our units comply with the requirements of the IED. The plan must therefore comply with the IED, meet the future requirements of the network and represent best value for our customers.

The table below summarises our recommended option for each site and the associated cost.

Station	Recommended option	Recommended option - anticipated allowance (outturn prices)
St Fergus (LCP)	17,500 hour derogation on units 2A and 2D and then decommission by 31st December 2023	<£10m
Kirriemuir	Unit D - 17,500 hour derogation and then decommission Unit E – De-rate and re-wheel (electric unit) Unit C – Decommission and install one new unit (MCP unit)	£50-100m
Moffat	500 hour derogation both units	£10-20m
Carnforth	Unit A - 17,500 hour derogation and then decommission Unit B – 500 hour derogation Site reconfiguration	£10-20m
Hatton	17,500 hour derogation on 3 affected units and then decommission by 31st December 2023. Install three medium sized units	£100m+
Warrington	500 hour derogation both units	<£10m
Wisbech	Unit A - 500 hour derogation Unit B – Maxi Avon conversion to Avon	<£10m
St Fergus (IPPC)	Two replacement units and decommission two units	£50-100m
Peterborough (IPPC)	Two replacement units and decommission three units	£50-100m
Huntingdon (IPPC)	Two replacement units and decommission three units	£50-100m

We believe, based on our analysis and stakeholder feedback that this programme represents an optimised set of investments to deliver the network that will best meet users' needs and future challenges. A like for like replacement programme would have cost over £900m, assuming a similar IPPC programme. Our engagement with stakeholders and the development of the range of options has enabled us to make the above recommendations at each site. The total of the recommended options is approximately £470m (outturn), of which £420m (outturn) is within RIIO-T1.

The maximum impact of this programme on customer bills, compared to a base case of no investment, is approximately 50p in any year compared to 2014/15 price levels.

For more information on the above recommended options please see the section titled "Assessment of options".

The Legislation and how it affects us

European environmental legislation has been developed over recent years introducing new standards which Member States must comply with to ensure their industrial activities have a limited impact on the environment.

The legislation aims to reduce the quantity of air, water and land pollutants which are responsible for damage to the environment (such as acid rain) and to human health (such as respiratory diseases). It is mandatory for all European countries to comply with the new minimum standards. In this section we describe the two main pieces of legislation that were previously introduced, then go on to discuss how these were brought together in the IED and how this new piece of legislation affects our compressor units.

Large Combustion Plant (LCP) directive

The LCP directive[2], implemented in 2001, applies to all combustion plants with a thermal input of 50 MW or more. Under the LCP directive, combustion plant must meet the Emission Limit Values (ELVs) which are defined in the directive. ELVs are legally enforceable limits of emissions to air, water or land for those installations. An ELV is the maximum permissible rate at which a pollutant is released. The ELVs set out in this directive can be met in one of two ways;

1) Choose to opt in – need to comply with the ELV or plan to upgrade and achieve compliance by a pre-determined date
2) Choose to opt out and comply with the restrictions defined in the derogations including the Limited Lifetime Derogation or the Emergency Use Derogation

Integrated Pollution Prevention and Control (IPPC) Directive

Under the IPPC[3], implemented in 2008, any installation with a high pollution potential is required to have a permit. One of the pre-requisites for this permit is that Best Available Techniques (BAT) are used to prevent emitting these pollutants.

BAT assessments are required when developing a solution to avoid or reduce emissions resulting from industrial installations and to reduce the impact on the environment as a whole. They take account of the balance between costs and environmental benefits as the installation is designed, built, maintained, operated and decommissioned.

For National Grid, this means that all of our compressor units are required to have a permit which specifies the maximum ELVs to air for that unit. For new projects, we have developed a BAT evaluation approach which will ensure that the relevant considerations relating to potential environmental impact, whole life costs and operating efficiency are taken into account.

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[2] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32001L0080&qid=1424163879246&from=EN

[3] http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32008L0001&qid=1424164715511&from=EN

We have an overarching IPPC strategy as agreed with the EA and the SEPA which allows us to review our compressors as a fleet on an annual basis, targeting sites emitting high levels of NO_x to maximise the environmental return. This process is managed through the Network Review, which culminates in an annual report. To date we have undertaken three phases of IPPC works and we are currently in the process of agreeing Phase 4, which is covered within this consultation.

The Industrial Emissions Directive

Subsequently, the IED[4], which came into force on 6th January 2013, brought together a number of existing pieces of European legislation which included the LCP directive and the IPPC directive.

The major provisions of the IED which impact on National Grid and our compressor units are;

1) The use of permits for installations
2) Establishment of BAT Reference documents
3) The updating of ELVs for installations above 50 MW
4) Limited Lifetime Derogation
5) Emergency Use Derogation
6) 1,500 hours derogation

Permits

The IED specifies that all installations must be operated with a permit. These permits specify the ELVs for polluting substances, which are likely to be emitted from the installation concerned. The permit conditions also determine the environmental risk of that installation and shall ensure that the principles of BAT have been applied. Therefore, this mirrors the specifications set out in the IPPC whereby installations have to comply with the ELVs set out in that permit, which are based on BAT. We have agreed to continue the Network Review process to comply with these requirements.

BAT Reference (BREF) Documents

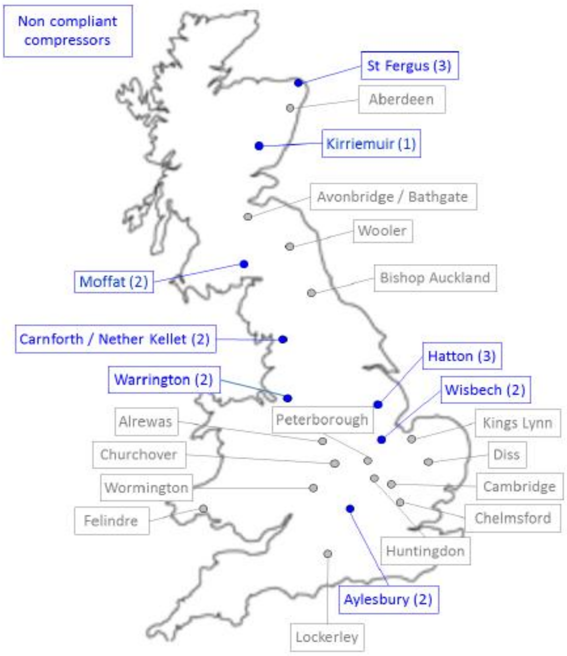
The IED also introduces an increased emphasis on the status of the BAT Reference (BREF) documents. These BREF documents draw conclusions on what the BAT is for each sector to comply with the requirements of IED. The BAT conclusions drawn as a result of the BREF documents will then form the reference for setting the permit conditions mentioned above. The BREF document for combustion plants is in draft form and it is anticipated that this will be finalised in 2016. From the date of finalisation there will then be a 4 year period for member states to implement. At this stage it is still uncertain how the BREF documents will be applied and what impact it will have on our compressor units.

Update of ELVs for installations above 50MW

The IED states that for installations with a thermal input over 50 MW it is mandatory for the following ELVs to be complied with;
Carbon Monoxide (CO) – 100mg/Nm^3
Nitrogen Oxide (NO_x) – 75mg/Nm^3 for existing installations and 50mg/Nm^3 for new installations. In this respect the IED mirrors the requirements set out in the LCP directive. These new limits introduced through IED affect 17[5] of our 64 units (although Aylesbury has already been funded). Our compressors that cannot meet the new ELVs for CO and NO_x must stop operating on 31st December 2015, unless the unit receives a derogation.

[4] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:334:0017:0119:EN:PDF

[5] After seeking further clarification, one of the units at St Fergus was re-classified and so is not subject to LCP. Therefore, in this document you will see analysis for 16 units rather than 17.



Limited Lifetime Derogation

In the IED[6] the requirements to be met to receive a Limited Lifetime Derogation are specified. It states that from January 2016 to 31st December 2023 combustion plant may be exempted from compliance with the ELVs for installations above 50 MW provided that certain conditions are fulfilled:

- The operator makes a declaration before 1st January 2014 not to operate the plant for more than 17,500 operating hours starting from 1st January 2016 and ending no later than 31st December 2023;
- The operator submits each year a record of the number of operating hours since 1st January 2016
- The ELVs set out in the permits as per the requirements of the IPPC Directive are complied with

We have already made the declaration referred to above and have been allowed to utilise this derogation for our current affected units. However, there is still the option to opt out of using this derogation prior to it coming into force on 1st January 2016.

Emergency Use Provision

The IED also makes a provision for using installations for emergency use;

"Gas turbines and gas engines for emergency use that operate less than 500 operating hours per year are not covered by the emission limit values set out in this point. The operator of such plant shall record the used operating hours."[7]

This means that we may be able to still use our affected compressor units that do not comply with the above ELVs if we use them for 500 hours or less. Therefore, as we discuss in the "Potential Solutions" section, this may be one of the solutions that is available at some of our sites. As with the Limited Lifetime Derogation, this would also be applicable from 2016.

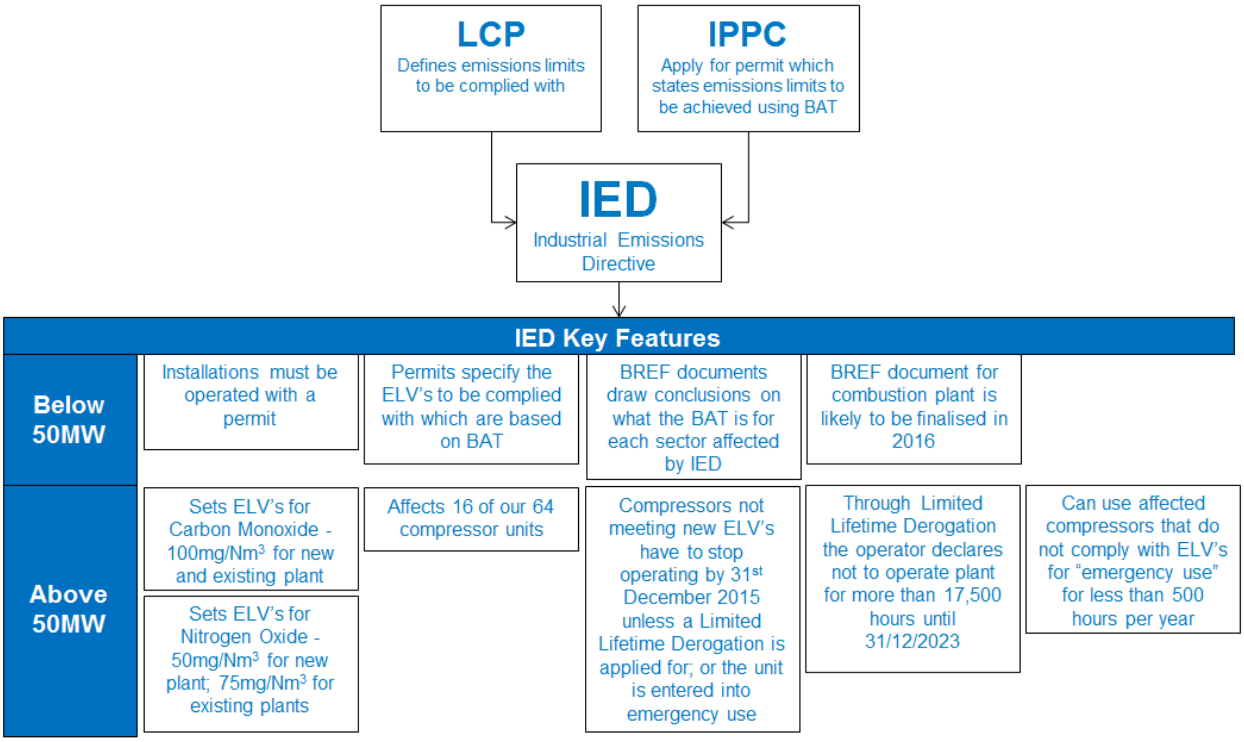
1,500 hours derogation

The IED legislation provides for a further derogation for gas turbines (including CCGTs) which were granted a permit before 27th November 2002. This applies to units which do not operate for more than 1,500 hours per year as a rolling average over a period of 5 years, increasing the emission limit value for NO_x to 150 mg/Nm^3, with the limit for CO remaining at 100 mg/Nm^3. However, our compressor units produce more NO_x than the limit specified in this derogation and therefore this does not represent a viable option.

The diagram on the next page illustrates how the LCP directive and the IPPC directive have fed into the IED and what has resulted in the key features of the IED split by installations below 50 MW and above 50 MW.

[6] Article 33

[7] Annex V, Part 1, para 6

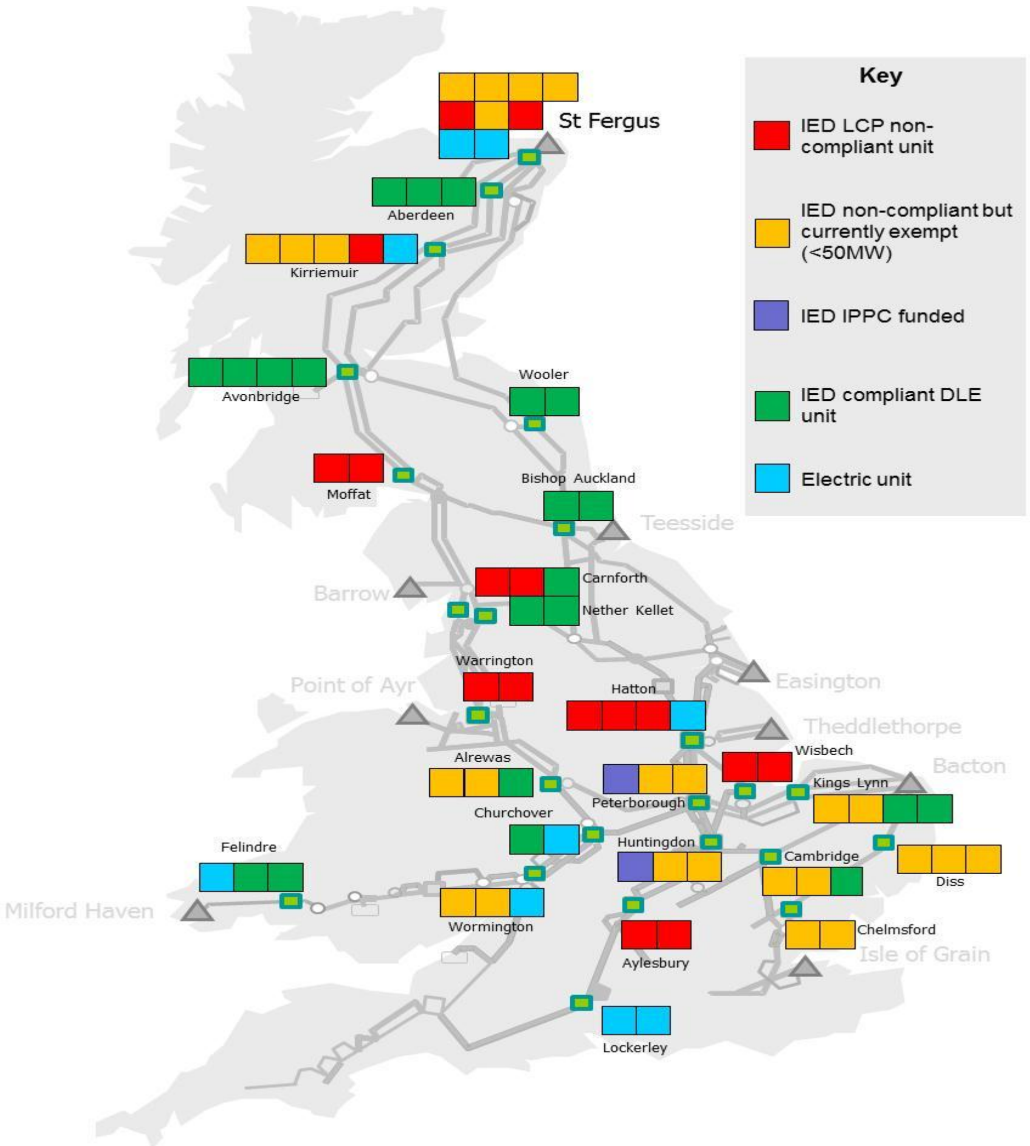

LCP
Defines emissions limits to be complied with
IPPC
Apply for permit which states emissions limits to be achieved using BAT
IED
Industrial Emissions Directive
IED Key Features
Below 50MW
Installations must be operated with a permit
Permits specify the ELV's to be complied with which are based on BAT
BREF documents draw conclusions on what the BAT is for each sector affected by IED
BREF document for combustion plant is likely to be finalised in 2016
Above 50MW
Sets ELV's for Carbon Monoxide - 100mg/Nm³ for new and existing plant
Sets ELV's for Nitrogen Oxide - 50mg/Nm³ for new plant; 75mg/Nm³ for existing plants
Affects 16 of our 64 compressor units
Compressors not meeting new ELV's have to stop operating by 31st December 2015 unless a Limited Lifetime Derogation is applied for; or the unit is entered into emergency use
Through Limited Lifetime Derogation the operator declares not to operate plant for more than 17,500 hours until 31/12/2023
Can use affected compressors that do not comply with ELV's for "emergency use" for less than 500 hours per year

Upcoming Legislation: *Medium Combustion Plant directive*

Following our *IED Investments: Initial Consultation* document, stakeholders asked to understand more about how MCP and BREF may impact our fleet and hence the decisions we are making with regard to the existing IED legislation. Although this RIIO re-opener submission is for the current legislation as a response to this feedback we provided the following description of our current understanding of the future legislation in the *IED Investments: Proposals Consultation*.

