Gas
Transmission

Our Performance.

2017/2018.

nationalgrid

National Grid Gas Transmission

Our Performance for 2017/18

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I. Strategic Performance Overview (SPO) for 2017/18

1. This report describes the financial and operational performance of National Grid Gas Transmission (hereafter abbreviated to National Grid) against the stakeholder outputs we have committed to deliver.

Director update on Business Plan, risks and future strategy

Performance Overview

2. I am proud to report that we have delivered strong output performance which is consistent compared to last year in most areas. Financially we have implemented a number of actions to drive efficiency in our Opex and Capex spend. I am pleased to report that this has led to a £85m performance improvement compared to last year, which means a reduction in our forecasted overspend to £151m for the RIIO-T1 period. We have again delivered strong customer satisfaction performance with customers remaining a key priority.

3. Our 2017/18 performance is contextualised by the operational challenges the business has faced during the financial year. We have effectively facilitated the delivery of 99.9% of gas requirements for customers. Achieving this level of performance is becoming more challenging year-on-year as we experience a continued trend of our customers using the network in different and more flexible ways.

4. When compared to 2016/17 we have seen an increase in supply point differences both within day and day-to-day. Overall compressor running hours have again increased compared to 2016/17, which had already doubled compared to 2015/16. Responding to these challenges requires us to ensure we continue to invest in our forecasting capability, configure the network in new and innovative ways, and continue to facilitate the increased volumes of maintenance in the summer months that result from much heavier use of our compressor fleet during the winter.

5. During winter 2017/18 we faced significant operational challenges as a result of the cold weather in February/March 2018 where we saw the highest level of daily demand in eight years (417.6 mcm). We saw a number of supply trips across the network late on the 28 February gas day, which when combined with the forecast for the 1 March gas day, led us to issue a Gas Deficit Warning to the industry in order to highlight the risk and encourage more gas to be brought onto the network. We are proud that through our actions the system was balanced by the end of the day and all necessary assets performed well with the demand placed on them.

6. To ensure safe, reliable and affordable gas supplies for current and future consumers we continue to improve the asset health of our network where there is a sound asset management need and it is in consumers' interests. As a consequence of higher compressor utilisation there is an increased need for

compressor remedial works which when combined with the overall increase in maintenance, repair and refurbishment of ageing plant and the way customers are using our network, creates significant challenges in acquiring the necessary outages.

7. In May 2018 we made five regulatory submissions to Ofgem to adjust our allowed funding through the reopener uncertainty mechanism. The submissions covered the Industrial Emission Directive (IED), One-off Asset Health Costs (Feeder 9), Enhanced Physical Security, Enhanced Security (operational) and Quarry and Loss. The impact of the reopeners is a forecast adjustment to increase allowances of £106m and the generation of a number of new outputs for consumers, namely emission reduction on one compressor unit at St Fergus, emissions compliance at Hatton equivalent to one large compressor unit and decommissioning of the compressor station at Warrington related to our *"Industrial Emissions RIIO-T1 Reopener Submission"*.

Output Delivery

8. We have continued to deliver strong performance for our customers against our five output categories, with performance broadly consistent to 2016/17. Table 3 on page 14 summarises our performance against each individual output and provides a comparison to our 2016/17 performance.

9. We have delivered strong **safety** performance with no injuries to the public and only one Gas Transmission employee lost time injury in 2017/18. We also remain on track to meet the Department for Business, Energy and Industrial Strategy (BEIS) requirements by introducing enhanced physical site security at our key sites. In May 2018 as part of the reopener window, we put forward our updated plans to comply with the BEIS requirements for further enhanced physical site security.

10. In 2017/18 we have continued to provide high levels of **reliability and availability** for our customers. This year we have again maintained a strong level of communication with our stakeholders throughout days of increased supply point differences described above. We held an extraordinary operational forum with around 70 attendees across the industry on 27 March 2018. Our customers have also benefitted through a reduction of £1.8m in our Operating Margin (OM) costs.

11. In 2017/18 we have increased our spend on asset health works by an additional 26%. We are forecasting to deliver the number of Replacement Priority 1 (RP1) assets reported through the current Network Output Measures (NOM) regime and remain on target to deliver all NOMs in aggregate by the end of RIIO-T1, thus maintaining the health of the network for the benefit of current and future consumers. This increase in work has been enabled by the surveying and planning work undertaken in the initial years of RIIO-T1 and the establishment of asset health campaigns to drive an increase in the volume and efficiency of work delivery.

12. In 2017/18 we made good progress with our key investment projects such as our River Humber Gas Pipeline Replacement Project (Feeder 9) which will replace a

3 km underwater section of the Feeder 9 pipeline with a tunnelled solution. This pipeline section is one of the most critical to UK gas supplies on the National Transmission System (NTS) and removing the risk associated with both tidal estuary erosion and third party interference is essential in continuing to provide a reliable and secure gas supply to our customers. Tunnelling activities commenced at the end of 2017/18 and in May 2018, as part of the reopener window, we submitted our project build funding request for the Feeder 9 pipeline, having achieved planning consent.

13. Changing supply patterns have had a significant impact on our **environmental** outputs. Moving greater volumes of gas away from entry points has resulted in increased emissions from our gas compressor fleet. This has negatively impacted our Green House Gas (GHG) emissions incentive. We provide our annual emissions performance as part of our Carbon Disclosure Project (CDP) submission. This enables us to benchmark our performance against other organisations. In 2017 we achieved an 'A' rating for our CDP submission, putting us in the top 5% of global companies recognised for our actions to reduce emissions and mitigate climate change.

14. We have delivered broadly consistent performance in **customer satisfaction** with the same stakeholder satisfaction score and a slight reduction of the customer satisfaction score. In 2017/18 our customer and stakeholders remained a key priority. As part of our customer transformation programme we have identified drivers for customer satisfaction and how to improve their experience. An example of our continued focus on our customers are the customer education activities on Constraint Management and the Capacity Regime we carried out in 2017/18. These activities received positive feedback from our customers.

15. In terms of **customer connections**, we continue to improve the service we offer both in terms of the products and charging structure. We are undertaking a self-lay trial with one customer and are progressing well with our Network Innovation Competition (NIC) funded Customer Low Cost Connections (CLoCC) project, which aims to reduce the time and cost to connect. In addition, we have met all requirements associated with connection and capacity requests submitted by our customers, except in one case where we agreed a delay of two days with a customer.

16. **Innovation** enables us to seek opportunities to deliver the greatest value for consumers. In 2017/18 we undertook 39 Network Innovation Allowance (NIA) projects, which focused on delivering value to the consumer and driving step changes in our key strategic innovation areas. We have developed a robust value tracking process which has demonstrated that £8.6m in value has been delivered by innovation to date based on a £1.9m NIA spend; a 4:1 cost-benefit ratio. A notable success this year has been the completion and first use of the Valve Sealant Line Grouted Tee. This facilitates the repair of corroded sealant lines, avoiding a costly full excavation to replace the main line valve. The first use of the tool on three valves at Kings Lynn Tee saved £817k and 1,500 tonnes of Carbon Dioxide (CO_2) compared to traditional methods of replacing the valve.

Financial Performance

17. Across RIIO-T1 our Totex is planned to be £3,188m against an allowance of £3,037m. This results in a forecasted spend above allowances of £151m which is an improvement of £85m compared to 2016/17. Over the RIIO-T1 period we plan to invest circa £1.9bn of Capex across our overall business.

18. The change in performance is due to a decrease in forecast Totex of £236m and a decrease in forecast allowances of £151m. The allowances have decreased as a result of our updated integrated plan for our IED investments and our updated view on Enhanced Physical Site Security investments based on the reopener submissions in May 2018. For our forecast allowances in the five categories relating to the reopener submissions we have assumed allowances equal costs.

19. We are forecasting to spend above our allowances in the areas of Transmission Owner (TO) Non Load Related Capex, TO Non Operational Capex and TO Opex. The improvements against allowances in 2017/18 are mainly a result of driving efficiencies in delivering our Capex projects and actions to reduce our Opex spend. Details on performance against allowances for each area and changes in performance compared to 2016/17 are detailed in the Performance Summary section.

Consumer Bill Benefit

20. In 2017/18 approximately £8.79 of an average domestic consumer bill of £569 related to the services we provide which equates to 1.6% of a typical gas bill. This compares to 2016/17 where the National Grid element of the consumer bill was £9.32 and the average bill cost was £604 (which also equates to 1.6% of a typical gas bill). The reduction in the average bill cost is largely driven by a reduction in average consumption by consumers. In 2016/17 average consumption was 12,500 kWh compared to 12,000 kWh in 2017/18.

Key Risks and Looking Ahead

21. In terms of major risks, our key areas of focus remain on managing our ageing asset base whilst facilitating changing customer requirements, responding to the dynamic cyber threat landscape and efficient and timely delivery of a number of high value projects, e.g. the River Humber Gas Pipeline Replacement Project (Feeder 9).

22. In 2017/18 we had a less balanced network which required higher utilisation of our compressor stations and resulted in increased venting of GHG. This comes at a time when we are requiring more outages to facilitate increasing asset health work of our ageing plant. As the long term need for the gas network has become clearer and we are reaching the physical end of life of a number of assets across the network, there is now a need to strategically re-life the network to deliver the required safety and reliability performance to meet our customers' expectations.

23. In 2018/19 our annual Capex spend will increase further, this is a result of the construction of the Feeder 9 tunnel, the compressor emission reduction work at Peterborough and Huntingdon and increased Enhanced Physical Site Security spend. Our focus will be on delivering these investments safely and efficiently. Following our five regulatory submissions to Ofgem in May 2018 to change our allowed funding through the reopener uncertainty mechanism, we will implement the outcome and continue the delivery of these key investment projects and associated outputs in 2018/19.

24. We will continue to innovate and seek to drive efficiencies in our operating costs and in delivery of our investment projects. As part of our drive for efficiency we have recently launched a consultation process with our employees on reviewing how we work to improve the experience for our customers. We will be exploring whether we are doing the right type of work, managing the right kind of processes and developing the right kind of capabilities to meet our customers' future needs. This process is in its early stages and our forecasts do not include the full resulting costs and benefits which will only become clear over the coming months.

25. A further requirement is to decarbonise the energy system by 2050 in the most affordable and least disruptive way. Customers and stakeholders have told us that gas has an integral role to play in delivering the most cost-effective decarbonised future across power, heat, transport and industry. In 2018/19 we will be further engaging with industry, policy makers and consumer groups to progress our understanding of the future of gas and what different futures mean for the Gas Transmission network. This work will help to underpin our next price control submission to ensure that the most efficient and sustainable solutions are selected for our customers.

26. Following submission of the final NOMs Methodology document in May 2018 we are currently developing our data/model validation approach, which will be agreed with Ofgem prior to submission of our final validation report later in 2018. This will give stakeholders confidence that the monetised risk calculations are robust and based on the best available evidence, in support of future Regulatory Reporting Pack (RRP) reporting and investment planning applications. We have also developed, and shared with Ofgem, a draft approach for rebasing our RIIO-T1 License targets using the principles of monetised risk. This will be used to assess our asset health investment performance at the end of the current regulatory period and quantify any due rewards or penalties, as part of RIIO-T1 close-out. It is expected that we will report using our new NOMs Methodology for the 2018/19 RRP.

27. I trust you find this performance report informative and we would welcome any feedback on how we can improve our reporting.

Phil Sheppard (Director, National Grid Gas Transmission Owner)

Performance Summary

Financial performance

28. Our Totex for the RIIO-T1 period is forecasted to be £3,188m against an allowance of £3,037m. This results in overspend of £151m, which is an improvement of £85m on the prior year.

29. Overall, we are still forecasting to spend above our allowances in RIIO-T1. Our improvements compared to 2016/17 are mainly due to further actions to drive efficiency in our Opex and Capex spend.

30. With reference to the restated[1] Totex table (see Appendix I. Totex Tables) compared to last year our forecast spend has decreased by £236m on a constant 2017/18 price base and the adjusted allowances have decreased by £151m.

Table 1: Eight-Year Forecasted Spend and Allowances Overview

Activity	Spend (£m)	Allowance (incl. uncertainty mechanism) (£m)	Cost vs Allowance (£m)
TO Load Related Capex	34	44	10
TO Non Load related Capex	1,422	1,346	-76
TO Non Operational Capex	131	70	-61
TO Opex	851	739	-112
SO[2] Capex	266	328	62
SO Opex	484	510	26
Total	**3,188**	**3,037**	**-151**

31. Based on the table above the main areas of differences between cost and allowances relate to:

- TO Load Related Capex – we are forecasting to spend below allowances as a result of lower spend on Scotland 1 in 20 as we continue to assess the need for these projects and System Flexibility where spend has been incurred within SO Opex. This is partially offset by additional spend to complete commissioning works of the Felindre Variable Speed Drive (VSD).

- TO Non Load Related Capex – we are forecasting to spend above allowances in terms of Asset Health. This is a result of us continuing to observe that the actual network condition is at a lower level (i.e. more observed condition

[1] In order to better understand the underlying position of spend versus allowances, Table 2.4 is restated to better align allowance with spend categories. This is within the IED category only. Restated Table 2.4 is included in Appendix I of this report.
[2] System Operator (SO)

issues) than the modelled view within our NOMs methodology, but we are continuously looking for efficiency in delivering the work required. We are forecasting to spend below allowances on the Aylesbury IED-Large Combustion Plant (LCP) works delivering an innovative catalyst solution, this is partly offset by additional spend on Integrated Pollutions Prevention and Control (IPPC) phase 1 and 2 works from the last price control period.

- TO Non Operational Capex – we are forecasting to spend above allowances driven by the need to invest in data and systems to improve the management of asset health of our network. We are also delivering additional projects on general cyber security and Project One, which is an update to our Enterprise Resource Planning (ERP) software.

- TO Opex – we are forecasting to spend above allowances on Business Support costs and Closely Associated Indirect costs. Costs in this area are to deliver the increase in asset health spend, which also has an impact on Business Support costs to support the larger business.

- SO Capex – we are forecasting to spend below allowances as a result of lower forecasted spend on Xoserve and Telemetry separation. The level of Xoserve spend is predominantly driven by the change in our Gemini strategy and a lower level of expected EU related Gemini change work than anticipated at the beginning of RIIO-T1.

- SO Opex – we are forecasting to spend below allowances due to a higher proportion of Xoserve allowances allocated to Direct Opex following the outcome of the review of agency costs.

32. Compared to the performance of cost against allowances reported in 2016/17 the main reasons for change are:

- TO Load Related Capex – compared to 2016/17 our performance compared to allowances in this area has increased by £4m, which is a result of a reduction of forecast spend on Environmental Aftercare.

- TO Non Load Related Capex – compared to prior year we have improved our performance by £35m. This is predominantly due to further scope certainty for Peterborough and Huntingdon IPPC phase 3 and 4 works reducing forecast spend and an adjustment of allowances compared to the prior year to align with the reopener submission. Additionally, we are forecasting efficiencies in delivery of lower cost options in General Asset Health spend, for example the use of high efficiency gearboxes within the National Above ground installation Renovation Campaign (NARC).

- TO Non Operational Capex – compared to 2016/17 we have seen reduced spend which is primarily driven by reduced IS spend. This is a result of scope reduction and efficiencies in delivering our back-office system and capability, following a review of the associated benefits case.

- TO Opex – compared to last year we show a £17m performance improvement. The reduction in spend is related to Closely Associated Indirect costs, partly driven by the change of scope of our transformation programme, and a reduction in planned inspection and maintenance. The forecast for planned inspection and maintenance was increased last year following the higher compressor utilisation seen in 2016/17. However we have not experienced the increase in costs expected, therefore the forecast has been reduced. The reduction in Opex was to an extent offset by increased business support costs.

- SO Capex – our performance compared to last year has improved by £17m which is primarily driven by a further reduction of Xoserve spend (moving to a sustain rather than a refresh strategy) and a continuing reprioritisation of our IS investments.

- SO Opex – compared to the prior year we are reporting a small decrease in performance of £1m driven by increased Business Support costs, partially offset by reduced Direct costs, including Xoserve related spend.

Return on Regulated Equity (RoRE)

33. In 2017/18 we have seen an increase in the eight-year average Return on Regulated Equity (RoRE) to 7.67% compared to 7.46% in 2016/17. Our RoRE is broken down in the table below.

Table 2: RoRE Breakdown

Activity	**2017/18 RRP 8 Year View**
Cost of Equity	6.80%
Under/(Over)spend Proportion Retained by TO	-0.56%
IQI[3] Additional Income	-0.06%
Stakeholder Satisfaction Output	0.16%
Permit Arrangements	0.14%
Various Payments	0.00%
Retained Tax Under Tax Trigger Deadband	0.06%
Under/(Over)spend Proportion Retained by SO	0.22%
SO IQI Additional Income	-0.02%
Constraint Management Incentive	0.49%
NTS Transportation Support Services Incentive	0.10%
NTS Shrinkage Incentive	0.18%
Residual Gas Balancing	0.04%

[3] Information Quality Incentive

Activity	2017/18 RRP 8 Year View
Quality of Demand Forecasting Incentive	0.11%
Greenhouse Gas Emissions Incentive	-0.02%
Maintenance Incentive	0.03%
SO Retained Tax Under Tax Trigger Deadband	0.00%
RoRE Total	**7.67%**

Primary outputs

34. Our primary outputs (as driven by incentives) are detailed in the Table 3 from page 14 onwards.

Overview of Performance

Maximum Allowed Revenue TO

35. The Gas Transmission TO Maximum Allowed Revenue for 2017/18 out-turned at £847.6m.

Licence Term	2016/17 (2016/17 price base in £m)	2017/18 (2017/18 price base in £m)	Commentary for year-on-year variance
Base Revenue (BR)	719.6	828.8	• +£96.2m (2016/17 price base) increase in opening base revenue allowances. • -£5.7m (2016/17 price base) decrease in MOD. Detailed MOD commentary included in **Final Proposals base revenue against adjusted base revenue** section. • -£6.2m relating to RPI True Up (TRU) (2016/17 price base) in 2017/18 as a result of the movement between forecast and actual RPI in 2017/18 compared to the movement in 2016/17. • +£24.8m due to further year's RPI uplift.
Pass Through (PT)	4.7	6.9	• Business rates, licence fees and policing costs are trued up against the ex-ante allowances with a two-year lag. The value from 2016/17 to 2017/18 has increased by £0.5m (nominal price base). • Independent systems costs are trued up within year. The true up value was £4.2m in 2016/17 and is £5.9m in 2017/18 (nominal price base).

Licence Term	2016/17 (2016/17 price base in £m)	2017/18 (2017/18 price base in £m)	Commentary for year-on-year variance
Incentives (OIP)	35.7	3.5	• The 2017/18 incentive includes the Customer and Stakeholder Satisfaction Incentive and Stakeholder Engagement Reward for 2015/16 performance. The incentive revenue is comparable to 2016/17, with both years being ~£3.5m (nominal price base). • The year of 2016/17 had the additional inclusion of incentive revenue relating to Permit Arrangements (£32.2m).
Network Innovation Allowance (NIA)	3.5	3.8	NIA costs have increased slightly on a year on year basis, due to an increase in the cost of sanctioned innovation projects through 2017/18.
Network Innovation Competition Funding (NICF)	18.0	11.6	As per the Ofgem direction, the NICF revenue term has decreased in 2017/18 compared to 2016/17. This year, two projects were awarded funding; Future Billing Methodology and HyDeploy.
PARCA (PTV)	0.0	0.0	There has been a Planning and Advanced Reservation of Capacity Agreements (PARCA) termination recorded in 2017/18. PARCA Termination Value (PTV) is subject to a two year lag, with the adjustment affecting the 2019/20 MAR.
Correction Term (-K)	16.1	-6.9	The correction term in 2017/18 is based on the £6.6m over-collection of revenue in 2015/16 (as reported in the 2015/16 submission) uplifted as per the licence algebra requirements.
Maximum Allowed Revenue	**797.6**	**847.6**	

Maximum Allowed Revenues SO

36. The Gas Transmission SO Maximum Allowed Revenue for 2017/18 out-turned at £190.8m.

Licence Term	2016/17 (2016/17 price base in £m)	2017/18 (2017/18 price base in £m)	Commentary for year-on-year variance
Base Revenue (SOBR)	160.2	93.2	• +£1.0m (16/17 price base) increase in opening base revenue allowances. • -£72.4m (16/17 price base) decrease in legacy revenue drivers in line with SC 3A Appendix 2. • +£2.5m (16/17 price base) increase in MOD. Detailed MOD commentary included in **Final Proposals base revenue against adjusted base revenue** section.

Licence Term	2016/17 (2016/17 price base in £m)	2017/18 (2017/18 price base in £m)	Commentary for year-on-year variance
			• -£0.9m relating to TRU (16/17 price base) in 2017/18 as a result of the movement between forecast and actual RPI in 2017/18 compared to the movement in 2016/17. • +£2.8m due to a further year's RPI uplift.
Constraint Management (CM)	11.6	11.7	The 2017/18 revenue includes the 2017/18 ex-ante allowance of £33.0m plus the cost adjustment of -£35.8m plus incentive revenue of £14.4m for 2015/16 performance. All values are quoted after the WACC and RPIF uplifts have been applied. The cost adjustment and incentive revenues are subject to a two year lag from the year of performance.
Transportation Support Services (TSS)	3.5	3.6	The 2017/18 revenue includes the 2017/18 ex-ante allowance of £9.2m plus the cost adjustment of -£10.0m plus incentive revenue of £4.4m for 2015/16 performance. All values are quoted after the WACC and RPIF uplifts have been applied. The cost adjustment and incentive revenues are subject to a two year lag from the year of performance.
Incentives (SOOIRC)	103.2	91.7	Further detail on incentive costs and performance is included in the relevant sections.
Correction Term (-SOK)	4.2	-9.4	The correction term in 2017/18 is based on the £9.4m over-collection of revenue in 2015/16 (as reported in the 2015/16 submission) uplifted as per the licence algebra requirements.
Maximum Allowed Revenue	**282.7**	**190.8**	

Innovation

37. Throughout the last year, we have focused on innovation that delivers a step change for customers, providing a safe, reliable and efficient energy system for the future. We have developed an innovation strategy with a clearer focus on the future of the network. We have delivered against our ambition for 2017/18; building on our capacity to measure the business value delivered from innovation and developing new ways to share this with our stakeholders and customers.

38. In 2017/18 we undertook 39 NIA projects across our key themes (safety, reliability, environment, strategic, system operability and customer and connections) at a cost of £4.2m. Particular successes this year have been projects such as 'Composite Pipe Supports Phase 2'. Replacing steel pipe supports with Glass Reinforced Plastic (GRP) offers significant benefits as the smart split body design enables the support to be withdrawn from the pipeline and re-used which allows easier and

cheaper withdrawal for pipeline inspection, has a design life of 40 years and is cheaper to purchase.

39. We have continued to build momentum on Project Gas Robotic Agile Inspection Device (GRAID) as we approach the end of the NIC Project, which is due to conclude in November 2018. Most significantly, the team has delivered a functional robot, launch vessel and test facility allowing the offline trials to be completed. We anticipate rolling out this innovation fully in RIIO-T2 to help assess the asset health of our pipeline assets on sites which we previously were unable to internally inspect.

40. Our ambition for 2018/19 is to continue the development of a dynamic portfolio of projects which deliver real value to our customers, stakeholders and the wider industry and is aligned to the Gas Network Innovation Strategy. We will continue our focus on the implementation of innovation into business as usual to drive value throughout everything we do. We will remain committed to sharing best practice across the industry to deliver a safe, reliable and efficient network that benefits gas consumers across the UK.

Table 3: Outputs and Incentives Performance (primary & secondary)

	Safety			
	Our output	**2017/18 Target**	**2016/17 Performance[4]**	**2017/18 Performance**
1	Comply with Health and Safety Executive (HSE) legislation	100%	**Complied**	**Complied**
2	Meet requirements for enhanced physical site security	Meet BEIS requirement by 2021	**On track**	**On track**
	Reliability and availability			
	Our Output	**2017/18 Target**	**2016/17 Performance**	**2017/18 Performance**
3	Maintain our security of supply obligations in Scotland (Network Flexibility)	Ensure compliance with 1 in 20 obligations by 2020	**Strategy in place to ensure compliance**	**Strategy in place to ensure compliance**
5	Meet our targets for investing in our assets to maintain their health (NOMs targets)	Deliver network replacement outputs in accordance with the licence	**In aggregate, on track to deliver eight-year target**	**In aggregate, on track to deliver eight-year target**
6	Replace Feeder 9 (pipeline that runs across the Humber Estuary)	Achieve planning consent ahead of reopener submission	**On Target – Planning approved and enabling works commenced**	**On target – Planning approved and construction underway, commissioning planned for September 2020**
7	Deliver benchmark performance for maintenance outage days	11 days (for Remote Valve Operations)	**1 maintenance day called**	**1 maintenance day called**
8	Minimise National Grid driven changes to maintenance planning	20.37 days (<7.25% of workload 20 of 281 days)	**No changes**	**No changes**
9	Meet constraint management target	£26.99m allowable costs for entry/exit capacity	**£0.58m costs**	**£0.43m costs**
10	Meet target for Transmission Support Services and for Constrained Liquefied Natural Gas & Long Run contracting	£9.1m allowable cost	**£0m cost**	**£0m cost**

[4] As reported in the 2016/17. Please note that all previous year figures are in 2016/17 price base unless otherwise stated.

	Reliability and availability			
	Our Output	**2017/18 Target**	**2016/17 Performance**	**2017/18 Performance**
11	Deliver existing capacity obligations in accordance with Unified Network Code (UNC), Licence and Gas Act	All UNC, Licence and Gas Act capacity obligations to be met in full	**System issues, including planned outages, impacted a minority of auctions**	**System issues, including planned outages, impacted a minority of auctions**
12	Deliver accurate 13:00 day ahead demand forecasting	9.03 mcm average forecast error	**8.53 mcm average**	**8.24 mcm average**
13	Deliver accurate demand forecasting at the two to five days ahead stage	13.70 mcm average forecast error	**12.39 mcm average**	**12.06 mcm average**
14	Meet target for residual balancing linepack performance measure	<2.80 mcm average daily change	**1.74 mcm average daily change**	**1.99 mcm average daily change**
15	Meet target for residual balancing price performance measure	Average daily difference between max and min price paid, to be within 1.5% of System Average Price (SAP)	**Difference 0.95% of SAP**	**Difference 1.77% of SAP**
16	Procure Operating Margins (OM) in an economic and efficient manner	Incur OM costs efficiently and publish report on the steps taken to promote competition	**Report published to time, £8.7m decrease in costs in 2016/17**	**Report published on time, £1.9m decrease in cost in 2017/18**
	Environment outputs			
	Our output	**2017/18 Target**	**2016/17 Performance**	**2017/18 Performance**
17	Develop an integrated and cost-effective plan to ensure the remainder of our compressor units are compliant with the Integrated Pollutions Prevention and Control (IPPC) and Industrial Emissions Directive (IED) legislation	Delivery date 2018	**On target for re-submission in May 2018**	**Integrated plan submitted as part of the May 2018 Industrial Emissions RIIO-T1 Reopener submission**
18	Undertake works at Peterborough and Huntingdon Compressor Stations as part of the IPPC legislation	Delivery date 2020	**On track to deliver one new unit at each site as part of IPPC 3**	**On track to deliver one new unit at each site as part of IPPC 3**
19	Undertake works at Aylesbury Compressor Station to ensure compliance with IED	Delivery date 2020	**On track to deliver installation of catalytic converter**	**Catalytic converter solution successfully commissioned at the beginning of 2018**
20	Report on our business carbon footprint	Publish in annual report	**Published in our annual report**	**Published in our annual report**

	Environment outputs			
	Our output	**2017/18 Target**	**2016/17 Performance**	**2017/18 Performance**
21	Meet greenhouse gas emissions targets	<2,897 tonnes for 2017/18	**3,590 tonnes**	**3,928 tonnes**
22	Meet our targets for the amount and the cost of the energy we use to run the network	<3,352 GWh (Gigwatt hours) gas equivalent usage target in 2017/18[5] <£83.2m cost target	**4,746 GWh** **£70.5m**	**3,816 GWh** **£71.2m**
	Customer Satisfaction outputs			
	Our output	**2017/18 Target**	**2016/17 Performance**	**2017/18 Performance**
23	Undertake annual satisfaction survey with our customers and stakeholders.	Customer 6.9/10 Stakeholder 5/10	**8.0 for customer** **8.0 for stakeholder**	**7.6 for customer** **8.0 for stakeholder**
24	Submit annual stakeholder engagement report	Cap of 9 and collar of 4	**Achieved a score of 6.5**	**Achieved a score of 4.3**
	Customer Connections outputs			
	Our output	**2017/18 Target**	**2016/17 Performance**	**2017/18 Performance**
25	Achieve our obligated times for delivering extra capacity on the system	Target of 24 months from the point of formal commitment	**Compliant - No incremental capacity due for delivery this year**	**Compliant - No incremental capacity due for delivery this year**
26	Meet timescales for connection applications as specified in UNC Modification 373 and comply with reasonable requests for a customer connection to the National Transmission System	2 business days for application acknowledgment 5 business days to confirm competent connection application 2 months for initial connection offer 9 months for full connection offer 3 months for a Feasibility Study Report	**Timescales met**	**8 of 9 offers timescales met** **1 offer two days outside of the specified timescales (timescales agreed with customer)**

Key

Red – Missed an annual output and forecast to miss the remainder of our eight-year output commitment

Amber – Missed annual output but on target to progress towards the remainder of our eight-year output/successful achievement of annual output and risk of failure of the remainder of our eight-year output

Green – Successful achievement of an annual output and on target to meet the remainder of progress towards our eight-year output commitment

[5] In accordance with the NTS Shrinkage Incentive Ex Ante Baseline Value Statement usage target and actuals are quoted in GWh gas equivalent, using a factor of three to convert from electricity to gas equivalent.

II. Operational Context

41. Our performance in 2017/18 is contextualised by a significant increase in the operational challenges the business has faced during the financial year. As the sole owner and operator of the Gas Transmission network in Great Britain, National Grid manages the day-to-day operation of the NTS including the residual balancing of the network, maintaining system pressures and assuring gas quality. During 2017/18 we have effectively facilitated the delivery of 99.9% of gas requirements for customers.

42. Achieving this level of performance is becoming more difficult year-on-year as we experience a continued trend of our customers using the network in different and more flexible ways. Whilst overall capacity sales are up on the previous year, we have seen a reduction in long term bookings replaced by increased take-up of short term interruptible products. This switch gives customers the opportunity to be flexible within their portfolios about where and when they put their gas in and take gas out of the network.

43. This commercial shift has manifested in a physical change during the year. When compared to 2016/17 we have seen an increase in supply point differences both within day and day-to-day. Some of this volume difference can be attributed to gas being the balancing fuel for much of the year and supporting periods of low renewable generation.

44. Responding to these challenges requires us to ensure we continue to invest in our forecasting capability, configure the network in new and innovative ways, and continue to facilitate the increased volumes of maintenance in the summer months that result from much heavier use of our compressor fleet during both the winter and the summer.

45. Despite our actions noted above, with the changing use of the network there are inevitably operational impacts of how it is now being used and operated. The most notable customer impact is as a consequence of higher linepack swings, which to our customers results in greater variability in system pressures at their connection points. We continue to manage this in the most economic and efficient way, with increased customer engagement throughout the year, such as the Operational Forum, to ensure continual communication of the operability challenges of the network. The average and peak linepack swing during the 2017/18 winter can be seen in Figure 4 below.

