GAS TRANSMISSION

ASSET MANAGEMENT PLAN 2017 UPDATE

First Gas Limited
September 2017

FOREWORD

Dear Stakeholders

Welcome to First Gas Limited's gas transmission Asset Management Plan update (AMP) for 2017.

This year we have elected to provide an update to our 2016 AMP, highlighting the material changes to our network since the publication of our formal disclosure. We have also taken the opportunity to reflect on our achievements over the last year and our priorities moving forward.

2016 was a significant year for our company, as we brought together the two transmission pipelines into one consolidated transmission business. We have safely delivered a major capital expenditure programme and undertaken significant work with the Gas Industry Company and stakeholders to progress a single access code for the transmission network. We have also realigned our business structure and processes, to enable us to deliver on our company's strategy of being a leading provider of safe, secure and reliable gas transmission services.

The coming year will see our business develop further, and is the first year of our recently reset default price-quality path (DPP). We have engaged proactively with the Commerce Commission and stakeholders over recent months to explain the value provided from our planned expenditure levels in managing the risk profile of our transmission network. We consider that the Commission's decisions on regulated revenue for the next five years strike a good balance that allows us to get on with the work that is required. We appreciate the constructive engagement we have had with the Commission and our customers during the DPP consultation process.

In 2017/18, we will continue our focus on the safe and efficient delivery of projects that increase the resilience of the gas transmission system for the future. We will be undertaking several significant projects to improve the physical security of the network, including realignment work at Gilbert Stream to address coastal erosion.

This project is a pre-cursor to the larger White Cliffs remediation project to be undertaken over 2021 – 2022, where we will be realigning both the Maui and non-Maui transmission lines. We intend to apply for a customised price-quality path (CPP) for this project, and will work with the Commerce Commission to strike the right balance between cost and certainty for this work.

We have taken on board your feedback about what you would like to see in our AMPs and what information about our transmission network is important and of value to you. We have sought to simplify the information contained in this AMP update and highlight the material areas of interest, while also meeting our regulatory obligations. We would welcome your feedback on this approach and intend to continue our regular engagement with our customers and stakeholders throughout the year.

We look forward to continuing to work with you over the coming year.

Paul Goodeve
Chief Executive

GLOSSARY

TERM	DEFINITION
AMP	Asset Management Plan
Capex	Capital expenditure – expenditure used to create new assets or upgrade physical assets in the network
Commission	Commerce Commission
CPP	Customised Price-Quality Path
DMS	Document management system
DP	Delivery point
DPP	Default Price-Quality Path
FEED	Front end engineering design
FY18	Financial year ending 30 September 2018
GIS	Geographical information system
GTB	Gas transmission business
HDD	Horizontal directional drilling
HSE	Health, Safety and Environment
ID	Information disclosure – requirements set by the Commerce Commission
Line pack	Amount of gas in the pipeline

TERM	DEFINITION
MAOP	Maximum Allowable Operating Pressure
MGUG	Major Gas Users Group
MPOC	Maui Pipeline Operating Code
OATIS	Open Access Transmission Information System
Opex	Operational expenditure – the ongoing costs directly associated with running the gas transmission system.
PIG	Pipeline inspection gauge tool
Pigging	A method of internally inspecting, cleaning or gauging a high-pressure pipeline, normally while in service to obtain information on pipeline condition
PJ	Petajoule, a unit of energy
RTE	Response time to emergencies
SCADA	Supervisory control and data acquisition
VTC	Vector Transmission Code
HDD	Horizontal directional drilling
HSE	Health, Safety and Environment

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1. INTRODUCTION

This document updates the Gas Transmission Asset Management Plan (AMP)[1] released by First Gas Limited (First Gas) on 1 October 2016.

The 2016 AMP was our first formal asset management disclosure since we purchased the gas transmission assets of Vector Limited and Maui Development Limited in April and June 2016, respectively. This update expands on our first AMP and outlines the material changes that have been made to our asset management plans over the past 12 months.

This section outlines the purpose of First Gas' AMP update, provides an overview of our gas transmission system, and outlines the key changes in the regulatory and external environment impacting on our gas transmission business.

1.1 PURPOSE OF THE AMP UPDATE

This AMP update focuses on the material changes influencing our planned expenditure and the risk profile of our gas transmission business over the coming years. We also see this AMP update as an important planning tool for our operational (Opex) and capital expenditure (Capex) over the next ten years. While priorities may change over the planning period, we think it essential that we clearly outline our plans for the network, while maintaining flexibility to adapt as the year progresses.

In addition, we are using this opportunity to update all our stakeholders on our progress against the 2016 AMP and to outline our key areas of focus for the year ahead. We see the release of this document as one part of our ongoing engagement with our stakeholders and customers, and it provides an important way in which our customers can evaluate the value being delivered by our capital programme.

AMP update aligned with regulatory requirements

The material disclosed in this AMP update meets the requirements set out in the Commerce Commission's Gas Transmission Information Disclosure Determination 2012 (ID Determination).[2] As specified in clause 2.6.5, our AMP update must:

1) *"Relate to the **gas transmission services** supplied by the GTB;*
2) *Identify any material changes to the **network** development plans disclosed in the last **AMP** under clause 14 of Attachment A[3] or in the last **AMP update** disclosed under this clause;*
3) *Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last **AMP** pursuant to clause 15 of Attachment A or in the last **AMP update** disclosed under this clause;*
4) *Provide the reasons for any material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b;*
5) *Provide an assessment of transmission capacity as set out in clause 8 of Attachment A;*
6) *Identify any material changes related to the legislative requirements as set out in clause 3.6 of Attachment A;*
7) *Identify any changes to the asset management practices of the GTB that would affect a Schedule 13 Report on Asset Management Maturity disclosure; and*
8) *Contain the information set out in the schedules described in clause 2.6.6 [Schedules 11a, 11b, 12a and 12b]."*

For a complete understanding of the basis for our asset management decisions over the planning period, we recommend that this AMP update be read in conjunction with our 2016 AMP.

Period covered by AMP update

First Gas' AMP update covers the ten-year period, from 1 October 2017 through to 30 September 2027 (the planning period) and incorporates both the Maui and non-Maui transmission pipelines and associated assets (compression stations, metering equipment etc.).

First Gas follows a 1 October to 30 September financial year and all regulatory, asset management and financial reporting is carried out on this basis. All First Gas' expenditure forecasts and planned projects over the ten-year planning period are based on our analysis of our customer, system and asset information.

The First Gas AMP update was approved by our Board of Directors on 6 September 2017. We will prepare a full AMP for both our gas transmission and distribution businesses next year, for publication in September 2018.

1. Gas Transmission Asset Management Plan 2016, First Gas Limited, http://firstgas.co.nz/wp-content/uploads/FGL_transmission_2016_asset_management_plan.pdf
2. Clauses 2.6.3 to 2.6.5, Gas Transmission Information Disclosure Determination 2012 (consolidated in 2015) – 24 March 2015, Commerce Commission, http://www.comcom.govt.nz/regulated-industries/gas-pipelines/key-information-gas/.
3. Attachment A of the ID Determination addresses the mandatory disclosure requirements with respect to AMPs.

Structure of the AMP update

Our 2017 AMP update includes the following information:

Section 1	Introduction – Update on the gas transmission network – Changes in regulatory and external factors
Section 2	The year in review (1 October 2016 to 30 September 2017) – Comparisons against the 2016 AMP – Significant projects and achievements
Section 3	The year ahead for gas transmission – Significant projects and initiatives
Section 4	Engagement with stakeholders
Section 5	Updates to Capex and Opex forecasts
Appendices	– Summary table of material changes – Information disclosure schedules – Capacity disclosure – Director certificate

For background information on our gas transmission business, please refer to our 2016 Gas Transmission Asset Management Plan which can be accessed on our website **here**.

For information on our gas distribution business, please refer to our 2017 Gas Distribution AMP update and our 2016 Gas Distribution AMP, which can be accessed on our website **here**.

1.2 OUR GAS TRANSMISSION SYSTEM

The First Gas transmission system incorporates both the Maui and non-Maui[4] transmission pipelines across the North Island, as set out in Figure 1 below. The transmission system is 2,523 km in length, with approximately 103 km installed in urban areas and the remainder in rural areas. The nominal internal diameter of the pipelines ranges from 50mm to 850mm, with the majority installed below ground.

The key statistics for the gas transmission system as of 30 June 2017, are set out in Table 1.

The key changes in the gas transmission system since the 2016 AMP relate to the construction and commissioning of Henderson Compressor station (see section 2.3 below).

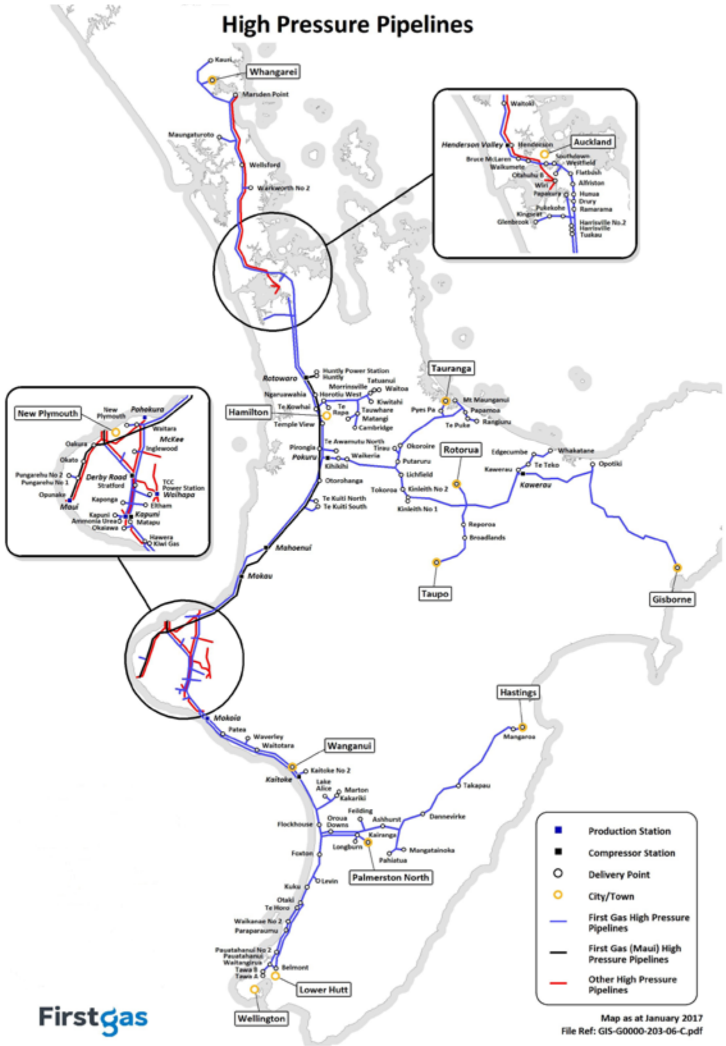
For a full overview of the gas transmission system, please refer to section 3 of our 2016 AMP.

Table 1: Key transmission statistics (30 June 2017)

STATISTIC	VALUE	CHANGE FROM 2016[5]
System length (km)	2,523 km	0
Compressor stations	9	0
Compressor units	24	+1
Delivery points	119	0

4. The gas transmission system purchased off Vector Limited in April 2016.
5. Compared to 30 June 2016 statistics provided in the 2016 AMP.

Figure 1: High pressure gas transmission pipelines



1.3 CHANGES IN REGULATORY AND EXTERNAL ENVIRONMENT

This section provides an overview of the changes in the regulatory environment following the recent reset of the Default Price-Quality Path (DPP) for our gas transmission business. We also discuss the heightened focus on infrastructure resilience, following the 2016 Kaikoura earthquake, and the impact of urban encroachment on our transmission network.

Reset of Default Price-Quality Path

On the 31 May 2017, the Commerce Commission published its final decisions[6] to reset the prices and quality standards for gas pipeline businesses for the period from 1 October 2017 to 30 September 2022. Table 2 summarises the key decisions from the 2017 – 2022 DPP reset.

Table 2: Key decisions from DPP reset

ITEM	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	TOTAL
Maximum allowable revenue for transmission ($million)	122	124	126	129	132	**655**
Opex ($million)	43.6	42.8	42.5	41.8	41.8	**212.5**
Capex ($million)	41.9	30.3	24.9	24.7	21.4	**143.2**

The Commission's final DPP decision equates to a 10% reduction in revenue for our gas transmission business. The Commission approved most of our forecast Capex and Opex expenditure for our gas transmission business, with only the White Cliffs remediation project expenditure excluded from the final DPP decision and forecast compressor fuel at Mokau (which is treated as a recoverable cost). The Commission felt that the scale of our White Cliffs remediation project was more suited to scrutiny via a customised price-quality path (CPP) application. We outline our intention to prepare a CPP application in section 3.2.

6. The Commerce Commission's final decision can be found on its website here: http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/

The level of expenditure approved by the Commission for the next five years shows:

- A heightened level of capex in the first two years, recognising the need to address near-term security and reliability risks (i.e. assessing and rectifying geo-hazard risks); and
- The step-down in opex from FY17 to FY18 reflects the efficiencies and forecasted costs of operating the network in 2016 AMP.

The final DPP reset decision provides First Gas with certainty of funding for our activities over the next five years (except for funding for White Cliffs), and will enable First Gas to plan and prioritise activities to ensure the level of service is maintained throughout the planning period.

It is important to note that the DPP reset decision does not dictate how regulated businesses will spend the money. While the DPP is based on forecast of category-level expenditure, First Gas can and will reallocate its resources to respond to changes within the regulatory period. These actual decisions around funding against the forecast levels in the AMP will be disclosed to stakeholders and customers via our annual information disclosure.

Other key decisions from DPP reset

Alongside the reset of prices, the Commission has also:

- Introduced a **new quality standard, relating to major interruptions**, as defined through the existing Critical Contingency Regulations; and
- Maintained the **existing quality standard** relating to Response Time to Emergencies (RTE).

While the new quality standard introduces a new potential cost for our transmission business in the event of a major interruption,[7] we consider that the new regulatory requirement does not change how we operate our transmission network. We remain committed to avoiding outages, in line with our customers' expectations and the requirements of AS/NZ Standard 2885.

7. For example, a breach of the new quality standard could see First Gas subject to fines under s87 of the Commerce Act 1986.

Learnings from robust assessment process

The Commission's DPP reset decisions were informed by a robust assessment of the First Gas' 2016 AMP, supplemented by requests for additional information from First Gas during the consultation process.[8] We consider that the process helped to test our areas of planned expenditure and improve how we explain our plans for the gas transmission network. These learnings will be reflected in future disclosures and stakeholder engagement.

Increased focus on infrastructure resilience

Following the Kaikoura earthquake in November 2016, there has been heightened focus on infrastructure resilience from both government and individual infrastructure businesses. First Gas has engaged with the Ministry of Business, Innovation and Employment over recent months to provide input into the Ministry's work on earthquake preparedness and response planning for energy services in Wellington. We provided information on our plans over the short to medium term to reduce our vulnerability to interruptions on our gas transmission system from an earthquake. We also outlined measures such as the degree of looped lines in the Wellington region and the initiatives underway to improve the resilience of the Wellington network.

First Gas is also facing an increase in our insurance costs. The increase reflects numerous market conditions, including consideration of earthquake risk and replacement value of our regulated assets.

To assist with infrastructure resilience, First Gas has also purchased additional hot tap and stopple equipment, and a range of emergency fittings. As outlined in section 2.4, this equipment will enable us to respond more promptly to emergencies on our high-pressure gas pipelines.

8. For further information on the consultation process followed for the DPP reset, and First Gas' submissions, please visit the Commerce Commission's website – http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/

Urban encroachment on our transmission network

Over the last 30 – 40 years, population centres have grown significantly, most notably around Auckland and Wellington. This has placed infrastructure and properties ever closer to our high pressure gas transmission assets. Subsequently, First Gas must be increasingly more vigilant about planned development works within a proximity of our transmission pipelines and stations, and to regularly assess the impact of this encroachment. First Gas are required to identify these new risks quickly and react, to manage this changing risk level.