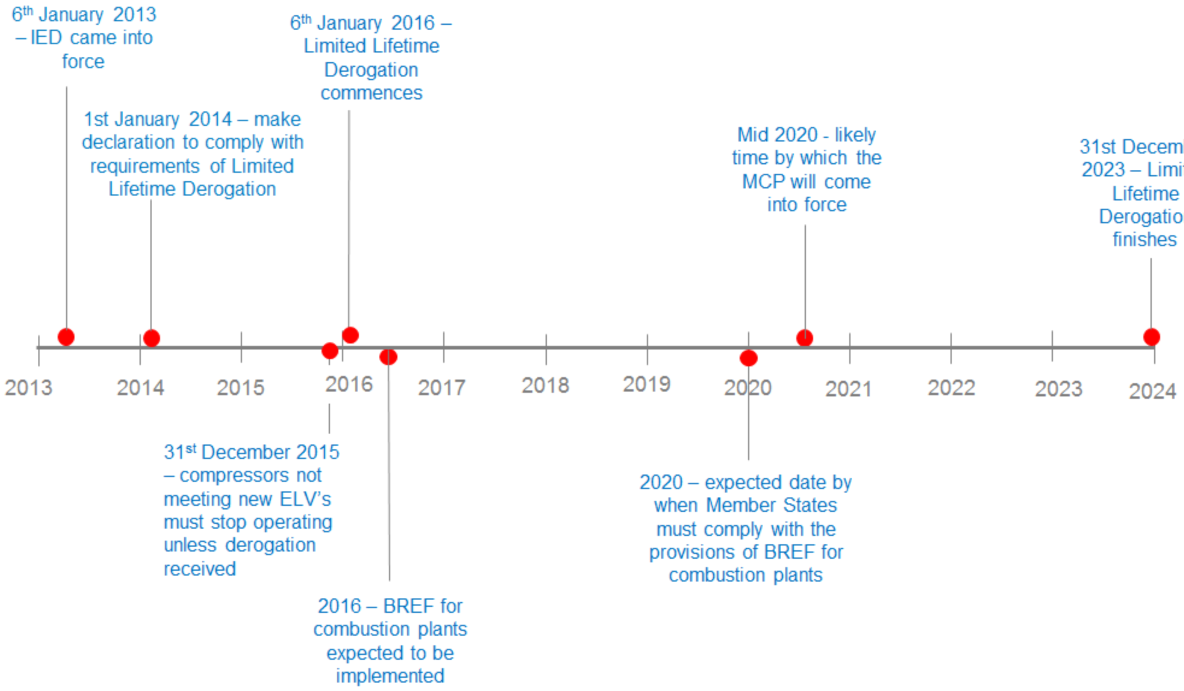
The MCP directive will apply limits on emissions to air from sites below 50 MW thermal input. It is expected that this legislation will introduce ELVs that are differentiated according to the plant's age, capacity and type of installation. It is thought that existing installations would be given a long transition period, up to 2025 for the larger (5-50 MW) plants and up to 2030 for the smaller units. It is expected that the MCP is likely to come into force by 2020. Currently the impact of the MCP on our compressor units is unclear; however, it could potentially impact 26 units.

In the "Assessment of options" section, for each site we expand on this interaction, however as an overview the chart below shows which units (highlighted in orange) could potentially be impacted by BREF and MCP, as well as those units captured by the LCP element of IED. In producing the chart, we have assumed that our existing Dry Low Emission (DLE) units remain compliant with the BREF note, if this turns out not to be the case additional decisions will need to be made for the units highlighted in green. Although the units at Aylesbury are coloured red as IED LCP non-compliant units we have already received funding to carry out work on these units as described in the "The RIIO deal" section.



Timeline

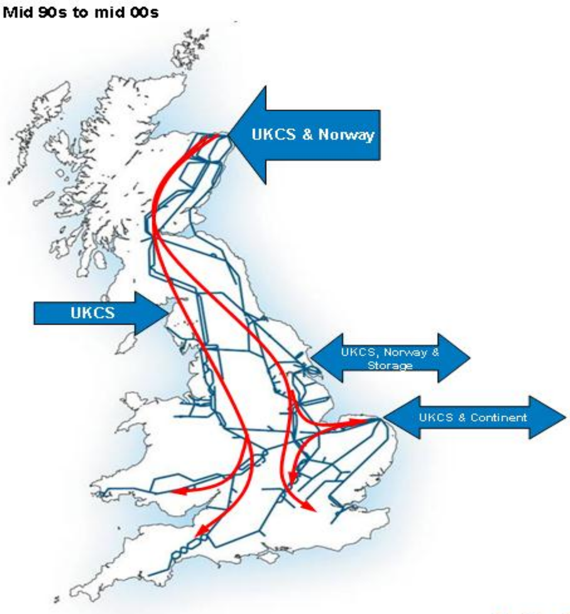
Below is a timeline of key dates and milestones related to the new emission abatement legislation.

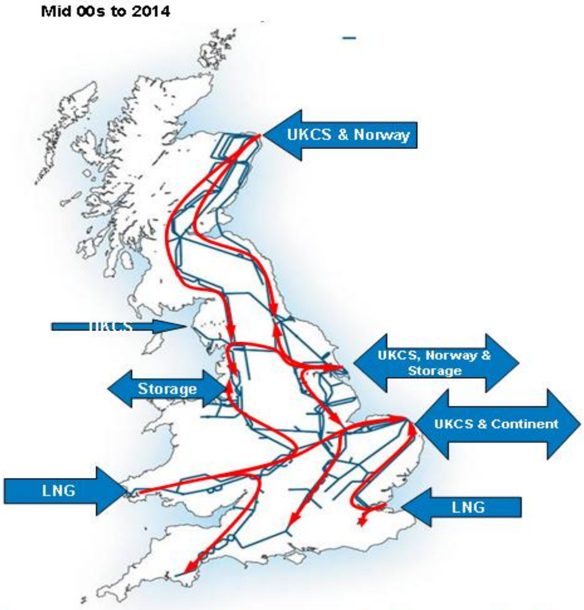


History, current and future use of the NTS and compressors

History and current use of the NTS

There has been a significant shift in the way the gas transmission network is utilised. Historically the NTS has operated on a north to south flow pattern with compression used to pull and push the gas from the main entry point at St Fergus to the high demand areas in England. However, as shown below, over the last 20 years this has changed significantly. There are now more entry points onto the system which are distributed around the country. The UK continental shelf supplies have declined and in 2004 the UK became a net importer of gas on an annual basis.





Note: Numerous proposed storage projects are not shown

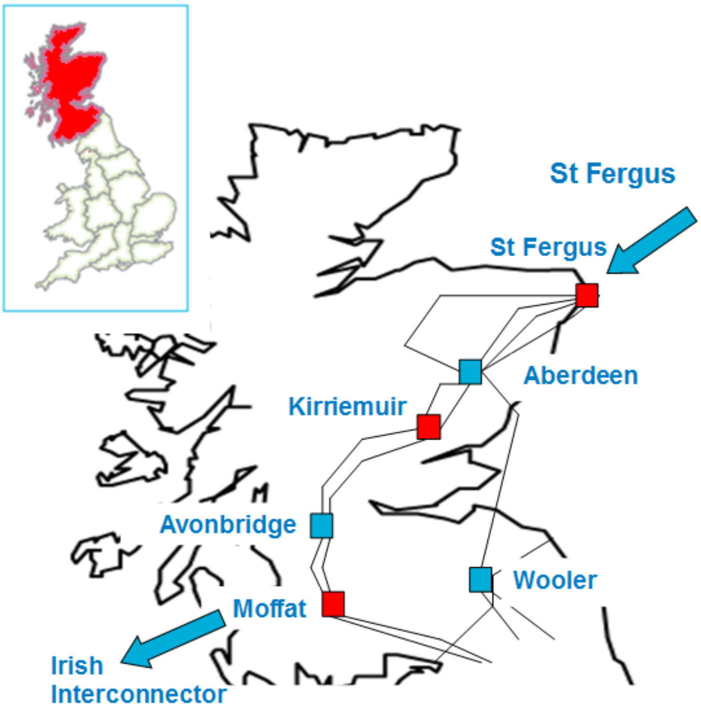
History and current use of compressors

The main reasons we use compressors are;

- To transport gas
- To maintain pressures within network design safety parameters
- To meet contractual capacity and exit pressure commitments
- To provide system flexibility to meet rapidly changing use and conditions
- Occasional use to facilitate maintenance

The changes on the network have resulted in changes to compressor utilisation. Some of the compressors are now required to support network flows in a reversed direction from their original design; some compressors have become increasingly important across a large demand range; and some only at peak demand conditions or certain supply patterns in order to avoid significant constraints. Below, on an area basis, the compressor sites are shown on the maps with the ones affected by the LCP element of the IED highlighted in red. For each of these sites a brief description is provided about the compressor site's historic and current usage.

Scotland:



Site *(avg annual usage per site)*	**Use**
St Fergus *(12,000 hrs)*	Pressurise gas from Total sub-terminal
Aberdeen *(1,900 hrs)*	Required under medium to high St Fergus flow scenarios and to maintain Scotland LDZ pressures
Avonbridge *(2,000 hrs)*	Maintain Scotland LDZ pressures
Kirriemur *(1,800 hrs)*	Required under high St. Fergus flow scenario; to maintain Scotland LDZ pressures and back-up Aberdeen and Avonbridge
Wooler *(450 hrs)*	Required under high St. Fergus flow scenario and to manage linepack in Scotland
Moffat *(150 hrs)*	Used for network resilience

The sites in Scotland that are affected by the requirements of the IED are St Fergus, Kirriemuir and Moffat. The hierarchy of compression usage in Scotland operationally is as follows:

1. Avonbridge
2. Aberdeen
3. Kirriemuir
4. Wooler
5. Moffat

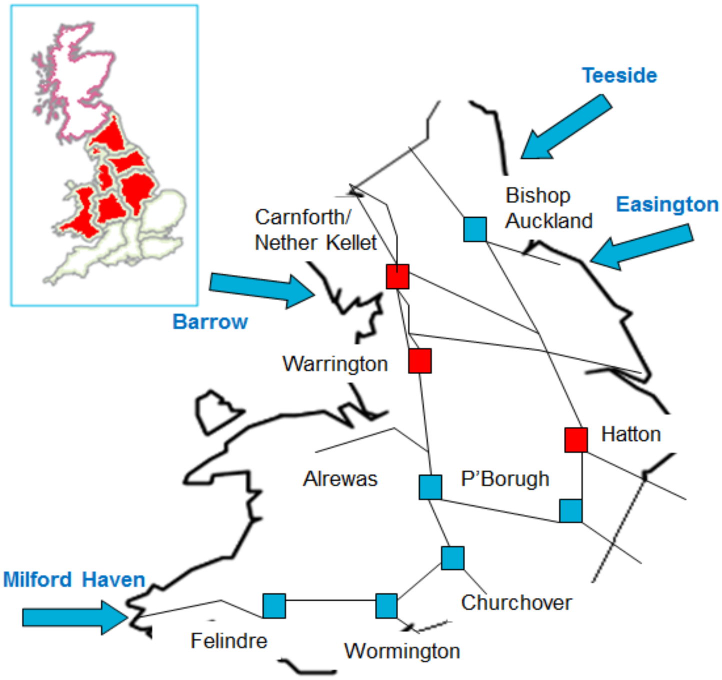
On a typical winter day, with high flows from St Fergus we would expect to have Avonbridge and Aberdeen running. For increased flows and resilience we currently have Kirriemuir, Wooler and Moffat at our disposal.

The compressors at St Fergus are at the Total sub-terminal and have a high usage rate as they are used to pressurise the gas brought in through this sub-terminal to the pressures required on the NTS. Therefore this means that the St Fergus compressors run when the Total sub-terminal is flowing, irrespective of the network conditions.

Use of Kirriemuir to transport high flows from the St. Fergus entry terminal has decreased due to the decline in St. Fergus flows, however Kirriemuir is still required to support Scottish LDZ pressures and offer resilience as back up to both Aberdeen and Avonbridge compressor stations.

Moffat provides network resilience as it is a first line back up unit and would be used to cover a station failure at Avonbridge under very high northern gas flows. It also supports baseline obligations at St Fergus, although FES indicates peak flow at below baseline levels at St Fergus.

North and Midlands



Site (avg annual usage per site)	Use
Peterborough (6,600 hrs)	Transmission of gas south, east and west and system flexibility
Carnforth / Nether Kellet (3,100 hrs)	High flows north to south. High Easington flows
Hatton (2,600 hrs)	Support north to south flows down East coast; meet Easington baselines; support east to west flows including Teeside and Theddlethorpe; support IUK interconnector
Alrewas (850 hrs)	Facilitates high Milford Haven flows and support North West storage and Welsh pressures
Wormington (3,200 hrs)	Facilitates high or low Milford Haven flows and supports South West and Welsh pressures
Churchover (1,000 hrs)	High or low Milford Haven flows to support Welsh pressures
Bishop Auckland (400 hrs)	Support high Teeside and St Fergus flows
Warrington (31 hrs)	Specific activities e.g. maintenance, resilience

The sites in the North and Midlands which are affected by the requirements of the IED are Carnforth and Nether Kellet, Hatton and Warrington. The order compression is utilised along the west coast of the network operationally is as follows;

1) Nether Kellet
2) Carnforth
3) Carnforth plus Nether Kellet
4) Warrington

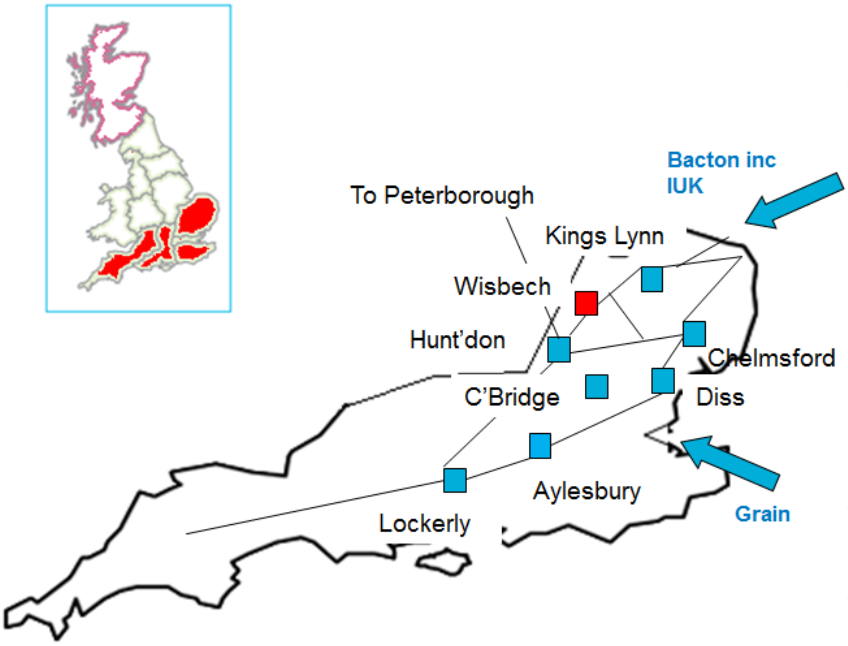
Carnforth and Nether Kellet have been required to support assured pressures at North West, West Midlands, East Midlands and South Wales offtakes and maximise St. Fergus and Barrow entry capability. Since construction of the trans-pennine pipeline, the stations can also be used to support high entry flows at Easington and therefore help reduce entry capacity constraint risk on the East Coast. Nether Kellet was constructed to support the large North West offtakes along Feeder 11, but can be configured to also support the main feeders into the North West instead of using Carnforth.

The units at Nether Kellet can be used in either single or parallel configuration; however there is limited operational experience of parallel configuration. Nether Kellet single configuration is required to maintain pressures in the area under low flow conditions, then unit C at Carnforth (lead unit) will be switched on if flows are higher (and Nether Kellet switched off). Barrow baseline can now be met by unit C since its reduction in 2007.

The decreased St. Fergus and Barrow flows along with the construction of the Milford Haven terminal have occurred since the installation of Warrington on the network in 1983. There have also been a number of storage sites added to the North West of the network, south of Warrington that provide support for Exit in the area on high demand days. This has considerably reduced the requirement for compression at Warrington which is now mainly used for resilience and maintenance purposes.

Hatton is one of the most critical stations on the NTS. It has historically been used to support north to south flows down the East coast, meet Easington baseline obligations and support large directly connected loads and storage sites in the North West. Hatton has recently also proved vital in supporting further east to west flows, including entry points at Teeside and Theddlethorpe and east to south flows. It also supports the IUK interconnector exit flows, which connects to the NTS at Bacton.

South West and South East



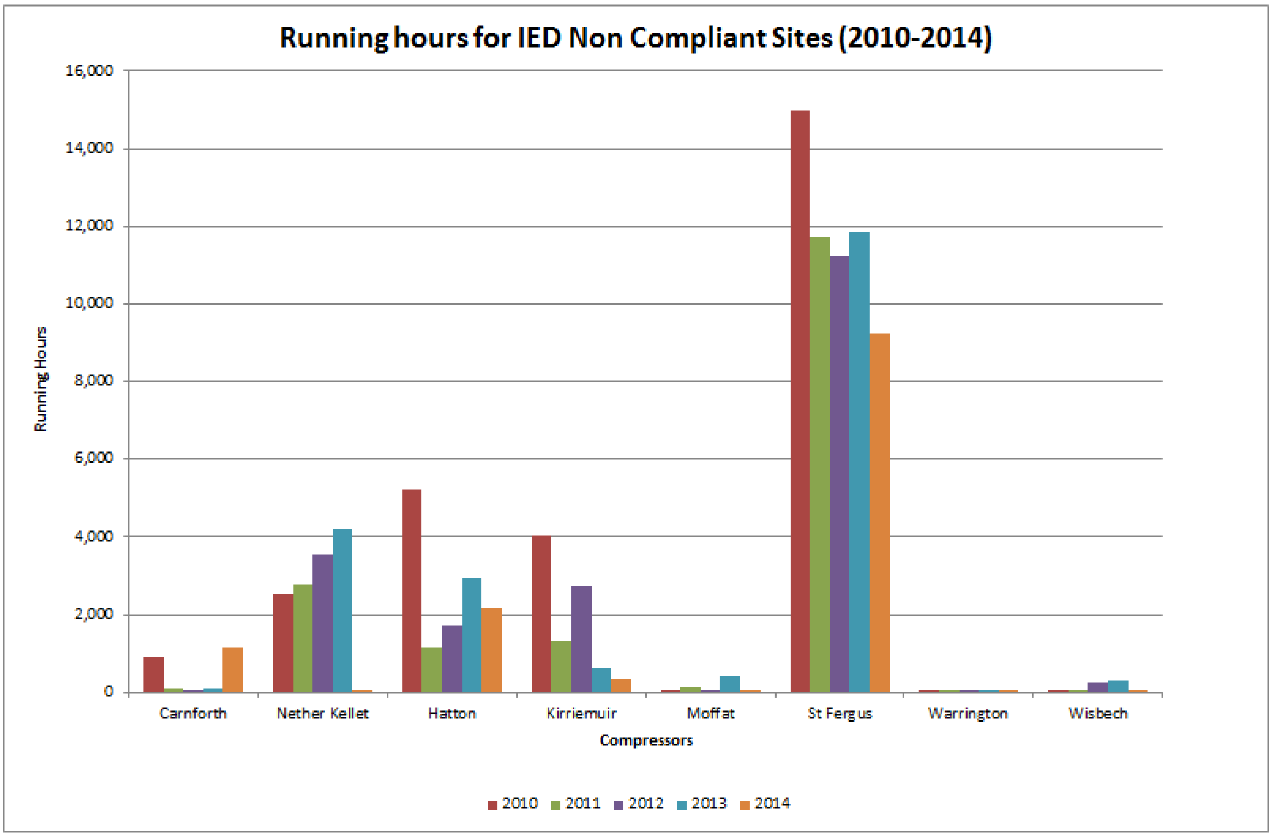
Site *(avg annual usage per site)*	Use
Huntingdon *(3,100 hrs)*	Flows south to South East and South West on high demands
Kings Lynn *(800 hrs)*	High-low Bacton, IUK east, to west
Lockerly *(700 hrs)*	South West pressure support during high demands
Wisbech *(100 hrs)*	High Transmission Flows, back up to Peterborough
Diss *(300 hrs)*	High Bacton flows or high South East demands, low Grain
Aylesbury *(200 hrs)*	South West pressures, high demands
Chelmsford *(100 hrs)*	High Bacton Flows
Cambridge *(100 hrs)*	Facilitates high or low Grain flows

The site in the South West and South East which is affected by the IED is Wisbech. Originally Wisbech was primarily required to support the Southern Feeder (Feeder 7) and ensure extremity pressures in the South West were maintained. This used to be the only compressor on the suction side of Huntingdon. Peterborough was not connected to Huntingdon, but was originally used as the East to West compressor to move Bacton gas and support Wales. As demand increased, the feeders connecting Peterborough to Huntingdon were added to the network therefore reducing the requirement for Wisbech to support Huntingdon.