Figure 4: Average and Peak Linepack Swings in 2017/18 compared to 2016/17

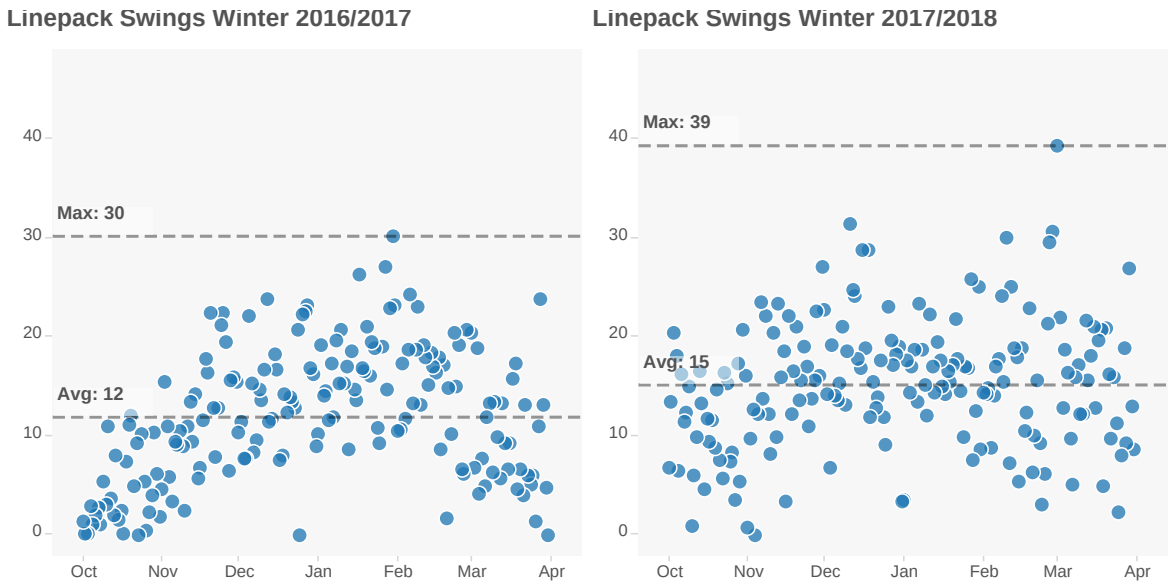
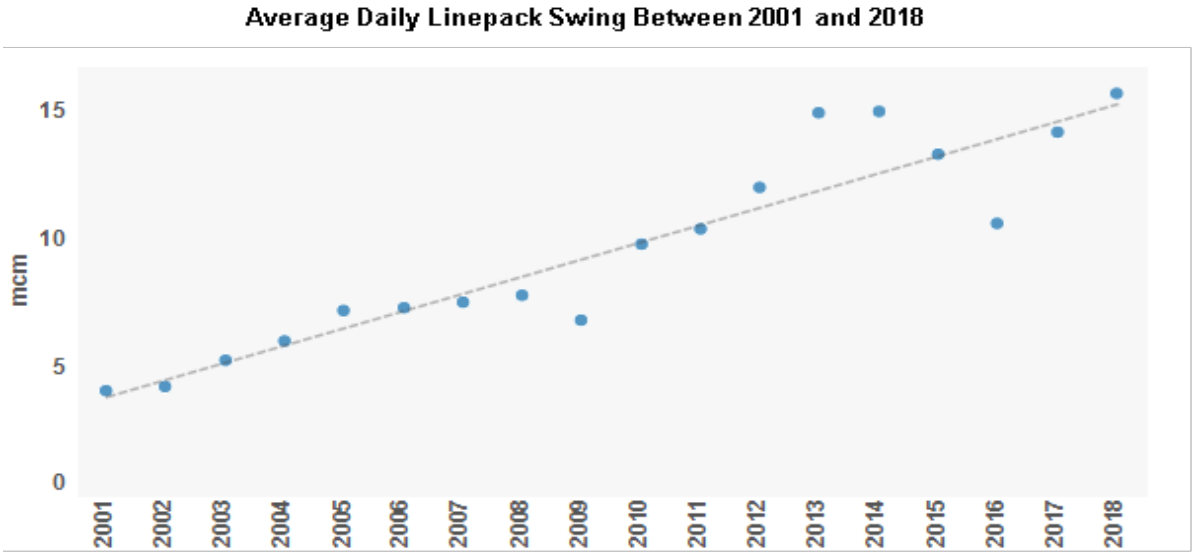


Figure 5: Average Linepack Swings in comparison from 2000/01 to 2017/18



46. In addition to these general trends there are number of more notable events we have managed during the course of the 2017/18 year:

- During the cold snap at the end of February/early March temperatures dropped to the 7th lowest seen in the past 58 years, and this, combined with the wind-chill, drove demand to the highest levels seen in the past eight years. We saw a number of supply trips across the network late on the 28 February gas day, which when combined with the forecast for the 1 March gas day, led us to issue a Gas Deficit Warning to the industry in order to highlight the risk and encourage more gas to be brought onto the network. This action worked with the system coming in balanced at the end of the gas day, with our assets holding up well to the requirements placed on them.

- The unexpected Forties Pipeline closure in mid-December very quickly changed the supply profile to the UK. Southern supply points became dominant, most notably Bacton. This sudden shift in supply profile led us to reduce physical supply at Bacton for a short period of time whilst we re-configured the network to adapt. This was restored in full within four hours allowing the use of commercial tools to manage the remaining operational impacts.

- This trend of increased southern flows continued into January, which saw us scale back interruptible capacity at Bacton Aggregate System Entry Point (ASEP) on eight occasions during the month. The utilisation of this tool is well understood by customers and fully in-line with our System Management Principles (SMP).

- During the summer months, we successfully facilitated network access for a record level of maintenance jobs with minimal disruption to our customers. This comes as a direct result of the continued high utilisation of the compressor fleet when compared to two years ago, and the need to safely maintain our ageing asset base.

- Delivering the increased maintenance plan during the summer comes against the backdrop of a continued seasonal switch in the flows on Interconnector UK (IUK). This switch effectively sees an increase in GB demand over and above what is consumed nationally as we meet both GB demand and the volume that we are exporting to Europe.

III. Outputs

47. Under the RIIO-T1 framework, National Grid's performance as owner and operator of the gas NTS is assessed against five key outputs:

- Safety
- Reliability and Availability
- Environment
- Customer Satisfaction
- Customer Connections

48. These outputs focus on delivery of outcomes that our customers and stakeholders have told us they value most. There are also a series of more specific outputs that sit within each of these five key output areas. These are detailed within the SPO (see page 14) and have been used in our assessment of our 2017/18 performance.

49. As previously described, 2017/18 has been a challenging year operationally as our customers continue to use the network in different and more flexible ways. We have continued to implement a number of strategies and applied these through a range of initiatives to deliver our outputs as efficiently as possible and to provide the greatest benefit to customers. Our 2017/18 performance against these key outputs is outlined further in the Output sections below.

IV. Outputs – Safety

50. The safety of our workforce, the public and our assets, remains a top priority at National Grid. We aim to deliver world class safety performance which is crucial to our customers, employees and contractors, the communities we serve and to the reputation of our business. Specific outputs under this theme relate to compliance with safety legislation and meeting the requirements for enhanced physical site security. In 2017/18 we were compliant with our safety related outputs. We are on track to meet BEIS's requirements for enhanced physical site security.

Gas Transmission Safety Performance

51. Within the Gas Transmission business, there were no public injuries and one employee lost time injury (LTI) in 2017/18. The employee was injured when they caught a metal weight plate (being stored in the office), causing it to fall on their foot. There were also four lost time injuries associated with contractors. Three of the contractor injuries resulted from slips/falls:

- One who slipped off a broken kerb resulting in an ankle injury, a slip in a site entrance resulting in a broken shoulder blade and a contractor who slipped and fell during grit blasting resulting in the grit blaster cutting their upper leg.

- The other contractor LTI happened when manually lifting a coupling guard, the load became unstable and the coupling guard tore through the contractor's glove lacerating his hand.

52. The combined employee and contractor lost time Injury Frequency Rate (IFR) was 0.21. Combined employee and contractor Total Recordable Injury Frequency Rate (TRIFR) closed on 0.51, based on 12 injuries.

53. There were no serious process safety events during 2017/18.

54. In 2017 (between May and October), the HSE investigated an incident at Paull AGI which had resulted in an uncontrolled ignition of gas internally within a water bath heater. Actions were taken to address the investigation findings (related to competence of operational staff), which were accepted by the HSE. The HSE were proactively engaged throughout the process. Further work is being undertaken to develop and enhance our operational staff competence management system which will be embedded during 2018/19.

55. Throughout 2017/18 we have implemented a number of initiatives to promote and encourage safety and wellbeing at National Grid. These include:

- Standards of Stewardship – Standards of Stewardship have been developed and implemented across our operational sites to improve site ownership and compliance. The standards set out clear expectations and ensure a consistent approach to day to day activities covering safety, environment, security, site care, data and information.

- Safe Control of Operations – We have carried out a systematic review to ensure we are following best practice guidance, and ensuring the information we provide is presented in a simple and understandable format for those required to utilise it. These improvements have strengthened our 'Safe Control of Operations' management for all such work activities at our Gas Transmission sites.

- Health and Wellbeing – Mental and physical health have continued to be a focus and we have deployed a mental health first aid training course for line managers to better support employees with mental wellbeing and have launched three new Wellbeing Principles: Be Active, Refuel and Switch off. These principles are being rolled out through engagement activities and workshops and are aimed at making small and sustained changes to our daily habits that lead to a positive impact on our health and wellbeing.

56. We continue to undertake a number of innovation programmes to support our pipeline safety initiatives. The first installations of polyethylene (PE) protection slabs for pipelines have been undertaken and further opportunities are being explored. Conventionally concrete has been used as the material of choice for impact protection but PE offers considerable advantages in terms of shallow ditch crossing situations and gives machine operators an early visual warning of pipeline proximity. We continue to explore other alternative technologies to enhance the management of the pipeline corridor and have conducted a pilot study utilising LiDAR (Light Detection and Ranging) to provide a topographical mapping of the pipeline which can then provide depth of cover details. This will offer opportunities to have a more holistic overview of the pipeline terrain. Further details can be found at:

http://www2.nationalgrid.com/uk/our-company/innovation/

Figure 5: LiDAR Web Portal Presentation (showing the pipeline superimposed on the topographical LiDAR corridor, pipe sections are colour coded according to depth to aid analysis)

Enhanced Physical Site Security

57. During the reopener window in May 2018, we submitted our updated plans to comply with the BEIS requirements for enhanced physical site security (*"Enhanced Physical Site Security RIIO-T1 Reopener Submission"*). Details of progress of our enhancements can be found within the Section XI. Non Load Related Capital Expenditure. In summary, we remain on track to meet BEIS's requirements.

V. Outputs – Reliability and Availability

58. The reliability and availability of our transmission network and the service it provides is vital to our customers. In 2017/18 we continued to provide high levels of reliability and availability for our customers to input and offtake gas from our system. The section below details how we have performed against our Reliability and Availability outputs outlined in Table 3. In summary, most of our outputs in this area have been met, and all are on target to be met within the remainder of the RIIO-T1 period. The only area where an issue has been experienced is with regards to 'Meet target for residual balancing price performance measure' (Output 15 in Table 3) and 'Capacity Obligations' (Output 25 in Table 3). This is discussed further in the 'Constraint Management Incentive Scheme' and 'Residual Balancing Incentive Scheme' sections below. Reliability and Availability outputs not discussed in the below section, are covered in Section X. Load Related Capital Expenditure and XI. Non Load Related Capital Expenditure.

Network Output Measures (NOMs)

59. The reliability and availability of the NTS to our customers depends predominantly on the health of our assets, both today and into the future. NOMs are currently being used as a proxy for network risk to measure the risk across the RIIO-T1 period. In previous submissions, we have reported that the actual network condition was at a lower level (i.e. more observed condition issues) than the modelled view within our current NOMs Methodology. This is still the case and it is therefore important to note that our asset health investment planning is not based on the modelled view but targeted to address actual network condition/issues and minimise disruption to customers.

60. During 2017/18 we have further increased the annual volume of asset health improvement work delivered, spending £126.5m compared to £100.1m in 2016/17. Comparing the end of 2017/18 with the end of 2016/17, the number of RP1 assets across the NTS has reduced slightly. The successful delivery of year 1 of NARC has contributed to the significant reduction in network risk and RP1 assets in the Pipelines category. Increases in RP1 assets in the other primary categories is due to the time lag between expenditure and confirmation of network risk being removed following asset commissioning. This time lag is typical for major projects such as Bacton and St Fergus where the profile of RP1 reduction will lag behind the cost profile.

61. We continue to forecast that we will meet the overall NOMs target outlined in our Licence by the end of the RIIO-T1 period, however the projected number of RP1 assets on the network is higher than we reported in 2016/17. Across the five primary categories, we see the majority of RP1 asset reductions within the Pipelines category. This reflects our current view, that addressing integrity risks on our high-pressure pipeline network delivers the best value for customers and stakeholders.

62. The forecast increase in RP1 assets at the end of RIIO-T1 from 2016/17 is due to the robust challenge that we have applied to our asset health programme over the last year. We have reviewed our projects for the remainder of the RIIO-T1 programme and looked at ways of delivering this work programme for less. This review has identified more targeted, lower cost interventions to mitigate network risk. In some areas we have been able to remove work from the programme such as Impact Protection assets (Secondary Asset Class 24). Following survey work, we have concluded that the majority of these assets do not pose a significant risk and we have focussed on a small number of high risk nitrogen sleeves close to public transport infrastructure. This work has a significantly higher unit cost, but addresses a higher risk therefore reducing the impact on our customers.

63. We have also identified innovative and low cost interventions to mitigate network risk that avoid full replacement and intrusive outage related activities. Our shallow dig technique for repairing the vent and sealant lines on buried valves is an excellent example of this. Avoiding the need for extensive excavations and full replacement of the vent and sealant line, this technique can be delivered at a fraction of the replacement cost.

64. Whilst this efficient approach to asset management is in the best interests of our customers and stakeholders, our current NOMs methodology often does not allow us to claim these interventions as a recognised output i.e. removal of an RP1 asset from the network.

65. We remain concerned that actual network condition is worse than the modelled view. We continue to target our asset health programme around key areas of risk identified through observed condition and issues. We are in effect “trading risk” across asset categories and prioritising high value asset categories such as Above Ground Pipework, Valves, Compressors and Gas Generators. The benefits of this risk trading approach will be assessed as part of the Reward and Penalty mechanism, designed to evaluate our asset health performance at the end of RIIO-T1.

66. This is discussed further in Section XI. Non Load Related Capital Expenditure under Asset Health and NOMs Methodology.

Maintenance Days Used Incentive Scheme

67. The Maintenance Days Used incentive is designed to reduce the impact we have on our customers when we undertake our routine maintenance activities. For 2017/18 the incentive only included maintenance days for Remote Valve Operations (RVO); the In Line Inspections (ILIs) element of the scheme ceased in 2015/16.

68. We have sought to align all of our routine valve maintenance work with customer outages where possible, and only three Maintenance Days for RVOs were requested ahead of the summer maintenance period (April to October). However this was reduced down to one after realigning the work with customers. This is the same figure of Maintenance Days as in 2016/17.

69. We have continued to build upon the improvements made in previous years to help us to improve the service we provide to customers.

Maintenance Day Changes Incentive Scheme

70. The aim of the Maintenance Day Changes incentive is to reduce the impact our maintenance activities have on customers should we make changes to our planned maintenance after 1 April for the forthcoming summer maintenance period. The incentive scope does not include changes which were initiated by customers, only those initiated by us.

71. The Maintenance Day Changes incentive includes any maintenance days called; it is not limited to RVOs. In total there were 281 days of planned maintenance in 2017/18 compared to 232 days in 2016/17. This large increase, driven in part by the initiation of our asset health campaigns, led to an updated benchmark for changes of 20.37 days in 2017/18, which is 7.25% of all Maintenance Days and Advice Notice Days[6] called. This compares to a benchmark of 16.82 days in 2016/17.

72. In 2017/18, there were no changes initiated by us during the maintenance period. This is the same level of performance as 2016/17. The incentive was more challenging this year because we received and acted on 41 days of customer change requests during the summer maintenance period, compared to 26 in 2016/17, demonstrating our commitment to be flexible to customers' requirements.

73. This performance was primarily delivered by several improvements that we made in 2017/18 including significantly improving our planning processes and telephoning/emailing customers eight weeks prior to the planned maintenance affecting them, allowing us to capture any changes to customer outages earlier.

74. Our annual maintenance programme review for 2017/18 can be found on our website at:

https://www.nationalgrid.com/uk/gas/market-operations-and-data/maintenance

Constraint Management Incentive Scheme

75. The Constraint Management incentive is designed to incentivise National Grid to maximise available capacity on the network and minimise constraint management costs through the efficient and economic planning and operation of the NTS. We therefore release as much capacity as possible, develop effective constraint management strategies and make economic and efficient NTS investment and planning decisions. This benefits our customers as the costs of commercial constraint management actions to the industry are minimised and balanced against NTS investment whilst access to the NTS is maximised. An effective Constraint Management incentive and strategy results in stronger incentive performance,

[6] Where a single maintenance activity affects multiple NTS Exit Points on a day, this is construed as a single day for the purposes of the Maintenance Incentives.

delivering value to the industry and ultimately to the end consumer. Our overall 2017/18 constraint management incentive scheme performance was £14.2m. The saving made against the incentive target is shared with consumers.

76. In 2017/18 (pre-sharing factor), overall revenue from Entry Capacity products, including Entry Capacity Overruns, increased to £3.4m from £3.0m in 2016/17. A key factor which contributed to the increase in Entry revenue is an increase in Entry Overrun revenue owing to a Shipper capacity trade error which resulted in an additional £1.2m of Entry Overrun charges. A reduction in revenue between 2016/17 and 2017/18 was seen from sales of Interruptible Entry capacity and from sales of Non-Obligated Entry capacity. Lower revenue for Interruptible Entry Capacity was seen for the period January to March 2018 compared to that received in 2016/17.

77. In Winter 2016/17, there was increased demand for capacity at St Fergus and Bacton United Kingdom Continental Shelf (UKCS) which drove up the price paid on a number of occasions. Whilst we have seen similar levels of demand for capacity at Bacton UKCS in 2017/18, the demand for capacity at St Fergus has reduced compared to 2016/17. Another reduction in revenue from 2016/17 is from sales of Long Term Non-Obligated Entry capacity as a result of lower capacity sales at Easington ASEP in 2017/18.

78. Revenue from Exit Capacity products increased to £1.1m in 2017/18 from £0.455m in 2016/17. This is largely attributable to an increase in demand for within-day sales of Obligated Firm NTS Exit capacity following the Gas Deficit Warning that was issued on 1 March 2018. In addition, higher revenue has resulted from the sale of Non-Obligated Exit capacity at five offtakes.

79. In 2017/18 we undertook a number of Entry Capacity constraint management activities. These are briefly detailed below:

- We actively managed an ongoing constraint risk in 2017/18 with the continuation of a turndown contract which was first put in place in December 2016 for a total of 12 months. This turndown contract helped mitigate risk of an Entry constraint at a certain point on the NTS.

- In July 2017, we carried out a four-week planned outage at Aberdeen compressor to complete essential maintenance works. Whilst this piece of maintenance work was underway, capability at St Fergus was reduced. Following recent years of high flows at St Fergus, a physical and commercial strategy was put in place to ensure the network was optimised to accommodate flows in the period of reduced capability.

- During Winter 2017/18, we experienced higher than expected flows through Bacton Interconnector combined with unplanned outages at both Huntington compressor and Kings Lynn compressor, both of which are imperative for minimising the risk of constraints specifically in the South East and South West, under this high flow scenario. There were a number of days across December 2017 and January 2018 that were particularly challenging due to

these high flows. With regard to the aforementioned unplanned compressor outages; to ensure that the high flows at the Bacton ASEP were effectively managed from a physical and commercial point of view, the following actions were undertaken:

i. We quickly mobilised our field force to ensure Kings Lynn compressor was locally manned. This meant having an Operative onsite to man the compressor site 24 hours a day for additional resilience whilst the gas flows at Bacton ASEP were high and the additional compression was required.

ii. A joint physical and commercial strategy was also compiled to minimise the risk of constraint should one of the Huntingdon compressor units fail unexpectedly. This strategy provided alternate options and steps to take should there be a unit failure.

- On 28 February 2018, we experienced low linepack due to unforeseen supply losses. There was a steep decline in instantaneous flow over a four-hour period. This continued into 1 March 2018 where, during the morning, there was a large imbalance between Demand and Supply, as described in section II. Operational Context, a Gas Deficit Warning was issued. As a result of the large imbalance between Supply and Demand, linepack was projected to fall below the normal operating range which would put meeting pressure obligations at risk. We utilised a number of commercial and operational tools to manage the network during this period.

- As outlined above, there have been a number of instances where we had to utilise both physical and commercial tools to manage a forecast or actual constraint. We have maintained a strong level of communication with Customers and Stakeholders throughout, both on the days themselves and via follow up agenda items at the Operational Forum. This included holding an extraordinary Operational Forum following the events at the beginning of March. This Operational Forum was well attended with approximately 70 attendees from across Industry.

80. We have carried out a number of customer education activities on Constraint Management and the Capacity Regime. These activities received positive feedback from our customers and included:

- A presentation and practical capacity constraint and energy balancing scenario game at the Operational Forum to aid understanding of Constraint Management and Energy Balancing interactions and the actions and tools available to potentially manage such a scenario.

- A Constraint Management webinar to the industry.

- Discussions and presentations relating to specific “interesting days,” giving the Industry the opportunity to ask for more information and enhanced understanding on how and why we use our commercial and operational tools.

81. During 2017/18 we experienced system issues that impacted our ability to run daily capacity auctions. These issues are largely attributed to planned and unplanned outages of Gemini and PRISMA[7]. Where there was an unplanned outage, we took steps to process auctions manually and invoked UNC contingency arrangements and fixed data issues.

Transportation Support Services Incentive Scheme

82. The TSS scheme incentivises National Grid to minimise the cost of procuring specific tools to support gas demand in the South West as an alternative to network investment. In 2017/18 we spent £0 against a target of £9.1m, the benefit of which is shared with consumers. This incentive will cease in October 2018.

83. Based upon our assessment of the supply and demand forecasts we determined that it was not economic or efficient to procure any TSS services in 2017/18. This meant any increase in the risk of network constraints was managed through the Constraint Management incentive scheme.

Demand Forecasting Incentive Schemes

84. We publish national demand forecasts for day ahead (D-1) and two to five days ahead (D-2 to D-5). These forecasts assist the industry in making efficient physical and commercial decisions to balance supply to, and demand from, the NTS. We strive to continuously improve the accuracy of these forecasts to ensure our customers can effectively and safely manage these elements on a day-to-day basis.

85. In 2017/18 the average error on the D-1 incentive was 8.24 mcm against a target of 9.03 mcm (fixed target of 8.5 mcm + storage adjuster of 0.53 mcm). The average error has decreased this year from 8.53 mcm in 2016/17. The D-2 to D-5 incentive average error was 12.06 mcm in 2017/18 against a target of 13.70 mcm. The average error has slightly decreased from 12.39 mcm in 2016/17.

86. This year, demand forecasting has been more challenging due to an increase in the day-on-day change in demand, which averaged 12.18 mcm in 2017/18, compared with 11.52 mcm in 2016/17.

87. There was also an increase in the number of instances of large changes in day-on-day demand, for example, in 2017/18 there were eleven instances of a day-on-day change greater than 40 mcm, compared with nine in 2016/17.

88. There were challenges in forecasting Local Distribution Zone (LDZ) demand based on historical performance and weather as day-on-day demand changes did not reflect the Composite Weather Variable (CWV) change.

89. The large swings in temperature across a short period of time led to difficulty in forecasting consumer demand. Power Station demand is also becoming more

[7] PRISMA is a European system for booking and trading gas capacities

difficult to predict as increased renewable generation leads to fluctuating electricity demand and higher volatility of the fuel mix.

90. The price spread between the National Balancing Point (NBP) and Zeebrugge (ZEE) at day ahead or week ahead is not a consistent indicator to forecast IUK's behaviours. We use the price spreads as one of the parameters to forecast interconnector flows.

91. Throughout 2017/18 we have embarked on several activities to drive improvements in the accuracy of our demand forecasts, including:

- Ongoing process improvements to improve forecasting Power Stations and LDZs.
- Process improvements – investigate changes to LDZ demand patterns to see if we can improve our modelling algorithms.
- Monitor weather errors and discuss performance with the provider.

Residual Balancing Incentive Scheme

92. The aim of the residual balancing incentive scheme is to incentivise National Grid's residual balancing activities in two ways:

- The linepack performance measure (LPM) incentivises us to minimise differences in linepack volumes between the start and end of each gas day. This is to ensure that any system imbalances within the day are resolved, and that any associated costs are levied across those system users responsible for that day's imbalance.
- The price performance measure (PPM) evaluates the impact we have on the market in our Residual Balancing role by measuring the price range of our trading actions compared to the System Average Price (SAP). This incentivises the System Operator to minimise the impact it has on market prices.

93. 2017/18 was a challenging year for our role as residual balancer. This was in part due to the very difficult winter period with increased demand and higher variability in linepack. In addition to the difficult winter period an increasingly challenging market was observed where a limited response to our balancing actions was often observed which compounded the effects of the prolonged winter spells.

94. Residual balancing patterns were different in 2017/18 than in previous years. To manage system risk more actions were required than previously. In 2017/18 trades were required to balance the system on 148 days during the year (41%). This is an increase from the last year where trades were only required on 90 days throughout the year (25%). Whilst there was an increased level of balancing actions, Figure 6 shows the distribution of the delta between System Marginal Price (SMP) (buy and sell) from the default SMP buy and sell cash out price for 2016/17 and 2017/18,

which indicates that the SMP in 2017/18 were closely aligned to last year. Similarly, annual linepack levels are within the range of the last five years (Figure 7), but an increased number of actions were required to maintain the historical range.

Figure 6: SMP Differential

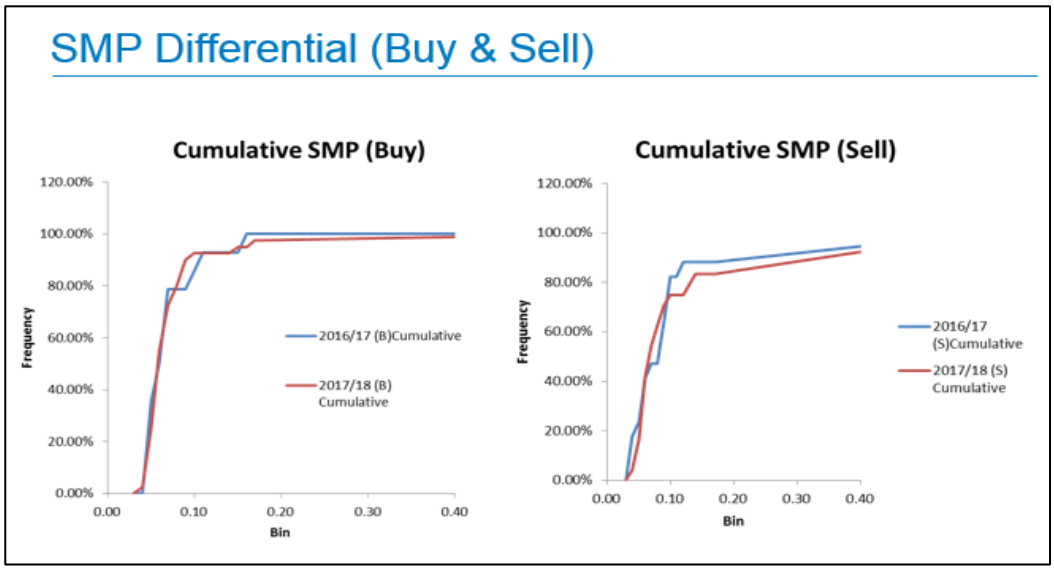
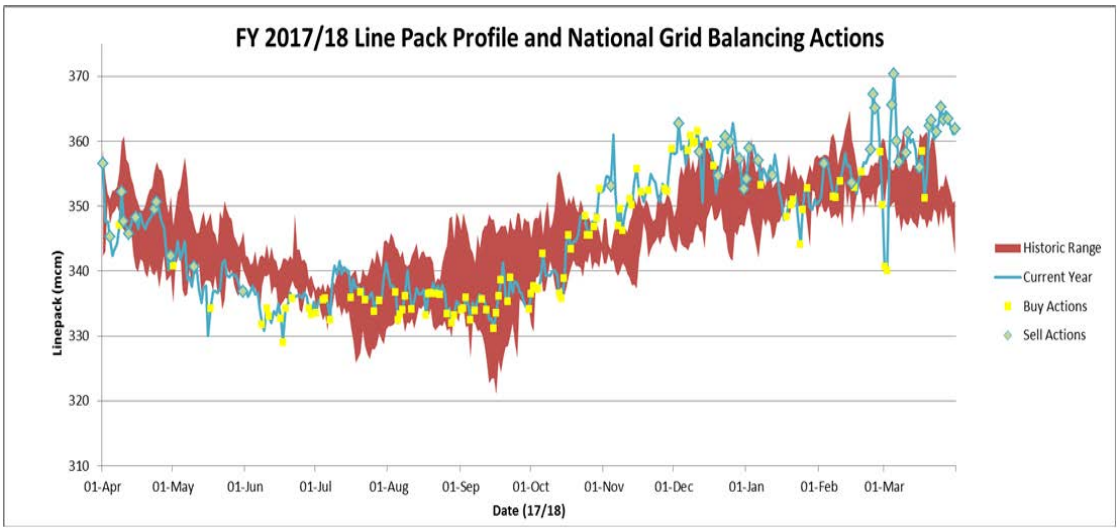


Figure 7: Line Pack Profile and National Grid Actions in 2017/18



95. The LPM element for 2017/18 achieved a daily average linepack performance of 1.99 mcm over the year, compared to the 2.8 mcm incentive target. This was slightly higher than the level for 2016/17 (which was 1.74 mcm). LPM was better than the target of 2.8 mcm on 282 days during the year (77% of days), a slight decrease compared to 2016/17 (306 days, 84% of days).

96. The PPM element achieved an average price spread of 1.77% of SAP, compared to the 1.5% incentive target. This represented a decrease in performance on the 2016/17 value of 0.95%.

97. When required to enter the residual balancing market we placed a greater operational focus on the expected market reaction and effect on system balancing. However, a larger price spread was required to achieve the market response. On the days when we took actions, the average price spread was 5.02%, compared with 4.27% in 2016/17 and 2.05% in 2015/16.

98. Events surrounding the Gas Deficit Warning of the 1 March 2018 had a significant impact on the price performance measure, where trades of 499p/therm and the SAP of 372.68p/therm were observed, compared to an annual average SAP of 48.05p/therm.

99. Following the implementation of Operational Balancing Accounts (OBAs) in October 2015, we have continued to work with adjacent Transmission System Operators (TSOs) to ensure OBA operations do not materially impact residual balancing.

Operating Margins (OM)

100. We are required to procure OM services to maintain pressure in the NTS in the intermediate period following operational stresses to allow market actions to take effect and during the potential run-down of the system in the event of a Network Gas Supply Emergency. The OM service was utilised on 1 March 2018.

101. All costs incurred for the procurement and utilisation of OM are a pass-through element within the Licence. Under the RIIO-T1 regime, we have a reputational incentive to promote competition in the procurement of OM services for customers. We aim to meet the OM requirement in the most economic and efficient manner.

102. OM procurement costs have decreased from £12.9m for 2016/17 to £11.1m for the 2017/18 incentive year despite a higher OM volume requirement (~0.7 Terawatt hours to ~0.9 Terawatt hours).

103. The lower cost base achieved for customers primarily reflects a continued focus on stimulating a more competitive market response, through industry engagement to bring in new service providers. We received tenders for the 2017/18 OM year from three new parties, between them offering OM service provision from storage, Liquefied Natural Gas (LNG) and interconnector sites.

104. We undertook an extensive review of OM contract templates including an industry consultation which has resulted in improved contracts and better alignment across the contracts for the different provider types. These have been well received by service providers.

105. Although increasingly challenging, we see potential for further competition, particularly from gas fired power stations for OM service provision. Supporting this, we made a proposal during the year (National Grid Gas - Capacity Market Rules CP278) to address a perceived blocker to power stations offering to provide an OM service. Although Ofgem's consultation document (Statutory consultation on amendments to the Capacity Market Rules 2014) indicates the proposal has not

been accepted, Ofgem's response does provide clarity that Combined Cycle Gas Turbines (CCGTs) are able to participate in both the Electricity Capacity Market and Gas Operating Margin Tenders. We will continue to explore the potential for further competition as we move forward.

VI. Outputs – Environment

106. As one of our key outputs under RIIO-T1, minimising the impact our business has on the environment is important both to us, and our customers.

107. In 2017/18 we have made good progress against some of our environmental outputs outlined in Table 3. We have reported appropriately on our Business Carbon Footprint and we are on track to meet our IED legislative obligations with delivery of works at Peterborough, Huntington and Aylesbury compressor stations. Further information about IED and works at our compressor stations can be found in Section XI. Non Load Related Capital Expenditure. In May 2018 we submitted our updated integrated plan as part of the *"Industrial Emissions RIIO-T1 Reopener Submission"*.

