nationalgrid

St Fergus IED Business Case

May 2018

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1 Executive Summary

This paper describes the options available to National Grid to comply with the IED legislation at St Fergus and recommends the option best placed to meet the future needs of gas transmission system users and customers.

As one of the highest utilisation compressor sites on the NTS, St Fergus enables UK Continental Shelf (UKCS) and Norwegian gas supplies entry onto the National Transmission System (NTS). Compression is required to raise the pressure of the gas supplied via the North Sea Mid-stream Partners (NSMP) sub-terminal to NTS pressure. The site comprises three compressor plants with ten berths and nine units: two variable speed drive electric units (VSDs), five Avon gas powered units and two RB211 gas powered units.

The site is one of the highest polluting sites on the NTS and is impacted by the requirements of the Industrial Emissions Directive (IED), which incorporates both the Integrated Pollution Prevention and Control (IPPC) directive and the Large Combustion Plant (LCP) directive. To ensure minimum compliance with IPPC, the paper evaluates replacement or emissions abatement of at least one of the five Avon units. To meet the requirements of the LCP directive, the two RB211 units (currently operating under the Limited Lifetime Derogation (LLD)) are evaluated to establish whether replacement, emissions abatement or decommissioning is the optimum solution.

There are several commercial and regulatory options that could potentially reduce the absolute level of compression at St Fergus or pay compensation where compressor back up is not adequate. These options are discounted as not being suitable for the size and scale of the flows through the St Fergus terminal. Focus therefore is given to a comprehensive list of 14 different asset based site options assessed within the Cost Benefit Analysis (CBA) methodology. The CBA gives quantitative justification for options including new gas units and the application of emissions abatement technology, Selective Catalytic Reduction (SCR) and Oxidation Catalysts, on both Avon and RB211 units. To enable a clear differentiation between the favoured options, an alternative, more complex technique of prescriptive modelling is applied. This tool applies operational criteria and monetised risk data to a decision tree model of St Fergus, providing a more robust justification for the options carried forward.

The recommended decision based on output from the tools, the CBA, prescriptive modelling and emissions data is to take forward two options (10a and 10b) to FEED (Front End Engineering Design). Option 10b, presented in the funding request involves a new Avon-sized unit for IPPC compliance and SCR and Oxidation Catalyst on the RB211 Unit 2D under the LCP directive. The RB211 unit 2A would be decommissioned post 2023. The total option cost in 2009/10 prices is less than £10m for decommissioning one unit, £20-40m for one new Avon sized unit and £20-40m for emissions abatement on one RB211.

Funding Request Summary (09/10 price base)

New Avon Unit: £20-40m
Emissions abatement on one RB211 Unit: £20-40m
Decommission one RB211: less than <£10m

RIIO Output - Emissions compliance on one Avon unit and one RB211 unit at St Fergus.

RIIO-T1 Activities - Completion of FEED (Front End Engineering Design) incorporating recommended option. OEM (Original Equipment Manufacturer) contract awarded and unit design and FAT (Factory Acceptance Test) complete. EPC (Engineering, Procurement and Construction) contract awarded and detailed design commenced.

2 Introduction

This paper describes the options available to National Grid to comply with the IED legislation at St Fergus and recommends the option best placed to meet the future needs of gas transmission system users and customers. This takes into account the current and future use of the site and the investment options available to us.

St Fergus terminal is a key strategic asset located in Scotland, which enables UK Continental Shelf (UKCS) and Norwegian gas supplies entry onto the National Transmission System (NTS). Gas from three adjacent sub-terminals: Apache, Shell and North Sea Mid-stream Partners (NSMP), flows through the St Fergus terminal and onto the NTS. Supplies from this terminal typically meet approximately 25% of the average national demand and there has been significant investment (approximately £3.5bn) in recent years to connect the West of Shetland gas fields into St Fergus terminal. This investment has been made by the developer of the West of Shetland gas fields (Total).

St Fergus is one of the highest utilisation compressor sites on the NTS. Compression is required to raise the pressure of the gas supplied via the NSMP sub-terminal to enable entry onto the NTS. The combined gas supplies from all three sub terminals at St Fergus flows via five feeders towards Aberdeen and further south.

The St Fergus compressor site is impacted by several aspects of the IED (Industrial Emission Directive) including both the Integrated Pollution Prevention Control (IPPC) and the Large Combustion Plant (LCP) elements. The future requirements of the Medium Combustion Plant (MCP) directive will also impact this site. The limitations under MCP legislation will not apply until 2030, so whilst investment decisions for the MCP units is not required at this time, the impact of MCP is considered in the analysis.

For minimum compliance with IPPC, unit replacement or emissions abatement on one or more of the five of Avon units on site is required whilst the two RB211 units are directly impacted by the LCP directive. These units are currently operating under the Limited Lifetime Derogation (LLD) and this paper evaluates whether replacement, emissions abatement or decommissioning is the optimum solution for these units before the LLD deadline of 31st December 2023.

3 The Site: Assets and Operation

The compressors at St Fergus have some of the highest run hours of the NTS compressor fleet. The compressors support the flows from the NSMP sub terminal, rather than providing compression for the general operation of the NTS, and are required to raise the pressure of the gas supplied via the NSMP sub-terminal to a pressure suitable for the gas to flow into the NTS. In contrast with all other compressors on the NTS, which are typically embedded in the network, St Fergus does not have an extended upstream pipe network so it must be able to respond to changes in the NSMP flow requirements on an almost immediate basis. It also requires any necessary resilience to be fully located on site rather than relying on alternative site back up.

Gas flows from the NSMP sub-terminal and enters into St Fergus terminal. The gas then flows through scrubbers and meter streams before passing through the compression plants where the gas pressure is raised. Depending on network conditions this is typically to between 60barg and 65barg, although often up to the maximum allowable system pressure for this part of the network of 70barg. The gas is then cooled in the aftercoolers to remove the heat of compression before being blended with gas from the Apache and Shell sub-terminals. The gas is supplied into the NTS down the five pipelines towards Aberdeen and further south.

In terms of configuration, the St Fergus compressor assets are divided into three separate plants: Plant 1, Plant 2 and Plant 3 with a total of 10 berths. Plant 1 and 2 were built as part of the original site, commissioned in 1978, with Plant 3 commissioned in 2015.

Plant 1 comprises four gas turbine driven compressors. All four are Rolls Royce (now Siemens) Avon units.

Plant 2 comprises three gas turbine driven compressors plus one empty berth. There is one Rolls Royce Avon unit and two Rolls Royce (Siemens) RB211 units.

Plant 3 comprises two electric variable speed drive (VSD) compressors.

Individual Avon units can support a nominal flow of 15mcm/d, whilst individual RB211s and the VSDs can support flows of up to 30mcm/d. The VSDs can support up to approximately 34mcm/d under favourable conditions.

Plants 1 and 2 offer flexibility; they can operate independently but are generally operated together. The supporting assets – scrubbers and after-coolers – are nominally assigned to the individual plants but can also be cross connected. Plant 3 provides baseload compression and is designed to operate in conjunction with Plant 1 and/or Plant 2 as these provide the necessary scrubbing, metering and after cooling.

For over 40 years of operation (circa mid 1970s to 2012) two RB211 driven compressor sets provided primary compression capacity at the St Fergus site, run in conjunction with the five Avon compressor sets. This provided successful operation for many years. A significant change occurred when the Plant 3 electrically powered VSD units were introduced, and since this point the VSDs and Avons have provided the main compressor capacity, with the RB211 units being used as backup to the VSDs.

The VSDs provide bulk compressions capability, effectively mimicking the capability of the RB211s. In order to effectively map the entire operating envelope of the site, the smaller Avon gas units continue to be required for when flows are:

- below the minimum turndown capacity of a single VSD;
- mid-range i.e. greater than a single VSD but less than two VSDs at minimum turndown capacity; or
- very high i.e. greater than two VSDs in parallel.

In addition, there is a requirement for gas turbine driven compressors to provide back up in the event of loss of the incoming electrical power supply or unavailability of the VSDs as a consequence of maintenance (the site operates 24 hours a day, 365 days a year).

The primary means of achieving the required flexibility is by selecting a combination of compressors of appropriate capacity with further flexibility achieved by exploiting the range of individual compressors. A load share controller ensures that the compression duty is shared evenly between the online compressors. Further flexibility in operation can be achieved by recycling gas via the plant recycle line but this is both noisy and inefficient and is thus minimised.

From an operational perspective, flows through St Fergus have always shown a high degree of variability. As shown by the red bars on the chart below, in the mid-2000s, typical daily flows through NSMP's sub terminal were in excess of 50mcm/d. However from 2009 flows were significantly lower and with the decline in UKCS gas, flows of 10-20mcm/d were more common. In 2016 with a change of ownership at the sub-terminal, there was a marked change in flows. Typical flows at the sub-terminal increased up to the region of 30-40mcm/d and then in October 2016 there was another significant increase up to 50-60mcm/d. On two days in January 2017 flows exceeded 60mcm/d.

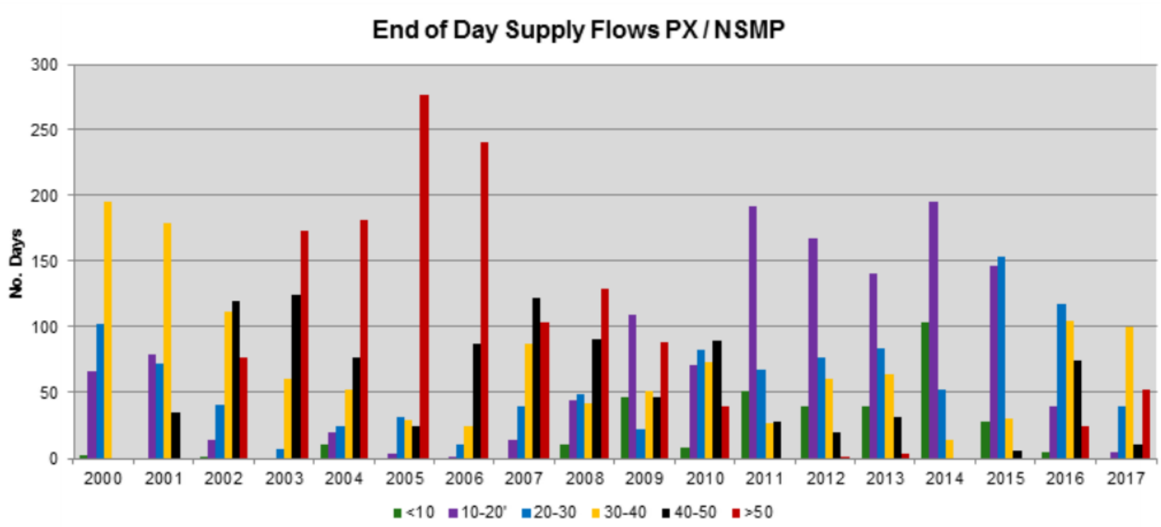


Figure 3.1: NSMP flows

The consequence of this has been a 30% increase in compressor run hours between 2015/6 and 2016/17. The running hours for each individual compressor unit over the past five years are shown below:

	Individual Unit Running Hours *(financial year)*				
	2013/14	2014/15	2015/16	2016/17	2017/18
Unit 1A	3,263	2,482	942	281	518
Unit 1B	175	25	632	339	447
Unit 1C	1,497	2,407	1,214	1,353	939
Unit 1D	833	1,371	776	1,458	465
Unit 2A	477	1,756	1,709	1,006	2726
Unit 2B	60	253	1,337	7	77
Unit 2D	4,592	1,131	152	740	1365
Unit 3A	N/A	N/A	618	4800	2211
Unit 3B	N/A	N/A	3001	4182	5420
Total	**10,897**	**9,425**	**10,381**	**14,166**	**14,168**

Table 3.1: Running Hours -

Plant 1 and 2 are still seeing significant service supporting the VSD units on Plant 3. Whilst the VSD units were commissioned relatively recently in 2015, the majority of the compressor related assets at St Fergus terminal have been in situ since 1977, reaching 40 years of service in 2017. Consequently there are significant asset health issues that need to be addressed to ensure continued safety and environmental compliance at the site. The cost and effectiveness of the various maintenance, repair and replacement options for the compressor assets impact the large items that make up the machinery train (gas turbine, power turbine, gas compressor) but also the wet gas seals and the auxiliary systems such as the cab ventilation, cab structure, exhaust stack and control systems.