Another requirement for Wisbech was associated with Theddlethorpe and Easington area Entry requirements. Historically, concurrent high Entry flows at the Easington and Theddlethorpe terminals could be met using both Hatton and Wisbech compressor stations. When the flow through the Hatton station approached the flow limit, high flows from the Theddlethorpe terminal could be directly diverted along Feeder 7 through Wisbech to avoid Entry constraints. The reduction in flows into the Theddlethorpe terminal have reduced the requirement for Wisbech under this scenario. Additionally, since the trans-pennine pipeline was built there is a further reduction in the requirement for Wisbech due to the introduction of an alternative route for East Coast gas. Finally, a decline in flows from St. Fergus and the introduction of additional LNG supply terminals in the South of the system require some gas from Easington to flow north towards Scotland and therefore reduces the requirement for Wisbech even further.

Compressor Running Hours

The graph below shows the running hours for the compressor stations that are affected by the IED over a 5 year period. The changes in the running hours each year illustrates the change in use of that compressor station.



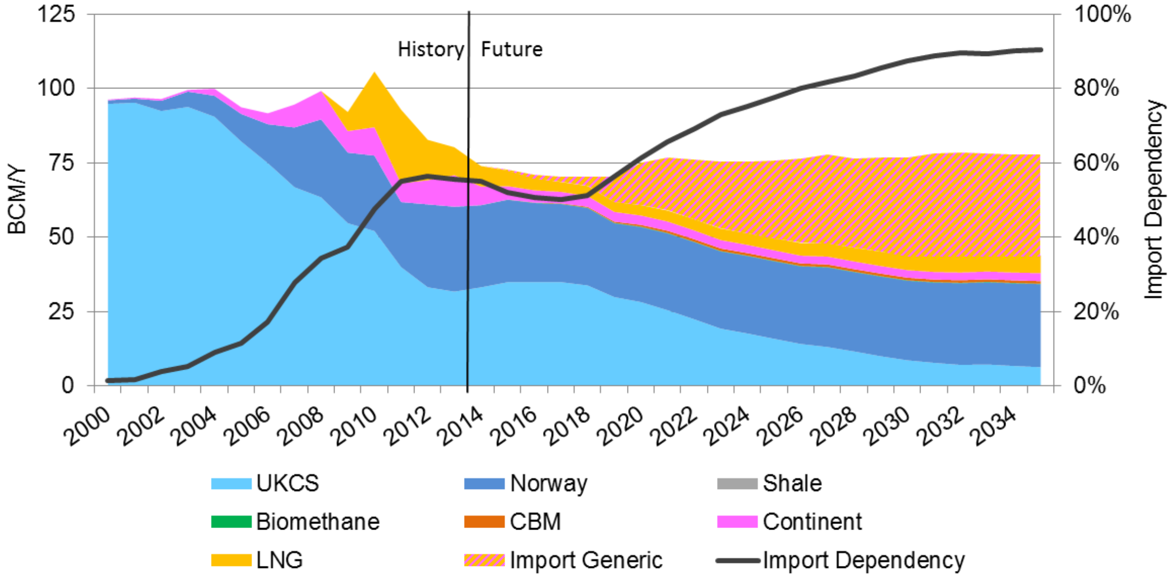
Future use of the gas system

Each year we publish our Future Energy Scenarios (FES)[8]. Our FES provide a detailed analysis of a range of plausible and credible conclusions for the future of energy. Our range of scenarios are based on the trilemma of security of supply, affordability and sustainability. Our scenarios flex the two variables of affordability and sustainability, giving the following four scenarios:

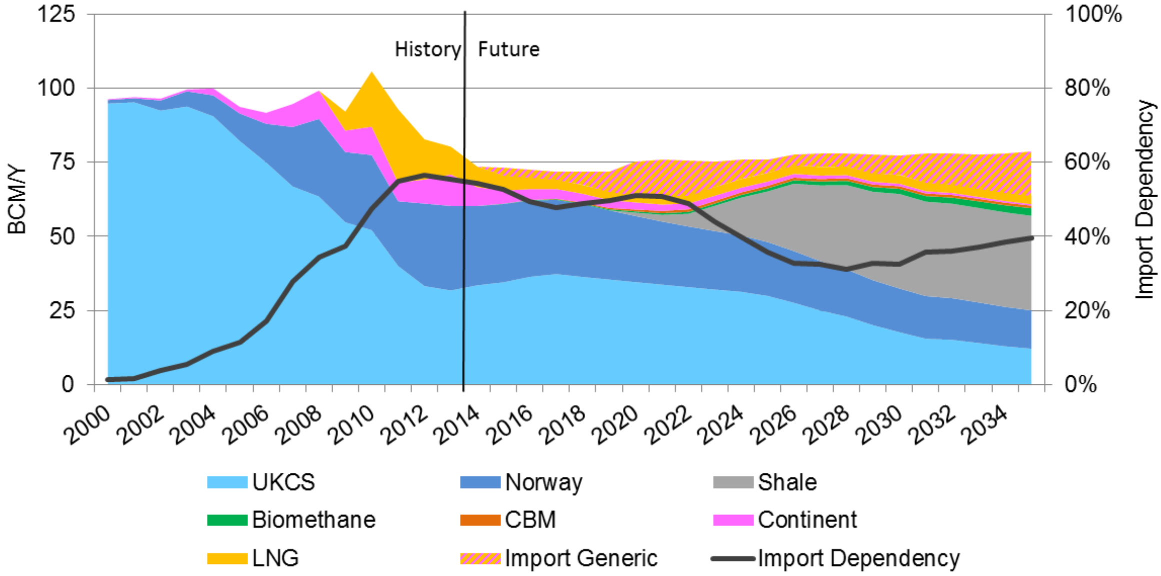
- Gone Green
- Slow Progression
- No Progression
- Low Carbon Life

Our 2014 FES outline the level of uncertainty we can expect to see in future gas supplies, in particular around shale gas. We have a potentially significant new source of gas in shale but the volumes vary from none in our “No Progression” scenario to 32 bcm/year in the early 2030s in our Low Carbon Life scenario. These two scenarios represent our extreme cases with the first graph below for No Progression showing a large hatched area for import generic, this area could be filled by any mix of LNG or continental gas, the split of which will be driven by many factors including the price and availability of LNG. The second graph below shows “Low Carbon Life” in which we see much higher flows from UKCS and from shale leaving much less room for imports.

[8] http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/



Annual Gas Supplies for no progression



Annual Gas Supplies for low carbon life

As a result, our network needs the capability to manage a wide range of potential supply patterns. The uncertainty as to which pattern may occur on a given gas day is increasing and could increase further into the future. The decisions we make on our compressor fleet need to work across the range of scenarios and provide flexibility to meet the changing requirements for the way the network is used. This is discussed further in the 'Interaction with other investment programmes' section.

In the four scenarios presented in FES there is a continuing requirement for gas. Although two of the scenarios show a decrease in gas demand by 2035, with slow progression showing a reduction of up to 20%, the other two scenarios show an increase.

The RIIO deal

Prior to RIIO-T1 we received an allowance to fund the first two phases of IPPC. Through the RIIO-T1 negotiations we discussed the potential impact the IED legislation could have on our compressor units. As a result of this we received an allowance for this work which can be split into three elements;

- An up-front allowance for three specific sites
- An allowance to undertake the emissions abatement optioneering plan
- A provisional allowance to fund the remainder of our compressors which do not meet the requirements of IED

Funding received prior to RIIO-T1

Prior to RIIO-T1 we received baseline funding for two phases of IPPC;

Site	Units	Funding mechanism
St Fergus	Units 3A and 3B	IPPC Phase 1
Kirriemuir	Unit E	
Hatton	Unit D	IPPC Phase 2

Up-front allowance

Under RIIO-T1 we then received an upfront baseline allowance for the following sites;

Site	Units	Funding mechanism
Peterborough	One unit	IPPC Phase 3
Huntingdon	One unit	
Aylesbury	Units A and B	LCP Phase 1

This work is to reduce the emissions at these sites and ensure they comply with the ELVs specified. The section of this document entitled "Progress on Peterborough, Huntingdon and Aylesbury" will go into further detail and developments at these sites.

Emissions abatement optioneering plan

We also received funding for "emissions abatement optioneering" to allow for the creation of an "integrated and cost efficient plan" and fund up-front engineering works. This plan sets out how we intend to ensure our units comply with the requirements of the IED at the remainder of our sites. Special Condition 5E of the Licence provides the mechanism to submit this plan under the RIIO-T1 re-opener window in May 2015.

Provisional allowance

In addition we received a provisional allowance of £374m (outturn prices) in RIIO-T1, this was associated with the remaining sites affected by the LCP element of IED and further work under IPPC. The provisional allowance was not based on particular solutions at the affected sites and was always intended to be adjusted through an uncertainty mechanism. The scale of the adjustment is based on the difference between the outcome of this submission and the provisional allowance. This means that if we were to be granted zero allowance from our submission, all of the provisional allowance would be removed. Our current plans, equate to £420m which would result in an upward adjustment.

The table below summarises the sites with interaction between the two elements of IED, with the associated funding mechanism;

Site	Units	Funding mechanism
St Fergus	2 * Electric Variable Speed Drives (Units 3A and 3B)	Received funding under IPPC Phase 1 prior to RIIO-T1
	5 * Avon units	Proposed replacement of 2 of these units as part of IPPC Phase 4 within this submission
	2 * RB211 (Units 2A and 2D)	Affected by LCP element of IED and recommended to be decommissioned in this submission
Peterborough	3 * Avon units (Units A, B and C)	Received baseline allowance in RIIO-T1 as part of IPPC Phase 3 for one replacement unit.
		Two replacement units proposed as part of IPPC Phase 4 within this submission
Huntingdon	3 * Avon units (Units A, B and C)	Received baseline allowance in RIIO-T1 as part of IPPC Phase 3 for one replacement unit.
		Two replacement units proposed as part of IPPC Phase 4 within this submission
Hatton	1 * VSD 35 MW machine (Unit D)	Unit funded under IPPC Phase 2 prior to RIIO-T1
	3 * RB211 (units A, B and C)	Affected by LCP element of IED and 3 medium replacement units recommended within this submission
Kirriemuir	1 * VSD machine (Unit E)	Unit funded under IPPC Phase 1 prior to RIIO-T1
	1 * RB211 (Unit D)	Affected by LCP element of IED and recommendation to decommission included within this submission along with replacing unit C

Progress on Peterborough, Huntingdon and Aylesbury

As mentioned in the "RIIO Deal" section during the RIIO-T1 negotiations we received an up-front allowance to fund work on specific units at Peterborough, Huntingdon and Aylesbury which are not compliant with the requirements of the IED.

Peterborough and Huntingdon

Peterborough and Huntingdon compressor stations are critical sites on the NTS and are each equipped with three gas compressors driven by Avon gas turbines. Both sites fall under the IPPC element of the IED. As described in the 'Legislation and how it affects us' section this requires us to comply with the ELVs for CO and NO_x specified in the permits for these sites. Due to the high running hours of these sites, we have agreed with the EA via the annual Network Review process that these sites should be targeted for the next phase of emissions reduction investment.

The early stages of the Front End Engineering Design (FEED) study concluded that the option of electrically driven compressors was not viable at Peterborough, but remained a possibility for the Huntingdon site. The tender process for Huntingdon included the option for suppliers to offer an electrically driven compressor option and a number of bids were received. The BAT assessment of all of the tender submissions, combined with further information on the availability and costs of an HV electrical supply to site concluded that the electric drives do not represent BAT. As a result of the assessment, the unit selected to reduce emissions at both sites is a 15.3 MW gas turbine unit.

The feasibility stage of the FEED study is now complete and completion of the conceptual design stage is on target to be finished in June 2015. Work is progressing to prepare the tender for the Main Works Contract and this is on schedule to be issued in summer 2015 with the contract being awarded during Q4 2015.

Detailed design work for the preparatory enabling works at Peterborough scheduled for summer 2016 is now in progress. At both sites, it will be necessary to retain all three existing units until the new units have been operationally proven.

Aylesbury

Aylesbury falls under the LCP element of the IED. This means that the site is required to comply with the ELVs set out in the directive. The upfront funding we received under RIIO-T1 was to fund works on two units at this site.

The existing engines at Aylesbury are prototype versions of an upgraded Rolls Royce Avon engine fitted with DLE technology to reduce emissions. These are the only engines of this type that we have within our fleet. DLE is today acknowledged as BAT for the control of emissions from gas turbines and is supplied as standard on all new gas turbines we are considering.

Analysis of the performance of the Aylesbury engines has shown that whilst they are able to achieve the required NO_x limits within their operating range, they are unable to achieve the required ELV for CO. Preliminary investigation has shown that the CO ELV can be achieved by the addition of a CO oxidation catalyst in the exhaust stack and we are working with Rolls Royce (now Siemens) to develop this innovative solution. The FEED study was completed in April 2015, and project completion is set for December 2016 subject to outages. Work is ongoing with Siemens to ensure provision of critical spares to maintain operation of these machines for a minimum of 20 years.

Interaction with other investment programmes

In order to maximise the value to our stakeholders, it is essential that we take a holistic view of the development of our network, considering the factors that impact our investments and the portfolio of projects we are progressing. In relation to IED, the two main other investment programmes that interact with the specific impacted sites are:

- Provision of system flexibility to meet rapidly changing conditions
- Maintaining our Scotland 1 in 20 obligations

Provision of system flexibility to meet rapidly changing conditions

Through the development of the Gas Transmission Gas Network Development scorecard stakeholders identified system flexibility as a key priority in the development of our recommendations for each compressor unit affected by the IED. When assessing the options available at each site we have scored them against all the priorities stakeholders identified, including system flexibility, and included commentary on our reasoning on a site-by-site basis, please see the “Assessment of options” section.

This section considers what system flexibility is, the issues we face and how this is being addressed both within this consultation and in our wider network development plans.

Definition

System flexibility can be defined as “a requirement for additional operational capability driven by changing user behaviour and explicitly not the provision of incremental entry or exit capacity”.

It is the ability of the NTS to cater for the rate of change in the supply and demand levels which results in changes in the direction and level of gas flow through pipes and compressors and which may require rapid changes in the flow direction in which compressors operate.

The issue

As discussed in the “History, current and future use of the NTS and compressors” section, customer requirements for use of the NTS and the actual way it is used are changing. This has resulted in very different gas flows than those for which the network was originally designed. Currently there is no existing mechanism to trigger enhancement to the capability of the system required specifically in response to changing and/or reducing flows on the network. However, once shippers have procured their entry and exit capacity, they have told us they want to use that capacity with the minimum of restrictions. A more comprehensive discussion on this topic, with an associated slide deck, took place at the second stakeholder workshop on 30th September. This slide deck can be found by following the link below.
http://www.talkingnetworkstx.com/IED-work-with-us.aspx

What we are doing

We are currently undertaking a project to review the future flexibility requirements for the NTS, considering how different events or factors across gas days and within day might affect the way that the system is managed. This work may lead to changes in the planning processes and may require changes in commercial options (rules), operational arrangements (tools) or physical investments (assets) to be progressed to deliver more capability in this area. We will also consider additional market services that could be provided as part of this.

With specific regard to the IED integrated plan, the range of options, as detailed in the “Assessment of Options” section, has been developed with consideration to the impact of system flexibility on a site-by-site basis. Therefore these options take account of flexibility requirements and you will see that in some cases we have included flexibility enhancements within the range of options in order to ensure that the solutions progressed for IED are fit for purpose into the future.

Stakeholder engagement

At our stakeholder event held on the 19th March 2015 as well as discussing our IED proposals we also commenced specific stakeholder engagement on System Flexibility with the industry. The first dedicated system flexibility stakeholder workshop was held on 14th May 2015 and there will be further engagement held on this topic in the near future.

Maintaining our Scotland 1 in 20 obligations

As mentioned in the “History and Use of Compressors” section, overall flows from St Fergus are decreasing and flows are less predominantly from north to south. The system was historically designed around high St. Fergus gas flows and hence significant north to south flows. The network presently has very limited physical capability to actively move gas south to north. Our planning analysis shows that we are approaching a point where, without additional network capability to deliver south to north flows, we will not be able to meet our 1-in-20 demand obligations in Scotland.

We identified a number of modifications to the network, designed to enhance the network capability to maintain Scottish pressures and enhance south to north flows. We requested and were granted funding for these projects within RIIO-T1. However there is a strong interaction between the potential Scottish 1-in-20 projects and the IED solutions at Moffat and Kirriemuir compressor stations. We are therefore progressing both investment programmes in parallel to ensure we develop the optimum solution and minimise any funding request. The output from this and further consultations will provide key inputs into the direction of the Scotland 1-in-20 work.

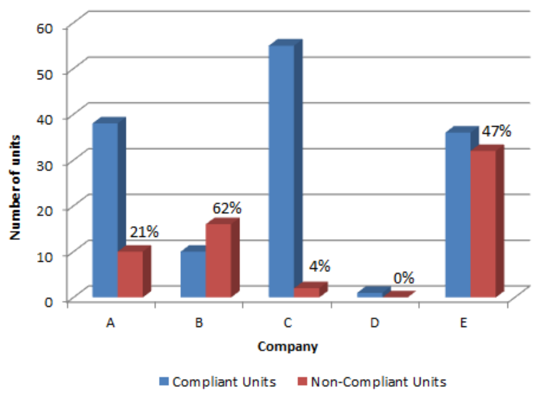
Best practice

Undertaking benchmarking with other Transmission System Operators (TSOs) enables us to learn how we are each complying with the IED and share best practice techniques.