108. Our outputs relating to environmental incentives continue to set challenging targets. In 2017/18, we had challenges around our GHG incentive performance. The increase in supply point differences we experienced over the last year have led to an increase in compressor utilisation as larger volumes of gas needed to be moved away from the higher gas flow entry points. The need to operate more compression to manage supply uncertainty and pressure limits to avoid entry constraints resulted in increased venting of GHG. We have implemented a number of initiatives aimed at driving performance and will continue to progress these throughout 2018/19.

Emissions

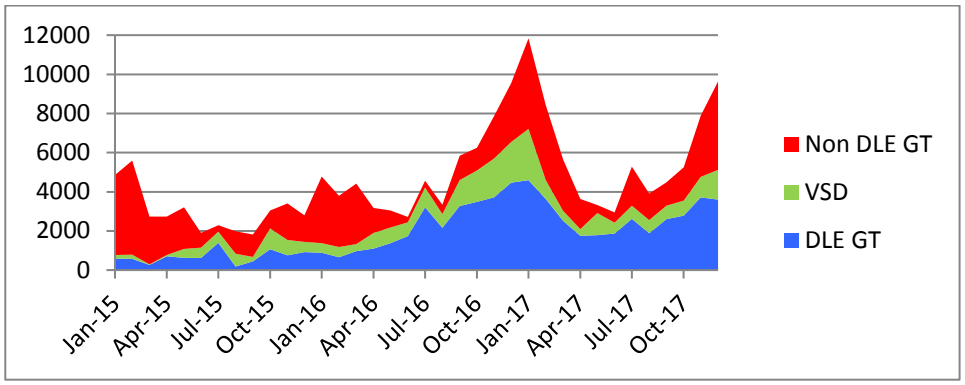
109. IED has been in force since January and February 2013, in Scotland and England/Wales respectively. In May 2018, we submitted an updated funding request as part of the reopener process. We have set out our plan to comply with this legislation by 2023. We report on progress within Section XI. Non Load Related Capital Expenditure. In summary, work at Peterborough and Huntingdon is progressing well. The catalyst solution at Aylesbury was commissioned at the beginning of 2017/18 and we have delivered our integrated plan. We have also commenced initial work for Hatton and St. Fergus. We are therefore on track to meet our outputs in this area.

110. In addition to IED, the Medium Combustion Plant Directive (MCP) was transposed into UK legislation in January 2018 and December 2017, in England/Wales and Scotland respectively. As part of these changes in UK legislation, the time derogation for gas driven compressors has been confirmed as 2030 from the original 2025, as influenced by our lobbying of EU stakeholders.

111. The MCP Directive applies to the smaller gas compressors and will affect a further 26 of the NTS compressor units. Other combustion plants, such as pre-heat systems, are also captured as part of this Directive. An impact assessment of the legislative requirements completed at the end of 2017 is now forming the basis of the investment strategy plans being drawn up for RIIO-T2.

112. In 2017/18 the compressor utilisation has experienced a further 1.5% increase over 2016/17, which in itself was a large increase over 2015/16. We have seen an increase in CO_2 emissions of 0.1%, we have also seen an increase in Nitrogen Oxides (NOx) emissions by 24.5% from 2016/17 levels. The NOx performance is due to the unavailability of the Hatton VSD unit and therefore increased utilisation of Non Dry Low Emissions (DLE) gas turbines. Figure 8 shows the marked change over from non-DLE to VSD and DLE gas turbines running over the last three years.

Figure 8: Compressor Utilisation by Unit Type between 2015 to 2018



Business Carbon Footprint

113. As a Group we have set a voluntary target to reduce our Scope 1 and Scope 2 GHG emissions across our UK and US businesses by 45% by 2020 based on 1990 levels. Our baseline emissions level was set, at group level, at 21.6m tonnes of carbon dioxide equivalent. Our current forecast is that we will better the 2020 target.

114. Scope 1 and 2 emissions in Gas Transmission can be broken down into sources including compression, venting, leakage, buildings and transport.

115. The majority of the emissions in Gas Transmission are from fuel use in gas and variable speed driven electric compressors. Emissions from compressor stations are largely dependent on the locational balance between supply and demand conditions, driven by market forces.

116. Scope 1 emissions have been relatively high for the past two years, with 585 $kTCO_2e$[8] in 2017/18 and 569 $kTCO_2e$ in 2016/17. These figures use an updated Global Warming Potential (GWP) of 25 for methane emissions. This has been driven by a significant increase in running hours for our gas-fired compressor fleet due to an increase in gas burnt for compressor operation (resulting in CO_2 emissions) and methane venting, both of which are correlated to compressor running hours. Scope 2 emissions, predominantly electricity consumption at our

[8] Aggregate System Entry Point

electric drive compressors, have also been relatively high - 101 kTCO2e in 2017/18 and 119 kTCO2e in 2016/17.

117. We provide our annual emissions performance as part of our CDP submission. This enables us to benchmark our performance against other organisations. In 2017 (for 2016/17) we achieved an 'A' rating for our CDP submission, putting us in the top 5% of global companies recognised for our actions to reduce emissions and mitigate climate change.

118. Our Greenhouse Gas (GHG) inventory, measurement, data collection, aggregation and reporting processes are verified by an independent third party providing assurance of relevance, accuracy, consistency, transparency and completeness.

Shrinkage Incentive Scheme

119. The aim of the Shrinkage incentive scheme is to minimise the costs we incur in our role as NTS Shrinkage Provider. These costs are recharged back to users as part of NTS commodity charges.

120. The overall volume of shrinkage gas and electricity procured for the combined elements of Shrinkage (Compressor Fuel Usage (CFU), Unaccounted for Gas (UAG) and calorific value (CV) shrinkage) was 3,816 GWh gas equivalent in 2017/18. This represents a decrease in overall volume of 930 GWh gas equivalent from 2016/17. This is largely due to a decrease of 413 GWh gas equivalent in the volume of CFU, and a decrease of 489 GWh in the volume of UAG (refer to the UAG Incentive section below for further detail).

121. The volume of CFU was 12% lower than in 2016/17, driven by small drop in the supplies at the St Fergus terminal, with gas and electricity components of CFU both lower. Compressor use is driven by the supply/demand patterns presented by the market, which vary year-to-year, and different compressor units at different sites have different efficiencies in relation to CFU. Although running hours were higher compared to last year, overall we have used less gas and less power due to the size of units run. We continued to manage the operation of electric units over periods of peak electricity demand to reduce transmission network use of system charges (often referred to as triad charges).

122. In forward trading for 2017/18 we continued to see relatively low liquidity of quarterly products. To help mitigate this we further increased our access to the brokered market, and enhanced our trading platform. We also gained access and utilised the Intercontinental Exchange (ICE) emissions market for the EU Emissions Trading Scheme (ETS) compliance where we purchase EU Allowances (EUAs).

123. In managing the NTS Shrinkage incentive scheme we incurred costs of £71.2m, including £49.6m for gas trades and £14.7m for electricity trades. This is similar to costs for 2016/17 (£70.5m). Against the total incentive target of £83.2m, this represents a £12m reduction in costs that are shared with customers.

Unaccounted for Gas (UAG)

124. UAG is a reputational incentive with a requirement on us to undertake projects and initiatives to investigate the causes and reduce sources of UAG.

125. UAG has continued the trend of year-on-year reduction experienced since 2009/10 (with the exception of 2015/16). The annual UAG energy for 2017/18 was 783 GWh[9], which is 38% less than the equivalent quantity for 2016/17.

126. We review and investigate UAG values on a daily basis paying particular attention to any days that exceed +/-20 GWh. During 2017/18 there were 35 days that exceeded the 20 GWh tolerance, which is five days less than 2016/17.

127. Reconciliations over the past year (36 in total) have equated to a net value of -19 GWh resulting in a reduced net UAG figure of 764 GWh for 2017/18. The upward trend in annual reconciliation quantities as a percentage of annual assessed UAG from 2013/14 to 2017/18 has continued.

128. In 2017/18 we have continued to look for ways to improve our UAG performance. The following areas remain key focus for our UAG management:

- Improving data handling between sites and billing systems, through the implementation of data visualisation, enhancing the D+5 close out data quality and reducing billing uncertainty;
- Introducing initiatives which aim to improve the customer experience in respect of reconciliations; and
- Maintaining a close relationship with all meter asset owners and validation agencies, providing a consistent and effective platform to receive metering system validations and to solve measurement issues.

129. Over the past 18 months, we contacted meter asset owners to request meter validation reports for all entry and exit facilities connected to the NTS. This initiative coincided with lower levels of UAG than have been observed since October 2016.

130. In 2017/18 we received meter validation reports for 98.1% of all the NTS entry and exit facilities, which is comparable to the percentage we received in 2016/17. These validation reports have been reviewed and, where necessary, queries raised with the asset owners. For the few sites where validation reports were not provided, or the equipment had failed, we have scheduled to witness the meter validations as part of our 2018/19 witness programme.

131. New initiatives have been implemented within our reconciliation process that improve the timeliness of reconciling measurement adjustments and the customer experience. New tools have been introduced to streamline checking and sign off processes along with a scheme that will enable the transparency of each

[9] Note these numbers are pre-reconciliation

reconciliation via regular progress updates and customer feedback. A repository for reconciliation data is also being developed that will assist with the production of future UAG reports.

132. A suite of new data visualisation tools has been developed to assist identification of the causes of UAG; this has involved the use of tableau data visualisation software. The dashboards have already helped identify several possible correlations, which are being investigated further. Our focus will be to identify missing or erroneous data in the calculation of UAG, and we intend to develop the new tools to improve the data quality during the pre-closeout period. A new procedure has been implemented that improves our ongoing investigation into high levels of positive or negative UAG.

133. An independent assessment of a dynamic baseline UAG, is currently being undertaken by Manchester University's mathematics department. It is also expected to provide a range of enhanced analytical methods for identifying potential causes of UAG. A prototype application that undertakes change point analysis on assessed UAG values has been developed. Baseline UAG analysis and further focus on the development of innovative change point techniques are being continued. These new techniques will be incorporated into the prototype application which is intended to be used for investigating periods when high levels of positive or negative UAG are observed. This three-year study will be completed in 2019.

Greenhouse Gas Emissions Incentive (GHG)

134. The aim of the GHG incentive scheme is to incentivise National Grid to reduce the amount of natural gas vented from our compressors which is primarily methane, and to reduce the effect of our operational activities on the environment.

135. The total amount of natural gas vented from compressors in 2017/18 was 3,928 tonnes, which was 36% or 1,031 tonnes higher than the target allowance set for 2017/18. The increase is mainly due to the entry supply imbalance position referenced in Section II. Operational Context and an increase in the within-day and end-of-day variability, resulting in less predictable regional demands, which in turn has led to more compressor running hours.

136. To ensure system resilience during periods of maintenance and within-day variability, there was also a need to run multiple contingency units sometimes in parallel to replace the primary compressor on outage to redistribute stock from the entry points to the area of demand and this led to a 9% increase in venting compared to 2016/17.

137. In 2017/18, three specific areas accounted for 71% of the total volume vented: Operational Process vents (which result from running and maintaining the compressor); Static Seal emissions (key design element of a pressurised compressor, while not running), and; Emergency Shut-downs (automatic shut-down and vent in response to safety alerts).

138. The work undertaken throughout 2017/18 provided a further breakdown into vent types and investigation into reportable and incentivised emissions has helped focus strategies to successfully reduce venting volumes and cost by ~13% on a like for like basis, further focus strategies to reduce venting volumes will be continued throughout 2018/19.

139. An external audit for 2017/18 was carried out (as required annually by the Licence) to ensure vented volumes are calculated according to the agreed methodology.

VII. Outputs – Customer Satisfaction

140. The RIIO-T1 price control recognised the need to encourage network companies to respond to the changing requirements of an evolving customer base and develop strategies to drive improvements in customer and stakeholder satisfaction.

141. Our customer satisfaction output is supported by two separate financial incentives:

- customer and stakeholder satisfaction survey; and
- stakeholder engagement incentive scheme.

142. It was important for us to build on our increase in responses in 2017/18. To do this we continued with the successful trigger based surveying and focussed on obtaining more contact details of customer contacts who interacted with us less frequently. Our customer and stakeholder response volume improved by 25% on 2016/17.

143. In 2017/18, we achieved a customer satisfaction score of 7.60 against a baseline of 6.90. The stakeholder satisfaction score was 8.00 against a baseline of 7.40.

144. The customer satisfaction score has decreased by 0.43 since last year's score of 8.03. The stakeholder satisfaction score has decreased slightly by 0.02 from the 2016/17 score of 7.98. We continue to strive to contact all customers and stakeholders who respond to our survey where they have stated they are happy to be contacted.

145. We received declining scores for all gas service areas apart from Gas Connections and Future Energy Scenarios. However, the learnings made through this broader range of stakeholder and customer engagement in the first half of 2017/18 (overall average score in 1st half of year 7.45), enabled the teams to focus on closing the feedback loop and begin to see a recovery in the latter part of 2017 (overall average score in 2nd half of year 7.73).

146. Putting our customers and stakeholders at the heart of everything we do, continues to be a key priority. During 2017/18 our customer transformation programme helped teams to identify the drivers of customer satisfaction and what was required to improve their experience. This is about us understanding what we should do and how we should do it by developing our products and services through the customer/stakeholder lens.

147. What we have learnt through our customer and stakeholder feedback during the past year has led us to produce five Customer Principles that guide how we should operate. (1.) We need to be more Agile and (2.) Transparent, (3.) we need to Care and (4.) deliver Value and (5.) we need to earn their Trust.

148. It was important for us in 2017/18 to reach a higher number of gas customers, including those who had less frequent contact with us in the past. It was through this broader audience that we learnt what drives overall customer satisfaction and

the steps we need the take to improve their experience, which includes closing the loop on feedback previously received.

149. We introduced a monthly customer experience governance body with the COO chairing to challenge decisions that impact our customers. The focus on our customers is a key priority in supporting us improve our core business performance across National Grid.

150. We also began an NPS programme to enable each of our customers to have a direct voice with the National Grid executive team. 43 Customers have so far engaged through this channel and all our UK executive team members have since met with each customer to listen to its needs, understand its business strategies and identify how we can collectively and collaboratively develop the energy system going forward.

VIII. Outputs – Customer Connections

151. Delivering timely capacity and connections to our customers is a licence obligation and key output under RIIO-T1. In 2017/18 one of nine connection offers was issued two days outside of the specified timescales. The delay of the offer was agreed with the customer. In total, we have progressed all nine NTS connection applications received and issued nine full connection offers.

152. Under this output our performance can be split into two main areas:

- the Connection Application to Offer (A2O) process and
- the Planning and Advanced Reservation of Capacity Agreement (PARCA) process and the delivery of incremental capacity.

The NTS Connection Application to Offer (A2O) Process

153. In total, there were thirteen live NTS connection applications within the Application to Offer (A2O) process during 2017/18. We received nine customer applications for an NTS connection within 2017/18[10]. There were a further four customer applications received in 2016/17 for which an offer was due to be made in 2017/18.

154. In 2017/18 we issued eight full connection offers within the timescales set out in the UNC, one connection offer was issued two days outside of the specified UNC timescale, one application was withdrawn by the customer, and three connection applications were still being processed at 1 April 2018 with offers due in 2018/19. The late offer had no impact on the customer's project timeline.

155. Of the nine offers made, three applications progressed to detailed design and construction, and five are with the customer awaiting a decision to proceed. One offer was not accepted by the customer due to the customer not being awarded an electricity capacity market contract.

Table 9: Summary of the NTS Connection Applications and Offers

Connection Applications		**Offers made in 2017/18**	
Received in 2016/17 and carried over to 2017/18	4	Offer made - Awaiting Response	5
Received in 2017/18	9	Application withdrawn by customer - no offer made	1
		Offer not accepted by customer	1
		Offer accepted	3
		Carried over to 2018/19	3
Total	**13**	**Total**	**13**

[10] Details of the NTS Connection Application to Offer (A2O) process can be found at the following link.

156. The trial self-lay connection offer made in 2016/17 is still being progressed. Processes have been developed for the customer to complete the detailed design and construction activities while we have auditing and asset acceptance roles. The project had been delayed due to customer issues. Should this trial be successful, we will look to offer self-lay as a standard option for all NTS connection customers.

157. Last year following a review to identify improvements in how we charge for connections that would benefit our customers, we introduced two new connection categories as well as categories covering disconnection, preservation and decommissioning of NTS offtakes. The two new connection categories cover minor modifications and re-applications.

Minor Modifications

158. Some of our customers apply for flow increases at existing offtakes that require minimal work such as re-ranging of meters, changes to gas regulator settings, and telemetry changes. For these sites the application fee would otherwise be medium (modification to an existing site) but the introduction of a minor modifications category and lower fee is now more cost reflective and represents better value for our customers. In 2017/18 we received three minor modification requests.

Re-applications

159. Some of our customers have applied for NTS connections and their offers have then lapsed due to their projects not progressing; in many cases due to not being successful in being awarded an Electricity Market Capacity Contract. Some of these customers have gone on to re-apply for a NTS connection at a later date; however, the application fee has not been reflective of the work required to review the work done under a previous application and make an updated connection offer. For these reasons, we introduced a re-application category where a discount to the standard application fee of up to 75% is made to better reflect the work required. Again, the lower fee is more cost reflective and thus fairer to customers. In 2017/18 we received two re-applications.

Disconnections

160. In 2017/18 we have received and progressed one disconnection application.

Future Connection Requirements

161. We have worked with our customers and stakeholders to understand their future connection requirements. This led to our successful NIC submission and the launch of Project CLoCC in February 2016. This three-year innovation project is aiming to reduce the timeline and cost for simple to medium NTS connections. The project focusses on unconventional gas connections, with every aspect of the connection process being challenged in order to reduce the cost of a connection to less than £1m and the timeframe to less than 12 months.

162. During 2017 the project team has been progressing through Stage 3, detailed design, build, testing and business readiness. Our new online gas connections portal is now undergoing user acceptance testing and our suite of standardised connection designs have been undergoing technical approval and appraisal. In January 2018 a number of UNC modifications were progressed, including the successful implementation of MOD 0627s enabling the consideration of non-ROV connections for exit projects. The project is due to completed by October 2018 and implemented into business as usual.

Figure 10: Image of Standard Design 80mm NB Skiosk (a combined telemetry kiosk with ROV and bypass pipework, factory built and tested requiring minimal site installation works)

Incremental Capacity and PARCAs

163. During 2017/18 we received twelve PARCA applications for NTS Entry (seven applications) or Exit Capacity (six applications) in excess of the baseline or obligated level of capacity. It should be noted that some of the applications were for proposed new NTS connections. The NTS exit points required for these proposed new NTS connections are not yet listed in 'National Grid's Gas Transporter Licence in respect of the NTS'. The Phase 1 Works for a number of these PARCA applications has been carried over to the 2018/19 formula year and are due to be completed in May 2018.

164. At the start of 2017/18 two applications were carried over. For one, the analysis works were substantially complete, with the offer made during April. The other PARCA application (for NTS Exit Capacity) was in progress having been deemed a Competent PARCA Application during the 2016/17 formula year. The required Phase 1 outputs for this application were completed successfully within the timescales set out in the UNC. NTS Exit Capacity was reserved and the PARCA proceeded to Phase 2. The reserved capacity was allocated to the NTS User and thereby released as non-incremental obligated capacity provided for by exit

capacity substitution. For the avoidance of doubt, this did not trigger a Revenue Driver.

165. Three of these applications could be satisfied through the reservation of unsold exit capacity within the existing baseline. PARCA offers were made and the exit capacity reserved for the applicant.

166. Two of these applications could be met through the proposed release of non-incremental obligated exit capacity provided for by exit capacity substitution. PARCA offers were made and the exit capacity reserved for the PARCA applicants in both cases. One of these PARCAs was later terminated as the request of the PARCA applicant.

167. The remaining seven applications have been carried over for completion in the 2018/19 formula year.

Table 11: Summary of the PARCA Applications and Offers

PARCA Applications			
Received in 2016/17 - carried over to 2017/18	2	Carried over to 2017/18 - Offer made 2017/18 - not accepted	1
		Carried over to 2017/18 - Customer accepted	1
Received in 2017/18 - offers made 2017/18	5	Offer made - Customer accepted	4
		Offer made - not accepted	1
Received in 2017/18 - carried over to 2018/2019	7	Carried over to 2018/19	7
Total	**14**	**Total**	**14**

168. None of the PARCAs referred to in paragraph 164 have yet had reserved capacity allocated to the NTS user. There has been no funded incremental entry or exit capacity release during 2017/18.

IX. Totex (TO and SO)

169. In 2017/18 our Totex spend was £474m compared to £380m last year. The year-on-year change is predominantly associated with the TO where:

- Baseline Capex increased by £52m, primarily due to increased spend on emissions reduction spend (£29m) and General Asset Health (£26m), partially offset by decrease in Non Operational Capex (£5m).
- Uncertainty Capex has increased by £41m, primarily due to an increased spend on Feeder 9 (£23m), Enhanced Physical Site Security (£13m) and Pipeline Diversions (£5m).
- Controllable Opex has increased by £10m, primarily due to an increase in Business Support costs (£5m).

170. Our updated forecast for the eight years is £3,188m compared to allowances of £3,037m. We have restated RRP Table 2.4 (see Appendix I. Totex Tables) to align allowance with spend categorisations. This impacts TO Non Load Related Capex and TO Opex. The adjustments are a recategorisation only and do not alter Totex spend or allowances.

Overview Transmission Owner (TO)

171. The TO Totex forecast for the eight years is £2,437m compared to an allowance of £2,199m.

172. In comparison to the 2016/17 restated Table 2.4, our forecast spend has decreased by £210m and the adjusted allowance has decreased by £142m. The primary reasons for these changes are:

Allowances:

- TO Non Load Related Capex allowances have reduced by £126m, primarily due to the reduction in allowances requested as part of the May 2018 “Industrial Emissions RIIO-T1 Reopener Submission” (£103m) and the “Enhanced Physical Site Security RIIO-T1 Reopener Submission” (£23m).
- TO Opex allowances have reduced by £16m in line with the “Quarry & Loss RIIO-T1 Reopener Submission”.
- For all allowances for the five reopener categories we have assumed cost equals allowances.

Spend:

- Baseline TO Capex spend has reduced in line with the May 2018 reopener costs. Further reductions relate to lower cost options in General Asset Health spend, for example the use of high efficiency gearboxes within NARC.

- Uncertainty Capex spend has reduced by £23m following the "Enhanced Physical Site Security RIIO-T1 Reopener Submission".

- Total Controllable Opex spend has reduced by £33m which is primarily due to reductions in Uncertainty Mechanism spend (£13m), Planned Inspections and Maintenance (£21m), Closely Associated Indirect costs (£16m), partially offset by an increase in Business Support costs (£17m).

173. The above items are covered in further detail within the relevant table narrative and in Section X. Load Related Capital Expenditure, XI. Non Load Related Capital Expenditure, Section XII. Non Operational Capital Expenditure (TO) and Section XIV. Operating Costs (TO and SO).

Overview System Operator (SO)

174. Our updated Totex forecast for the eight years is £751m compared to an adjusted allowance of £838m.

175. In comparison to 2016/17, our forecast spend has decreased by £25m and allowances have decreased by £9m. The reasons for these changes are:

- Baseline Capex has reduced by £24m due to a reduction in XoSserve spend forecast as a consequence of the Gemini replacement strategy.

- SO Opex has increased by £1m due to an increase in Business Support costs, partially offset by a reduction in Direct costs (including Xoserve).

- Allowances have reduced by £9m (£7m Capex, £2m Opex), primarily due to the data centre and cyber security reduced forecast spend in line with the May 2018 "Enhanced Security Reopener Submission" (for all allowances for the five reopener categories we have assumed cost equals allowances).

176. The above items are covered in further detail within the relevant table narrative and in Section XIII. Capital Expenditure (SO) and Section XIV. Operating Costs (TO and SO).

Summary of Spend and Allowances

177. The table below shows forecast spend and allowances against the six main activity areas as per RRP Table 2.4.

Table 12: Overview Eight-Year Forecasted Spend and Allowances

Activity	Spend (£m)	Allowance (incl. uncertainty mechanism) (£m)	Cost vs Allowance (£m)
TO Load Related Capex	34	44	10
TO Non Load related Capex	1,422	1,254	-168
TO Non Operational Capex	131	70	-61
TO Opex	851	831	-20
Total TO	**2,437**	**2,199**	**-238**
SO Capex	266	328	62
SO Opex	484	510	26
Total SO	**751**	**838**	**87**
Total	**3,188**	**3,037**	**-151**

178. In order to better understand the underlying position of spend versus allowances, Table 2.4 is restated to better align allowance with spend categories. The adjustment made to the baseline position in Table 12 are detailed below:

- IED allowances of £92m are currently included within baseline TO Opex in Table 2.4. All IED spend is captured within the TO Non Load Related Capex category. Therefore, the IED allowances within TO Opex are reallocated to TO Non Load Related Capex to be consistent with the treatment of spend.

179. See the restated Table 2.4 and main reasons for differences between costs and allowances in the SPO on page 7 and Appendix I. Totex Tables.

Customer Bill Impact

180. In 2017/18 approximately £8.79[11] of an average domestic consumer bill of £569 related to the services we provide which equates to 1.6% of a typical gas bill. This compares to 2016/17 where the National Grid element of the consumer bill was £9.32 and the average bill cost was £604 (which also equates to 1.6% of a typical gas bill). The reduction in the average bill cost is largely driven by a reduction in average consumption by consumers. In 2016/17 average consumption was 12,500 kWh compared to 12,000 kWh in 2017/18.

181. We have aimed to be consistent with Ofgem's method for identifying the components of a domestic consumer's bill. Approximately 50% of gas transmission charges are recovered via entry charges and classified by Ofgem as costs entering

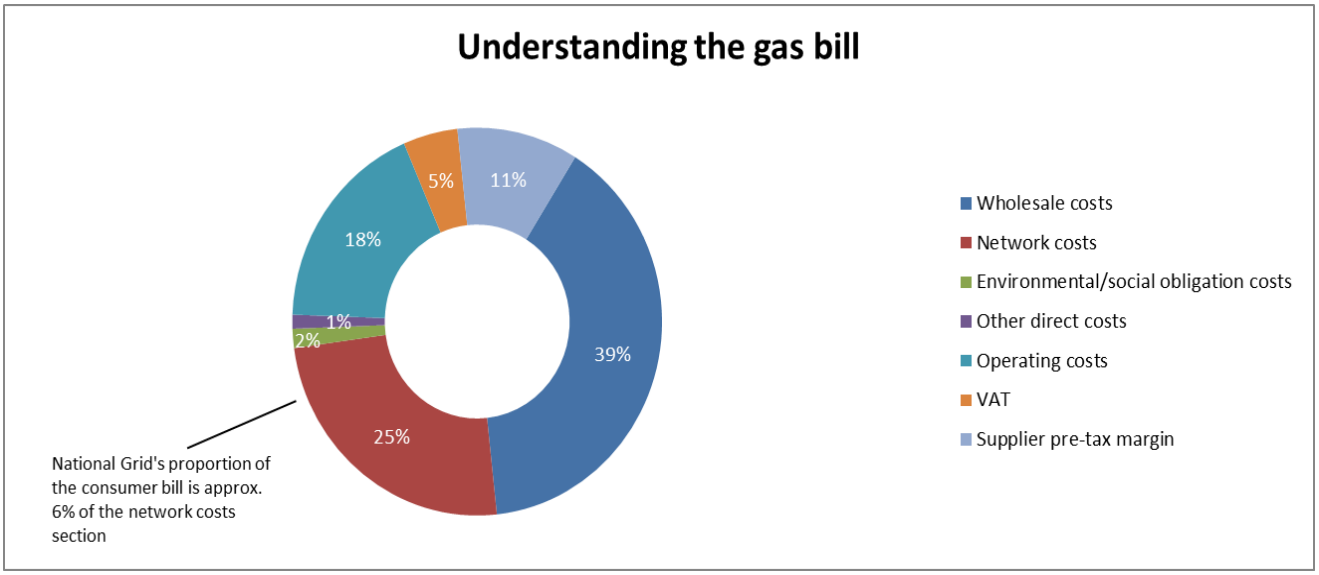
[11] In 2016/17 following the previous calculation method the value calculated was £16.29 (in 2016/17 prices)

the wholesale market prices. The exit costs which include the 'direct' domestic sector consumption are allocated to Gas Transmission network costs.

182. This year we aligned our calculation of the customer bill impact to the above approach (allocating entry charges to the wholesale sector). This is a change on last years' Regulatory Reporting Pack where the entry costs were also allocated to gas transmission network costs.

183. Our current estimate is that the Gas Transmission element of an average domestic consumer bill will rise by £0.61 by the end of the RIIO-T1 period.

Figure 13: Breakdown of the Consumer Gas Bill[12]



[12]Gas bill breakdown available from Ofgem: https://www.ofgem.gov.uk/publications-and-updates/infographic-bills-prices-and-profits

X. Load Related Capital Expenditure (TO)

Introduction

184. This section covers our load related capital expenditure. In 2017/18 our expenditure was £2.7m and our updated forecast for the eight years is £34.0m[13] compared to an allowance of £44.3m. Compared to last year forecast spend has reduced by £4.0m on a constant 2017/18 price base due to a reduction of £4.0m in the Baseline Entry category.

185. The reasons for the reductions in forecast compared to 2016/17 are explained in more detail in the narrative below but in summary are due to movements on:

- Felindre VSD (-£0.9m)
- Environmental Aftercare (-£2.3m)
- Release of long standing land dispute accrual (-£0.9m)

System Flexibility

186. In 2017/18 we continued with our system flexibility project which was initiated to re-assess the needs case utilising the 'seedcorn' funding received under RIIO-T1. Although the baseline allowances for this activity are included within Load Related Capital Expenditure, the spend incurred during 2017/18 falls within SO Opex, further detail can be found in Section XIV. Operating Costs.

Scotland 1 in 20

187. Under our 1 in 20 demand obligation we have continued to assess the need case for the Scotland 1 in 20 suite of projects.

188. During 2017 the step change in the flows through the St Fergus terminal continued but at a reduced level with supplies peaking at 106 mcm/d; 6 mcm/d less than the previous period.

189. The average flow through St Fergus reduced to 89 mcm/d, from 93 mcm/d in 2016/17.

190. The high level of uncertainty of flows from the terminal remains. The current levels could remain or decline to a level that it is no longer possible to maintain the current Assured Operating Pressures [14](AOPs) in Scotland.

[13] The £2.7m expenditure and £34.0m forecast exclude Offtakes
[14] A minimum pressure at an offtake from the NTS to a DN that is required to support the downstream network. AOPs are agreed and revised through the annual Offtake Capacity Statement process.

191. Updated analysis to assess the capability against the 2017 Future Energy Scenarios (FES) has been carried out in 2017/18. This shows the risk of not meeting the AOPs in Scotland has moved out six years from 2021 to 2027.

192. However this analysis doesn't take account of a supply loss at a St Fergus sub-terminal. If the flows declined along the low case scenario from the 2017 FES, in 2020 it would not be possible to meet AOPs with the loss of the largest sub terminal.

193. There is a limited ability to set up Operating Margin contracts with only the St Fergus terminal for supply contracts and only a small number of Direct Connects with insufficient volume available. This would require contracts with the Distribution Networks (DNs) or the Irish interconnector neither of which have been done before, but this option has not been discounted at this stage.

194. An option of bringing forward the 1-in-20 investment to increase the network resilience in the event of a supply loss is being considered within the optioneering in progress.

195. In 2017/18 it was not possible to complete a second trial with Scotia Gas Network (SGN) to reduce some of the higher AOPs in Scotland during this winter. This was due to issues on their network requiring contracted pressures to be available.

196. A Cost Benefit Analysis (CBA) will be completed following the optioneering to resolve the supply loss risk and a decision is expected in 2018/19 on how best to proceed.

Avonmouth

197. On the 24 February 2017, Ofgem published its overall decision on the Mid Period Review. Part of this was to remove National Grid's Avonmouth pipelines output and £168.8 million (09/10 prices) in funding. In accordance with our Planning Code we will continue to monitor the demand situation in the South West, however at this time there is no investment requirement.

Environmental Aftercare

198. The planning consent conditions for two pipeline projects completed during the Transmission Price Control Review 4 (TPCR4) (Wormington to Sapperton and Milford Haven to Tirley) included undertaking monitoring and aftercare regimes for a period of 10 years after project completion. This was to ensure that there were no enduring negative environmental impacts from the pipeline projects. The environmental aftercare category also included funding to complete the Tirley pressure reduction station and associated works (which included activity at Felindre compressor station) delayed into RIIO-T1 due to difficulties obtaining planning consent at Tirley.

