Firstgas

GAS TRANSMISSION BUSINESS

Asset Management Plan Update

Year commencing 1 October 2019

First Gas Limited
September 2019

MESSAGE FROM THE CHIEF EXECUTIVE OFFICER

Dear Stakeholders

Welcome to First Gas Limited's gas transmission Asset Management Plan (AMP) Update for 2019. Our business remains focused on delivering the benefits of natural gas to our customers and ensuring that gas is an attractive fuel source. We have maintained our focus on continuously improving our business and are making great progress on our asset management improvement programme.

Over the last 12 months, we have again delivered a significant capital programme that was aligned with what we forecast in our 2018 AMP. A priority project was the Pariroa pipeline bypass project, responding to the discovery of a crease in the Maui transmission pipeline. To prioritise pipeline security, First Gas took a collaborative approach with stakeholders and installed a temporary bypass in December 2018. This minimised the impact on stakeholders, and our collaborative approach to this work saw First Gas nominated as a finalist in the 2019 Deloitte's Energy Awards.

In the coming year, we will be undertaking the second phase of the Pariroa project, as well as completing the Gilbert Stream realignment project. Our focus also remains on geohazard monitoring and remediation, alongside progressing a compression strategy to optimise how we operate our network. Next year will also see the introduction of a new single access code, the Gas Transmission Access Code (GTAC). We have valued stakeholder's intensive engagement on this strategic initiative for the gas sector and believe it will reduce barriers to market entry and improve the efficiency of the gas market.

Following the launch of the new look 2018 AMPs, we have continued to develop the "dashboards" that present key indicators for asset health and criticality on our networks and show how our expenditure programmes are influencing overall asset health and managing risk. The Commerce Commission is currently undertaking a review of gas pipeline businesses' practices around risk management and asset criticality.

First Gas intends to use the findings of this review to improve our AMP dashboards and how we communicate our overall asset management approach. The findings of this review and our subsequent changes will be included within our 2020 full AMP.

Finally, the past year has seen a continued and heightened effort on addressing climate change, with the Government progressing work to support the goal of net zero emissions by 2050. At the time of writing, the *Climate Change Response (Zero Carbon) Amendment Bill* is before Parliament, a new National Energy Development Centre has been announced for New Plymouth, and discussion is increasing on the role that future fuels like hydrogen can play in New Zealand.

Gas infrastructure will make an important contribution to decarbonisation in New Zealand. Gas networks provide a flexible and resilient way to transport and store energy, supporting a higher renewables electricity grid. The Vivid Economics report we commissioned with Powerco highlighted that natural gas and gas infrastructure have high option value to address hard-to-treat sectors such as high-temperature process heat. We will continue to proactively engage with Government and stakeholders to ensure that gas plays its part in this transition.

We look forward to continuing to work with you all.

Paul Goodeve
Chief Executive Officer

GLOSSARY

TERM	DEFINITION
AMMAT	Asset Management Maturity Assessment Tool
AMP	Asset Management Plan
Asset grades	Grade 1: means end of service life, immediate intervention required Grade 2: means material deterioration but asset condition still within serviceable life parameters. Intervention likely to be required within three years Grade 3: means normal deterioration requiring regular monitoring Grade 4: means good or as new condition Grade unknown: means condition unknown or not yet assessed
Capex	Capital expenditure – the expenditure used to create new or upgrade existing physical assets in the network, as well as non-network assets
CCC	Climate Change Commission, government body proposed to be established through the Climate Change Response (Zero Carbon) Amendment Bill
CCO	Critical Contingency Operator
CCMP	Critical Contingency Management Plan
COO	Chief Operating Officer
CPP	Customised Price – Quality Path
CPU	Central Processing Unit
DP	Delivery Point
DPP	Default Price – Quality Path
FEED	Front End Engineering Design
FY2019	Financial year ending 30 September 2019
GIC	Gas Industry Company – New Zealand's gas industry co-regulatory body
GM	General Manager
GMS	Gas Measurement System – commonly referred to as a gas meter
GTAC	Gas transmission access code – the single commercial code for the transmission system which will replace the Maui Pipeline Operating Code and the Vector Transmission Code. The GTAC is effective from 1 April 2020.
GTB	Gas Transmission Business
HDD	Horizontal directional drilling

TERM	DEFINITION
HSEQ	Health, Safety, Environment and Quality
ICP	Installation Control Point
IMs	Input Methodologies – documents set by the Commerce Commission which promote certainty for suppliers and consumers in relation to the rules, requirements, and processes applying to the regulation under Part 4 of the Commerce Act 1986
IS	Information Systems
IT	Information Technology
KGTP	Kapuni Gas Treatment Plant
KPI	Key Performance Indicators
MLV	Main line valve
NZTA	New Zealand Transport Agency
NEDC	National Energy Development Centre
OATIS	Open Access Transmission Information System, to be replaced by TACOS when the Gas Transmission Access Code goes live.
Opex	Operational expenditure – the ongoing costs directly associated with running the gas transmission system. This includes costs both directly related to the network (e.g. routine and corrective maintenance, service interruptions/ incidents, land management) and non-network related expenditure (e.g. network and business support)
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 (unit of energy). 10^{15} joules = 1,000 TJ
RAB	Regulated Asset Base
RTE	Response Time to Emergencies
SCADA	Supervisory control and data acquisition
TACOS	Transmission Access Commercial Operations System, will replace OATIS when the Gas Transmission Access Code takes effect.
TJ	Terajoule (unit of energy) = 10^{12} Joules
UAV	Unmanned aerial vehicle

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1. INTRODUCTION

This is First Gas Limited's (First Gas) Gas Transmission Asset Management Plan (AMP) Update for 2019.

First Gas owns and operates New Zealand's gas transmission system. Our system transports large volumes of natural gas from production stations to distribution networks and large customers across the North Island.

As the sole provider of gas transmission services, we are regulated by Part 4 of the Commerce Act 1986 and subject to both price-quality path and information disclosure requirements. Producing an AMP or AMP Update each year is one of these requirements, as well as being a key document guiding investment and operational priorities of our business.

This section outlines the purpose, scope and structure of our 2019 AMP Update and provides an overview of the material changes from our AMP published in 2018. We also set out the key regulatory and environment changes that are influencing our gas transmission business.

1.1 PURPOSE OF THE AMP UPDATE

This AMP Update focuses on the material changes from the 2018 AMP that influence our planned expenditure and the growth 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 this planning period, we consider it essential that we clearly outline our plans for the transmission system, while maintaining flexibility to adapt and respond to customer and shipper requests as the year progresses.

In addition, we are using this opportunity to update all our stakeholders and customers on our progress against the plans stated in the 2018 AMP, and to outline our focus areas for the year ahead. We see the release of this document as one part of our ongoing engagement with our customers, and it provides an important way for our customers to evaluate the value being delivered by our capital programme.

Alignment with regulatory requirements

Our AMP Update aligns with regulatory requirements, as it:

1. Relates to the gas transmission services supplied by the GTB.
2. Identifies any material changes to the network development plans disclosed in the last AMP under clause 14 of Attachment A3 or in the last AMP update disclosed under this clause.
3. Identifies 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. Provides 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. Provides an assessment of transmission capacity as set out in clause 8 of Attachment A.
6. Identifies any material changes related to the legislative requirements as set out in clause 3.6 of Attachment A.
7. Identifies any changes to the asset management practices of the GTB that would affect a Schedule 13 Report on Asset Management Maturity disclosure.
8. Contains the information set out in the schedules described in clause 2.6.6 (Schedules 11a, 11b, 12a and 12b).[1]

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 2018 AMP, which is available here.

Objectives for our gas transmission system

Throughout this AMP Update, we describe how we will achieve the following important objectives for our gas transmission system:

- **Safety commitment:** Explain that the safety of our staff, service providers and the general public is paramount.
- **Engaged stakeholders:** Consult with our stakeholders, particularly on our planned investments, and inform them about how we intend to manage the gas transmission system. This requires us to provide clear descriptions of our assets, key strategies and objectives.
- **Performance accountability:** Provide visibility to stakeholders on how we are performing and provide information on the performance of our system.
- **Investment planning:** Provide visibility of forecast investment programmes and upcoming medium-term construction works, with a clear rationale as to why planned investments are the best way to meet service requirements.
- **Informed staff and contractors:** Provide guidance and clarity on our asset management approach to staff and service providers to ensure a common understanding and suitable resourcing.
- **Regulatory compliance:** Ensure we meet our Information Disclosure obligations set by the Commerce Commission.

1. As set out in clause 2.6.5 of the *Gas Transmission Information Disclosure Determination 2012,* consolidating all amendments as of 3 April 2018, Commerce Commission

1.2 PERIOD COVERED BY THE AMP

The AMP Update covers the ten-year period from 1 October 2019 through to 30 September 2029 (the planning period). This aligns with our 1 October to 30 September financial and pricing year. The expenditure forecasts presented in this AMP Update are expressed in constant 2019 prices (unless otherwise stated).

The 2019 First Gas AMP Update was approved by our Board of Directors on 14 August 2019.

1.3 STRUCTURE OF THE AMP

The structure of the AMP Update is based on the full AMP summary and is a standalone document that provides a high-level overview of the material changes from the 2018 AMP. It outlines what we have achieved over the past 12 months, and the key activities in the coming year. It also provides a summary of our forecast expenditure over the next ten years. We have designed this document for those customers and stakeholders who want a concise overview of our asset management plan for the planning period.

First Gas also owns and operates a gas distribution business that serves consumers across Northland, Waikato, the Central Plateau, Bay of Plenty, Gisborne and Kapiti. For information on our gas distribution business, please refer to our 2019 Gas Distribution AMP Update, which can be accessed on our website **www.firstgas.co.nz**

The First Gas Group also owns energy infrastructure assets across New Zealand through our affiliate Gas Services NZ Limited (GSNZ), a separate business with common shareholders that owns the Ahuroa gas storage facility and Rockgas. These businesses were both added to the First Gas Group in the past 12 months, providing valuable perspectives from different parts of the gas supply chain for our regulated transmission business.

The Ahuroa gas storage facility (trading as Flex Gas Limited) can store up to 18PJ of gas, with expansion planned over the next two years to increase the injection and withdrawal rates of the facility. Visit the website **www.flexgas.co.nz**

Rockgas has over 80 years' experience providing LPG to 100,000 customers throughout New Zealand.
Visit the website **www.rockgas.co.nz**

2. OVERVIEW OF FIRST GAS

This section introduces our gas transmission business and provides an overview of how the organisation is structured. It also provides information on our gas transmission system, our approach to asset management and managing risk, and the key regulatory and environmental factors influencing our business over the past year.

2.1 CORPORATE STRUCTURE OF FIRST GAS

First Gas Limited is owned by First State Funds, part of the Commonwealth Bank of Australia's group of companies. First State Funds[2] comprises two infrastructure funds managed by First State Investments. First State Investments (known in Australia as Colonial First State Global Asset Management) is a leading global infrastructure asset manager, overseeing approximately $240 billion of infrastructure assets across Australia, New Zealand and Europe.

On 20 April 2016, First Gas took control of Vector Limited's gas transmission assets and gas distribution assets located outside of Auckland. In a separate transaction, First Gas took ownership of Maui Development Limited's gas transmission assets on 15 June 2016. The creation of First Gas has resulted in a company with a focus on gas-related assets. We believe that this focus is delivering three distinct advantages for gas industry participants and our customers:

- A strong commercial interest in maximising the competitiveness of gas, both now and into the future;
- An opportunity to add new capabilities to our team to drive growth in the use of the gas transmission system; and
- An ability to operate the gas transmission system and manage our assets in ways that better serve the interests of our customers.

First Gas Board

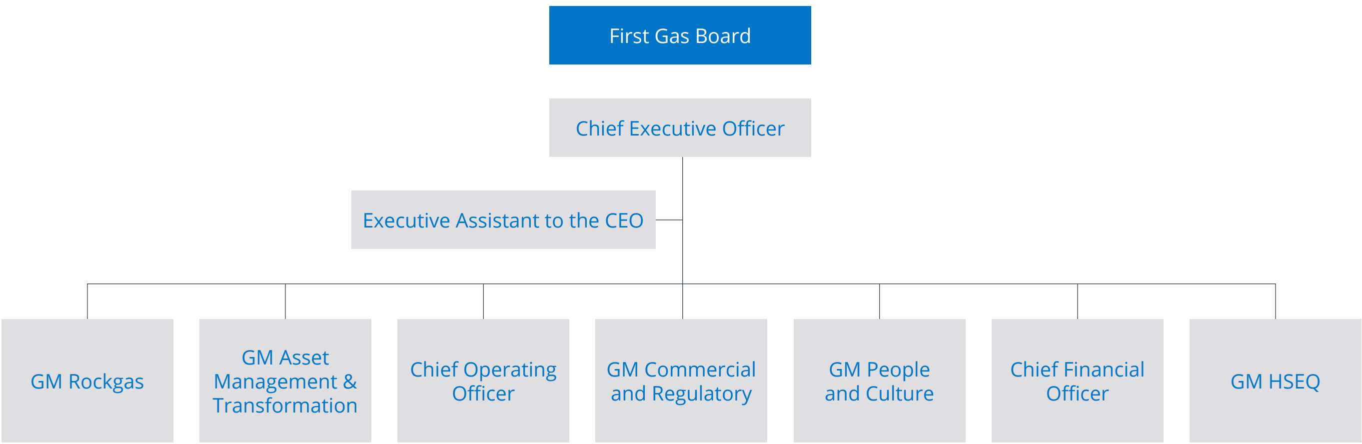
First Gas is governed by a Board of Directors, chaired by Philippa Dunphy. The Board has a mixture of professional infrastructure experience from both sides of the Tasman. Biographies of our Board are available on our website **www.firstgas.co.nz**.

2.2 ORGANISATIONAL STRUCTURE

First Gas employs approximately 180 staff in our corporate centres and pipelines business. Most staff are based in our headquarters in Bell Block, New Plymouth; with small teams located in Wellington, Palmerston North and Hamilton. Our Executive team is headed by Chief Executive Officer Paul Goodeve, with seven direct reports: Chief Operating Officer (COO), Chief Financial Officer, General Manager Commercial and Regulation, General Manager People and Performance, General Manager Asset Management and Transformation, General Manager Health, Safety, Environment and Quality (HSEQ) and General Manager Rockgas.[3]

Our organisational structure is illustrated in Figure 1 below.

Figure 1: Organisation chart



2. More information on First State Funds is available on their website https://www.firststateinvestments.com/global/about-us/corporate-profile.html
3. Biographies of our Executive Team are available on our website www.firstgas.co.nz

2.3 CONTINUED PUSH TO MAXIMISE COMPETITIVENESS OF GAS

Since the establishment of First Gas, we have put significant effort into promoting the benefits of natural gas to our customers and making it an attractive fuel source.

We acknowledge that for many of our customers, gas is a fuel of choice. Unlike electricity, which is universal across New Zealand households and businesses, reticulated natural gas is often considered an option, rather than a necessity. This means we need to actively market natural gas to compete with other forms of energy available in New Zealand.

Our focus on gas directly influences our approach to asset management through our strong desire to investigate and convert growth opportunities across our gas transmission network. We believe that having more customers, with more diverse needs, makes our business more resilient, ultimately leading to more competitive prices for our customers when accessing and using the transmission network.