The study:

In order to ensure we benefit from best practice, we initiated a benchmarking study through the Gas Transmission Benchmarking Initiative.

Including ourselves, 5 European TSOs participated in the benchmarking study with a range of proportions of compliant to non-compliant units as can be seen on the chart below with the percentage of non-compliant units shown;



Compliance methods

The results of this benchmarking study showed that the most commonly used compliance method is to use one of the available derogations contained within the legislation and then to decommission the unit. The other options considered by participants to the study were to either replace the units, to undertake a retrofit, or to immediately decommission the unit.

Following the data collection exercise a Gas Compressor Forum was held in November 2014. Nine TSOs attended the Forum where compliance techniques with the IED were discussed. The main discussion focussed around the possible derogations that are applicable under the IED legislation. However, one TSO stated that they are testing a Selective Catalytic Reduction (SCR) technology as a compliance technique. Although we had previously evaluated retrofit options, we have not had any experience with SCR technology. We therefore initiated a BAT assessment to evaluate the potential of this technology. Please see the section titled “Potential Solutions” for the outcome of the BAT assessment on this technique.

Stakeholder process

Stakeholder engagement is of fundamental importance to us. We have listened to our stakeholders views and acted on what they told us.

As we work to meet environmental legislation and replace ageing assets it is crucial that we are transparent and clear about the tasks ahead, and that we work with our stakeholders to produce a compressor strategy that meets their requirements.

Given the importance we place on stakeholder engagement, we have tried to ensure we use a thorough range of communication methods of engagement including;

- An Introductory Letter
- An Article on our Connecting website
- The Talking Networks Website
- Video
- Stakeholder Workshops
- New innovative techniques e.g. OCC tool
- Transmission Workgroup
- Bilateral meetings
- Webinars

Introductory Letter

In order to reach as wide an audience as possible and publicise the project we sent an initial introductory letter to stakeholders in April 2014 explaining the IED and its implications for the NTS, and asked stakeholders to tell us how they would like to be engaged on this topic.

Article on our Connecting Website

We also promoted the start of the engagement through an article on our Connecting website[9] to reach a wider audience and capture further comments, and provided background information to the consultation on our gas compressor strategy.

Talking Networks

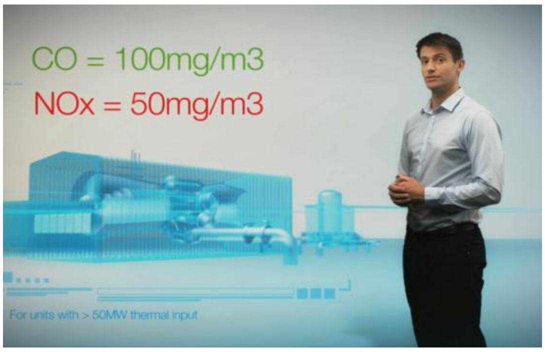
To support our stakeholder engagement we developed a project specific website under the Talking Networks umbrella. This provides further background information on the legislation, in addition to originally hosting the initial engagement questionnaire, details of stakeholder workshops, the consultation documents and the ability to register for updates on the project.

Stakeholders have regularly been directed to the consultation on our Talking Networks site where there is a short film, message from the Director of Transmission Network Services, clear articulation of the IED and what it means for the future of the NTS. This site also contains the written consultations along with the responses and all the presentation material used at the stakeholder workshops.

[9] http://www.nationalgridconnecting.com/we-want-your-views/

Video

We commissioned a video which provides an overview of the IED legislation and its impact on our network and its users. We showed this video at our first stakeholder workshop discussing this matter and it is also on our website.



Stakeholder Workshops

Stakeholder consultation began with an initial workshop in July 2014 and subsequent workshops in September, November and March. Attendance (22 different attendees across all workshops), represented a wide range of industry participants including shippers, Distribution Networks (DNs) and trade associations. The following companies participated: Energy UK, National Grid Distribution, Scotia Gas Network, Centrica Storage, Centrica, Oil and Gas UK, Chemical Industries Association, Bord Gais, RWE Supply and Trading, Apache, GE Oil and Gas, E.On, Baringa, Cornwell Energy, Statoil, Ofgem, and IHS.

167 Stakeholders contacted by letter	**29** Stakeholders responded to our letter and survey
10 Stakeholders attended each workshop	
All Stakeholder on the Joint Office distribution lists for UNC, Transmission and Distribution invited to workshops	

As a result of the first workshop in July, the content of the next workshop was refined to suit stakeholders areas of interest and concern, as detailed in the next section of the document. Stakeholders were asked to actively contribute in these discussions and to provide feedback via forms at the end of events, voicing their ideas, interests and concerns. The timeline for engagement was also adjusted consequently.

> **Useful to articulate these IED scenarios – well presented, accessible and easy to engage with**
>
> **Stakeholder comment**

In the first workshop to get a better understanding of stakeholders requirements we asked delegates to complete a Gas Transmission Network Strategy scorecard, to identify the network capability criteria that were most important to them and why. We used this scorecard in the evaluation of the options available, to present the impact of the different options back to stakeholders in an easily digestible form, and ultimately to make a recommendation.

> **Scenarios were interesting, good case study, and good insight from other industry participants**
>
> **Stakeholder comment**

IED Investments: Initial Consultation

On the 17th November 2014 we published the *IED Investments: Initial Consultation*. In this consultation we asked for stakeholders views on a range of questions including the stakeholder engagement process and the range of available options for compliance at each affected site. The consultation closed on 19th December 2014 and we received 6 responses from SGN, Centrica, RWE, Total E&P UK, E.On and Energy UK.

We published *the IED Investments: Initial Consultation Stakeholder Feedback* document on 16th January 2015 which outlined what stakeholders told us in the responses, what we would do as a result. The feedback document and the responses can be found here; http://www.talkingnetworkstx.com/IED-work-with-us.aspx

For more information on this please see “Our response to what stakeholders have told us” section.

IED Investments: Proposals Consultation

On the 13th March 2015 we published the *IED Investments: Proposals Consultation*. This consultation developed the *IED Investments: Initial Consultation* in light of stakeholder feedback received. It also provided a recommended option to achieve compliance at each site. The consultation closed on 10th April and we received 5 responses from Centrica, RWE, Total, National Grid Distribution and Energy UK.

In their responses stakeholders broadly agreed with our recommendations. The four responses to this consultation that are not confidential can be found here; http://www.talkingnetworkstx.com/IED-work-with-us.aspx

Transmission Workgroup

In February 2015 we presented at the Transmission Workgroup on our stakeholder engagement process to date and how this has fed into the development and assessment of the options considered at each site. We also covered the feedback we had received from our *IED Investments: Initial Consultation* document and outlined what we would do as a result of that feedback.

Further Stakeholder Engagement

We offered specific engagement with stakeholders. We have held a number of bilateral discussions to address particular concerns for these parties. These bilateral meetings with customers are significant, especially where customers may be directly affected by our decisions. Of the 4 Distribution Networks (DNs), Scotia Gas Networks (SGN) and National Grid Distribution attended the workshops. In October 2014 we held a webinar with the DNs and have followed up with bilateral meetings with each one. All these instances have enabled us to listen to these specific stakeholders’ areas of interest and concern.

New Innovative Techniques – OCC Tool

We commissioned Oxford Computing Consultants (OCC) to develop a tool which will help to visualise and articulate the impact that different supply and demand scenarios and different investment options will have on the network. This work is still on-going but, at the workshop held on 19th March 2015 we showed a video, developed using the OCC tool, of scenarios considered and their impact at Moffat. At the workshops stakeholders were complimentary, particularly as it directly feeds from our network analysis tool. They said it would be useful to develop the tool for other areas of gas network development. The Moffat video can be viewed on the Talking Networks website at the following link; http://www.talkingnetworkstx.com/IED-work-with-us.aspx

Our response to what stakeholders have told us

We place great value on all comments we have received as we worked with stakeholders, from telling us how they would like to be engaged to identifying the most important issues to them. We have listened to what stakeholders have said and acted upon this.

The workshop format was favoured by our stakeholders and from the event on 16th July 2014 stakeholders articulated what specific information they wanted and needed; stakeholder comments were used to inform the next workshop on 30th September 2014. Our response was therefore to adjust the workshop material so that content was specifically what stakeholder told us they wanted to address. Below is a summary of some of the aspects stakeholders wanted more information about and how we tailored our engagement to respond to their requests.

Stakeholders said	We have done
"We need to know more about what compressors do today and how we use them"	We presented the Network Evolution Story at the September 2014 stakeholder workshop
"More information on different options and impacts"	We presented the LCP compressor options at the September 2014 workshop and covered the options at specific site examples in detail. A full range of options was presented at the November 2014 stakeholder workshop
"Focus on IED legislation"	We provided a further overview of the legislation and the timings at the September 2014 stakeholder workshop and put the presentation pack on Talking Networks.

In the first workshop delegates were asked to develop Gas Transmission Network Strategy scorecards to identify the most important criteria in developing the NTS compressor strategy.

Here is a summary of the scorecard completed by participants at the workshops showing the importance they attached to the various criteria;

Criteria	Importance (from 1 to 10)	Key Question
Future Flexibility	0 5 8 9 10	Does this option allow National Grid to meet future flexibility requirements?
Encouraging new investment	9	Does this options remove barrier for encouraging new investment?
Impact on customer charges	6 8 9	Does this option have a negligible impact on customer charges?
Future Proofing	7 8 9	Is this option future proof?
Exit Capacity Obligations	5 8 10	Can National Grid meet Exit Capacity obligations considering this option?
Current utilisation	5 8 10	Does this option allow National Grid to retain current capability?
Resilience	5 7 9	Does this option represent an appropriate level of resilience on the network?
Entry Capacity Obligations	4 7 9	Can National Grid meet Entry Capacity obligations considering this option?
Sensitivity analysis beyond FES supply and demand scenarios	4 6 8	Does this option allow the network to be operated in sensitivities beyond FES?

Key	▲ = Lowest score	◆ = Average score	■ = Highest score

From this summary it is apparent that stakeholders want to ensure that the chosen option provides future flexibility for system users and encourages new investment. This priority is then followed with ensuring that the option allows current capability to be maintained, including exit capacity obligations, at a negligible cost to consumers and in a manner which is future proof.

“We need to maintain the levels of flexibility and capability we have today”

Stakeholder comment

We have listened to what stakeholders consider to be the most significant outputs of our investment and this information has informed our compressor options which can be found later in this document.

“The cost to customers and the impact on transmission charges are a key concern”

Stakeholder comment

Initial Consultation document

In our *IED Investments: Initial Consultation* we asked stakeholders a series of questions to gain their feedback. In January 2015, we published our feedback document where we captured this feedback and committed to do certain things as a response, this is summarised in the table below. In the *IED Investments: Proposals Consultation* we ensured that we delivered on these actions.

Stakeholders' said	We committed to doing	We have done
Improve engagement with GDNs	Looking to establish a new or modify an existing group to improve engagement with GDNs.	Had early conversations with the GDNs and are scoping Terms of Reference for the group
Provide updates on key discussion points at Transmission Workgroup	Raised the topic at January's meeting and will provide an update in February's meeting	Provided update at February 2015 meeting
Like more information on MCP directive and BREF	Will publish further information in the Proposals Consultation including what we envisage the impact to be on our compressor units	Please see the section titled "The Legislation and how it affects us"
1,500 hours derogation should be considered	Will outline the option and explain in the Proposals consultation why we are unable to use this derogation	Please see the section titled "The Legislation and how it affects us"
Due to the forthcoming introduction of the MCP it may be most appropriate to use available derogations to delay the final decisions on the sites affected by the LCP element of IED	Decisions will take this into account but delaying may jeopardise the delivery of works due to outage constraints. In the Proposals Consultation we will provide further information on our proposed outage programme	Please see the section titled "Assessment of Options"
In the table included in the "Initial Scoping of Options" section it was not clear what we mean by the red, amber, green methodology	In our Proposals Consultation we plan to include a clearer explanation of what the colours mean	Please see the table in the "Assessment of Options" section
Interaction between our current allowance for IPPC Phase 4 works and our proposed works is unclear	We will provide further clarity on this in our Proposals Consultation	Please see the section titled "IED – IPPC Phase 4"
More consideration to system flexibility. Consider market services	In the Proposals Consultation we will highlight how system flexibility has been taken into account when assessing the options and provide further detail where appropriate. We will consider additional market services as we progress the wider debate on system flexibility.	Highlighted how system flexibility has been taken into account in the Assessment of Options section
Useful to understand how decisions might impact on transportation charges, to understand new NTS tariffs and other cost savings.	Currently undertaking analysis to establish the impact on transportation charges and NTS tariffs which we hope to share in the Proposals Consultation along with how our work may provide other cost savings.	Please see the section titled "Impact on Charges"

Proposals Consultation document and addendum

Following the publication of our *IED Investments: Proposals Consultation* we held a workshop on 19th March 2015. At that workshop stakeholders raised a few points which they said they would like further information about. As a result, we published the *IED Investments Proposals Consultation Addendum* on the 19th March 2015 to clarify these points.

Stakeholders' said	We did
More information on what we have been funded for so far under earlier phases of IED LCP and IPPC	In the addendum document we clearly set out what we have been funded for under each phase
Not convinced that it is the right time to undertake the required works on Kirriemuir unit C	In the addendum document we set out our reasoning as to why we feel it is appropriate that we carry out the works on Kirriemuir unit C as part of this phase
Clarification on whether we would intend to bring Carnforth unit A back into service	Stated that we would intend to decommission Carnforth unit A to avoid additional asset health costs
More information on the difference in costs between installing three medium sized units and two large units at Hatton	In the addendum document we used the unit cost model to articulate what this cost difference would be
Clarification on what the impact would be on a customer bill of the proposed programme on a base case of zero	Undertook this analysis and included in the addendum document that this would increase a customer bill by 48p (2014/15 prices) on a zero base case

In the responses to the *IED Investments: Proposals Consultation* stakeholders were not convinced of the need to undertake work on unit C at Kirriemuir at this stage when we would be revisiting the site as part of MCP. As a result of this, we held internal meetings to clarify this situation as outlined in the "Assessment of options".

Potential solutions

For each site affected by the LCP element of the IED the following potential options in isolation or in combination could be considered:

1) Retain under the Limited Life Derogation and subsequently decommission
2) Retain under the Emergency Use Derogation
3) Retrofit
4) Catalytic Converter
5) Replace with the same capability
6) Replace with different capability

1) Retain under the Limited Life Derogation and subsequently decommission

The Limited Life Derogation provides an "opt out" from complying with the specified ELVs. It allows units to continue to operate for a maximum of 17,500 hours from 1st January 2016 to the 31st December 2023, after which time the unit would need to be decommissioned. A declaration to comply with these requirements had to be made by 1st January 2014. If no other solutions have been implemented at those units to ensure they are compliant with the ELVs by 31st December 2023 then those units must be removed from the network by that date. We have made a declaration to comply with these requirements for all of our affected units. However this option leads to a reduction in capability and therefore a change in risk profile that needs to be considered together with one or more combinations of the following:

- Improve resilience elsewhere on the network;
- Reinforce the network elsewhere;
- Manage commercial risk through long term contracts;
- Manage commercial risk through locational buy and sell actions on the day;
- Manage commercial risk by reducing baselines;
- Change the UNC rules to manage constraints;
- Reflect in constraint management incentive cost target in RIIO-T2.

2) Retain under Emergency Use Derogation

As mentioned in "The legislation and how it affects us" section a further "opt out" option is to use the emergency use provision. This means that we will be able to use our affected units that do not comply with the ELVs if we use them for 500 hours a year or less. This provision will be available to us from 1st January 2016. Similar concerns about reduction in capability exist to the above option and therefore a risk management strategy as described above will also need to be considered.

Additional Asset Health Costs

In RIIO-T1 we forecasted that the asset health related investment on compressor stations would decline from 2015/16 given the forecast compressor replacement works required to ensure compliance with the IED. However, if we now retain the units under either the Limited Life Derogation or the Emergency Use Derogation the requirement for the asset health related investments on these units will not decline as the units will remain in operation. We have assessed the asset health costs associated with each site where either of these two options are recommended. These asset health costs are for the remainder of the RIIO-T1 period.

3) Retrofit

Gas driven compressors are a continuously evolving technology. A retrofit is the exchange or modification of an aspect of the compressor unit with newer elements which offer lower emissions. Under this option only some of the unit will be upgraded, meaning that the unit as a whole will be limited to its original lifespan. Retrofitting of existing gas turbines is possible but is limited due to increased space required and conformity with existing equipment. The environmental performance and total cost of ownership can be less favourable compared with a new low emission package. We have undertaken detailed studies of retrofit options for our compressor fleet and due to minimal upfront cost benefit compared to replacement and generally a lack of performance guarantees, it has been determined that retrofit does not represent a suitable solution for our units affected by the LCP element of IED.

4) Catalytic Converter

The use of catalysts to treat stack exhaust gases is well established. Catalytic converters can be used to either oxidise the CO or to reduce the NO_x.

Oxidation of CO

The process to oxidise CO into CO_2 is straightforward. When the CO is passed over a catalyst the CO in the exhaust gases will react with the excess oxygen to produce CO_2. Technically this solution is relatively simple, requiring sufficient physical space to fit the exhaust gas catalyst unit and in some cases continuous monitoring of exhaust gas (to ensure a sufficient degree of abatement). Oxidation of CO to CO_2 is considered to be BAT for the post combustion control of CO.

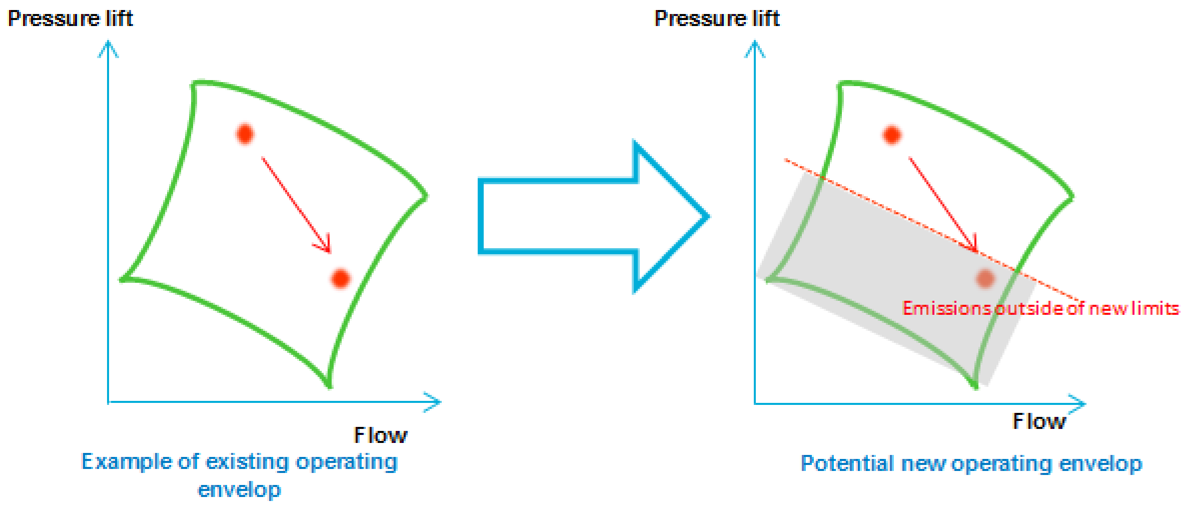
Reduction of NO_x

NO_x can be reduced to nitrogen and water using a SCR. This technique requires a source of hydrogen to be added to the exhaust gases before being passed over the catalyst. SCR is a significantly more complex process to implement than the oxidation of CO. The reducing agents (typically ammonia or urea) are considered hazardous and subject to their own specific control conditions under the Control of Substances Hazardous to Health legislation. To ensure the continuous operation of the plant there would be a requirement to store large quantities of the reducing agent on site, along with the catalyst units themselves and associated process control and monitoring equipment.