Milford Haven to Tirley

199. The Milford Haven to Tirley pipeline project consisted of circa 320km of 48 inch pipeline routed from Milford Haven, South West Wales to Tirley, Gloucestershire. We began the aftercare works in 2009 with an anticipated closure of the scheme following sign-off by two key stakeholders; Brecon Beacons National Park Authority and Natural Resources Wales in 2019.

200. Within last year's RRP submission, we reported that confirmation had been received from BEIS that the consent conditions had been discharged. Internal closure of the scheme was completed in February 2018.

201. The final outturn cost of the scheme was £14.7m which is substantially below the original anticipated cost of £22.2m. The cost reduction is the result of the quality of the original construction work, combined with working closely with the stakeholders to agree when a location had achieved the required standard sooner than was originally forecast.

Wormington to Sapperton

202. The Wormington to Sapperton pipeline project consisted of a 44km, 36 inch pipeline routed through the Cotswolds Area of Outstanding Natural Beauty (AONB). We began the aftercare works in 2011 with an anticipated closure of the scheme following sign-off by the key stakeholder the Cotswolds Conservation Board (CCB) in 2020.

203. Within last year's RRP submission, we reported that confirmation had been received from BEIS that the consent conditions had been discharged. Internal closure of the scheme was completed in October 2017.

204. The final outturn cost of the scheme was £0.5m, which is substantially below the anticipated cost of £3.4m. Similar to the Milford Haven to Tirley scheme, the reduction is the result of the quality of the original construction work, combined with working closely with CCB to agree when a location had achieved the required standard sooner than was originally forecast.

Felindre

205. Felindre Compressor Station was built as part of the South Wales Expansion Project (SWEP), triggered by the requirement to connect the Milford Haven LNG terminal to the NTS.

206. The compressor station was designed as one VSD with two gas turbine units (GTs) as back-up. Construction of the compressor station was completed in 2010 but final commissioning could not commence until completion of the Tirley pressure reduction installation, which had been delayed by planning issues. Tirley was completed and commissioned in September 2012, however the expected volumes of gas at Milford Haven did not materialise and flows were not high enough to

commission the VSD compressor although progress was made in commissioning the smaller GT units.

207. Although Tirley pressure reduction installation was completed, work is ongoing to complete associated works. This is expected to be closed in 2018 with total outturn cost in the RIIO-T1 period of £5.1m.

208. Commissioning runs of the GTs were completed in 2015/16 and they were made available for operation under local work procedures, both on-site and in the Gas National Control Centre (GNCC). Most work specific to the GTs has been completed, enabling removal of local work procedures and unrestricted use of the units. Full commissioning of the control system will be completed with the VSD commissioning, expected in 2020.

209. In January 2014, due to the continuing low flows through Milford Haven, the VSD unit was put into preservation to avoid degradation of the equipment. The preservation expired in January 2016 and the decision was made to progress with commissioning the VSD due to higher flow forecasts at Milford Haven. The decision was also made at this time to proceed with creating a recycle loop within the network. The loop will reduce dependence on the unpredictable Milford Haven flows for commissioning the VSD and enable operational and environmental testing of any of the Felindre units.

210. Design of the cross connection that will create the loop has been completed. This will create a new site on the NTS, named Alltwern. Planning permission approval and land acquisition are expected to complete in July and October 2018 respectively. Due to delays in meeting the planning requirements and obtaining approvals, construction has now been scheduled to start in early 2019. The indicative outturn cost of the Alltwern site is £3.8m, within the original estimated £3m to £5m.

211. Work to prepare the VSD for commissioning is also progressing. Uncoupled runs were completed during 2017 which allowed an initial evaluation of the interaction with the local electricity network. Final commissioning is expected in 2020, following completion of the Alltwern cross-connection. Works are currently paused for a review of the delivery strategy and to ensure cost certainty. The outturn commissioning cost of the VSD is anticipated to be £7m.

XI. Non Load Related Capital Expenditure (TO)

Introduction

212. This section covers our Non Load Related Capex. In 2017/18 our expenditure was £248.7m[15] and our updated forecast for the eight-year RIIO-T1 period is £1,422m[16] compared to an allowance of £1,346m[17]. Compared to last year our forecast spend has decreased by circa £161m on a constant 2017/18 price base. The key variances in forecast are due to:

- A reduction of £133m (including a £7m reduction in IED Decommissioning) in planned emissions investment in RIIO-T1. The forecast is in line with the *"Industrial Emissions RIIO-T1 Reopener Submission"* in May 2018.
- A forecast reduction in enhanced physical site security costs of £23m as a result of removing sites from the programme following confirmation that no physical site security enhancements are required at these sites. The forecast is in line with the *"Enhanced Physical Site Security RIIO-T1 Reopener Submission"* from May 2018.
- A forecast reduction in Asset Health costs of £15m (£12m baseline and £3m Uncertainty Mechanism).

Asset Health

213. In 2017/18 we have increased the delivery of our asset health works, investing £126.5m to manage network risk and continue to deliver a safe and reliable gas transmission network for our customers. This is an increase of £26.4m on the 2016/17 workbook and has been enabled by the surveying and planning work undertaken in the initial years of RIIO-T1 and the establishment of asset health campaigns to drive an increase in efficient project delivery and workload.

214. The key asset health campaigns (and spend in 2017/18) that have commenced and/or delivered over the year are as follows:

- National AGI Renovation Campaign (NARC) – Year 1 (£36m)
- St Fergus Campaign (£11.8m)
- Bacton Campaign (£9.8m)
- Compressor Programme (£6.6m)

[15] Excluding customer contributed Diversions spend of £3.6m
[16] Excluding customer contributed Diversions spend of £83.4m
[17] As per restated table 2.4 (see Appendix I. Totex Tables)

215. As we have reported in previous RRP submissions, we continue to observe that the actual network condition is at a lower level (i.e. more observed condition issues) than the modelled view within our current NOMs methodology. We continue to forecast a higher overall workload and therefore cost for asset health baseline investments of £672.5m over the RIIO-T1 period which is circa £96.4m over allowances.

Smart Delivery

216. During 2017/18, we have reviewed our asset health investment plans for the remainder of the RIIO-T1 programme and looked at ways of delivering this work programme for less. We have gained a better understanding of the work required to maintain the health of our assets and continue to identify lower cost options to mitigate risk on the network. Through these innovative and low cost options, we have been able to revise our overall forecast downwards, a reduction of £12m on our 2016/17 RRP submission.

217. We have developed more refurbishment and repair options that can be used to avoid replacement, minimise cost and deliver value for customers. Our key projects section describes several of these lower cost intervention options. A notable example being our shallow dig technique for repairing the vent and sealant lines on buried valves. This relatively low cost repair technique avoids more intrusive refurbishment or replacement options.

218. Where replacement is the most cost effective option, we are careful to only replace the asset or equipment that is defective. At Bacton Terminal, we have carefully assessed the condition of the pipe supports across the site, repairing where possible and replacing only if cost effective. We are mindful that our asset health forecast remains above allowances, and are committed to keeping this programme under continuous review and finding ways of delivering the same risk reduction for less money.

219. Whilst smarter, targeted and more cost-effective delivery of risk reductions is in the best interests of customers, we recognise that often our current NOMs methodology does not allow us to claim these interventions as a recognised output. The reasons for this can be complex but the most common is that the unit of measure is often larger than the asset we have worked on. For example, the unit of measure for Civil Asset (Pipe Supports & Pits) (SAC12) is the whole site and unless we demonstrate that we have re-lifed more than 50% of the site then we do not claim this as removal of an RP1 asset. More information on NOMs outputs is provided in Section V. Outputs – Reliability and Availability.

Managing Risk

220. The risks associated with our ageing asset base poses a significant challenge. Balancing the risk of failure with the need to reduce costs requires careful management. To support this, we have implemented an Operational Risk Assessment and Mitigations (ORAM) approach to manage the risks at site level. This approach is helping us to manage the upward cost pressure on our asset

health programme and maximise value for our customers and stakeholders. Our engineers apply local risk assessment to asset health issues and seek to mitigate first through lower cost actions that can be delivered locally.

221. Given the clear need for the gas transmission network in the future we need to invest appropriately. We have been able to reduce our forecast and contain our expenditure in the latter years of RIIO-T1 through efficient delivery, innovative solutions and focussing on immediate safety and reliability issues. However, it remains our firm belief that we need to increase investment in our network in the future.

222. As part of our RIIO-T2 preparations, we will be engaging with our customers and stakeholders to establish what they require of the gas transmission network and the level of network risk they are prepared to pay for. Our monetised risk models are supporting the development of our RIIO-T2 asset health strategy and we plan to use this approach to demonstrate the benefits of our future investment plans.

223. The final year of our plan (2020/21) shows a modest increase on the preceding year and this represents the preparatory work that we anticipate to commence to enable delivery in year 1 of RIIO-T2. Our current planning assumption is that we will need to ramp up asset health investment in RIIO-T2 in order to manage the risk on our ageing network. Therefore, our final year forecast is subject to considerable uncertainty and dependent on the outcome of RIIO-T2 preparations this year and engagement with customers and stakeholders on the level of network investment required.

Campaign Approach

224. We continue to deliver the majority of our programme through asset health campaigns to drive an increase in work delivery. During 2017/18 we have delivered more asset health work than ever before. It should be noted that there is usually a time lag between the asset health spend being incurred and the final commissioning of the asset which allows the network output to be claimed. We would expect a significant proportion of the of network outputs linked to spend in 2017/18 to materialise in 2018/19.

225. Our campaign approach is successful because we are able to provide more focussed scopes of work for our contractors, utilise standard designs, streamline project documentation and make better use of available system outages. Without this approach, our work delivery would be constrained by our ability to take outages on the network.

226. Asset health campaigns are successful because they provide an agile approach to asset health investment. Outcome based scopes of work are provided to our delivery units and contractors and this promotes development of innovative solutions to address asset health issues. Campaign Decision Panels (CDPs) are used to review the results of surveys and agree the specific interventions that will be undertaken during the delivery phase, including repair/refurbishment options and rescheduling the work if the risk is deemed acceptable.

227. Through our campaign approach we are able to utilise standard designs, streamline project documentation and make better use of available system outages. Without this approach, our work delivery would be constrained by our ability to take outages on the network

Developing our Asset Management Capability

228. We manage our network risk as efficiently as possible, however we recognise that our current approach is more reactive than we would like. Through our ISO55001 accreditation, we are continuously improving our asset management processes to ensure our asset strategies effectively manage risk and deliver value for our customers. A fundamental building block in improving our asset management capability is our investment in processes, data and technology systems as described in Chapter XII. Non Operational Capital Expenditure.

229. Improved asset data and technology, in conjunction with our new NOMs Methodology, are key enablers on our journey to asset management excellence. This will enable the planning and targeting of investments, and the reporting of investment outcomes using a monetised risk-based approach.

<u>NOMs Methodology Development</u>

230. During 2017/18 we have finalised our NOMs Methodology, working closely with Ofgem. We have continued to hold bi-monthly meetings with Ofgem to allow regular feedback during the development and testing of the Methodology, and for improvements to be incorporated prior to public consultation.

231. Our NOMs Methodology documents were submitted for public consultation on the 3 April 2018, with a closing date of the 15 May 2018. Prior to, and during, the consultation we held a number of face-to-face and telephone engagement sessions with stakeholders including Citizens Advice, Environment Agency/Scottish Environment Protection Agency (SEPA), Electricity Distribution Networks and Gas Distribution Networks. We received three, largely favourable, written responses which were used to review and challenge our approach prior to submission, but no actual changes to the documents were necessary. Following resubmission of the final documents, Ofgem notified us that they were minded not to reject our Methodology on the 19 July 2018, but further validation of results will be required before it can be used with confidence for RIIO-T1 Rewards and Penalties assessment and RIIO-T2 investment planning.

232. Following agreement of the final NOMs Methodology document we are progressing with the final stages of our Calibration, Validation and Testing (CVT) process. We have submitted details of our calibration and testing approach within the Probability of Failure, Consequence of Failure and Service Risk Framework supporting documents, which were published as part of the wider NOMs Methodology consultation. We have appointed external consultants to undertake an expert review of the model data and results, focusing on the sensitive model data and benchmarking outputs with similar industries in the UK and world-wide. We are currently developing our data/model validation approach, which will be agreed with

Ofgem prior to submission of our final Validation Report in September 2018. This will give stakeholders confidence that the monetised risk calculations are based on the best available evidence and the Methodology can be applied with confidence.

233. Improvement to the granularity of data and the structure of our data in our Asset Register is essential for ensuring the methodology is fit for purpose to make investment decisions and report our asset health investment performance. A further Asset Register data update was carried out in January 2018, with a final data update planned for August 2018. This will inform our final Validation Report to be submitted in late 2018.

234. We have developed, and shared with Ofgem, a draft approach for rebasing our RIIO-T1 Licence targets using the principles of monetised risk. This will be used to assess our asset health investment performance at the end of the current regulatory period and quantify any rewards or penalties due, as part of RIIO-T1 close-out. Our final rebasing approach and an initial set of monetised risk values will be submitted to Ofgem by 2018. It is expected that we will report using our new NOMs Methodologies for the 2018/19 RRP.

Data

235. The improvements to our approach of asset management together with the anticipated demands of the new NOMs methodology require a significant enhancement of our asset data and investment in our asset management technology systems and data analysis capability. To achieve this we are progressing two major improvements, these projects are detailed in Section XII. Non Operational Capital Expenditure.

Key Project Delivery for 2017/18

236. This section of the narrative details key project deliveries in 2017/18. It should be noted that although the projects may largely have completed within the reporting year, the actual NOM count may be reported in next year's RRP submission.

National AGI Renovation Campaign (NARC)

237. Since2015 we have accelerated asset health works on the network. Our identified approach is to batch work into asset classes for survey and delivery by contractors with the requisite skill sets. One of these work batches is the NARC, which covers a number of NOM categories and aims to maximise the value from time limited and costly feeder outages.

238. NARC renovates AGIs and sections of compressor stations to resolve Plant Status Issues. The campaign covers invasive work requiring gas outages such as valve replacement, pipe-throughs and replacement block valve assemblies. It also undertakes actuator replacements, valve enhancements, such as new vent and sealant lines, various integrity based work and an element of civils that is associated with the mechanical work.

239. In 2017/18 we successfully implemented the CDPs which have the responsibility to agree the scope and approved construction works outside of usual governance cycles, increasing efficiency and pace of delivery. This approach approved the rectification of 704 Plant Status Issues, this was achieved via 13 meetings over a two-month period. For NARC we achieved accelerated rectification of over 341 Plant Status Issues over 48 sites using four Main Works Contractors (MWCs) from the asset health framework which will achieve 129 NOMs before April 2019.

240. An overview of the sites completed in 2017/18 is shown in Figure 14.

Figure 14: NARC 2017/18 Progress Map

241. The NARC team applied outage and contingency planning and utilised technician and Mechanical Damage Assessor capability within the team to complete over 30 pipeline damage assessments and repairs during 2017 improving the integrity of the system.

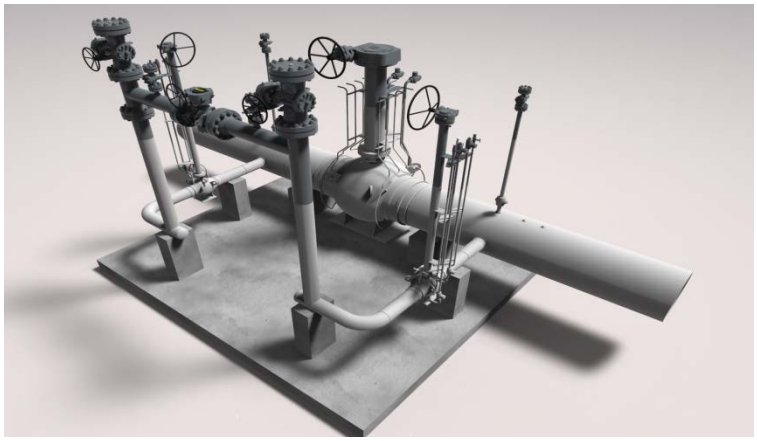
242. In 2017/18 NARC successfully delivered the following examples of work:

- Generation of Design Phase 3D images and completion of virtual rehearsal to aid stakeholder engagement, improve process safety assessments, verify constructability and reduce cost and program uncertainty.

Figure 15: 3D Lifting Operation Rehearsal (left); Completed Operation (right)

- The campaign developed modular block valve designs achieving efficiency via a standardised design solution. This design allows efficient offsite fabrication, safe offsite hydrostatic testing and minimises network outage period for installation.

Figure 16: Modular Block Valve Design



- NARC completed a pipe through and removal of the Duxford block valve which reduced whole life cost, compared with replacing the block valve, particularly valve maintenance and coating inspection. This example has validated the ‘pipe-through’ approach, where the needs case supports the block valve removal.

- The NARC 1 campaign delivered 17 actuators and control cabinet replacements (ten electric and seven gas) and another 12 are planned in 2018/19, rectifying operator issues in Scotland, East and West areas.

Figure 17: New Gas Actuators at Michelmersh AGI (left); New Gas Actuators at Crieff AGI (right)

- As part of the NARC 1 campaign 30 high efficiency gearboxes have been installed on non-critical locally operated valves, in replacement for hydraulic and electric actuators, successfully realising £825k financial and operational benefits from reduced material and installation costs.

Figure 18: High Efficiency Gear Box installed at Rockland St Peter Block Valve (left); Hardwick AGI renewed (right)

- In 2017/18 we completed four block valve replacements, activities including offsite fabrication and hydro testing, tie in welds and Non-Destructive Testing (NDT), coating, cathodic protection, backfill and all site civil work.

Figure 19: Design Image of Planned Block Valve Site

Figure 20: Photo of Rockland St Peter Block Valve at Completion in August 2017

- In 2017 pipe support work was incorporated into NARC for delivery. The contact points between pipe supports and pipelines is an area where corrosion can occur and must be inspected as supports reach the end of their life. The work on these assets typically involves inspection and repair or replacement of the concrete and steelwork as required. To check for corrosion of the pipeline, the works include removal of the support around the pipeline, often requiring complete removal and replacement of the concrete plinth. The NARC team has inspected beneath more than 100 saddle supports.

- One of the main projects in 2017/18 was the completion of the re-shape of Cambridge Tee; 36 inch valves and associated pipework, equipment has been replaced providing isolations between the compressor station and Feeder 3. This included all operating equipment which has been brought above ground for easy access and negating pit entry. The best available technique assessment was undertaken at Cambridge Tee leading to installation of three electro-hydraulic actuators which improves our environmental footprint as well as meeting safety and operational requirements.

Figure 21: New Cambridge Tee (left); Previous Cambridge Tee Pit (right)

243. Part of NARC innovation assessed the condition of Feeder 3 valves removed from the ground as part of the replacement block valve works, after over 45 years of service. Two contractors were commissioned for the work and random samples taken to conduct material analysis. The preliminary results (one example shown in Figure 22 below) show numerous crack indications, potentially indicating stress corrosion cracking. Further work is ongoing to validate this and the impact on future asset health decisions, in advance of a full report being issued.

Figure 22: Potential Stress Corrosion Cracking on Feeder 3 Valves

244. The innovation project for GRP pipe supports has been successfully progressed for use in 2018 and a prototype was manufactured. Crush testing has confirmed its vertical load capability and a design specification has been produced.

245. During summer 2017 surveys and conceptual design reports were completed for five feeder sections and five compressor stations/large AGIs to inform NARC 2 work scope, which was successfully agreed by the CDPs. NARC 2 design phase is nearing completion with recompression completed on the first outage section and construction works taking place over summer 2018.

246. Current declared efficiencies for NARC 2 are £9m, made up of £4m by utilising five pipe-through solutions instead of full site replacements, and efficiency cost savings of £5m due to competitive tender, contractor efficiencies, and recompression efficiencies.

247. Building Information Modelling (BIM) utilisation has continued with great success for NARC 2 construction works, not just with the creation of modular designs, but especially in the negotiation and agreement to date of several difficult outage works with third parties. It embeds the temporary works design with the permanent works increasing installation efficiency and safety, reducing risk and cost.

Figure 23: Design Image (utilising BIM) of Brisley Site Works

248. The following innovations are planned for incorporation into NARC 2 during summer 2018:

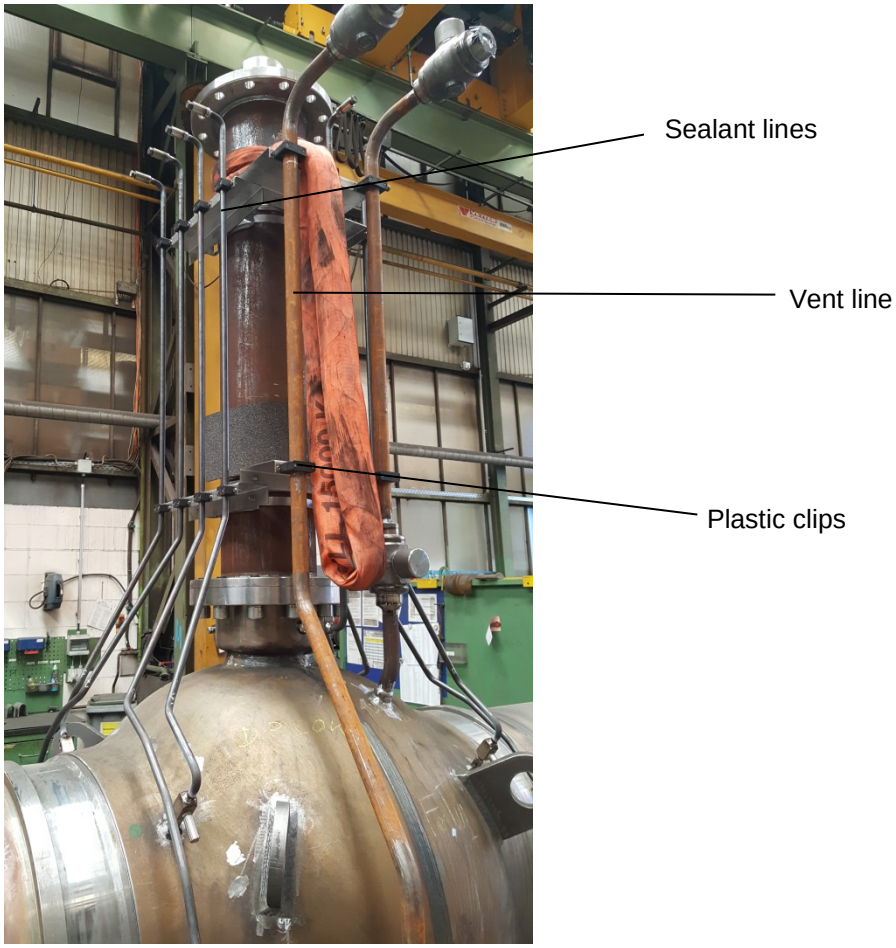
- Continuing the strategy of using high performance gearboxes on non-critical valves and further developing the use of these gearboxes to replace remote valve actuation.

- Planning the first site installation of GRP supports which, due to our smart split body design, enables the support to be withdrawn from the pipeline and allowing easier and cheaper withdrawal for pipeline inspection. It is lightweight and will not corrode, has a design life of 40 years and is cheaper to purchase.

- NARC is currently reviewing shallow dig techniques for vent and sealant line replacement on block valves.

- Following learning from corrosion of the V/6 specified welded vent and sealant line supports NARC have implemented a design change with our 2018 long lead valve supplier to ensure ball valves are supplied with plastic anti-corrosion clips. These are currently being manufactured in Germany.

Figure 24: 36 inch Valve with Plastic Clips during Factory Acceptance Test



St Fergus Campaign

249. St Fergus Terminal is a key gas entry point into the UK which was built in 1975 in a coastal environment which accelerates corrosion degradation. Across the site, investment is being made on various work streams, prioritised through the ORAM process which began in late 2016. The investment being made on site focuses on management of existing asset issues that pose a potential safety risk, whilst in parallel retaining appropriate levels of compression capability and meeting our environmental targets. ORAM has prioritised corrosion remediation and restoring the compressor cabs to full operational capacity as critical work. These themes, along with valve actuator refurbishment, and completion of Plant 2 metering formed the most significant areas of investment at St Fergus Terminal during 2017/18.

250. Through the first half of 2017/18, corrosion management surveys were completed for all the assets on the site and the quantity of corrosion related defects requiring intervention became evident. By July 2017 approximately 2825 defects were rated visually as grades 4, 5 or 6 as per the CM/4 survey process, indicating the need for continued investment in the corrosion theme, which had commenced with the Plant 2 outage undertaken through 2016/17 and 2017/18.

251. In terms of corrosion investment, over 400 defects have been remediated during the Plant 2 outage and other related works. Analysis of the CM/4 survey (a visual inspection for corrosion) data indicated sixteen defects which were rated as high risk and in need of immediate resolution. These defects, where accessible, were remediated during 2017/18 with the remaining four now isolated for remediation during the Plant 1 outage which is commencing May 2018. The outage in Plant 2 and rare outages on incomers from the sub-terminals Apache and PX Group, have provided the opportunity to address corrosion defects on these areas of plant.

252. Issues on the Plant 2 aftercoolers which were identified during inspection in 2016 and delayed their re-commissioning have now been completed. A phased re-introduction of the aftercooler cooling fans enabled the gas path to be restored early, and allowed access to other areas of plant for necessary remedial works. The outage in Plant 2 has also provided the opportunity to re-life the Plant 2 scrubbers, which were beyond their expected asset life and in need of significant investment.

253. A large part of 2017/18 has been the preparation for the Plant 1 outage in 2018/19. Our increased knowledge of the asset condition, and more robust site-wide risk assessment process has enabled us to better scope works for prioritised and efficient delivery. A large portion of effort has been spent undertaking surveys, scoping for future years work and developing detailed designs.

254. An optioneering activity was undertaken associated with the replacement of the actuating gas ring main. The gas ring main is heavily corroded and serves as the operational gas supply for actuators on the Emergency Shutdown (ESD) Valves. The optioneering report and associated Formal Process Safety Assessment (FPSA) identified that actuation for the ESD valves would be better provided by an Electrical/Electro Hydraulic solution rather than gas actuation. This option additionally yields a saving of circa £6m on a like for like replacement of the gas ring main. Following the optioneering report an order of long lead materials circa £1.2m was undertaken with spend realised during 2017/18. The completion of the detailed design and commencement of implementation will occur in the second half of 2018/19.

255. While the gas ring main optioneering was ongoing a number of gas actuators were either refurbished or replaced with a manual operating system. Approximately 37 actuators were either refurbished or replaced as part of the actuator refurbishment project. The refurbishment project was ceased on the basis of the future gas ring main replacement. It is intended that the refurbished actuators will be utilised in future on other parts of the NTS or kept for use as strategic spares.

256. The new Plant 2 Metering scheme was recommenced early 2017 and concluded during March 2018. The work was the culmination of a scheme sanctioned in January 2015 but halted mid-construction due to more critical corrosion activities being undertaken. The work was required in order to replace three existing orifice plate meters on Plant 2. The existing meters were located in an enclosed pit which constituted a confined space thus making access for maintenance difficult, they no

longer met the required accuracy, were difficult to calibrate and suffered from persistent problems with flange leaks, giving rise to both process and occupational safety risks. The old meters were replaced with new ultrasonic meters located above ground and which conform to current measurement standards.

257. 2017/18 also saw the commencement of improvements to the existing compressor cab infrastructure. Units 1A, 1B, 1C, 1D, 2A and 2D all received minor upgrades associated with existing ventilation and insulation systems to lower cab operating temperatures. Major work was commenced on Unit 1D which will see the exhaust stack replaced, the volute refurbished and the ventilation system improved. Similar work will be undertaken on the other cabs as part of 2018/19 works. This year we also carried out an update on the Integrated Security Solution System.

Bacton Campaign

258. The Bacton terminal is a key gas entry point into the UK both currently and into the future. The site commenced operation in 1968 in a coastal environment which accelerates degradation. Bacton as a site had 237 Plant Status issues as a starting baseline. These are being progressed through our investment process. By examination of the risks and consideration of the needs case work at Bacton, we have identified issues that should be prioritised and are considering options to retain safe operation of the site while we complete the final stages of the need case review. At Bacton there is a strong interaction between asset health and the needs associated with future operating scenarios. The current phase of asset health works exemplifies this interaction. Only those assets deemed 'Least Regrets'[18] are currently being replaced. The works completed at Bacton in 2017/18 are:

Bacton AH-1A: Installation of 11 new valves on in-comer streams and ring main

259. During the period from Spring 2017 through to Autumn 2017, a total of 11 new main line valves were installed. In addition, numerous smaller valves were installed around these mainline valves to facilitate safe operational use of the larger valves. This work necessitated considerable interaction with our close neighbours and customers, such that we could share outage periods on our respective plants and minimise disruption to both parties. The full incomer valves on Perenco 1 and Shell 1 were replaced, along with the addition of a new valve on Shell 4 to facilitate later isolation phases ensuring that we do not require to disrupt the Shell 4 incomer. In addition, two of the ring main valves were replaced. The design phase and delivery phases were developed using an 'agile' methodology. The approval and sign off of the finalised design is currently running around two to three phases ahead of the current installation phase. Some re-phasing of delivery phases has required re-planning, these primarily being undertaken to share outages with other projects or customers to reduce the risk of constraint costs.

[18] The assets that are most likely to be required in any future operating scenario

Figure 25: New pre-fabricated Perenco 1 Incomer Section commencing Installation

260. The use of BIM – 3D modelling has become part of business as usual within the Bacton projects. BIM has considerably reduced the likelihood of fabrication issues and onsite 'clashes' with other pipework or assets. It is used during design review meetings. In addition, completed works are laser scanned upon completion with the final as-built records being generated from the laser scan 'point cloud survey'.

Bacton AH-1A: Painting

261. In addition to the valve replacements, the corrosion protection painting works to be completed onsite were commenced during summer 2017. These works were planned for the Feeder 3 part of the site, utilising the depressurised condition of plant that had been shut down to facilitate the NARC works further down the feeder. This effective sharing of outages between projects maximises the work that can be achieved on a depressurised section. These works are currently planned to continue to be delivered for the duration of the AH-1A investment scheme.

262. In addition to above ground painting systems being renewed, work has also commenced on dealing with the repair of wind/water-line corrosion features. An earlier survey of the site had shown coating failure on all of the surveyed sections. Whilst these had not escalated to severe corrosion defects, it is imperative that repairs are affected early, thereby minimising costs and removing potential for future asset health integrity issues.

Bacton AH-1A: Pipe supports and bolt replacement

263. Because of the coastal environment and its ability to accelerate corrosion issues, the AH-1A scheme is also required to replace bolts on the flange faces onsite. These are being replaced with a coated variant that will better withstand the local environment. This work is being co-ordinated with painting activities such that completely finished areas of plant can be signed off as complete against AH-1A requirements.

264. Along with the painting requirements associated with the above ground pipework, the AH-1A scheme is required to investigate and remediate the pipe support arrangements onsite. This work has been reviewed during 2017/18 and is about to commence on a phased basis in 2018/19 delivery window. The assessment of a range of differing support designs onsite will be completed, and this will better inform a phased approach to addressing asset health issues for these assets.

Gas Robotic Agile Inspection Device (GRAID)

265. Separate to the asset health works onsite, is the installation of the GRAID connection. During 2017/18 design and civil installation works were completed for GRAID. The mechanical connection is due for completion mid-summer 2018. This connection facility, will permit online testing of the GRAID robot to commence. The long-term aim will be to gather data to better inform future asset health and future operating strategy decisions.

Future works - Preheat 3

266. The site Preheat system provides heat to the incoming gas supplies, prior to them entering flow control equipment, to prevent the formation of liquids in the pipework and ice build-up on the external surfaces. There remain a number of Asset Health Plant Status Issues associated with the Preheat systems. Preheat 3 is due to be sanctioned in late summer 2018 and will enter a delivery phase during autumn 2018/19 to permit continued safe operation of the Preheat system.

Future works – Asset Health 2 – Electrical Assets

267. A scheme has been commenced to collate a composite scope to inform future decisions on the integrity matters associated with power supplies onsite. A number of the assets are now aged and are no longer directly supportable. Scope development is required now to permit timely development of the scheme such that it is addressed in a safe and efficient delivery window, mindful of our outage restrictions and plant access interactions with those customers immediately adjoined to site.