It is frequently necessary to apply mitigation measures to First Gas assets, to reduce the likelihood of a gas emergency event. This requirement is prescribed in our operating standard (i.e. AS/NZS 2885), where we seek a risk level described "As Low as Reasonably Practicable" (ALARP). Potential measures to mitigate these risks include:

- Relocating the asset away from the identified risk;
- Concrete slab protection to reduce the likelihood of third party damage;
- Installing vehicle protection around stations to reduce the likelihood of damage from vehicle collisions;
- Increased patrolling by field staff and over line flying to reduce potential third party damage; and
- Increased signage to promote awareness of the location of First Gas assets.

There is also an increasing need to invest in other schemes to control the risk level impacted on by urban sprawl. These costs are frequently not recoverable from parties who create the problem, but will increase the overall First Gas operating costs. As these risks are identified and mitigation actions developed, the cost impact will be identified in the annual AMPs.

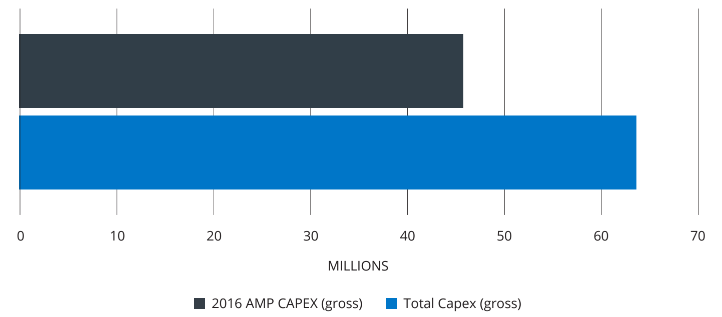
2. YEAR IN REVIEW

This section provides an overview of First Gas' major projects and initiatives over the past year ending 30 September 2017. We also review our forecast expenditure against the plans stated in our 2016 AMP, and discuss the variances in activities undertaken.

2.1 EXPENDITURE SUMMARY

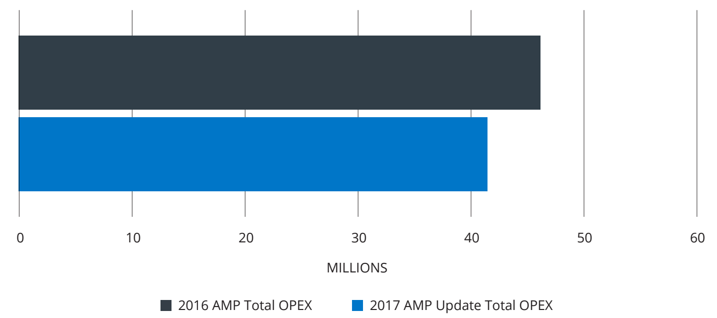
Figure 2 outlines our actual expenditure for the year ended 30 September 2017 and compares actual expenditures to the forecasts presented in our 2016 AMP. Not all project capex costs shown will be commissioned during FY17 and added to the regulatory asset base (RAB) in the current year.[9]

Figure 2: Expenditure in 2016/17 versus forecast expenditure in 2016 AMP



Major capex variances relate to:
- Mokau compressor station upgrade
- Procurement of emergency hot tapping equipment
- Replacement of obsolete metering assets
- Upgrading of the Kaitoke compressor station control systems and gas cooler within FY17 and FY18

9. The expenditure in these graphs has not been audited. The final audited figures will be disclosed in our Information Disclosure.



Major opex variances relate to:
- Extensive refurbishment of assets, rather than maintenance (re-categorisation of opex works to capex) e.g. major compressor overhauls
- Asbestos removal programme cost less than planned
- Optimised aerial surveillance monitoring

2.2. SIGNIFICANT PROJECTS

The last year has been a significant year as we have established the First Gas business, delivered a significant capital works programme and established separate IT systems to support the business going forward. Table 3 outlines the most significant projects that were delivered during the last year.

Most of these projects were identified in our 2016 AMP, with the scope and justification provided for each project. However, three additional projects were added to First Gas' work plan during the year. These additional projects were required to mitigate an identified business or compliance risk associated with the security of the gas network and provided improvements to the systems overall efficiency.

We discuss these projects below, as well as the work on developing a single transmission access code (section 2.6) and the information technology initiatives (section 2.7) completed to support our gas transmission business.

Table 3: Significant projects completed in 2016/17

SIGNIFICANT PROJECTS		
Commissioning of Henderson Compressor Station and new Marsden Point delivery point (section 2.3)	$10 million	In 2016 AMP
Increasing resilience of the network (section 2.4):	43.6	
– Installation of pigging facility on Wellington pipeline	$1.5 million	
– Mitigation of geo-hazard risk at Mangatea Road	$1 million	
– FEED review for White Cliffs remediation project	$0.4 million[10]	
– Scoping study for Gilbert Stream remediation project	$0.3 million	
Independent IT systems (section 2.7)	$3.9 million	
Increasing resilience of the network (section 2.4):		Not signalled in 2016 AMP
– Purchase of additional emergency hot tapping equipment	$3.9 million	
– Replacement of Kaitoke pneumatic station and compressor control systems[11]	$1.8 million	
Increasing resilience of the network (section 2.4):		
– Installation of compressor dry seals and re wheeling of Mokau compressor station	$5.5 million	

10. Most of this expenditure in FY17 was OPEX.
11. This was in the 2016 AMP, but we have altered the timing of this project.

2.3. COMMISSIONING OF THE HENDERSON COMPRESSOR STATION AND MARSDEN POINT DELIVERY POINT

The construction and commissioning of the Henderson Compressor station[12], and the associated new delivery point at Marsden, in June 2017 was a significant development for the gas transmission business. This was the largest gas infrastructure upgrade project undertaken by First Gas (or its predecessors) in the last decade, at a total cost of $20 million.

The project was driven by the New Zealand Refining Company's requirement for significantly higher volumes of gas at their Marsden Point site. The project also provides broader benefits, increasing the overall capacity of the transmission system for all consumers north of greater Auckland.

The project was delivered well within budget and on schedule, enabling the customer to commence nominating higher gas volumes to its plant. First Gas also fully upgraded the Marsden Point delivery point that is located adjacent to the customer's site, within the same timeframe as the compressor station.

▲ *An aerial view of the newly commissioned Henderson Compressor station*

12. See sections 6.9 and 8.4 of the gas transmission 2016 AMP.

The Henderson compressor station uses electric drive compressors. The choice of this technology minimises disturbance to neighbours and efficiently meets the resource consent conditions of the site.

A view inside of Henderson Compressor shed.

2.4. INCREASING THE RESILIENCE OF THE NETWORK

A significant number of projects undertaken over the last year relate to increasing the resilience of the transmission network, and ensuring a secure supply of gas for our customers.

Installation of pigging facility on Wellington pipeline

First Gas has successfully designed and installed a pigging facility at the Tawa end of the Wellington high pressure supply pipeline, to enable the 8 kilometre pipeline to be internally inspected.[13] This project has been identified in previous AMPs. We identified this project as a significant priority for the business, to both mitigate security of supply risk to Wellington, as well as facilitating growth within the region.

The Wellington pipeline from Waitangirua to Tawa operates at a pressure of approximately 20 bar, which restricts the available operational capacity to central Wellington. Historic surveys of the pipeline have identified several coating defects along the entire length of the pipeline. However, the inability to internally "pig" this pipeline in prior years[14] had left our business unable to ascertain whether the known coating damage has led to any pipeline corrosion defects.

With the successful installation of this pigging facility, First Gas will be able to carry out an inspection of the line in FY2018. This inspection will enable us to understand the pipeline's overall condition and identify any repair work required for future years. We intend to inspect the pipeline internally on a regular basis to ensure it remains fit for purpose. Further projects will be initiated to operate the pipeline at a higher pressure to increase available capacity for potential Wellington consumers.

Mitigation of geo-hazard risk at Mangatea Road

As signalled in the 2016 AMP, First Gas has placed considerable priority on undertaking a more active programme of geo-hazard assessment and remediation, which is essential to ensuring a resilient gas transmission network. This has involved establishing a 10-year activity schedule of work, which categorises each area of the network based on geo-hazard risk.

13. See section 6.7.1 of the gas transmission 2016 AMP.
14. This pipeline runs through a largely residential area.

We have recently completed work north of Mokau, to mitigate the risk of a section of pipeline being over stressed by ground movement. Our recent geo-hazard survey programme identified a significant potential risk to the 200-mm diameter high pressure pipeline in Mangatea Road.[15] There was a large amount of recorded ground movement, raising concerns that it had placed undue stress on the pipeline, compared to the standard prescribed stress limit.

To address this risk, First Gas excavated a considerable length of the pipeline to allow the pipeline to be de-stressed from ground movement. Once satisfied the pipeline movement was stabilised, we then also completed repairs to the pipeline coating and carefully re-buried the pipeline. A considerable amount of ground drainage was installed to slow down any future ground movement that would impact the pipeline and the site was re-contoured to allow the landowner to continue to use the surrounding area for livestock grazing.

Purchase of additional emergency equipment

First Gas has recently procured 350mm, 750mm, 850mm (14-inch, 30-inch and 34 inch) hot tap and stopple equipment, and a range of emergency fittings. This will enable us to respond more promptly to emergencies on our high-pressure gas pipelines, ensure more resilient infrastructure[16] and undertake work across the range of pipeline diameters found within our network.

We currently own and regularly use hot tap and stopple equipment when undertaking commissioning and decommissioning work on our network. However, this current equipment is only suitable for pipeline sizes up to and including 300mm (12-inch) diameter. First Gas owns and operates significant lengths of pipeline assets that are 350mm, 750mm, 850mm (14-inch, 30-inch and 34-inch) diameter, which require regular work. In coming years, we will also be commencing works at Gilbert Stream and White Cliffs (both areas with 750 mm pipeline diameters).

Hot tapping equipment

Purchasing the additional hot tap and stopple equipment and emergency fittings enables us to:

- undertake the commissioning/decommissioning work across our network; and
- mobilise faster in the event of a gas supply emergency on any size pipeline and undertake quicker repairs where needed.

Given the projects planned for the next five years which will require this equipment, we consider that the payback on the purchase price on these items is short and the benefits of greater resilience accrue immediately.

Without this emergency equipment, we would be reliant on sourcing the required tools from the world-wide market and transporting it to New Zealand. Based on our experience, sourcing such equipment can take several weeks, compared to the few days required to mobilise the tools we own within the North Island.

15. See section 6.7.1 of the gas transmission 2016 AMP.
16. A point highlighted by the 2016 Kaikoura earthquakes and discussed in section 1.3 above.

Replacement of Kaitoke station compressor control system

First Gas has substantially completed the replacement of the pneumatic station and compressor control systems at the Kaitoke station near Whanganui. This project is part of our ongoing programme of replacement for obsolete pneumatic control systems on compressors in the overall fleet, with completion of this work expected within the next year.

In our 2016 AMP, we planned to upgrade the pneumatic control system on a compressor located at the Mahoenui Station. However, following an asset investment risk review that considered the reducing operating hours of the Mahoenui compressors, it was determined that resources should be prioritised to the Kaitoke station. The Kaitoke system is critical for gas supply security to Wellington during winter and is similar of age to the Mahoenui equipment.

An example of a compressor control system

2.5. INCREASING THE EFFICIENCY OF OPERATIONS

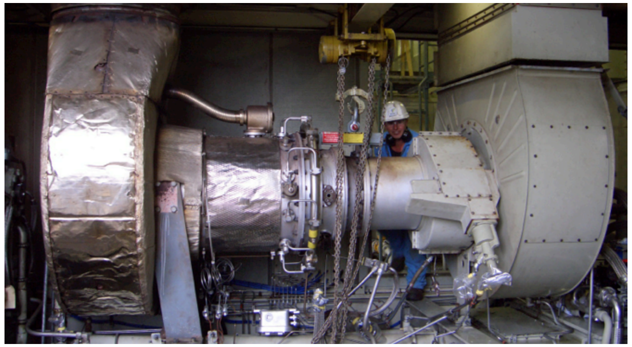
With First Gas owning and operating the entire gas transmission system, we are now able to consider how the whole system is operated. This enables us to consider new options for system compression, line pack management and flow directions. Thus, we have new opportunities to optimise the overall system to improve system security, reduce the risk of critical contingencies being triggered, reduce maintenance requirements and operate the system in the most efficient manner.

Compressor strategy to optimise efficiency

A key initiative in the last year has been the deployment of our new compressor operation strategy that seeks to:

- Improve the efficiency of how we operate the compressors, while reducing the overall operational and maintenance costs of compression; and
- Increase the ability of the transmission pipeline to cope with unplanned production station outages, and therefore reduce the risk of critical contingencies.

From 26 December 2016, First Gas increased the linepack in the Maui Pipeline and has been using the Mokau compressor continuously, with the support of other strategic compressor sites. To prevent a build-up of gas north of Mokau, from 18 January 2017, the quantity of gas flowing through Pokuru 1 (off the Maui Pipeline) has also been increased, while the flow through Pokuru 2 (off the 200 pipeline) has decreased by an equal amount. First Gas made consequential changes to how it implements the Kapuni to Pokuru 2 transmission service, which we still provide to shippers.



Turbine package

This new compressor strategy utilising a higher level of linepack enables First Gas to minimise the risk of critical contingencies, while also providing better performance in the management of pressure within the target range for the south section of the Maui pipeline. We also continue to meet our RPO obligations to transport gas consistent with the linepack and pressure limits defined in the Maui Pipeline Operating Code (MPOC) and in accordance with the Vector Transmission Code (VTC).

We note that there have been a couple of production station trips this year, that we believe would have caused issues had we not been operating the transmission network under the new compressor strategy. Further work is required on our procedural processes to support the new compressor strategy, to further improve efficiency.

Compressor upgrade programme

Due to the pivotal role of Mokau under the new compressor strategy and the change in daily flow profiles experienced, the Mokau compressors have been re-wheeled to deliver a higher outlet supply pressure, with the same inlet pressure. This project was not identified in the 2016 AMP, but was prioritised during the year when we realised the supply security improvements that were achievable.

First Gas has also installed “dry gas” seals on the Mokau compressors. The original “wet gas” oil seal system installed at the compressor system was obsolete, and created operational challenges. The new “dry seals” achieve the same objectives as the “wet seals”, while reducing the ongoing maintenance issues with the seals.

Several other associated compressor upgrade projects have also been completed at the same time to increase reliability and optimise efficiency of the transmission system further.

Learnings from critical contingency event

Even though First Gas has been operating the transmission system with higher linepack since December 2016, a critical contingency event did occur on 23 May 2017. This event resulted from the combination of a production station outage at a time when the transmission linepack was already depleted by shipper imbalances. First Gas has undertaken a review of the critical contingency event and has identified a series of recommendations around actions we can take as the transmission system operator to minimise the chance of reoccurrence of such an event.[17]

17. For full information on the 23 May 2017 critical contingency event, please visit the Gas Industry Company website - http://www.gasindustry.co.nz/work-programmes/critical-contingency-management/cc-events/system-imbalance-event-may-2017/

2.6. DEVELOPING A SINGLE TRANSMISSION ACCESS CODE

With the two gas transmission systems now under First Gas ownership, we have embarked on a significant programme of work to replace the MPOC and VTC with a single new access code to cover the entire gas transmission system. We consider that a single access regime will make it easier and simpler for current and future shippers to use the gas transmission system, provide a consistent approach across the entire system and be simpler to implement.

We are working in partnership with the Gas Industry Company (GIC) and in close consultation with the industry to develop a single access code that can come into effect from 1 October 2018. We are seeking to establish new access and pricing terms that will:

- Enable the use of gas;
- Minimise the cost of transporting gas;
- Keep it simple;
- Promote flexibility; and
- Increase transparency.

We have run a robust consultation process with the industry since late 2016, where we have scoped the parameters for a single code, discussed a range of possible access products and code features, before moving into more detailed design. Figure 6 below outlines the key programme milestones over the last year.