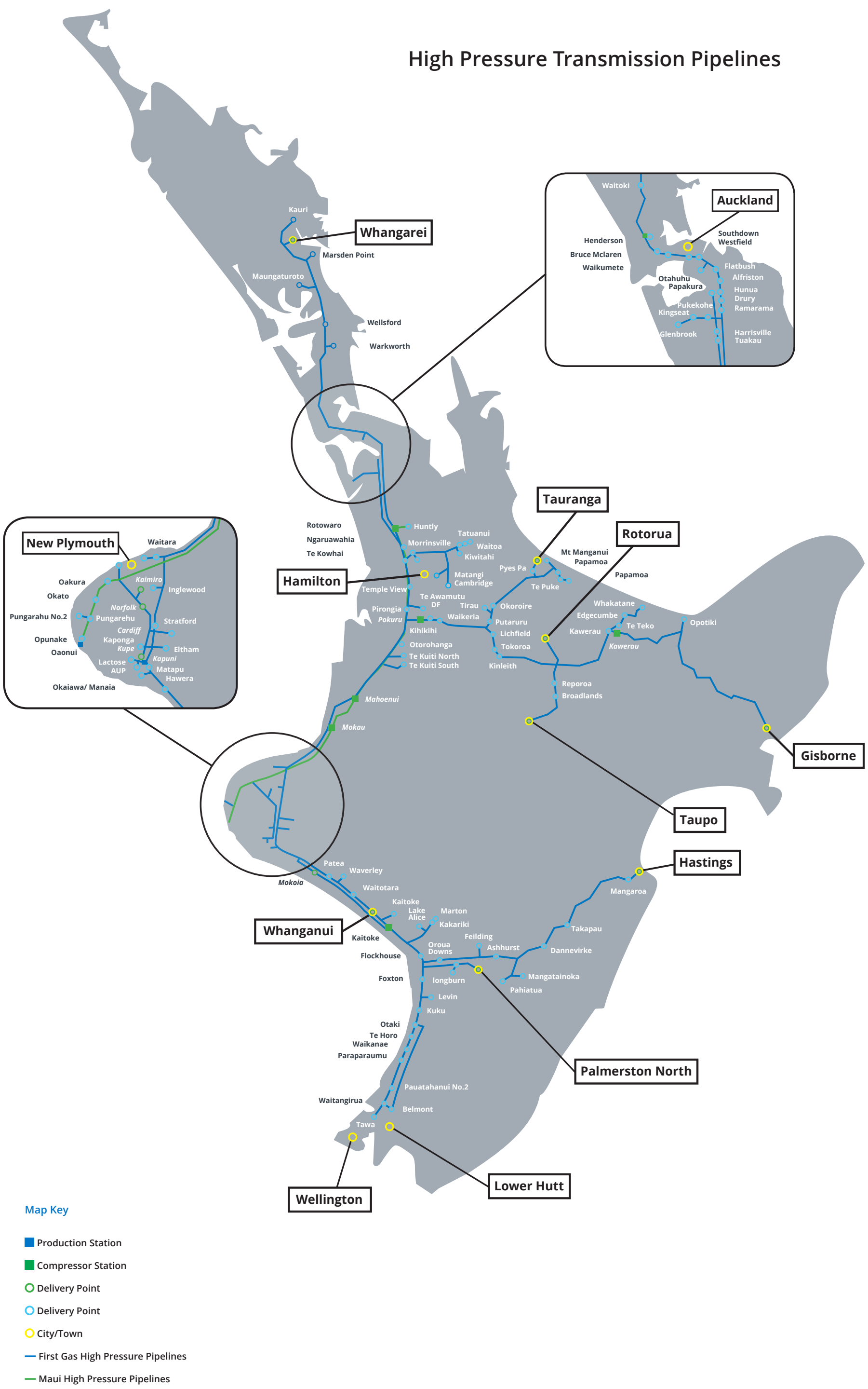
2.4 OUR GAS TRANSMISSION SYSTEM

First Gas owns and operates a gas transmission system consisting of underground pipelines, compressor facilities and above ground stations in the North Island of New Zealand. The transmission system incorporates both the Maui and non-Maui[4] transmission pipelines, as set out in Figure 2.

The transmission system is 2,513 kilometres in length, with approximately 137 kilometres installed in urban areas and the remainder in rural areas. The nominal internal diameter of the pipelines range from 50mm to 850mm, with the majority installed below ground. The pipelines connect 252 stations that contain a range of equipment designed to receive, transmit and deliver gas safely and efficiently to customers.

The key statistics for our gas transmission network, as at 30 June 2019, are set out in Table 1.

Figure 2: Our gas transmission system



4. The gas transmission system purchased off Vector Limited in April 2016.

Table 1: Key gas transmission statistics as at 30 June 2019

STATISTIC	VALUE	CHANGE FROM 2018
System length (kilometres)	2,513	2km
Compressor stations	9	0
Compressor units	23	0
Delivery points	120	1

Asset categories across the transmission system

The types of assets used across our transmission system are described in Table 2.

Table 2: Asset categories

ASSET CATEGORY	DESCRIPTION
Compressor stations	Compressor stations are situated at strategic locations and are designed to increase the pressure of the transport gas to ensure that the required gas pressure and quantity is delivered to the extremities of the system. There are reciprocating, gas turbine, and electric drive compressors in use on our system.
Heating systems	When gas pressure is reduced by pressure regulators at delivery points, the gas temperature reduces. To maintain gas temperature above the lower limit specified in *NZS 5442 – Gas Specification for Reticulated Natural Gas*, heating systems are required.
Odorisation plants	Gas odorisation is used to provide a means for the detection and location of gas escapes. We odorise gas using electronic pumped odorant injection systems, supported by bulk odorant storage tanks at KGTP and the major receipt points from the Maui transmission pipeline.
Coalescers and filter/separators	Coalescers and filter/separators are used to protect downstream facilities such as compressors, pressure regulators and meters from fine particles of liquid contaminants and impurities in the gas streams.
Metering systems	Metering systems are used to provide accurate gas volume flow data. Meters have rotary-displacement, turbine, ultrasonic, mass flow or diaphragm gas volume measurement mechanisms.
SCADA and communications	The SCADA system constantly monitors asset operating conditions at strategic pipeline locations, including high-volume delivery points and delivery points at pipeline extremities. It also provides remote control of compressors and some MLVs.
Gas chromatographs (GCs)	A GC is a chemical analysis instrument for analysing chemical components in a complex sample. It uses flow through a narrow tube known as a column, through which different chemical constituents of a sample pass in a gas stream (carrier gas, mobile phase) at different rates depending on their chemical and physical properties and their interaction with a specific column filling (stationary phase). As the components exit from the end of the column, they are detected and identified electronically.
PIG launchers and receivers	PIG launchers and receivers facilitate the use of In Line Inspection (ILI) survey tools for pipeline condition monitoring and internal cleaning tools. PIG receivers also act to contain and facilitate safe disposal of debris which is removed from the pipeline by PIGs.
Pressure regulators	Pressure regulators reduce the pressure of the flowing gas to a pre-determined downstream pressure. Pressure regulators form part of delivery point equipment that supplies gas at reduced pressure to gas distribution networks, directly to customers or to downstream parts of the transmission system.

ASSET CATEGORY	DESCRIPTION
Pressure relief valves	Pressure relief valves are installed to protect pipelines or pressure vessels from over pressurisation. Pressure relief valves limit pressure to a pre-determined value by safely venting gas contained within the protected equipment to the atmosphere.
Isolation valves	Isolation valves are used to isolate sections of station pipe work, instrumentation tubing, equipment or control systems to facilitate maintenance, replacement or emergency shutdown.
Filters	Filters are installed to remove solid particulate contamination from the system and protect downstream equipment from erosion by impingement and blockage from build-up of contaminants.
Critical spares and equipment	We own a stock of critical spares and equipment for an anticipated range of pipeline repair options. Whenever new assets are introduced, an evaluation is made of the necessary spares and equipment items required to be retained to support the repair of any equipment failures.

Greater detail on our transmission assets is provided in the 2018 AMP in **Appendix C.**

2.5 OUR ASSET MANAGEMENT APPROACH

First Gas' approach to asset management is guided by a suite of asset management documents and practices that ensure we are meeting our performance objectives and the expectations of our stakeholders. Our approach incorporates:

- **Asset Management Framework:** This framework describes our approach to ensuring alignment between our corporate objectives and our day-to-day asset management activities. It covers our strategic plan, which guides the subsequent development of our Asset Management system, asset management policy, objectives and ultimately this AMP Update (and full AMPs).
- **Asset Management System:** This system links our corporate objectives and stakeholder needs to specific asset management approaches through our Asset Management Policy. It aligns with the requirements of ISO 55001, the international standard for asset management, and seeks to reflect good practice.
- **Performance Measures:** These documents set out the overall asset management performance objectives and the key performance indicators (KPIs) that First Gas regularly monitor to ensure we provide a safe and reliable gas transmission system. Where appropriate, the targets have been developed to align with the definitions developed by the Commerce Commission for Information Disclosure.

Our AMPs and AMP Updates capture the key elements of this asset management document suite in a summarised form and explains our asset management strategy and approach to both internal and external stakeholders. Greater detail on our approach to asset management and KPIs is set out in our 2018 AMP in **Appendix H.**

Addressing risks on our transmission system

Risk management is a key component of good asset management. The consideration of risk plays a key role in our asset management decisions; from transmission system development planning, asset replacement decisions through to operational decisions. The assessment of risk and the effectiveness of options to minimise risk is one of the main factors in our investment choices.

Key risk and review elements for First Gas include:

- **Risk management:** Our core processes are designed to manage existing risks, and to ensure emerging risks are identified, evaluated and managed appropriately.
- **Contingency planning and response:** This ensures we are prepared for and can respond quickly to a major incident that occurs or may occur on our gas transmission system.
- **Event management:** This provides clear definitions and guidance for all disciplines working for First Gas in order to ensure a consistent approach in recognising and reporting events.

Given the potentially severe nature of failures in operation (particularly loss of containment), appropriate and effective risk management is integral to our day-to-day asset management approach. Our asset management information systems and our core processes are designed to manage existing risks, and to ensure emerging risks are identified, evaluated and managed appropriately. Our approach is centred around:

- **Prioritising safety:** We prioritise those risks that may impact the safety of the public, our staff and service providers.
- **Ensuring security of supply:** Our works development and lifecycle management processes include formal evaluation of our assets against our security criteria.
- **Addressing poor condition/non-standard equipment:** Our lifecycle management processes seek out critical items of equipment that are at a higher risk of failure or are non-standard.
- **Formal risk review and sign-off:** Our processes include formal requirements to manage the risks identified, including mandatory treatment of high-risk items and formal management sign-off where acceptance of moderate risk is recommended.

- **Use of structured risk management:** We use structured risk capture and management processes to ensure key residual risks are visible and signed off at an appropriate level.

Gas industry codes require risk management to be a continuous process at all stages throughout the lifecycle of our gas transmission network. The nature of the gas transmission business is such that there are many inherent risks. In addition, safety management is one of our top operational priorities.

Greater detail on our approach to risk management is set out in our 2018 AMP in **Appendix H.**

Improving how we communicate asset health and criticality information

In our 2018 AMPs, we introduced new "dashboards" that described asset health and criticality, and how our expenditure programmes are influencing overall asset health and managing risk. These dashboards were in response to customer feedback that they sought greater clarity around our expenditure and are driven by our asset management improvements.

In late 2018, the Commission commenced a review of all gas pipeline businesses' Asset Management Plans (AMPs). The review focused on two aspects:

- A review of all businesses' asset **risk management** and associated practices, looking at matters such as asset criticality, resilience, use of cost-benefit analysis, asset data accuracy and consideration of customer expectations.
- A review of First Gas' management of **geotechnical risks** on the transmission network.

The AMP review involved a desk top review of the AMPs and supporting documentation by independent experts, as well as meetings with staff in mid-March 2019. At the time of writing, the findings of the Commission's review were expected to be finalised by September 2019. We intend to use these findings to improve how we:

- Demonstrate the link between asset health, asset criticality with expenditure.
- Demonstrate how we manage high impact low probability (HLP) events.
- Show how we manage network risk on behalf of customers, which demonstrates the trade-off between cost and risk mitigation.

We plan to discuss these improvements with both internal and external customers in the coming year and will incorporate the updated dashboards in our 2020 AMP (the next full AMP).

Transmission System Owner and Operator

In addition to our role as the asset owner, First Gas also undertakes the key role of system operator for the gas transmission system.

The system operator is a market operation service provider that performs a crucial role for the gas transmission system in New Zealand. The system operator manages the security of the transmission system and co-ordinates the supply and demand for gas. The system operator receives the gas from producers, transports it via our pipelines through the system to the customers.

As system operator, we fulfil several roles relating to the day to day operation and running of the transmission system, including the administration of the nominations regime, OATIS[5] process management and calculation of line pack and capacity. We are strongly focused on ensuring enough information is readily available to support our security of supply requirements (as set out in **Appendix G** of our 2018 AMP).

Figure 3: Our gas transmission control room

5. OATIS will be replaced by the new IT system, TACOS, to support the Gas Transmission Access Code (GTAC)

Role of the Critical Contingency Operator

The Gas Industry Company administers the *Gas Governance (Critical Contingency Management Regulations 2008) Regulations.* The purpose of these regulations is to achieve the effective management of critical gas outages and other security of supply contingencies, without compromising long-term security of supply. The regulations achieve this principally through the appointment of a **Critical Contingency Operator (CCO)** who has a range of powers including the curtailment of gas consumption during critical contingencies.

Critical contingencies occur when there is a shortage of gas supply relative to demand. The pressure in the transmission system subsequently falls to a level where intervention is required to ensure that sufficient supply of gas is maintained in the transmission system to supply distribution networks and domestic consumers.

The CCO role is performed by persons approved by Gas Industry Company. The role of the CCO[6] includes:

- Determining and declaring the onset of a Critical Contingency;
- Calling for load curtailment as required to balance the system;
- Monitoring the supply/demand balance and adjusting load curtailment directions as necessary; and
- Determining when it is safe to terminate a Critical Contingency.

If a critical contingency event occurs, the CCO will issue instructions to the industry designed to ensure that the balance between supply and demand is maintained. The transmission system operator (First Gas) always remains in direct control and management of the transmission system, and activates processes and procedures contained in the Critical Contingency Management Plan (CCMP).

2.6 REGULATORY AND POLICY ENVIRONMENT

This section provides an overview of the regulatory environment that our gas transmission business operates within. A key milestone achieved this year was the approval of the Gas Transmission Access Code (GTAC), which will come into effect from 1 April 2020. We have seen a reasonably stable year for other regulatory settings, with the business focused on implementing new Information Disclosure amendments introduced by the Commerce Commission in late 2017.

We also discuss the recent changes in policy for the gas sector, and the Government's increased focus on climate change and its intention to introduce a net zero carbon target into legislation. We set out how First Gas is responding to this changing environment and demonstrating the important role that natural gas has a role to play in assisting New Zealand's transition to a lower-emissions economy.

Approval of single access code for the gas transmission system

In February 2019, the Gas Industry Company (GIC) released its final assessment of the Gas Transmission Access Code (GTAC), concluding that the GTAC was materially better than the existing arrangements.[7]

The assessment of the GTAC was a three-step assessment process, comprising of:

- A detailed bottom up analysis of the components of the GTAC relative to the equivalents in the existing codes;
- A top down analysis comparing the expected performance of the GTAC against the MPOC and VTC in each dimension of the objectives; and
- An overall assessment of whether, considered as a whole, the GTAC would be materially better than the current terms and conditions for access to and use of the transmission pipelines.

This project was initiated in August 2016 and is a strategic initiative for the New Zealand gas industry. We strongly believe that the consolidation of the two existing codes into the single GTAC will provide a more effective way of making pipeline capacity available. It should also reduce barriers to market entry and improve the efficiency of the gas market.

The approval of the GTAC has enabled First Gas to move to the implementation phase of the project, as we get ready for a go live date of 1 April 2020.

Under the GTAC, shippers will make nominations for how much capacity they require on each day to deliver gas to their customers at any delivery point or zone. Figure 4 shows the zones for pricing under the GTAC.

6. For more information, see the Critical Contingency Operator website, http://www.cco.org.nz/.
7. The Maui Pipeline Operating Code (MPOC) and the Vector Transmission Code (VTC).