In order to facilitate the necessary asset health work, Plant 2 was taken out of service (for the first time in almost forty years) during the summer of 2016 and Plant 1 is due to be taken out of service during the summer of 2018. This places additional demands on the remaining operational plant to provide supplementary and back up capability to the VSDs. Further plant outages are likely to be required in support of future construction or upgrade projects e.g. to facilitate the removal and replacement of the 40+ year old unit isolation and emergency shutdown valves.

The VSD units themselves have experienced some availability issues in the period following commissioning. This is most likely to be a function of the bedding in process and it is expected availability levels will pick up once these issues are resolved.

It is important to note that there is a fundamental difference between the electric and gas turbine driven compressor machinery trains. For an electric drive compressor, any significant mechanical or electrical failure of the motor is likely to result in an extended outage whilst the motor is returned to the OEM for repair (typically 6 months). The motors are effectively bespoke to each application which makes it uneconomic to carry ‘fleet spare’ machines. Even if a similar motor exists at another location, it would be a costly and time consuming process to modify and relocate the motor to a different location. By contrast, a failed gas turbine can be replaced within typically 3 – 5 days utilising a fleet spare, an OEM exchange engine or an engine borrowed from a low utilisation site. These types of failures are low probability events but will impact the overall availability of the VSD units.

4 Emissions and the impact of IED

4.1 IED: LCP

The LCP element of the IED applies to all combustion plants with a net thermal input of 50MW or more. Under the LCP directive, combustion plant must meet the Emission Limit Values (ELVs) which are defined in the directive. Both of the RB211 units, 2A and 2D are impacted by this requirement

The deadline for compliance with the legislation associated with the LCP element of IED came into force on 1st January 2016 and in December 2015 a decision was made regarding the individual affected units, 2A and 2D. The options at this stage were whether to decommission the units immediately, or enter them into either the Emergency Use or Limited Lifetime Derogations. Neither immediate decommissioning nor use of the Emergency Use Derogation were considered to be suitable. The EUD limits running hours to just 500 hours per year, which was not adequate to meet the site requirements, particularly as the VSDs were not operationally proven at that point. In line with the outcome from stakeholder engagement carried out as part of our IED submission in May 2015, units 2A and 2D were put onto the Limited Lifetime derogation. This allows the units to operate for a maximum of 17,500 hours or until 31st December 2023 whichever is sooner. With the 2023 deadline approaching, the investment decision as part of this re-opener is to consider whether these units should now be replaced, abated or decommissioned.

4.2 IED: IPPC element

As part of the IED legislation, based on the IPPC requirements, all relevant installations need to have a permit and the permit conditions should be based on BAT. If these conditions are not met the UK environment agencies will remove our site permits which would mean our compression activities would have to cease. It is recognised and understood by the three UK environment agencies that it is not feasible or economic to comply with the BAT requirement across our whole fleet immediately. Therefore we have agreed with the environment agencies to develop an environmental investment strategy through an annual Network Review, which is embedded within the permit conditions.

The priority of sites targeted for investment is reviewed annually through the Network Review process which documents our environmental investment strategy, together with historical and forecast compressor utilisation and NOx emissions. The St Fergus compressor site is affected by the requirements of the IPPC element of IED as it is one of the highest run hour sites on the network (see chart below).

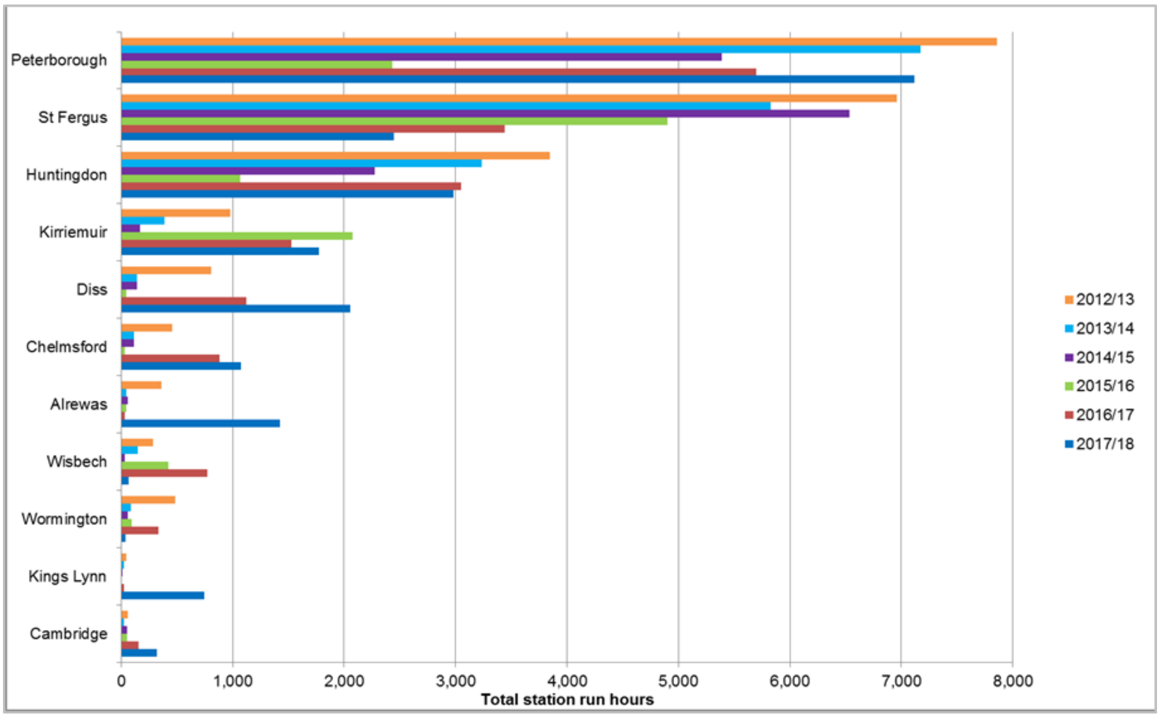


Figure 4.1: Ranked run hours for IED non-compliant compressor units by station 2012-2017

To reduce our fleet NOx emissions we have completed two phases of investment as part of our IPPC programme of works. The first phase focused on St Fergus and Kirriemuir with the installation of three new electrically driven compressors, two at St Fergus and one at Kirriemuir. The second phase focused on the installation of an electrically driven compressor at Hatton. All of the units installed as part of IPPC Phase 1 and 2 are now the lead units at these compressor stations.

IPPC Phase 3 was proposed as part of our RIIO-T1 business plan in 2012. This focused on reducing emissions at Peterborough and Huntingdon, the sites with the next highest levels of NOx emissions with the intention of significantly reducing NOx emissions from both sites by 2021. The IPPC Phase three works will deliver one new dry low emission (DLE) unit at both Peterborough and Huntingdon.

We provisionally identified Alrewas, Diss and Wormington compressor sites in our RIIO-T1 business plan for inclusion in the IPPC Phase 4 programme of works. These sites were identified based on prevailing and forecast future network flows in 2011/12. Due to a number of uncertainties, baseline funding was not provided for IPPC Phase 4 but funding was provided in RIIO-T1 to develop an integrated plan for IED and IPPC Phase 4, which would form the basis of this reopener.

In 2013/14, we re-assessed the compressor station run hours as part of our IPPC Phase 4 site need case analysis. All three of the provisionally identified stations were found to have declining run hours, with five-year historical averages of less than 500 hours, and similar future operating requirements. The electric unit at Wormington was being increasingly used in preference to the Avon units at this site.

Compressor station	Units	Running Hours					
		2009	2010	2011	2012	2013	5 year average
Alrewas	A and B (Avon 1533s)	221	1061	305	258	146	398
	C (Solar Titan DLE)	222	1091	1209	28	120	534
Diss	A, B and C (Avon 1533s)	108	432	15	19	918	298
Wormington	A and B (Avon 1533s)	456	3746	5053	541	81	1975
	C (Electric VSD)	907	1098	2021	961	926	1183

Table 4.1: Run hours of sites initially identified as part of IPPC Phase 4

The focus of the IPPC Phase 4 works shifted to other sites with units with significantly higher current and forecast future running hours, this identified remaining units at St Fergus, Huntingdon and Peterborough as priority sites.

Compressor station	Units	Running Hours					
		2009	2010	2011	2012	2013	5 year average
St. Fergus	**5 Avon 1533 Units**	**6397**	**6346**	**8816**	**6987**	**6902**	**7090**
	2 RB211 Units	7527	8645	2916	4255	5893	5847
	Electric VSD Unit	N/A	N/A	N/A	N/A	N/A	N/A
Peterborough	A, B and C (Avon 1533s)	5559	8268	4958	6621	7448	6571
	Single Avon Operation	**1660**	**1803**	**2501**	**3442**	**884**	**2058**
Huntingdon	A, B and C (Avon 1533s)	2964	6201	1444	842	4586	3207
	Single Avon Operation	**1190**	**643**	**441**	**425**	**1235**	**787**

Table 4.2: Run hours of IPPC Phase 4 priority sites

The IPPC Phase 1 works successfully reduced the annual NOx levels on site to less than half their pre-2015 levels. However St Fergus remains one the highest polluting sites on the network.

The Avon units are still shown to be required for a significant number of run hours as they have the ability to deal with lower flows through the site - operating for over 3,400 hours in 2016/17, emitting 32 tonnes of NOx, primarily on Units 1C and 1D. Therefore investment options on one or more of the Avon units need to be assessed and implemented to comply with IPPC at this site.

In 2014, as part of our May 2015 stakeholder engagement process, we presented the IPPC Phase 4 analysis and our future compressor strategy. We received positive feedback from our stakeholders that St Fergus, Peterborough and Huntingdon were the most appropriate sites to take forward as part of IPPC Phase 4.

4.1 MCP Directive

The MCP directive will apply limits on emissions to air from gas turbines below 50 MW net thermal input. There are five units at St Fergus that will be affected by the MCP directive. These are Avon units 1A, 1B, 1C, 1D and 2B. These units will have to be compliant with the MCP directive by the 1st January 2030, after which the units will be restricted to 500 operating hours per year as a rolling average over a period of five years. Compliance with MCP is not an investment decision for this reopener; however the analysis considers the implications of MCP at the site.

4.2 Emissions Summary

The current investment decision looks to review the two units currently operating under the LCP derogation; whether to replace, abate or decommission Units 2A and 2D by 2023. The St Fergus investment decision also considers options to achieve compliance with IPPC; replacement or abatement of one or more Avon units. Consideration is given to the future requirements of the MCP directive, as the Avon units will all be captured under this legislation from 2030. Due to the interaction between the different units at St Fergus, a holistic evaluation must be undertaken in order to determine the optimum solution.

A summary of the current status of all units is given in the table below.

	IED LCP and MCP Summary	IPPC Summary	Allowed Operating Hours	Year Applicable from	Legislative year of closure
Unit 1A	Captured under MCP from 2030	Evaluation for IPPC Phase 4	N/A	2030	TBD
Unit 1B	Captured under MCP from 2030	Evaluation for IPPC Phase 4	N/A	2030	TBD
Unit 1C	Captured under MCP from 2030	Evaluation for IPPC Phase 4	N/A	2030	TBD
Unit 1D	Captured under MCP from 2030	Evaluation for IPPC Phase 4	N/A	2030	TBD
Unit 2B	Captured under MCP from 2030	Evaluation for IPPC Phase 4	N/A	2030	TBD
Unit 2A	LCP Limited Life Derogation	-	17500hrs total until 2023	2016	2023
Unit 2D	LCP Limited Life Derogation	-	17500hrs total until 2023	2016	2023
Unit 3A	Compliant	IPPC Phase 1	N/A	N/A	N/A
Unit 3B	Compliant	IPPC Phase 1	N/A	N/A	N/A

Table 4.3: IPPC, LCP and MCP unit summary

5 The Future Requirements

With the wide-ranging impact of IED on the compressor units at St Fergus, a number of different sources have been used to validate future requirements of the site. Considerations include the obligated baseline entry capacity, Future Energy Scenarios (FES), the Network Entry Agreement (NEA) and standby requirements.