Figure 6: Development of a single transmission access code

TIMING	STAGE	CONTENT AND OUTPUTS
October 2016 – February 2017	Scope possible options	Describe high-level options for new code
March – August 2017	Detailed design working papers and IT procurement	Work through detailed proposals for main elements of code (code exposure drafts and working papers): – Code governance – Access products – Pricing methodology – Balancing and allocation – Technical requirements (metering, gas quality)

With support from the GIC and many industry players, we are pursuing a single transmission access code that will include Daily Nominated Capacity as the principal access product, and Priority Rights that offer increased firmness in parts of the system that might face congestion.

In section 3.9, we outline the plans for finalising the code and detailed drafting, as well as implementing a new IT platform to support the operation of the transmission system. For background information on the development of a single transmission access code, please visit the Gas Industry Company website **here**.

2.7. IMPLEMENTING SEPARATE IT SYSTEMS

Over the last 12 months, First Gas has focused on transitioning from the previous owners' Information Technology (IT) systems to our own separate IT systems.

These new systems, along with new business processes, are helping us better understand the performance of our assets, optimise maintenance to maximise asset life and improve our overall management of risk.

The key IT-related milestones are outlined in Table 4 below.

Table 4: IT projects during 2016/17

Kapua data centre commissioned	The First Gas infrastructure has been successfully migrated from the temporary cloud service onto our own hardware.
Main office infrastructure	The infrastructure at our main office in Bell Block has been upgraded to support our gas transmission systems, incorporating increased storage, new switches and an upgrade to a virtual environment platform.
Telephony	Skype for Business has been installed as a cost effective telephony solution for all First Gas offices. We have implemented inter-site resiliency measures to ensure call and instant messaging functionally functionality can be delivered during a Wireless Area Network (WAN) failure.
Single platform for GIS	First Gas has migrated all transmission and distribution GIS information onto a single platform, ESRI ArcGIS.
Desktop hardware lifecycle	We have implemented a desktop hardware lifecycle of 3 years to keep all desktop hardware under a current warranty. We have replaced 70 desktops this year, including an upgrade to the Windows 10 operating system.
Extension of OATIS	First Gas has approved a "life extension" project to upgrade the current OATIS solution to a supported architecture. This will provide us with time to develop a more comprehensive OATIS replacement, as required through the development of the single transmission access code (see section 3.9).
Data warehouse and business intelligence	First Gas is consolidating its two existing data warehouse environments (inherited from previous owners) into a single data warehouse. This is in line with industry best practice and will deliver a scalable and maintainable data warehouse, with a single source of truth for business intelligence and reporting.
Risk review of information systems	Following a security and risk review of our information services, First Gas has made improvements to internet access, removeable media control, system updates and patching, mobile device management, administrative accounts, quality of the server and network rooms, and data recovery.
Land management information	First Gas is implementing a new database product for all its Land Management information. The new product selected is used by most high-pressure pipeline owners and utility businesses in Australia, and includes a range of improved features such as a core database, customisable map viewer and field-based data capture.

3. YEAR AHEAD FOR TRANSMISSION

This section sets out the areas of focus for First Gas over the coming year commencing on 1 October 2017, the first year of the DPP reset for FY18 – FY22. We have established a good understanding of our gas transmission business over the last year and are now embarking on several significant projects in 2017/18, as set out in Table 5.

Table 5: Significant transmission projects for year commencing 1 October 2017

SIGNIFICANT PROJECTS FOR GAS TRANSMISSION BUSINESS	
Gilbert Stream realignment project (section 3.1)	$3.2 million
White Cliffs remediation project (section 3.2)	$2.5 million
Cooler replacement at the Kapuni gas treatment plant (section 3.3)	$0.8 million
Recoating sections of the 100 line to extend asset life (section 3.4)	$2.4 million
Realignment of the Turakina pipeline to address river bank erosion (section 3.5)	$1.2 million
Replacement of Grove 80 regulators (section 3.6)	$2.0 million

These projects were identified in the 2016 AMP, and except for the White Cliffs remediation project, all project expenditure is included within the DPP reset for the next five years. We outline each of these projects below, along with our work on geo-hazard risk assessment and remediation, establishment of a risk management system, implementation of a single transmission access code and the continued improvements to our IT systems. We intend to commence all projects early in the 2017/18 year.

The above projects represent almost 25% of the overall capex programme for FY17. The remaining capex projects consist of work scopes to address geo-hazard risks, asset replacement of obsolete and life expired equipment, further IT upgrades and growth projects to support current and future customer requirements.

3.1 GILBERT STREAM REALIGNMENT PROJECT

The Gilbert Stream realignment project[18] is a priority for First Gas, with coastal erosion now within 10 metres of the 750mm (30-inch) high pressure pipeline at Gilbert Stream.

We have completed significant preparatory work – we have completed the FEED work, completed the emergency response plan and are commencing detailed design work. We have worked closely with the Commerce Commission to ensure the expenditure for the project is covered by the DPP. Work is planned for 2017 – 2019, following the consenting, detailed design and procurement phases of the project.

This picture illustrates the proximity of the pipeline to the coastal erosion.

18. See section 6.2.2 of the gas transmission 2016 AMP.

We continue to regularly monitor the site and have developed an emergency response plan, which involved the urgent ordering of emergency hot tap and stoppling equipment and fittings last year. Should the coastal erosion reach a prescribed proximity limit, we intend to immediately install gas bypass pipework to protect against a loss of supply event.

The Gilbert Stream realignment project provides First Gas with a good opportunity to optimise our project planning and communications, prior to embarking on the White Cliffs remediation project.

3.2. WHITE CLIFFS REMEDIATION PROJECT

First Gas intends to commence the next stages of the White Cliff remediation project[19] in the coming year, with the intention to apply to the Commission for a CPP in late 2018 and commence on-site construction during 2019/20. The completion date for this project has been brought forward to FY21 (previously FY23) to address the change in risk levels, with greater erosion experienced on site. UAV surveys of the area are being conducted at 3 monthly intervals to monitor any change in the area.

The White Cliffs project involves the realignment of both high-pressure pipelines at White Cliffs, Taranaki (the 750 mm diameter (30-inch) Maui pipeline and adjacent 200mm diameter (8-inch) pipeline that is part of the non-Maui system). These two pipelines are impacted by ongoing coastal erosion that threatens to eventually expose the pipelines, which supply gas across the North Island. The project has been discussed extensively in previous AMPs and has been subject of much discussion with the Commission and stakeholders.

We have completed the initial project options phase. We have identified several options and will begin working with stakeholders and affected land owners to proceed to completion of the FEED study, consenting, detailed design and execution.

We regularly monitor the coastal erosion to review the risk level, and emergency hot tapping and stoppling equipment and fittings have been procured over the last year to allow faster emergency response if needed (see section 2.4).

Figure 7: Bank erosion at White Cliffs site

Figure 8: Current location of transmission pipelines at White Cliffs

The photo highlights the proximity of the coastal erosion to the First Gas pipelines in the White Cliffs area.

19. See section 6.2.2 of the gas transmission 2016 AMP.

Preparing for a CPP

As outlined above, the expenditure for the White Cliffs remediation project will need to be sought via a CPP. First Gas intends to prepare a CPP application for submission to Commission in late 2018, with intention of the CPP taking effect from 1 October 2019.

First Gas has included an allowance of $1.5 million for our estimated costs of preparing a CPP application and meeting the consultation and verification requirements to obtain funding approval for the White Cliffs project. This expenditure is phased over 2017/18 and 2018/19.

We have begun discussions with Commission staff about the scope of our CPP and the process for applying. These discussions include whether the standard requirements for a CPP can be modified to help manage the costs and risks of an application, given the project-specific nature of our application. We will also continue discussion with our customers throughout the CPP preparation process, through regular engagement with groups such as MGUG and through the formal consultation requirements set out by the Commission.

3.3. COOLER REPLACEMENT AT THE KAPUNI GAS TREATMENT PLANT

First Gas will be replacing two coolers within the Kapuni gas treatment plant to address damage caused by corrosion, which if left unchecked could impact on security of supply.

We currently own and operate 3 gas reciprocating engine-driven compressors at the Kapuni plant in South Taranaki. One of the coolers was replaced in 2013, but the remaining two coolers are now approaching end of their life. Their efficiency has reduced to a point where they are unlikely to limit the compressor outlet gas temperature to an acceptable standard on hot days. Excessive outlet temperatures have the potential to heat the downstream pipeline to the point where its external coating disbonds, allowing subsequent corrosion defects to form.

We intend to replace one cooler in 2017/18 and the second in the following year, to avoid the above issue escalating.

3.4. RECOATING OF THE 100 LINE

First Gas will be recoating sections of the 100 pipeline, which runs from the Kapuni gas treatment plant to Wellington, to extend the life of this asset.

Following cathodic protection checks, the original coal tar enamel coating of the 250 kilometre pipeline has been found to have disbonded over several sections of the pipeline. The pipeline coating system, combined with the cathodic protection system is essential to prevent external corrosion defects forming on the pipeline surface.

First Gas plans to excavate pipeline sections where the coating is in the greatest need of repair, and recoat the pipe with a paint and wrap system. This will enable us to avoid replacing long pipeline sections, which would involve much greater cost. This chosen solution therefore allows the life of the asset to be extended more efficiently.

The photo above is an example of recoating work being conducted on First Gas assets.

We will monitor corrosion defects on this pipeline using internal pigging surveys to ensure the integrity of the pipeline is not compromised and worsening defects are excavated and repaired when they are identified and evaluated. Repairing urgent corrosion defects does have the potential to reduce system capacity in the short term, while we address the repairs. This risk is managed by carrying out live gas repair work and where necessary, keeping operational repair timeframes to a minimum where these require a reduction in pipeline pressure.

3.5 REALIGNMENT OF THE TURAKINA PIPELINE

We will be realigning the 100 pipeline at Turakina (near Whanganui) next year, to address river bank erosion which is threatening the security of supply along this section of the pipeline.

River bank erosion regularly creates pipeline problems for gas pipelines, where river banks and sometimes river beds are scoured away over time. At Turakina, the 100 pipeline can be seen exposed in the river bank and initially above the water line heading across the river. Efforts have been made to protect the bank-side with wooden constructed protection, but subsequent erosion behind these temporary solutions has exposed the pipeline further.

To prevent potential damage from debris in the river, the pipeline must be replaced over a significant length. The new section must be installed at a much deeper level under the river bed, by directionally drilling (HDD) well back from the river on either side. HDD drilling under rivers is generally the most environmentally-friendly technique, avoiding river bank and bed damage and negative impacts to wildlife. This approach will avoid the risk of pipeline damage repairs affecting downstream gas consumers.

The photograph above is of the existing Turakina river bank protection.

First Gas continually surveys its pipelines across the country to look out for similar situations where ground erosion reduces the ground cover protection around any pipeline infrastructure. In all such cases, we put mitigation measures in place to manage risk, until permanent repairs can be undertaken.

3.6. REPLACEMENT OF GROVE REGULATORS

First Gas will be replacing 8 Grove regulators at delivery points in 2017/18 and at the remaining delivery points in 2018/19, to reduce the risk of regulator failure and supply disturbances for our customers.

Historically, Grove regulators were installed at most delivery points to reduce pressure to the agreed level for supply to distribution networks and directly connected customers. While these regulators were regularly maintained to ensure reliability, the Grove regulators are now obsolete and the soft parts for them are no longer manufactured.

To address this risk, First Gas purchased a significant number of soft parts for our large population of regulators and established a regulator replacement programme.

We are keen to replace all Grove regulators by 2019/20, when the stock of soft parts is likely to be exhausted. We are currently on track to achieve this target.

In the long-term, First Gas will be moving towards a newer model of regulators, removing the risk around issues with these soft parts.

The photo below is an example of Grove regulators that are being replaced through a program.

3.7 Geo-hazard ASSESSMENT AND REMEDIATION PROGRAMME

As outlined in section 2.4, geo-hazard assessment and remediation[20] is a priority for First Gas. We have a continuing programme of identifying and rectifying geo-hazard risk areas. This involves pipeline specific surveys followed by risk assessment and the identification and prioritising of remediation projects (for example, Mangatea Road work completed over 2016/17).

The costs for this work was estimated in the 2016 AMP, based on historical experience. Although First Gas currently considers these estimates are appropriate, there is a high potential for necessary remediation projects to significantly exceed the historical average costs planned. We will report on these costs as they are identified and disclosed through annual information disclosures.

3.8. MATURING OF OUR RISK MANAGEMENT SYSTEM

This AMP update reflects our continued desire to improve the way we communicate our asset health and what we are doing to maintain a resilient network.

The next step in this maturation of our asset management is to develop a risk management system that evaluates and compare the different risks that the First Gas business is exposed to, and translate that into a single risk profile that will provide an overall asset health indicator. This will also allow First Gas to describe how the annual Capex and Opex programmes are influencing the overall asset health to control risk and describe to customers the potential for these risks to impact overall gas supply. We anticipate undertaking this work over the next two years.

The risk profile of the business will be a dynamic indicator that will need regular review to ensure that we are focusing on continuous improvement and are investing our expenditure in the right areas. We will also be using this information as supporting evidence for our CPP application for the White Cliffs remediation project (see section 3.2).

20. See section H.1 of the gas transmission 2016 AMP.

3.9. IMPLEMENTING A SINGLE ACCESS CODE FOR TRANSMISSION

First Gas intends to replace the MPOC and VTC with a single transmission code and access regime that covers the entire gas transmission system (known as the Gas Transmission Access Code or GTAC). We see significant benefits in allowing our customers to ship gas from source to destination under a single contract, and to enable First Gas to operate the system in a more efficient way.

Our current work plan aims to have the GTAC take effect from 1 October 2018. The initial scoping work for the single code has been undertaken over the last year in partnership with the Gas Industry Company (see section 2.7). First Gas is now completing the detailed drafting and negotiation of new access code terms, and developing an implementation plan for the new code. The key steps in this process are set out in Table 6.

Table 6: Implementation of the single transmission access code

STAGES	TIME FRAME
Drafting and approvals for new code	Now to March 2018
IT system procurement	Now to January 2018
IT system design and implementation	January 2018 to October 2018

As First Gas develops and implements the new code, we will be looking at how:

- The access products under the new code can be given effect through our asset management planning, ensuring that all parties have an adequate and equal understanding of the likelihood of congestion;
- We can provide better information, particularly on transmission system capacities and the prospect of constraints; and
- We provide an IT solution that meets everyone's expectations of a modern, professional transaction management system, with up to date information on system conditions.

Procurement of a new IT system

The new access code will require an IT system that supports the new requirements. The new system will be the main capital element of the GTAC project. We have budgeted up to approximately $6 million for the new system, which includes software purchase and modifications.[21]

First Gas notes that we are not budgeting for significant opex savings resulting from the move to a single transmission access code. Our current view is that the GTAC will enable the most effective processes to allocate and manage transmission system contracts. However, the level of involvement from First Gas teams (for activities such as scheduling and commercial negotiation) will not materially change.

21. This budgeted cost does not include provision for annual software maintenance or licence fees, upgrades later in the software life, or the costs incurred by First Gas during implementation. No contracts have been entered into for the new system.

3.10. CONTINUED IMPROVEMENTS TO IT SYSTEMS

First Gas will be continuing its work programme to establish IT systems to support our transmission business. Embedding these new IT systems will allow us to work more efficiently and improve our business processes. The key IT programmes are outlined in Table 7.

Table 7: IT projects for 2017/18

SCADA upgrade (started in 2016/17)	We will be upgrading our the existing SCADA software to a supported version and replacing the out of warranty hardware. This upgrade will provide supported functionality through to 2023, allowing the business time to develop the details of the next stage of the SCADA roadmap in line with business requirements and direction.
Documents and records management	First Gas has created a new Document Management System (DMS) and will transferring all control documents from the legacy Vector systems and First Gas File Server over to this new DMS.
System integration	Work will be undertaken on First Gas' systems to ensure that all of our systems can integrate, automatically share data and operate as one large system. First Gas uses a modular approach to its system architecture, which means the establishing a robust system integration process is an important element in keeping a common data format. We also want to reduce the need to manually transfer data between systems.