Following the best practice sharing with other TSOs we have undertaken a SCR BAT assessment. The costs of the technology, based on an initial evaluation look promising, particularly for units with low running hours. However, the technology is not yet proven or demonstrated for this application. We have therefore discounted the options for the highly utilised sites. However, we will undertake an innovation project to assess the technology at one of our sites so that we can consider it for the May 2018 RIIO re-opener and MCP affected sites.

5) Replace with the same capability

Under this option the capability provided by each unit would be replaced with the same capability which would result in no change in risk profile. However it may not be the optimum solution for the site due to the significant changes in supply and demand patterns over the last 15 years and the way in which shippers use capacity. However, to ensure the same capability, replacement may not be like-for-like (i.e. the same sort of unit) due to technology changes. As shown in the charts below, due to emissions limits for new technology the operating range of a compressor could be significantly reduced. However, this could be addressed by the installation of multiple smaller units to provide the same operating range and capability.



6) Replace with different capability

Under this option, we will determine the capability requirement for each site based on forecast flows, operating strategy and legal obligations and replace non-compliant technology with BAT. This enables us to take account of the current and future needs of the system and provide a solution that should be a better fit to the outputs that stakeholders have said are important to them.

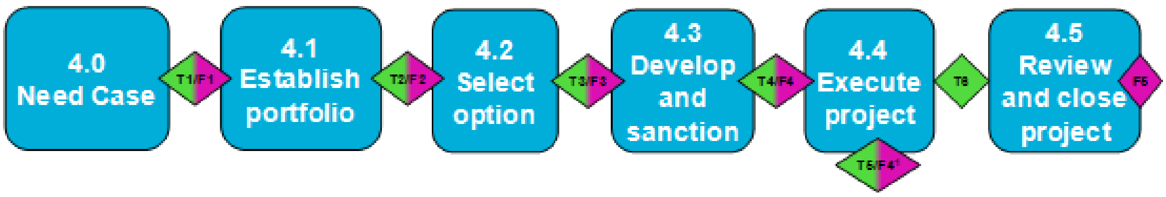
Assessment of options

For each of the sites affected by the LCP element of the IED we have assessed the range of credible options available against what stakeholders told us is important to them through the development of the Gas Transmission Network Strategy scorecard.

The options for IED compliance for our affected compressor units have been assessed through our Network Development Process (NDP). For each affected site the network capability requirements have been assessed and a range of high level options for each site defined.

The purpose of our Network Development framework is to define the process for decision making, optioneering, development, sanction, delivery and closure for all projects. The aim of having an end to end process is to deliver the lowest whole-life cost, fit for purpose projects required to meet stakeholders' needs and our RIIO outputs.

The diagram below shows the end to end NDP stages;



For each site we have assessed a range of options applicable to that site. This has included looking at the options of entering the affected units into the emergency use derogation or decommissioning the units at every site along with any specific options which are applicable.

The assessment criteria are based on what stakeholders identified as being important through the development of the Gas Transmission Network Strategy scorecard. Following stakeholder feedback to our *IED Investments: Initial Consultation*, we clarified the assessment criteria in the *IED Investments: Proposals Consultation* to show exactly what we mean by the red, amber, green methodology. The grid on page 35 shows the scale used for each criterion.

As well as providing an overview of how we have scored each option against the scorecard we have also included a more detailed explanation for each element. Following this, at the end of each site assessment our recommended option is set out with our reasoning.

There is also a further section “Holistic Assessment”, which takes an overall view of all of the proposed options, including those for IPPC Phase IV. Any necessary adjustments are made at this point to ensure that the programme represents best value and is in accordance with our duties as a gas transporter and other statutory obligations relating to safety and environmental matters and our obligations to plan and operate the system in an economic and efficient manner.

> For more information on the overall view of all the proposed options please see the section titled "Holistic assessment".

Assessment criteria

There are a few points to note in relation to the assessment criteria.

One of the criteria identified is whether the option has a negligible impact on customer charges. In assessing the options against this criterion the assessment considers capital costs and any additional asset health costs where the units are not being replaced.

> For more information on how this translates into customer charges please see the section titled "Impact on charges".

Some of the criteria are an aggregation / disaggregation of other criteria, where this is the case for example a "barrier to investment" the worst case of entry and exit obligations has been assumed.

The definition of current capability now references sold and FES levels and assesses each option against the ability to meet these.

The units highlighted in red are the ones at each site which are affected by the IED.

On the tables showing the assessment of each option against the criterion, generally the lowest cost options are on the left and the most expensive on the right.

Criteria	Description				
Does this option allow National Grid to meet future flexibility requirements?	Reduces system flexibility and will impact users' current requirements.	Reduces system flexibility and may impact users' future requirements.	Reduces system flexibility, but this is unlikely to affect users' future requirements.	Provides similar level of system flexibility as the existing situation.	Increases the system flexibility to assist in meeting users' future requirements.
Does this option remove barrier for encouraging new investment?	Will reduce network capability and how the NTS is currently used and will create a barrier to new investment.	Will reduce network capability and may create a barrier to new investment.	Will reduce network capability, but unlikely to be a barrier to new investment.	Maintains network capability - no impact on new investment.	Increases network capability, facilitating new investment.
Does this option have a negligible impact on customer charges?	The cost is in excess of £100m.	The cost is between £50-£100m.	The cost is between £20-£50m.	The cost is between £10-£20m.	The cost is <£10m.
Is this option future proof? (flexibility is covered above so this deals with legislation i.e. BREF and MCP)	When future legislation is implemented will need to revisit.	It is likely that when future legislation is implemented will need to revisit.	May need to be revisited when future legislation is implemented.	Although there is some interaction with future legislation should not require revisiting.	Ability to respond to future legislation
Can National Grid meet Exit Capacity obligations considering this option?	Existing obligations that users currently require will not be able to be met.	Existing obligations that users may require to use in the future will not be met.	Existing obligations that users are unlikely to use in the future will not be met.	The ability to meet existing obligations is maintained.	Increases the ability to meet existing obligations.
Does this option allow National Grid to retain current capability?	Will reduce capability and impact how the NTS is currently used.	Capability reduced to a level insufficient to meet sold capacity and /or FES levels	Capability reduced to potentially be insufficient to meet sold capacity and /or FES levels	Sufficient capability to meet sold capacity and /or FES levels	Increased capability to meet sold capacity and/or FES levels.
Does this option represent an appropriate level of resilience on the network?	Does not provide resilience for the loss of the largest credible unit(s) at the station.	Reduces resilience considering the loss of units at interacting stations, where the affected units are currently next in line.	Reduces resilience for the loss of units at interacting stations, where the affected units are not currently first in line.	Provides similar level of resilience as the existing situation.	Increases the resilience of the network.
Can National Grid meet Entry Capacity obligations considering this option?	Existing obligations that users currently require will not be able to be met.	Existing obligations that users may require to use in the future will not be met.	Existing obligations that users are unlikely to use in the future will not be met.	Ability to meet existing obligations in the future is maintained.	Increases the ability to meet existing obligations in the future.
Does this option allow the network to be operated in sensitivities beyond FES?	FES cannot be met.	Significantly reduces capability to exceed FES.	Reduces capability to exceed FES.	Provides similar capability as the existing situation to exceed FES.	Enhances the ability over the existing situation to exceed FES.

St Fergus

St Fergus comprises of 3 plants, 4 units at plant 1, 3 units at plant 2 and 2 units at plant 3. Plant 1 comprises of;

- 4 * Avon 12.34 MW gas generators coupled with GEC EAS1 power turbines (units 1A, 1B, 1C and 1D)

Plant 2 comprises of;

- 2 * RB211 21.2 MW gas generators coupled with GEC ERB1 power turbine (built in 1980; units 2A and 2D)
- 1* Avon 13.97 MW gas generator coupled with GEC EAS1 power turbine (unit 2B)

Plant 3 comprises of;

- 2 * 24 MW Electric Variable Speed Drives (VSD) (currently undergoing gas commissioning and flow trials; units 3A and 3B)

The recent running hours at St. Fergus are as follows;

	2009	2010	2011	2012	2013	2014
Avon 1533	6397	6346	8816	6987	6902	6647
RB211	7527	8645	2916	4255	5893	2605

At St Fergus the two RB211 gas generators, units 2A and 2D, are affected by the requirements of the IED. However, as part of IPPC Phase 1, two new electric drives, units 3A and 3B are in the process of being commissioned to take up bulk duty and which will largely replace the capability provided by units 2A and 2D. The intention when units 3A and 3B are approved was to retain units 2A and 2D for back-up. Back-up compression at St Fergus is required to cover for a loss of both electric drives due to the risk of a common electricity supply failure.

The four options for units 2A and 2D, which bound the credible range, are as follows:

1) Enter both units into Limited Life Derogation (i.e. 17,500 hours from 1st January 2016) and decommission the units once the electric drive units have been operationally proven and accepted. Note the RB211s will need to cease operation by the end of 2023.

2) Adopt the Emergency Use Derogation on both units (i.e. limit it to 500 hours running from 1st January 2016 in perpetuity).

3) Utilise 17,500 hour derogation until electric drives are operationally proven then decommission both units and install one replacement unit.

4) Utilise 17,500 hour derogation until electric drives are operationally proven then decommission both units and install two replacement units.

The table on the next page summarises the suitability of each solution. The assessment recognises that the electric drives may not be operationally proven by 1st January 2016 and therefore assesses the position both in the short term, when only units 2A and 2D and units 1A, 1B, 1C, 1D and 2B are available, and the medium term, when units 3A and 3B are fully available. It should be noted that options 3 and 4 are in effect the same as option 1 until the new units have been commissioned.

St Fergus	**Option 1:** 17,500 hours derogation on both units until 2023 then decommission	**Option 2:** 500 hours derogation on both units	**Option 3:** 17,500 hours derogation on both units, then decommission both units & install 1 replacement unit	**Option 4:** 17,500 hours derogation on both units then replace both units
Does this option allow National Grid to meet future flexibility requirements?				
Does this option remove barrier for encouraging new investment?				
Does this option have a negligible impact on customer charges?				
Is this option future proof? (flexibility is covered above so this deals with legislation i.e. BREF and MCP)				
Can National Grid meet Exit Capacity obligations considering this option?	n/a	n/a	n/a	n/a
Does this option allow National Grid to retain current capability?				
Does this option represent an appropriate level of resilience on the network?				
Can National Grid meet Entry Capacity obligations considering this option?				
Does this option allow the network to be operated in sensitivities beyond FES?				

Key Considerations

- Flexibility – St Fergus compressor station provides very little flexibility to the operation of the general NTS whilst providing flexibility at the Total sub terminal. Once the electric drives are operational, none of the options above have a material detrimental impact to this ability. Installing one or two replacement units optimised for the new station configuration could potentially increase operational flexibility at the Total sub terminal should this be required.

- Barrier to new investment – the St Fergus compressors support flows at the Total sub terminal. Options 3 and 4 could provide additional capability if configured to operate in parallel with the electric drives and hence encourage new investment at the sub terminal.

- Customer charges – In our RIIO submission we assumed we would replace units 2A and 2D. However under option 2, where we will not replace the units and will need to keep them running longer on 500 hours we will incur additional asset health costs, this is estimated to be in the range of £10-£20m. The cost for decommissioning in option 1 is estimated to be less than £10m. For option 3, the replacement of one unit would result in capital costs between £20-£50m. For option 4 the cost for two new units would be between £50-£100m.

- Future proof – under option 1 the MCP decision on the Avons can be considered as a standalone issue. Option 2 provides the ability to respond to future legislation. Options 3 and 4 although interact with future legislation we would not expect the decision to be revisited. There is also an interaction with the proposals for IPPC Phase IV. We will consider this interaction in the holistic assessment section.

- Exit obligations – the St Fergus compressor units do not support exit obligations and the proposed options do not change this position.

- Current capability – the new electric drive units will largely replace the capability of units 2A and 2D and will not operate in conjunction with them. Therefore options 1, 3 and 4 bridge the gap until the electric drives are operationally proven. Adding replacement units configured to operate in conjunction with existing units could increase current capability.

- Resilience – Option 2 would result in insufficient back-up to the electric drives whilst these are being operationally proven and thus result in reduced station resilience. Options 1, 3 and 4 which utilise the 17,500 derogation will allow enough running hours to ensure the electric units are operationally proven and accepted before decommissioning units 2A and 2D thus maintaining station resilience, with the Avons then providing back up to cover the failure of both electric drives as well as low flow operation. Installing one or two replacement units provides increased station resilience.

- Entry obligations – St Fergus supports entry flows at the Total sub terminal. Options 1 and 2 do not result in a change in peak flow capability. Options 3 and 4 could be configured to operate in conjunction with the electric drive units to increase the ability to meet entry obligations.

- FES – options 1 and 2 provide similar capability as the existing situation to meet FES. With the additional units, options 3 and 4 enhance the ability to exceed FES.

Recommendation

Based on the above assessment, we propose to adopt option 1.

Rationale

The main downside with adopting option 1 is resilience, as we will need to rely more on using the aging Avon units; however we will revisit this as part of the 'Holistic Assessment' section. Options 3 and 4 are also credible, but we believe the additional costs for the increased level of resilience are not justified.

For more information on the proposed investment on the Avon units please see the section titled "Holistic assessment".

Kirriemuir

Kirriemuir consists of 5 compressor units and was constructed in 1977;

- 3 * Avon 1533 12.34 MW machines (installed in 1977; units A, B and C)
- 1 * RB211 25.3 MW machine (installed in 1985; unit D)
- 1 * VSD 35 MW machine (commissioned in March 2015; unit E)

Only one unit is affected at Kirriemuir, unit D. All units can be used in single configuration with the exception of unit C which can be used in parallel with any of the other gas driven units for high flow requirements. Parallel configuration is possible with any combination of units A to D apart from A and B in parallel. A and B can be used in series configuration. Operationally, unit D is currently the lead unit due to its reliability and flexibility. The condition and reliability of A and B units are below our expected standards, due to the age and running history of the units. In addition, at present Unit C is not operational and it is unlikely the unit will be returned to service.

The recent running hours at Kirriemuir compared to the running hours in 2003 are as follows;

	2003		2009	2010	2011	2012	2013	2014
Avon 1533	6175		140	891	499	997	457	169
RB211	6710		2402	3127	795	1756	157	176

The five options, which bound the credible range are as follows:

1) Enter unit D into the Limited Life Derogation (i.e. 17,500 hours from 1st January 2016) and then decommission. Note the unit will need to cease operation by the end of 2023.

2) Enter unit D into the 17,500 hour derogation and then decommission unit D. Derate & rewheel unit E. Note: unit D will need to cease operation by the end of 2023. De-rating and re-wheeling unit E will enable it to cater for lower flows.

3) Adopt the Emergency Use Derogation on unit D (i.e. limit it to 500 hours running from 1st January 2016 in perpetuity) and de-rate and re-wheel unit E so it can cater for lower flows.

4) Enter unit D into the 17,500 hour derogation, install one new unit and de-rate and re-wheel unit E so it can cater for lower flows. Once the new unit is operationally proven decommission unit D.

5) Enter unit D into the 17,500 hour derogation and then decommission it. De-rate and re-wheel unit E. Decommission and replace unit C.

Please note we have changed option 4 from our consultation document in November. The option now also includes de-rating and re-wheeling unit E. The reason for this change is that due to the decline in flows at St Fergus this will enable us to maximise the use of this unit and the Kirriemuir station. We have also included a new option 5 which provides a smooth transition to MCP.

The table on the next page summarises the suitability of each solution.

Kirriemuir	**Option 1:** 17,500 hours derogation then decommission unit D	**Option 2:** 17,500 hours derogation then decommission unit D; de-rate/re-wheel unit E	**Option 3:** Unit D on 500 hours derogation; de-rate / re-wheel unit E	**Option 4:** 17,500 hours derogation on unit D then decommission and install 1 replacement unit; de-rate and re-wheel unit E	**Option 5:** 17,500 hours derogation on unit D then decommission; de-rate and re-wheel unit E; decommission and replace unit C
Does this option allow National Grid to meet future flexibility requirements?					
Does this option remove barrier for encouraging new investment?					
Does this option have a negligible impact on customer charges?					
Is this option future proof? (flexibility is covered above so this deals with legislation i.e. BREF and MCP)					
Can National Grid meet Exit Capacity obligations considering this option?					
Does this option allow National Grid to retain current capability (excluding flexibility)?					
Does this option represent an appropriate level of resilience on the network?					
Can National Grid meet Entry Capacity obligations considering this option?					
Does this option allow the network to be operated in sensitivities beyond FES?					

Key Considerations

- Flexibility – Kirriemuir provides limited system flexibility, for example in moving gas away from the St Fergus terminal in response to within day changes. We would lose this capability if we adopted Option 1**.** Options 2 – 4 more closely align the operating envelope of the electric drive to unit D and therefore provide similar levels of flexibility. As there is limited need for additional flexibility at this point on the system option 4 and 5 are rated similar to options 2 and 3.

- Barrier to new investment – existing peak flow capability has historically been used to predominantly support the St Fergus baseline and DN exit requirements in Scotland. All options provide similar levels of capability on a non-time limited basis, with initially unit D and then the re-wheeled and de-rated electric drive covering this duty.

- Customer charges – Options 1, 2 and 3 should be less than £10m, whereas option 4 and 5 would cost between £50-£100m.