5.1 Obligated Baseline Entry Capacity

The obligated entry level at the St Fergus Aggregated System Entry Point (ASEP) is 154.22mcm/d. This is the total entry for all three sub-terminals, Apache, Shell and NSMP together and it is not broken down to sub-terminal level. The compression requirement at St Fergus relates to the NSMP flows only.

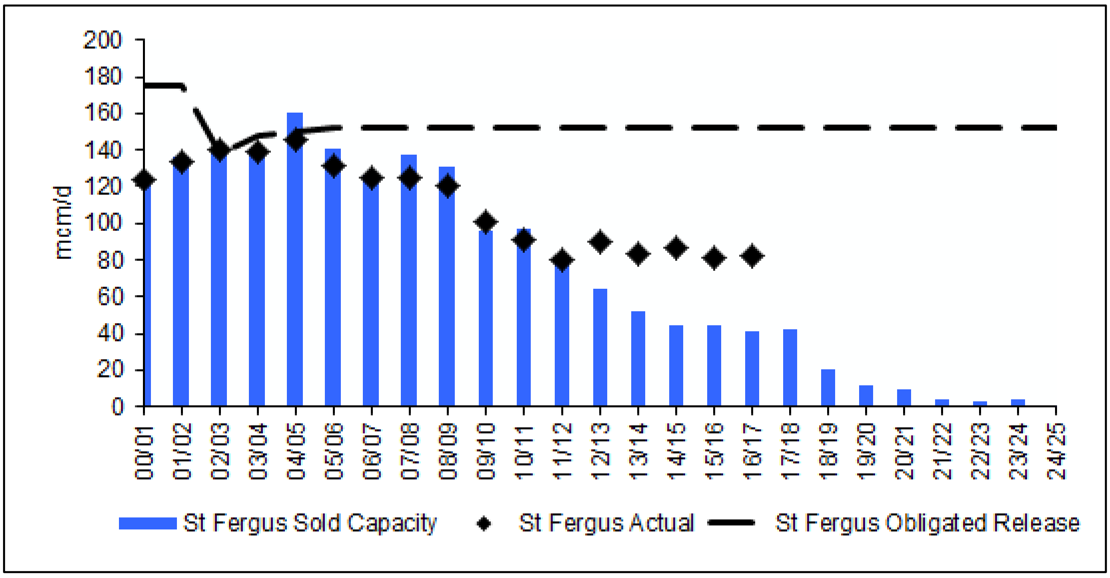


Figure 5.1: St Fergus capacity and flow

The chart above shows the level of capacity sold at St Fergus since 2000. The sold levels are well below the entry baseline for the ASEP with shippers deciding to wait to obtain capacity on the day for free as opposed to paying the entry charges. Therefore, sold levels cannot be taken as a guide to the likely physical flows through the ASEP into the future.

5.2 Requirements under FES and forecast run hours

Looking to the future, the analysis carried out as part of FES 2017 indicates there is a capability requirement at St Fergus out to 2040 and beyond. The forecast flow range for NSMP is large, between 20mcm/d and 69mcm/d across the four different scenarios. Overall, the predicted flows show a slight decline over the next 10 years. There is an increase in flows from 2024/25 as new fields connect in at the West of Shetland until flows reduce again from 2036 onwards. The increase is more pronounced in two of the FES scenarios as those flows are forecast to come through the NSMP sub-terminal whereas future UKCS gas is spread more evenly across the other sub-terminals in the other two scenarios. The recent change in ownership at NSMP, and the associated change in strategy for their upstream assets are likely to push actual supplies towards the top of the range in the chart below.

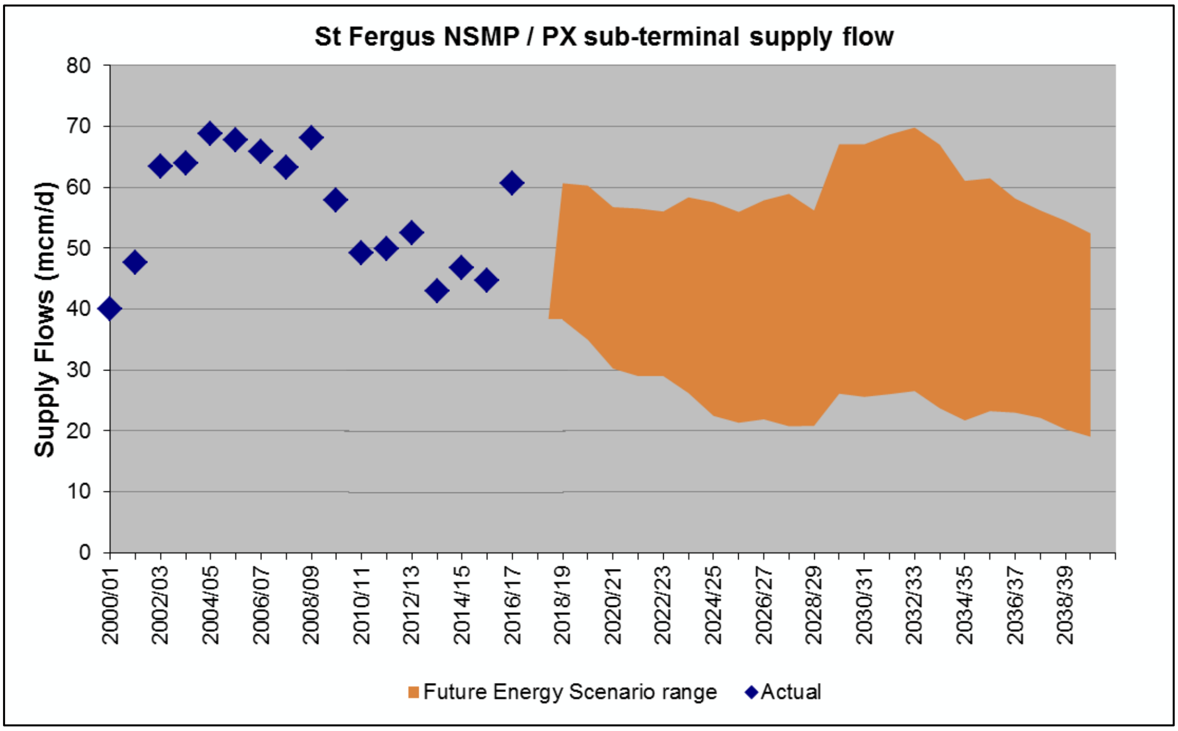


Figure 5.2: St Fergus NSMP sub-terminal flow

In line with the expected sub terminal flows, forecast run hours for the St Fergus compressor units over the next four years remain at over 10,000 hours per year with a fairly static ratio between the gas and electric drive units.

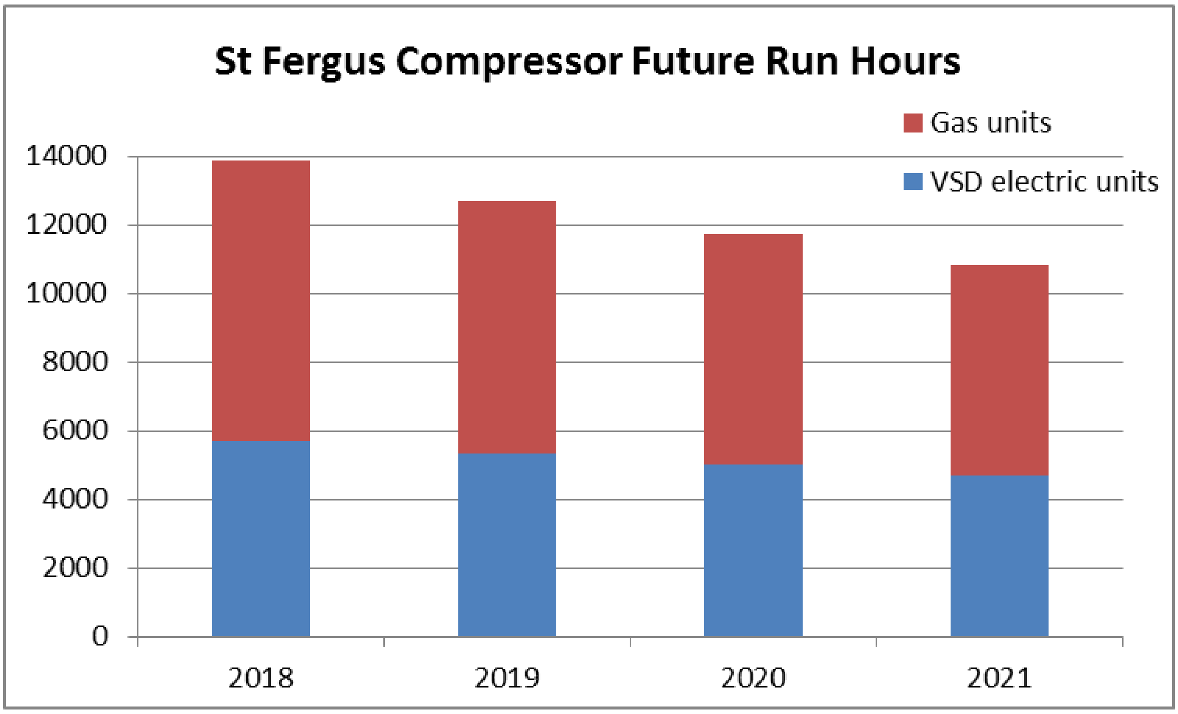


Figure 5.3: Forecast run hours - as reported in the Regulatory Reporting Pack

5.3 Standby requirements

The compression at St Fergus is used to provide a sub-terminal specific pressure service, not bulk transmission, hence there is no viable Operating Margins (OM) alternative or ability to provide any back up at other compressor sites. The level of stand-by compression needs to be balanced with the expected availability of units as part of the Cost Benefits Analysis (CBA). The Transmission Planning Code (TPC) sets out what should be assessed when considering compressor standby. The investment decision therefore considers the required transmission capability, forecast compressor run hours, economic and efficient system operation, maintenance and fuel security (electricity and/or gas).

5.4 Future Requirements Summary

This assessment of the site's future requirements is a key factor in the St Fergus options assessment and analysis in the next section. Taking into consideration the four sources outlined above it is clear there are multiple indicators to inform the maximum level and also the potential range of compression required going forward. The two key values for the maximum flow are:

- 69mscm/d – The highest peak flow from the 2017 FES;
- The likely minimum flow is 20mcm/d across the full period and run hours up until 2021 are above 10,000 per year in total.

The options for the LCP impacted units 2A and 2D (replacement, emissions abatement or decommissioning) and the options for the Avon units (replacement or emissions abatement) to ensure compliance with IPPC are critical in ensuring we have sufficient flexibility in the compressor capability at the site to meet the flows across the full flow range required.

6 Options Considered

6.1 The Counterfactual

Having ascertained the likely future usage of the site, a counterfactual option was defined. This option is closest to business as usual and which is compliant with all the relevant elements of IPPC and IED.

The counterfactual option is to decommission the unit 2C empty berth and immediately construct one new Avon-sized unit, on the footprint of unit 2C to satisfy IPPC requirements. For compliance with LCP, the Limited Life Derogation in place on the two existing RB211 units 2A and 2D, would be utilised with the effect that they both cease operation in December 2023 or after 17,500 hours of operation (from 1st January 2016), whichever is sooner and then be decommissioned. The Emergency Use Derogation would be utilised on all the existing Avon units 1A, 1B, 1C, 1D and 2B, and operate less than 500 operating hours per year from 1st January 2030 in perpetuity.

Under this option it is assumed that the most economic solution for compliance with LCP is to decommission both RB211 units, which does offer certain advantages: minimal site interfaces, limiting operational working constraints and outages etc. However, this option loses flexibility across the wide envelope of site operation that an RB211 unit can provide, and after the RB211 units are decommissioned in 2023, there would also be uneven capability between the three plants which could result in operational issues.