4. ENGAGING WITH STAKEHOLDERS

First Gas recognises the importance of regular engagement with our major gas users and customers who rely on the consistent delivery of large volumes of gas to maintain their ongoing productivity and business. We are focused on establishing regular dialogue with stakeholders throughout the year, in addition to established consultation through workshops and our regulatory obligations. We believe it is important that we get timely feedback to assist us to improve the ongoing transmission services we provide across our networks.

First Gas has prioritised taking part in in regular major gas user group (MGUG) briefings to share our detailed operational plans, over and above that provided in the 2016 Transmission AMP. We have also met with many of our major customers directly to discuss relevant asset issues over the past year. This engagement has uncovered that our major gas users are keen to better understand the linkages between First Gas Capex and Opex and the service levels we deliver, particularly in terms of system risk and reliability. As mentioned in this AMP update, we are working to respond to this request as part of our process to improve our asset management maturity.

We met with several stakeholders during the DPP consultation process in early 2017, to discuss the rationale for our proposed expenditure and how this is necessary for maintaining the risk profile of our network. Our work on the single transmission access code has also enabled up to enter continuous dialogue with shippers as we determine the best access arrangements for our network going forward. We look forward to continuing to engage with our stakeholders are we implement these developments.

Our engagement approach will continue throughout the DPP 2017 – 2022 period, allowing parties to share understanding and focus resources on where they deliver the greatest value. We recognise and understand that major gas users place a high value on gas supply reliability, and we are focused on bringing the overall condition of our assets up to a standard that reflects that value.

5. UPDATES TO CAPEX AND OPEX EXPENDITURE FORECASTS

5.1. CAPEX

The next DPP period FY18 – FY22 is highlighted in bold.

Table 8: 2016 AMP Capex forecast

2016 AMP	FY17	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**	FY23	FY24	FY25	FY26
Consumer Connection	13,025	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
System Growth	1,159	8,832	2,006	2,060	2,000	2,000	2,000	2,000	2,000	2,000
Asset Replacement and Renewal	19,799	32,359	20,022	18,442	16,444	34,695	65,116	14,795	16,350	12,964
Asset Relocations	7,605	7,000	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700
Non-Network	4,223	6,370	4,917	1,483	3,855	1,407	1,483	1,798	1,407	1,483
Total Capex (gross)	**45,812**	**57,561**	**32,645**	**27,686**	**27,999**	**43,802**	**74,299**	**24,293**	**25,457**	**22,147**

Table 9: 2017 AMP Update Capex forecast

2017 AMP Update	FY17	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**	FY23	FY24	FY25	FY26	FY27
Consumer Connection	13,299	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	3,200
System Growth	984	6,105	4,661	2,047	2,052	2,050	2,073	2,100	2,150	2,200	2,200
Asset Replacement and Renewal	32,562	28,530	24,153	36,576	60,943	13,735	11,926	13,647	13,442	14,241	20,764
Asset Relocations	5,262	4,040	7,875	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350
Non-Network	6,190	8,472	6,356	1,974	1,898	4,346	1,974	2,289	1,898	1,974	2,244
Total Capex (gross)	**58,298**	**49,147**	**45,045**	**44,948**	**69,243**	**24,481**	**20,324**	**22,387**	**21,840**	**22,765**	**30,758**

Note: gross figures are reflected for Asset Relocations category, a 90% recovery is assumed for a net relocation forecast.

Table 10: Variances between 2017 AMP Update and 2016 AMP forecasts

VARIANCE	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
Consumer Connection	274	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)	(1,000)
System Growth	(175)	(2,727)	2,655	(13)	52	50	73	100	150	200
Asset Replacement and Renewal	12,763	(3,829)	4,131	18,134	44,499	(20,960)	(53,190)	(1,148)	(2,908)	1,277
Asset Relocations	(2,343)	(2,960)	5,175	(350)	(350)	(350)	(350)	(350)	(350)	(350)
Non-Network	1,967	2,102	1,439	491	(1,957)	2,939	491	491	491	491
Total	**12,486**	**(8,414)**	**12,401**	**17,263**	**41,244**	**(19,321)**	**(53,975)**	**(1,907)**	**(3,617)**	**618**

Explanation of major Capex variances

- The strategic review of compressor operating regime has resulted in the significant investment in Mokau Compressor station to upgrade the existing compressors in FY17.
- Replacement programme of obsolete meters was accelerated in FY17 ($1 million).
- The White Cliffs project has been brought forward to be completed within the DPP period, whereas previously the major construction was planned to occur outside the DPP.
- Replacement of the OATIS system has been brought forward to FY18.

5.2. OPEX

The next DPP period FY18 – FY22 is highlighted in bold.

Table 11: 2016 AMP Opex forecast

2016 AMP	FY17	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**	FY23	FY24	FY25	FY26
Network OPEX	**25,878**	**23,827**	**23,614**	**23,585**	**22,807**	**23,074**	**22,992**	**23,200**	**22,839**	**22,937**
Service Interruption & Emergencies	652	652	652	652	652	652	652	652	652	652
RCMI	19,593	17,391	17,280	17,252	16,474	16,741	16,659	16,867	16,505	16,604
Compressor Fuel	4,800	4,951	4,951	4,951	4,951	4,951	4,951	4,951	4,951	4,951
Land Management Activities	833	833	730	730	730	730	730	730	730	730
Non-Network OPEX	**20,205**	**19,570**	**19,570**	**19,209**	**19,209**	**19,209**	**19,209**	**19,209**	**19,209**	**19,209**
System Operations	3,129	3,269	3,269	3,269	3,269	3,269	3,269	3,269	3,269	3,269
Network Support	3,895	4,255	4,255	3,895	3,895	3,895	3,895	3,895	3,895	3,895
Business Support	13,181	12,045	12,045	12,045	12,045	12,045	12,045	12,045	12,045	12,045
Total	**46,083**	**43,397**	**43,183**	**42,794**	**42,016**	**42,283**	**42,201**	**42,409**	**42,048**	**42,146**

Table 12: 2017 AMP Update Opex forecast

2017 AMP UPDATE	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27
Network OPEX	**18,985**	**20,096**	**20,296**	**19,596**	**18,796**	**18,396**	**18,096**	**17,896**	**17,896**	**18,096**	**17,896**
Service Interruption & Emergencies	468	666	666	666	666	666	666	666	666	666	666
RCMI	15,232	15,882	16,082	15,382	14,582	14,182	13,882	13,682	13,682	13,882	13,682
Compressor Fuel[22]	3,285	3,549	3,549	3,549	3,549	3,549	3,549	3,549	3,549	3,549	3,549
Land Management Activities	990	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
Non-Network OPEX	**21,513**	**22,894**	**21,944**	**21,494**	**21,544**	**21,394**	**21,094**	**21,094**	**21,094**	**21,094**	**21,094**
System Operations	2,087	2,719	2,719	2,719	2,719	2,719	2,719	2,719	2,719	2,719	2,719
Network Support	3,426	3,716	3,666	3,516	3,566	3,416	3,116	3,116	3,116	3,116	3,116
Business Support	16,000	16,459	15,559	15,259	15,259	15,259	15,259	15,259	15,259	15,259	15,259
Total	**41,488**	**44,002**	**43,252**	**42,102**	**41,352**	**40,802**	**40,202**	**40,002**	**40,002**	**40,202**	**40,002**

22. Compressor fuel has been set at a flat line but will be adjusted as we realise efficiencies from the compressor efficiency work.

Table 13: Variances between 2017 AMP Update and 2016 AMP forecasts

2017 VARIANCE	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
Network OPEX	**(6,061)**	**(2,925)**	**(2,614)**	**(3,285)**	**(3,308)**	**(3,975)**	**(4,192)**	**(4,600)**	**(4,239)**	**(4,137)**
Service Interruption & Emergencies	(185)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)	(13)
RCMI	(4,361)	(1,509)	(1,199)	(1,870)	(1,892)	(2,559)	(2,777)	(3,185)	(2,823)	(2,722)
Compressor Fuel	(1,515)	(1,402)	(1,402)	(1,402)	(1,402)	(1,402)	(1,402)	(1,402)	(1,402)	(1,402)
Land Management Activities	157	179	282	282	282	282	282	282	282	282
Non-Network OPEX	**1,308**	**3,325**	**2,375**	**2,285**	**2,335**	**2,185**	**1,885**	**1,885**	**1,885**	**1,885**
System Operations	(1,042)	(551)	(551)	(551)	(551)	(551)	(551)	(551)	(551)	(551)
Network Support	(469)	(539)	(589)	(379)	(329)	(479)	(779)	(779)	(779)	(779)
Business Support	2,819	4,415	3,515	3,215	3,215	3,215	3,215	3,215	3,215	3,215
Total	**(4,752)**	**400**	**(239)**	**(1,000)**	**(973)**	**(1,790)**	**(2,307)**	**(2,715)**	**(2,354)**	**(2,252)**

Explanation of major Opex variances

- The reduced Service Interruptions and Emergencies is considered anomalously low in FY17. Although severe weather has continued to cause major infrastructure problems for New Zealand (such as the Manawatu Gorge), we have been fortunate this year that our assets have been less affected than previous years.
- RCMI reduced spend is forecast going forward, reflecting issues previously managed through opex programmes now being resolved with programmes qualifying for capital.
- Reduced compressor fuel reflects the efficiencies gained through our system compression strategy discussed in section 2.5.
- As previously discussed in section 1.3, increased urban encroachment and other third party driven risks to the pipeline requires additional patrolling and other stakeholder engagement activity.
- Some costs previously associated with System Operations and Network Support have moved across to Business Support. Business Support costs have increased year on year due to allowances for a CPP application, new GTAC project costs, insurance increases and IT support.

APPENDIX A: SUMMARY OF MATERIAL CHANGES

The table below:

- Summarises the material changes in our asset management plan, as compared with our 2016 gas transmission AMP; and
- Demonstrates our compliance with the requirements for an AMP update, as set out in the Gas Transmission Information Disclosure Determination 2012 (ID determination).

We have no material changes to disclosure for clauses 2.6.5(4) – 2.6.5(7) of the ID Determination.

ID REQUIREMENT	DISCUSSION
Clause 2.6.5 For the purposes of clause 2.6.3, the AMP update must:	
Clause 2.6.5 (1) Relate to the gas transmission services supplied by the GTB	This AMP update relates to both the Maui and non-Maui transmission pipelines. Information on First Gas' gas distribution business (GDB) can be found in the separate 2017 AMP update.
Clause 2.6.5 (2) Identify any material changes to the network development plans disclosed in the last AMP under clause 14 of Attachment A or in the last AMP update disclosed under this clause	The Ports of Auckland pipeline relocation project was identified for execution by FY18. This project has now been put on hold by the customer and is no longer planned.
Clause 2.6.5 (3) Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP pursuant to clause 15 of Attachment A or in the last AMP update disclosed under this clause	The White Cliffs pipeline replacement project was planned to be completed by FY23. This work is now planned to be completed by FY21. Procurement of emergency hot tap and stopple equipment and fittings to improve response and repair times for large diameter strategic pipelines was included in FY17 expenditure. Brought forward the replacement of the obsolete pneumatic control system at Kaitoke compressor station into FY17 and FY18. A maintenance strategy review was planned to be completed over FY17 – FY18. This will now be completed over FY17 – FY19. The Asset Management Strategy was planned to be defined during FY17. This will now be defined over FY18. Fleet plans were planned to be delivered during FY17. This will now be delivered over FY18. Brought forward the replacement of a number of obsolete meter replacement projects into FY17. The previous AMP describes the use of the Non-Routine Activity Management System (NRAMS) for managing operational risks and prioritising work. Work has commenced to migrate risks to Maximo to achieve the same objective. This will allow NRAMS to be decommissioned during FY18. The main line valve (MLV) remote actuation programme was planned to be strategically reviewed during FY17. This will now be completed during FY18. The SCADA master control system upgrade was planned to be replaced during FY17. This work has commenced but will now be completed during FY18. The Rotowaro historian server was due to be replaced during FY17. This will now be planned for replacement during FY18 – FY19.

ID REQUIREMENT	DISCUSSION
Clause 2.6.5(8) Contain the information set out in the schedules described in clause 2.6.6	See Appendix B.
Clause 2.6.6 Subject to clause 2.13.1, before the start of each disclosure year, each GTB must complete and publicly disclose each of the following reports by inserting all information relating to the gas transmission services supplied by the GTB for the disclosure years provided for in the following reports – 1) the Report on Forecast Capital Expenditure in Schedule 11a; 2) the Report on Forecast Operational Expenditure in Schedule 11b; 3) the Report on Asset Condition in Schedule 12a; 4) the Report on Forecast Demand in Schedule 12b;	See Appendix B.

APPENDIX B: INFORMATION DISCLOSURE SCHEDULES

Schedule 11a: Report on forecast capital expenditure
Schedule 11b: Report on forecast operational expenditure
Schedule 12a: Report on asset condition
Schedule 12b: Report on forecast demand

Company Name	**First Gas Limited**
AMP Planning Period	**1 October 2017 – 30 September 2027**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
GTBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**30 Sep 17**	**30 Sep 18**	**30 Sep 19**	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (nominal dollars)**										
10	Consumer connection	13,299	2,035	2,041	2,040	2,040	2,040	2,040	2,040	2,040	2,040	3,264
11	System growth	984	6,212	4,838	2,168	2,217	2,259	2,330	2,407	2,514	2,624	2,676
12	Asset replacement and renewal	32,562	29,026	25,072	38,731	65,830	15,134	13,403	15,644	15,717	16,984	25,259
13	Asset relocations	5,262	4,110	8,175	2,488	2,538	2,589	2,641	2,694	2,748	2,803	2,859
14	Reliability, safety and environment:											
15	Quality of supply											
16	Legislative and regulatory											
17	Other Reliability, Safety and Environment											
18	**Total reliability, safety and environment**											
19	**Expenditure on network assets**	52,107	41,383	40,126	45,428	72,626	22,022	20,414	22,785	23,018	24,450	34,058
20	Expenditure on non-network assets	6,190	8,620	6,598	2,091	2,050	4,788	2,219	2,624	2,219	2,355	2,730
21	**Expenditure on assets**	58,298	50,002	46,724	47,519	74,676	26,810	22,633	25,409	25,237	26,805	36,787
22												
23	*plus* Cost of financing	498	420	385	384	591	209	174	191	187	194	263
24	*less* Value of capital contributions	4,736	3,699	7,357	2,240	2,285	2,330	2,377	2,424	2,473	2,522	2,573
25	*plus* Value of vested assets											
26	**Capital expenditure forecast**	54,060	46,723	39,751	45,663	72,983	24,689	20,430	23,176	22,951	24,477	34,477
27												
28	Assets commissioned	46,693	46,999	37,158	27,932	100,288	24,149	21,398	22,765	23,191	24,407	32,899
29												
30		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31	for year ended	**30 Sep 17**	**30 Sep 18**	**30 Sep 19**	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**
32		**$000 (in constant prices)**										
33	Consumer connection	13,299	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	3,200
34	System growth	984	6,105	4,661	2,047	2,052	2,050	2,073	2,100	2,150	2,200	2,200
35	Asset replacement and renewal	32,562	28,530	24,153	36,576	60,943	13,735	11,926	13,647	13,442	14,241	20,764
36	Asset relocations	5,262	4,040	7,875	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350
37	Reliability, safety and environment:											
38	Quality of supply	-	-	-	-	-	-					
39	Legislative and regulatory	-	-	-	-	-	-					
40	Other Reliability, Safety and Environment	-	-	-	-	-	-					
41	**Total reliability, safety and environment**											
42	**Expenditure on network assets**	52,107	40,675	38,689	42,974	67,345	20,135	18,349	20,097	19,942	20,791	28,514
43	Expenditure on non-network assets	6,190	8,472	6,356	1,974	1,898	4,346	1,974	2,289	1,898	1,974	2,244
44	**Expenditure on assets**	58,298	49,147	45,045	44,948	69,243	24,481	20,324	22,387	21,840	22,765	30,758
45	**Subcomponents of expenditure on assets (where known)**											
46	Research and development											