Delivery Zones

- **(NTHL) Te Tai Tokerau (Northland)**
  Marsden 2, Waitoki, Warkworth, Wellsford, Whangarei
- **(AUCK) Tāmakimakaurau (Auckland)**
  Alfriston, Drury 1, Flat Bush, Glenbrook, Greater Auckland, Harrisville 2, Hunua, Hunua (Nova), Hunua 3, Kingseat, Pukekohe, Ramarama, Tuakau 2, Waiuku
- **(WKTN) Waikato ki te Raki (Waikato North)**
  Cambridge, Horotiu, Kiwitahi 1 (Peroxide),Kiwitahi 2, Matangi, Morrinsville, Morrinsville DF, Tatunanui DF, Waitoa
- **(HMTN) Kirikiriroa (Hamilton)**
  Greater Hamilton
- **(KING) Te Rohe Pōtae-Taupiri (King Country-Taupiri)**
  Greater Kihikihi, Huntly, Ngaruawahia, Otorohanga, Pirongia, Te Awamutu DF, Te Kuiti North, Te Kuiti South
- **(WKTS) Waikato ki te Tonga (Waikato South)**
  Kinleith, Kinleith (Pulp & Paper), Lichfield 2, Lichfield DF, Okoroire Springs, Putaruru, Tirau, Tirau DF, Tokoroa, Waikeria
- **(TNGA) Tauranga**
  Greater Mt Maunganui, Greater Tauranga, Rangiruru, Te Puke
- **(TAPO) Central Plateau**
  Broadlands, Kawerau, Kawerau (Tissue), Kawerau (Pulp & paper), Reporoa, Rotorua, Taupo
- **(WHAK) Whakatane**
  Edgecumbe, Edgecumb DF, Te Teko, Whakatane
- **(EAST) Te Tai Rawhiti (Eastland)**
  Gisborne, Opotiki

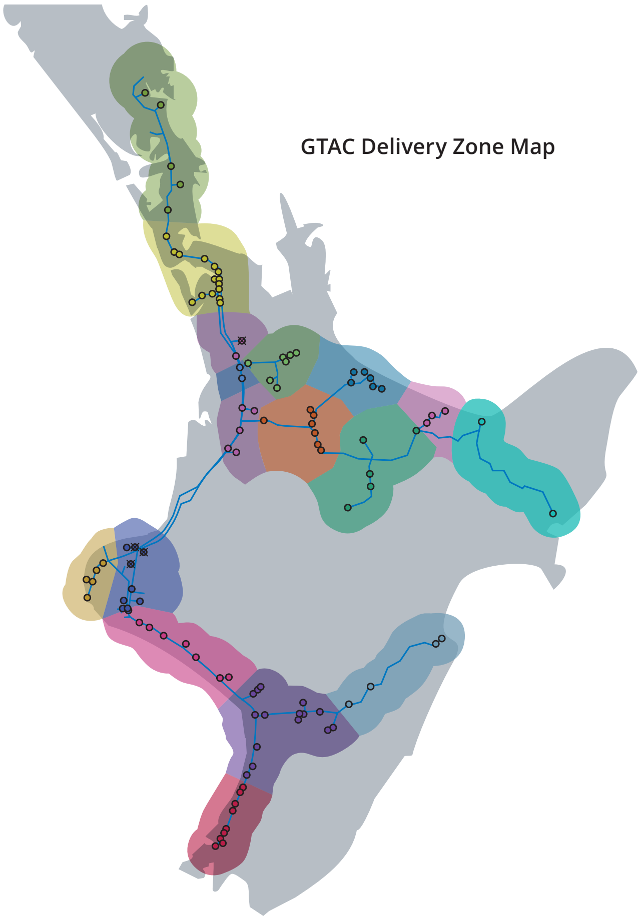
Zone South

- **(TKIE)Taranaki ki Uta (Inland Taranaki)**
  Ballance 8201, Ballance 9626, Eltham, Inglewood, Kaimiro, Kaponga, Kapuni (Lactose etal), KGTPmDelivery, Kupe Delivery Point, New Plymouth, Stratford, Stratford 3, Tikorangi 3, Waitara
- **(TKIW) Taranaki ki Tai (Coastal Taranaki)**
  Oakura, Okato, Opunake, Pungarehu 1, Pungarehu 2
- **(ATEA) Aotea (South Taranaki Whanganui)**
  Hawera, Hawera (Nova), Kaitoke, Manaia, Matapu, Mokoia, Patea, Waitotora, Whanganui, Waverly
- **(TRUA) Tararua (Manawatu-Horowhenua)**
  Ashhurst, Feilding, Flockhouse, Foxton, Kairanga, Kakariki, Kuku, Lake Alice, Levin, Longburn, Mangatinoka, Marton, Oroua Downs, Pahiatua, Pahiatua DF, Palmerston North
- **(HWKB) Kahungunu (Hawke's Bay)**
  Dannevirke, Hastings, Hastings (Nova), Mangaroa, Takapau
- **(WGTN)Whanganui-a-tara/Kapiti (Kapiti-Wellington)**
  Belmont, Greater Kapiti, Greater Waitangirua, Otaki, Pauatahanui 2, Tawa A, Tawa B (Nova), Te Horo

Individual Delivery Zones

(BERD) Bertrand Road (Waitara Valley)
(FAUD) Faull Road
(HUPS) Huntly Power Station
(MAND) Mangorei (Delivery)
(NGRD) Ngatimaru Road (Delivery)

Figure 4: Our gas transmission system



Refinements to Part 4 regulation

The regulatory environment for the gas transmission business has been relatively stable over the past year, with First Gas now moving into the third year of the 2017 – 2022 DPP regulatory control period. We have been focused on implementing the changes to the Information Disclosure requirements, that were introduced by the Commerce Commission in December 2017. These changes were driven by the decisions from the 2016 review of gas Input Methodologies.

The key changes particularly relevant to First Gas were:

- Increased audit requirements and narrative in the Auditor's opinion, focusing on any key matters that have required the auditor's attention and significant judgements;
- New disclosure and reporting requirements for related party transactions; and
- Changes to the cost allocation methodology for our business.

These changes will be incorporated into our Information Disclosure reporting for the year ending 30 September 2019, that we will publish in March 2020. We have elected to incorporate some of the information required under the new related party transaction rules into this year's AMP Updates, in addition to our annual information disclosures at the end of the disclosure year. Sections 5.1 and 5.2 set out the new maps of anticipated network expenditure, currently we do not have any projects related to constraints on the system.

Learnings from other regulated sectors

The electricity distribution businesses (EDBs) and Transpower are currently going through a reset of their price quality paths with the Commerce Commission to determine their allowable revenue for the next five years.

First Gas is following this process, to identify any learnings that may apply to our next price-quality path reset for gas transmission for 2022 – 2027. We are particularly interested in the proposed introduction of mechanism to fund innovation projects. The Commerce Commission[8] has proposed a new recoverable cost for innovation costs, with EDBs required to show any proposed project will potentially benefit consumers. We support the Commerce Commission exploring options to encourage innovation across New Zealand's regulated energy businesses. We would welcome a similar mechanism for gas pipeline businesses to support innovative projects and enable the sharing of sector knowledge.

Changes in the broader gas sector

There have also been increased work in the broader gas sector to review the overarching legislation and the information disclosed on the operation of the gas market.

Focus on greater information disclosure

The Gas Industry Company is currently consulting on options to increase the level of information disclosed on the gas market. This new workstream for 2018/2019 was driven by a request by the Minister of Energy, following the recent spring outages at Pohokura. The workstream explores the potential information issues, the different approaches to information disclosure (from voluntary through to regulated options) and ways of publishing this information.

First Gas believes that the main information gaps relate to planned and unplanned outages at major gas production and user facilities. These information gaps would be best addressed through a regulated option. Next steps on this workstream are expected later in 2019.

Review of the Gas Act

The Government is also reviewing the Gas Act 1992, focusing on three key areas:

- Emerging challenges for the Gas Act with the expected introduction of alternative fuels (such as hydrogen and biogas);
- Potential changes to the penalty regime; and
- Information disclosure requirements (to enable regulated options to be introduced by the GIC, as above, if required).

First Gas supports this timely review of the Gas Act. We advocate for regulations and standards to support the development of emerging fuels such hydrogen and biogas, while also ensuring that gas remains of a specification that it can transported safely within New Zealand's gas infrastructure and safely and reliably used by consumers.

Government's climate change policy

The past year has seen a heightened focus on climate change and the role of the energy sector, as the Labour-led coalition Government enters into its second year. The Government has introduced the *Climate Change Response (Zero Carbon) Amendment Bill* into Parliament, a key policy in its work to address climate change. The Bill[9] will:

- Set a new greenhouse gas emissions reduction targets – reducing all greenhouse gases (except biogenic methane) to net zero by 2050 and reducing emissions of biogenic methane;
- Set a series of emissions budgets to act as stepping stones towards the long-term target;
- Establish a new, independent Climate Change Commission to provide expert advice and monitoring; and
- Require the Government to develop and implement policies for climate change adaptation and mitigation.

At the time of writing, this Bill was currently before Select Committee, with the Government expecting the Bill to come into force in late 2019.[10] Alongside this key Bill, the Government has an

8. *Default price-quality paths for electricity distribution businesses from 1 April 2020 – Draft decision*, Commerce Commission reasons paper, 29 May 2019, https://comcom.govt.nz/__data/assets/pdf_file/0023/149801/Default-price-quality-paths-for-electricity-distribution-businesses-from-1-April-2020-Draft-Reasons-paper-29-May-2019.pdf
9. Information on the Bill is available on the Ministry for the Environment's website here.

extensive programme of work addressing the role that the energy sector plays in the country's transition to a net zero economy.

One workstream of immediate interest to First Gas, is the Interim Climate Change Committee's final report,[11] setting out its recommendations to Government on the "transition to 100% renewable electricity by 2035 (which includes geothermal) in a normal hydrological year".

Gas currently plays a key role within the electricity sector, maintaining security of energy supply as it can fill supply shortfalls created by the weather and seasonal dependency of renewable sources. Natural gas supply is also resilient to hazards like earthquakes and can keep energy prices down while the price of renewable generation steadily falls.

Alongside central government action, there has been increasing activity on the local front. A number of local councils have declared a climate change emergency and there is an increased public activity calling for action on climate change.

Announcement of new National Energy Development Centre

During the Just Transition Summit held in May 2019 in New Plymouth, the Prime Minister took the opportunity to announce the establishment of a new National Energy Development Centre (NEDC) in Taranaki.[12]

The Government intend to invest $27 million to set up the centre and $20 million over four years to establish a new science research fund for cutting edge energy technology.

The NEDC is intended to create new business and jobs in Taranaki while helping New Zealand move towards clean, affordable, renewable energy to achieve the aim of net zero emissions. The NEDC will look at the full range of emerging clean energy options such as offshore wind, solar batteries, hydrogen and new forms of energy storage.

First Gas' role in the country's transition towards net zero

First Gas supports the Government taking action on climate change and committing to a net zero emissions target by 2050. As a business, we are committed to exploring the distribution of alternative fuels such as green hydrogen, biogas and gas blends, that will reduce New Zealand's carbon emissions. Our gas transmission and distribution networks cover much of the North Island and are ideally placed to support the development, transfer and use of emerging fuels.

The big question is how the nation transitions steadily towards 100% renewable energy, keeping energy prices down while renewable sources are built and their output gets cheaper to use, and providing supply for winter demand peaks, dry years, electric vehicle use, and during natural disasters. We can lower emissions right now by switching things like industrial boilers and dryers from coal to gas and switching cars to electricity.

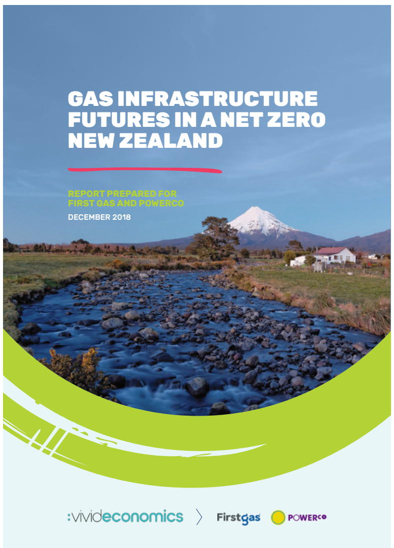
We recognise that action on climate change has created some uncertainty around the long-term future of gas supply, and the willingness of industries to invest in making coal to gas conversions. However, we believe that with the establishment of government policies that set a steady reduction path (that takes account of the nation's practical and financial constraints), Government and industry can work together to achieve the opportunities from a low carbon economy.

Understanding the future use of gas and gas infrastructure

First Gas and Powerco commissioned Vivid Economics in 2018 to explore the potential scenarios for future use of the gas infrastructure, as New Zealand moves to a low-carbon economy. The report explores three different scenarios – a diversified energy mix, a green gas (hydrogen and/or biogas) option and an all-electric future – and the impact of these scenarios on gas infrastructure use and affordability. The cost to New Zealand in dollars and GDP of the three scenarios is illustrated in Figure 5.

Vivid Economics' report finds that there are many uncertainties in New Zealand's changing policy environment, and it is too early to pick one preferred energy source for a low-carbon economy. The report recommended further research into the potential for hydrogen and electrification options, the feasibility of carbon capture and storage in New Zealand and the impacts of large-scale afforestation.

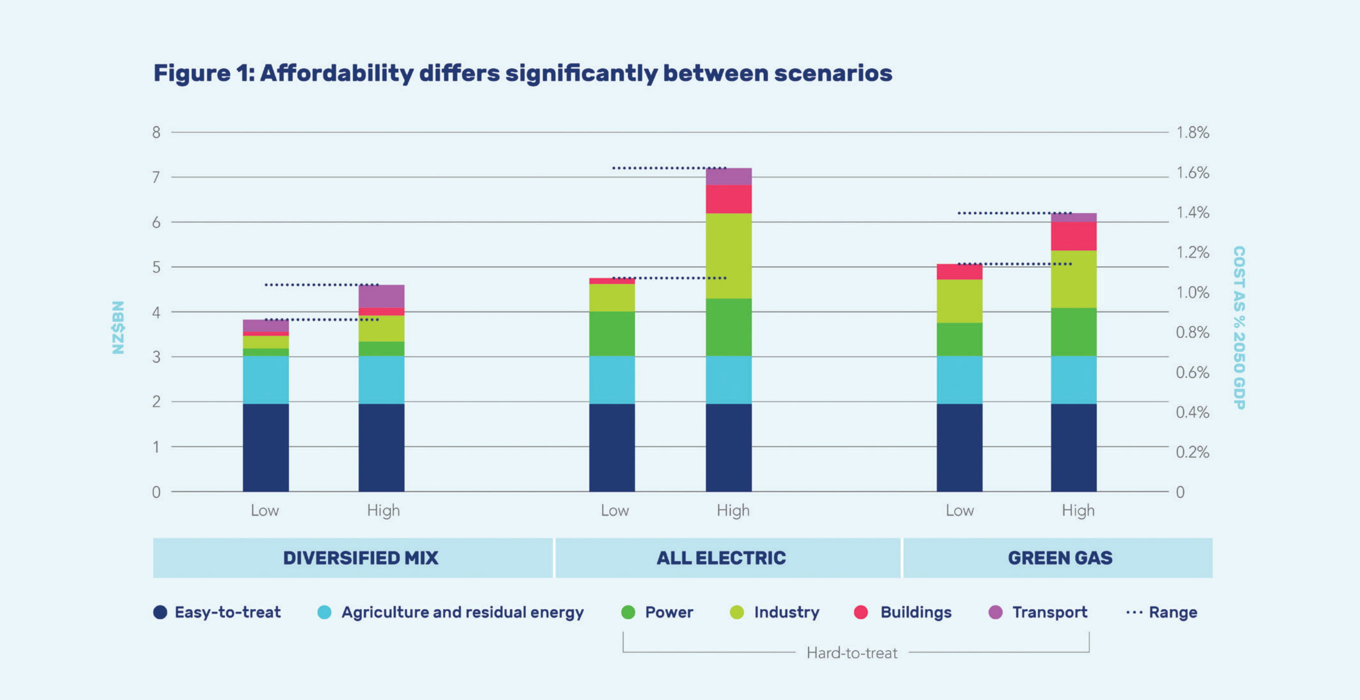
The full report was completed in December 2018 and is available on our website.[13]



This picture shows the front cover of the 2018 Vivid Economics report

10. A copy of First Gas' submission on the Bill is available here: https://firstgas.co.nz/wp-content/uploads/First-Gas-submission_Climate-Change-Response-Amendment-Bill.pdf
11. https://www.iccc.mfe.govt.nz/what-we-do/energy/ and https://www.iccc.mfe.govt.nz/what-we-do/energy/electricity-inquiry-final-report
12. https://www.beehive.govt.nz/release/government-invests-clean-energy-centre-help-power-new-zealand%E2%80%99s-economy
13. Vivid Economics report, press release and supporting video are available here: https://firstgas.co.nz/news/gas-infrastructure-futures-in-a-net-zero-new-zealand/

Figure 5: Affordability differs significantly between scenarios



Affordability differs between scenarios, and a decision now to completely decarbonise using electricity would risk unnecessary costs. The total annual cost of meeting the net zero target could be around $3.8–$4.6 billion, equivalent to 0.9–1.0% of national income if forestry is used to offset residual gas emissions (expressed differently, the annual cost could be around $1,700 per household, with incomes projected to rise around 35% over this period). However, this cost could rise to $6.2–7.2 billion, equivalent to around 1.4–1.6% of national income (or around $2,700 per household), if hydrogen or electrification is needed to address hard-to-treat sectors.