In order to evaluate the true economic case for the counterfactual, a number of other commercial and physical options have been assessed for the purposes of comparison. These options have been developed through a process of stakeholder engagement, including previous feedback generated for the May 2015 reopener, site asset and operational assessments and investigation and assessment of new technology. For the physical options, a cost benefit assessment (CBA) has been undertaken demonstrating a clear and robust comparison of 14 different unit and ancillary system configurations for St Fergus terminal. Within the CBA, all of the costs and benefits are calculated for the first 30 years, and then discounted using 45 years through the RAV (Regulatory Asset Value). The assessment is therefore over a 45 year period and the price base for the St Fergus CBA is 2016/17.

6.2 Commercial Options

The commercial assessment of options to meet the St Fergus terminal compression requirements includes both contractual and regulatory code alternatives. The relevant commercial options are those which reduce emissions from one Avon unit (IPPC compliance) or offer benefits above decommissioning the two RB211s (counterfactual position for LCP compliance).

Capacity buy-back mechanisms can be considered as a commercial option to reduce absolute compression through the site. Typically used as a way to manage a physical constraint risk on the NTS, entry capacity is only sold at the ASEP level rather than the sub-terminal level. Capacity buy-backs can therefore only economically address a constraint at an ASEP level. This means at St Fergus, there is no effective means of targeting capacity buy-backs at the specific shippers who are unable to flow gas through the affected sub-terminal, as opposed to the broader portfolio of shippers in possession of entry capacity at the ASEP. In this case only the shippers at NSMP would be impacted by the lack of compression, not those flowing through the other two sub terminals. There has been a precedent for breaking up the ASEP at Bacton terminal following European legislation, designed to harmonise transparent and non-discriminatory access to transmission capacity at interconnection points across the European Union. This necessitated different arrangements and processes for the European Interconnectors (BBL and IUK) than for the other Bacton sub terminals bringing in gas from the UK continental shelf. The process was longwinded and complex, driven by the need for legislative change. It was not broadly supported by industry, as a break up of the ASEP reduces the optionality for shippers looking to trade their flows between different sub-terminals. In contrast to breaking up the ASEP, current debate within the industry is considering a zonal approach to capacity, i.e. combining capacity from a number of different ASEPs to create more choice and flexibility, in particular for smaller industry players. Based on this expected change in industry practice, a break up of the ASEP is not a preferred option to take forward.

As capacity buy back mechanisms are not appropriate we have also considered the use of alternative flow based contractual arrangements. These would be designed to reduce peak flows at the sub terminal and therefore minimise investment in compression capability. Feedback indicates that entering into a turn down contract where compression is needed is contradictory to the agreement we have to provide pressures to accommodate flow onto the network from the sub terminal. In addition, the price of such a contract would be very high given consequential impact of calling off flows at any time, impacting multiple shippers. It is also difficult to put in place an enduring agreement of this type, potentially leading to high renegotiation costs, or resulting in a position of no contract and no available compression due to compliance with the IED legislation. Feedback through stakeholder engagement clearly suggests that fundamentally stakeholders want to flow gas onto the network – they do not want National Grid to have to restrict flow even with financial compensations.

Another commercial option considers changes to the Uniform Network Code (UNC). Under UNC Section Y, National Grid is entitled to levy a compression charge to shippers to recover compressor fuel costs where compression is needed to increase the pressure of gas delivered from the NSMP sub terminal. One alternative code change considered was the option to modify the UNC (Section Y) whereby National Grid can levy a charge for the cost of investment in the compressor assets as well as the fuel usage for the compression. This option was discounted as although it would change the proportion of the investment cost picked up by relevant shippers – it would not alter the total cost of investment – and would be subject to a code review process.

In summary, these options whilst designed to either reduce absolute compression at the site or pay compensation where back up is inadequate, have been discounted. Given the criticality of the St Fergus sub terminal and the volume of flows through the site, commercial and regulatory options cannot offer a better alternative than the counterfactual.

6.3 Physical Options

6.3.1 Options Overview

The physical options were created through a process of evaluating the site's future requirements across a range of three main potential investment solutions: no further investment, emissions abatement and investment in new units. A number of secondary factors associated with the three main solutions are then assessed including combinations of green field and brown field sites, new Avon sized units, new VSD compressors, use of emission abatement technology to achieve ELVs (SCR (Selective Catalytic Reduction to reduce NOx emissions) and Oxidation Catalysts ('OxyCat' to reduce CO emissions), use of existing ancillary assets, and the enduring use of the Emergency Hours derogation. It should be noted that it will be necessary to demonstrate that any chosen technology represents Best Available Technique (BAT) to the satisfaction of the environmental regulator.

This option development was carried out in conjunction with the factors highlighted as important during our stakeholder feedback such as:

- Does this option allow National Grid to meet future flexibility requirements?
- Does this option have a negligible impact on customer charges?
- Is this option future proof?
- Does this option remove barriers for encouraging new investment?

As discussed, Option 0 is the counterfactual - the option against which all of the other options have been assessed. This represents the Do Minimum option which ensures that we are compliant with legislation. For St Fergus terminal, Option 0 is designed to reduce site NOx emissions under IED-IPPC and to ensure compliance with the two units impacted by IED-LPPC. This is achieved through the installation of one new Avon size unit and the RB211s would be decommissioned after 2023.

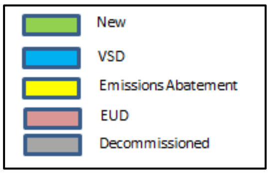
Initially a number of options were considered, including considering early investment in all the MCP impacted units in conjunction with IPPC compliance. However as these options were not proven to be economic investments to make at the current time, they were discounted and 14 options are presented from the CBA methodology. The CBA assessment for St Fergus includes the investment costs, asset health costs, site operating expenditure, compressor fuel usage and the liabilities for each of the options.

The list of options analysed under the CBA are summarised in the table below.

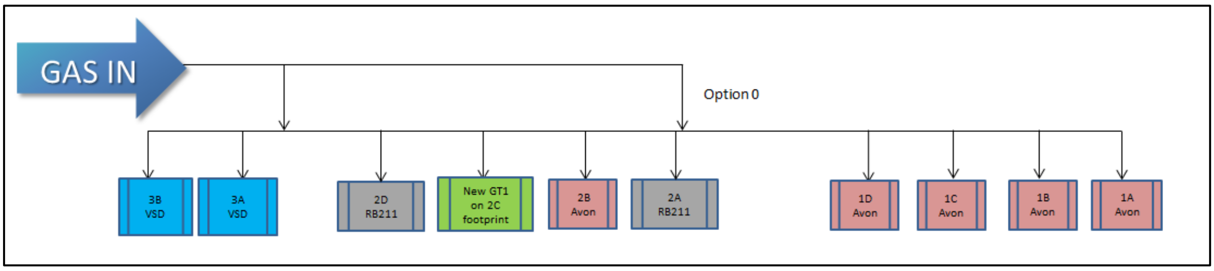
Option Number and description	Existing VSD	New VSD	AVON UNITS			RB211 UNITS		Existing plinths	Greenfield/ Brownfield	Plant Balance
			Number of New Units	Number of SCR Units	Number of Old Units (on limited running hours post 2030)	Number of Units with emissions abatement	Number of Old Units (decommissioned post 2023)			
0 – One new unit on brownfield	2	0	1	0	5	0	2	Yes	B	No
8 - One new unit on greenfield	2	0	1	0	5	0	2	No	G	No
8a – Emissions abatement on one Avon	2	0	0	1	5	0	2	Yes	B	No
9 – Two new units on greenfield	2	0	2	0	4	0	2	No	G	No
9a – Emissions abatement on two Avon units	2	0	0	2	4	0	2	Yes	B	No
9b - Emissions abatement on two Avon units with timing offset	2	0	0	2	4	0	2	Yes	B	No
9c - Two new units on brownfield	2	0	2	0	4	0	2	No	B	Yes
10 - Emissions abatement on one RB211 and one new unit on greenfield	2	0	1	0	5	1	1	No	G/B	No
10a - Emissions abatement on one RB211 and on one Avon unit	2	0	0	1	5	1	1	Yes	B	No
10b - Emissions abatement on one RB211 and one new unit on brownfield	2	0	1	0	5	1	1	Yes	B	Yes
11 - Emissions abatement on one RB211 and two new units on greenfield	2	0	2	0	4	1	1	Yes	G/B	No
11a - Emissions abatement on one RB211 and on two Avon units	2	0	0	2	4	1	1	Yes	B	No
11b - Emissions abatement on one RB211 and two new units on brownfield	2	0	2	0	4	1	1	Yes	B	No
12 – One new electric unit	2	1	0	0	5	0	2	No	G	No

Table 6.1: Option summary

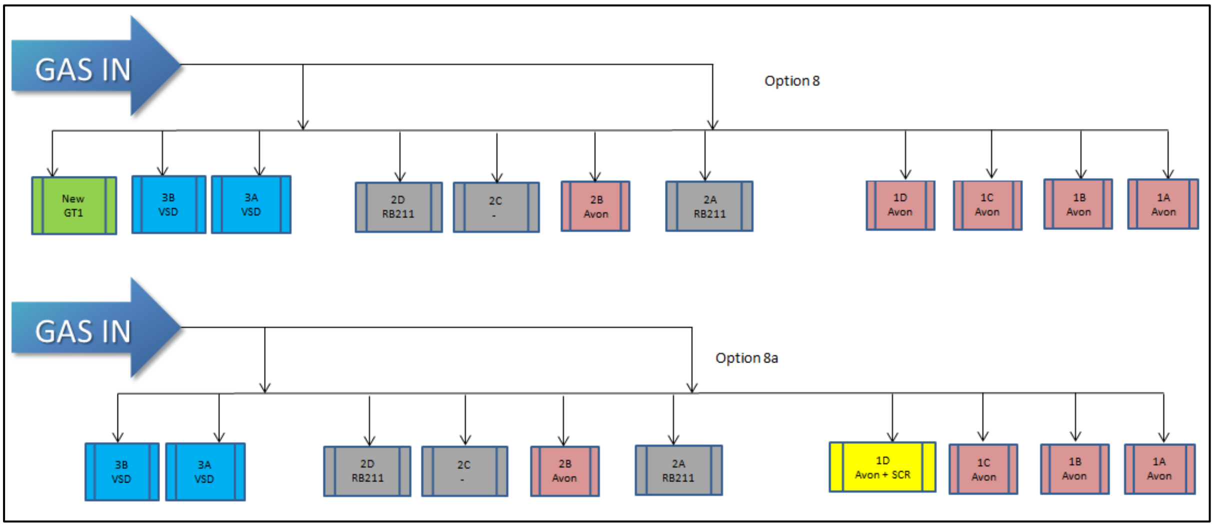
The options are designed to contrast and evaluate different characteristics. Options 8 and 8a have similar capability to Option 0 but delivered through SCR technology rather than a new unit, and existing rather than new plinths. Options 9, 10 and 11 have increasing levels of capability with the various sub options including new Avon sized units and emissions abatement technology on both the Avon and RB211 units. These options are presented in the diagrams below with the following key:



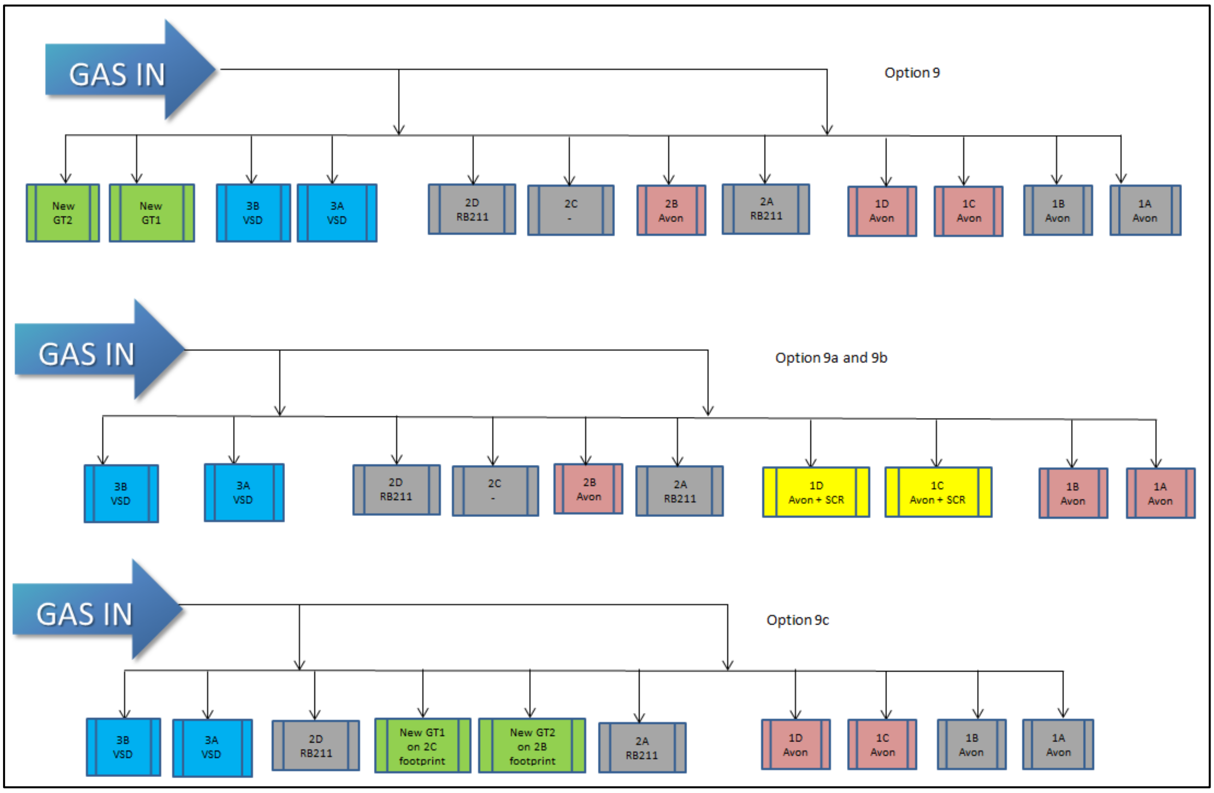
The site layout for **Option 0** is represented in the table below, with the new gas unit on plant 2 highlighted in green.



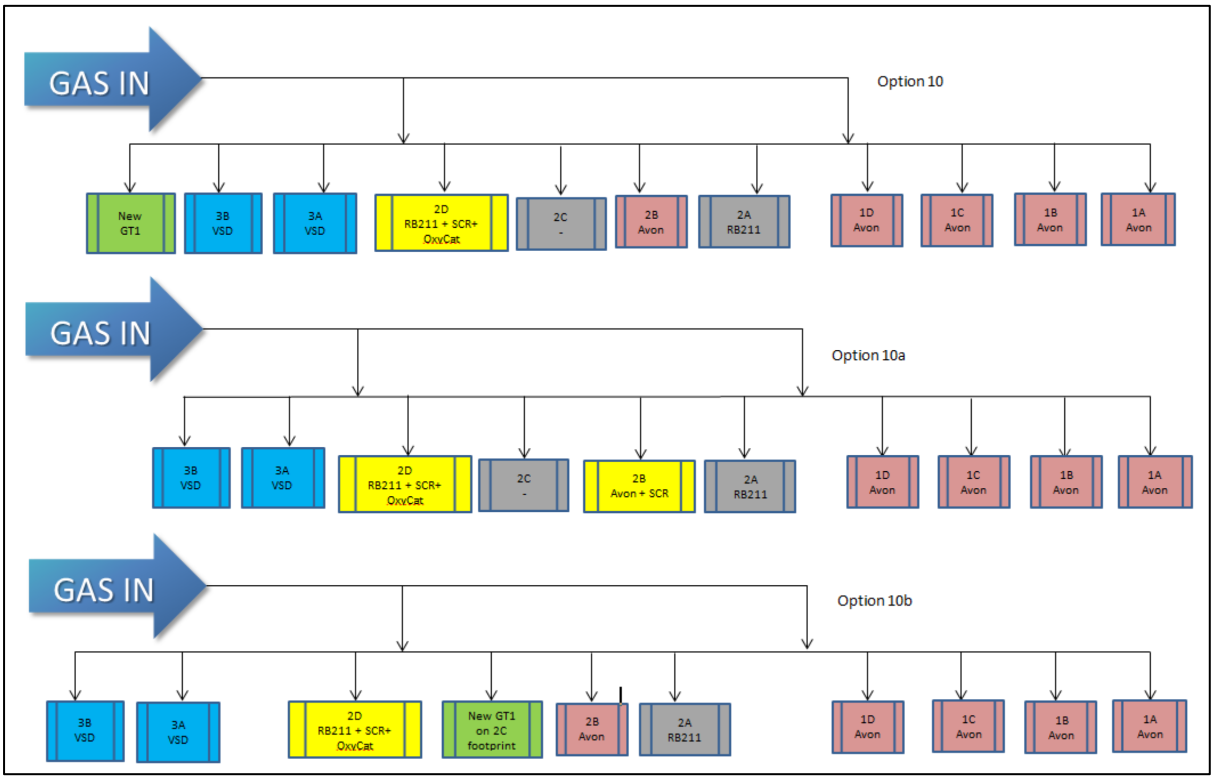
Options 8 and 8a include investment in one Avon sized unit, either a new unit or the existing unit fitted with SCR.



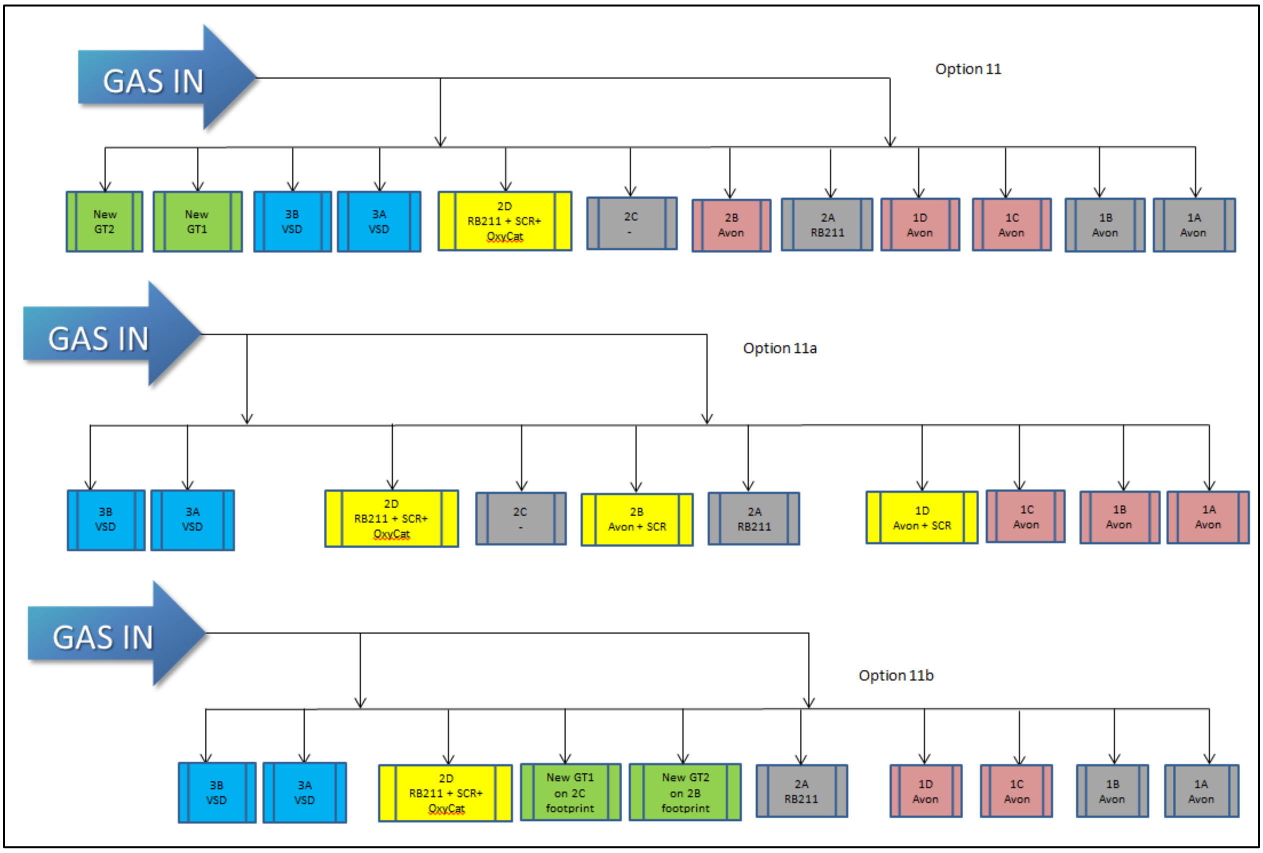
Options 9, 9a, 9b and 9c all involve variants of two Avon sized unit alternatives, either new units or fitted with SCR. Option 9b is a timing variant of 9a, whereby one unit is installed first, followed by the next. Under Option 9 and 9c, two existing Avons 1A and 1B are decommissioned as soon as possible after new units are installed and proven in use.



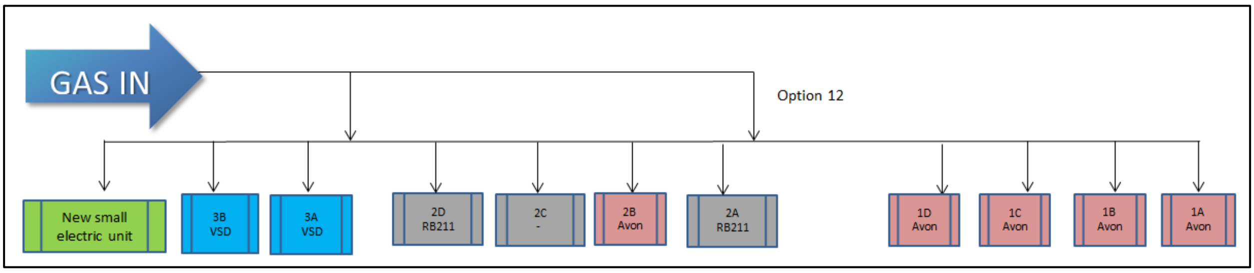
Options 10, 10a and 10b include investment in one RB211 unit as well as one Avon sized units. Emissions abatement on the RB211 unit requires both SCR and OxyCat.



Options 11, 11a and 11b comprise of investment in one RB211 and two Avon sized units. The RB211 investment option comprises of SCR with OxyCat technologies, whilst the Avon sized options include SCR and new units.



Option 12 is one new VSD.



6.3.2 Cost Benefit Analysis

With Option 0 defined as the counterfactual, each of the other 13 options is compared to Option 0 to give a Relative NPV (Net Present Value). The CBA assessment shows a wide range of relative NPVs. The most positive is produced by Option 10b at £54m, with the least positive produced by Option 12 at -£158m. The absolute Net Present Values range from -£839m (Option 12) to -£626m (Option 10b) with a few options (Options 8,9,10 and 11) clustered between -£700m and -£640m. The range within each option is primarily driven by fuel costs and investment costs. The fuel cost range is fairly similar across all of the options, whilst the high capability options, such as the Options 11, 11a and 11b have higher investment cost range. The lower capability options, such as the counterfactual and Options 8 and 8a have a higher range on liability costs.

Focussing on the most favourable options to take forward, presented below are those with the highest NPVs relative to the counterfactual. Option 8a provides the same capability (in terms of station throughput) as the counterfactual but at a lower cost. All other options identified provide additional capability, resulting in both lower liability costs and greater emission savings. Option 10b, with the highest NPV represents the optimum investment based on the CBA results.