- Future proof - the decision at Kirriemuir is not contingent on decisions at other stations due to the limited interactivity with other stations. However the three existing Avons at the site will need to be addressed as part of MCP. Under options 1, 2 and 4 there would be no requirement to revisit. Options 3 and 5 allow us the ability to respond to MCP and in the case of option 5 this would assist in transitioning to the likely end state for the station which is one large unit and one smaller unit, with appropriate back-up[10]. Our assumption is that the requirements of MCP will result in all the Avons (units A, B and C) being non-compliant and thus needing to be addressed by 2025. Therefore we need to plan an optimum investment strategy to reach the desired position by 2025. We believe it is not worth bringing unit C back into service, particularly as it is not required whilst units A and B are available and the unit would be non-compliant with MCP.

  In the responses to the *IED Investments: Proposals Consultation* stakeholders were not convinced of the need to replace unit C at this stage when we would be revisiting the site as part of MCP. As a result of this, we held internal meetings to clarify this situation. When MCP does come into effect, we envisage placing units A and B on the 500 hour derogation which we expect to be a provision available under MCP. Therefore as we would not be returning to site to undertake investments on units A and B under MCP then replacing unit C at this stage, when we are undertaking other works at site, would optimise the delivery timescales and efficiencies. This would have the effect of reaching the end state for the site by unit E being the large unit, unit C being the smaller unit and units A and B providing back up. Furthermore, due to the timescales involved in complying with MCP, as mentioned in the "The legislation and how it affects us" section, we expect the programme and outage planning to be very challenging and so undertaking work on unit C at this stage would be very beneficial.

- Exit obligations – Kirriemuir supports exit obligations in Scotland, however none of the options should impact this ability as this need is primarily met by the Avons, however there are concerns about the resilience of these units (see above) – which we address within the resilience section. Therefore all options provide similar capability to the existing situation.

  It should be noted that the re-wheel and de-rate of the electric drive would be able to provide resilience to cover some of this duty.

[10] Subject to full network analysis

- Current capability – Options 1, 2, 4 and 5 provide similar levels of capability on a non-time limited basis, with initially unit D and then the re-wheeled and de-rated electric drive covering this duty. Option 3 should still be sufficient to meet sold and/or FES levels.

- Resilience – due to the different operating envelopes of the units in option 1 the resilience at the station is not sufficient to cover one of the Avon units failing. Under option 3 we would solely be relying on two of the Avon units and unit D on 500 hours as unit C is currently not operational and unit E is not operationally proven. Options 2, 4 and 5 would provide similar levels of resilience.

- Entry obligations – Kirriemuir supports the baseline obligation at St Fergus and all options maintain the existing capability to do this.

- FES – all options should provide similar capability as the existing situation to exceed FES.

Recommendation

Based on the above assessment we propose to adopt option 5.

Rationale

It is evident from the assessment above that Options 1 and 3 for differing reasons are not preferred solutions. Option 2 is a significantly lower cost solution than option 4 and if we only look at the IED LCP obligations would be our recommended option. However, due to the condition of the Avons, particularly unit C, we think that it would be more advantageous to install one new unit as well as de-rate and re-wheel unit E.

Moffat

Moffat consists of 2 compressor units and was constructed in 1980;

- 2 * RB211 21.2 MW machines (units A and B)

These units are both affected by the LCP element of IED. The units can only be used in single configuration. The recent running hours at Moffat compressor station are as follows;

	2009	2010	2011	2012	2013	2014
RB211	515	56	138	48	427	36

The four options, which bound the credible range are as follows:

1) Enter both units into Limited Life Derogation (i.e. 17,500 hours from 1st January 2016) then decommission. Note the units will need to cease operation by the end of 2023.

2) Adopt the Emergency Use Derogation on one unit (i.e. limit it to 500 hours running from 1st January 2016 in perpetuity) and adopt the 17,500 hour derogation on the other and then decommission this unit. Note the unit on the 17,500 hour derogation will need to cease operation by the end of 2023.

3) Adopt the 500 hours derogation on both units.

4) Enter units A & B into the 17,500 hours derogation and install two new units. Once the new units are operationally proven decommission units A & B.

The table on the next page summarises the suitability of each solution.

Moffat	**Option 1:** 17,500 hours derogation on both units then decommission	**Option 2:** 500 hours derogation on one unit; 17,500 hours derogation on other unit then decommission	**Option 3:** 500 hours derogation on both units	**Option 4:** 17,500 hours derogation on both units; install 2 new units, decommission both units
Does this option allow National Grid to meet future flexibility requirements?				
Does this option remove barrier for encouraging new investment?				
Does this option have a negligible impact on customer charges?				
Is this option future proof? (flexibility is covered above so this deals with legislation i.e. BREF and MCP)				
Can National Grid meet Exit Capacity obligations considering this option?				
Does this option allow National Grid to retain current capability (excluding flexibility)?				
Does this option represent an appropriate level of resilience on the network?				
Can National Grid meet Entry Capacity obligations considering this option?				
Does this option allow the network to be operated in sensitivities beyond FES?				

Key Considerations

- Flexibility – Moffat provides limited system flexibility, for example in moving line pack out of Scotland. Therefore for options 1, 2 and 3 this capability would be diminished, however there are generally alternatives such as Wooler that could provide similar functionality. Option 4 would allow us to install two small units that could be advantageous in the future for the Irish interconnector.

- Barrier to new investment – existing peak flow capability has historically been used to predominantly support the St Fergus baseline. Option 1, 2 and 3 will reduce the prolonged capability at the St Fergus terminal by approximately 5-10 mcm/d. However, FES indicates 70 mcm/d peak flow below baseline level at this terminal. Option 4 could provide increased exit capability at the Irish interconnector.

- Customer charges – option 1 should be less than £10m, options 2 and 3 due to the asset health requirements are likely to be between £10-20m, whereas option 4 would cost between £50-£100m.

- Future proof – the decision at Moffat is not contingent on decisions at other stations due to the limited interactivity. Therefore the decision taken at Moffat should not need to be revisited. Options 1, 2 and 4 would not need revisiting. Option 3 provides the ability to respond to future legislation.

- Exit obligations – with the currently sized units at Moffat it does not support exit obligations. Options 1, 2 and 3 therefore provide similar levels of capability, whilst option 4 would enable us to install smaller units that could provide exit support to the Irish interconnector in the case of the Irish compression units being unavailable.

- Current capability - options 1, 2 and 3 are sufficient to meet sold and/or FES levels. Option 4 has the potential to improve the situation due to the more appropriately sized units.

- Resilience – Moffat is a first line back up unit and would be used to cover a station failure at Avonbridge under very high northern gas flows. Option 1 reduces the current level of resilience. Option 2, 3 and 4 provide similar levels of resilience, although this is with limited running hours for options 2 and 3.

- Entry obligations – Moffat supports the baseline obligation at St Fergus, options 1, 2 and 3 will reduce the prolonged capability at this terminal by approximately 5-10 mcm/d. However, FES indicates 70 mcm/d peak flow below baseline levels at this terminal. Option 4 could increase the ability to meet existing capability.

- FES – options 1, 2 and 3 provide similar capability as the existing situation to exceed FES. Option 4 would provide additional capability.

Recommendation

Based on the above assessment we propose to adopt option 3 and retain both units on 500 hours and review the decision at the May 2018 reopener.

Rationale

The main advantage of retaining capability at Moffat is network resilience and secondly to support very high St Fergus flows beyond FES sensitivities. However, at Moffat the asset health costs are not inconsiderable, therefore the decision to retain both units on 500 hours for resilience purposes needs to be balanced against this cost. In addition, retaining the units on 500 hours reduces our capability on a prolonged basis to meet the St Fergus baselines by approximately 5-10 mcm/d. Therefore if we maintain these units on 500 hours then as part of RIIO-T2 development we will seek to reduce the baseline at St Fergus or alternatively include the increased network risk in any subsequent constraint management scheme. We will discuss this further within the holistic assessment section.

For more information on the St Fergus baselines please see the section titled “Holistic assessment”

Carnforth (and Nether Kellet)

Carnforth consists of 3 compressor units and was constructed in 1989;

- 2 * RB211 25.3 MW machines (installed in 1989; units A and B)
- 1 * LM2500 DLE 27.6 MW (installed in 2000; unit C)

Nether Kellet compressor station (adjacent to Carnforth) consists of 2 compliant compressor units and was constructed in 2003

- 2 * SGT400 12.9 MW

The units at Carnforth compressor station can be used in single configuration and any combination in parallel configuration. However, Unit A is not currently operational and remedial works would be required to bring it back into service. The units at Nether Kellet compressor station can be used in single or parallel configuration, however limited operational experience exists of parallel running. The recent running hours at Carnforth and Nether Kellet compressor stations are as follows:

		2009	2010	2011	2012	2013	2014
Carnforth	**RB211**	1259	480	76	50	68	15
	LM2500	1464	431	35	14	28	1130
Nether Kellet	**SGT400**	542	2542	2795	3535	4219	8

The five options, which bound the credible range, are as follows:

1) Enter both units into Limited Life Derogation (i.e. 17,500 hours from 1st January 2016) and decommission. Note the units will need to cease operation by the end of 2023.

2) Enter both units into 17,500 hours derogation. Reconfigure the site to allow Carnforth and Nether Kellet to be operated as one station and therefore maximise resilience and provide for more flexible operation. The works would involve uprating the pressure operation at Nether Kellet, additional regulators and providing reverse flow capability. Note the units will need to cease operation by the end of 2023.

3) Adopt the Emergency Use Derogation on both units (i.e. limit it to 500 hours running from 1st January 2016 in perpetuity). Undertake site reconfiguration as per option 2.

4) Utilise 17,500 hours derogation and decommission unit A, 500 hours derogation on unit B and undertake site reconfiguration

5) Utilise 17,500 hours derogation and decommission both units, install one new unit and undertake site reconfiguration as per option 2.

The table below summarises the suitability of each solution. Where the option is to decommission unit A, we would undertake these works as soon as possible rather than bring it back into service in order to avoid additional asset health costs.

Carnforth	**Option 1:** Decommission units A & B	**Option 2:** Decommission units A & B; site reconfiguration	**Option 3:** Units A & B on 500 hours derogation; site reconfiguration	**Option 4:** 17,500 hours derogation on unit A then decommission; 500 hours on unit B; site reconfiguration	**Option 5:** 17,500 hours derogation on both units then decommission; one replacement unit; site reconfiguration
Does this option allow National Grid to meet future flexibility requirements?					
Does this option remove barrier for encouraging new investment?					
Does this option have a negligible impact on customer charges?					
Is this option future proof? (flexibility is covered above so this deals with legislation i.e. BREF and MCP)					
Can National Grid meet Exit Capacity obligations considering this option?					
Does this option allow National Grid to retain current capability (excluding flexibility)?					
Does this option represent an appropriate level of resilience on the network?					
Can National Grid meet Entry Capacity obligations considering this option?					
Does this option allow the network to be operated in sensitivities beyond FES?					

Key Considerations

- Flexibility – Carnforth and Nether Kellet provide flexibility in predominantly managing North West storage exit flows, within day supply variations at the Easington entry terminal and within day distribution network requirements. Option 1 will result in a reduced operating envelope for the Carnforth station, but we do not anticipate this will affect users' future flexibility requirements. Options 2-5, will allow Carnforth and Nether Kellet to operate as one station and push gas northwards, which should be beneficial in meeting users' future flexibility requirements, for example in responding to reducing flows at Northern terminals.

- Barrier to new investment – existing peak flow capability of the site is predominantly utilised when St Fergus and Barrow are flowing at baseline. However, this requirement can be met by unit C, following the reduction in the Barrow baseline in 2007. Therefore this capability is not impacted by the various options.

- Customer charges – the decommissioning cost for option 1 would be less than £10m. For option 2 we would anticipate being able to undertake the decommissioning and site reconfiguration also for under £10m. Option 3 would require increased asset health spend and for unit A in particular this is anticipated to exceed £10m when combined with the flexibility enhancements. Under option 4 asset health spend on unit B would be required along with decommissioning unit A and undertaking site reconfiguration at a cost in the range of £10-20m. Option 5 would cost between £20-50m.

- Future proof – assuming that BREF does not tighten the emission limits to a point where unit C and the units at Nether Kellet cannot comply then there will be no site impact from future legislation. Options 1, 2 and 5 would not need revisiting. Options 3 and 4 provide the ability to respond to future legislation. Therefore the IED LCP decision, only needs to consider potential interactions with neighbouring stations, principally Alrewas and Peterborough. We will consider the Peterborough interaction in the holistic assessment section. In terms of the impact of future legislation at Alrewas we do not believe this has any impact on the decision to be taken at Carnforth, due to the different functions performed by both stations.

- Exit obligations – Carnforth predominantly supports North West storage exit flows and North West / West Midland Distribution Networks. Option 1 results in similar capability levels, Options 2-5, due to the reverse flow, provide additional capability under low Northern terminal flows to meet northern exit obligations.

- Current capability – Options 1-4 provide sufficient capability to meet sold and/or FES levels. Option 5 has the potential to improve the situation.

- Resilience – Option 1 would not provide sufficient resilience at the Carnforth station, as we would not have resilience at the site to cover the loss of Unit C. By reconfiguring the site and making Carnforth and Nether Kellet one station, options 2-5 provide similar levels of resilience to the current situation.

- Entry obligations – existing peak flow capability of the site is predominantly utilised when St Fergus and Barrow are flowing at baseline. However, as described above this requirement can be met by Unit C. Option 5 would largely replicate the existing capability.

- FES – All options provide similar capability as the existing situation to exceed FES.

Recommendation

Based on the above assessment we propose to adopt option 4 of retaining unit B on 500 hours, decommissioning unit A and undertaking the site reconfiguration. Our intention would be then to revisit the position on Unit B during the 2018 reopener window or RIIO-T2 negotiations, at which point we would consider retaining the unit on 500 hours, decommissioning or replacing with a new unit.

Rationale

Options 2-5 are generally preferred as a result of the benefits provided by the site reconfiguration. Due to the current condition of unit A, Option 3 of retaining both units on 500 hours is not favoured, but there is merit in retaining unit B on 500 hours. We would not envisage needing to run the unit for more than 500 hours, but it would provide resilience while the other works at the station are being undertaken.

Hatton

Hatton consists of 4 compressor units and was constructed in 1989;

- 3 * RB211 25.3 MW machines (installed in 1989, units A, B and C)
- 1 * VSD 35 MW machine (yet to be fully commissioned, unit D)

Three compressor units (units A, B and C) are affected by the requirements of the LCP element of IED at Hatton. All units can be used in single configuration and any combination of parallel operation is possible including with the new electric drive unit.

Unit D has been designed to take up bulk duty requirements and was sanctioned due to IPPC emissions requirements. Once unit D is commissioned and operationally proven, units A, B and C were intended to be used as back-up and also to provide additional capability to compress high flows above the capability that unit D currently provides. The recent running hours at Hatton are as follows;

	2009	2010	2011	2012	2013	2014
RB211	5371	5207	1169	1705	2936	2184

The four options, which bound the credible range, are as follows:

1) Enter all 3 units into Limited Life Derogation (i.e. 17,500 hours from 1st January 2016) and decommission. Note the units will need to cease operation by the end of 2023.

2) Adopt the Emergency Use Derogation on the 3 units (i.e. limit it to 500 hours running from 1st January 2016 in perpetuity).

3) Utilise 17,500 hour derogation until electric drive is operationally proven then install 2 new large units and decommission the 3 existing units.

4) Utilise 17,500 hour derogation until electric drive is operationally proven then install 3 new medium units and decommission the 3 existing units.

The table on the next page summarises the suitability of each solution.

In terms of the electric drive, this is intended to cover bulk duty and largely replaces the operation of one of the RB211s and can also cover the part of the operating envelope which was previously managed by running 2 RB211s at part load. The assessment recognises that the electric drive may not be operationally proven by 1st January 2016 and therefore assesses the position both in the short term, when only the RB211s are available, and the medium term when the electric drive is fully available.

Hatton	**Option 1:** 17,500 hours derogation and then decommission all 3 units	**Option 2:** 500 hours derogation on all 3 units	**Option 3:** 17,500 hours derogation until electric drive proven; install 2 large new units then decommission existing 3 units	**Option 4:** 17,500 hours derogation until electric drive proven; install 3 medium new units then decommission existing 3 units
Does this option allow National Grid to meet future flexibility requirements?				
Does this option remove barrier for encouraging new investment?				
Does this option have a negligible impact on customer charges?				
Is this option future proof? (flexibility is covered above so this deals with legislation i.e. BREF and MCP)				
Can National Grid meet Exit Capacity obligations considering this option?				
Does this option allow National Grid to retain current capability (excluding flexibility)?				
Does this option represent an appropriate level of resilience on the network?				
Can National Grid meet Entry Capacity obligations considering this option?				
Does this option allow the network to be operated in sensitivities beyond FES?				

Key Considerations

- Flexibility – Hatton provides flexibility in managing East coast supplies, large directly connected loads and storage facilities. It is one of the most critical stations on the system and has the potential to be configured to support a number of flow patterns. Options 1 and 2 would severely reduce the flexibility that the site could offer impacting users current requirements. Option 3 combining 2 new units with the electric drive would provide similar levels of flexibility as the existing situation. However, at Hatton there is the opportunity to provide additional flexibility by installing three medium size units and configuring these to operate in conjunction with the electric drive.

- Barrier to new investment – Options 1 and 2 would mean that we would be unable to meet certain baseline obligations, most notably Easington.

Therefore these options would discourage new investment. Options 3 and 4 largely replicate the existing peak flow capability at the site and therefore have no real impact on new investment - as it would be intended that the three medium sized units would be of a similar aggregate power to two RB211s.

- Customer charges – Option 1 decommissioning would cost £0-£10m. For option 2 we would need to increase asset health spend, as part of the RIIO-T1 submission we had assumed we would replace three units at a cost of £10-£20m. Options 3 and 4 would cost in excess of £100m. On the basis of our allowances under the agreed unit cost model, two 30 MW units would cost approximately £10m (2009/10 prices) more than three medium sized 15 MW units.

- Future proof – from a site perspective there are no other units that would be subject to future legislation. Therefore the IED LCP decision, only needs to consider potential interactions with neighbouring stations, principally Peterborough and Huntingdon. We will consider this interaction in the holistic assessment section. At this stage it is considered that options 1, 3 and 4 would not need revisiting. Option 2 provides the ability to respond to future legislation.

- Exit obligations – as well as supporting large directly connected loads and storage sites in the immediate vicinity, Hatton is also critical to exit loads across the south of the country and international exports. Option 1 would reduce our ability to meet these obligations which are currently used. Option 2 would potentially enable existing exit requirements to be met, but may not satisfy future needs within current obligations. Options 3 and 4 would provide similar capability to the existing situation.

- Current capability – Options 1 and 2 will reduce current capability and how the NTS is used, please refer to the entry and exit descriptions for specific details. Options 3 and 4 provide similar capability to the existing situation.