Hydrogen trial announced

In May 2019, First Gas announced our hydrogen-pipeline trial as one of the first projects likely to start at the National Energy Development Centre being set up in Taranaki. We welcome the opportunity to work on a piece of the puzzle for New Zealand's energy future.

We intend to base staff at the centre to design and run a trial of transmission and end use of hydrogen or hydrogen-blend gas. The first task is to identify the best part of the pipeline network to use to test a range of assets on various blends of hydrogen gas, the best sources of hydrogen at those locations, how to measure and meter energy flows, if there are any regulatory issues that need to be addressed and ensure end-users can safely and efficiently use the gas for their energy needs.

The feasibility assessment and network selection has started this year. This work establishes a timeframe and work programme to tool up a section of the network to start transporting hydrogen to participating end users. Hydrogen sources are available locally, and local expertise and technology could provide a dedicated source using wind or other renewable generation to power an electrolyser that splits water into hydrogen and oxygen.

3. YEAR IN REVIEW

This section provides an overview of First Gas' major projects and initiatives over the past year ending 30 September 2019. We review our forecast expenditure against the plans stated in our 2018 AMP and discuss the variances in activities undertaken.

3.1 EXPENDITURE SUMMARY

First Gas remains focused on building and maintaining a safe and resilient gas transmission network for our customers, whilst actively pursuing growth across our network. This focus is reflected in the work programme that was undertaken over the last 12 months. Figures 6 and 7 outline our actual expenditure for the year ended 30 September 2019,[14] and compares actual expenditure to the forecasts presented in our 2018 AMP.

There was very little variance for both Capex and Opex levels compared to what was published in our 2018 AMP.

Figure 6: Total Capex in FY2019 versus forecast Capex in 2018 AMP

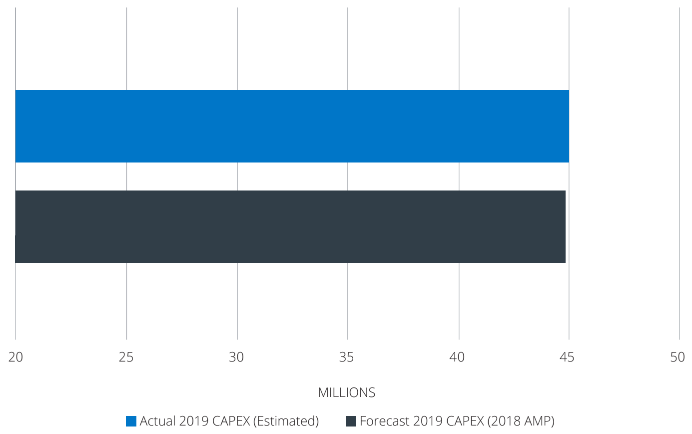
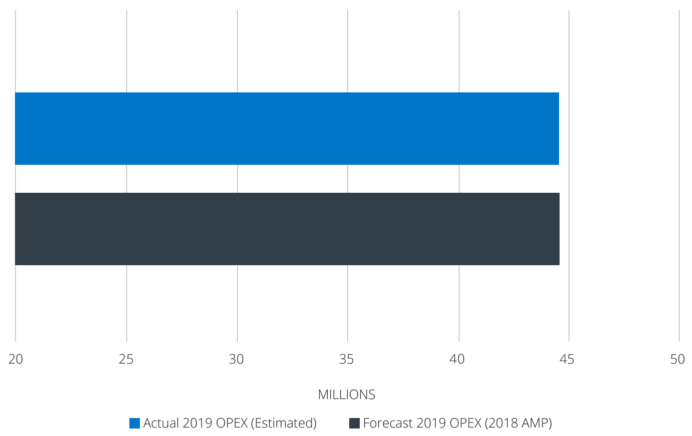


Figure 7: Total Opex in FY2019 versus forecast Opex in 2018 AMP



14. All data from 1 July 2019 to 30 September 2019 has been forecasted, in order to provide a complete 12 months of data.

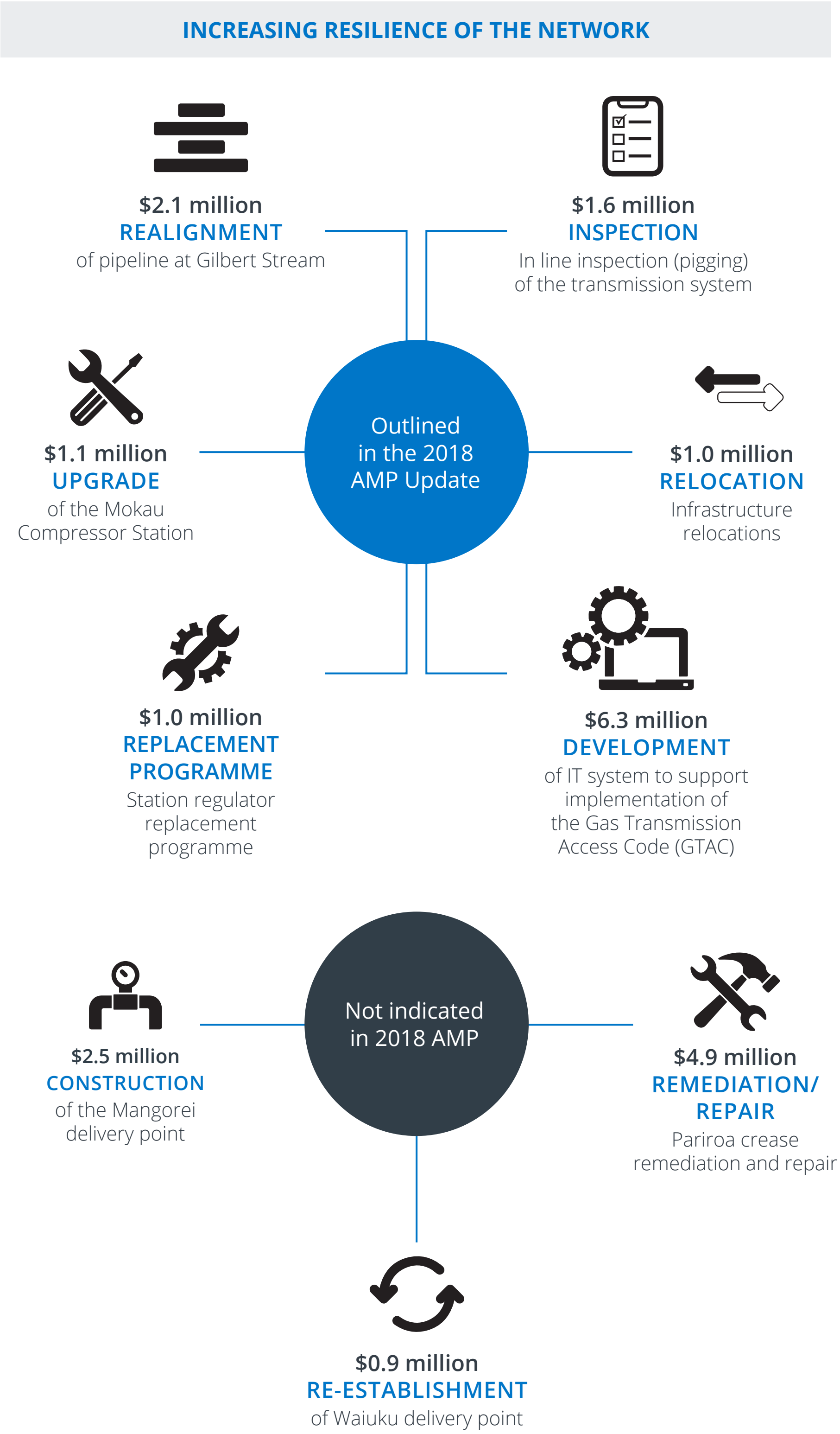
3.2 SIGNIFICANT ACTIVITIES UNDERTAKEN IN FY2019

First Gas has continued to deliver on the significant capital works programme that was set out for this DPP period (1 October 2017 – 30 September 2022). Figure 8 outlines the most significant projects that were delivered during the last 12 months.

Most of these projects were identified in our 2018 AMP, with the scope and justification provided for each project. However, work on the Pariroa defect had to be prioritised in the last year, which resulted in the main works for Gilbert Stream project works being deferred to FY2020.

We discuss these projects below, as well as the significant work we have undertaken through our asset management improvement programme.

Figure 8: Significant projects completed in FY2019



Pariroa crease remediation and repair

A key project undertaken last year was the installation of a bypass pipeline, to address the pipeline crease identified at Pariroa, Northern Taranaki. This workstream was prioritised over other projects to address the pipeline strain caused by land movement.

Routine pipeline pigging was conducted by First Gas on the Maui pipeline (30-inch 400 pipeline) in April 2018. The pigging data from this activity identified a pipeline crease between Frankley Road and the Mokau compressor station, approximately 9.3 kilometres south of Mokau compressor station. The crease was located close to a previously identified pipeline strain site at an active and complex landslide. The crease in the pipeline had the potential to impact on pipeline integrity and required a prompt response to address the risk.

First Gas put an emergency response plan in place to respond quickly if the integrity failed, whilst a longer-term remediation was planned. The project was split into two phases, with phase one being completed during FY2019.

The first phase responded to the immediate risk to the pipeline and included:

- Constructing a by-pass pipeline, with the tie in points away from the landslide area;
- Isolation and depressurisation of the pipeline at the adjacent mainline valves; and
- Connection of the bypass pipeline, and removal of damaged section.

By utilising this option, we could carry out a planned outage to minimise the impact to our customers. The by-pass installation was completed in Dec 2018.

A review following the event allowed us to draw the following conclusions:

- Our pipeline monitoring frequency is suitable for the risk profile and allows for flexibility as required;
- We have appropriate asset management and governance processes in place. Risks and key decisions were escalated appropriately;
- We undertook robust analysis to identify repair options for the damaged pipeline; and
- Customer/stakeholder communications were appropriate and positive feedback was received by First Gas on their management of the event.

The second phase of the project is planned for FY2020 (see section 4.1).

Feedback from customers and stakeholders on the Pariroa bypass work

I email you to record our appreciation to your team for the professional manner they dealt with the Maui pipeline repair completed over the weekend.

From the communication over the past two months, we knew you had a very competent team of First Gas staff and contractors planning and executing the necessary repairs. The culmination of all this hard work was of course successful completion of the work without disruption to supply.

– Bluescope Steel

I just wanted to pass on my thanks to … FirstGas, for keeping the national security system so well informed throughout the Maui Pipeline repair project.

The communication effort has been excellent, providing us with a good source of reassurance that the issue was being managed appropriately.

… my compliments and congratulations of course to FirstGas and their team of people for their speedy and effective installation of the bypass.

– Department of Prime Minister and Cabinet

Aerial view of Pariroa worksite

Aerial view of Pariroa worksite

Gilbert Stream realignment project

The works on the Gilbert Stream realignment project were deferred to enable First Gas to respond to the Pariroa crease defect. However, the project remains a priority for First Gas, with enabling works scheduled to start in October 2019. The main re-alignment work is expected to be completed in the latter part of the summer 2020, when site conditions are best suited to undertake activities.

During the last year, we have continued to conduct regular monitoring of the area to ensure there is no escalation of risk. We have also conducted detailed pipeline and civil designs, undertaken detailed construction reviews, tendered for construction and submitted consents for the works.

The realignment is a complex project with many stakeholders. To achieve a successful outcome, we are undertaking an extensive planning process to ensure we are ready to execute in the summer months. The impact of the works is also currently being modelled so we can understand the impact and how to minimise impact to our customers.

In line inspection (pigging) of the transmission system

Through the course of FY2019, we conducted intelligent pigging in the North of Auckland, and on the 111 pipeline between Waitangirua and Tawa, following a project in 2017 to make the line piggable.

The frequency that the individual pipelines are intelligently pigged, is driven by our Pipeline Integrity Management Plan. For all our piggable pipelines, it is a requirement from our pipeline certifier that we conduct the pigging at our specified intervals to maintain our certificate of fitness. Typically for pipelines that transit urban area or are in areas that pose an increased risk, the pipelines are pigged more frequently. The pipeline integrity management plan is reviewed every five years to ensure that our pipeline integrity is being managed in an appropriate manner.

Upgrade of the Mokau Compressor Station

As part of our strategic compression review, the Mokau compressor station was upgraded to provide a pressure increase to the system North of the Mokau. Whilst this work was being completed, we have expanded the scope of the review to incorporate other strategic compressor stations on the network.

The aim is to determine how best to meet the needs of our customers, develop a compressor fleet that is standardised and modern, has flexibility that allows us to accommodate changes to the network in an efficient manner, and provides resilience to the network. Details on this compressor strategy are outlined in section 4.1 below.

Station regulator replacement programme

First Gas has continued with the work programme to replace our fleet of obsolete Grove 80 regulators.

We received notification in 2013 of the planned obsolescence of the regulators and supporting soft parts by the manufacturer. The regulators were used across a large number of our sites, so the programme has targeted a number of sites each year to upgrade to newer equipment.

The programme is now nearing an end, having started in FY2017. The final replacement of obsolete regulators is planned for FY2020.

Projects to relocate pipeline infrastructure

We generally have a number of infrastructure relocation projects in various stages of execution. These projects are driven by requests from third parties and the timelines are driven by needs of the customer. Schedules for the projects may change and is outside of our control.

Implementation of the new Gas Transmission Access Code

A key milestone was reached in February 2019, when the Gas Industry Company (GIC) released its final assessment of the Gas Transmission Access Code (GTAC), concluding that the GTAC was materially better than the existing arrangements.[15] This decision enabled the First Gas team to begin the detailed development and implementation of the necessary commercial and operational arrangements and supporting IT infrastructure, which are expected to go live from 1 April 2020.

The GTAC will be supported by a new IT system from Tieto[16], a supplier to gas infrastructure markets in 35 countries. This new system, the Transmission Access Commercial Operating System (TACOS), will provide efficiencies in managing the commercial operations of the transmission pipeline system through automated nominations, approvals and scheduling systems.

Background information on the GTAC is available on our website.

15. The Maui Pipeline Operating Code (MPOC) and the Vector Transmission Code (VTC).
16. The Transmission Access Code Operating System (TACOS) is the new IT system being developed to support the GTAC.

Construction of the Mangorei delivery point

Construction of a new Mangorei delivery point

This project involved the construction of a dedicated delivery point to supply a new peaking power station, that is being constructed near Junction Road in New Plymouth.

The terms of the interconnection agreement were still being negotiated when we published the 2018 AMP. As there was a significant amount of uncertainty, we did not include this project in the 2018 AMP. The Interconnection Agreement (ICA) has since been agreed and the project has now progressed to execution, with a gas on date scheduled for the last quarter of 2019 calendar year.

Redevelopment of the Waiuku delivery point

First Gas has reached an agreement to connect Gourmet Waiuku, a capsicum growing operation in the Waiuku area, southwest of Auckland. Gourmet Waiuku have agricultural glasshouses that are currently heated using LPG and coal. Natural gas will allow Gourmet Waiuku to heat their glasshouse more efficiently and to enrich the growing environment with CO_2 which increases capsicum production by about 20 percent.

To allow this customer to connect to natural gas, the project required the redevelopment of the dismantled Waiuku delivery point and the construction of approximately 8.5 kilometres of distribution medium pressure pipe to and through the Waiuku township. More information is available in the 2019 Distribution AMP Update[17] regarding the medium pressure works that were undertaken.

These investments will be completed within our current DPP allowances for growth expenditure. Redevelopment of this delivery point will enable us to connect further customers in the future.

White Cliffs realignment project

As detailed in previous AMPs, the White Cliffs project involves the realignment of both high pressure pipelines at White Cliffs, Taranaki. These two pipelines are impacted by coastal erosion that threatens to eventually expose the pipelines that supply gas across the North Island. Expenditure for this project was not approved as part of the DPP reset for 2017 – 2022. The Commerce Commission considered that this project required further analysis and scrutiny through a Customised Price-Quality Path (CPP) application. This section provides an update on the project planning and our approach to securing funding for this essential project.