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended	30 Sep 17	30 Sep 18	30 Sep 19	30 Sep 20	30 Sep 21	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26	30 Sep 27
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	35	41	40	40	40	40	40	40	40	64
System growth	-	106	177	121	165	209	257	307	364	424	476
Asset replacement and renewal	-	496	919	2,155	4,888	1,398	1,477	1,997	2,275	2,743	4,495
Asset relocations	-	70	300	138	188	239	291	344	398	453	509
Reliability, safety and environment:											
Quality of supply	-	-	-	-	-	-	-	-	-	-	-
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other Reliability, Safety and Environment	-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
Expenditure on network assets		708	1,437	2,454	5,281	1,886	2,065	2,688	3,077	3,660	5,544
Expenditure on non-network assets	-	-	-	-	-	-	2,813,747	(70,479)	726,491	244,720	110,876
Expenditure on assets		708	1,437	2,454	5,281	1,886	4,879	2,617	3,803	3,904	5,655

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	30 Sep 17	30 Sep 18	30 Sep 19	30 Sep 20	30 Sep 21	30 Sep 22
*Consumer types defined by GTB**	**$000 (in constant prices)**					
New Connection/Load Increase	13,299	2,000	2,000	2,000	2,000	2,000
** include additional rows if needed*						
Consumer connection expenditure	13,299	2,000	2,000	2,000	2,000	2,000
less Capital contributions funding consumer connection						
Consumer connection less capital contributions	13,299	2,000	2,000	2,000	2,000	2,000

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Pipes	984	3,025	2,500			
Compressor stations						
Other stations		3,080	2,161	2,047	2,052	2,050
SCADA and communications						
Special crossings						
System growth expenditure	984	6,105	4,661	2,047	2,052	2,050
less Capital contributions funding system growth						
System growth less capital contributions	984	6,105	4,661	2,047	2,052	2,050

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**30 Sep 17**	**30 Sep 18**	**30 Sep 19**	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**
11a(iv): Asset Replacement and Renewal							
		$000 (in constant prices)					
Pipes		6,720	13,081	15,425	26,213	55,086	8,581
Compressor stations		10,450	6,783	2,414	4,934	1,755	1,306
Other stations		12,287	4,718	4,218	3,457	2,092	1,755
SCADA and communications		854	1,604	194	194	194	109
Special crossings			44	44		44	44
Components of stations (where known)							
Main-line valves			502	700	700	700	700
Heating system		510	526	486	452	451	454
Odorisation plants			249	43			89
Coalescers			298	88			88
Metering system		1,741	261	439	439	439	439
Cathodic protection			214	104	189	104	172
Chromatographs			249			79	
Asset replacement and renewal expenditure		32,562	28,530	24,153	36,576	60,943	13,735
less Capital contributions funding asset replacement and renewal							
Asset replacement and renewal less capital contributions		32,562	28,530	24,153	36,576	60,943	13,735
11a(v): Asset Relocations							
Project or programme*							
Whirkino Bridge re-alignment		3,436	35				
Transmission Gully		1,491	600				
430 Re-alignment- NZTA East West link			800	3,825			
Southdown DP relocation NZTA East West Link				1,700			
Murphys road Re-alignment			2,550				
** include additional rows if needed*							
All other projects or programmes - asset relocations		335	55	2,350	2,350	2,350	2,350
Asset relocations expenditure		5,262	4,040	7,875	2,350	2,350	2,350
less Capital contributions funding asset relocations		4,736	3,636	7,088	2,115	2,115	2,115
Asset Relocations less capital contributions		526	404	788	235	235	235
11a(vi): Quality of Supply							
Project or programme*							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
[Description of material project or programme]							
** include additional rows if needed*							
All other projects or programmes - quality of supply							
Quality of supply expenditure		-	-	-	-	-	-
less Capital contributions funding quality of supply							
Quality of supply less capital contributions		-	-	-	-	-	-

11a(vii): Legislative and Regulatory

Project or programme*						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
** include additional rows if needed*						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

11a(viii): Other Reliability, Safety and Environm

for year ended	*Current Year CY* **30 Sep 17**	*CY+1* **30 Sep 18**	*CY+2* **30 Sep 19**	*CY+3* **30 Sep 20**	*CY+4* **30 Sep 21**	*CY+5* **30 Sep 22**
Project or programme*	**$000 (in constant prices)**					
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
** include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment total	-	-	-	-	-	-
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	-	-	-	-	-	-

11a(ix): Non-Network Assets

Routine expenditure

Project or programme*	**$000 (in constant prices)**					
ICT						
Building Refurbishment			1,711	170	170	170
Motor Vehicles			316	316	316	316
Plant and Equipment	178	465	834	175	175	175
** include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	178	465	2,860	661	661	661
Atypical expenditure						
Project or programme*						
ICT	3,965	7,411	3,496	1,313	1,237	3,685
Building refurbishment	953	170				
Motor Vehicles	1,094	427				
** include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	6,012	8,007	3,496	1,313	1,237	3,685
Expenditure on non-network assets	6,190	8,472	6,356	1,974	1,898	4,346

Company Name	**First Gas Limited**
AMP Planning Period	**1 October 2017 – 30 September 2027**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
GTBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
7												
8		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
9	for year ended	**30 Sep 17**	**30 Sep 18**	**30 Sep 19**	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**
10	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
11	Service interruptions, incidents and emergencies	468	677	691	705	719	733	748	763	778	794	810
12	Routine and corrective maintenance and inspection	15,232	16,158	16,362	15,967	15,441	15,319	15,295	15,376	15,684	16,231	16,317
13	Asset replacement and renewal											
14	Compressor fuel	3,285	3,610	3,684	3,758	3,833	3,910	3,988	4,068	4,149	4,232	4,317
15	Land management and associated activity	990	1,029	1,050	1,071	1,093	1,115	1,137	1,160	1,183	1,206	1,231
16	**Network opex**	19,974	21,475	21,786	21,501	21,086	21,077	21,168	21,367	21,794	22,464	22,674
17	System operations	2,087	2,766	2,822	2,879	2,937	2,996	3,056	3,117	3,179	3,243	3,308
18	Network support	3,426	3,781	3,805	3,723	3,852	3,764	3,502	3,572	3,643	3,716	3,790
19	Business support	16,000	16,746	16,151	16,158	16,483	16,813	17,149	17,492	17,842	18,199	18,563
20	**Non-network opex**	21,513	23,293	22,779	22,761	23,272	23,572	23,707	24,181	24,664	25,158	25,661
21	**Operational expenditure**	41,488	44,768	44,566	44,262	44,358	44,649	44,875	45,547	46,458	47,621	48,335
22		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
23	for year ended	**30 Sep 17**	**30 Sep 18**	**30 Sep 19**	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**
24		**$000 (in constant prices)**										
25	Service interruptions, incidents and emergencies	468	666	666	666	666	666	666	666	666	666	666
26	Routine and corrective maintenance and inspection	15,232	15,882	16,082	15,382	14,582	14,182	13,882	13,682	13,682	13,882	13,682
27	Asset replacement and renewal											
28	Compressor fuel	3,285	3,549	3,549	3,549	3,549	3,549	3,549	3,549	3,549	3,549	3,549
29	Land management and associated activity	990	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
30	**Network opex**	19,974	21,108	21,308	20,608	19,808	19,408	19,108	18,908	18,908	19,108	18,908
31	System operations	2,087	2,719	2,719	2,719	2,719	2,719	2,719	2,719	2,719	2,719	2,719
32	Network support	3,426	3,716	3,666	3,516	3,566	3,416	3,116	3,116	3,116	3,116	3,116
33	Business support	16,000	16,459	15,559	15,259	15,259	15,259	15,259	15,259	15,259	15,259	15,259
34	**Non-network opex**	21,513	22,894	21,944	21,494	21,544	21,394	21,094	21,094	21,094	21,094	21,094
35	**Operational expenditure**	41,488	44,002	43,252	42,102	41,352	40,802	40,202	40,002	40,002	40,202	40,002
36	**Subcomponents of operational expenditure (where known)**											
37	Research and Development											
38	Insurance											
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**30 Sep 17**	**30 Sep 18**	**30 Sep 19**	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions, incidents and emergencies	-	11,582	25	39	53	68	82	97	113	128	144
43	Routine and corrective maintenance and inspection	-	276,346	280	585	859	1,137	1,413	1,694	2,002	2,349	2,636
44	Asset replacement and renewal	-	-									
45	Compressor fuel	-	61,745	135	209	285	361	439	519	601	684	768
46	Land management and associated activity	-	17,601	38	60	81	103	125	148	171	195	219
47	**Network opex**		367	479	893	1,278	1,669	2,060	2,459	2,886	3,356	3,767
48	System operations	-	47,309	103	160	218	277	337	398	460	524	589
49	Network support	-	64,657	140	207	286	348	386	456	527	600	675
50	Business support	-	286,393	592	899	1,224	1,554	1,890	2,233	2,583	2,939	3,303
51	**Non-network opex**		398	835	1,266	1,728	2,178	2,612	3,086	3,570	4,063	4,567
52	**Operational expenditure**		766	1,314	2,160	3,006	3,848	4,673	5,546	6,456	7,419	8,333

Company Name **First Gas Limited**

AMP Planning Period **1 October 2017 – 30 September 2027**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a.

sch ref

				Asset condition at start of planning period (percentage of units by grade)						
7										
8	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
9	Pipes	Protected steel pipes	km	-	0.81%	37.68%	61.51%	-	3	0%
10	Pipes	Special crossings	km	-	-	32.61%	67.39%	-	3	-
11	Stations	Compressor stations	No.	-	-	88.90%	11.10%	-	3	-
12	Stations	Offtake point	No.	-	4.60%	94.70%	0.70%	-	3	4%
13	Stations	Scraper stations	No.	-	-	100.00%	-	-	3	-
14	Stations	Intake points	No.	-	-	100.00%	-	-	3	-
15	Stations	Metering stations	No.	-	-	100.00%	-	-	3	-
16	Compressors	Compressors—turbine driven	No.	-	-	100.00%	-	-	3	-
17	Compressors	Compressors—electric motor driven	No.	-	-	-	100.00%	-	4	-
18	Compressors	Compressors—reciprocating engine driven	No.	26.31%	42.11%	31.58%	-	-	3	5%
19	Main-line valves	Main line valves manually operated	No.	-	12.99%	87.01%	-	-	3	-
20	Main-line valves	Main line valves remotely operated	No.	-	18.18%	81.82%	-	-	3	-
21	Heating systems	Gas-fired heaters	No.	-	31.10%	61.20%	7.70%	-	3	-
22	Heating systems	Electric heaters	No.	-	-	66.67%	33.33%	-	3	-
23	Odorisation plants	Odorisation plants	No.	-	4.35%	95.65%	-	-	3	-
24	Coalescers	Coalescers	No.	-	-	100.00%	-	-	3	-
25	Metering systems	Meters—ultrasonic	No.	28.57%	57.14%	14.29%	-	-	4	-
26	Metering systems	Meters—rotary	No.	54.10%	8.20%	36.06%	1.64%	-	4	10%
27	Metering systems	Meters turbine	No.	52.70%	17.57%	20.27%	9.46%	-	4	30%
28	Metering systems	Meters—mass flow	No.	-	-	100.00%	-	-	4	-
29	SCADA and communications	Remote terminal units (RTU)	No.	12.98%	33.16%	31.16%	22.70%	-	3	8%
30	SCADA and communications	Communications terminals	No.	100.00%	-	-	-	-	3	100%
31	Cathodic protection	Rectifier units	No.	-	38.30%	61.70%	-	-	3	23%
32	Chromatographs	Chromatographs	No.	28.57%	42.86%	28.57%	-	-	4	30%

SCHEDULE 12b: REPORT ON FORECAST DEMAND

This Schedule requires a forecast of new connections (by consumer type) and gas delivered for the current disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP and the assumptions used in developing the capital expenditure forecast in Schedule S11a [and 11b]

sch ref

12b(i): Connections

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**30 Sep 17**	**30 Sep 18**	**30 Sep 19**	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**
Connection types defined by GTB						
Distribution System	1	-	-	-	-	-
Direct Connect	-	-	1	-	-	-
Bi-Directional	-	-	-	-	-	-
Receipt Point	-	-	-	-	-	-
** include additional rows if needed*						
Connections total	1	-	1	-	-	-

12b(ii): Gas conveyed

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**30 Sep 17**	**30 Sep 18**	**30 Sep 19**	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**
Intake volume (TJ)	166,509	174,130	178,477	179,759	180,019	180,281
Quantity of gas delivered (TJ)	166,764	176,443	178,726	180,016	180,284	180,553
Gas used in compressor stations (TJ)	483	483	499	502	505	508
Gas used in heating systems (TJ)	124	130	134	135	135	135
Total gas conveyed (TJ)	167,371	177,056	179,359	180,653	180,924	181,196

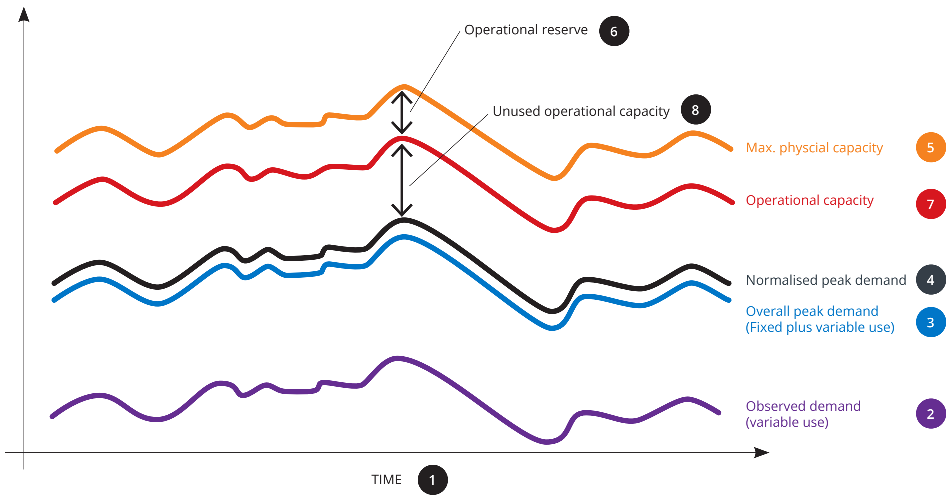
APPENDIX C: PIPELINE CAPACITY

This appendix describes our capacity determination methodology and sets out our forecast station capacities.

1. CAPACITY FORECASTING METHODOLOGY

Our approach to determining the physical capacity of our pipeline systems is based on several factors. The steps followed, and the assumptions made are described below. To aid in this description, reference is made to the schematic in Figure C1.

Figure C1: Overview schematic for pipeline capacity determination



The eight steps to determine pipeline capacity are as follows:

1. Determine the time period sufficient to reveal the pipeline's performance, in particular the cycle of pressure depletion and recovery;
2. Obtain actual demand profiles for variable demands during the selected time period;
3. Decide which demands (if any) need to be modelled as fixed loads;
4. Normalise the variable demand profiles to reflect long-term trends;
5. Run the model to determine the maximum physical demand that can be sustained without breaching the System Security Standard;
6. Allow for an "operational reserve" to cover abnormal peaks (e.g. severe winter demand), as well as an appropriate "survival time" for the pipeline.
7. This establishes the available "operational capacity"; and
8. Deduct existing normalised peak demand at a delivery point from the operational capacity to determine the unused operational capacity at that delivery point.

Step 1: Peak demand period

The peak demand period relevant to the determination of physical pipeline capacity should be the period of greatest demand from the pipeline during which pipeline pressures:

- do not fall below the minimum acceptable level at any point; and
- following any depletion, recover to at least their starting levels[23].