Other future works at Bacton

268. Asset health Scheme AH-1A continues to be planned over a four-year period due to the need to keep the site operational throughout the works. Further work is required on valves and actuators and the specifics of this will be based upon the

outcome of the Future Operating Scenarios review currently being conducted. Until this review and the resulting works are completed, ORAMs will be conducted to ensure the plant remains safe and effective in its operation.

Compressor Programme

269. The compressor machinery used on the gas turbine driven compressor units is made up of three component parts: gas generator, power turbine and centrifugal gas compressor. The investments on these parts carried out in 2017/18 are detailed below.

Gas Generator

270. We have five different asset types of gas generator making up the national fleet of 61 gas generators currently in operation across the NTS; in addition we have a number of spare gas generators to provide resilience to the operational units. The gas generators (commonly referred to as the prime mover) are a combination of light industrial and aero-derivative turbines and are monitored and maintained routinely through a series of work and management procedures carried out by our operational field force.

271. Gas generator 'major maintenance interventions' including overhaul, are typically carried out every 24,000 consumed hours or based on condition. Indicators from our approach undertaken in 2016 highlighted the need for a number of major interventions. During 2017/18, we undertook six overhaul activities and rotated positions of a number of gas generators. Our experience of these overhauls has resulted in a change of approach for some engine types representing better certainty on cost and overhaul requirements. All future LM2500+ gas generators will be 'service exchanged' when a major intervention is required – this will guarantee prices and risk providing an 'as' new engine regardless of the condition of the engine we commit to overhaul.

272. The recent increase in running demand placed on the fleet of compressor plant and ancillary equipment is likely to remain for the foreseeable future. The future years gas generator overhaul and maintenance programme reflects this likely demand to guarantee availability and reliability of plant.

Power Turbine

273. Power turbines receive the exhaust gases generated by the gas generator. The power turbine harnesses these exhaust gases; and being directly coupled to a gas compressor, they provide the motive energy to turn the compressor. Power turbine maintenance and overhaul requirements, as with the other machine train components, are heavily influenced by both run hours and elapsed time.

274. During 2017/18, we undertook overhaul activities on two power turbines. The recent increase in running demand placed on the fleet of compressor plant and ancillary equipment is likely to remain for the foreseeable future. The future years power turbine maintenance and overhaul programme reflects this likely demand.

Centrifugal Gas Compressors

275. Gas compressors provide the actual compression of the natural gas within the NTS. All of the NTS compressors are centrifugal compressors. They are driven, either by a power turbine or an electric motor. In the case of the power turbine driven units, the prime mover is a gas generator, referred to above.

276. During 2017/18, we undertook limited overhaul and maintenance on the gas compressors. An evaluation of upcoming requirements has been factored into future works programmes with a number of major interventions on our gas compressors planned from 2018/19 onward. Along with the other machinery train components, the future years compressor maintenance and overhaul programme reflects the recent change in demand patterns. These interventions are required to guarantee availability and reliability of plant.

Pipelines Campaign

277. In total 583 km of pipeline was in-line inspected in 2017/18 and 26 significant pipeline excavations and repairs were completed from previous inspections in 2016/17. The selection of the pipelines requiring inspection is driven by a condition and risk based approach, considering pipeline condition, criticality and performance of corrosion prevention.

278. The volume of excavation works to further examine and address defects identified through our 2017 ILI programme was broadly similar to the 2016 volumes.

279. In 2017/18, remedial work was completed on a number of nitrogen sleeves which provide additional protection for our pipelines as they cross under roads, railways and rivers. Following the initial works in 2016 using the methodology developed by United Kingdom Onshore Operators Association (UKOPA), a new simplified methodology has been developed to prioritise the most critical sleeves for intervention.

280. Following the initial trials in 2016/17, we will capture XYZ mapping data for all of the 2018 ILI runs. The XYZ mapping uses a series of reference beacons placed on the ground above the pipeline from which the ILI vehicle can determine its true geospatial position as it passes beneath them. This positioning data will be combined with LiDAR data, providing an enhanced view of pipeline depth of cover as part of the assessment of the threat from potential third party damage.

Cathodic Protection (CP)

281. CP is applied to buried steel pipelines to prevent the steel from corroding. It is achieved by applying a direct current to the buried steel from an external anode with the result that the anode corrodes. If the CP system is effective then the pipeline inspection frequency can be lengthened, which results in fewer inspections and therefore cost savings.

282. In 2017/18 we have undertaken Close Interval Potential Surveys (CIPS) on approximately 160 km of NTS pipelines. The results of the surveys have been analysed and where appropriate, remediation activities have been scoped and scheduled. These programmes of work have required significant stakeholder engagement, in particular with landowners where our pipelines cross their property. Before we undertake any surveys associated with rural pipeline CIPS, we send out a letter informing them of the proposed dates of our activities. We then work with landowners to agree a suitable timeslot to coordinate our activities in a way that causes minimal disruption and optimum efficiency.

283. In order to assess if sites which are not protected by pipeline CP have adequate protection from their site CP system it is essential to carry out CIPS. All sites in scope of the AGI CIPS survey programme have been completed in 2017/18. Throughout 2018/19 we will continue to progress the remediation works identified.

Huntingdon/Peterborough Asset Health Investment Campaign

284. At the start of the RIIO-T1 period, both Peterborough and Huntingdon consisted of three Avon machines each. We continue to advance the programme of works to deliver new gas turbine compressor units at each site under IPPC Phase 3 and Phase 4, as required to maintain efficient transmission capability across the centre of the network and to meet south west exit capacity obligations (see the Emissions chapter of this section for progress on these projects).

285. The programme of asset health works was sanctioned for £32.7m in 2016, this is financially separate from IPPC Phase 3 and Phase 4 core and extraordinary work scopes, but bundling presented a significant opportunity to leverage outage and project management efficiencies.

286. At Huntingdon we continued to deliver the replacement of obsolete and unsupported Fire and Gas Detection systems, which were operationally accepted in November 2017. We also started the delivery of similar asset health works at Peterborough to replace existing obsolete and unsupported Fire and Gas Detection systems, which are due for operational acceptance by the end of 2018.

287. We started work to replace the unit control system on compressor Unit C at Huntingdon, which is also obsolete and no longer supported. Operational Acceptance is due at the end of 2018. Additionally pipe supports on various above ground pipe has been replaced and various vibration issues have been addressed.

288. At Peterborough, we have continued to advance the Detailed Design for the asset health work in conjunction with the IPPC Phase 3 and Phase 4 works with the MWCs. To support the asset health delivery for future years we have also started the procurement of critical items of process plant, such as station control systems, valves, actuators and scrubbers (including condensate tank).

Carnforth Asset Health

289. Carnforth consists of three units. Units A and B are both RB211s which are not compliant with IED-LCP emissions limits, Unit C is a compliant DLE machine.

290. We entered Unit B into the 500 hours derogation and Unit A into the Limited Life Derogation (LLD). We have since taken the decision to close Unit A, undertaking asset health works on Unit B to ensure continued availability of backup to Unit C until the site modification works have been completed. The works carried out on the units and station are to ensure the availability of the compressor station which is a back-up to Nether Kellet Compressor Station.

291. In 2017/18 the works carried out on Unit B included the replacement of assets that were at the end of their life, including the emergency shutdown valves, unit isolation valves and the replacement of exhaust and volute lagging and the fuel gas governor valve and actuator. This resolves a number of valve issues where valves were not operating as required and overheating issues where lagging had deteriorated.

292. On Unit C the air intake filters for the gas generator have been replaced in addition to the valve control cabinets and the coating issues on various assets has been remediated to prevent further deterioration and possible future operational restrictions.

293. Within the compressor station six valves have been replaced on the compressor station AGI and the scrubber condensate pipework which had been removed due to corrosion has been replaced to allow for any condensate collected in the scrubbers to be drained, avoiding the potential for a station outage if large volumes of condensate were to be present in the gas. Various civil and building remedial works have been carried out to ensure the station can remain operational.

294. The majority of the current asset health work has been completed and all works are scheduled to be completed by the end of 2018.

Preheaters

295. We require pre-heat in a number of situations where:

- we have pressure reduction either on installations where exit pressures are lower than inlet pressures;
- we require lower pressure gas for local operations such as boiler gas supply; and
- we have Offtakes with legacy Network Exit Agreements (NExA) which require that we supply gas to a contractually agreed temperature, typically at power stations.

296. Where pre-heat is required due to pressure reduction this is to counteract the Joules Thompson Effect which occurs as gas expands. Low temperature gas can cause damage to downstream assets and prevent correct functioning.

297. To provide pre-heat we have historically installed water bath heaters which are now considered an inefficient method of heating; more recent installations employ modular boilers and heat exchangers. Monitoring of temperatures back to control systems is typically in place to ensure that required temperatures are maintained with low temperature alarms set to inform he GNCC.

298. We completed the replacement of an existing modular boiler at Keadby and the replacement of existing water bath heaters with a new modular boiler/heat exchanger arrangement at Shell Star during 2017/18.

Keadby

299. At Keadby we replaced the existing modular boiler (having numerous failing units) with a new modular boiler on the existing base. Works were completed during a site outage at Keadby Power Station which allowed for the re-use of the existing base, flow and return water and gas supply pipework. This led to a saving in the region of £300k compared to the installation of new modular unit in parallel to the existing unit.

Figure 26: Existing Pathways/Ducting to the New Boiler House

Shell Star

300. At Shell Star we replaced the existing water bath heaters with a new modular boiler and heat exchanger arrangement which was completed alongside a package of asset heath work. Combining multiple asset health works on this site and the neighbouring Helsby site ensured efficient programming and delivery of the works. To minimise costs, the existing isolation valves for the water bath heaters were used as the isolation valves for the new heat exchangers.

Figure 27: Left: before, Right: after

Design for 2018/19 works

301. A campaign to replace pre-heat at five power station offtakes was sanctioned in 2017/18. Detailed design works are complete for the replacement of existing modular boilers at Kings Lynn and Little Barford during 2018/19. Both sites will utilise existing civils bases and gas supply pipework. At Kings Lynn the water flow and return pipework is to be replaced due to the poor condition of the existing pipework.

302. At Little Barford, it was originally intended to install a new modular boiler in parallel due to insufficient time to remove the existing boiler house (complex lift over live pipework / cut up of existing modular building), extend the base to suit a compliant modular boiler house and fit new. Further discussions with the modular boiler supplier have allowed a compliant modular boiler to be designed which will fit the existing concrete base. A review of the risks associated with lifting on the site has been held and agreement with RWE on the use of its car park for the crane to complete the lift(s) made. This collaborative working has led to revised plans for replacement on the existing base utilising existing flow/return and gas supply pipework rather than having to install new.

303. Options for improving the poor asset health of the pre-heat at Medway and Stallingborough are in progress. Options to replace the modular units within the existing housing are to be considered alongside full building replacement. At Stallingborough consideration is being given to combining the two existing modular boilers into one.

304. The modular boiler at Cilfrew is also to be replaced during 2018/19. Design and materials procurement were completed during 2017/18.

The River Humber Gas Pipeline Project (Feeder 9)

305. In 2017/18 we have continued to progress the replacement of the Feeder 9 pipeline where it crosses the Humber estuary. This is driven by our continuing concerns over the integrity of Feeder 9 due to rapid and unpredictable estuary movements that are reducing the depth of cover over the pipeline.

306. As the sole transportation route across the river Humber, Feeder 9 is one of the most critical pipelines on the NTS. It plays a pivotal role in the provision of entry gas from the Easington area to demand centres in the South and East and to the UK gas market as a whole. Network analysis using FES demonstrates that there is a long term requirement for the Feeder 9 pipeline to perform this function.

307. If Feeder 9 was to become unavailable, UK Security of Supply would be significantly impacted and there could be substantial entry capacity buy back costs. Capacity buy back costs and the increase in wholesale gas prices associated with a long term unplanned supply loss would result in increased costs for the industry and the end consumer.

308. Through our strategic optioneering process and extensive stakeholder engagement including a national Development Consent Order (DCO) planning process, we have determined that a replacement pipeline in a tunnel is the most economic and least environmentally harmful long term solution. We are therefore progressing with a replacement pipeline solution as well as continuing to monitor and, where appropriate, conduct remediation activities on the current pipeline crossing.

Existing Feeder 9

309. Based on the decision made in January 2017, we have continued with the two-monthly survey regime to continue close monitoring of the crossing. Latest survey results show that the frond mattress remediation is working as intended, but that some areas of the mattresses appear to be more exposed than other areas. We will therefore continue to monitor every two months and take further remediation action if required.

310. The lease from the Association of British Ports (ABP) to operate the existing Feeder 9 pipeline in the Humber expired in September 2016. Lease renewal negotiations have continued through 2017/18, whereby the existing lease will continue to ‘roll over’ with its existing terms intact until this process is concluded.

311. During 2017/18 we have also continued negotiations for a new lease for the tunnelled replacement pipeline, with the new lease signed on 7 February 2018.

Feeder 9 Replacement Project

312. The completion of the detailed design was on the critical path and was made up of several elements, these being; Tunnel Boring Machine (TBM) specification and design, Slurry treatment plant design, Cathodic protection detailed design, Pipeline

installation design, tunnel lining design and tunnel alignment design. These critical elements were completed ahead of TBM launch in early April 2018.

313. Enabling works also started at Paull during 2017/18, with the completion of the site establishment compound, delivery of pipeline sections and commencement of the reception pit at Paull.

314. The pipeline (line-pipe and concrete coated) sections also commenced delivery at Goxhill during 2017/18 and testing was successfully completed on the concrete coating to pipeline coating interaction.

315. The TBM (160m in length) was designed, constructed and passed Factory Acceptance Tests, prior to a successful delivery from Germany to site at Goxhill throughout December 2017.

316. Due to the size and weight of the TBM sections (cutter head, shield, thrust pipe, shield and 15 gantries, up to 16m long each and weighing up to 95 tonnes), an abnormal load order was required. Through engaging a specialist subcontractor and regular dialogue with the local authorities, a safe and successful delivery was ensured.

Figure 28: Delivery of TBM to Goxhill

317. The TBM was then subjected to site construction and site acceptance testing during January 2018 through to March 2018. The launch of the TBM was completed in early April 2018 and is expected to arrive at the reception pit in Paull during spring 2019.

318. The tunnelling element of the project represents the highest risk activity during delivery. Therefore, to mitigate some of the tunnelling programme risks, a short section of above ground tunnel has been constructed at Goxhill. This facilitates the

rehearsal of installing auxiliary equipment, interventions to the TBM cutter as well as rehearsals for emergency planning.

319. Following on from the decision to install a concrete coated pipeline with an aqueous filled tunnel, chemical testing had shown Humber sea water to contain extremely aggressive bacterial / electrolytic properties, potentially leading to excessive degradation of the concrete tunnel lining. Therefore, during 2017/18, we started to conduct a series of tests to review and confirm the behaviours and condition of the CP system within an aqueous filled concrete lined tunnel so that any adjustments can be made before installation.

320. In 2017/18 we have made good progress with project delivery but we are behind our original tunnelling programme schedule. Due to the unique nature and scale of the project we are overcoming many difficulties but there are still many challenges facing us, which may result in increased project costs. We are working with our MWC to develop a revised programme and to look for opportunities to improve in other areas of the works.

321. Throughout 2018/19 we will continue with the drive of the TBM, complete the construction of the reception pit at Paull and undertake preparation works to enable pipeline tie-in at Paull AGI.

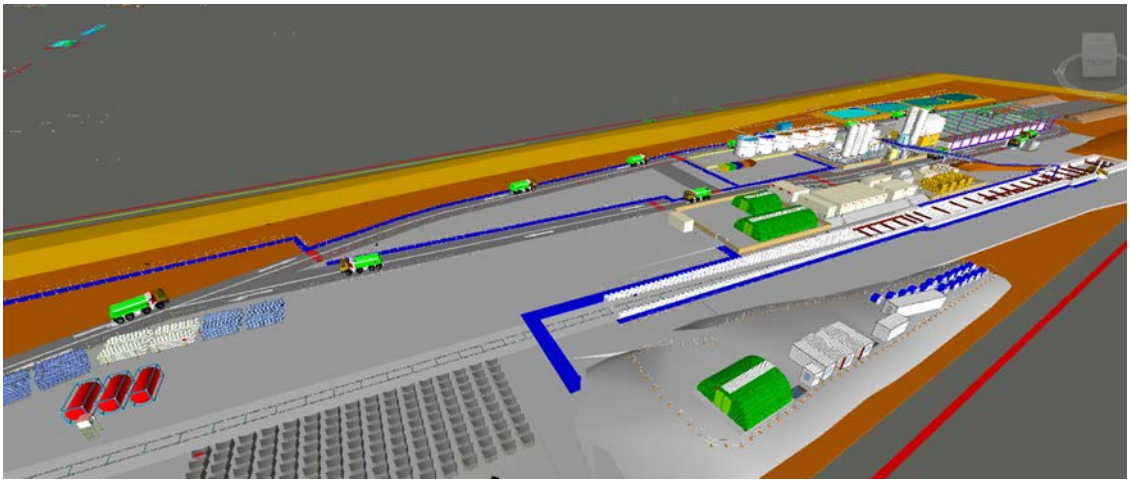
Feeder 9 Innovation

322. The River Humber Gas Pipeline, once constructed will be the world's longest pipeline river crossing in a tunnel. This unique combination of civil and mechanical construction requires the highest standard of planning. Throughout the project development we continue to look for opportunities to explore innovative ways of working and delivering efficiencies.

323. As part of our enduring commitment to innovation, the Feeder 9 Project was used as a case study during 2017/18 for the Extreme Value Analysis (EVA) innovation project. This was initiated to support the cost-benefit analysis of high impact, low probability events associated with the existing Feeder 9. The project has provided an extreme value analysis support tool and methodology for the Feeder 9 project that enables a robust assessment of the cost and benefits of investments that involve extreme risks and extreme uncertainty.

324. We have sustained the use of intelligent 3D modelling during 2017/18 for items such as, constructability studies and linkage to the construction programme (4D) and will continue to use this technology where appropriate to drive efficiencies throughout the duration of the project.

Figure 29: BIM screenshot of the tunnel driveshaft, slurry treatment plant, filter press and segment storage at Goxhill



Paull

325. Paull AGI is a shared offtake site between National Grid and Northern Gas Networks (NGN). The configuration of the site meant that at the point of sale to NGN in 2005 the transfer of assets ('Project Blackwater') was different to that on more common offtakes, resulting in us having ownership for additional assets.

326. The existing assets required significant asset health investment as a result of their age and condition. We reviewed the requirements for the site with NGN and developed an optimum solution to rationalise the site into a standard minimum connection. This approach is planned to result in a transfer of assets to NGN during Q4 2018.

327. Communication with Ofgem continued through 2017, in accordance with the Standard Special Condition A27 (Disposal of relevant assets and restriction on charges over Receivables) of National Grid's Gas Transporter Licence in respect to the transfer of part of the operational assets at Paull AGI to NGN.

The rationalisation of the site:

- improves the reliability of the network and removes the safety risks associated with poor condition assets;
- enables the proposed new Feeder 9 pipeline to enter Paull AGI in a more cost efficient location achieving an estimated saving of £0.9m on the Feeder 9 project;
- achieves full telemetry and electrical separation from NGN, in line with our current policy; and
- is consistent with other National Grid distribution offtakes.

328. On 1 June 2017, we received consent from Ofgem to transfer ownership of a number of assets at Paull AGI to NGN.

329. Whilst the majority of works were completed in 2015/16 and 2016/17, we have continued working with NGN and our MWC through 2017/18, with the new assets commissioned in March 2018.

330. During 2017/18, we have also been developing with support from NGN, several legal documents (Offtake Agreement Document, Land Lease and Asset Sale Agreement) in preparation for the transfer of assets to NGN, due to be completed Q4 2018.

331. Based on Ofgem consent, we have started to decommission the existing poor condition plant during 2017/18 and will continue through 2018. Whereby, the reporting of NOMs for the work will follow in 2018/19 once the works have been completed.

Decommissioning (formerly Quasi-Capex)

332. As our network changes, some assets are no longer required for operation whilst others can be rationalised reducing the asset health investment on these sites.

Churchover Compressor A and B units

333. The Churchover Compressor Station Orenda (A and B) units were replaced by one gas turbine and one electrically driven unit, which are Best Available Technology (BAT). Disconnection work has progressed in 2017/18 and the A and B units have been physically isolated in accordance with our policies and procedures. Work is ongoing to ensure safety and compliance of the disconnected assets left on site, which will be removed at a later date.

334. During the procurement of the dome end required for the isolations, the quality assurance process highlighted non-compliance with our specification. This caused delays and increased costs due to re-work. The National Grid approved vendor holds the liability for supplying non-compliant materials and recovery of the additional cost is being sought. Outturn cost for disconnection of the A and B units is currently estimated to be £2.3m but our costs are expected to be in the order of £1.4m subject to successful recovery of costs from the materials vendor.

Bacton Eni Incomer

335. The Bacton Eni incomer was physically disconnected during spring/summer 2016. The work completed in 2016 included:

- Positive isolation of the Eni road crossings from all National Grid assets and the assets within the Eni fence line.
- Positive isolation of the Eni National Grid assets from the remainder of the Bacton plant.

- Disconnection of all instrumentation cables and power supplies to former Eni incomer assets and withdrawal of wiring.

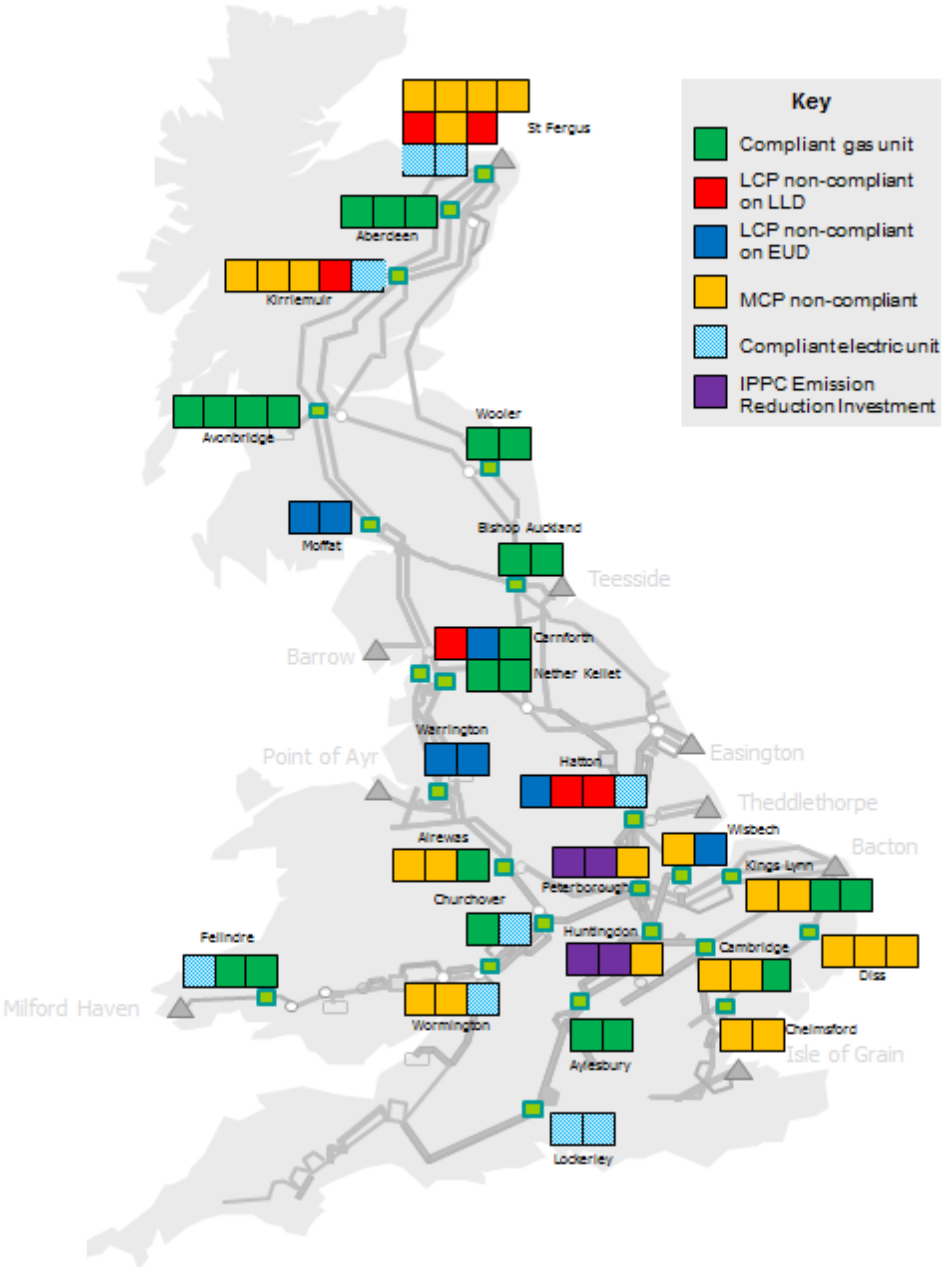
336. The final closure of this scheme was completed in February 2018. The major assets remain installed at Bacton, but disconnected from all pressure and motive power sources. A subsequent scheme will be required at Bacton to remove all redundant assets.

Emissions

337. This section covers all emissions related work that we have progressed throughout 2017/18.

338. In May 2018 we submitted an IED re-opener and a brief overview of the proposals are included in this section. Further details regarding the emissions related projects can be found in the re-opener submission.

Figure 30: Compressor unit type and compliance with environmental legislation



IED - IPPC Phases 3 and 4 Peterborough and Huntingdon

339. At the start of the RIIO-T1 period, both Peterborough and Huntingdon consisted of three Avon machines each. Both sites are critical to maintaining efficient transmission capability across the centre of the network and meeting south east and south west exit capacity obligations. We continue to advance the programme of works to deliver new gas turbine compressor units at each site under IPPC Phases 3 and 4. Phase 3 consists of one new unit on each site and Phase 4 was procured in parallel to efficiently deliver the required additional unit on each site.

340. The programme of works was sanctioned internally in late 2016, including core and extraordinary work scopes such as new station control buildings and new electrical supplies.

341. The MWC mobilised to site at Huntingdon in Q3 2017, to prepare the site ahead of taking delivery of the compressor machinery train package from Solar Turbines.

342. During 2017/18 the main works at Huntingdon consisted of:

- completion of the delivery of the rotating machinery train packages and noise enclosures;
- completion of the detailed design; and
- mobilisation of the sub-contractors to undertake piling activities for the new compressor units.

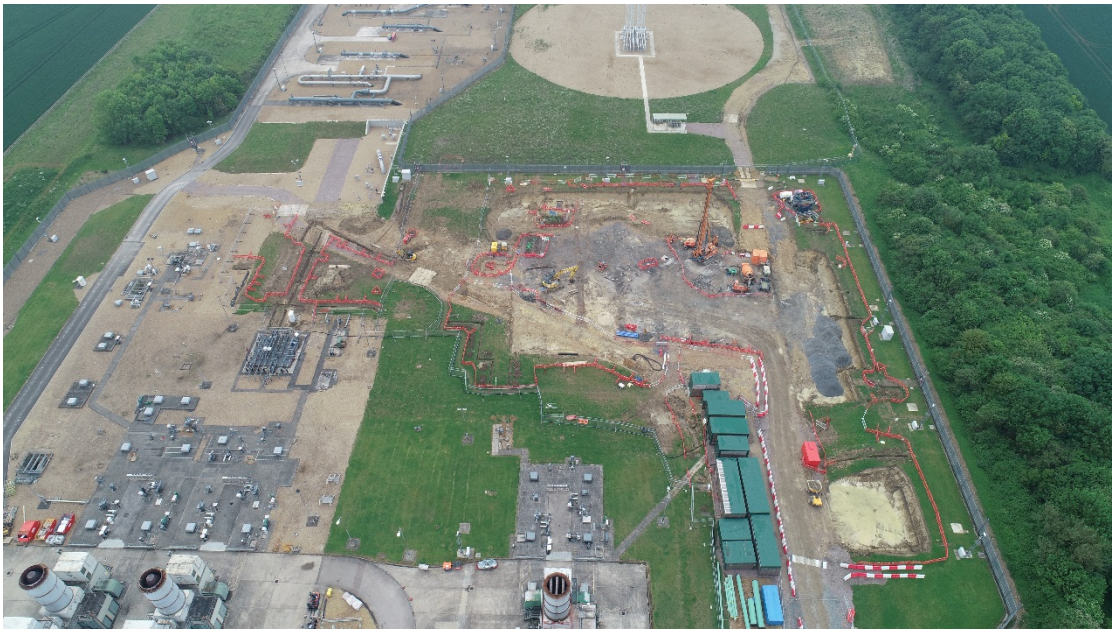
343. The MWC also mobilised to Peterborough early in 2018, in preparation for taking delivery of the compressor machinery train packages from Solar Turbines in late 2018.

344. During 2017/18 the main works at Peterborough consisted of:

- completion of the site contractor set-up;
- continuation of the detailed design; and
- commencement of the installation of a new station vent stack to facilitate the removal of the existing station vent stack and create space for the new compressor trains.

345. Both projects are on schedule, with operational acceptance of the new units planned for 2020 at Huntingdon and for 2021 at Peterborough.

Figure 31: Ongoing Site Works at Huntingdon



IED - IPPC Phase 4 and IED – LCP Phase 2 St Fergus

346. St Fergus comprises of three plants; Plant 1 has four Avon units, Plant 2 has one Avon and two RB211s and Plant 3 has two electric VSDs.

347. The gas driven compressors at St Fergus are required both to supplement the operation of electric drives and to provide backup capability. Unlike our other compressor stations, St Fergus' position as an entry point means that it is not possible for other sites in the network to provide backup. If compression is not available on site, gas cannot enter the network from one sub-terminal.

348. Our strategy for St Fergus proposes a programme of work, which both addresses the LCP requirement associated with the two RB211s and continues to reduce our fleet emissions in accordance with our IPPC obligations.

349. In terms of LCP, we gained approval from SEPA to enter the RB211 units, 2A and 2D, into the LLD from 1 January 2016. In the May 2018 reopener the options assessment indicated that an enduring solution to LCP would be the abatement of one of the RB211s, with the second machine closing once the limits of the LLD have been reached.

350. To meet our IPPC obligations, we are proposing to either abate or replace one of the smaller Avon machines.

351. The initial sanction of the St Fergus investment, which defined the strategic approach to the site, was made in August 2016. The preferred options from the CBA and the Front End Engineering Design (FEED) were incorporated and a 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 2019.

IED – LCP Phase 1 Aylesbury

352. We operate two Rolls-Royce Avon 1535-190G DLE gas turbine driven compressor machinery trains at this site (Units A and B). The two units are unique prototype DLE engine units that were installed in 1999 and are compliant with the 'existing plant' Emission Limit Values (ELVs) contained in the IED for NOx. In 2016 we completed the construction phase of a catalyst installation to reduce Carbon Monoxide (CO) emissions to achieve the new CO ELVs. Unit B was successfully commissioned to Operational Acceptance stage in Q1 2017 and Unit B followed in Q1 2018 after a period of unit unavailability. The successful IED commissioning on Unit A was achieved by deferring the remainder of the supporting asset health work which will now be completed across 2018/19. Asset acceptance and project closure is expected to conclude in 2019/20.

Figure 32: Exhaust stack and catalyst abatement system at Aylesbury compressor station

IED – LCP Phase 2 and the "Industrial Emissions RIIO-T1 Reopener Submission" from May 2018

353. Our plans to achieve compliance with the requirements of the IED-LCP legislation have evolved since the submission of our initial RIIO-T1 business plan. The new proposals as submitted in the 2018 Reopener take account of the extended use of derogations in addition to updated actual flows and future flow forecasts.

354. The following sections give a brief overview of the work and proposals at each LCP Phase 2 site, based on the proposals from our Integrated Emissions Plan submitted in May 2018.

IED – LCP Phase 2 Wisbech

355. At Wisbech, we previously reported how we have retained the RB211 unit A on a 500 hour/year derogation and exchanged the gas generator in unit B from a Maxi Avon to a compliant Avon. We have continued to review the longer term need of this station, balancing asset health costs against the resilience provided by the station. The network resilience provided by the station while IED emissions related works are ongoing at Peterborough and Huntingdon confirms the need for the

station to at least 2023. With further IED works required at Hatton and potential MCP compliance works at other East area compressors in RIIO-T2, Wisbech will continue to provide valuable network resilience for a number of years. Further asset health work associated with retaining the existing units will be required to maintain capability.