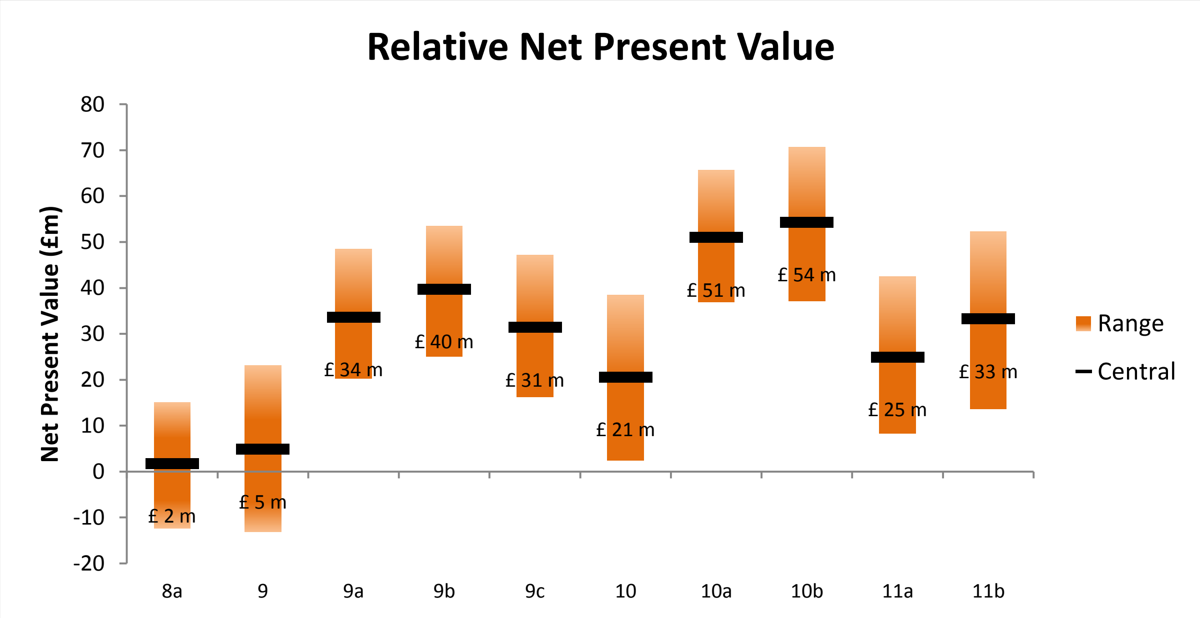


Figure 6.1: Relative NPV

Option 8a has the lowest investment costs, which is to be expected given this involves only SCR on one Avon unit. However it has by far the highest constraint costs of the options in this short list, which given its lower capability is to be expected. Options 11a and 11b have the high investment costs but also the lowest constraint costs. This is to be expected as these options involve investment in two Avon units and one RB211. The higher upfront costs being partly offset by lower liability costs due to the higher capability.

Options 9a, 9b, 9c, 10a and 10b all have similar investment costs as they are all addressing emissions on two of the engines, either two Avon units or one Avon and one RB211. The optimum combination however is offered with options 10a and 10b due to the comparatively lower liability costs for the greater capability offered by the RB211 compared to an Avon.

Considering liabilities in more detail, it can be seen how the options accrue costs differently over time. Liability costs do not play a particularly key role in the short term and they tend to be far more significant after 2030 than before, due to the 500 hour limitation applied to Avon units under MCP. However, most of the investments will occur in the shorter term, over a broadly similar time period regardless of which option.

As seen on the chart below, Options 9a, 9b and 9c have similar capability and so have near identical liability costs. The same is true for Options 10 and Options 11. Whilst there are some constraints before 2030, under all options these costs do not become sizeable until after the impact of MCP. Post 2030, when any remaining unabated units are placed on Emergency Use Derogation (500 hours per year) the overall capability of the site will be significantly reduced once these hours are used up. In Option 8a this loss of capability is particularly significant as there are less units not subject to the 500 hour limit.

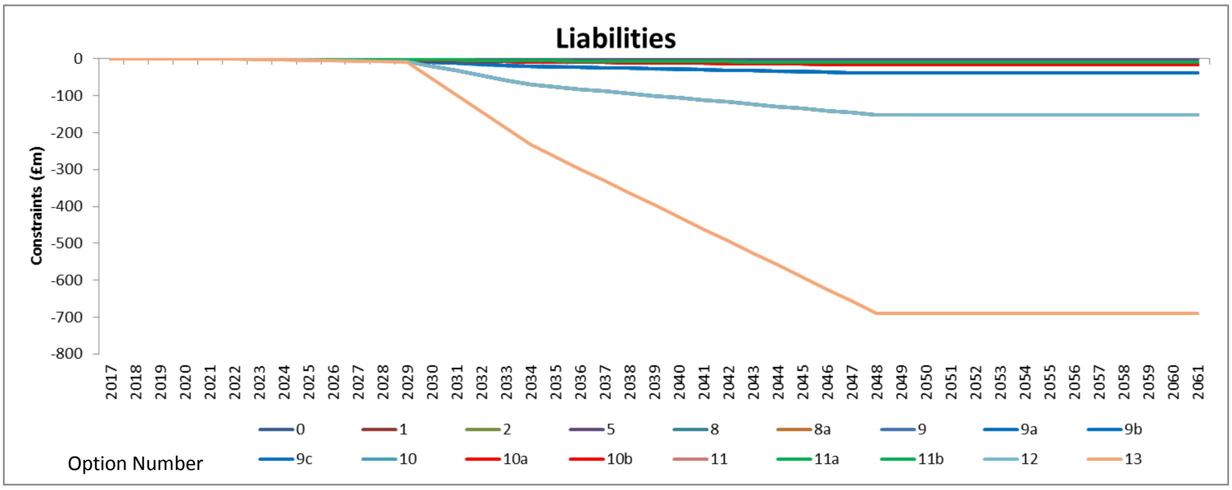


Figure 6.2: Liability costs

In comparing options over the full timeline of the analysis, higher capability options are valued highly with the higher investment costs offset by lower liabilities.

6.3.3 Sensitivities

Given the uncertainties over the flows at St Fergus a number of sensitivities have been explored to test the results of the CBA, in particular the ranking of the options. To test for the impact of lower flows a sensitivity test was run using the Slow Progression FES scenario, which has the lowest flows through St Fergus terminal. This is compared to the Steady State FES scenario with higher St Fergus flows. As expected, the consequence of lower flows was reduced liabilities so this sensitivity reduced the relative benefit of the options with greater capability than the counterfactual.

Another key uncertainty is the reliability and availability of the compressors, in particular the VSD units. The VSDs should experience the highest number of running hours. However, since commissioning in 2015, the start reliability of both VSD units has been low. Whilst it can be expected that over time any teething issues will be resolved so that overall reliability improves, there is still the risk of a serious compressor failure which for an electric drive unit, means that the unit is taken out of service for a prolonged period of time (6+ months). A sensitivity scenario was created that assumes the availability of these units is just over 50%. This significantly increases the liabilities seen across all options, but far less so with those with the greatest capability such as options 11a and 11b.

Relative NPV (£)	Central	Low Availability	Low Flows
	Steady State scenario with 75% availability	Steady State scenario with 75% availability on gas turbines and 56% on VSDs (Position Ranking)	Slow Progression scenario with 75% availability (Position Ranking)
Option 10b	54.3	220.6 (3)	-5.7 (2)
Option 10a	51.0	217.7 (4)	-8.6 (3)
Option 9b	39.7	175.8 (6)	-13.9 (4)
Option 9c	33.6	168.7 (8)	-21.6 (6)
Option 9a	33.2	170.9 (7)	-19.7 (5)
Option 11b	31.4	270.2 (1)	-29.4 (7)
Option 11a	24.9	262.0 (2)	-37.2 (8)
Option 10	20.6	187.5 (5)	-39.4 (9)
Option 8a	1.7	1.8 (9)	1.8 (1)

Table 6.2: Low availability and low flow sensitivities

6.3.4 CBA Summary

The CBA analysis has provided a consolidated short list of options. As well as the counterfactual, the analysis focusses on Options 10a, 10b, 9a, 9b and 9c which do well in overall NPV terms. However in the short term (up to 2030) and in low flow scenarios the counterfactual and Option 8a is favoured. Option 11 offers high capability so is a highly ranked option in low availability scenarios. Options 10a and 10b are consistently ranked highly across the sensitivities. There are however, combinations of units involving SCR and new units across a range of levels of capability where it is not possible to clearly distinguish the benefits of one option over another. To assist with this, and to validate the results of the CBA a more complex technique involving prescriptive modelling was introduced.

6.3.5 Prescriptive Modelling

The prescriptive modelling technique involves modelling multiple constraints including operational, asset and financial constraints and accounting for asset interdependencies. The model can therefore be used for the St Fergus terminal analysis to calculate the impact of various forecasts or scenarios whilst also taking into account operational constraints. Having used the prescriptive model to incorporate a wider range of input variables and criteria than the CBA, the results were then used iteratively to improve the CBA e.g. inclusion of compressor fuel data.

The absolute NPVs are different between the two techniques due to the different treatment of risk, liabilities and fuel costs in the two tools. The average NPV under the prescriptive modelling is -£711m, compared to -£833m under the CBA. However as shown in the table below, the relative ranking of the NPVs is broadly similar with Options 10a and 10b looking favourable using either technique.

NPV Position Ranking	CBA	Prescriptive Modelling
1	Option 10b	Option 10b
2	Option 10a	Option 10a
3	Option 9b	Option 10
4	Option 9c	Option 0
5	Option 11b	Option 11a
6	Option 9a	Option 11b
7	Option 11a	Option 11
8	Option 10	Option 8
9	Option 8a	Option 9
10	Option 9	Option 9b
11	Option 0	Option 9a
12	Option 8	Option 8a
13	Option 11	Option 9c
14	Option 12	Option 12

Table 6.3: NPV position ranking

Primarily, the prescriptive model can more clearly illustrate the benefits of options 10a and 10b - whereby the lowest TOTEX costs are combined with significant emissions reduction (63% less than the counterfactual). Option 11a does offer higher emission reduction but at £30m higher TOTEX over the evaluation period.

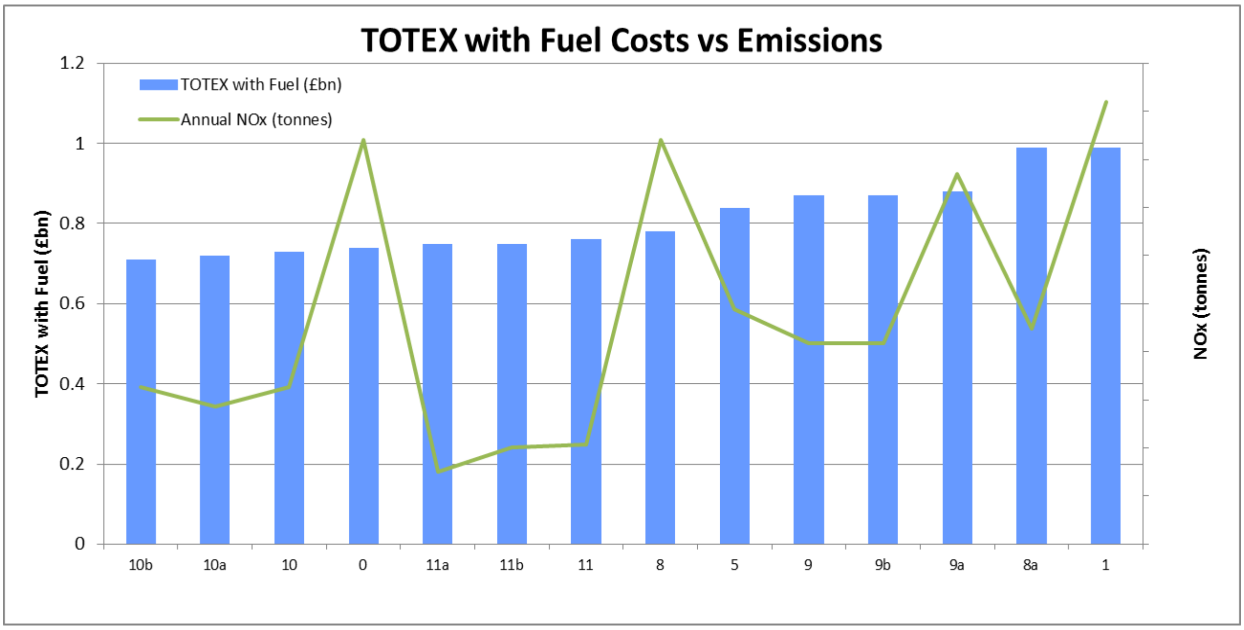


Figure 6.3: TOTEX with fuel costs vs emissions

The counterfactual (Option 0), Option 8, 8a and 12 all have significantly higher NOx emissions than the other options which is not favourable under the requirements of IPPC. It is noticeable that Options 9a, 9b and 9c are not favourable options using this prescriptive modelling technique (position 9 and lower out of 14), although they were more highly ranked options under the CBA. Option 11 is more strongly favoured. This can be explained by the more complex risk calculations in the prescriptive tool. In general the option 9 variants, with fewer units overall, have a much higher risk of simultaneous asset failure (as shown in the chart below), with financial penalties associated with end of day shortfall. Although the Option 11s have higher capital and operational costs, this is offset by higher resilience to risk of multiple asset failure.