Project planning

To inform our project planning, we continually monitor coastal erosion at the site. Our latest monitoring results indicated that the cliff-face erosion has currently stabilised and there have been no significant episodic events in the past 12 months. We are however continuing to prepare for the realignment works, with the focus over the last 12 months being on the concept study, scope of works and stakeholder engagement plans.

Project funding

First Gas has reviewed our approach to the White Cliffs realignment project to ensure that we are appropriately managing pipeline security risks and can manage the financial impacts of the project. Following our engagement with the Commerce Commission on funding during the last year, we now propose to break the project into two distinct phases:

- **Phase 1: execution readiness.** This phase includes securing land access, carrying out customer and stakeholder consultation, completing detailed project design, ordering long-lead items, and preparing an emergency response plan; and
- **Phase 2: project execution.** This phase will occur once physical triggers are breached (i.e. remaining cliff being below maximum expected episodic event plus a margin).

We believe that this two-phase project delivery approach provides greater assurance to our customers and stakeholders that a solution can be implemented when required. It also provides opportunities to better manage costs to consumers as well as financial impacts on First Gas.

Due to the updated approach and expected timing for this project, we have committed to prepare a Customised Price-Quality Path (CPP) application. Our application will cover a five-year period (2022 – 2027) and cover all expenditure for our transmission network, including phase two of the White Cliffs project. A project team to lead the CPP application has been established, with the intention to submit a CPP application to the Commerce Commission by 30 September 2021.

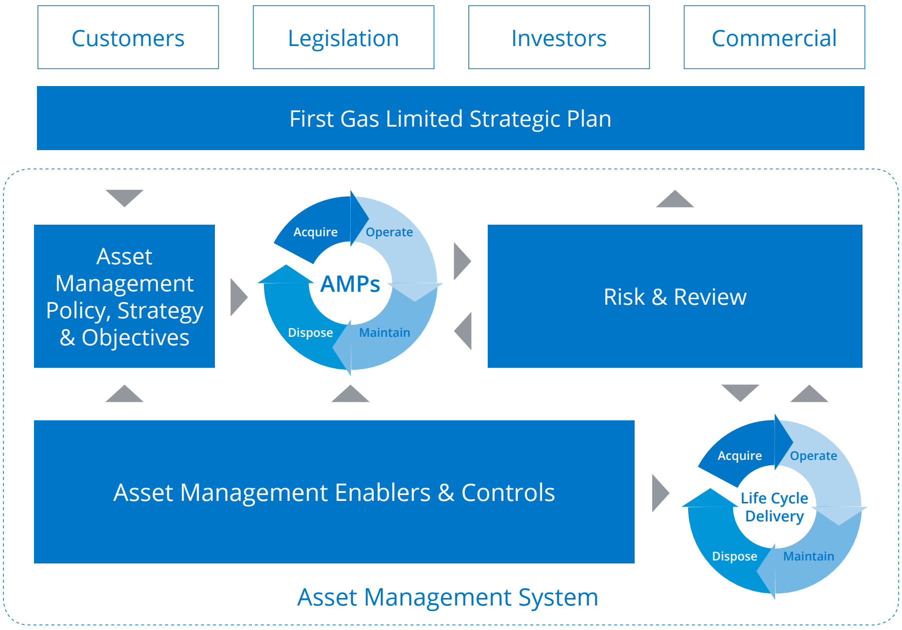
17. https://firstgas.co.nz/about-us/regulatory/distribution/

Asset Management improvement programme

Over the last year, the focus has been on embedding and further developing our overall asset management framework, asset management system elements and relative documentation as illustrated in Figure 9. This improvement programme is aligned with our increased strategic focus on asset management and included work on the following areas:

- Capital expenditure
- Maintenance optimisation
- Risk management
- Planning and scheduling
- Project management
- Programme delivery
- Documents and records management

Figure 9: Overview of asset management framework



Addressing geohazard risks on our system

As outlined in section two, First Gas has implemented a new programme to better understand and manage geohazard risks on our gas transmission system. This significant programme of work involves:

- Initial reporting of each of the geohazards, assessing each feature for its likely impact to pose a risk to the pipeline;
- Conducting more detailed field assessments, geotechnical assessments, and pipeline integrity impact assessments. This work is aligned with our intelligent pigging reports to gain a more detailed understanding of the specific feature, how active it is and the impact to the pipeline; and
- Remediation is planned where required, alongside routine monitoring on the feature.

This process of work enables us to ensure that the activities we undertake follow a risk-based approach. In our 2018 AMP in **Appendix C**, we provide greater detail on the status of our current risks and planned activities for each site.

Figure 10: Changes to geohazard risks on the system

LOCATION	HAZARD	ACTIONS	ASSESSED RISK	CHANGE IN RATING (FROM 2018 AMP)
Waikokowai Road	Pipeline crossed through the head of an active lobe associated with a larger relic landslide. Potential for pipeline deformation from land induced stress	Remediation works completed. Routine monitoring ongoing	Low	Changed from high to low
Mangatea Road, Te Kuiti	Pipeline ascends through an active landslide. Ongoing land movement has potential for pipeline deformation from land movement induced stress	Works completed, routine monitoring ongoing	Low	Changed from High to Low
Turakina river crossing	Pipeline exposed on bank side of river	Works completed, Routine monitoring ongoing	Low	Changed from High to Low

3.3 PERFORMANCE OF THE TRANSMISSION SYSTEM

A key premise for the AMPs and AMP Updates is that existing reliability, safety and supply quality levels will be maintained and improved. We have quality standards and have set additional targets that help drive performance improvements and measure our progress in delivering reliable, safe and high-quality service (these targets are detailed in our 2018 AMP in **Appendix H).** To align with regulatory disclosures, the data presented covers the year ending 30 September 2018.

The table below refers to some of the key KPI's that we report on for Information Disclosure as part of the Commerce Commission requirements.

- Our KPI scores for FY2018 are reported in the first column of the table;
- The trend column represents the movement in the KPI between FY2017 and FY2018; and
- The target column refers to the score we would like to achieve over the next 12 months.

Table 3: KPIs for gas transmission network

KEY PERFORMANCE INDICATORS	2018	TREND	2020 TARGET
Safety: Lost time injuries	0	▶	**0**
Response time to emergencies*	100%	▶	**100%**
Unplanned interruptions	2	▶	**0**
Major interruptions*	0	▶	**0**
Environmental	0	▶	**0**
Asset Management Maturity Assessment	2.7	▲	**3.0**
Public Reported Escapes and Gas Leaks	2	▲	**<5**
Lloyds annual audit compliance	0	▲	**0**
Compressor availability	83.36%	▼	**>95%**

* Quality measure under Default Price-quality Path (DPP) 2017 – 2022

4. YEAR AHEAD

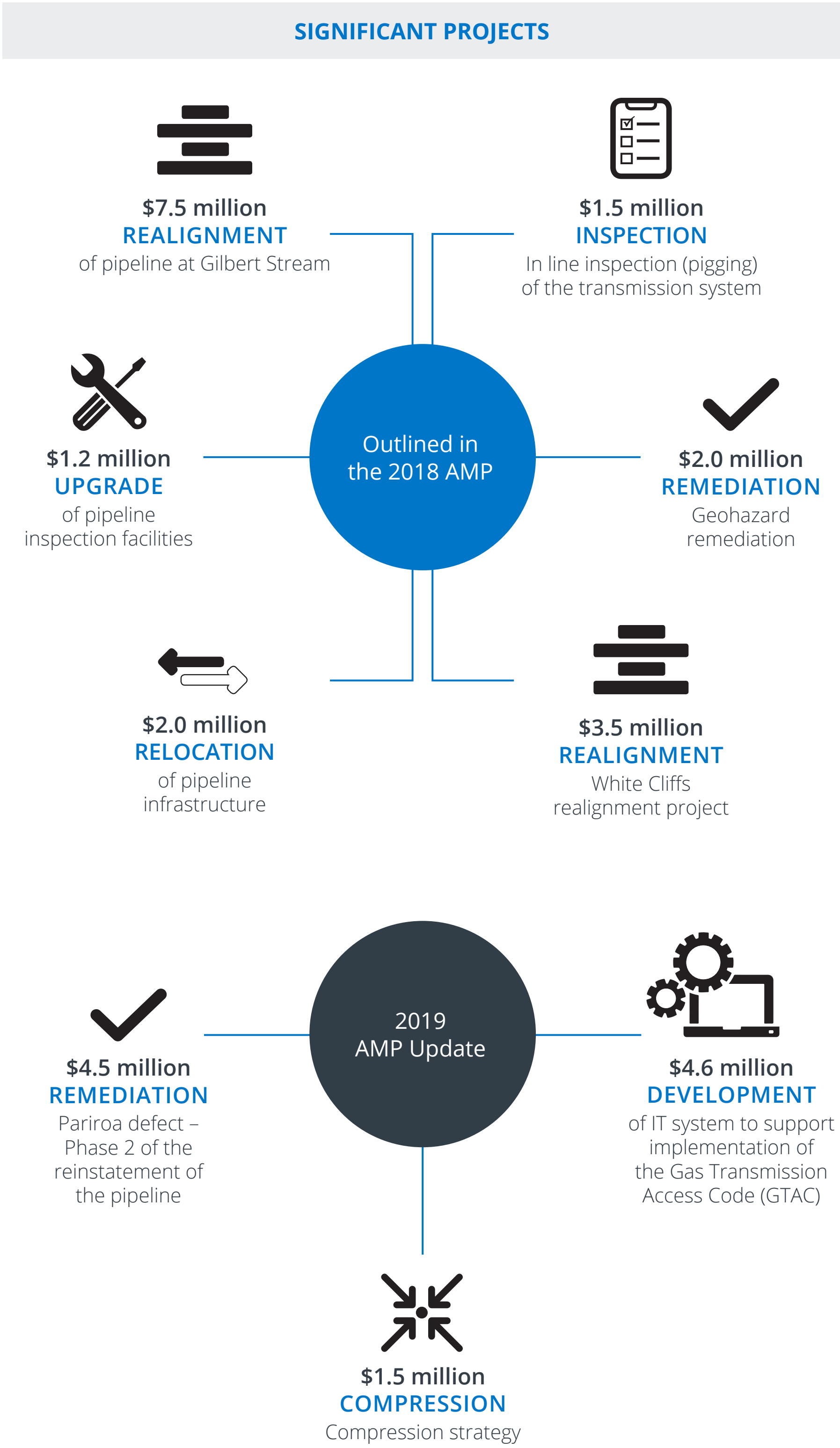
This section sets out the areas of focus for First Gas over the next year commencing 1 October 2019, the third year of the DPP reset for 2017 – 2022. The focus remains on providing our customers with a safe and resilient transmission system, while maturing and optimising our approach to asset management.

4.1 SIGNIFICANT ACTIVITIES FOR FY2020

Figure 11 sets out the major activities we plan to undertake on our gas transmission network throughout FY2020. The location of these significant projects is shown in Figure 12, and we outline each of these projects below.

We also provide details on the next steps for our asset management improvement programme.

Figure 11: Significant projects for FY2020



Phase two of the Pariroa crease remediation

By splitting the Pariroa project into two stages, we have been able to focus on designing a long term solution for Pariroa feature, whilst dealing with the immediate issue. We are currently monitoring the area and finalising the remediation plan, if possible the works may be aligned with the Gilbert stream realignment project planned for FY2019/2020.

Activities for phase two of this work will entail:

- Installation of the new 750mm section of pipe and removal of the bypass;
- Commissioning of the new section of pipeline;
- Remediation of environment and stabilisation of landslip area; and
- Demobilisation from the site.

Gilbert Stream realignment

As outlined in the section above, the Gilbert Stream realignment was deferred to FY2020 to enable us to respond to the Pariroa pipeline crease defect.

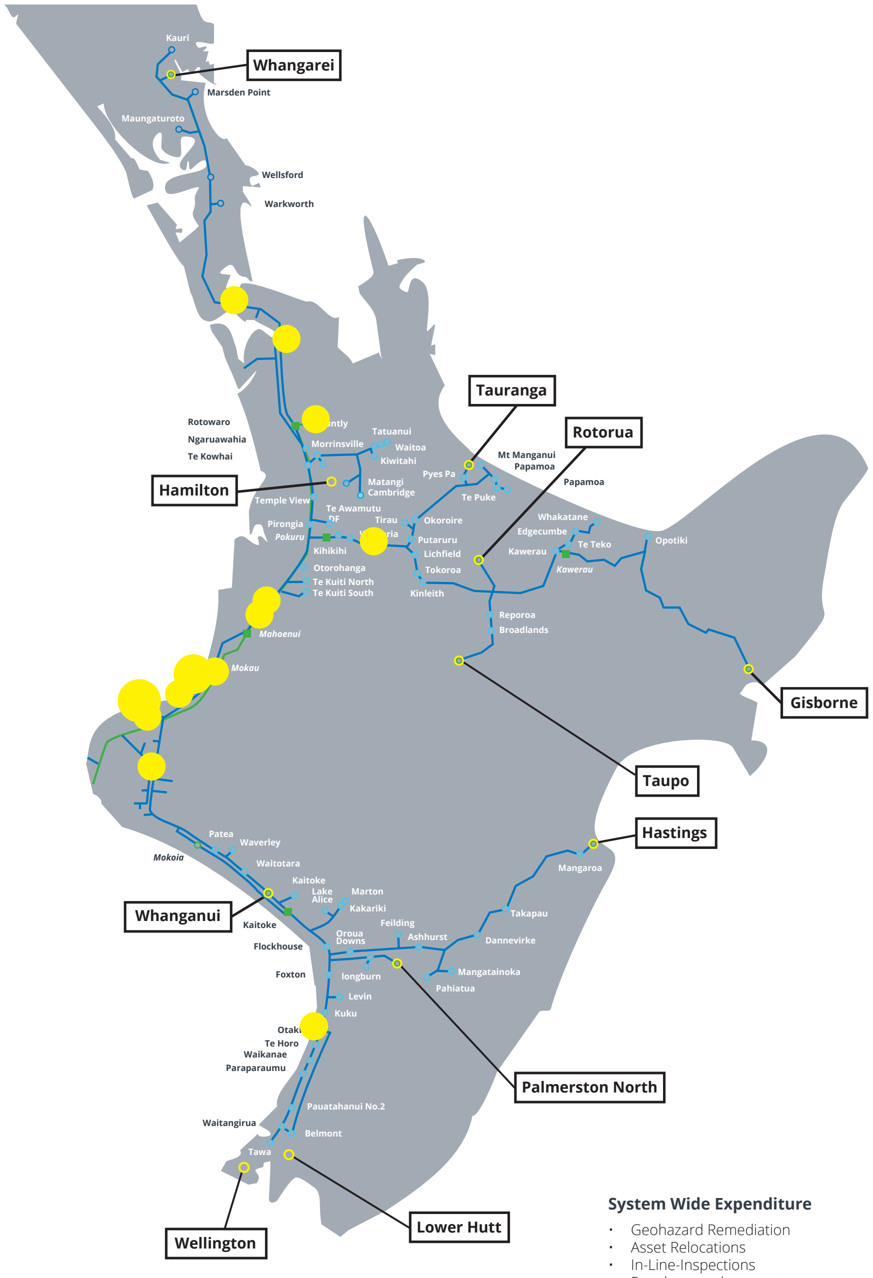
The Gilbert Stream realignment project will now move to execution phase in late 2019. We are planning for the bulk of the physical works to be undertaken during the summer of 2019/2020, with the final tie-in occurring in late 2020. Implementation of this project will provide valuable lessons for the larger White Cliffs realignment project, located north of the Gilbert Stream site.

Intelligent pigging

Through the course of FY2020, we are planning to conduct intelligent pigging on the 8 inch pipelines North and South of Taranaki, pipelines north of Auckland and the Hastings areas pipelines.

The frequency that the individual pipelines are intelligently pigged is driven by our Pipeline Integrity Management Plan.