For most pipelines this period is usually a sequence of high demand days (which may or may not include the absolute peak demand day).

Peak demand almost always occurs during the working week. Overall demand on most pipelines (although not necessarily at all delivery points) is lower on weekends. For this reason, modelling is generally based on the 5 days (Monday – Friday, inclusive) with the highest aggregate demand (the "5-day peak[24]").

At the start of a 5-day peak pressures are generally at their highest. Through the period, should more gas be drawn from the pipeline than can be replenished on a day, pressures

23. Indicating that a further such peak demand period would be sustainable.
24. The Saturday and Sunday immediately following are also modelled to check that pressures recover sufficiently before the start of the next week. Hence any reference in this paper to modelling the 5-day peak should be understood to mean that the relevant 7 days are considered.

in the pipeline will fall.[25] To determine a pipeline's sustainable capacity, pressures at the end of a 5-day peak must have recovered to what they were at the start.

The use of a 5-day peak, as opposed to a 24 hour period, recognises that the provision of gas transmission capacity (role of First Gas) is different from gas balancing (for which producers, shippers, and end-users have primary responsibility). Using a 24-hour period would materially reduce the transmission capacity that we could allocate, by curtailing the use of system line pack to cover short-term differences between input and offtakes. As long as we can continue to operate the system can within prudent operating levels and in accordance with our security standard, we will maintain the 5-day peak approach.

Step 2: Actual (variable) peak demands

The second step is to assemble gas demand profiles[26] during the 5-day peak (or other peak demand period) for all delivery points on the pipeline. Loads to be modelled as fixed (i.e. that will be assumed to be "on" in whatever the 5-day peak is determined to be) are excluded in this process.

This captures the diversity in variable demands on a pipeline, which often arises (in the case of delivery points supplying distribution networks) from large populations of individual gas consumers. This means we do not need to apply artificial diversity factors. Gas demand profiles for the most recently observed 5-day peak are normally used.

Under the current (non-Maui) regime where we sell (annual) Reserved Capacity to shippers, there is a theoretical risk that, if all shippers simultaneously started using their full contractual capacity, they could exceed a pipeline's physical capacity leading to a critical contingency event.[27] Certain features of the current regime mitigate this risk however, as well as shippers' practice of reserving capacity in a way that reflects load diversity. Under the GTAC the risk will essentially be eliminated, the main reason being the requirement on shippers to request capacity daily via nominations. In the unlikely event we do not have enough capacity, we will apply "congestion management" which, as a last resort, will allow us to curtail nominates to match the capacity available.

25. Meaning that, while the pressure at different points in the pipeline will cycle up and down within a day, the minimum and maximum levels reached may trend lower from day to day. This may occur for several reasons, including operational reasons, coincident peak demand being higher than anticipated or shippers exceeding their capacity entitlements. Where there is compression at the inlet to a pipeline, First Gas generally operates it in a constant pressure mode (maintaining inlet pressure at relatively constant level).
26. The model uses hourly gas flow rates at each delivery point. In this context therefore, "demand profiles" refers to hourly demand quantities for the days comprising the 5-day peak (or other peak demand period). Collectively, such hourly demands are also referred to as the "flow profile" for the relevant delivery point.
27. As discussed in the System Security Standardare also referred to as the "flow profile" for the relevant delivery point.

When modelling to determine pipeline capacity, all contractually interruptible load on a pipeline is set to zero.

Dairy factories' peak demand periods may not coincide with the 5-day peak of the pipelines from which they are supplied. They are modelled as variable loads, which is generally when they are in their off-peak periods. Like other large end-users (excluding power stations) they are normally modelled according to their actual demand during the 5-day peak however.

Step 3: Loads assumed to be fixed

To complete the overall demand on a pipeline, fixed loads (if any) need to be added into the model.

Currently, power stations are the prime examples of such loads. While their demand is not literally fixed, when operating at maximum generating capacity they normally represent the biggest load(s) on the relevant pipeline and, by comparison with most other loads, can run nearly continuously. Power stations can also fire up to full capacity at any time of the year so that even if they were not actually operating during the 5 day peak they might have, and might in the future.

We may also have firm, multi-year contractual capacity commitments to such users. Hence we model such loads as running at their maximum contractual entitlement during the relevant 5-day peak.

Step 4: Normalised peak demand

The fourth step in the capacity determination process is to "normalise" 5-day peaks to the relevant long-term trend (where appropriate).

While actual demand peaks may vary materially from year to year, long-term trends can be discerned for some delivery points. On most of our pipelines,[28] this annual variance correlates closely with winter weather patterns, which arises from delivery points for distribution networks supplying large numbers of smaller, weather-sensitive consumers (amongst others).

28. The Bay of Plenty pipeline does not currently display a consistent winter peak overall.

A capacity allocation requires an understanding of the underlying demand growth trend. To determine this trend, it is necessary to normalise out annual demand fluctuations that are caused by unpredictable external events (such as unexpected temperature levels). This normalisation is done by adjusting actual demand profiles (where relevant) to the long-term trend in 5-day peak demands. Such an adjustment can be both upwards (in a milder-than-average year, peak consumption can be below the long-term trend), or downwards (in a colder-than-average year, peak consumption can be above the long-term trend). The adjustment is achieved by applying a multiplication factor, meaning that while the shape of the demand profile unchanged, actual hourly consumption levels are moved up or down depending on the normalising factor.

Step 5: Model to find maximum physical capacity

The fifth step is to determine the maximum physical capacity of a pipeline, based on the loads defined in accordance with steps 2, 3 and 4.

Prudent pipeline operation requires that under all reasonably anticipated operating conditions the design capacity of pipeline components is not exceeded and that the system security standard is not breached.

Modelling to determine maximum physical capacity is a scenario-based exercise, involving the simulation of increased demand. This involves using one or more of the following methods at a delivery point, or more than one delivery point in certain cases:

1. Applying a factor to the (normalised) 5-day peak demand profile.
2. Adding a constant flow rate to the (normalised) 5-day peak demand profile.
3. Adding a separate flow profile to the (normalised) 5-day peak demand profile.

The method(s) used depends mainly on the information available and the purpose of the modelling, e.g. whether it is being undertaken to provide a general indication of unused physical capacity, or in response to a specific request from a shipper.

With all 3 methods, load is increased to the point just short of that at which a breach of the security standard would occur. This is normally when the pressure at the critical point on the pipeline would just go below the applicable minimum acceptable pressure criterion or limited by compressor constraints.

Method 1 is the most commonly used, and may be most applicable to simulation of "organic growth" on a large distribution network, where the factor is often quite small (i.e. from year to year). Method 1 can also be used to give an indication of spare capacity where that is very large, e.g. where the factor is a large number like 5, 10 or 20. (It would need to be borne in mind, however, that such a large new load might well exhibit a flow profile materially different from the existing one, which in turn might change the factor.

Method 2 is commonly used to simulate a new "fixed" demand.[29] Method 2 is often used as a first, conservative go/no-go test of a pipeline's capacity to supply a new load. For example, if the prospective new load is set at a constant flow rate at the level of its maximum hourly quantity (MHQ) and the pipeline can sustain that, further (more realistic) modelling may be unnecessary.

Method 3 is used to simulate a different flow profile from the observed 5-day peak. This can be used where the flow profile of a new load is known, and differs materially from the profile of the existing load at the relevant delivery point. Another use might be to test additional load complying with contractual criteria of MHQ and maximum daily quantity ("MDQ"), on a continuous basis, to be sure of the amount of additional contractual capacity that could be allocated at the delivery point. (Though this does involve crafting an artificial flow profile for the relevant delivery point.)

Steps 6 and 7: Operational reserve and operational capacity

As a reasonable and prudent operator, we must operate pipelines at "safe" levels of capacity, which involves ensuring that the system security standard is not breached, other than due to events beyond our reasonable control.

The "safe" level of physical capacity is termed the "operational capacity" of a pipeline (albeit determined at the delivery point level). Such operational capacity is determined by reducing the maximum physical capacity by an amount known as the "operational reserve".

29. It is also used with flow rate set at the estimated MHQ (maximum hourly quantity) as a conservative first test of a pipeline's ability to support a prospective new load. That is not to imply such an amount of contractual capacity would be allocated.

In practice the operational reserve is necessary to allow for two main factors:

- **Winter severity:** As noted above, winter ambient temperatures are a key determinant of overall peak gas demand on most of our pipelines.[30] We have adopted a 1-in-20 year winter to determine the level at which transmission capacity shortfalls do not occur at an unacceptably high frequency. While this standard is a also common in many overseas jurisdictions, it will be subject to periodic review.
- **Survival time:** Compression is a key to increasing capacity on most pipeline systems. Our compressor stations are designed with n-1[31] redundancy (as set out in the system security standard). However, a spare compressor may also fail, or not start,[32] requiring additional time to be allowed for any such failure to be remedied – the so-called "survival time". This time is determined as the likely time it would take a technician to attend a site, fault-find and manually start a compressor. Again, future economic testing may identify a need to amend this.

The practical effect of the operational reserve is to reduce the total quantity of transmission capacity available that may be allocated as contractual capacity at delivery points on a pipeline. The amount of such reduction is different for each pipeline and must be determined for each pipeline individually. This also applies to any pipeline where the 5-day peak is not determined by winter conditions.

Step 8: Determine unused operational capacity

The amount of the operational capacity that shippers are not currently using represents capacity to ship additional gas through the pipeline during the 5-day peak without breaching the system security standard, even in the event of a 1-in-20-year winter occurring.

"Unused" operational capacity for a delivery point is calculated simply by subtracting the normalised peak demand from the operational capacity. As noted above, the amount of such capacity is directly affected by the assumptions made about the additional load at the delivery points during modelling.

30. The exception, the Bay of Plenty pipeline, has in recent years experienced early summer peaks, which appear to correlate with the gas demand of dairy factories.
31. An N-1 redundancy level means that a failure on any single component will not affect the ability of the system to deliver its required output.
32. The availability of compressors, which are complex mechanical units, while still high, is an order of magnitude lower than that of most other components of the transmission system. Compressor failures therefore can occur at a relatively high frequency.

"Uncommitted" operational capacity for a delivery point is calculated by subtracting the aggregate of shippers' current contractual capacity from the operational capacity. Under the non-Maui regime (i.e. the VTC), such contractual capacity is either Reserved Capacity or non-standard capacity ("Supplementary Capacity"). This will change under the GTAC.

2. SYSTEM CAPACITY TABLES

The following section identifies the Aggregate Contractual Capacity already committed in the entire transmission system and the Unused Operational Capacity (UOC) over three separate forecast years (FY17, FY22 and FY27). The peak week demand in 2016 is used as the peak 5-day demand period.

The uncommitted operational capacity at each delivery point on a pipeline is exclusive of, not additive to, the UOC at all other delivery points on the same pipeline. This stems from the modelling approach applied to generate these (pipeline) tables, i.e. in which we step through the delivery points one at a time, keeping the load constant at all the others. Hence, the capacities listed as unused are only available at any one of the locations stated and not available at all locations at the same time. Also as capacity is used or committed incrementally at many locations, the balance of UOC will shift.

While we state the peak week on which the capacity numbers are based, that does not by itself confirm that the same amount would be available at all other times of the year.

Following each table of pipeline capacity, is a geographical pipeline map which has a coloured key to show the same capacity information for the baseline year of FY17 only (not FY22 or FY27) shown in the tables. These maps can be used to quickly identify area's in the country where it is likely that large amounts of UOC can be made available and conversely, where UOC is currently at its lowest i.e. < 2000GJ/day.

First Gas will not be consequently addressing all areas where UOC is less than 2000GJ/day as a matter of course, but will be considering options for reinforcement to area's where demand growth is forecast to increase significantly and UOC is generally very low.

These maps may only be used as a general guide, as load requests are regularly being considered and approved to dynamically change the landscape and so, it is essential that any large requests for capacity are presented to First Gas for consideration and acceptance throughout the year, before any firm customer commitments are made.

North System pipeline capacities

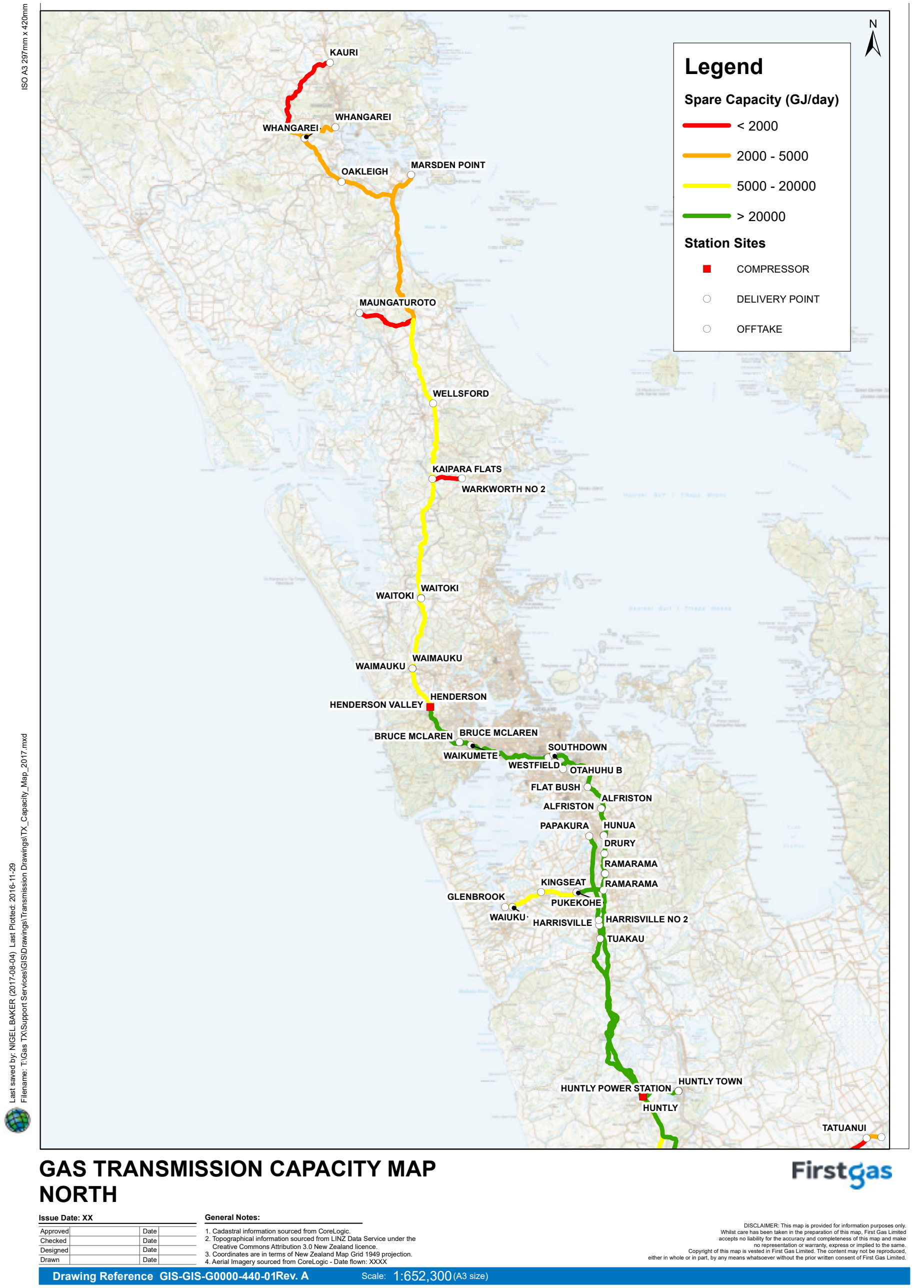
Table C1: Pipeline capacity – North System

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY17	FY22	FY27
Tuakau	2,749	24,456	24,370	24,283
Harrisville	1,855	27,919	27,859	27,798
Ramarama	123	12,701	12,698	12,695
Drury (1 & 2)	1,113	90,689	78,991	67,293
Pukekohe	236	21,944	21,861	21,778
Glenbrook	6,775	13,228	13,179	13,129
Greater Auckland	47,901	37,628	36,732	35,836
Hunua	1,118	84,773	83,883	82,994
Flat Bush	1,763	71,114	70,108	69,102
Waitoki	481	7,557	7,274	6,991
Marsden	13,600	2,176	2,040	1,904
Whangarei	552	2,155	2,042	1,928
Kauri + Maungaturoto	4,500	441	382	323
Alfriston	80	7,139	7,139	7,139
Warkworth	1,579	648	642	637

Notes:

- No/negligible demand was observed at Wellsford and Kingseat Delivery Points during the North System's peak week. Pipeline capacity calculations are not feasible for these sites.
- Rotowaro compression has been modelled at a constant discharge pressure of 84 barg
- Henderson compression has been modelled at a constant discharge pressure of 84 barg high frequency.
- The peak week for this system is the week ending the 12th of August 2016.