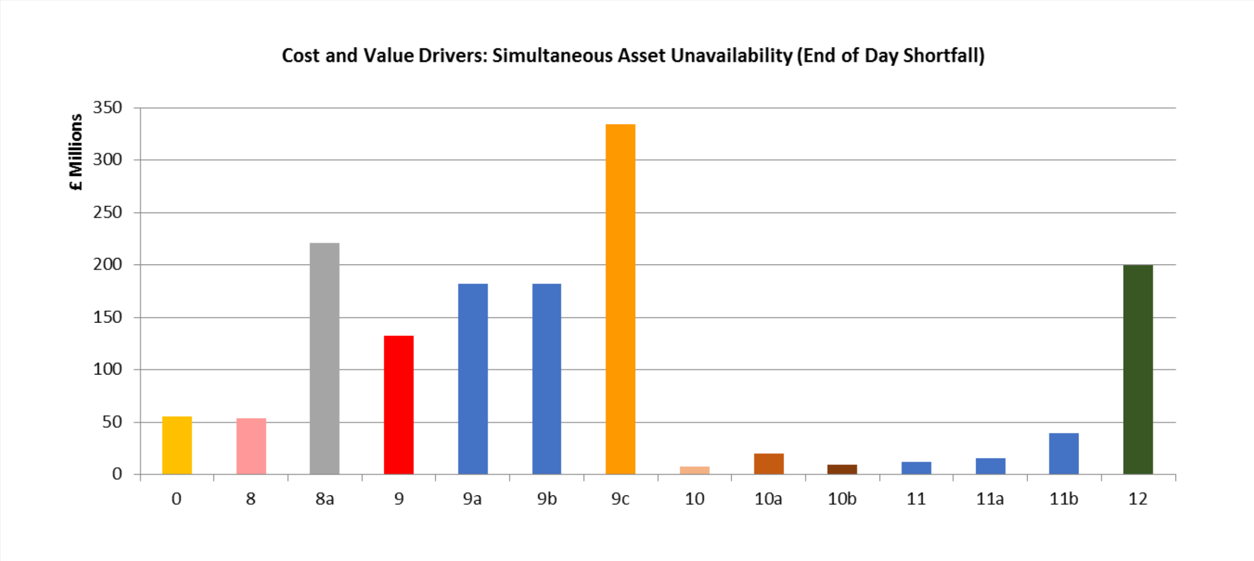


Figure 6.4: Simultaneous Asset Unavailability

Option 8a includes in investment in one Avon on Plant 1, ranks less highly in the prescriptive model, than the CBA due to the 'plant balance' and risk of simultaneous asset unavailability. The balance of capability between Plants 1 and 2 is a key operational consideration and whilst the value of this operational aspect is not calculated within the CBA, it is captured within the prescriptive model. Uneven capability between the two plants could result in insufficient back-up to the electric drives should the more capable of either Plant 1 or 2 be on outage. Under Option 8a, the capability is heavily weighted towards Plant 1. The prescriptive model analyses the impact of multiple failure types; simultaneous asset unavailability, single asset unavailability and trip impacts. But specifically the model can derive the financial consequences of the risk of asset failure of one plant, as shown on the chart below. Eight options are vulnerable to this type of asset failure- losing one single plant, with options 8a and all the options 9 showing the highest financial risk.

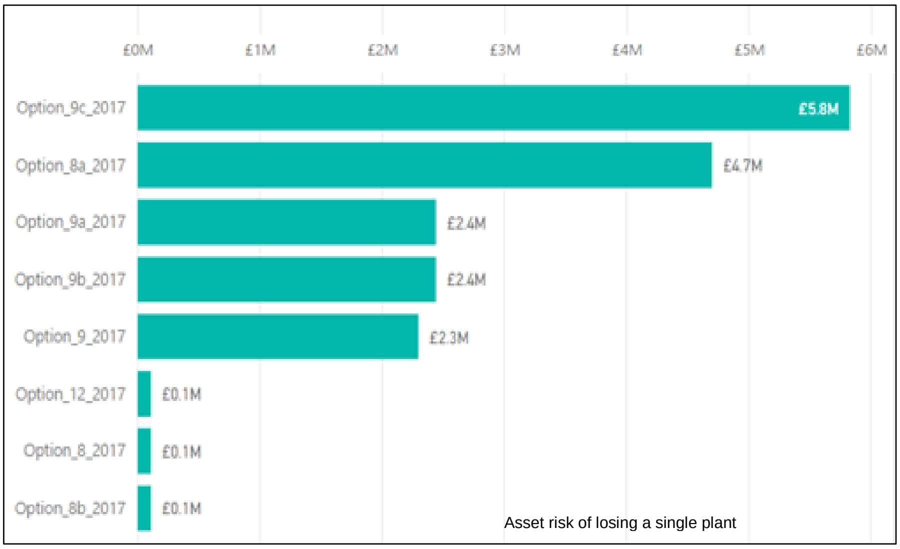


Figure 6.5: Asset failure risk

In considering all the cost and value drivers for the top five options under the prescriptive model in more detail, although the total investment costs, comprising investment in new assets, asset health and decommissioning costs, for Option 0 are the lowest (£152m), the costs associated with unavailability are significantly higher than under any other option.

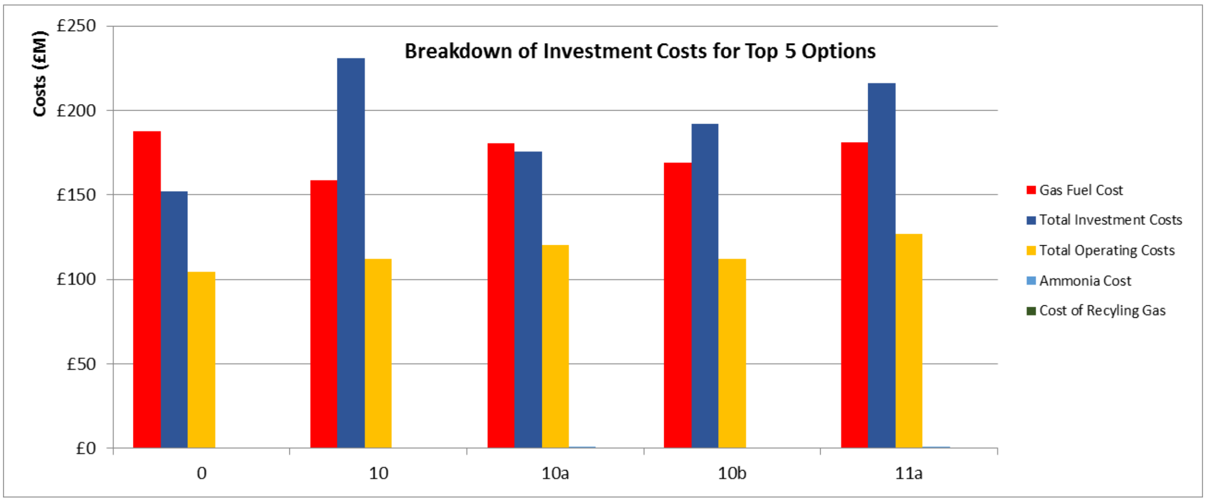
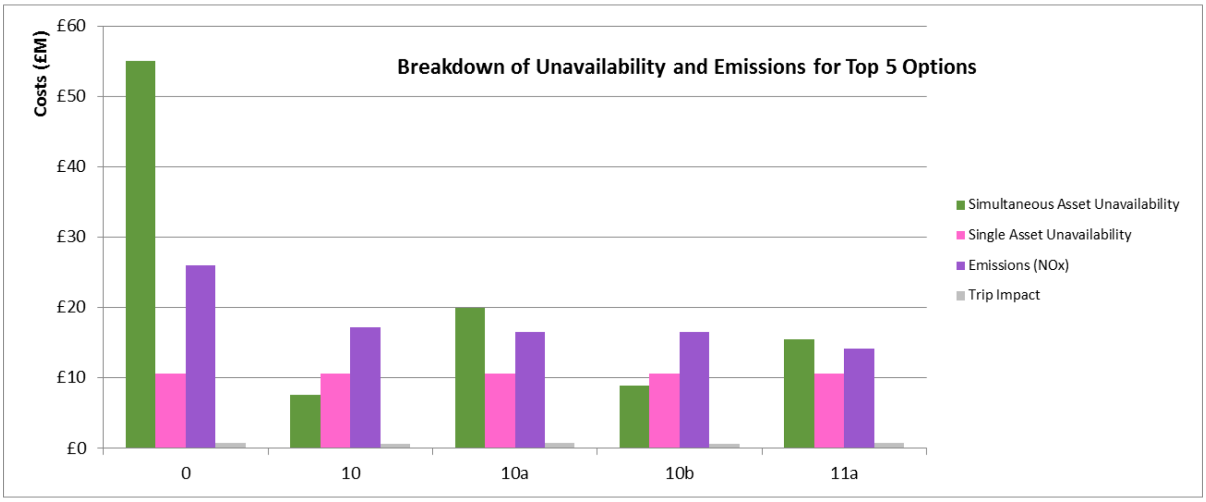


Figure 6.6: Cost breakdown



Note: Due to scale, electricity costs are not included in the charts above. These costs are very similar across all options, ranging from £415m – £419m

Figure 6.7: Unavailability and emissions breakdown

Total investment costs are lower under Options 10a and 10b (£176m and £192m respectively), than under Option 10 (which is a greenfield option, £216m). Electricity costs to run the VSD units remain fairly consistent at around £415- £419m across all options. Total operating costs are higher for the higher capability options – Option 11, and also the options including SCR, whereby more regular maintenance overhauls are required. Gas fuel costs are lowest under Options 10 and 10b; both options have new gas units, which have a higher efficiency compared to the SCR options. Comparing the aggregate cost of all investment, operational and unavailability variables across the five options, 10a and 10b have the lowest TOTEX, as per Figure 6.10.

6.3.6 Emissions: NOx and CO

The prescriptive analytics tool calculates the NOx and CO levels for each of the options. From the chart below it is possible to see emissions impact of each of the options considered. Options 8 and 9 with small units (both new and SCR) show higher levels of NOx and CO. Option 11 with a combination of large and small units shows the lowest levels of NOx. Option 10 sits in a middle rank position. Across all options where a new unit is installed over a SCR unit, emissions are higher. This is because the emissions abatement technology will reduce emissions to a value lower than what can be achieved by a compliant new unit.