- Resilience - Options 1 and 2 do not provide sufficient resilience to be able to cover the loss of the electric drive for any reasonable period of time. Options 3 and 4 provide similar levels of resilience to the existing station configuration.

- Entry obligations – Hatton is pivotal in the transmission of high east flows to the wider network, therefore the main relevant entry points are Teesside, Easington, and Theddlethorpe. In addition Hatton also supports entry flows from North West storage entry points. Options 1 and 2 would not allow us to meet existing user requirements. Options 3 and 4 provide similar capability to the existing situation.

- FES – Option 1 is unlikely to enable us to meet the FES forecast flows at the Easington entry point. Option 2 would only enable us to meet the FES forecast flows for a limited duration and significantly reduces our ability to exceed FES. Options 3 and 4 provide similar capability to the existing situation.

Recommendation

Based on the above assessment, we propose to adopt option 4.

Rationale

Flexibility is a key concern for both stakeholders and us. This option enables us to better address current and future flexibility needs at a similar cost to option 3.

Warrington

Warrington consists of 2 compressor units and was constructed in 1983;

- 2 * RB211 22.3 MW machines (units A & B)

The units can only be used in single configuration. The recent running hours at Warrington are as follows;

	2009	2010	2011	2012	2013	2014
RB211	91	25	51	16	13	50

The four options, which bound the credible range are as follows:

1) Enter both units into Limited Life Derogation (i.e. 17,500 hours from 1st January 2016) and then decommission. Note the units will need to cease operation by the end of 2023.

2) Adopt the Emergency Use Derogation on one unit (i.e. limit it to 500 hours running from 1st January 2016 in perpetuity) and adopt the 17,500 hour derogation on the other and then decommission this unit. Note the unit on the 17,500 hour derogation will need to cease operation by the end of 2023.

3) Adopt the Emergency Use Derogation and limit both units to 500 hours running from 1st January 2016 in perpetuity.

4) Enter units A & B into the 17,500 hour derogation, install two new units and configure the site for reverse flow capability. Once the new units are operationally proven decommission units A & B.

Please note we have changed option 4 from our consultation document in November. The option now also includes configuring the site to enable the station to push gas northwards. The reason for this change, is due to the fact that if we installed new units we would want to maximise their usage and benefit to the network, configuring the site for reverse flow capability would enable this.

The table below summarises the suitability of each solution.

Warrington	**Option 1:** 17,500 hours derogation on both units then decommission	**Option 2:** 500 hours derogation on one unit; 17,500 hours derogation on other units then decommission	**Option 3:** 500 hours derogation on both units	**Option 4:** 17,500 hours derogation on both RB211s; install 2 New units + reverse flow; decommission both RB211s
Does this option allow National Grid to meet future flexibility requirements?				
Does this option remove barrier for encouraging new investment?				
Does this option have a negligible impact on customer charges?				
Is this option future proof? (flexibility is covered above so this deals with legislation i.e. BREF and MCP)				
Can National Grid meet Exit Capacity obligations considering this option?				
Does this option allow National Grid to retain current capability (excluding flexibility)?				
Does this option represent an appropriate level of resilience on the network?				
Can National Grid meet Entry Capacity obligations considering this option?				
Does this option allow the network to be operated in sensitivities beyond FES?				

Key Considerations

- Flexibility – Warrington has the potential under certain supply and demand scenarios to provide flexibility for maintenance operations e.g. in-line inspection of pipelines and could be beneficial to a limited extent to support future North West storage within day exit requirements. Option 1, 2 and 3 largely provide similar system capability due to the limited amount of flexibility provided by Warrington in the first place. Option 4 would allow us to install two small units that could be advantageous in the future when coupled with the reverse flow capability.

- Barrier to new investment – existing peak flow capability has historically been used to predominantly support St Fergus and Barrow baselines. Option 1, 2 and 3 will reduce the ability at these Northern terminals by approximately 0-5 mcm/d.

However, FES indicates 70 mcm/d aggregate flows below baseline levels at these terminals. This capability is based on Moffat being available, the interaction with Moffat will be considered in the holistic assessment. Option 4 due to the reverse flow capability would enable increased entry capability at North West storage sites.

- Customer charges – Options 1, 2 and 3 should cost less than £10m, whereas option 4 would cost between £50-£100m.

- Future proof - the decision at Warrington interacts with decisions at Carnforth and Alrewas. However these interactions are not sufficient to require the decision at Warrington to be contingent on their outcomes. Therefore options 1 and 4 would not need revisiting. Options 2 and 3 provide the ability to respond to future legislation if required.

- Exit obligations – under unfavourable, for example very high St Fergus and Barrow flows, Warrington could be required to support exit obligations in the North West. However, these scenarios are well outside our planning sensitivities. Therefore options 1-3 provide similar exit capability to the existing situation. Option 4 has the potential to improve the situation due the reverse flow capability and more appropriately sized units.

- Current capability - Options 1-3 provide sufficient capability to meet sold and/or FES levels. Option 4 has the potential to improve the situation

- Resilience – Warrington is not required as back-up for any other sites and could only provide back-up under very high northern entry flows beyond the current FES. Therefore options 1, 2 and 3 provide similar levels of resilience to the existing situation. Option 4, however would provide additional resilience in moving gas northwards, from Milford Haven in the case of a station failure at Alrewas.

- Entry obligations – Warrington supports combined baseline obligations at St Fergus and Barrow. Option 1, 2 and 3 will reduce the ability at these Northern terminals by approximately 10-15 mcm/d. However, FES indicates 70 mcm/d aggregate flows below baseline levels at these terminals. Option 4 due to the reverse flow capability would enable increased entry capability at North West storage sites.

- FES – Options 1, 2 and 3 provide similar capability as the existing situation to exceed FES. Option 4 would provide additional capability.

Recommendation

Based on the above assessment, we propose to adopt option 3 where both units are retained on 500 hours and this decision is reviewed at the May 2018 reopener.

Rationale

The main advantage of retaining capability at Warrington is to support very high northern gas flows, beyond FES sensitivities, and to a lesser extent to facilitate maintenance.

Adopting option 3 and reviewing that decision at the May 2018 reopener reduces our capability on a prolonged basis to meet the combined St Fergus and Barrow baselines by approximately 10-15 mcm/d. Therefore, if we maintain this option into the future, as part of RIIO-T2 development, we will seek to reduce the baseline at St Fergus and/or Barrow or alternatively include the increased network risk in any subsequent constraint management scheme. We will discuss this further within the holistic assessment.

Wisbech

Wisbech consists of two compressor units and was constructed in 1980;

- 1 * RB211 21 MW machine (unit A)
- 1 * Avon 1534 13.97 MW machine (unit B)

Both machines are affected by the LCP element of IED. The units can only be used in single configuration with the Avon being the lead unit and the RB211 used as back up. The recent running hours at Wisbech are as follows;

	2009	2010	2011	2012	2013	2014
Avon 1534	2	18	10	218	200	41
RB211	3	6	6	19	104	20

It should be noted that in recent times Wisbech has been predominantly used as back up units to Peterborough and Huntingdon, therefore the developed options are influenced by the planned works at both of these stations. The five options, which bound the credible range, are as follows:

1) Enter both units into Limited Life Derogation (i.e. 17,500 hours from 1st January 2016) and decommission the units once the works at Peterborough and Huntingdon are completed. Note the units will need to cease operation by the end of 2023.

2) Adopt the Emergency Use Derogation on both units (i.e. limit it to 500 hours running from 1st January 2016 in perpetuity).

3) Adopt the Emergency Use Derogation on unit A, change unit B from a maxi Avon to an Avon.

4) Enter unit A into the 17,500 hours derogation then decommission once the works at Peterborough and Huntingdon are completed. Replace the maxi Avon with an Avon, providing unlimited running hours, although this would be captured by IPPC and MCP (when introduced).

5) Enter both units into the 17,500 hours derogation until the works at Peterborough and Huntingdon are completed then decommission both units and install two new units.

The table on the next page summarises the suitability of each solution. The assessment recognises that the works at Peterborough and Huntingdon will not be completed until the latter part of the RIIO-T1 period.

Wisbech	**Option 1:** 17,500 hours derogation on both units then decommission	**Option 2:** 500 hours on both units	**Option 3:** 500 hour derogation on unit A; replace maxi Avon with Avon	**Option 4:** 17,500 hours derogation on unit A then decommission; replace maxi Avon with Avon	**Option 5:** 17,500 hours derogation on both units then decommission; install 2 new units
Does this option allow National Grid to meet future flexibility requirements?					
Does this option remove barrier for encouraging new investment?					
Does this option have a negligible impact on customer charges?					
Is this option future proof? (flexibility is covered above so this deals with legislation i.e. BREF and MCP)					
Can National Grid meet Exit Capacity obligations considering this option?					
Does this option allow National Grid to retain current capability (excluding flexibility)?					
Does this option represent an appropriate level of resilience on the network?					
Can National Grid meet Entry Capacity obligations considering this option?					
Does this option allow the network to be operated in sensitivities beyond FES?					

Key Considerations

- Flexibility – previously Wisbech provided flexibility to manage within day flow variation at Theddlethorpe, Easington and Bacton. However more recently this flexibility has been provided by Peterborough and the requirement has also been reduced due to the construction of the Transpennine pipeline and the reduction in St. Fergus flows. Option 1 reduces system flexibility, but so long as Peterborough is available, this should not impact users' future requirement. Options 2-4 largely retain the current capability and Option 5 provides an opportunity to increase flexibility in this area.

- Barrier to new investment – existing peak flow capability has historically been used to support Easington and Theddlethorpe entry terminals. However, due to more recent investments on the NTS, such as the Transpennine pipeline, this capability is no longer required. In addition Wisbech provides support to South East exit baselines. Option 1 and 2 reduce entry and exit capability, but should not act as a barrier to future investment. Options 3 and 4 predominantly maintain peak flow capability and Option 5 could enhance peak flow capability, which would support new exit signals in the South East.

- Customer charges - Options 1 - 4 are anticipated to cost less than £10m. Generally the condition of the station is good with limited major works planned. The cost for option 5 would be between £50 and £100m.

- Future proof – the Wisbech options interact with the decisions at Peterborough, Huntingdon and Hatton. We will consider this interaction within the holistic assessment section, as all three stations are addressed within this consultation. Options 1 and 4 would not need revisiting. Options 2 and 3 would provide the ability to adapt to future legislation if required. At this point, we recognise that option 5 would need to be revisited if we do not land full station decisions at Peterborough and Huntingdon as part of this re-opener.

- Exit obligations – Wisbech can support southern exit obligations, however Peterborough and Huntingdon are currently the preferred units to provide this support. On a peak day, if all southern exit points approached baseline obligations and there was an unfavourable supply pattern we would run Wisbech. However this is outside the credible sensitivities applied to FES. Option 1 reduces ability to meet exit obligations. Option 5 increases the ability to meet existing obligations and options 2 - 4 maintain similar capability.

- Current capability – Options 1- 4 provide sufficient capability to meet sold and/or FES levels. Option 5 has the potential to improve the situation.

- Resilience – Wisbech is first line back up to Peterborough and also provides resilience for Huntingdon. Option 1 would reduce resilience, whereas the other 4 options maintain similar levels in the long term; however, in the interim period until Peterborough is operationally proven, option 2 would reduce resilience. At Peterborough there is existing on-site back up, however a full station outage may require Wisbech to be used. As we will need to take full station outages, whilst the new unit(s) is installed at Peterborough, at least one unit at Wisbech is required on unlimited running hours until all the main works at Peterborough, and ideally Huntingdon, are completed.

- Entry obligations – As discussed previously Wisbech facilitated entry flows predominantly at Easington and Theddlethorpe, however this duty is now covered by other stations and investments. Options 1 and 2 reduce our ability to meet existing obligations, although we would expect these not to be utilised. Options 3 and 4 provide a similar level of entry capability and option 5 has the potential to enhance this.

- FES – option 1 reduces our capability to exceed FES. Options 2 - 4 provide a similar level of capability and option 5 has the potential to exceed our current capability.

Recommendation

Based on the above assessment, we recommend option 3 of retaining the RB211 unit on the 500 hours derogation and converting the maxi Avon to an Avon. We would then propose to revisit the decision on the Avon and the RB211 when we have clarity on the implications of MCP.

Rationale

We do not recommend Option 1 as this does not provide suitable resilience post 2023. The benefits provided by Option 5 we believe are outweighed by the costs. We see merit in Option 2 in the longer term and Option 4 in the shorter term whilst the works at Peterborough and Huntingdon are on-going hence option 3 represents a good compromise.

IED – IPPC Phase 4

As discussed within “The RIIO Deal” section, the May 2015 reopener covers both the LCP aspects of IED and the next phase of IPPC, termed IPPC Phase 4.

As part of our RIIO submission we proposed undertaking works to reduce emissions at the three most polluting sites. We have therefore undertaken analysis to identify these, taking into account historic running hours, the investments currently in progress and future supply and demand patterns.

Historic running hours

The table on the next page shows the running hours at each site, with relevant breakdowns by unit. Units highlighted in red are potential candidate units for replacement under IPPC Phase 4, due to their size and emissions performance.

Compressor station	Units	Running Hours					
		2010	2011	2012	2013	2014	5 year average
Alrewas	A and B (Avon 1533s)	1061	305	258	146	66	367
	C (Solar Titan DLE)	1091	1209	28	120	50	500
Cambridge	A and B (Avon 1533s)	117	18	40	42	49	53
	C (Cyclone DLE)	4	21	44	26	27	24
Chelmsford	A and B (Avon 1533s)	28	15	27	553	10	127
Diss	A, B and C (Avon 1533s)	432	15	19	918	45	285
Kings Lynn	A and B (Avon 1533s)	14	8	21	66	7	23
	C and D (Siemens SGT400)	1392	505	69	1723	42	746
Kirriemuir	A, B and C (Avon 1533s)	891	499	997	457	169	603
	D (RB211)	3127	795	1756	157	176	1202
	E (Electric VSD)	N/A	N/A	N/A	N/A	N/A	N/A
St. Fergus	5 Avon 1533 Units	6346	8816	6987	6902	6647	7140
	2 RB211 Units	8645	2916	4255	5893	2605	4863
	Electric VSD Unit	N/A	N/A	N/A	N/A	N/A	N/A
Wormington	A and B (Avon 1533s)	3746	5053	541	81	62	1897
	C (Electric VSD)	1098	2021	961	926	1455	1292
***Peterborough**	A, B and C (Avon 1533s)	8268	4958	6621	7448	5785	6616
***Huntingdon**	A, B and C (Avon 1533s)	6201	1444	842	4586	2503	3115

* One new unit to be installed as part of IPPC Phase 3

Based purely on a five year historical average, the most likely candidate sites are:

St Fergus – 7140 hours
Peterborough – 6616 hours
Huntingdon – 3115 hours
Wormington - 1897 hours

Adjusting for recent and planned investments

At all of the above four sites there have been or will be investments that impact these future running hours, a review of these is provided below:

St Fergus – two new electric drives are in the process of being commissioned, these will largely take up the bulk duty previously undertaken by the two RB211s. However, we do not anticipate these significantly reducing the usage requirement of the Avons, which are required for single duty operation and start-up.

Peterborough – one new unit will be installed to cover bulk duty which was funded under IPPC Phase 3, however there is still a requirement for a small single unit to cover the lower part of the operating envelope. Based on a historical view of single unit operation this has been estimated at approximately 2000 hours per annum.

Huntingdon – one new unit will be installed to cover bulk duty which was funded under IPPC Phase 3, however there is still a requirement for a small single unit to cover the lower part of the operating envelope. Based on a historical view of single unit operation this has been estimated at approximately 800 hours per annum.

Wormington - the commissioning of the Felindre gas compressors and increased confidence in the electric drive unit at Wormington are likely to significantly reduce operating hours of the two Avon units. It can be seen that over the last 5 years there has been growing reliance on the electric drive, with run hours at Wormington A and B reducing to only 62 hours in 2014.

Future supply and demand patterns

We then considered whether changes in supply and demand patterns would have a significant impact on the candidate compressors. The best way to consider this is to consider the driver for the usage of each site:

St Fergus – required to support entry flows at St Fergus, although St Fergus flows are forecast to decrease, significant volumes are still anticipated at the Total sub-terminal for the foreseeable future. Therefore a high level of run hours on the Avons is likely into the future.

Peterborough – mainly used to support demand, therefore continued regular use anticipated into the future. In addition, Peterborough is used to provide flexibility, therefore if this requirement increases, additional running hours may be experienced.

Huntingdon – mainly used to support southerly demand, therefore continued regular use anticipated into the future.

Wormington – supply driven site, running hours highly dependent on Milford Haven flows, as can be seen from historic running hours. Therefore running hours are likely to remain variable.

Summary

Based on the analysis described above the three sites at which investment is most likely to provide the greatest emission reduction are St Fergus, Peterborough and Huntingdon.

In considering Peterborough and Huntingdon and looking at the end state for the site following the introduction of MCP, the ideal solution is to have three equally sized units – as identified through the BAT assessment. If we only replace one unit, in addition to the unit funded under IPPC Phase 3, back up will need to be provided by the three remaining Avons which will only be permitted for low utilisation. In addition, the Avons will need to be replaced once MCP is introduced. To obtain a further series of outages at these critical sites following completion of the works at Hatton will be very challenging. Therefore we propose to install two new units at each site in addition to the single units funded through IPPC Phase 3.

This would mean that all units at these critical sites would be compliant with IED and therefore we would not need to undertake further works to respond to the requirements of BREF and MCP. In addition constructing two units at the same time, rather than in a piecemeal fashion is more efficient and will deliver savings to the benefit of all stakeholders. For efficiency and environmental reasons we similarly propose installing two new units at St Fergus.

Holistic assessment

We have looked at all the individual decisions taken and adjusted the plan where necessary to ensure that we optimise decisions across the network.

The table below summarises for each station the recommended option.

Station	Recommended option	Recommended option - anticipated allowance (outturn prices)
St Fergus (LCP)	17,500 hour derogation on units 2A and 2D and then decommission by 31st December 2023	<£10m
Kirriemuir	Unit D - 17,500 hour derogation and then decommission Unit E – De-rate and re-wheel (electric unit) Unit C – Decommission and install one new unit (MCP unit)	£50-100m
Moffat	500 hour derogation both units	£10-20m
Carnforth	Unit A - 17,500 hour derogation and then decommission Unit B – 500 hour derogation Site reconfiguration	£10-20m
Hatton	17,500 hour derogation on 3 affected units and then decommission by 31st December 2023. Install three medium sized units	£100m+
Warrington	500 hour derogation both units	<£10m
Wisbech	Unit A - 500 hour derogation Unit B – Maxi Avon conversion to Avon	<£10m
St Fergus (IPPC)	Two replacement units and decommission two units	£50-100m
Peterborough (IPPC)	Two replacement units and decommission three units	£50-100m
Huntingdon (IPPC)	Two replacement units and decommission three units	£50-100m

Overall across all of the stations, our greatest concern in terms of the LCP recommendations is related to decommissioning the two units at St Fergus, however if we replace two of the old Avon units under IPPC before the RB211s are decommissioned we consider that the resilience of the station will be appropriately maintained. We have also been concerned about decommissioning a number of units and stations along the West Coast i.e. Warrington, Moffat and Carnforth. Therefore utilising the 500 hour derogation at this point appears the correct decision at this point in time.