Figure 12: Location of significant projects for FY2020



System Wide Expenditure

- Geohazard Remediation
- Asset Relocations
- In-Line-Inspections
- Regulator replacements

Map Key

- Compressor Station
- Delivery Point
- City/Town
- First Gas High Pressure Pipelines
- Maui High Pressure Pipelines
- Up to $5 million
- Up to $10 million

Upgrades of pipeline inspection facilities

Pipeline pigging is an essential asset management activity. First Gas uses a tool referred to as a "PIG" (Pipeline-Inspection-Gauge), which is inserted into the pipeline at dedicated launch and receive locations. Pigging of the pipelines allows us to carry out maintenance and inspection activity without stopping the flow of gas. We will continue with our programme to upgrade our existing pig inspection facilities taking into account current pigging technologies and configurations.

We have identified a number of sites that will be upgraded in FY2020. The upgrades to the existing facilities are planned to be completed prior to the intelligent pigging programme.

Geohazard remediation projects

As highlighted in previous AMPs, the impact of geotechnical risk to our pipelines is a focus for us. As we are assessing the potential geohazards, we are prioritising our work plans to remediate the risk. We have a number of projects planned for FY2020 and are currently developing the detailed scopes of work. Two of the significant projects under this category are detailed below.

Land erosion at Awakau Road

There are two areas we are addressing with this project. The instability features are located on steep slopes, with the following features identified:

- **Awakau Road 1:** Recent tension cracking/the historic landslide headscarp approximately 0.6 – 3 metres from the pipeline over approximately a 50-metre pipeline length.
- **Awakau Road 2:** Principally old tension cracking and landslide headscarps approximately 1 – 4 metres from the pipeline over approximately a 55-metre pipeline length wall showing signs of deterioration.

Land instability at Richardson Road

Our Rotowaro-Southdown pipeline (400N Line) passes through an area of known instability in Brookby. The site is located approximately 17.5 kilometres south/upstream of the Southdown Delivery Point.

We have conducted a detailed site investigation including a pipeline survey in January 2019, following heavy rainfall events in late December 2018. The investigation noted land movement of 300 – 400 millimetres (downslope) around the pipeline. The recommendation is to remove excess material from the head of the landslide and install sub-surface drainage in the southern slope and at least part of the main landslide. Works are planned to be completed in FY2020.

Projects to relocate pipeline infrastructure

We typically have a number of projects to relocate pipeline infrastructure, following requests from third parties. timelines for these projects can shift significantly to meet the customers' needs, and we need to remain flexible to work with our stakeholders. Below are a couple of examples of the more significant relocations we have underway.

Murphy's Road bridge realignment

Vista Estate LP are progressing a residential development with associated access ways within an area of land on Murphy's Road in Flat Bush, Auckland. The First Gas owned and operated DN350 pipeline in an easement that runs through a large portion of the area for development.

Execution of this infrastructure project is dependent on the schedule of the stakeholders that have requested the relocation, and schedules can and do often change to meet the needs of the project.

Ports of Auckland

Ports of Auckland Limited (POAL) have purchased a block of land in Te Rapa just North of Hamilton. New Zealand Railways Main Trunk Railway for the North Island runs through this land and POAL plan to turn the purchased land into an inland port. The First Gas 6-inch 402 line runs through the land that has been purchased.

The line is required to be realigned and lowered to allow the POAL works to progress. The current depth of cover over the pipeline is not of sufficient depth nor has sufficient protection to allow for the POAL development. The works were originally planned to be completed in FY2019, but this has been deferred to FY2020 to meet the needs of the customers.

White Cliffs re-alignment project

Following our engagement with the Commerce Commission on funding last year, we now propose to break the project into two distinct phases (see section 3.2 above). Over the next 12 months, we will continue with the execution readiness activities. This includes:

- Securing land access;
- Carrying out customer and stakeholder consultation;
- Completing detailed project design;
- Ordering long-lead items; and
- Preparing an emergency response plan.

Developing our CPP application

As outlined above, First Gas will be preparing a CPP application, with the intention to submit this to the Commerce Commission by 30 September 2021. Over the coming year, First Gas management will be establishing the scope of our application and socialising this with our customers and stakeholders. We will also begin the detailed preparation of the application with a full project team and will be looking to engage the verifier, who will review our CPP application. A summary of key milestones in the coming months is set out on the next page.

Table 4: Next steps for CPP application

TASK	DATE
Discussions held with all potential verifiers	By 30 October 2019
Internal sign-off of High-Level Summary (HLS) setting out what our CPP application will cover	December 2019
First Gas start preparation of draft CPP application	From January 2020
HLS provided to the Commerce Commission	Late January 2020
Verifier confirmed and deed signed	February 2020
Formal customer consultation led by First Gas	June to December 2020

Compression strategy

We have expanded the compression strategy undertaken at Mokau compressor to include all strategic compressor sites. This has allowed us to better understand the needs of customers with respect to their gas demand and to ensure that we are developing the network in a manner the optimises our compression needs, improves on our reliability and flexibility. In the coming year, we will be focused on developing and deploying a compression strategy.

Where possible, we want to:

- Achieve standardisation of our assets;
- Plan for replacement of ageing and obsolete assets;
- Review our compressor station locations to determine if existing locations meet the needs of our network now and into the future; and
- Create a compressor fleet that has flexibility designed into the fleet to allow us to meet the changing needs of the network.

Rotowaro is a strategic compression site for our network. We have undertaken a review of our compression needs in order to meet future demand, and a number of key activities were planned for the Rotowaro Compressor station throughout FY2019/2020. However, we have determined that looking at a single compressor station in isolation would not allow us to make informed decisions on the future needs on our assets.

Asset condition (Schedule 12A)

Schedule 12A (report on asset condition) provides a high-level overview of the asset condition rating as per the Commerce Commission's grading categories.[18] Our asset management strategies and expenditure are targeted to addressing instances where the condition rating is falling below the required standard.

Assessing asset condition is a dynamic process and gradings will change as the assets age or as specific issues are identified.

A summary of the work programmes where we have identified assets as being grade 1 (meaning end of service life, immediate intervention required) include:

- **Odorant systems** (12.5% are classified as grade 1): A programme is underway to upgrade the existing odorant injection system with current technology and carry out hours-run based major overhauls. This will result in 12.5% of the assets being replaced in the next five years.
- **Gas fired heaters** (16.4% are classified as grade 2): A refurbishment programme will be ongoing through the period. This will result in 22% of the assets being replaced in the next five years.
- **Metering systems** (63% of rotary meters and 36% of turbine meters are classified as grade 1): Meter replacements are an ongoing programme throughout the AMP Update period. Over the next five years, we anticipate that 10% to 20% of the meters will be replaced. This replacement programme is based on age of the existing meters. Performance will be monitored to ensure that the replacement programme is targeted to the meters where performance issues warrant the replacement.
- **SCADA and communications, remote terminal units** (13% are classified as grade 1): A programme to replace the CPU component within the remote terminal unit (RTU) will result in the extension of life of all the RTUs at a significantly reduced cost than replacing the entire RTU. A 100% replacement programme of the CPU component will be undertaken in the next five years.

Further detail on the condition, risks and issues, and planned activities can be found in our 2018 AMP in **Appendix C**.

18. When First Gas assesses asset condition, we consider a number of factors. This includes, but is not limited to, criticality, risk and our condition monitoring strategy for that asset or fleet. This information informs our replacement and refurbishment programmes. This means there is not an exact relationship between our view of asset condition and the Commerce Commission's grading categories which results in some variations between grading and replacement strategies.

5. EXPENDITURE FORECASTS

As First Gas is improving our asset management approaches and systems, we are gaining a greater understanding of our risk profile and where we need to allocate our funding. The key driver of our expenditure throughout the planning period is to reduce risk and maintain our level of service.

5.1 CAPEX FORECAST

Our forecast Capex spend over the next ten years is set out in Figure 13. **The changes within this DPP period** (2017 – 2022) relate to:

- Rebalancing of the work programme for asset replacement and renewal to respond to the Pariroa defect;
- Rescheduling the White Cliffs work to start in the next regulatory period (planning completed in this regulatory period);
- An increase in asset replacement and renewal expenditure for Pariroa phase 2 to be completed over FY2020 – FY2021; and
- An increase in non-network assets expenditure for the completion of the GTAC project in FY2020.

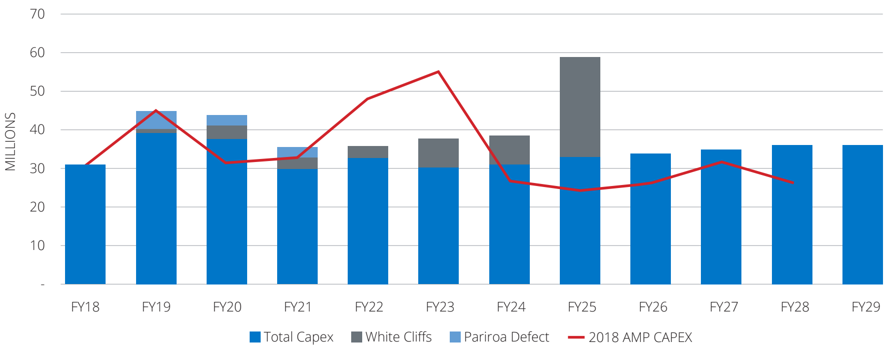
Excluding the White Cliffs project, this equates to an increase of $9.6 million compared to the amount disclosed in the 2018 AMP.

The **changes in the next regulatory period** (2022 – 2027) relate to:

- Rescheduling the White Cliffs work to start in FY2023;
- An increase in asset replacement and renewal expenditure to address geohazard risks and ageing assets on the system; and
- An increase in asset replacement and renewal expenditure for SCADA and communications upgrades.

Excluding the White Cliffs project, this equates to an increase of $39 million compared to the amount disclosed in the 2018 AMP.

Figure 13: Total Capex forecast for the planning period (all figures in FY2019 prices)



Largest capex projects in the planning period

This year we have elected to include within our AMP Update the high-level heat map that shows the largest Capex projects we have planned for the next ten years (FY2020 to FY2029). This heat map is part of the new related party transaction Information Disclosure requirements, that were announced by the Commerce Commission in December 2017 (see section 2.7). Figure 14 sets out the location of the largest ten projects, with greater detail in Table 5.

The identified projects are all network Capex. Network Capex is forecast to be completed by our related party, Gas Services New Zealand Limited (GSNZ) under an operations and management (O&M) agreement between First Gas and GSNZ. This O&M agreement was entered into with the change in ownership of the transmission business in 2016 and will be reviewed before September 2022. GSNZ manages a number of third-party contractors to deliver this network Capex.

Figure 14 depicts our anticipated significant planned expenditure during the planning period. It is a snapshot in time, with the information we have available, and may change. As we progress into the 10 year plan, we will develop the activities according to our processes to develop more accurate forecasts and delivery schedules. The activities will form part of the Information Disclosure requirements for March 2020.

More detail on the Capex projects identified in Table 5 can be found in our 2018 AMP. Where the identified projects include some reinforcement work, there may be possible future network or equipment constraints.

Figure 14: Largest Capex projects

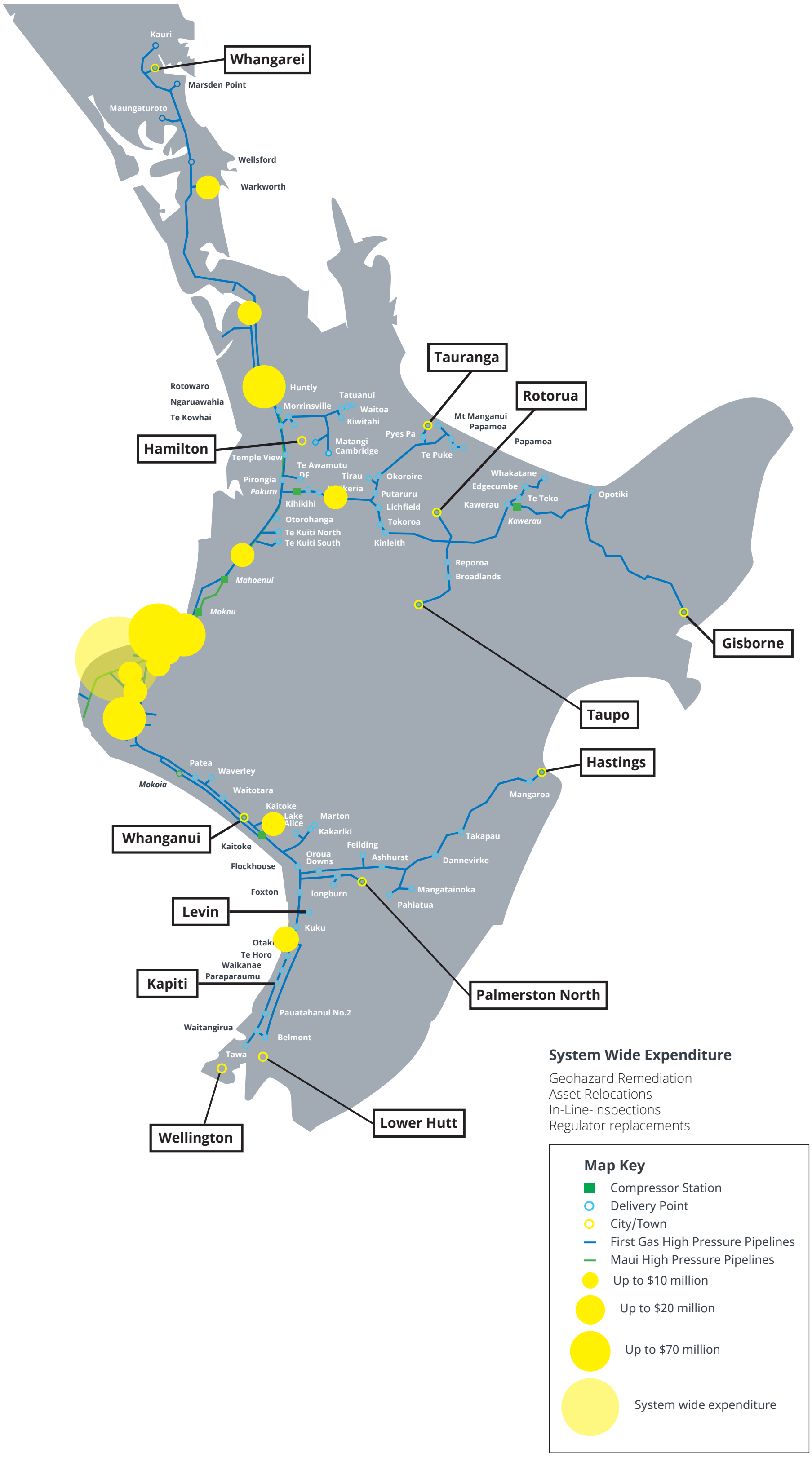


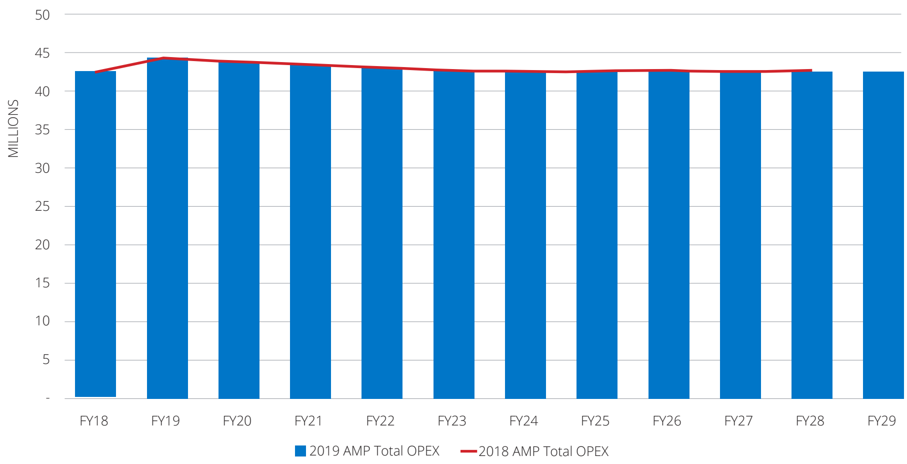
Table 5: Description of largest Capex projects

PROJECT	DESCRIPTION	REGION	COST (CONSTANT $)	PERIOD
Geohazards	Risk remediation projects resulting from geotechnical hazards	System wide	$57 million	FY2020 – FY2029
Compression strategy	Upgrade and standardisation of ageing fleet of compressors	Strategic compression sites	$20 million	FY2020 – FY 2029
Gilbert Stream realignment	Geohazard risk remediation from coastal erosion	North Taranaki	$10 million	FY 2018 – FY2020
Heating systems	Replacement of ageing fleet of water bath heaters	System wide	$30 million	FY2020 – FY2029
Warkworth expansion	Increasing pipeline capacity to meets increase in demand	Northern system	$5 million	FY2021– FY2022
Pipeline inline inspections	Pipeline pigging operations undertaken on piggable lines	System wide	$5 million	FY2020 – FY2029
SCADA and communications	Upgrade and replacement of SCADA master server	North Taranaki	$10 million	FY2023 – FY2029
White Cliffs project	Geohazard risk remediation from coastal erosion	North Taranaki	$70 million	FY2020 – FY2025
Pariroa defect	Pipeline defect repair and land stabilisation	North Taranaki	$7.5 million	FY2019 – FY2021
Asset relocations	Relocation of infrastructure	System wide	$20 million	FY2020 – FY2029
Customer connections	Supporting system growth and new customers	System wide	$40 million	FY2020 – FY2029

5.2 OPEX FORECAST

The forecast Opex over the planning period is set out in Figure 15. There is no significant change in ongoing Opex from that set out in the 2018 AMP.