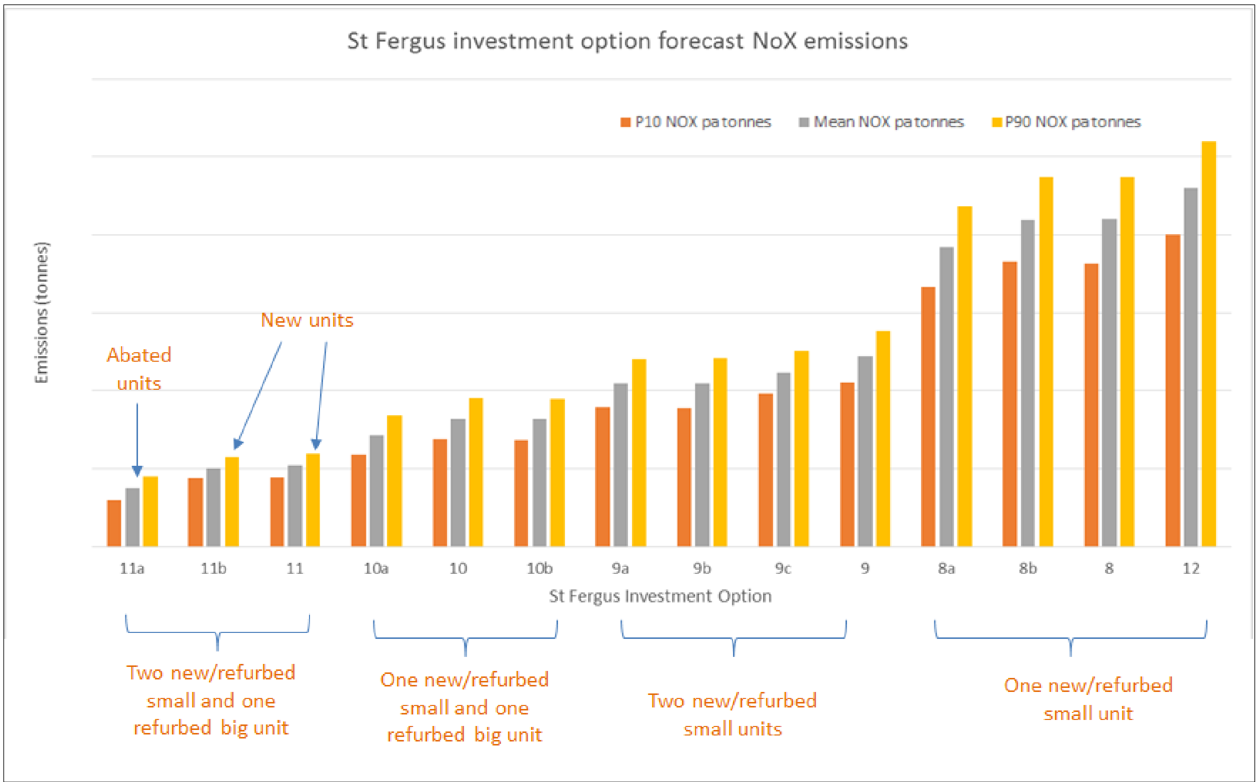


Figure 6.82: Forecast NOx

6.3.7 Stress Tests

A number of stress tests were designed to examine the consequences of changing key inputs within the prescriptive model. In particular the stress tests considered increasing capital expenditure; even with 90% higher capex, option 10b and 10a remain second and third in the ranking position. Increasing the costs or the emissions associated with SCR technology does not alter the ranking of options 10b and 10a. Changing the model's assumptions around asset failure and the risk of liabilities also does not alter the ranking of options 10b and 10a. These limited changes in position of the top five options provide reassurance around the robustness of the options assessment.

Position Ranking	Base Case	All options 90% higher Capex	SCR Capex plus 10%	Failure rate frequency increased by 90%	Consequence of asset failure increased by 90%	SCR emissions plus 100%	Low Flow Supply from NSMP
1	Option_10b	Option_0	Option_10b	Option_10b	Option_10b	Option_10b	Option_0
2	Option_10a	Option_10b	Option_10a	Option_10	Option_10	Option_10a	Option_10b
3	Option_10	Option_10a	Option_0	Option_11a	Option_10a	Option_10	Option_10a
4	Option_0	Option_10	Option_10	Option_10a	Option_11a	Option_0	Option_10
5	Option_11a	Option_8	Option_11a	Option_11	Option_11	Option_11a	Option_11b
		[Option_11a = 6]		[Option_0 = 6]	[Option_0 = 6]		

Table 6.9: Option ranking of sensitivities

6.3.8 Optionality (Qualitative)

Looking out to the long term impacts of the IED decisions, there are some permanent consequences associated with certain options. The main impact is the loss of capability provided by the RB211s post 2023 for options 8a, 9a, 9b and 9c. Options 10a /10b however retain the RB211 capability, and also retain future options on additional Avon units. This is captured in a non-quantitative way in the chart below:

Option	Total Capability	Retain RB211	Future Capability through existing Avon	Optionality Position Ranking
Option 8a	VSD + 75	No	Yes (5 units)	
Option 9a	VSD + 75	No	Yes (5 units)	
Option 9b	VSD + 75	No	Yes (5 units)	
Option 9c	VSD + 60	No	Yes (4 units)	
Option 10a	VSD + 105	Yes	Yes (5 units)	2
Option 10b	VSD + 120	Yes	Yes (5 units)	1
Option 11a	VSD + 90	Yes	Yes (4 units)	=3
Option 11b	VSD + 90	Yes	Yes (4 units)	=3

Table 6.10: Optionality

The prescriptive analysis models operating hours as shown on the chart below. This shows Avon units operating in the region of 200-400 hours per year in a central case scenario. 400 hours per year would be approaching very close to the rolling 500 hours derogation limit and from an operational perspective could result in unacceptable risk. Looking forward to the decision around MCP and variability in the long term flow levels through the terminal, keeping options open for the existing Avon units is strategically valuable.

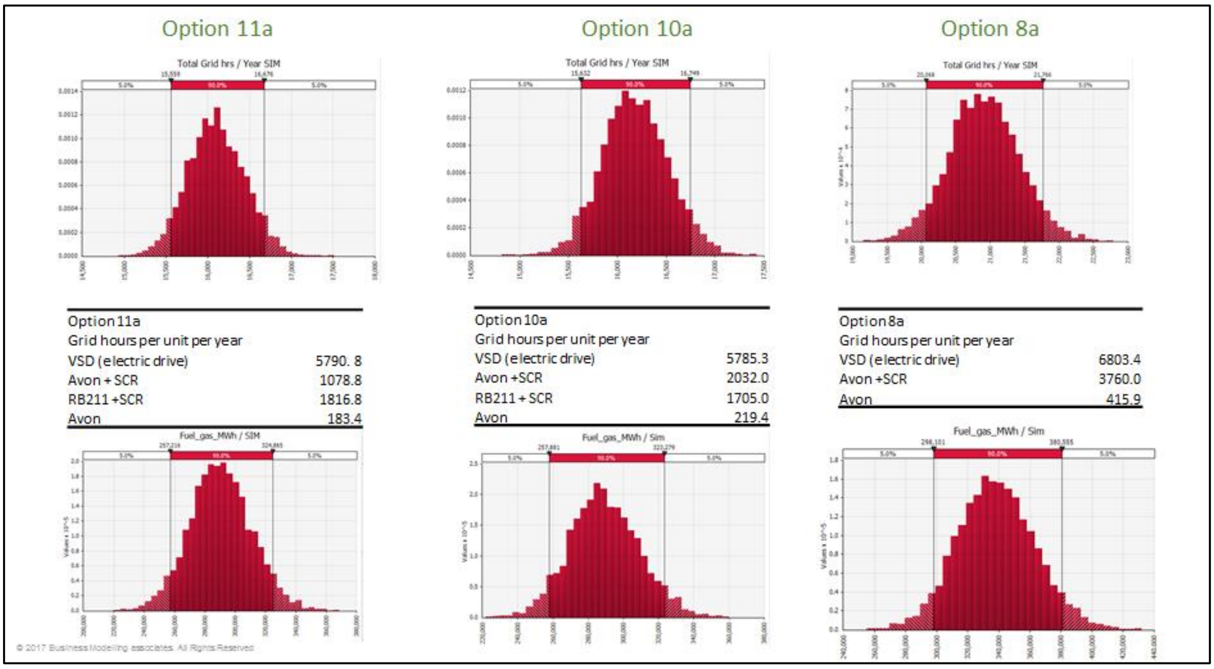


Figure 6.3: Operating hours

7 Stakeholder Engagement

The consultation for this reopener builds on the comprehensive programme of stakeholder engagement undertaken in 2015. In addition to a series of workshops in October 2016, we have conducted several bi–lateral meetings with interested parties and have incorporated their views. In January and February 2018 there were two presentations at the Transmission Working Group, where we shared our analysis and responded to questions from stakeholders. A formal consultation was held between 14th March 2018 and 13th April 2018. There were several responses relevant to St Fergus: some respondents noted the wide range given for the costs of new compressors and emissions abatement, and indicated a preference for new units if the whole life costs of each option was very close. One respondent noted that the cost to producers of constraints at St Fergus was likely to exceed the UNC costs that we had assumed. We asked respondents whether they agreed with our specific proposals for each compressor site. Two respondents expressed an opinion about our proposals at St Fergus; both stressed the importance of maintaining compression capability at this important location, but suggested that the wide cost ranges made it difficult to assess whether these were the best options.

8 Recommended Options

A summary of the top options under each technique and scenario is presented in the table below:

	Core		Sensitivities					
OPTION Place	NPV	Prescriptive Model	Low Availability	Low Flows	Prescriptive Model Stress Tests	Emissions	Plant Balance	Optionality
1	Option 10b	Option 10b	Option 11b	Option 8a	Option 10b	Options 11	=10b	10b
2	Option 10a	Option 10a	Option 11a	Option 10b	Option 10a	Options 1, 2, 5	=10a	10a

3	Option 9b	Option 10	Option 10b	Option 10a	Option 10	Options 10	=10	=11a
4	Option 9a	Option 0	Option 10a	Option 9b	Option 0	Options 9	=11b	=11b
5	Option 11c	Option 11a	Option 10	Option 9a	Option 11a	Options 8, 0	=11a	

Table 8.1: Recommendation

Having considered a number of variables, including financial CBA and other non-monetised aspects, the recommendation is to take forward options 10a and 10b to FEED (Front End Engineering Design). These options provide the lowest overall NPV under the CBA, and the underlying risk and cost analysis from the prescriptive tool favours these two options. 10a and 10b both combine low cost and low risk together with flexibility to perform well under key sensitivities and produce lower emissions than the counterfactual.

While option 8a does result in the lowest overall cost prior to 2030 the loss of optionality of installing SCR would result in higher overall costs in the long term. In addition, it delivers significantly lower emissions reduction than the other lead options.

Option 10a and 10b therefore represent the optimum solution to comply with the emissions legislation.

9 Delivery

The initial sanction of the St Fergus investment was made in August 2016, the output from which defined the strategic approach for the site. Incorporating the preferred options from the CBA, the FEED and feasibility sanction was approved in December 2017. With the FEED now underway, the approval to proceed to conceptual design and procurement of long lead time items is currently expected to begin in January 2019. As part of this process we have updated costs for the preferred options from those included in the CBA. These revised costs incorporate the timings associated with installing two units in one combined programme under Options 10a and 10b.

10 Conclusion

The recommended decision based on output from the tools, the CBA, prescriptive modelling and emissions data is to take forward two options (10a and 10b) to FEED (Front End Engineering Design). Option 10a is the application of emissions abatement technology; SCR on one Avon unit to ensure compliance with IPPC and SCR and Oxidation Catalyst on the RB211 Unit 2D under the LCP directive. Option 10b involves a new Avon-sized unit on the empty 2C berth for IPPC compliance and SCR and Oxidation Catalyst on the RB211 Unit 2D under the LCP directive. The FEED process will provide greater detail and accuracy on the option costs and allow for a choice to be made between these two final options.

The table below summarises the funding request based on Option 10b. The total option cost is less than £10m for decommissioning one unit, plus £20-40m for one new Avon sized unit and plus £20-40m for emissions abatement on one RB211.

Funding Request Summary (09/10 price base)

New Avon Unit: £20-40m

Emissions abatement on one RB211 Unit: £20-40m

Decommission one RB211: less than £10m

RIIO Output - Emissions compliance on one Avon unit and one RB211 unit at St Fergus.

RIIO-T1 Activities - Completion of FEED (Front End Engineering Design) incorporating recommended option. OEM (Original Equipment Manufacturer) contract awarded and unit design and FAT (Factory Acceptance Test) complete. EPC (Engineering, Procurement and Construction) contract awarded and detailed design commenced.

T1 Expenditure Risk: The risk of not completing the works prior to 2021 is medium. The FEED process is underway.