Map C1: Pipeline capacity – North System



Central (North) System pipeline capacities

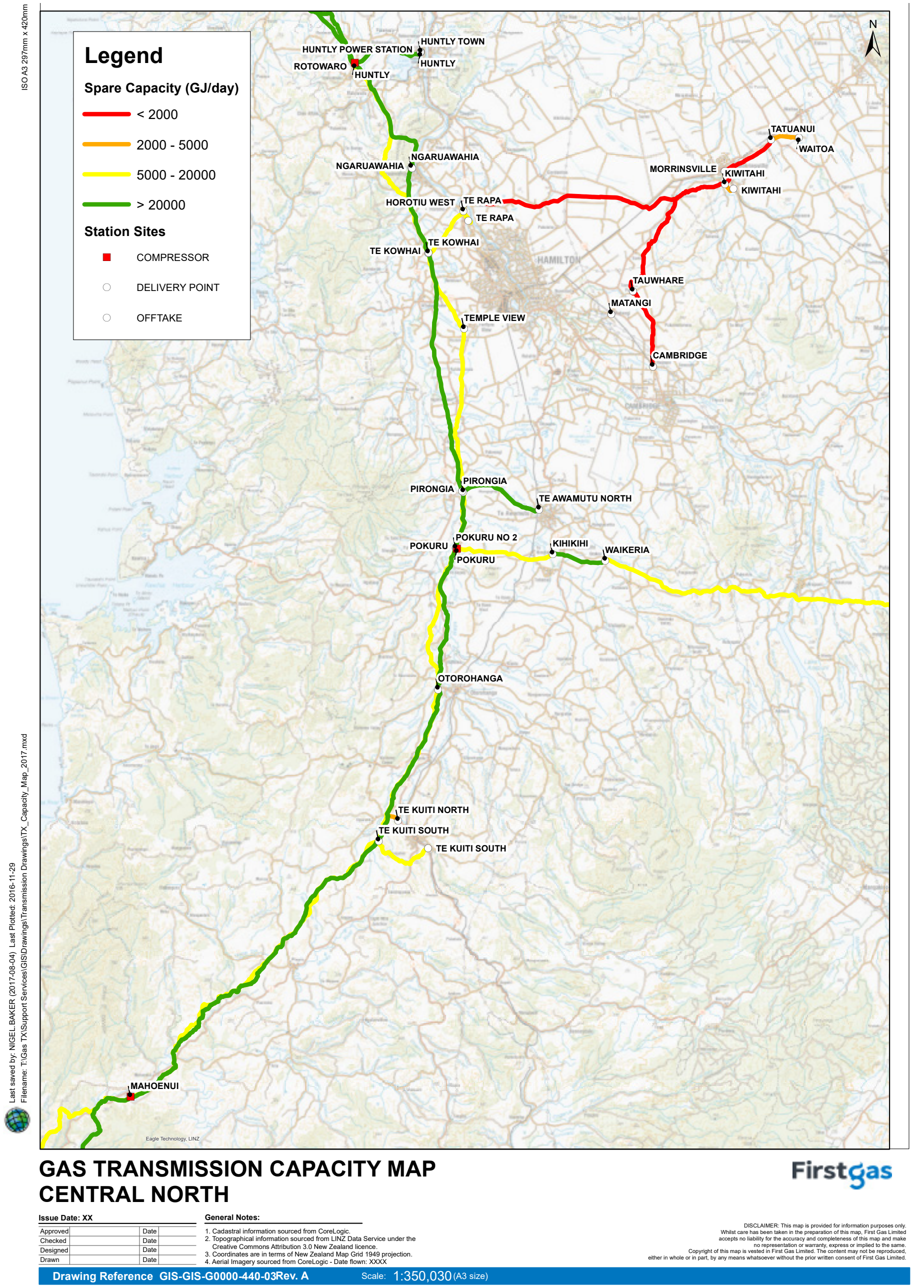
Table C2: Pipeline forecasts – Central (North) System

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY17	FY22	FY27
Cambridge	1,946	1,607	1,528	1,448
Greater Hamilton	7,877	17,625	14,809	11,993
Horotiu	546	7,171	5,187	3,203
Kiwitahi	1,094	3,350	2,684	2,018
Morrinsville	1,268	759	538	316
Tatuanui	1,500	1,909	1,639	1,369
Te Rapa Cogen	23,200	12,064	9,744	7,424
Waitoa	1,580	2,964	2,476	1,989

Notes:

- The Aggregate Contractual Capacity for Greater Hamilton in FY22 and FY27 is 8,453 GJ/day.
- The Aggregate Contractual Capacity for Horotiu Delivery Point in FY22 and FY27 is 1,746 GJ/
- Peak week is the week ending the 12th of August 2016
- Due to negligible flow, calculating the Operational Capacity at Matangi Delivery Point was not feasible.
- Compression at Rotowaro is modelled at a constant discharge pressure of 84 barg.
- No hourly flow was observed at Matangi Delivery Point. Calculating pipeline capacity is not feasible.

Map C2: Pipeline capacity – Central North System



Central (South) System pipeline capacities

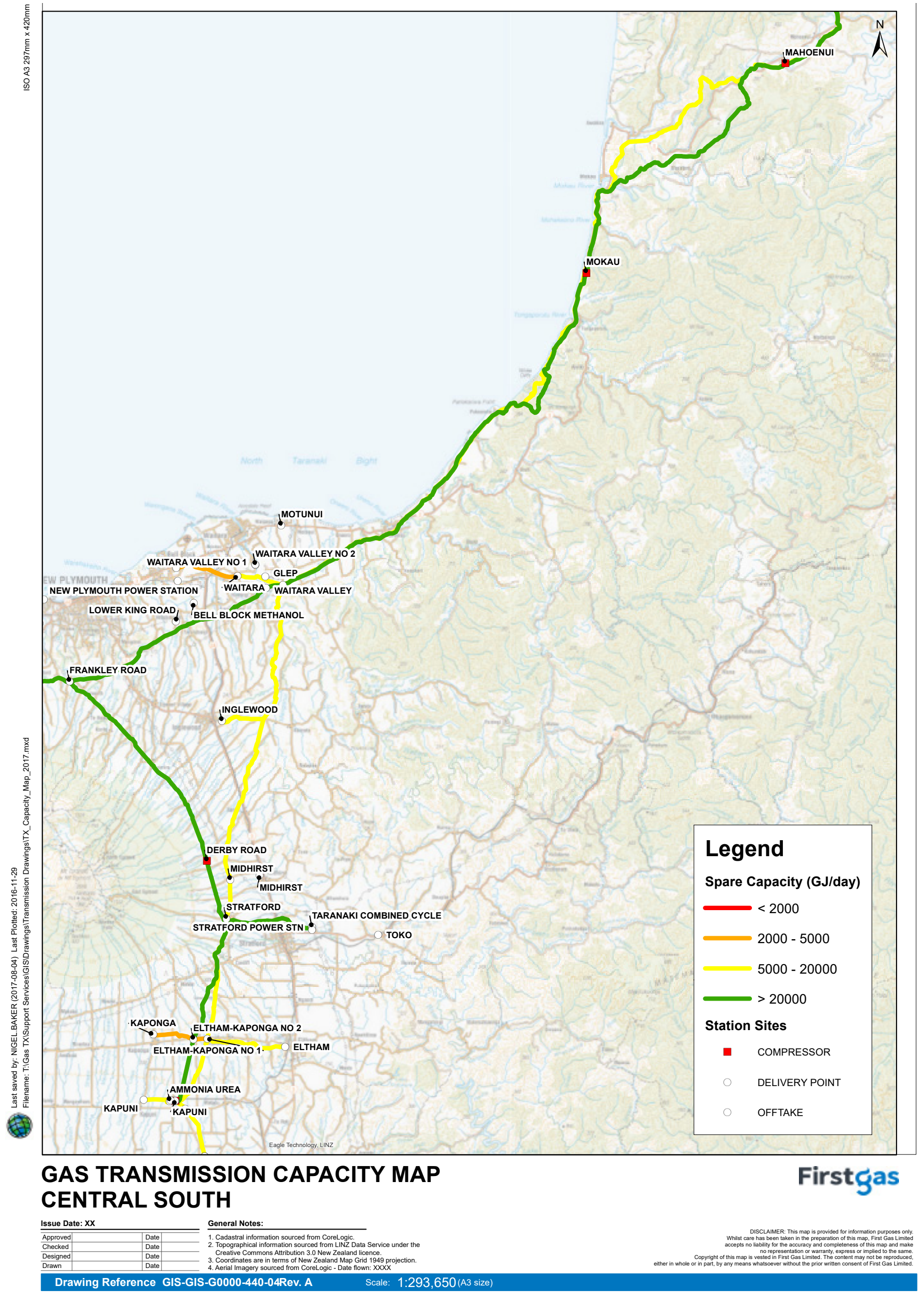
Table C3: Pipeline capacity – Central (South) System

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY17	FY22	FY27
Eltham	600	8,898	8,898	8,898
Inglewood	146	7,693	7,693	7,693
Kaponga	7	3,785	3,783	3,782
New Plymouth	3,736	2,872	2,872	2,872
Stratford	259	14,213	14,180	14,147
Waitara	350	5,694	5,660	5,627

Notes:

- Peak week is the week ending the 12th of August 2016.
- The demand at Pokuru offtake is modelled as being fully interrupted.
- Compression at Mahoenui was not modelled.
- Kapuni compression is modelled at a constant discharge pressure of 84 barg.

Map C3: Pipeline capacity – Central South System



Bay of Plenty System pipeline capacities

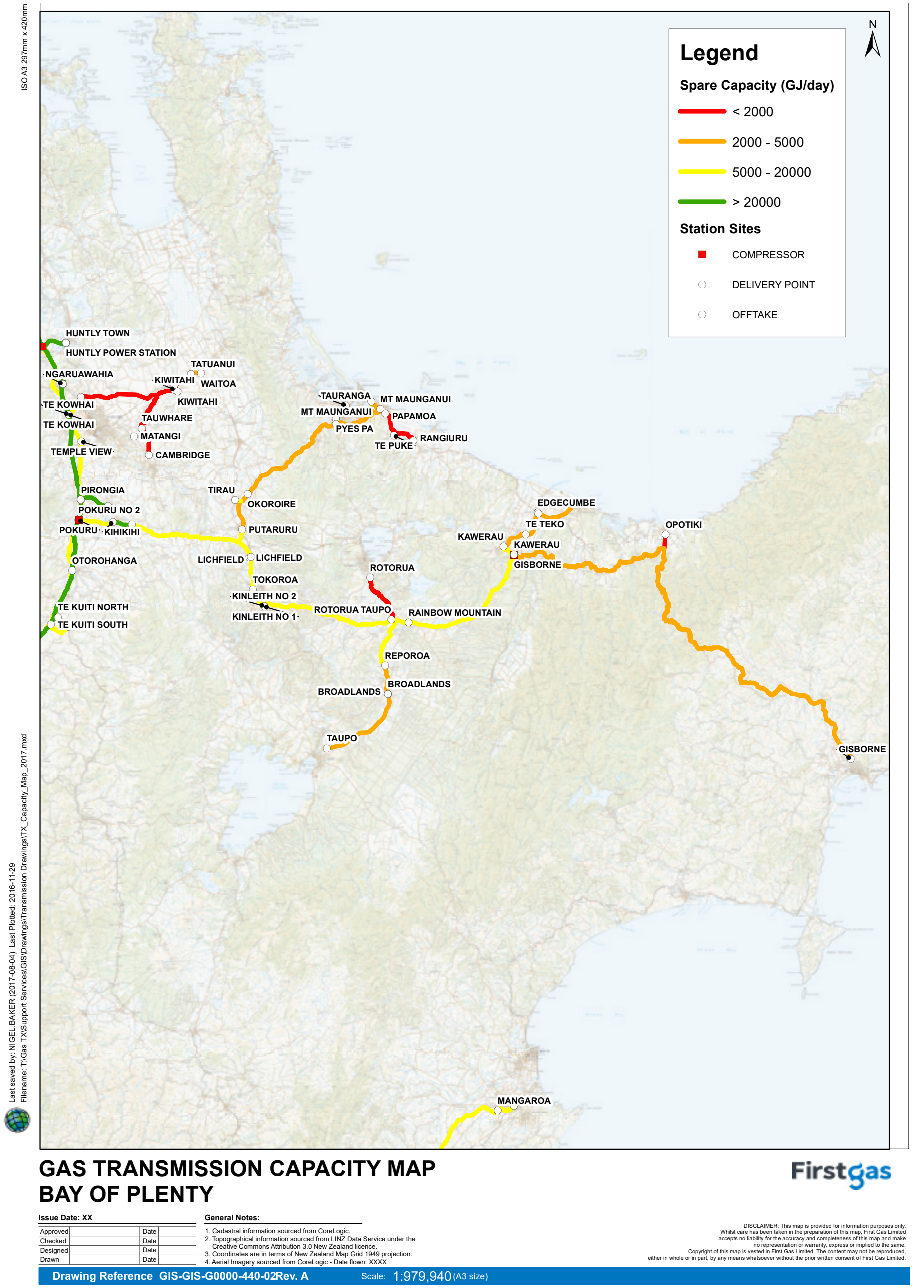
Table C4: Pipeline capacity – Bay of Plenty System

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY17	FY22	FY27
Broadlands	300	2,315	2,299	2,282
Edgecumbe	4,491	4,163	3,844	3,525
Gisborne	1,224	2,826	2,824	2,821
Greater Mount Maunganui	2,499	2,645	2,462	2,278
Greater Tauranga	1,179	2,121	1,928	1,735
Kawerau	2,353	13,350	12,356	11,362
Kihikihi	346	9,925	9,508	9,091
Kinleith	10,987	12,322	11,796	11,270
Lichfield	1,593	13,091	12,521	11,951
Opotiki	68	873	865	858
Putaruru	439	14,630	14,347	14,065
Rangiuru	210	1,990	1,929	1,868
Reporoa	1,898	5,860	5,802	5,744
Rotorua	1,756	1,358	1,338	1,319
Taupo	652	2,481	2,434	2,387
Te Puke	153	1,623	1,546	1,468
Tirau	1,475	11,354	11,336	11,318
Tokoroa	545	15,547	15,070	14,593
Waikeria	115	20,280	19,543	18,805
Whakatane	384	4,687	4,655	4,622

Notes:

- The peak week for the BOP system is the week ending 23rd September 2016.
- No hourly demand was observed at Okoroire and Te Teko DP during the BOP system's peak week.
- Pokuru compression is modelled at a constant discharge pressure of 74 barg.
- Kawerau compression is modelled as available when calculating pipeline capacity to Gisborne and Opotiki delivery points.