IED – LCP Phase 2 Carnforth

356. Carnforth consists of three units. Units A and B are both RB211s which are not compliant with IED-LCP emissions limits. Unit C is a compliant DLE machine.

357. Our strategy for Carnforth is to decommission units A and B and to use Unit C to provide the operational capability required, making use of the physically adjacent Nether Kellet site (consisting of two smaller compliant DLE machines) to provide the required backup. This work is planned to be completed in 2021.

358. Carnforth and Nether Kellet require minor site reconfiguration works to achieve this strategy. This is a more economical solution than retaining Carnforth units A and B as backup.

359. Unit A is physically disconnected from the compressor station pipework and is not available for use within the NTS. The unit remains on site and we are utilising parts as spares to lower the cost of maintaining unit B, until site modification works are completed.

IED – LCP Phase 2 Hatton

360. Hatton is a high utilisation compressor station enabling the efficient movement of gas from the Northern and East coast terminals towards demand centres in the south of the network. In addition to the electric VSD, the site consists of three RB211 machines which supplement the VSD and provide backup capability. The RB211s are IED-LCP non-compliant.

361. In December 2017 the VSD unit was found to have suffered damage to the compressor rotor assembly and the unit was taken out of service. The cause of the damage is under investigation by the Original Equipment Manufacturer, who has confirmed that a replacement impeller will have to be manufactured.

362. One RB211 was placed on the 500 hour Emergency Use Derogation and the remaining two units on the Limited Life Derogation. Entering one unit into the 500 hours derogation provides flexibility in terms of the future solution for the site and extends the potential construction window for any new units. Our current investment plan is based on new compliant gas powered compression of equivalent capability to the 35MW Electric VSD and the decommissioning of the two life limited machines after 2023. The FEED study will consider the options in detail and be progressed through 2018/19.

Kirriemuir

363. Following prior investment of the build of the 35MW electric VSD, our updated integrated plan for our IED investments identified further investment requirements for the RB211 unit D which is impacted by IED-LCP legislation and is on a Limited Life Derogation. A decision to disconnect unit D was previously made ahead of significant expenditure on a major overhaul. Furthermore decommissioning to plinth level has now been chosen for unit D with no replacement capability to be installed. Three Avon gas turbines and the VSD will remain on the site.

Moffat

364. Moffat consists of two RB211 units (A and B) which are not compliant with IED-LCP. The units were previously placed on the 500 hour Emergency Use Derogation (EUD). Against the background of increased St Fergus flows, the continued availability of Moffat provides valuable resilience and facilitates network access to support outages for maintenance and construction on other compression sites. The 2018 reopener therefore proposed to undertake asset health works in 2018/19, maintaining the RB211s on 500 hours EUD and ensuring availability and ongoing compliance with the IED legislation.

Warrington

365. Warrington consists of two RB211 units (A and B) which are not compliant with IED-LCP. Both compressor units are currently on 500 hour EUD in order to comply with the LCP element of IED.

366. The use of compression at Warrington has fallen significantly over the last ten years. Based on the current FES, Warrington is no longer required to support the entry flows it was designed for. Although there is the potential for future user signals to require additional West coast compression, there is no certainty over when these signals will be received, if at all, nor is it certain that the current capability at Warrington would necessarily be the best fit for this need. We are therefore proposing to decommission the compressor station at Warrington by 2020.

Diversions (non-customer funded)

367. We have various agreements for the location of our pipelines (e.g. Deed of Easement or Deed of Grant) so that we can undertake maintenance and gain access to the asset. A number of these easements contain existing liabilities or other obligations to divert pipelines, for example “lift and shift clauses”. In some instances we are required to pay the costs associated with the pipeline diversion.

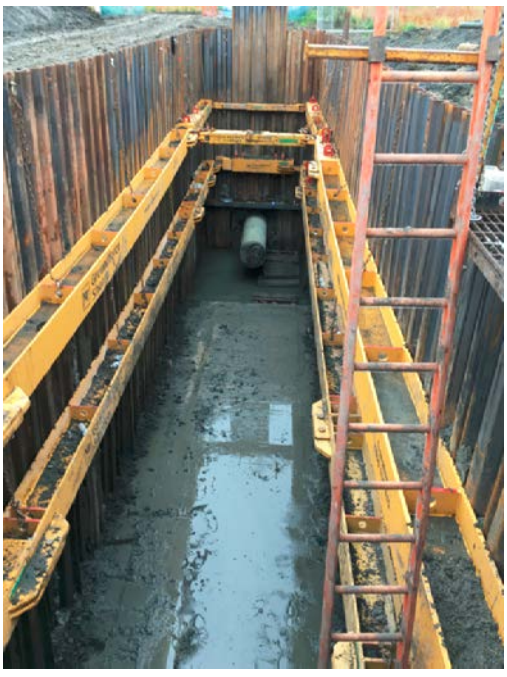
Willington Down Feeder 7 Diversion

368. A historical Deed of Easement exists requiring, at the land owner’s request, that we fund the protection or diversion of approximately 2 km of Feeder 7 pipeline between the Chalgrove multi-junction and Didcot power station. Construction

works were completed as planned during summer 2017, thereby avoiding an estimated compensation claim in the region of £40M for loss of development.

369. The affected section of Feeder 7 is a direct feed to the RWE Didcot power station. Completion of the diversion was completed via use of a full pipeline outage, the safest and lowest cost method, delivering a saving of approximately £1m in comparison to installing a stopple and bypass to maintain the flow of gas to the power station. We have worked with RWE, the impacted customer, to schedule the outage and, at their request, to reduce the duration we significantly condensed the outage from 20 days down to 11 days. RWE then sought to schedule some maintenance of the power station during the reduced outage.

Figure 33: Diversion works at Willington Down



Diversions (customer funded)

370. Some of these types of deeds described above do not have extra liabilities and thus the developer pays for the diversion on a cost pass-through basis. At all times, we endeavour to work with developers to ensure costs are kept to a minimum.

Highways England M49 Pipeline Diversion

371. Highways England approached us regarding to the proximity of a planned upgrade of a motorway junction on the M49 to the Feeder 14 pipeline; requiring a diversion of the pipeline. Originally, we had a requirement for the customer to complete enablement works prior to our mobilisation to ensure that the diverted pipeline would be suitably protected from the traffic load on the upgraded road. During the design phase, it became apparent that these works would not be completed by the customer, hence our scope of works expanded to enable the project to continue in line with the customer's requested timescales.

372. Following collaboration with two customers downstream of the diversion works, Seabank Power and Wales & West Utilities, a six-week full pipeline outage was agreed, avoiding the need for an expensive stopple operation. The cost saving is estimated to be £1M and safety improvements will also be achieved by avoiding the need for hot works and for fittings to remain on the pipeline. Diversion works will be completed during summer 2018.

High Speed 2

373. We have been working with High Speed 2 (HS2) since 2012. Five feeders are affected by the HS2 Phase 1 route from London to Birmingham and all require diversion with works scheduled to take place during 2018, 2019 and 2020. Close working relationships have been established with the HS2 team to ensure that diversion designs are developed with a view to minimising overall cost and are aligned with stakeholder requirements. Examples of areas that have been taken forward with the HS2 designs are:

- alignment with HS2 site accommodation/access routes to minimise cost and impact on the local community;
- working with HS2 designers to request modification of the HS2 civils design such as the location of balancing ponds (drainage that would be lower cost than to extend pipeline diversion routes);
- alignment of diversions with other utility providers ensuring coordinated approach to land requirements: and
- re-route to avoid removal of mature trees.

374. Work has now commenced on HS2 Phase 2a route (Birmingham to Crewe) and 2b route (Crewe – Manchester and Birmingham – Leeds) and is in its early stages with diversions scheduled for 2021 onwards.

A13 Thurrock

375. We are working with Thurrock Country Council in relation to the widening of the A13 which will require the diversion of Feeder 5. The diversion is planned to be delivered in 2019. Discussions have commenced to determine whether a full

outage can be provided as this requires an associated power station outage. We will work with the Customer and the Power Station to see if we can negotiate an outage.

A1 Morpeth

376. We are working with Highways England on proposals to divert the A1 at Morpeth which will require a Diversion of Feeder 13, a key feeder for flows from St Fergus. Initial network analysis results suggested that the diversion could only be completed via stopples due to the requirement for the ability to flow gas from St Fergus to be available at all times. Further work is ongoing in this area and a UNC modification 0607 regarding gas quality has improved the likelihood of a full outage to facilitate the customer funded work.

377. The Diversion is planned to be delivered in 2019 or 2020 depending on the customer's approval and consenting processes. To ensure we provide the customer with the flexibility they need, we have developed two programmes and are working in tandem.

Initial Works

378. We are currently working with the Lower Thames Development scheme and road schemes proposed for the A358, A428, A30, A500 plus a number of Housing Developments. We are keen to emphasise to customers that early engagement and development of diversion options is key to ensuring successful completion of the customer's scheme and can lead to significant overall cost savings.

Enhanced Physical Site Security

379. The Physical Security Upgrade Programme (PSUP) is a government mandated initiative to enhance physical site security. All works are closely evaluated by the Department for BEIS.

380. In 2014 BEIS completed a review of National Grid sites in which a number of gas transmission sites were identified as requiring a PSUP solution.

381. Of these gas transmission sites, those identified by BEIS prior to the site review in 2014 formed Phase I of our programme of works. The remaining sites included by BEIS constituted our Phase II programme of works.

Phase I

382. PSUP solutions at all Phase I sites were completed as of 31 March 2018, with all sites now being monitored by the Alarm Receiving Centre (ARC). Spend on Phase I is in excess of the allowances awarded from the May 2015 reopener, but broadly in line with those requested.

Phase II

383. Subsequent to the agreement of the site list by BEIS in February 2015 we identified that, for a number of Phase II sites, the rationale for inclusion in the PSUP was no longer valid. Following discussion with BEIS it has been confirmed that no physical security enhancements are required at these sites and we have proposed to return allowances through our May 2018 reopener.

384. The remaining Phase II sites have had detailed designs developed. These have been placed under contract with our MWC Consortium partners and are in full construction. All solutions will be delivered by 31 March 2021.

385. In our RRP in 2016/17, we reported costs for our Phase II programme of £105.30m (17/18 prices), which included the delivery of solutions to a number of sites now removed from the programme. Our latest cost forecast for the remaining sites is £81.05m.

386. The majority of the cost reductions are a result of removing a number of sites from the programme. The remaining reduction has been achieved by implementing the efficiencies realised through the 'Five Pillars of Success' strategy and the Innovation Forum, created with our Joint Venture partners, and through utilising our delivery experience from our Phase I programme.

Shared Sites

387. As part of the BEIS review of sites in 2014/15, a number of Shared Sites were classified as requiring PSUP solutions. In this case Shared Sites are sites owned by Gas Distribution Networks (GDNs) but contain assets owned by National Grid. We are responsible for funding and delivering PSUP solutions to a subset of these sites.

388. Of the remaining shared sites there is one site where we are not required to deliver the solution but are liable for a share of the costs, in line with Ofgem guidelines.

389. Site assessments have been completed at the sites by our internal team. These capture the site specific asset quantities and site characteristics.

390. In line with our May 2018 reopener all PSUP solutions that we are responsible for delivering will be completed by 31 March 2021

391. We have requested an allowance in our May 2018 reopener for funding the PSUP solutions of these sites.

Site Extensions

392. There are occasions when our sites need to be extended, for example to accommodate additional assets. If this is required at a site at which physical security has already been upgraded through the PSUP then the existing solution must then be modified and extended to ensure the revised perimeter meets the PSUP specification.

393. For sites requiring site extensions we invited our existing PSUP third party suppliers to tender for the works in line with the site requirements.

394. A number of design options have been considered for each site to establish the most effective and efficient solution. An innovative solution was identified providing £1.3m of main work contractor savings to the PSUP site costs.

395. All PSUP activities are currently forecast to be completed by March 2021. We have requested an allowance in our May 2018 reopener for funding the PSUP solutions of these sites.

Phase III

396. We worked with BEIS to update the collective understanding of threat to our assets and the impact of this on the NTS. Through further analysis a number of additional sites were identified for inclusion in the PSUP. These will form Phase III of the programme.

397. Due to our ongoing commitment to deliver the remainder of the Phase II site solutions by the end of the RIIO-T1 period, we are not proposing to undertake any construction activities on the Phase III PSUP sites in the period. We propose to scope works for these sites by the end of RIIO-T1. We have requested an allowance in our May 2018 reopener for funding this work. The physical building of the solutions will occur in RIIO-T2. We are currently working on our plans for RIIO-T2 so that we can deliver these projects early in RIIO-T2, to reduce the vulnerability from threat in a timely manner.

XII. Non Operational Capital Expenditure (TO)

Introduction

398. In 2017/18 our Non Operational Capex was £18.3m and our updated forecast for the eight-year RIIO-T1 period is £130.6m compared to an allowance of £69.8m. Compared to the prior year the forecast spend has reduced by £11.7m in real terms. The forecasted decrease mainly relates to:

- Technology and data (£7m)
- Land and Buildings (£4.1m)
- Vehicle costs (£1.4m)

399. The main movements in technology and data are driven by reductions in the Gas Transmission change programmes. These decreases have been offset by increased costs in:

- other IS programme allocations such as Cyber Security enhancements, Project One (SAP HANA implementation) and Office 365; and
- Plant and Machinery (£1.2m).

Transmission Foundation System (TFS)

400. Through 2017/2018 the business implemented the key components of this programme:

- upgraded Enterprise Asset Management (EAM) system (Ellipse version 6 upgraded to Ellipse version 8; and
- implementation of GeoGrid replacing the old T-MAPS Geographical Information System (GIS).

401. Both implementations were required due to our existing systems reaching end of asset life and technical support ending. Through 2018/19 and 2019/20 the data structures within Ellipse will be reviewed and improved to support critical asset management processes.

Transformation Programme

<u>Gas Asset Information Systems (GAInS)</u>

402. The GAInS programme was officially closed in 2017/18 having delivered improved field capability (through refreshed application of field devices, improved mobility and connectivity), new analytical capability leading to better informed asset management decisions in operations, process safety and work management and new Enterprise Content Management (ECM) solutions for better document

management and control. GAInS also provided the platform for Richmond – our Gas Transmission Change Programme.

Richmond

403. In last year's RRP we described a plan to design the Gas Transmission change programme and we forecast the remaining year's expenditure during RIIO-T1 based on that programme. Following this design there is now a single change programme called 'Richmond'. The key focus of Richmond is to establish a robust operating model across the business covering efficient and effective asset management strategies, policies, processes, data, technology, capability and organisational structure.

404. Richmond will improve our asset management capability by aligning our processes and systems with ISO 55000 best practice to ensure we provide value to customers and stakeholders.

405. This programme will deliver enhanced asset management, investment management and data analytics capabilities whilst assuring verified data from the asset data enhancement activity is successfully uploaded into core asset management systems.

406. These developments are partially system related Non Operational Capex and partially Opex business change activities. The benefits of these projects will begin to be realised in 2018/19. These projects will support the development of our NOMs methodology, development of our future business plans and provide insight into the management of network risk at least cost.

Asset Data Enhancement

407. The improvements to our asset management approach together with the anticipated demands of the NOMs methodology require a significant enhancement of our asset data and investment in our asset management technology systems and data analysis capability.

408. This Asset Data Enhancement programme is delivering enhanced asset data to support an improved asset management approach and a NOMs methodology based on monetised risk. It includes: ensuring that all of our assets are correctly recorded to an appropriate level of granularity in our core asset management system; and ensuring that we have consistent and coherent data in the appropriate structure that allows adherence to our internal data quality standards with the appropriate controls. Work is now progressing and to date asset data has been verified at 476 sites following a robust quality assurance process.

409. A schedule to verify the data at the remaining 59 sites is in place and we are planning to complete all works in summer 2018. Once complete the central asset register held on core systems will have been validated and updated driving greater asset management capability and supporting the new NOMs methodology.

XIII. Capital Expenditure (SO)

Introduction

410. This section covers our SO Capex investment. In 2017/18 total SO Capex was £26.4m which was £7.7m lower than in 2016/17. Compared to last year there was a £6m increase in spend on data centres which was partially offset by lower spend in other areas due to key projects having reached completion in 2016/17. This includes Gas Control Suite (GCS) (£9.5m), gas remote site connectivity (£2.8m) and Market Information Provision Initiative (MIPI) infrastructure refresh (£2.1m).

411. The SO Capex forecast for the full RIIO-T1 period is £266.4m and has reduced by £24.3m compared to last year, driven predominantly by a planned change in our Xoserve Gemini strategy (£12.6m), a reduction of forecasted Cyber Security spend (£4.6m), a lower level of expected EU related Gemini change work (£3.7m) and a continuing reprioritisation of our IS investments to meet customer requirements (£3.4m). The performance in this area reflects our commitment to prioritise investments that will deliver value to our customers at the pace they value during a period of increased industry change. Looking forwards, we will continue to review our plans in light of these changes to ensure the overall investment portfolio delivers the optimal balance of customer value and future risk mitigation.

Property, Critical Infrastructure and Data Centre & Cyber Security Strategy (as well as RUMES)

412. The mechanical and electrical assets associated with the Critical National Infrastructure (CNI) systems contained with the control rooms (transformers, generators and switchboards) are approaching the end of their expected life. In addition to this the current electrical power distribution systems are not aligned to those of other sites. The work to replace aged mechanical and electrical assets and various system upgrades at Warwick will align systems with those of our other Data Centres and will provide end to end infrastructure resilience to CNI systems and other critical functions. To date we have constructed a new plant room at National Grid House containing back-up generators, switchboards and transformers, spending £4.5m in 2017/18.

413. The threats posed by the cyber environment continue to adapt and change in nature bringing the issues of the protection and availability of CNI services and associated network security resilience to the forefront. To be able to maintain security and service levels in this area we are forecasting significant investment. During 2017/18 the strategic decision was made to move from a Data Centre Build and a Data Centre Hosted site solution to a fully hosted solution. Following this decision delivery has focused on the connection of the Wide Area Network (WAN) to enable enhanced security based on a resilient infrastructure and completing designs for the migration of the first CNI application from the gas estate.

414. Following the 2017/18 strategic shift (as mentioned above) we have partnered with the UK Government to enhance the security and quality of the solution whilst

effectively managing costs. Extensive work is underway to bring to operational status the two new Data Centres, including the delivery of a highly secure CNI network that connects the new Data Centres to existing operational control rooms and other CNI sites and services. Our gas CNI services are planned to be fully operational in the new Data Centres from Q3 2019.

415. Cyber security is viewed as a critical issue by the Government and this is evidenced by the development of the National Cyber Security Centre (NCSC). This has been formally recognised by EU Government through the introduction of EU Legislation to enhance the security and resilience of networks and information systems. The Networks and Information Systems (NIS) Directive places requirements on providers of essential services, including National Grid, to ensure their networks and IT systems are effectively protected from cyber-attack. This new legislation was transposed into UK law in May 2018 with energy sector specific guidance due to be published in late 2018.

416. To be able to maintain cyber security, physical security and resilience in the services we provide, we are forecasting significant investment in this area. Our costs incorporate several elements of work across Data Resilience and Security, Data Centres and Operational activity. On 8 May 2018, we submitted a notice of adjustment to allowances in relation to enhanced security to Ofgem. This includes a request for SO costs within the RIIO-T1 period.

417. In 2017/18 we spent £3.3m on Cyber Security as we continue to implement our planned strategy around mitigating cyber risk to critical systems. The threat to CNI systems and wider cyber security remains one of the top five key risks at National Grid Board level.

Telemetry

418. Telemetry systems allow us to monitor and control the flow of gas through the NTS; they consist of telemetry outstations and the communications network which connects the outstations to the GCS. This facilitates safe operations and ensures the quality and quantity of gas meets consumer requirements.

419. Throughout the RIIO-T1 period we will be investing in the refurbishment and replacement of telemetry outstations in order to manage the risk of asset ageing and obsolescence. With total spend of £2.6m, 2017/18 saw the Phase 3 and 4 roll out of the telemetry replacement programme as well as procurement of a new solution for future phases to comply with EU regulations. We continue to review the drivers for Distribution Network separation at telemetry sites focusing on a risk based approach which will provide efficient investment for customers.

Market Facilitation – Xoserve

420. Xoserve Gemini regulatory driven system enhancements work continued in delivering regulatory driven changes with the main focus this year being on implementation of the EU phase 4 changes to the Gemini system.

421. Xoserve costs of £1.7m in 2017/18 were lower than forecast due to a lower than anticipated level of regulatory change/enhancement required for Gemini. Also work on sustaining the Gemini system which was originally planned to start during 2017 will now ramp up in 2018/19.

422. Gemini re-platforming: Gemini is currently operating on ageing hardware and infrastructure software, which brings increasing risks to its security, availability and resilience. A sustain strategy was agreed in 2017/18 after customer engagement and we will be working with Xoserve to deliver this solution by 2020.

Gas Control Suite (GCS)

423. Enhancements to the GCS systems continue to focus on improving and updating forecasting tools (Simone) to ensure future viability and lower maintenance costs by integrating forecast and future simulated data with current operational data. This will allow us to develop further capability to assess and manage operational risks. The implementation of a data storage monitoring solution into the suite will further improve the accuracy of regulatory and reporting requirements in line with EU incentives and code obligations. Spend in this area was £1.5m in 2017/18

424. In addition to the projects specified above, there was a £5.4m lower level of spend on smaller projects within our investment portfolio where we are continuing to prioritise investments to ensure value for customers.

XIV. Operating Costs (TO and SO)

Introduction

425. This section covers our TO and SO operating costs. The costs and allowances outlined within this section are based on our restated Table 2.4 (see Appendix I. Totex Tables), as referenced in the SPO. In 2017/18 our expenditure was £178m and our updated forecast for the eight years is £1,335m compared to an allowance of £1,249m. Compared to last year our eight-year forecast spend has reduced in real terms by £34m.

426. Within TO there has been a reduction of £33m in the forecast year-on-year with reductions in Planned Inspections and Maintenance (£21m) and Closely Associated Indirect costs (£16m) and Uncertainty Mechanism (£13m), offset by an increase in Business Support costs (£17m).

427. Within SO there has been a small reduction of £1m in the forecast year-on-year with a decrease in Direct Costs (including Xoserve) of £3m offset by an increase in Business Support costs of £2m which is described in more detail in the SO Overview below.

TO Overview

428. TO Controllable Opex spend in 2017/18 was £118.3m, representing a real term increase versus prior year of £9.7m. Our updated TO Opex (including uncertainty mechanism spend) forecast for the eight years is £851m which is £112m above our allowances of £739m. Compared to last year our forecast spend has reduced in real terms by £33m. The main movements within year and for the eight-year forecast are:

- Closely Associated Indirect costs have increased year-on-year in real terms by £1.4m. The increase has been largely driven by a reclassification of vehicle costs (+£1.3m) with a corresponding reduction reported in Direct Costs, Network Engineering delivering an increased focus on policy for Asset Management and Engineering (+£1.5m), offset by efficiency savings in Health, Safety and Environment (-£1.4m). The £16m reduction in the eight-year forecast in real terms reflects additional efficiencies identified in the cost of Transformation programme (now referred to as Richmond).

- Planned Inspections and Maintenance have reduced year-on-year in real terms by £1.8m. The eight-year forecast of £223m is below the allowances of £242m (2017/18 prices) and £21m lower in real terms than the previous year forecast following a further review of the maintenance strategy. The forecast for planned inspection and maintenance was increased last year following the higher compressor utilisation seen in 2016/17, however we have not experienced the increase in costs expected, therefore the forecast has been reduced.

- Business Support costs have increased year-on-year in real terms by £4.9m. The main increases in costs related to Data and Technology spend to support the transformation project (£1.8m), the realignment of the UK Assurance team from Corporate Centre reflecting the UK focus of work (£1.2m), consultancy and staff costs relating to deep dives on Sarbanes Oxley controls and change in external auditors (£1.7m) and RIIO-T2 preparation (£0.5m).

- The eight-year forecast of £262m for Business Support costs is now £108m above allowances of £154m and £17m higher than the previous year forecast. The higher forecast is mainly driven by supporting the efficient development and delivery of the increasing asset health works as we manage network risk.

- Uncertainty Opex costs have increased year-on-year in real terms by £2.4m. The eight-year forecast of £60m is now £3m above the allowances of £57m and £13m lower in real terms than the previous forecast. The major movement from the previous forecast relates to a potential claim for quarry and loss of development (£13m) which has been significantly reduced following a reassessment of the claim.

SO Overview

429. In 2017/18, our SO Controllable Opex was £59.4m (including £0.4m Uncertainty Mechanism costs), which was £5.6m lower than forecast. This was mainly due to a true up of prior year Xoserve costs (£1.9m) and lower Business Support costs (-£2.9m). The forecast for SO Opex for the eight years is £484.8m which is £2.1m lower than last year.

430. SO Controllable Opex costs have decreased by £2.4m year on year with a small increase in direct costs being offset by £2.9m lower Business Support costs. Controllable costs were £2.2m below allowances.

431. Direct costs were £0.6m higher than prior year. Xoserve costs increased £2.6m due to a higher underlying cost recharge £2.0m, amortisation of UK Link capital contributions post system go-live in June 2017 £1.2m, offset by a higher level of prior year rebate received in 2017/18 £0.6m. This Xoserve cost increase was offset by a change in allocation of shared customer support costs £0.4m and £1.6m of other smaller costs savings in legal fees, strategy and severance costs.

432. Underlying Business support costs (including Uncertainty Mechanism costs) were £3.1m lower than prior year. Upward cost pressures due to management initiatives (£0.6m) were offset predominantly by lower cash severance payments (£1.3m) and higher sublet income from our Northampton site (£0.5m). There was also one off cost of £1.6m associated with transitioning to the new Gas Control Suite in 2016/17.

433. Our eight-year forecast for Controllable Opex costs is £25.2m below forecasted allowances. As in the prior year our direct costs excluding agency costs are expected to exceed allowances mainly due to the cost of supporting our role in Europe which is not fully funded. Agency costs are forecast to be £33.7m below

allowances which is due to the reallocation of Xoserve allowances from Non Operational Capex to controllable Opex following the outcome of the agency services review in 2016/17.

System Flexibility

434. In 2017/18 we continued with our system flexibility project which was initiated to re-assess the needs case utilising the 'seedcorn' funding received under RIIO-T1. Activities have been split between system flexibility analyses and external stakeholder engagement.

435. Our second Gas Future Operability Planning document was published alongside the 2017 Gas Ten Year Statement, to provide a holistic view for stakeholders on how changes in the energy landscape impact future system operability, investment and commercial solutions.

436. We have now moved to a quarterly series of publications, which allows us to focus on specific areas of operability more closely, and encourages a richer and more focused debate with our stakeholders.

437. The first of these was published in March 2018 and focused on the interaction between gas transmission and electricity generation. We have used webinars, attended forums, and arranged bilateral meetings to capture the views of stakeholders and incorporate them into our documents. Our findings and stakeholder feedback highlighted two further areas of study that will start in 2018/19.

438. Future documents are planned to be published in June and September 2018 and will focus on the changing patterns of gas supplies and how these affect the operability of the NTS.

439. A significant portion of the analysis in these documents has been carried out using the Gas Flexibility Tool, a gas market model developed in partnership with Baringa Partners LLP. The tool allows us to test more "extreme" cases of changing customer behaviour and unexpected events. This will help to determine whether additional flexibility might be required to manage future flows effectively.

440. Further work on the Gas Flexibility Tool, in collaboration with Baringa Partners LLP, was carried out in 2018 to refine model parameters and provide supporting documentation. This has helped to provide a more detailed and enduring knowledge of the capabilities of the Gas Flexibility Tool.

Econometric Benchmarking - E2Gas

441. In mid-January 2017, the Council of European Energy Regulators (CEER) with its contractor Sumicsid initiated a 14-month project to benchmark European electricity and gas transmission operators. We agreed to participate in the study which includes approximately 20 electricity TSOs and a similar number of gas TSOs. The study aims to provide information on the relative efficiency of TSO asset

development and maintenance activities for a 2017 snapshot, and by repeating the analysis biannually in the future, identify how efficiency improvement initiatives progress over time. The study aims to improve on methodological and transparency aspects of earlier electricity and gas high-level benchmarking studies for the benefit of regulators and companies.

Greenhouse Gas Investigative Mechanism (GHGIM)

442. During December 2017, we fulfilled the Licence direction in Special Condition 8J of National Grid's Transportation Licence and concluded the investigation into enhanced monitoring and field validation for this project.

443. On 27 March Ofgem published its decision to award us 100% of the spend invested in the innovative GHG emissions project in recognition of the improved understanding and quantification of methane emissions (this will be recorded in our revenue in 2019/20).

444. We have designed and developed a cost effective bespoke measuring tool with an associated methodology to enable us to monitor and control fugitive emissions from AGIs on the NTS and to understand both planned and unplanned venting events.

445. The project involved trialling a proposed method over a one-year period to assess the practicality, performance and cost effectiveness of the approach. In addition we were able to validate the "portability" of the equipment to expand the application beyond AGIs.

446. The current industry methodology to identify leaks involves a 4-yearly walkover survey at our AGI sites. The near real-time methodology trialled in this project suggests that leakage volumes may be significantly higher than the former methodology suggested, not least because we were able to quantify emissions above ground-level for the first time. Whilst the project data has been validated to an extent, the next step is to conduct further trials at different locations.

447. With further development to increase confidence in the methodology, we could ensure that the financial, environmental, and reputational benefits of reducing emissions are fully realised and deliver environmentally-beneficial outcomes for our customers.

448. We are working on internal funding proposals to further develop this work through the remaining RIIO T1 period.

XV. Innovation

449. Throughout the last year we have focused on innovation that delivers a step change for customers, providing a safe, reliable and efficient energy system for the future. We have developed an innovation strategy with a clearer focus on the future of the network. In the last 12 months we have delivered against our ambition for 2017/18; building on our capacity to measure the business value delivered from innovation and developing new ways to share this with our stakeholders and customers.

450. In 2017/18 we spent £4.2m of the £5.8m allowable NIA expenditure. Of this spend, £738k (17.6%) was internal expenditure. Our total NIC expenditure incurred in 2017/18 for Project GRAID and CLoCC totalled £3m.

451. We undertook 39 NIA projects across our key themes; safety, reliability, environment, strategic, system operability and customer and connections. Particular successes this year have been projects such as 'Composite Pipe Supports Phase 2'. Replacing steel pipe supports with GRP offers significant benefits. The lightweight nature of GRP makes it easier and safer for our engineers to install the supports and the intelligent design makes inspections simpler and faster, avoiding the need to breakout and replace concrete each time resulting in significantly lower costs.

Figure 34: Crush testing of a composite pipe support

452. Another significant NIA project is Valve Sealant Line Grouted Tee which facilitates repair of corroded sealant lines, typically occurring at the wind and waterline. Applying this Grouted Tee technique, a costly full excavation to replace the main line valve can be substituted by just a shallow dig using vacuum excavation. The

first use of the tool on three valves at Kings Lynn Tee avoided the costs associated with replacing the valves and saved £817k and 1,500 tonnes of CO2. With this solution still in the early-stages of implementation, the savings for the network and our customers will greatly increase in the future.

453. We launched a call for ideas for the 2018 NIC in October 2017, reaching out to new and existing partners to help us identify our next flagship low carbon innovation project. The call was well received, with over 25 initial submissions received from industry. The submissions underwent an internal review process during which, several potential projects were identified. Due to the nature and scale of these projects they were deemed more suitable for funding under NIA and are currently under development. They have the potential to solve significant operational challenges on the NTS, providing tools and techniques to operate the network in the most efficient way to drive value for our customers.

454. We have continued to build momentum on Project GRAID as we approach the end of the NIC Project, which is due to conclude in November 2018. Most significantly, the team has delivered a functional robot, launch vessel and test facility allowing the Offline trials to be completed. This extensive test phase lasted over six months which subjected the robot to a number of challenging tests focusing on navigating around the complex pipework, operating in pressures up to 100 bar(g) and flows of 5m/s, taking wall thickness readings and understanding how the equipment can work operationally. In parallel, the live trial sites have been selected on the NTS, with the first trial scheduled for June 2018, the second to follow in August. The GRAID team has attended a variety of conferences and events to promote the work completed and answer any questions for those interested in knowing more, these include the Low Carbon Networks & Innovation, Technology for Future & Ageing Pipelines and Utility Week conferences.