Figure 15: Total Opex forecast for the planning period (all figures in FY2019 prices)



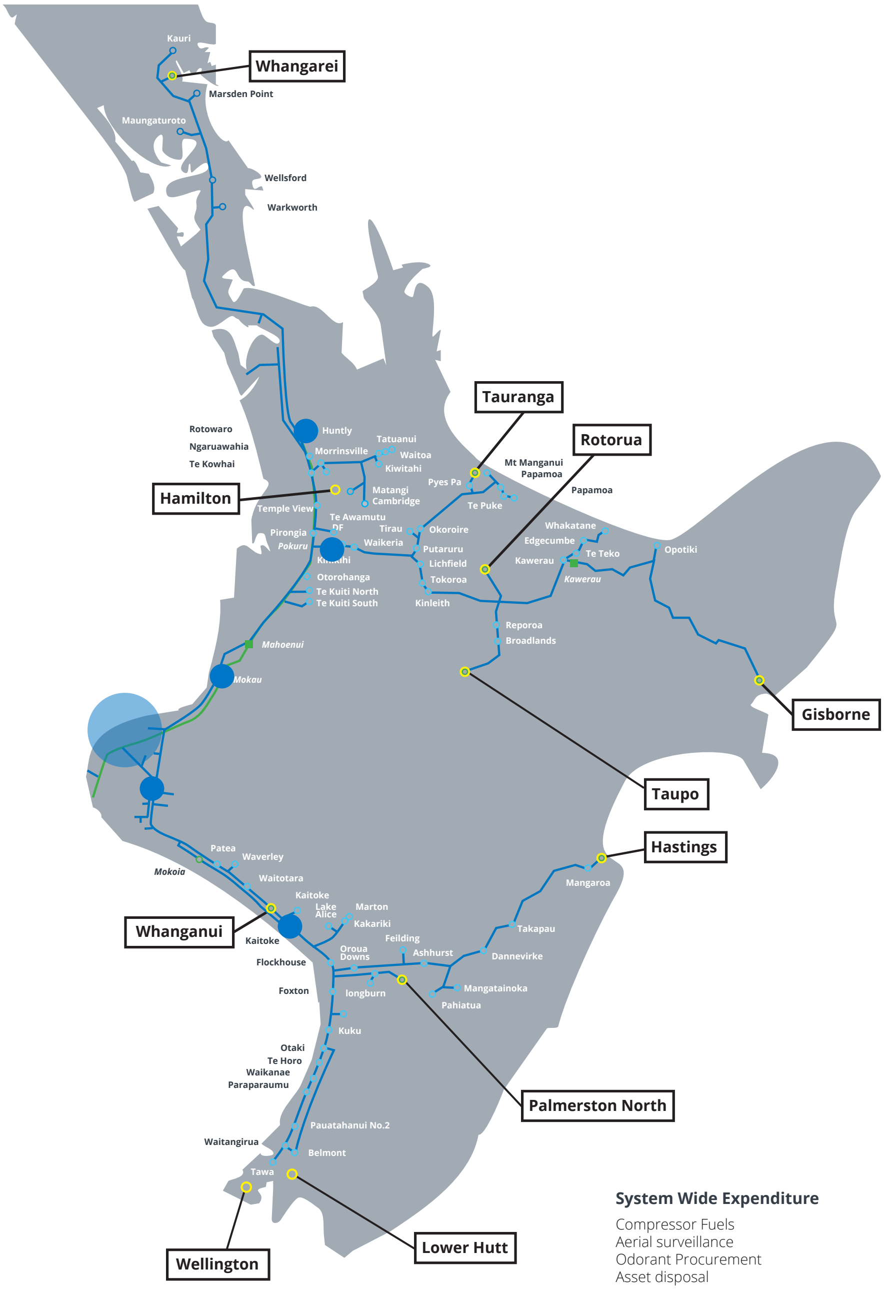
Largest Opex projects in the planning period

This year we have also elected to include within our AMP Update the high-level heat map that shows the largest Opex activities for the next 10 years (FY2020 to FY2029). Figure 16 sets out the location of the largest 10 activities, with greater detail in Table 6.

All network Opex, except for the purchase of compressor fuel, is forecast to be completed by our related party, Gas Services New Zealand Limited (GSNZ) under the Operations and Management (O&M) agreement between First Gas and GSNZ. This agreement was entered into with the change in ownership of the transmission business in 2016 and will be reviewed by September 2022. GSNZ manages a number of third-party contractors to deliver this network Opex.

All activities are network related works, and none are a result of future network or equipment constraints.

Figure 16: Largest Opex projects



System Wide Expenditure

Compressor Fuels
Aerial surveillance
Odorant Procurement
Asset disposal

Map Key

- Compressor Station
- Delivery Point
- City/Town
- First Gas High Pressure Pipelines
- Maui High Pressure Pipelines
- Compressor Station Maintenance
- System wide expenditure

Table 6: Description of largest Opex projects

ACTIVITY	DESCRIPTION	REGION	COST (CONSTANT $)	PERIOD
Kapuni Gas Treatment Plant maintenance	Ongoing maintenance costs associated with assets at KGTP	Taranaki	$12.0 million	FY2020 – FY2029
Rotowaro Compressor Station maintenance	Ongoing maintenance costs associated with assets onsite	Northern System	$2.9 million	FY2020 – FY2029
Mokau Compressor Station maintenance	Ongoing maintenance costs associated with assets onsite	Taranaki	$3.0 million	FY2020 – FY2029
Kaitoke Compressor Station maintenance	Ongoing maintenance costs associated with assets onsite	Southern system	$2.5 million	FY2020 – FY2029
Pokuru Compressor Station	Ongoing maintenance costs associated with assets onsite	Bay of Plenty system	$1.8 million	FY2020 – FY2029
Bulk odorant purchasing	Procurement of odorant	System wide	$1.8 million	FY2020 – FY2029
Odorant systems maintenance	Ongoing maintenance costs associated with assets onsite	System wide	$3.4 million	FY2020 – FY2029
Aerial surveillance	Helicopter and fixed wing aerial surveillance costs	System wide	$5.8 million	FY2020 – FY2029
Compressor fuel costs	Procurement of fuel to run compressors	Compressor stations	$40.0 million	FY2020 – FY2029
Asset decommissioning	End of lifecycle costs to decommission assets	System wide	$10.0 million	FY2023 – FY2029

6. STAKEHOLDER ENGAGEMENT

First Gas recognises the importance of regular engagement with our major gas users and stakeholders who rely on the consistent and safe delivery of large volumes of gas to maintain their ongoing productivity and business. Throughout the year, we have focused on maintaining regular dialogue with our stakeholders and sought out timely feedback, to improve the transmission services we provide.

6.1 CONTINUED ENGAGEMENT AND RELATIONSHIP BUILDING

The development and implementation of the single Gas Transmission Access Code (GTAC) has continued to be a key focus for our stakeholder engagement over the past year.

We worked closely with stakeholders during the second half of 2018, to address stakeholders' concerns and queries on the draft GTAC, prior to re-submitting it to the Gas Industry Company (GIC) for assessment in October 2018. The GIC released a positive preliminary assessment of the GTAC on 5 December 2018, followed by its final decision in February 2019.

For the implementation phase, First Gas has continued our GTAC engagement with stakeholders and held several workshops to progress matters such as the supplementary agreements policy and the development of a new transmission pricing methodology. We have also worked with stakeholders on the development of the new IT system (TACOS) to support the GTAC. We have welcomed the openness of our stakeholders to engage on this project and shape a path forward, as we head towards the go live date of 1 April 2020.

First Gas has also engaged proactively with stakeholders around the Pariroa crease remediation project, as we installed the temporary bypass. The First Gas team carried out a robust communications plan to ensure that all stakeholders were briefed before, during and after the work at Pariroa. We met with several companies individually, gave presentations on the approach to addressing the crease, and provided weekly emails informing all stakeholders of progress. We were nominated as a finalist for two categories at the 2019 Deloitte Energy Excellence Awards, for our work at Pariroa – the "Network Initiative of the Year" and the "Community Initiative of the Year".[19]

First Gas has continued to regularly attend major gas user group (MGUG) briefings to share our detailed operational plans, over and above that set out in our AMPs. We also continue to meet with our large gas users and upstream gas producers, to better understand their businesses and how we can assist and work with them. We also work with gas sector participants annually on the critical contingency exercise run by the Critical Contingency Operator. This exercise is a good opportunity to apply our Critical Contingency Management Plan and look at possible improvement going forward to ensure security of supply for our customers.

Future of our gas infrastructure

Following the release of the Vivid Economics report and announcement of our hydrogen trial (see section 2.7 above), we have increased our discussions with government officials and stakeholders around the future use of our gas infrastructure.

We are now a member of the New Zealand Hydrogen Association and are taking the opportunity to discuss our hydrogen trial with other stakeholders who are actively exploring hydrogen for New Zealand. We are also in discussions with gas pipeline businesses internationally who are exploring the transportation of future fuels through gas infrastructure.

6.2 LAND AND PLANNING STAKEHOLDER MANAGEMENT

First Gas' Land and Planning team's stakeholder management is continuing its drive on building and sustaining relationships with stakeholders. Following on from the goals and objectives of the Stakeholder Management Plan, the focus for the past twelve months has been to start improving access to information, reframing key messaging and promoting feedback opportunities with our stakeholders.

One important outcome of this effort was to start measuring the effectiveness of our safety awareness programmes for our key stakeholders, particularly landowners and contractors. The initial feedback from this was very positive, reinforcing that while we still have opportunities to improve, the majority of landowners and contractors are aware of their pipeline safety requirements and satisfied with the support First Gas provides.

Over the last 12 months new initiatives have included:

- Annual landowner and contractor phone and online surveys to measure and track safety awareness and our interface performance;
- Updating the First Gas public website with a fresh look and a dedicated safety awareness site with targeted information for farmers, councils, contractors, developers, landowners and the community. The website also includes online feedback mechanisms;
- First Gas engaged new stakeholder management team support personnel – a Marketing Consultant and a stakeholder management staff member with a focus especially with Iwi;
- Contractors online annual newsletter linked to information and feedback opportunities;
- Updated pipeline safety awareness presentations for contractors, emergency services, lifelines and other interested parties. This also included developing safety videos targeted for specific stakeholder groups;
- Publications updates with more simple and consistent messaging around pipeline safety awareness practises and requirements. This focuses on how we work in partnership with stakeholders to help each other achieve a safe living and working environment, e.g. new welcome pack, landowner and contractors' booklets (online and hard copies);

19. https://firstgas.co.nz/news/first-gas-triple-finalist-in-national-energy-awards/

- Stakeholder engagement plans to guide the business in managing stakeholder relationships and also project specific engagement plans for major activities to address potential stakeholder impacts;
- Engagement with the New Zealand utilities sector through the joint development and advocacy for a National Planning Standard for utilities, with the aim for adoption by the Ministry for Business, Innovation and Employment (MBIE);
- Development in relationships with Iwi through the review and implementation of the Stakeholder Engagement Plan, memorandums of understanding (MOU's) and a Cultural Heritage Policy; and
- Partnering with commercial organisations such as equipment hire companies and rural HSE app providers to develop and grow other avenues for promoting pipeline safety awareness.

6.3 MANAGING CONFLICTING INTERESTS

In the operation of any large organisation with numerous stakeholders and diverse interests, situations will inevitably arise where not all interests can be accommodated, or where conflicting interests exist. For example, different customers may place greater or lesser emphasis on price or quality. First Gas' roles in the gas industry can also give rise to conflicts between our roles as pipeline owner and system operator, and our ownership of regulated and unregulated businesses.

We consider that conflicting interests are best managed by:

- Clearly identifying and analysing internal and stakeholder conflicts (existing or potential). Regulated information disclosures require First Gas to be transparent about how it uses related parties to deliver capex and opex activities on our network, and to ensure that these transactions are representative of arms-length arrangements.
- Having a clear set of fundamental principles that help to guide a resolution. We are legally bound to make decisions that are consistent with the transmission operating codes (which include obligations relating to confidentiality) and we need to comply with the Health and Safety in Employment (Pipelines) Regulations 1999 and other relevant legislation.
- Seeking solutions that are consistent with the principles found in the codes and in relevant legislation or regulation.
- Communicating effectively with stakeholders so that all parties know where they stand.

In all instances of conflicting interests, we will strive to engage with stakeholders in a transparent manner to explain our decisions.

APPENDICES

This section sets out the required information disclosure schedules that must be completed each disclosure year. It also summarises the material changes made since the 2018 AMP and includes our signed director certificate

APPENDIX A: SUMMARY OF MATERIAL CHANGES AND COMPLIANCE

The table below:

- Summarises the material changes in our 2019 AMP Update, as compared with our 2018 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).

Table 6: Summary of material changes and compliance

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 First Gas's Transmission business. Information on the First Gas' distribution business (GDB) can be found in the separate 2019 distribution 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.	There have been no material changes to the network development plans disclosed in the 2018 AMP.
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.	There has been some rebalancing of the asset replacement and renewal work programme to respond to the Pariroa defect. The Gilbert Stream project has been rescheduled for completion in FY2020. The White Cliffs project has been rescheduled to start in FY2023.
Clause 2.6.5 (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.	There have been no material changes to Forecast Operational Expenditure disclosed in the 2018 AMP. There has been an overall increase in asset replacement and renewal expenditure for Pariroa phase two in FY2020 and FY2021. There has been an overall increase in non-network expenditure for the GTAC project in FY2020. There has been an overall increase in asset replacement and renewal expenditure to address geohazard risks and ageing assets on the system for FY2023 to FY2027. There has been an overall increase in asset replacement and renewal expenditure for SCADA and communications upgrades for FY2023 – FY2027.
Clause 2.6.5(5) Provide an assessment of transmission capacity as set out in clause 8 of Attachment A.	See **Appendix C.**
Clause 2.6.5 (6) Identify any material changes related to the legislative requirements as set out in clause 3.6 of Attachment A.	There have been no material changes to the legislative requirements directly affecting management of the assets as set out in clause 3.6 of Attachment A.