If we follow the recommended course of action, there should be relatively limited need to undertake significant commercial changes. The only commercial changes that need to be considered are managing the increased risk of the St Fergus and Barrow baselines as a result of the restricted running hours and hence reduced capability at Moffat and Warrington.

This likely reduction in capability would be approximately 10-15mcm/d. This risk could be managed as part of the RIIO-T2 negotiations by reducing the aggregate baselines by a corresponding amount or adjusting any subsequent constraint scheme target to factor in this risk.

Programme and outages

In order to carry out the investment programme in the required timescales we have developed a programme of works and outage plan.

At some of the affected sites our recommended option for compliance with the IED will require investment on the NTS. In order for us to make this investment it is imperative that we have a clear programme of works and outage plan.

On the following page there is an overview of the outage programme for the works required on the affected units.

Where the recommended option is to replace a unit, that unit would firstly be placed under the Limited Lifetime Derogation from the 1st January 2016. As mentioned in “The legislation and how it affects us” section, under the Limited Lifetime Derogation, units may only operate for 17,500 hours between 1st January 2016 and 31st December 2023. Therefore, this means that all replacement work should ideally be completed before 31st December 2023.

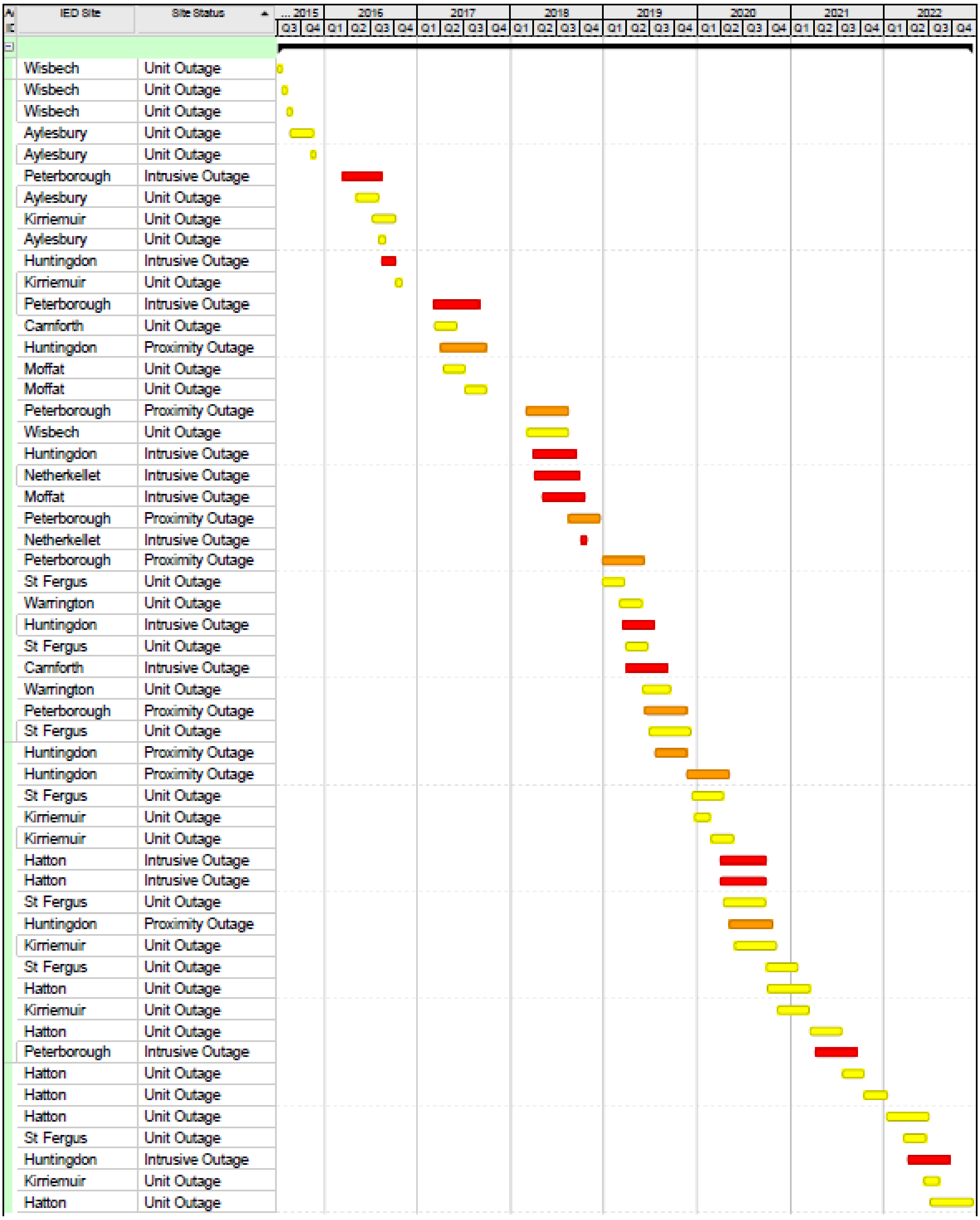
At some of the affected sites the recommended option is to decommission the unit. It is the most economic and efficient option to decommission these units as soon as they are no longer required and hence this work is included in the programme of work and outage plan to take place at this point.

For the proposed investment programme it is important to sequence work where stations interact. For example we would not want to take Peterborough, Huntingdon and Hatton on concurrent major station outages.

The programme is very challenging and the time constraints are exacerbated by the fact that we can only do work which requires a station outage during the summer period, when gas demand is low, which is generally for just 7 months in the year. This can be seen on the timeline.

As mentioned in the ‘Legislation and how it affects us’ section, at this stage we expect the MCP to affect 26 of our compressor units. We anticipate that the timescales around the implementation of the MCP directive would mean that we have to complete the works on these affected units by 2025. Therefore, given the extent of the anticipated work involved with the introduction of the MCP we are unlikely to be able to carry over IED related work.

Current best view of outage programme



This plan includes the Peterborough, Huntington and Aylesbury work funded for under baseline allowances in RIIO-T1 as the works required at these sites will have an impact on the rest of the programme.

Financial summary

The table below summarises for each station the anticipated allowance of the recommended option. For the purposes of confidentiality we have retained the ranges used within the option assessment, however the total figure uses actual cost information. The costs are based on Ofgem's unit costs for new compressor units, which were set as part of the RIIO-T1 settlement and budget prices for other capital works developed by an engineering consultancy.

Station	Recommended option - anticipated allowance (outturn prices)
St Fergus (LCP)	<£10m
Kirriemuir	£50-100m
Moffat	£10-20m
Carnforth	£10-20m
Hatton	£100m+
Warrington	<£10m
Wisbech	<£10m
St Fergus (IPPC)	£50-100m
Peterborough (IPPC)	£50-100m
Huntingdon (IPPC)	£50-100m

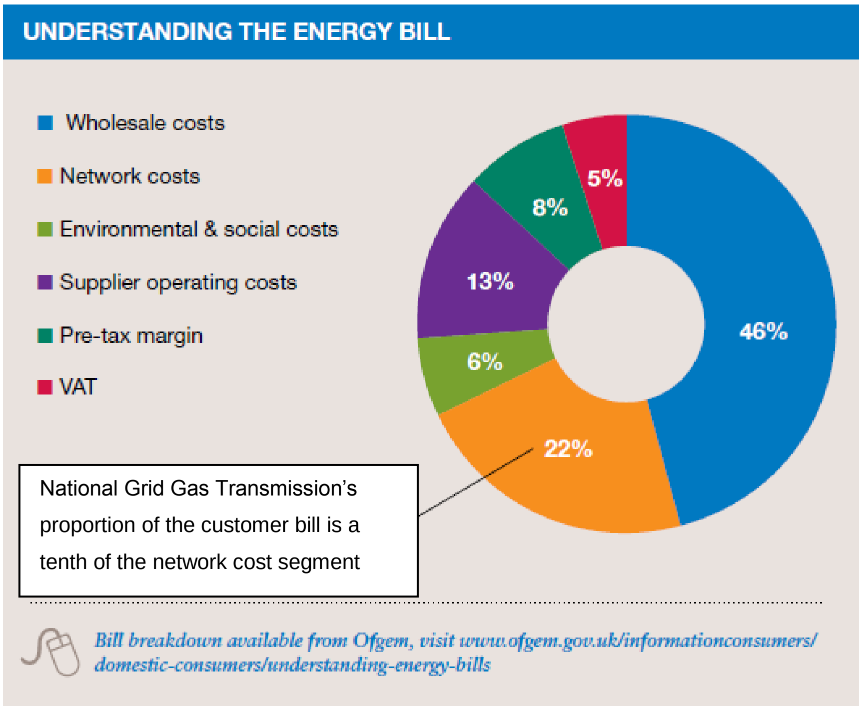
The total of the recommended options is approximately £470m (outturn), of which £420m (outturn) is within RIIO-T1. The following sections consider the impact of this programme on customer bills and transportation charges.

Impact on charges

Under RIIO our allowances are set by Ofgem through to 2021. In return for these allowances, we have committed to deliver the outputs agreed with stakeholders. Our allowances form the basis of what we charge our customers.

Customer Bills

In 2014/15 approximately £18 of an average domestic customer bill related to National Grid Gas Transmission's services. This represents 2.2% of the £755 typical gas bill as can be seen on the chart below.



The total allowance associated with our proposals would be approximately £470m (outturn), of which circa £420m (outturn) is within RIIO-T1. The maximum impact of this programme on customer bills, compared to a base case of no investment, is approximately 50p in any year compared to 2014/15 price levels.

Transportation charges

Similarly the maximum impact of the annual IED investment programme during RIIO-T1 on transportation charges is shown below;

	Units	**Transportation charge impact of IED programme**
NTS TO Entry Capacity charge	p/kWh/d	No Change
NTS TO Entry Commodity charge	p/kWh	0.0030
NTS TO Exit Capacity charge	p/kWh/d	0.0006
NTS TO Exit Commodity charge	p/kWh	0.0010

Glossary

Best Available Technique (BAT) = the most effective and advanced stage in the development of activities and their methods of operation which indicates the practical suitability of particular techniques for providing the basis for emission limit values and other permit conditions designed to prevent (and where that is not practicable), to reduce emissions and the impact on the environment as a whole.

BAT Reference Documents (BRef) = a series of reference documents covering, as far as is practicable, the industrial activities listed in Annex 1 of the EU's IPPC Directive. They provide descriptions of a range of industrial processes and their respective operating conditions and emission rates. EU Member States are required to take these documents into account when determining best available techniques generally or in specific cases under the Directive.

Buyback = National Grid may request to buyback Firm capacity rights to manage a constraint on the NTS after any Interruptible/Off-peak capacity has been scaled back.

Capability = the physical limit of the NTS to flow a volume of gas under a given set of conditions; this may be higher or lower than the capacity rights at a given exit or entry point.

Capacity
Entry Capacity = holdings give NTS users the right to bring gas onto the NTS on any day of the gas year. Capacity rights can be procured in the long term or through shorter term processes, up to the gas day itself. Each NTS Entry point has an allocated Baseline which represents a level of Capacity that National Grid is obligated to make available for delivery against on every day of the year.
Exit Capacity = holdings give NTS users the right to take gas off the NTS on any day of the gas year. Capacity rights can be procured in the long term or through shorter term processes, up to the gas day itself. Each NTS Exit point has an allocated Baseline which represents a level of Capacity that National Grid is obligated to make available for offtake on every day of the year.

Control of Substances Hazardous to Health (COSHH) = the law that requires employers to control substances that are hazardous to health.

Carbon Monoxide (CO) = a colourless, odourless and tasteless gas produced from the partial oxidation of carbon-containing compounds. It forms when there is not enough oxygen to produce carbon dioxide (CO_2), such as when operating an internal combustion engine in an enclosed space.

Carbon Dioxide (CO_2) = a naturally occurring chemical compound composed of 2 oxygen atoms and a single carbon atom. If there is not enough oxygen to produce CO_2, carbon monoxide is formed.

Distribution Network (DN) = an administrative unit responsible for the operation and maintenance of the local transmission system and <7barg distribution networks within a defined geographical boundary. There are currently eight DNs, each consisting of one or more Local Distribution Zones.

Dry Low Emissions (DLE) = a technology that reduces NOx emissions when producing power with gas turbines.

Environment Agency (EA) = a non-departmental public body, sponsored by DEFRA, with responsibilities relating to the protection and enhancement of the environment in England.

Emission Limit Values (ELV) = limits set for industrial installations by the LCP directive and IPPC under the umbrella of the IED.

Front End Engineering Design (FEED) = the FEED is basic engineering which comes after the conceptual design or feasibility study. The FEED design process focusses on the technical requirements as well as an approximate budget investment cost for the project.

Future Energy Scenarios (FES) = an annual industry-wide consultation process encompassing questionnaires, workshops, meetings and seminars to seek feedback on latest scenarios and shape future scenario work. The Future Energy Scenarios document is produced annually and contains our latest scenarios.

High Voltage (HV) = electrical energy above a particular threshold.

Industrial Emissions Directive (IED) = an EU directive that came into force in January 2011. It combined 7 existing directives including the LCP directive and IPPC detailed below.

Integrated Pollutions Prevention and Control (IPPC) = an EU directive which requires industrial installations to have a permit containing emission limit values and other conditions based on the application of Best Available Techniques (BAT) .It is set to minimise emissions of pollutants likely to be emitted in significant quantities to air, water or land.

Interconnector UK (IUK) = the pipeline transporting gas between Bacton and Zeebrugge. It is capable of flowing gas in either direction and provides a strategic energy link between the UK and continental Europe.

Intrusive Outage = significant outage works impacting the whole station and where the station cannot be returned to service until the scheduled works are completed.

Large Combustion Plant (LCP) = an EU directive to reduce emissions from combustion plants with a thermal output of 50 MW or more. Combustion plant must meet the emission limit values (ELVs) given in the LCP directive for NO_x, SO_2, and particles.

Local Distribution Zone (LDZ) = a geographic area supplied by one or more NTS Offtakes, consisting of local transmission and distribution system pipelines.

Liquefied Natural Gas (LNG) = gas stored and/or transported in liquid form.

Medium Combustion Plant (MCP) Directive = a future EU directive to reduce emissions from combustion plants between 1-50 MW. The proposals include requirements to register these combustion plants, and set emission limit values and monitoring and reporting requirements. It is unlikely to come into force before 2018.

Mg/Nm^3 = a measurement of milligrams per normal meter cubed.

Mega Watt (MW) = a unit of power equal to one million watts.

Network Development Process (NDP) = the process by which National Grid identifies and implements physical investment on the NTS.

Network Review = the Network Review process allows National Grid to identify the key environmental priorities with regard to ongoing operation of the compressor fleet and agree National Grid's Network Environmental Investment and Regulatory Strategy with both the EA and SEPA.

Nitrogen Oxide (NO_x) = a molecule with chemical formula NO and is a by-product of combustion of substances in the air, such as gas turbine compressors.

National Transmission System (NTS) = the high-pressure system consisting of terminals, compressor stations, pipeline systems and offtakes. Designed to operate at pressures up to 85 barg. NTS pipelines transport gas from terminals to NTS offtakes.

Oxford Computing Consultants (OCC) = company developing a tool which will help to visualise and articulate the impact that different supply and demand scenarios and different investment options will have on the network.

Office of Gas and Electricity Markets (OFGEM) = the regulatory agency responsible for regulating Great Britain's gas and electricity markets.

Operating Envelope = All NTS compressors have been designed to operate within a certain range of parameters, namely maximum and minimum gas flow rates and maximum and minimum engine speeds. The limits of these ranges define the performance of a compressor and are referred to as the operating envelope.

Operationally Proven = A unit is operationally proven when it can be shown to be operating reliably and post commissioning / early life issues have been resolved.

Proximity Outage = significant works on a site for which safety precautions must be put in place which make the station unavailable, but the station is capable of being returned to service in a few hours if required as the works taking place are not intrusive to the operation of the station.

Replacement = installing a new unit to replace the capability provided; this may not be a like-for-like replacement.

RIIO (Revenue = Incentives + Innovation + Outputs) = the new regulatory framework set out by OFGEM, building on the previous RPI-X regime. RIIO-T1 is the first transmission price control review to reflect the framework; it sets out what the transmission network companies are expected to deliver and details of the regulatory framework that supports both effective and efficient delivery for energy consumers over the eight years from 2013 – 2021. RIIO-T2 will be the second price control review.

1-in-20 Obligations = the 1 in 20 peak day demand is the level of demand that, in a long series of winters, with connected load held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters, with each winter counted only once.

Selective Catalytic Reduction (SCR) = a means of converting nitrogen oxides (NO_x) with the aid of a catalyst into diatomic nitrogen, N_2, and water, H_2O. A gaseous reductant, typically anhydrous ammonia, aqueous ammonia or urea, is added to a stream of flue or exhaust gas and is adsorbed onto a catalyst. Carbon dioxide (CO_2) is a reaction product when urea is used as the reductant.

Scottish Environment Protection Agency (SEPA) = Scotland's environmental regulator and flood warning authority.

Shipper = a company with a Shipper Licence that is able to buy gas from a producer, sell it to a supplier and employ a transporter to convey gas to consumers.

System Flexibility = the ability of the gas transmission network to cater for the rate of change in the supply and demand levels which results in changes in the direction and level of gas flow through pipes and compressors and which may require rapid changes in the flow direction in which compressors operate.

Talking Networks = National Grid's dedicated stakeholder website for Transmission stakeholders. Talking Networks was developed as part of National Grid's price control and business plan development for stakeholder engagement.

Unit Outage = significant outage works impacting a single or only some of the units on a compressor station, the unit cannot be returned to service until the scheduled unit works are completed, however, the station can still operate with other available units.

United Kingdom Continental Shelf (UKCS) = the region of waters surrounding the United Kingdom, in which the country claims mineral rights.

Uniform Network Code (UNC) = the Uniform Network Code replaced the Network

Code and, as well as covering the arrangements within the Network Code, covers the arrangements between National Grid Transmission and the Distribution Network Operators.

Appendix I
Cost / Allowance Assessment

Redacted

Appendix II
Budget Cost Summaries

Redacted

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