Figure 35: Offline Testing of the Project GRAID robot

455. Project CLoCC is now in its third year. Several key milestones have been achieved, in particular, changes to the commercial process which will offer improved flexibility to renewable energy customers. These changes include updating the Oxygen content specification in the National Grid Gas Ten Year Statement (GTYS) from 10 ppm to 2000 ppm to ensure we can consider requests for Oxygen content up to the Gas Safety (Management) Regulations (GS(M)R) specifications. We also removed the absolute requirement for an exit connection to have a ROV, which came into force in January 2018, meanwhile safety will be guaranteed through the relevant Hazard Operability Study (HAZOP) studies to be performed. By doing so, we have simplified the exit connection process and significantly reduced the costs involved. The connection application fees for lower-flow gas customers have also been reduced. The new application fee for standard design customers will be reduced by at least 80% due to the suite of standardised connection designs and the gas connections portal developed as part of Project CLoCC. This assists renewable energy customers as the upfront costs of connection are reduced which better suits their project cashflow.

456. We had a very successful showcase at the Low Carbon Networks and Innovation (LCNI) conference held in Telford in December 2017. Through presentations and the exhibition, we featured several NIA and NIC projects, including CLoCC, the artificial intelligence categorising of corrosion project and the Valve Sealant Line Grouted Tee. The event provided a great platform for sharing learnings with the other network licensees and wider industry and provided a platform to reach out to our stakeholders.

Figure 36: National Grid Showcase at the LCNI Conference

457. We have continued to share learning and work collaboratively with other network licensees, including actively participating in the Gas Innovation Governance Group (GIGG) and hosting the Institution of Gas Engineers and Managers (IGEM) Affiliates Event. We worked closely with the other network licensees to launch a NIC call for proposals, reaching out to small and specialist organisations in order to meet our business challenges and the wider challenges facing the gas industry.

458. A major achievement has been the publication of the first Gas Network Innovation Strategy, driven by our stakeholder consultation and produced with the Gas Distribution Networks and the Energy Networks Association (ENA). The strategy identifies the most important challenges and opportunities facing our industry, setting out new areas of focus for innovation to ensure we continue providing benefits to customers. A formal consultation on the strategy ran from 1 November to 22 December 2017. During this period we engaged stakeholders across a number of forums, including presentations and a joint interactive session with the Gas and Electricity networks at the LCNI conference. Feedback received during the consultation period was directly fed into the strategy.

459. This year our value tracking process has been embedded within the business, delivering several new case studies on recently implemented innovations, whilst continuing to track the value accruing from innovations delivered to date. So far, innovation has delivered over £8.6m in value, sustaining a cost – benefit ratio of 4:1. Following the publication of our first ‘Embedding Innovation Value’ report last year, we have focused on making this information more accessible to our stakeholders, with the creation of an online library of case studies.

460. Our ambition for 2018/19 is to continue the development of a dynamic portfolio of projects which deliver real value to our customers, stakeholders and the wider industry and is aligned to the Gas Network Innovation Strategy. We will continue our focus on the implementation of innovation into business as usual to drive value throughout everything we do. We will remain committed to sharing best practice across the industry to deliver a safe, reliable and efficient network that benefits gas consumers across the UK.

XVI. Market Facilitation

461. We have a number of roles in facilitating the GB and EU gas markets. This section discusses the areas we have focussed on in 2017/18 including the Future of Gas (FoG) project, Brexit and the Gas Transmission Charging Review. Our customers and stakeholders have told us that one of their priorities is that we "facilitate and lead the debate" and this section will highlight examples of how we have engaged them and built systematic processes to continuously gather feedback from and respond to them. We have received positive feedback from our customers and stakeholders over the year and will look to build on this to make improvements in the future.

Background

462. Over the coming years there is set to be significant changes in the UK energy industry and it will be important to ensure the GB gas regime remains flexible and adaptable to this change. Financial year 2017/18 has been a significant year for us as we have worked with our customers and stakeholders to ensure our business strategy fully prepares us for the future. Most notable these activities include:

- FoG project which sets out our view of the key role Gas Transmission can and will play throughout the 2020s to 2050;
- the implications of the Brexit vote through the EU referendum, the impacts on the EU and GB gas regime and preparation for the UK's exit from the EU; and
- Gas Transmission Charging Review (GTCR) to deliver significant improvements to the GB charging regime.

463. We continue to play an active role in the GB and EU gas market activities by influencing the development of EU change both in terms of the continued development of EU Network Codes, other Code and legislative developments. Within the GB market we are proactively reviewing our Gemini strategy and Xoserve arrangements as a service provider to ensure that this is fit for purpose and has the ability to manage future industry change.

Future of Gas Project (FoG)

464. The FoG engagement programme aimed to develop insights on the future role of gas and the gas transmission system in GB. In July 2017 we published Future of Gas: Progress report, our interim publication highlighting the work to date. This included the emerging themes and three sensitivities; High Electrification, Two Degrees and Decarbonised Gas, providing a wide range of possible gas supply and demand cases while meeting the UK's 2050 carbon targets.

465. Through our stakeholder engagement, research into developments and from feedback on our documents we developed a series of beliefs for the future of gas. These were:

- gas has an important long term role but as the pathways are uncertain, now is not the time to shut down optionality;
- we need to decarbonise heat but nothing substantial will change for heat in the short term;
- gas supports wider UK economy as it represents good value for consumers and supports industrial processes;
- decarbonising transport with gas is happening today so could be an early priority;
- supply sources are going to change; we need to consider the market rules to ensure GB remains attractive;
- system operability is going to become more and more challenging, making gas and electricity interactions more important;
- whilst energy storage is growing in importance, the gas system itself remains a critical store;
- innovation in gas is imperative: Government, regulators and industry need to work together to investigate and facilitate different technologies, in particular Carbon Capture and Storage (CCS); and
- hydrogen will play a role in the energy future, but how big a role remains uncertain.

466. These beliefs formed the basis of the second phase of the future of gas programme running from August 2017 to March 2018.

467. In September 2017 we hosted a workshop to test the beliefs, measure how successful we had been in engaging with and understanding our customers' and stakeholders' views and ensure that our forward work plan incorporated these views. The workshop was oversubscribed and we held follow up bilateral discussions to ensure everyone's voice was heard. The first half of the workshop posed three deliberately bold statements to measure how successful our engagement programme had been. Stakeholders were invited to comment on each of the following statements:

- FoG has articulated the challenges for gas as the UK moves towards 2050, we have left no gaps;
- we have engaged in a timely manner and the approach has been the most appropriate one for the industry; and
- Futureofgas.uk is being used effectively as an industry hub.

468. Stakeholders were generally supportive of our approach and the programme, stating that we are well placed to bring the industry together as well as consensus that the engagement had been timely and appropriate. There were suggestions such as explore the link between future of gas and industrial growth, make air quality a more specific focus, articulate the end goal and include more third party information on the website. All of the feedback received helped us to plan the latter parts of the FoG programme.

469. The second session sought views on the FoG beliefs; this feedback allowed us to refine our beliefs and helped to shape the final document in March 2018. A full summary of the workshop is available here http://futureofgas.uk/wp-content/uploads/2017/09/Future-Of-Gas-Stakeholder-Workshop-outputs-final.pdf

470. Internally we used the feedback on the beliefs and the FoG sensitivities to analyse the capabilities of the network and build a series of pathways to 2050.

471. In March 2018, we published our conclusions report '*Future of Gas: How gas can support a low carbon future*'. This document combined all of the stakeholder engagement, research and internal analysis to set out our views of the role of gas in supporting the UK meeting the 2050 carbon targets. We set out five key themes:

- decarbonisation of heat;
- decarbonisation of industry;
- decarbonisation of transport;
- whole energy system; and
- future networks and markets.

472. For each theme we explored the problem, the potential solutions, the actions we will take, triggers for potential further work and policy recommendations. We launched the report with over 100 stakeholders in attendance and speeches from National Grid's UK Executive Director and the Director of Sustainable Energy Division for the UN Economic Commission for Europe.

473. The report, specifically the actions we will take, the triggers for potential further work and the policy recommendations, along with the Future Energy Scenarios, are being used to shape our business strategy and has helped to shape the direction of the business from today. One of the first deliverables is the Gas Industry Change Plan that will establish a long term, industry backed programme of strategic change, enabling resource and investment to be properly planned.

Brexit

474. Following the UK's decision to leave the EU in the referendum held on 23 June 2016, the two-year withdrawal process was triggered in a letter to the EU Council President on 29 March 2017. Under the terms of Article 50 of the Treaty of Lisbon,

the UK is scheduled to leave the EU on 29 March 2019. This may be extended to end 2020, should a 'transition period' be agreed by all remaining 27 EU Member States at the October 2018 EU Council meeting, by the European Parliament and the UK Parliament.

475. During 2017/18 we have been working to assess and prepare for the UK withdrawal from the EU. This has involved working with BEIS and Ofgem and wider stakeholders on the changes required to industry codes and related agreements to maintain the legal basis for industry processes and commercial arrangements in place. This is specifically in relation to system operation, balancing and interconnection points to EU Member States. We have participated in workshops, bilateral meetings and responded to industry consultations.

476. We will continue our work during 2018/19 to make ready the legal framework for post 29 March 2019, both in the event of a transition period being agreed and without. We are also working to the outcome that Transmission System Operators from the UK continue to participate in the work of European Network of Transmission System Operators for Gas (ENTSOG) with the same rights as other TSOs. Additionally, we aim to continue our working membership with Gas Infrastructure Europe (GIE) as on today's basis.

Gas Transmission Charging Review (GTCR)

477. The Gas Charging Review continued its development through industry workgroups (National Transmission System Charging Mechanism Forum (NTSCMF) and Modification specific workgroups) in 2017/18. In June 2017, we raised UNC Modification 0621 to cover all the aspects of the charging review that included delivering compliance with EU Commission Regulation 2017/460 (the EU Tariff Code). Meetings with industry were frequent, often taking place twice per month. We undertook substantial engagement with stakeholders, customers and interested parties.

478. The initial modification raised proposed a new Reference Price Methodology (RPM) based on a Capacity Weighted Distance (CWD) framework with remaining elements to be developed through the workgroups. Over the summer of 2017 we proposed through NTSCMF and UNC Modification 0621 workgroups a structure to discuss and develop the components of the modification. This included facilitating many charging review sub workgroups with outputs played through NTSCMF to ensure transparency and awareness with the industry.

479. Subsequent versions of the modification incorporated the outputs from these discussions to inform the proposals. This also helped manage the alternative modifications so that awareness of the areas where potential alternatives might be raised was more visible. A number of alternatives have been raised to UNC Modification 0621 which are also being managed through the workgroups.

480. In March 2018, we received a Licence direction to use reasonable endeavours to return UNC Modification 0621 and any alternative modifications to UNC panel for 17 May 2018.

481. UNC Modification 0621 and all alternatives raised are expected to go to the UNC Panel for May 2018 to be consulted on through the UNC change process. An impact assessment along with the required EU Consultations (required under the EU Tariff Code) are also expected to be completed before the end of 2018/19.

European Market Activities

EU Capacity Allocation Mechanisms (CAM) Network Code

482. The CAM code standardises EU capacity mechanisms at Interconnection Points (IPs). Over the past year, further work has been undertaken to complete the commercial framework for the CAM Incremental process. We

- liaised with adjacent TSOs to align processes;
- updated and consulted upon the Capacity Release and Substitution Methodology Statements;
- provided and consulted upon the Alternative Allocation Mechanism (AAM) and IP PARCA documents. The IP PARCA document is based on the standard PARCA contract but updated to reflect the requirements of the CAM process at IPs; the AAM describes how the GB PARCA process will fit within the CAM framework; and
- we have worked with Ofgem to make changes to the NTS Licence for CAM Incremental, to make sure the IP process worked within the framework developed for PARCA.

483. The process was run for the first time in 2017 in line with the new framework (no demand indications for Incremental capacity were received).

484. We proposed modification UNC0616s to introduce a Capacity Conversion service by 1 January 2018, as required by the amended CAM Regulation. We have been active in the development of the service within ENTSOG and made sure the modification was consistent with the ENTSOG model for Capacity Conversion. We worked with Xoserve and stakeholders to make the service as flexible as we could while simultaneously trying to minimise system impacts and implementation costs.

EU Tariff (TAR) Network Code

485. The TAR code aims to establish a network code on harmonised transmission tariff structures for gas. It sets out the EU-wide rules which aim to enable market integration, enhance security of supply and to promote the interconnection between gas networks. Due to the different regimes in place across Europe, gaining agreement between relevant parties has been challenging which has resulted in changes to the development timeline.

486. We have provided regular updates and held discussions with stakeholders and customers at industry fora including UNC Transmission Workgroup, the NTS

Charging Methodology Forum and the Gas Storage Operators Group as well as in a number of bilateral meetings and communications with individual stakeholders. Industry discussions on the TAR code have been incorporated into the Charging Review to ensure a holistic approach is taken in the development of a GB charging framework that is both fit for purpose and compliant with the EU tariff code. The TAR Code will drive a number of changes to the GB charging regime such as the removal of fixed price capacity tariffs at interconnection points, a drive that most of the allowed revenue should be recovered via capacity tariffs and increased obligations in transparency and consultation. We have also been proactive in the development of the TAR code both at a European level and by working closely with BEIS and Ofgem by seeking to influence the codes and to ensure they are implemented effectively. The implementation solutions were developed in consultation with customers and stakeholders as part of the Charging Review but we have successfully influenced the final TAR code such that we were able to largely preserve our current TO/SO model and that there was sufficient flexibility in the code that many of the changes considered in the Charging Review were largely driven by GB requirements rather than simply EU compliance.

487. The TAR code entered into force on 6 April 2017.

488. We continue to be active at the European level to facilitate a coherent implementation of the TAR code between Member States and to influence the development of the process by which ENTSOG shall monitor implementation of the TAR code in its role to assist the Agency for the Cooperation of Energy Regulator's (ACER's) monitoring duties.

Gas Quality Developments

EU Gas Quality Harmonisation

489. The European Committee for standardisation (CEN) published its gas quality standard EN 16726 in December 2015. The standard covers a number of gas quality parameters but does not include the key safety parameter of Wobbe Index because EU level agreement could not be reached. While the application of the standard to member states is voluntary, the EC stated its intention to make it legally binding via an amendment to the EU Interoperability Network Code and in 2016 asked ENTSOG to lead an initiative with stakeholders to examine the impacts and issues associated with doing so. ENTSOG's work concluded that the standard should not be made binding, which the EC agreed with at the Madrid Forum in October 2016. However, the EC also invited CEN to continue its work on a harmonised Wobbe Index for inclusion in the standard and stated that it would revisit harmonisation again upon the conclusion of this work, which is likely to be around 2020. The Sector Forum Gas committee within CEN established a number of taskforces to achieve this and while there is no direct GB representation, we have been able to monitor developments, contribute via ENTSOG and provide progress updates to the industry.

GB Developments

490. The IGEM has established an industry working group to explore changes to the GB gas specifications in the GS(M)R. This group is investigating whether the upper Wobbe Index limit can be increased; this was recommended by SGN following the conclusion of the Opening up the Gas Market (OGM project). OGM involved a year-long field trial of wider Wobbe gas injected and utilised within Oban, one of the Scottish Independent Undertakings (SIUs). More information about OGM can be found on the SGN website https://www.sgn.co.uk/oban/. This working group is also considering whether the gas quality specification contained in the GS(M)R can be transferred to an IGEM standard.

491. Within GB, carbon dioxide has again been the subject of industry debate. In December 2016, BP raised UNC Modification 0607 in order to facilitate an increase in the carbon dioxide limit at the North Sea Midstream Partners (NSMP) sub-terminal at St Fergus from 4.0mol% to 5.5mol%. BP sought this change in order to facilitate continued gas flows from the high CO_2 Rhum gas field (and others that feed into the offshore pipeline that delivers gas into the NSMP terminal) in the event that lower CO_2 gas is unavailable to blend offshore to meet the current specification. While our analysis indicates that such a limit would be acceptable for NSMP volumes at St Fergus, it is not a limit that we could currently accommodate more generally on the NTS. Therefore, the modification was amended to be time-limited and provide us with a right to review the limit if such flexibility were requested by others that could not otherwise be accommodated. Ofgem direction to implement this modification was published in February 2018, following which we and NSMP enacted the necessary changes to the Network Entry Agreement between the parties.

492. In October 2017, we issued a separate consultation to the industry about the likelihood of future requests to widen gas quality specifications, review the current change process and explore any demand for our gas quality services in the longer term. The consultation report was published in February 2018 and may be viewed, together with all other documentation in respect of this consultation at http://www.talkingnetworkstx.com/gas-quality-consultation.aspx

493. Project CLoCC aims to facilitate new sources of gas to connect to the NTS. In order to facilitate the connection of biomethane customers in particular, any requests for oxygen specification in excess of the NTS requirement and within the GS(M)R limit will be considered on a case-by-case basis.

494. The development of shale gas is still in its infancy in the UK and at present there is uncertainty over the quality of such gas until wells are drilled. We continue to work with customers and monitor developments in this area.

Gas EU Security of Supply Regulation

495. The revised Gas Security of Supply Regulation (amended to Regulation (EU) No 994/2010) came into effect in November 2017 and contains a phased implementation of obligations until 1 March 2019. Some of the new obligations contained within the revised Regulation are direct on TSOs. Other obligations sit with Member States but have an indirect obligation on TSOs to contribute towards their fulfilment.

496. During 2017/18 we have been working closely with BEIS and Ofgem to interpret the obligations, ensuring compliance and providing our expertise in terms of how obligations can be implemented in the most effective way. It has been imperative that we have played an active role in both the influencing and the implementation phases of the introduction of this revised Regulation to ensure minimal impact on the GB gas regime.

GB Market Activities

Xoserve and Gemini

497. Xoserve provides a number of services to us and to our customers, which in the main are associated with Gemini operations and change management, shipper invoicing, energy balancing processes and shipper lifecycle activities. Under the current regulatory arrangements, we received a funding allowance for the provision of these services from Xoserve.

Xoserve Relationship/Performance

498. The customer experience when interfacing with our back-office systems has continued to be a key area of focus for us this year, this has led us to continue to work closely with Xoserve to review and seek improvements in the delivery of data services across a range of operational areas in partnership with Xoserve. The results of this work have led us to:

- gain Xoserve support and attendance at our Gas Operational forum, allowing Xoserve to provide updates to our customers on issues and market changes which may affect them, as well as being available to answer any specific questions on the services Xoserve provides on our behalf. A key area of focus at these sessions has been to provide the industry with updates on Unidentified Gas.

- seek input from our customers at the Gas Operational forum on the Xoserve service desk and the challenges they have experienced, to enable us work collaboratively with Xoserve to focus on improvements which will make a real difference to them.

499. In terms of the current interface, we have restructured how we manage the relationship to deliver a new balanced scorecard, this allows both us and Xoserve to highlight challenges or areas of customer concern in a structured way. This

approach is delivering a more efficient relationship management function, ensuring we are focussing on the issues at the right times and action plans are clear where issues are identified. It also ensures we are able to maintain a collaborative approach where both sides are comfortable and clear on where to raise areas where we need to focus in a timely manner.

Gemini Strategy within RIIO-T1

500. The Gemini IT system underpins the nominations and energy balancing regime and is the means by which we transact capacity with customers. The system is owned by us and operated and maintained by Xoserve.

501. Xoserve identified an investment requirement to sustain Gemini's infrastructure because it is currently operating on ageing hardware and infrastructure software which brings increasing risks to its security, availability and resilience. We plan to sustain Gemini via a re-platform activity which is much more efficient than a full replacement and explained our thinking to customers and stakeholders at the Operational Forum in November 2017 who supported this approach. We raised a change proposal accordingly in December 2017 and have since embarked on an analysis phase with Xoserve prior to design and build of the IT solution, see Section XIII. Capital Expenditure (SO) and Section XIV. Operating Costs for detail on spend and allowances

502. We also want to improve the customer experience of using Gemini and engaged with customers and stakeholders at Operational Forums in November 2017 and February 2018 to capture the 'pain points' that are currently experienced with the system. We plan to run this project to enhance Gemini in parallel with the re-platform project and will be engaging further during 2018/19.

Future Capacity and Balancing System and Services in RIIO-T2

503. RIIO-T2 provides us with the opportunity to ensure that the system and services which shippers use to book capacity and balance their portfolios (currently Xoserve and Gemini) provide value in the future. This project shall ensure not only that the right system and services are delivered but also that they can adapt to future change as identified in the Industry Change Plan referred to in the FoG section of this narrative.

504. To date this work has involved reviewing the services we currently procure from Xoserve, mapping the current process and understanding the impact of the future on the current system and services. Throughout 2018/19 we will be building on the engagement carried out with the industry during RIIO-T1 on this topic, to seek views on their future requirements, both in terms of functionality but also in terms of how system change should be delivered. We will use this feedback to build options which we will test with the industry and feed into our RIIO-T2 business plans.

XVII. Operational Review

505. In 2017/18 we have seen a relatively average winter which is classed as 25th warmest winter in the past 58 years. The highest daily demand seen this year was 417.6 mcm on the 1 March 2018. This was higher than the highest demand experienced in 2016/17 and higher than demand seen in the past eight years.

506. In winter of 2017/18 the System Average Price was 56 pence per therm (p/th) and ranged from 41 p/th to 373 p/th. This was an increase compared to the previous winters average of 46 p/th ranging from 30 p/th to 60 p/th. The significant change was largely due to the cold snap in late February and early March 2018.

507. The total consumption for the year was 89.8 bcm compared to 87.1 bcm in 2016/17. This increase was largely driven by an increase in demand from LDZ Offtakes and IUK export.

508. The coldest day in 2017/18 was recorded on the 1 March 2018. The lowest demand seen was 132.48 mcm on 25 June 2017. This was 17.9 mcm higher than last year's minimum.

509. Late on the 28 February gas day we saw a number of supply trips across the network that we confirmed through the day, which when combined with the forecast for the 1 March gas day, led us to issue a Gas Deficit Warning and to utilise Operating Margins gas during the 1 March gas day.

510. In 2017/18 we experienced a number of operational challenges largely brought about by the changing flow patterns experienced at the St Fergus, Easington and Bacton terminals. With regards to St Fergus, supplies decreased from 30.7 bcm in 2016/17 to 29.43 bcm in 2017/18 and we saw increases at Bacton and Easington terminals. In addition, and contrary to expectation, we received lower volumes of LNG with only 49 cargoes received compared to 64 cargoes in 2016/17.

511. Throughout these periods of operational challenge, we have endeavoured to minimise customer disruption and maintain performance. In 2017/18 99.9% of significant offtake pressure customer obligations were delivered during the year with no material impact reported on days where they could not be met. The construction and execution of our operational plans ensured 100% of firm capacity purchased by customers was made available for use and 483 maintenance operations were completed successfully during the year.

Operational challenges

512. Within day operability has remained an ongoing challenge, caused principally by the behaviour of fast cycle medium range storage and supplies being delivered predominantly through three entry points. This has resulted in a less balanced overall network and the need to operate high levels of compression to move gas away from entry points.

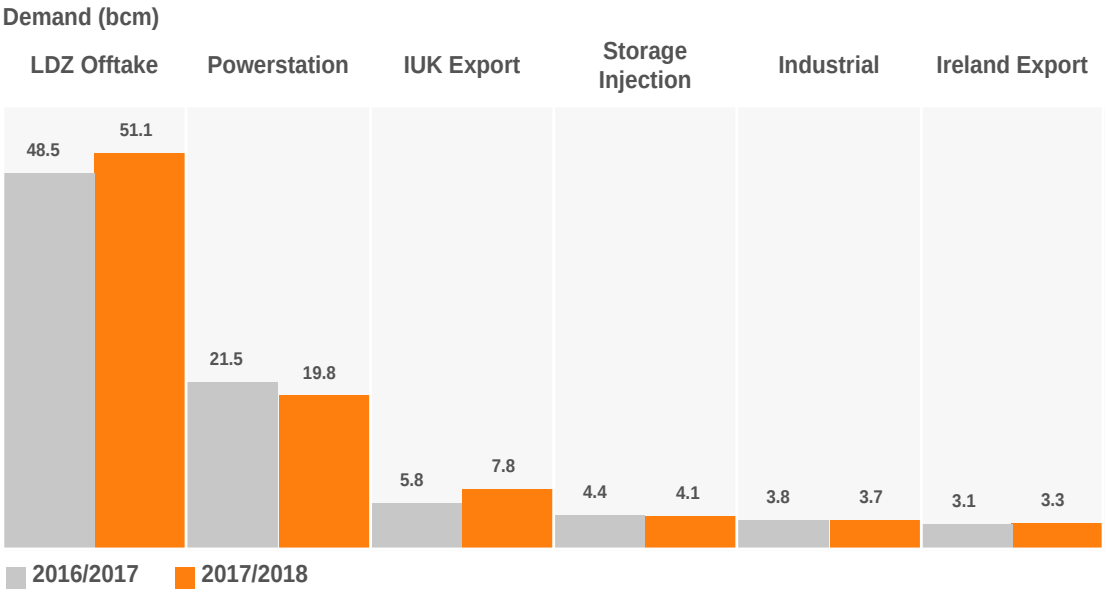
513. During the winter, there were 136 Gas Safety (Management) Regulations supplier excursions, which were resolved using the relevant processes.

514. There were unplanned system events at one NTS offtake for a partial gas day resulting in a loss of flow to the offtake. All efforts were made to return the flow in a timely manner, whilst ensuring the safe operation of the NTS.

Gas Demand and Supply

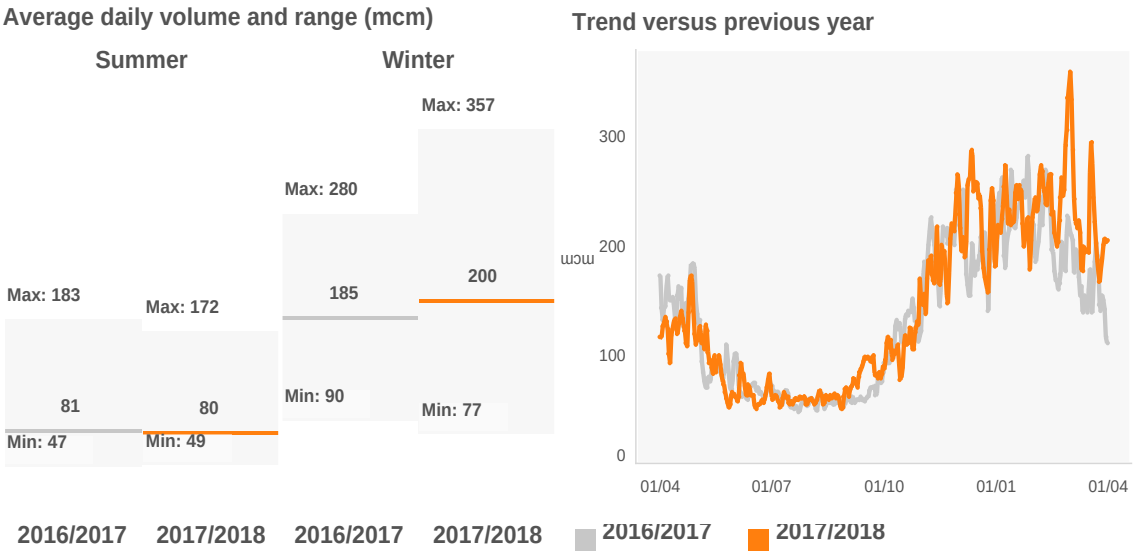
515. The chart below displays the gas demands for the past 12 months by the individual demand components.

Figure 37: Gas demand in 2017/18 by demand components



516. LDZ demand was higher in 2017/18 at 51.1 bcm compared to 48.5 bcm in 2016/17; averaging 200 mcm in winter 2017/18 compared to 185 mcm in 2016/17. IUK exports over the summer period increased by 34%.

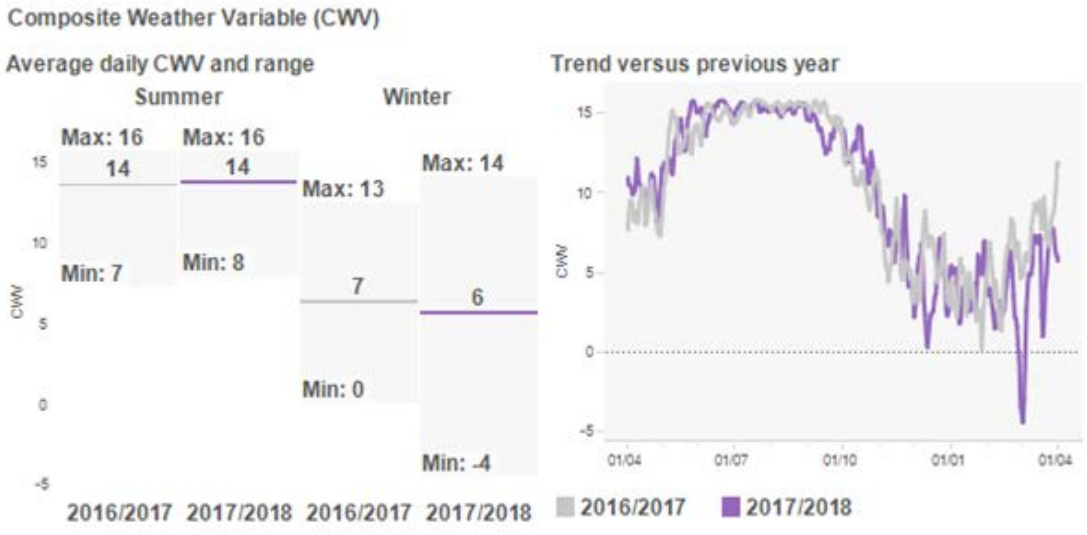
Figure 38: LDZ demand average daily volume and range and trend previous years



Weather

517. The CWV is a single measure of daily weather and is a function of actual temperature, wind speed, effective temperature and seasonal normal effective temperature. The CWV highlights a colder winter than last year which correlates with LDZ demand levels seen. The range of CWV is also wider in Winter, when compared to the previous year, this is in line with the wider range of LDZ demand.

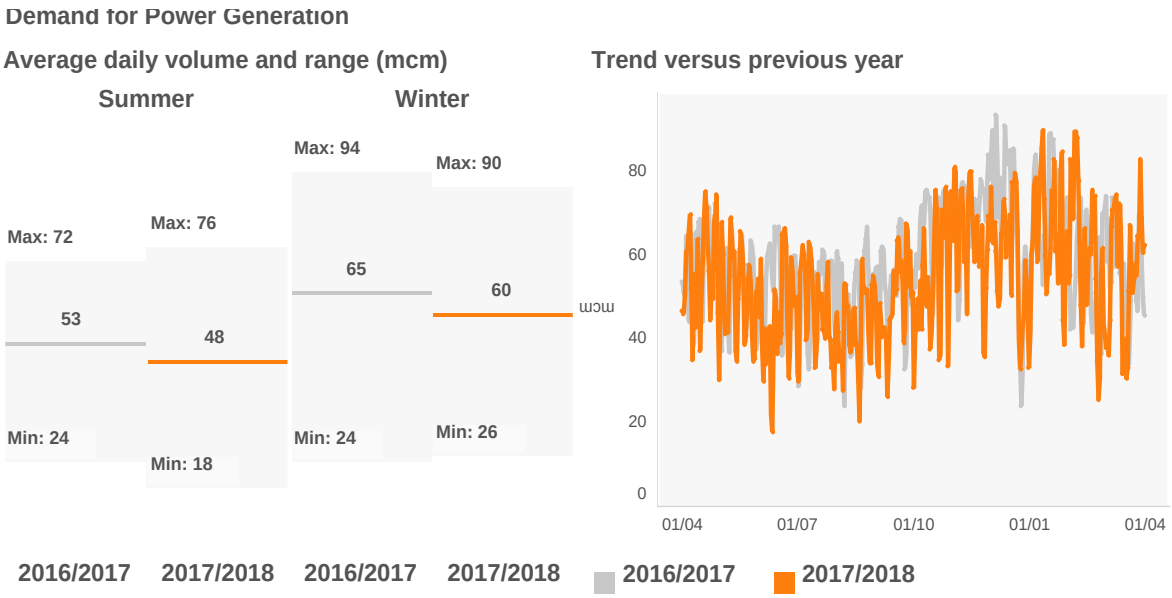
Figure 39: National Composite Weather variable data



Demand for Power Generation

518. The chart below shows the gas demand for power generation this year, compared to the previous year. In the Summer, the range of demand was slightly wider when compared to the previous year, with little change in Winter.