Map C4: Pipeline capacity – Bay of Plenty System



South System pipeline capacities

Table C5: Pipeline capacity – South System

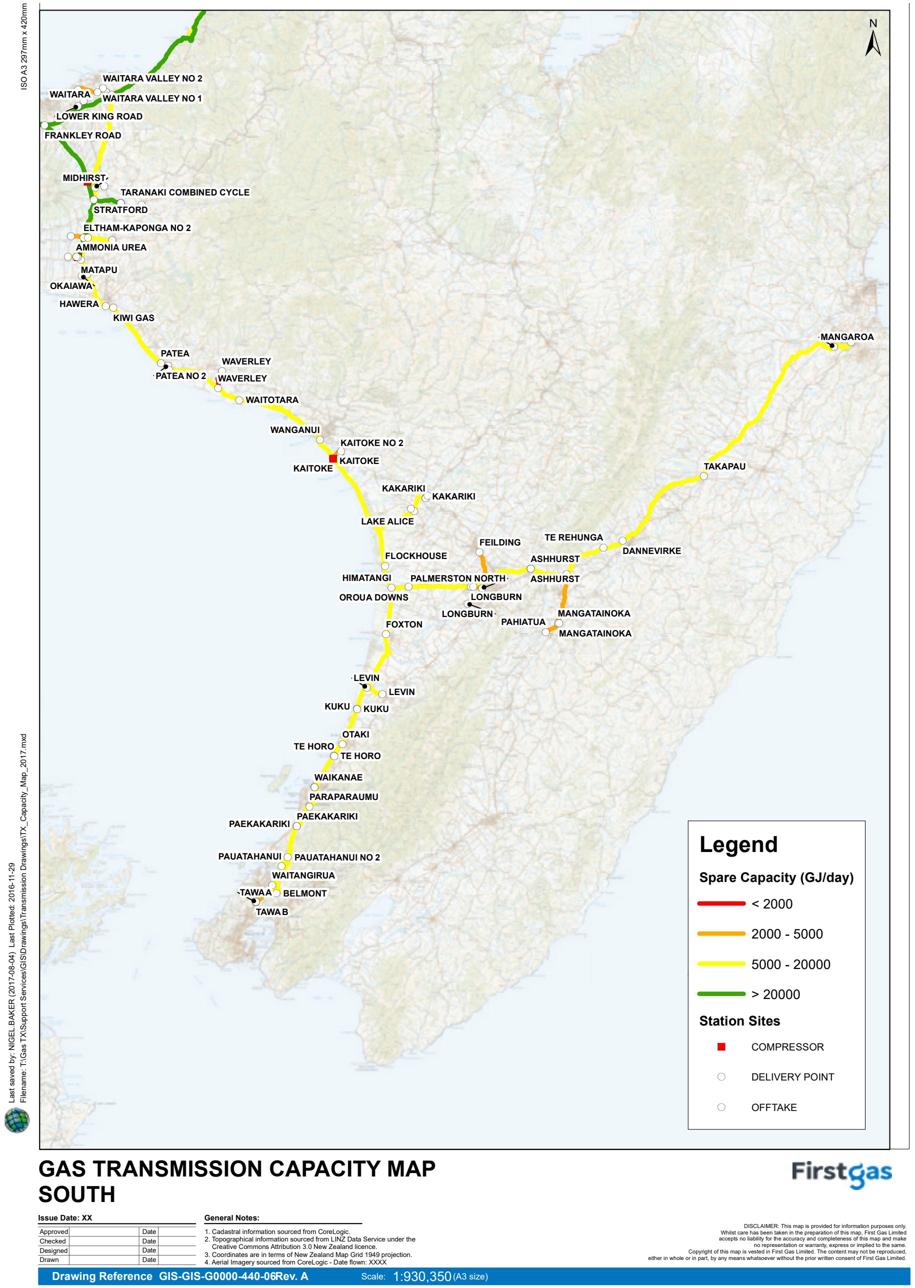
DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY) FY17	FY22	FY27
Ashurst	45	12,304	12,083	11,862
Belmont	6,500	11,946	11,755	11,563
Dannevirke	294	8,311	8,267	8,222
Feilding	1,045	3,929	3,913	3,898
Foxton	180	11,913	11,666	11,419
Hastings	7,659	5,054	4,999	4,943
Hawera	1,343	6,476	6,336	6,196
Kaitoke	88	3,978	3,972	3,967
Kakariki	368	6,488	6,435	6,381
Lake Alice	233	4,222	4,206	4,190
Levin	1,209	5,482	5,461	5,441
Longburn	978	5,767	5,760	5,753
Manaia	74	4,098	4,098	4,098
Mangaroa	91	9,263	9,216	9,169
Marton	835	5,330	5,281	5,232
Okaiawa	1,680	1,681	1,681	1,681
Otaki	102	12,468	12,257	12,045

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY17	FY22	FY27
Pahiatua	3,683	3,039	3,023	3,007
Palmerston North	4,289	4,111	3,979	3,848
Paraparaumu	694	13,138	13,056	12,974
Patea	133	10,132	9,936	9,741
Takapau	509	8,897	8,867	8,837
Tawa	10,235	2,036	1,926	1,815
Waikanae	233	11,849	11,688	11,527
Greater Waitangirua	1,532	12,700	12,698	12,695
Waitotara	133	7,344	7,215	7,086
Wanganui	4,085	9,486	9,252	9,019
Waverley	4	1,062	1,062	1,062

Notes:

- Due to negligible hourly flow, or no flows, calculating Operational Capacities at Flockhouse, Kairanga, Kuku, Matapu, Oroua Downs, Pauatahanui 2, Mangatainoka and Te Horo Delivery Points has not been feasible.
- The calculation of Uncommitted Operational Capacity at Tawa is based on pressures at the Tawa A and B Offtakes being limited to 14 barg. Although not defined in the Gas Transmission Security Standard, 14 barg is the minimum accepted pressure for distribution.
- The South System's Peak week is the week ending the 12th of August 2016.
- Kapuni compression is modelled at a constant discharge pressure of 84 barg
- Kaitoke compression is modelled at a constant discharge pressure of 84 barg

Map C5: Pipeline capacity – South System



Frankley Road system pipeline capacities

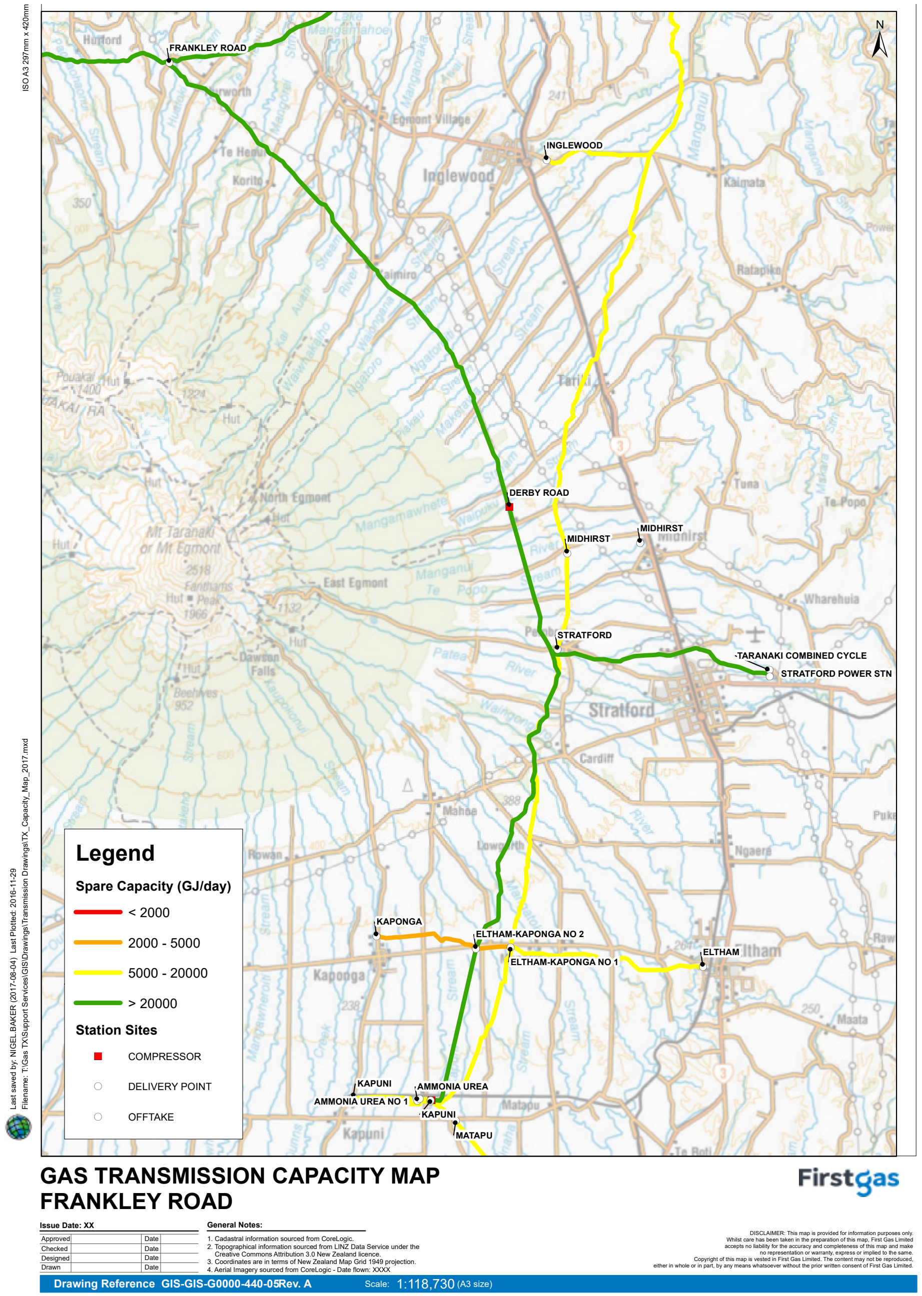
Table C6: Pipeline capacity forecasts – Frankley Road System

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY17	FY22	FY27
AUP	22,500	12,023	12,023	12,023
Kapuni (Lactose)	170	14,819	14,819	14,819
TCC+Strat Power+Strat storage	170,000	73,855	73,855	73,855

Notes:

- Peak week is the week ending the 3rd of January 2016.
- The gas pressure at Frankley Road is modelled as 44 barg entering this system.
- This system normally within the target Taranaki pressure, which is generally in the range of 42 – 48 barg.

Map C6: Pipeline capacity – Frankley Road System



Maui System pipeline capacities

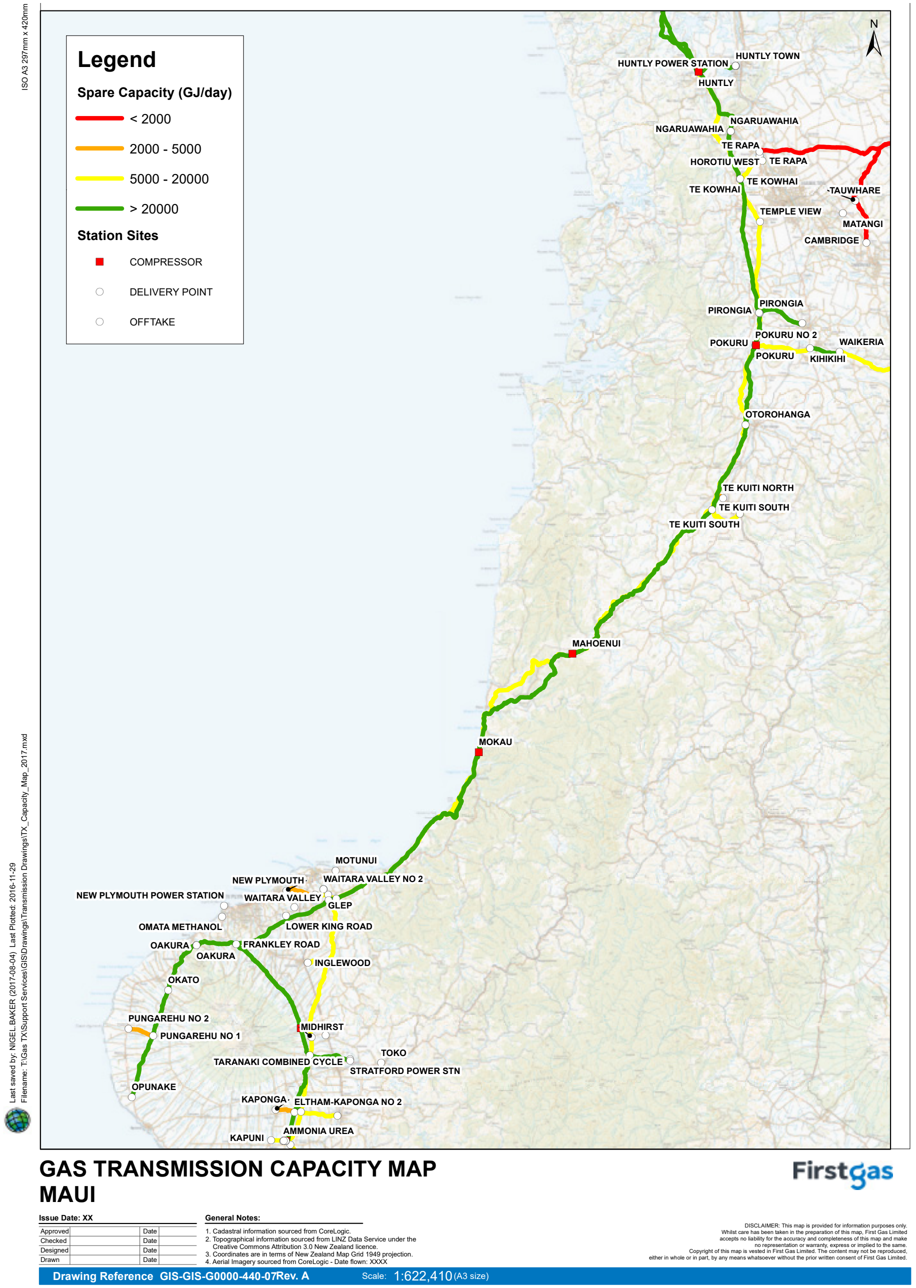
Table C7: Pipeline capacity forecasts – Maui System

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY17	FY22	FY27
Huntly (town)	52	26,872	20,970	15,067
Pirongia	571	38,230	37,374	36,518
Otorohanga	49	61,924	46,281	30,638
Ngaruawahia	24	54,919	40,895	26,872
Te Kuiti North	80	3,020	2,530	2,041
Te Kuiti South	896	6,009	5,982	5,955
Oakura	36	3,351	3,242	3,133
Okato	10	255,725	248,840	241,955
Rotowaro	93,718	86,221	63,261	40,301
Pokuru	18,345	79,802	59,403	39,005
Bertrand Road	95,863	185,974	172,554	159,133
Huntly Powerstation	71,436	70,721	52,148	33,575

Notes:

- Due to zero flow/negligible demand at Pungarehu No1 and Pungarehu No2, calculating Uncommitted Operational Capacities at these sites has not been feasible.
- Calculating the Spare Capacity at Opunake Delivery Point is not feasible since this delivery point is immediately downstream of the Oaonui Production Station.
- Calculating Spare Capacity at Frankley Road and Ngatimaru Road Delivery Points is not feasible since these have bi-directional metering, that also act as Intake Points into the Maui System.
- A 46 barg source pressure has been assumed at Oaonui Production Station
- Mokau compression has been modelled at a constant discharge pressure of 56 barg
- The peak week for this system is the week ending the 12th of August 2016.

Map C7: Pipeline capacity – Maui System



APPENDIX D: DIRECTOR CERTIFICATE – TRANSMISSION

Certification for Year-beginning Disclosures

Clause 2.9.1

We, Philippa Dunphy and Richard Krogh, being directors of First Gas Limited, certify that, having made all reasonable enquiry, to the best of our knowledge:

a) the following attached information of First Gas Limited prepared for the purposes of clauses 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the *Gas Transmission Information Disclosure Determination 2012* in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards; and

c) The forecasts in Schedules 11a, 11b, 12a and 12b are based on objective and reasonable assumptions which both align with First Gas corporate vision and strategy and are documented in retained records.

Philippa Dunphy **Director**	**Richard Krogh** **Director**
06 September 2017	06 September 2017
Date	**Date**