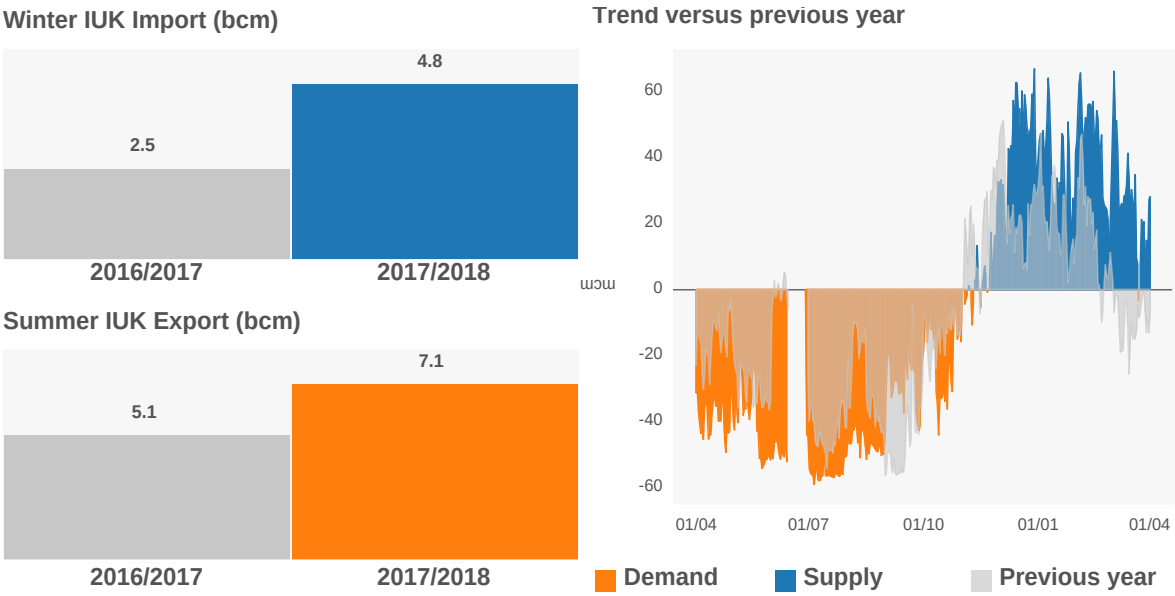
Figure 40: Demand for power generation



Import/Export Flows at IUK

519. Figure 41 shows the import/export flows at IUK for this year in comparison to last year showing an overall increase in both imports and exports.

Figure 41: IUK import/export volumes for 2017/18 vs 2016/17

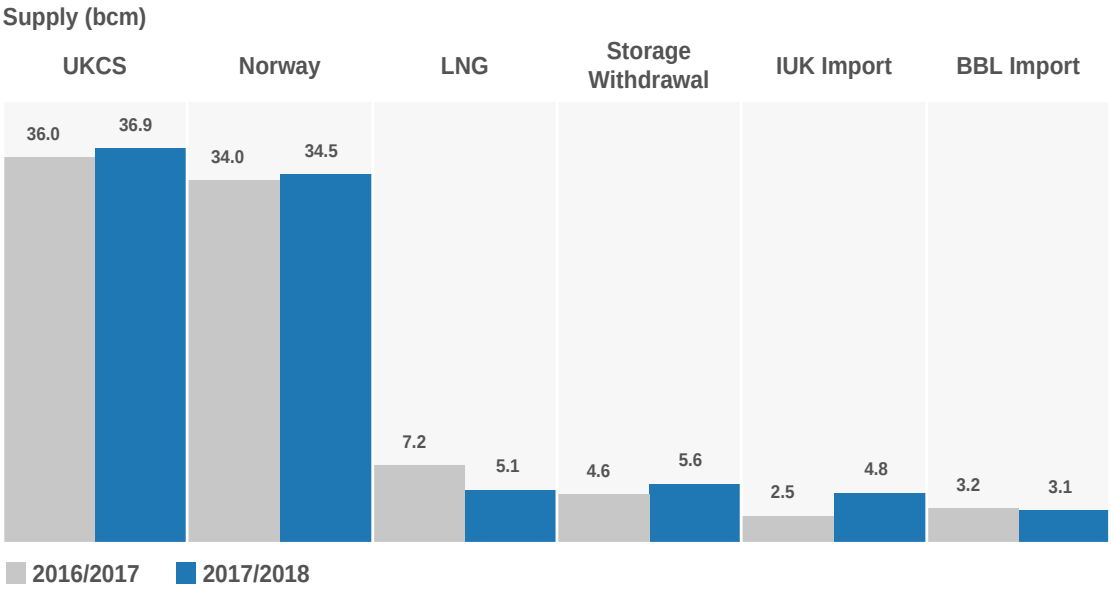


Supply Breakdown

520. Figure 42 shows the volume of supply by source type. Compared to the previous year, the largest elements of the supply profile; UKCS and Norway have remained at similar levels.

521. There has been a reduction in supply from LNG, which has been offset by an increase in storage withdrawal and import via IUK.

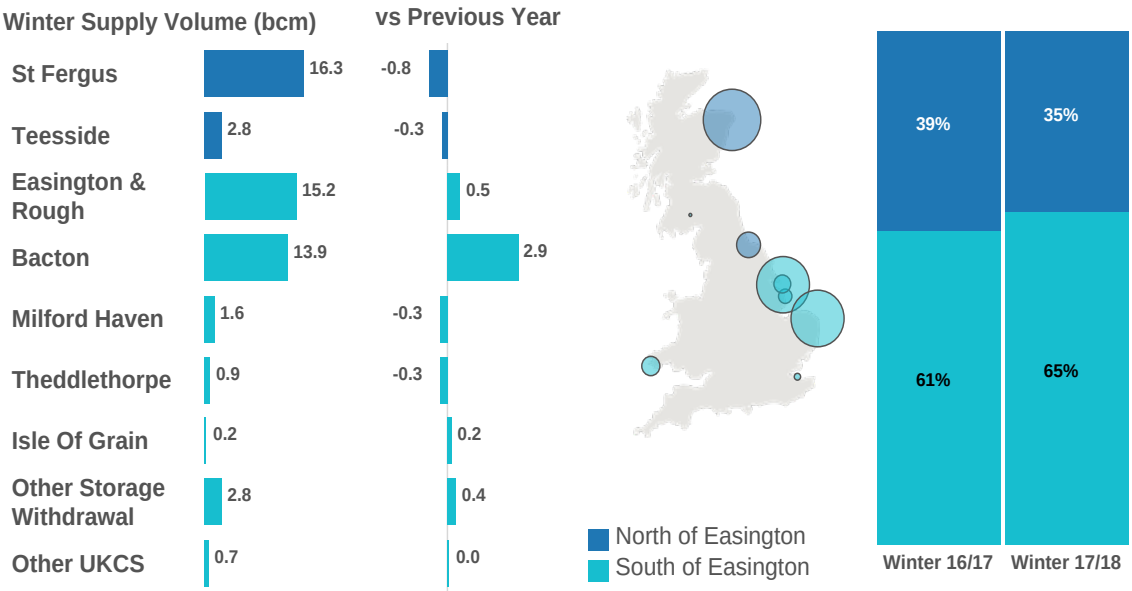
Figure 42: Gas supply breakdown 1 April 2017 to 31 March 2018 vs 2016/17



Supply Profile by Location – Winter 2016/17 vs Winter 2017/18

522. The below chart shows the percentage of gas supplied to GB by geographic location, and shows that most gas continues to be supplied through Easington, St Fergus and Bacton, however the locational profile has changed to some extent. When compared to the previous year, there has been an increase in the volume of supply entering the NTS South of Easington.

Figure 43: Supply profile by location for winter 2016/17 and winter 2017/18

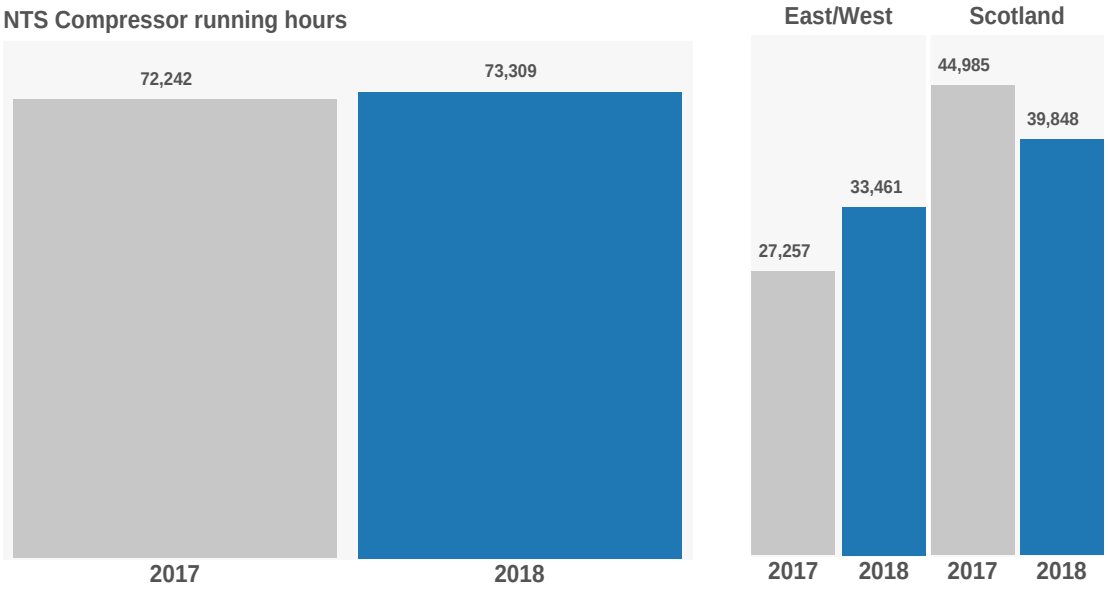


Compressor Utilisation

523. Overall compressor running hours have increased slightly from 72,242 in 2016/17 to 73,309 hours in 2017/18. Running hours at some specific sites increased significantly due to the change in flow pattern.

524. Resulting from the changes in volume of supply by location, the regional profile of compressor running hours has changed, with an increase in East/West and a decrease in Scotland.

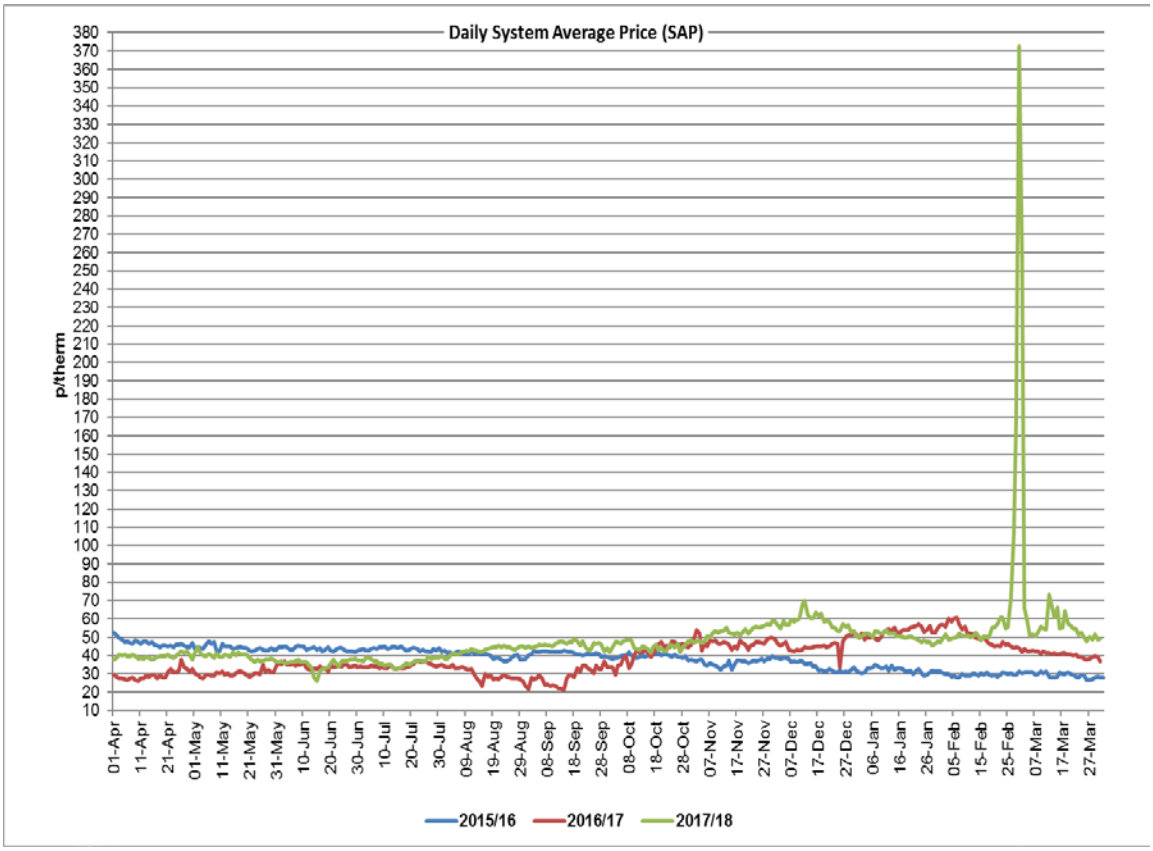
Figure 44: Compressor running hours from 2016/17 to 2017/18



Commercial prices

525. Commercially, gas prices were higher this winter ranging between 41 p/th to 373 p/th.

Figure 45: Daily SAP from 2015/16 to 2017/18

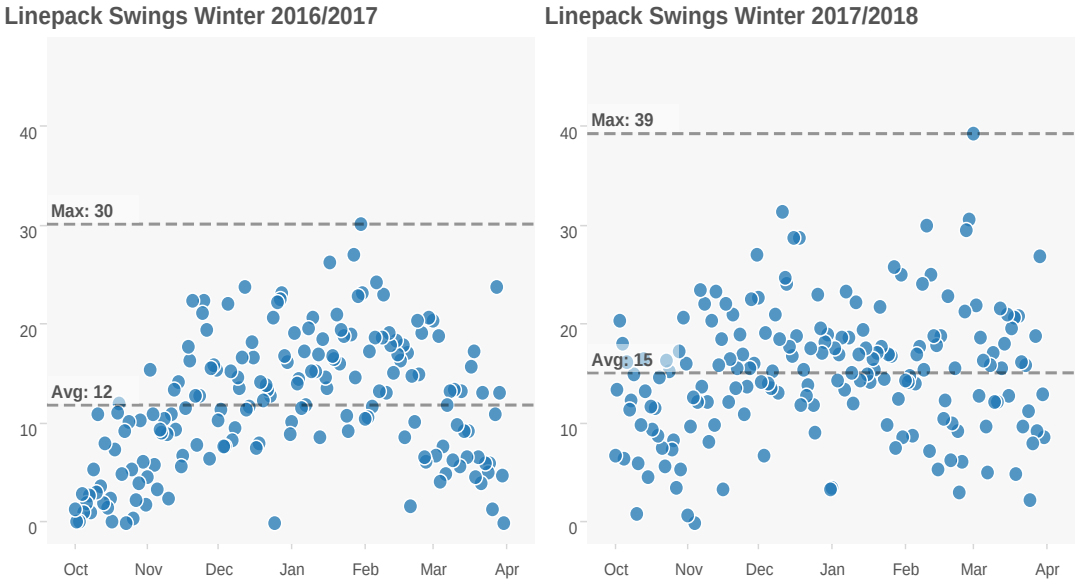


Comparison of NTS linepack swing

526. Within day profiling remains an ongoing issue for system operability, since the NTS and associated contractual rules, have historically been built to operate based on flat supply and demand profiles. It can therefore be challenging to meet customer requirements, in particular maintaining required pressures on days of significant linepack swing.

527. When comparing the daily linepack swings recorded in Winter 2017/2018 versus Winter 2016/17, both the average and maximum linepack swings have increased.

Figure 46: Chart showing daily linepack swing in Winter 2016/2017 and Winter 2017/2018



Appendix I – Totex Tables

Totex
National Grid Gas Transmission
2017/18

2.4 Published Totex

Actual/Forecast Expenditure (£m, 2017/18 Prices)

		Actual 2014	Actual 2015	Actual 2016	Actual 2017	RIIO-T1 Forecast 2018	2019	2020	2021	Total
TO	Load Related Capex	3.8	1.6	1.5	1.8	2.7	6.9	12.4	3.4	34.0
	Asset Replacement Capex	61.4	58.6	79.0	100.1	126.5	106.6	69.4	70.7	672.5
	Other Capex	32.7	36.2	29.9	15.5	44.9	71.8	74.2	44.8	350.1
	Non Operational capex	13.4	12.7	14.2	22.9	18.3	22.4	18.6	8.1	130.6
	Total Capex	**111.3**	**109.1**	**124.6**	**140.3**	**192.3**	**207.7**	**174.7**	**127.0**	**1,187.1**
	Opex									
	Faults	9.3	6.5	3.3	4.5	4.9	4.5	4.2	4.5	41.8
	Planned Inspections and Maintenance	26.2	28.1	25.4	28.4	26.6	30.6	29.3	28.1	222.7
	Other direct costs	1.1	6.8	5.3	5.2	5.7	5.5	5.4	5.4	40.4
	Closely Associated Indirect Costs	23.2	20.4	25.2	31.0	32.4	33.0	29.4	30.1	224.7
	Business Support	24.5	26.4	30.0	32.2	37.2	39.1	36.7	35.6	261.7
	Adjustment for IAS 19 pension accrual	- 0.7	0.2	- 0.2	- 0.8	1.0	-	-	-	- 0.4
	Total Controllable Opex	**83.8**	**88.6**	**89.0**	**100.4**	**107.7**	**112.7**	**105.0**	**103.7**	**790.9**
	UNCERTAIN EXPENDITURE									
	Load Related Capex	-	-	-	-	-	-	-	-	-
	Asset Replacement Capex	-	4.9	3.1	31.9	54.6	64.8	15.0	3.9	178.1
	Other Capex	39.0	25.4	15.4	4.1	22.7	36.0	48.9	29.4	220.9
	Total Uncertain Capex	**39.0**	**30.3**	**18.5**	**36.0**	**77.3**	**100.8**	**63.9**	**33.3**	**399.0**
	Controllable Opex	6.5	4.6	6.5	8.2	10.6	9.6	7.8	6.2	60.1
TO	**TOTEX**	**240.6**	**232.6**	**238.6**	**285.0**	**387.9**	**430.8**	**351.4**	**270.2**	**2,437.1**
SO	**Non Operational capex**	22.6	34.8	45.6	34.2	26.4	40.1	36.7	26.1	266.4
	Direct costs	29.9	34.7	36.1	34.5	35.1	36.9	35.4	33.3	275.9
	Business Support	23.6	24.4	24.8	27.2	24.3	28.7	27.9	27.8	208.9
	Adjustment for IAS 19 pension accrual	- 0.4	0.2	- 0.2	- 0.6	0.6	-	-	-	- 0.4
	Controllable Opex	**53.1**	**59.3**	**60.7**	**61.2**	**60.0**	**65.7**	**63.3**	**61.1**	**484.4**
SO	**TOTEX**	**75.7**	**94.0**	**106.2**	**95.3**	**86.4**	**105.8**	**100.0**	**87.3**	**750.8**

Total Allowances (£m, 2017/18 Prices)

		RIIO-T1 Allowances 2014	2015	2016	2017	2018	2019	2020	2021	Total
TO	Load Related Capex	19.3	7.8	1.6	1.3	7.6	6.4	0.3	-	44.3
	Asset Replacement Capex	110.6	128.2	142.8	166.5	190.9	166.3	137.0	119.8	1,162.0
	Other Capex	34.2	23.2	13.7	16.1	40.8	41.6	26.1	8.2	204.0
	Non Operational capex	13.1	12.3	8.4	7.8	7.1	5.3	8.1	7.5	69.8
	Total Capex	**177.2**	**171.5**	**166.5**	**191.8**	**246.4**	**219.7**	**171.5**	**135.4**	**1,480.0**
	Faults	8.2	8.3	8.4	8.4	8.5	8.5	8.6	8.7	67.8
	Planned Inspections and Maintenance	28.9	29.2	30.1	30.0	30.4	30.6	31.7	31.2	242.1
	Other direct costs	6.7	6.5	6.4	6.4	6.4	6.4	6.3	6.3	51.4
	Closely Associated Indirect Costs	19.4	20.2	21.0	20.8	21.1	21.0	21.1	21.3	165.9
	Business Support	18.9	18.4	18.9	19.2	19.1	19.4	19.8	20.0	153.8
	Adjustment for IAS 19 pension accrual	-	-	-	-	-	-	-	-	-
	Total Controllable Opex	**82.2**	**82.6**	**84.8**	**84.8**	**85.6**	**86.0**	**87.5**	**87.6**	**681.0**
	UNCERTAIN EXPENDITURE									
	Load Related Capex	-	-	-	-	-	-	-	-	-
	Asset Replacement Capex	0.1	4.9	3.1	31.9	54.7	64.7	15.0	3.9	178.2
	Other Capex	- 1.7	1.1	- 17.2	- 63.1	- 76.0	- 64.1	10.4	12.5	- 197.9
	Total Uncertain Capex	**- 1.6**	**6.0**	**- 14.1**	**- 31.2**	**- 21.3**	**0.7**	**25.4**	**16.4**	**- 19.7**
	Controllable Opex	**6.5**	**4.6**	**6.2**	**7.8**	**8.8**	**8.7**	**7.8**	**7.0**	**57.4**
TO	**TOTEX**	**264.3**	**264.7**	**243.3**	**253.2**	**319.5**	**315.0**	**292.2**	**246.5**	**2,198.8**
SO	**Non Operational capex**	**68.2**	**42.8**	**35.2**	**35.9**	**35.2**	**40.7**	**39.5**	**30.7**	**328.2**
	Direct costs	56.2	59.0	64.6	66.5	61.0	65.7	68.2	68.8	510.0
	Business Support	-	-	-	-	-	-	-	-	-
	Adjustment for IAS 19 pension accrual									-
	Controllable Opex	**56.2**	**59.0**	**64.6**	**66.5**	**61.0**	**65.7**	**68.2**	**68.8**	**510.0**
SO	**TOTEX**	**124.4**	**101.8**	**99.9**	**102.4**	**96.3**	**106.4**	**107.7**	**99.5**	**838.2**

Variance Actual/Forecast v Allowances

		Variance to Allowance 2014	2015	2016	2017	2018	2019	2020	2021	Total
TO	Load Related Capex	15.5	6.3	0.1	- 0.4	4.9	- 0.5	- 12.1	- 3.4	10.4
	Asset Replacement Capex	49.2	69.6	63.7	66.3	64.4	59.6	67.6	49.0	489.5
	Other Capex	1.5	- 13.1	- 16.2	0.6	- 4.1	- 30.2	- 48.1	- 36.6	- 146.1
	Non Operational capex	- 0.3	- 0.4	- 5.8	- 15.1	- 11.2	- 17.0	- 10.5	- 0.6	- 60.8
	Total Capex	**65.9**	**62.4**	**41.9**	**51.5**	**54.1**	**11.9**	**- 3.2**	**8.4**	**292.9**
	Faults	- 1.1	1.8	5.1	3.9	3.6	4.0	4.4	4.2	26.0
	Planned Inspections and Maintenance	2.7	1.0	4.7	1.6	3.8	0.0	2.4	3.1	19.4
	Other direct costs	5.5	- 0.3	1.1	1.2	0.7	0.9	0.9	0.9	11.0
	Closely Associated Indirect Costs	- 3.8	- 0.2	- 4.2	- 10.2	- 11.3	- 12.0	- 8.3	- 8.8	- 58.8
	Business Support	- 5.6	- 8.0	- 11.1	- 13.0	- 18.0	- 19.7	- 16.9	- 15.6	- 107.9
	Adjustment for IAS 19 pension accrual	0.7	- 0.2	0.2	0.8	- 1.0	-	-	-	0.4
	Total Controllable Opex	**- 1.6**	**- 6.0**	**- 4.2**	**- 15.6**	**- 22.2**	**- 26.7**	**- 17.4**	**- 16.1**	**- 109.9**
	UNCERTAIN EXPENDITURE									
	Load Related Capex	-	-	-	-	-	-	-	-	-
	Asset Replacement Capex	0.1	- 0.0	0.0	0.0	0.1	- 0.0	0.0	- 0.0	0.2
	Other Capex	- 40.7	- 24.2	- 32.6	- 67.2	- 98.7	- 100.1	- 38.5	- 16.9	- 418.9
	Total Uncertain Capex	**- 40.6**	**- 24.2**	**- 32.6**	**- 67.2**	**- 98.6**	**- 100.1**	**- 38.5**	**- 16.9**	**- 418.7**
	Controllable Opex	- 0.0	- 0.0	- 0.3	- 0.4	- 1.8	- 0.9	- 0.1	0.8	- 2.6
TO	**TOTEX**	**23.7**	**32.1**	**4.7**	**- 31.8**	**- 68.4**	**- 115.8**	**- 59.1**	**- 23.7**	**- 238.3**
SO	**Non Operational capex**	45.6	8.1	- 10.3	1.7	8.8	0.6	2.8	4.5	61.8
	Direct costs	26.3	24.3	28.5	32.0	25.9	28.8	32.8	35.5	234.1
	Business Support	- 23.6	- 24.4	- 24.8	- 27.2	- 24.3	- 28.7	- 27.9	- 27.8	- 208.9
	Adjustment for IAS 19 pension accrual	0.4	- 0.2	0.2	0.6	- 0.6	-	-	-	0.4
	Controllable Opex	3.1	- 0.3	3.9	5.3	1.0	0.0	4.8	7.7	25.6
SO	**TOTEX**	**48.7**	**7.7**	**- 6.4**	**7.0**	**9.8**	**0.6**	**7.7**	**12.2**	**87.4**

Appendix II – Published Outputs

Totex
National Grid Gas Transmission
2017/18

2.5 Published Outputs

1. Stakeholder Satisfaction

	2014	2015	2016	2017	2018	2019	2020	2021
NGGT Customer survey - baseline	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
NGGT Customer survey - score	7.2	7.6	7.6	8.0	7.6	-	-	-
Stakeholder survey - baseline	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Stakeholder survey - score	7.8	7.9	8.0	8.0	8.0	-	-	-

2. Incremental Capacity

	2014	2015	2016	2017	2018	2019	2020	2021
Signals for incremental capacity (GWh/day)								
Entry								
Exit								

3. Gas Constraints

	2018
Constraint management revenues - Entry	3.4
Constraint management revenues - Exit	1.1
Constraint management costs - Entry	0.4
Constraint management costs - Exit	0.0

Appendix III – Glossary

Acronym	Meaning
A2O	Application to Offer
AAM	Alternative Allocation Mechanism
ACER	Agency for the Cooperation of Energy Regulators
AGI	Above Ground Installation
AH	Asset Health
AONB	Area of Natural Beauty
AOP	Assured Operating Pressure
ARC	Alarm Receiving Centre
ASEP	Aggregated System Entry Point
BAT	Best Available Technology
bcm	Billion cubic metres
BEIS	Business, Energy and Industrial Strategy
BIM	Building Information Modelling
BR	Base Revenue
CAM	Capacity Allocation Mechanism
Capex	Capital Expenditure
CBA	Cost Benefit Analysis
CCB	Cotswold Conservation Board
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDP	Carbon Disclosure Project
CDPs	Campaign Decision Panels
CEN	European Committee for Standardisation
CFU	Compressor Fuel Usage
CIPS	Close Interval Potential Surveys
CLoCC	Customer Low Cost Connection
CM	Constraint Management
CNI	Critical National Infrastructure
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COO	Chief Operating Officer
CP	Cathodic Protection
CV	Calorific Value
CVT	Calibration, Validation and Testing
CWD	Capacity Weighted Distance
CWV	Composite Weather Variable
DLE	Dry Low Emissions
DN	Distribution Network
EAM	Enterprise Asset Management
ECM	Enterprise Content Management
ENA	Energy Networks Association
ENTSOG	European Network of Transmission System Operators for Gas
ERP	Enterprise Resource Planning
ESD	Emergency Shutdown (valves)
ETS	Emissions Trading Scheme
EU	European Union
EUA	EU Allowance
EUD	Emergency Use Derogation
EVA	Extreme Value Analysis
FES	Future Energy Scenarios
FoG	Future of Gas
FPSA	Formal Process Safety Assessment
GAInS	Gas Asset Information Systems

GCS	Gas Control Suite
GDN	Gas Distribution Network
GHG	Green House Gas
GIGG	Gas Innovation Governance Group
GIS	Graphical Information System
GIS	Gas Infrastructure Europe
GNCC	Gas National Control Centre
GRAID	Gas Robotic Agile Inspection Device
GRP	Glass Reinforced Plastic
GS(M)R	Gas Safety (Management) Regulations
GT	Gas Turbine
GTCR	Gas Transmission Charging Review
GTYS	Gas Ten Year Statement
GWh	Gigawatt hours
GWP	Global Warming Potential
HAZOP	Hazard Operability Study
HSE	Health and Safety executive
ICE	Intercontinental Exchange
IED	Industrial Emissions Directive
IFR	Injury Frequency Rate
IGEM	Institute of Gas Engineers and Managers
ILI	In Line Inspection
IP	Interconnection Point
IPPC	Integrated Pollutions Prevention and Control
IQI	Information Quality Incentive
IS	Independent Systems (Costs Paid)
IUK	Interconnector UK
kTCO2e	Kilo Tonnes of Carbon Dioxide equivalent
kWh	Kilowatt hours
LCNI	Low Carbon Networks and Innovation
LCP	Large Combustion Plant
LDZ	Local Distribution Zone
LiDAR	Light Detection And Ranging
LLD	Limited Life Derogation
LNG	Liquefied Natural Gas
LPM	Line-pack Performance Measure
LTI	Lost Time Injury
MAR	Maximum Allowed Revenue
mcm	Million cubic metres
MCP	Medium Combustion Plant
MIPI	Market Information Provision Initiative
MOD	Modification to revenues calculated annually in Price Control financial model
MWC	Main Works Contractor
NARC	National Above ground installation Renovation Campaign
NBP	National Balancing Point
NCSC	National Cyber Security Centre
NDT	Non Destructive Testing
NExA	Network Exit Agreements
NGN	Northern Gas Networks
NIA	Network Innovation Allowance
NIC	Network Innovation Competition
NICF	Network Innovation Competition Funding
NIS	Network and Information Systems
NOM	Network Output Measure
NOx	Nitrous Oxide
NSMP	North Sea Midstream Partners
NTS	National Transmission System

NTSCMF	National Transmission System Charging Mechanism Forum
OBA	Operational Balancing Account
OGM	Opening up the Gas Market (project)
OIP	Outputs Incentive revenue adjustment
Opex	Operating Expenditure
ORAM	Operational Risk Assessment and Mitigations
PARCA	Planning and Advanced Reservation of Capacity Agreements
PE	Polyethylene
PPM	Price Performance Measure
PS	Power Station
PSUP	Physical Security Upgrade
PT	Pass Through
RIIO-T1	Revenue=Incentives + Innovations + Outputs, first Transmission price control
RoRE	Return on Regulatory Equity
ROV	Remotely Operable Valve
RP1	Replacement Priority 1
RPI	Retail Price Index
RPIF	Retail Price Index Forecast
RPM	Reference Price Methodology
RVO	Remote Valve Operations
SAC	Secondary Asset Class
SAP	System Average Price
SEPA	Scottish Environment Protection Agency
SGN	Scotia Gas Network
SIU	Scottish Independent Undertakings
SMP	System Management Principles
SO	System Operator
SOBR	System Operator Base Revenue
SOK	System Operator revenue adjustment
SOOIRC	System Operator Output Incentive Revenue
SPO	Strategic Performance Overview
SSOR	Site Specific Operational Requirements
SWEP	South Wales Expansion Project
TAR	Tariff
TBM	Tunnel Boring Machine
th	Therm
TO	Transmission Operator
Totex	Total Expenditure
TRIFR	Total Recordable Injury Frequency Rate
TRU	RPI True Up (TO)
TSO	Transmission System Operator
TSS	Transportation Support Services
UAG	Unaccounted for Gas
UKCS	United Kingdom Continental Shelf
UKOPA	United Kingdom Onshore Operators Association
UNC	Unified Network Code
VSD	Variable Speed Drive
WACC	Weighted Average Cost of Capital
WAN	Wide Area Network

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