ID REQUIREMENT	DISCUSSION
Clause 2.6.5(7) Identify any changes to the asset management practices of the GDB that would affect a Schedule 13 Report on Asset Management Maturity disclosure.	There have been no material changes to the asset management practices that would affect the Asset Management Maturity disclosure in the 2018 AMP.
Clause 2.6.5 (8) Contain the information set out in the schedules described in 2.6.6.	See **Appendix B.**
Clause 2.6.6 Subject to clause 2.13.2, 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.**
Clause 2.7.2 Before the start of each disclosure year, every GTB must complete and publicly disclose the Mandatory Explanatory Notes on Forecast Information in Schedule 14a by inserting all relevant information relating to information disclosed in accordance with clause 2.6.6.	See **Appendix B.**

APPENDIX B: INFORMATION DISCLOSURE SCHEDULES

This appendix includes the following 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 Utilisation

Schedule 12c – Report on Forecast Demand

Schedule 14a – Explanatory Notes on Forecast Information

Schedule 11a: Report on Forecast Capital Expenditure

Company Name	**First Gas Transmission**
AMP Planning Period	**1 October 2019 – 30 September 2029**

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

sch ref			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 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**	**30 Sep 28**	**30 Sep 29**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (nominal dollars)**										
10		Consumer connection	3,473	1,632	1,873	2,017	2,165	2,209	2,365	2,642	2,813	2,869	2,926
11		System growth	204	1,319	3,301	6,103	2,353	2,319	2,422	2,528	2,578	2,630	2,682
12		Asset replacement and renewal	30,286	28,719	24,255	23,407	30,438	32,392	54,951	27,089	29,220	30,660	31,273
13		Asset relocations	880	2,397	2,445	2,494	2,544	2,595	2,647	2,700	2,754	2,809	2,865
14		Reliability, safety and environment:											
15		Quality of supply	-	510	520	531	541	552	563	574	586	598	610
16		Legislative and regulatory											
17		Other Reliability, Safety and Environment											
18		**Total reliability, safety and environment**	-	510	520	531	541	552	563	574	586	598	610
19		**Expenditure on network assets**	34,843	34,578	32,394	34,552	38,041	40,067	62,949	35,534	37,950	39,565	40,356
20		Expenditure on non-network assets	10,251	9,842	4,324	3,467	3,205	2,943	3,601	3,372	2,663	3,376	3,444
21		**Expenditure on assets**	45,094	44,420	36,719	38,019	41,247	43,010	66,550	38,906	40,613	42,941	43,800
22													
23	*plus*	Cost of financing	385	559	402	481	512	367	568	332	347	367	374
24	*less*	Value of capital contributions	792	2,158	2,201	2,245	2,290	2,336	2,382	2,430	2,479	2,528	2,579
25	*plus*	Value of vested assets											
26		**Capital expenditure forecast**	44,687	42,822	34,920	36,256	39,469	41,042	64,736	36,808	38,481	40,780	41,596
27													
28		Assets commissioned	42,070	37,884	32,311	34,152	54,499	34,161	36,851	38,944	40,774	43,005	44,174
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 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**	**30 Sep 28**	**30 Sep 29**
32			**$000 (in constant prices)**										
33		Consumer connection	3,473	1,600	1,800	1,900	2,000	2,000	2,100	2,300	2,400	2,400	2,400
34		System growth	204	1,293	3,172	5,750	2,173	2,100	2,150	2,200	2,200	2,200	2,200
35		Asset replacement and renewal	30,287	28,153	23,308	22,052	28,114	29,333	48,786	23,578	24,934	25,650	25,650
36		Asset relocations	880	2,350	2,350	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	-	500	500	500	500	500	500	500	500	500	500
39		Legislative and regulatory	-	-	-	-	-	-					
40		Other Reliability, Safety and Environment	-	-	-	-	-	-	-	-	-	-	-
41		**Total reliability, safety and environment**	-	500	500	500	500	500	500	500	500	500	500
42		**Expenditure on network assets**	34,843	33,897	31,130	32,552	35,137	36,283	55,886	30,928	32,384	33,100	33,100
43		Expenditure on non-network assets	10,251	9,648	4,156	3,267	2,961	2,665	3,197	2,935	2,272	2,825	2,825
44		**Expenditure on assets**	45,095	43,544	35,286	35,819	38,098	38,948	59,083	33,863	34,656	35,924	35,924
45	**Subcomponents of expenditure on assets (where known)**												
46		Research and development		500	500	500	500	500	500	500	500	500	500

	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 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**	**30 Sep 28**	**30 Sep 29**
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	(0)	32	73	117	165	209	265	342	413	469	526
System growth	-	26	129	353	180	219	272	328	378	430	482
Asset replacement and renewal	(0)	566	946	1,354	2,323	3,059	6,166	3,511	4,286	5,010	5,623
Asset relocations	-	47	95	144	194	245	297	350	404	459	515
Reliability, safety and environment:											
Quality of supply	-	10	20	31	41	52	63	74	86	98	110
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other Reliability, Safety and Environment	-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment	-	10	20	31	41	52	63	74	86	98	110
Expenditure on network assets	(0)	681	1,264	1,999	2,904	3,784	7,063	4,606	5,566	6,465	7,257
Expenditure on non-network assets	-	194	169	201	245	278	404	437	391	552	619
Expenditure on assets	(0)	876	1,433	2,200	3,149	4,062	7,467	5,043	5,957	7,017	7,876

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	**30 Sep 19**	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**
*Consumer types defined by GTB**	**$000 (in constant prices)**					
Delivery point	3,273	1,200	1,800	1,900	2,000	2,000
Receipt Point	200	400	-	-	-	-
** include additional rows if needed*						
Consumer connection expenditure	3,473	1,600	1,800	1,900	2,000	2,000
less Capital contributions funding consumer connection						
Consumer connection less capital contributions	3,473	1,600	1,800	1,900	2,000	2,000

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Pipes						
Compressor stations						
Other stations	204	1,293	3,172	5,750	2,173	2,100
SCADA and communications						
Special crossings						
System growth expenditure	204	1,293	3,172	5,750	2,173	2,100
less Capital contributions funding system growth	-	-	-	-	-	-
System growth less capital contributions	204	1,293	3,172	5,750	2,173	2,100

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
85		for year ended	**30 Sep 19**	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**
86	**11a(iv): Asset Replacement and Renewal**							
87			**$000 (in constant prices)**					
88	Pipes		14,468	20,356	13,800	14,102	20,699	19,601
89	Compressor stations		5,322	2,429	3,405	3,100	3,072	2,632
90	Other stations		9,055	3,070	3,774	2,373	1,736	4,194
91	SCADA and communications		550	294	106	221	534	950
92	Special crossings		-	22	44	88	44	44
93	*Components of stations (where known)*							
94	Main-line valves		19	336	787	872	700	700
95	Heating system		181	572	414	620	385	385
96	Odorisation plants		81	276	21	89	89	89
97	Coalescers		-	-	-	88	-	-
98	Metering system		612	650	655	250	689	439
99	Cathodic protection		-	149	224	248	87	172
100	Chromatographs		-	-	79	-	79	128
101	**Asset replacement and renewal expenditure**		30,287	28,153	23,308	22,052	28,114	29,333
102	*less* Capital contributions funding asset replacement and renewal		-	-	-	-	-	-
103	**Asset replacement and renewal less capital contributions**		30,287	28,153	23,308	22,052	28,114	29,333
104	**11a(v): Asset Relocations**							
105	**Project or programme***							
106	Murphys Road		30	350	-	-	-	-
107	Ports of Auckland		220	1,200				
108								
109								
110								
111	** include additional rows if needed*							
112	All other projects or programmes - asset relocations		630	800	2,350	2,350	2,350	2,350
113	**Asset relocations expenditure**		880	2,350	2,350	2,350	2,350	2,350
114	*less* Capital contributions funding asset relocations		792	2,115	2,115	2,115	2,115	2,115
115	**Asset Relocations less capital contributions**		88	235	235	235	235	235
116	**11a(vi): Quality of Supply**							
117	**Project or programme***							
118	Continuous Improvement Initiative		-	500	500	500	500	500
119								
120								
121								
122								
123	** include additional rows if needed*							
124	All other projects or programmes - quality of supply							
125	**Quality of supply expenditure**		-	500	500	500	500	500
126	*less* Capital contributions funding quality of supply							
127	**Quality of supply less capital contributions**		-	500	500	500	500	500
128								

11a(vii): Legislative and Regulatory

Project or programme*		Current Year CY 30 Sep 19	CY+1 30 Sep 20	CY+2 30 Sep 21	CY+3 30 Sep 22	CY+4 30 Sep 23	CY+5 30 Sep 24
** 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 19	CY+1 30 Sep 20	CY+2 30 Sep 21	CY+3 30 Sep 22	CY+4 30 Sep 23	CY+5 30 Sep 24
Project or programme*		**$000 (in constant prices)**					
		-	-	-	-	-	-
** 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*	Current Year CY 30 Sep 19	CY+1 30 Sep 20	CY+2 30 Sep 21	CY+3 30 Sep 22	CY+4 30 Sep 23	CY+5 30 Sep 24
	$000 (in constant prices)					
ICT	8,284	2,444	2,731	2,337	2,145	1,849
Building Refurbishments	556	570	174	200	200	200
Plant and Equipment	353	300	300	300	300	300
Motor Vehicles	1,059	1,075	950	430	316	316
	-	-	-	-	-	-
** include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	10,251	4,389	4,156	3,267	2,961	2,665

Atypical expenditure

Project or programme*	Current Year CY 30 Sep 19	CY+1 30 Sep 20	CY+2 30 Sep 21	CY+3 30 Sep 22	CY+4 30 Sep 23	CY+5 30 Sep 24
ICT		4,600				
Plant and Equipment		659				
** include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	5,259	-	-	-	-
Expenditure on non-network assets	10,251	9,648	4,156	3,267	2,961	2,665

Company Name	**First Gas Transmission**
AMP Planning Period	**1 October 2019 – 30 September 2029**

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 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**	**30 Sep 28**	**30 Sep 29**
10	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
11	Service interruptions, incidents and emergencies	691	733	764	779	795	811	827	843	860	877	895
12	Routine and corrective maintenance and inspection	16,362	16,010	15,482	15,359	15,334	15,416	15,724	16,273	16,359	17,025	17,366
13	Asset replacement and renewal											
14	Compressor fuel	3,684	3,758	3,834	3,910	3,988	4,068	4,150	4,233	4,317	4,404	4,492
15	Land management and associated activity	1,050	1,071	1,093	1,114	1,137	1,160	1,183	1,206	1,230	1,255	1,280
16	**Network opex**	21,787	21,572	21,172	21,162	21,254	21,454	21,883	22,555	22,767	23,561	24,032
17	System operations	2,822	2,879	2,937	2,995	3,055	3,116	3,179	3,242	3,307	3,373	3,441
18	Network support	3,805	3,659	3,786	3,699	3,442	3,511	3,581	3,653	3,726	3,800	3,876
19	Business support	16,151	16,476	16,807	17,143	17,486	17,836	18,192	18,556	18,927	19,306	19,692
20	**Non-network opex**	22,778	23,014	23,530	23,838	23,983	24,463	24,952	25,451	25,960	26,479	27,009
21	**Operational expenditure**	44,565	44,586	44,702	45,000	45,237	45,917	46,835	48,006	48,727	50,040	51,041
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 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**	**30 Sep 28**	**30 Sep 29**
24		**$000 (in constant prices)**										
25	Service interruptions, incidents and emergencies	691	719	734	734	734	734	734	734	734	734	734
26	Routine and corrective maintenance and inspection	16,362	15,694	14,878	14,470	14,164	13,960	13,960	14,164	13,960	14,243	14,243
27	Asset replacement and renewal											
28	Compressor fuel	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684	3,684
29	Land management and associated activity	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050	1,050
30	**Network opex**	21,787	21,147	20,346	19,938	19,632	19,428	19,428	19,632	19,428	19,711	19,711
31	System operations	2,822	2,822	2,822	2,822	2,822	2,822	2,822	2,822	2,822	2,822	2,822
32	Network support	3,805	3,587	3,638	3,485	3,179	3,179	3,179	3,179	3,179	3,179	3,179
33	Business support	16,151	16,151	16,151	16,151	16,151	16,151	16,151	16,151	16,151	16,151	16,151
34	**Non-network opex**	22,778	22,560	22,611	22,458	22,152	22,152	22,152	22,152	22,152	22,152	22,152
35	**Operational expenditure**	44,565	43,708	42,957	42,396	41,784	41,580	41,580	41,784	41,580	41,863	41,863
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 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**	**30 Sep 28**	**30 Sep 29**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions, incidents and emergencies	-	14	30	45	61	77	93	109	126	143	161
43	Routine and corrective maintenance and inspection	-	315	604	889	1,171	1,456	1,764	2,109	2,400	2,782	3,123
44	Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
45	Compressor fuel	-	74	150	226	304	384	466	549	633	720	808
46	Land management and associated activity	-	21	43	64	87	110	133	156	180	205	230
47	**Network opex**	-	425	826	1,225	1,622	2,026	2,455	2,923	3,339	3,850	4,321
48	System operations	-	57	115	173	233	294	357	420	485	551	619
49	Network support	-	72	148	214	263	332	402	473	546	621	697
50	Business support	-	325	656	992	1,335	1,685	2,041	2,405	2,776	3,155	3,541
51	**Non-network opex**	-	453	918	1,379	1,831	2,310	2,800	3,299	3,808	4,327	4,856
52	**Operational expenditure**	-	879	1,744	2,604	3,453	4,337	5,255	6,222	7,147	8,177	9,178

Schedule 12a: Report on Asset Condition

Company Name	**First Gas Transmission**
AMP Planning Period	**1 October 2019 – 30 September 2029**

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										
7				**Asset condition at start of planning period (percentage of units by grade)**						
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	-	0.85%	37.49%	61.66%	-	3	-
10	Pipes	Special crossings	km			100.00%	-	-	3	-
11	Stations	Compressor stations	No.			100.00%		-	3	-
12	Stations	Offtake point	No.			100.00%		-	3	-
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.	-	-	75.00%	25.00%	-	3	-
17	Compressors	Compressors—electric motor driven	No.			100.00%		-	3	-
18	Compressors	Compressors—reciprocating engine driven	No.	-	50.00%	50.00%	-	-	3	28%
19	Main-line valves	Main line valves manually operated	No.		100.00%			-	3	30%
20	Main-line valves	Main line valves remotely operated	No.		100.00%			-	3	30%
21	Heating systems	Gas-fired heaters	No.	-	16.36%	74.55%	9.09%	-	3	22%
22	Heating systems	Electric heaters	No.			100.00%		-	3	-
23	Odorisation plants	Odorisation plants	No.	12.50%	-	87.50%	-	-	3	13%
24	Coalescers	Coalescers	No.			100.00%		-	3	-
25	Metering systems	Meters—ultrasonic	No.	-	-	100.00%	-	-	4	-
26	Metering systems	Meters—rotary	No.	63.93%	1.64%	32.79%	1.64%	-	4	20%
27	Metering systems	Meters turbine	No.	36.23%	10.14%	49.28%	4.35%	-	4	10%
28	Metering systems	Meters—mass flow	No.			100.00%		-	3	-
29	SCADA and communications	Remote terminal units (RTU)	No.	12.98%	33.16%	53.86%		-	3	100%
30	SCADA and communications	Communications terminals	No.			100.00%		-	3	-
31	Cathodic protection	Rectifier units	No.	-	31.25%	68.75%	-	-	3	19%
32	Chromatographs	Chromatographs	No.	-	20.00%	80.00%	-	-	4	-

Schedule 12b: Report on Forecast Demand

Company Name	**First Gas Transmission**
AMP Planning Period	**1 October 2019 – 30 September 2029**

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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7	**12b(i): Connections**						
8		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**30 Sep 19**	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**
10	**Connection types defined by GTB**						
11	Distribution System	1					
12	Direct Connect	1	1	1			
13	Bi-Directional						
14	Receipt Point		1				
15							
16	** include additional rows if needed*						
17	**Connections total**	2	2	1	-	-	-
18							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
19	**12b(ii): Gas conveyed**						
20		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
21	for year ended	**30 Sep 19**	**30 Sep 20**	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**
22							
23	Intake volume (TJ)	167,879	170,204	173,222	174,797	175,647	176,501
24	Quantity of gas delivered (TJ)	167,533	169,786	172,738	174,253	175,050	175,901
25	Gas used in compressor stations (TJ)	545	545	545	545	545	545
26	Gas used in heating systems (TJ)	123	123	123	123	123	123
27	**Total gas conveyed (TJ)**	168,201	170,454	173,406	174,921	175,718	176,569

Schedule 14a: Explanatory Notes on Forecast Information

Forecasts are in constant value terms. In preparing Schedules 11a and 11b we have escalated our real forecasts to produce nominal forecasts for Information Disclosure. While we expect to face a range of input price pressures over the planning period, we have based our escalation approach on the consumer price index (CPI). This has been done to align forecast inflation with the initial 'exposure' financial model for the gas DPP. Therefore, for the purposes of this AMP Update we have assumed changes are limited to CPI rather than adopting more specific indices or modelling trends in network components or commodity indices. Similarly, we have not sought to reflect trends in the labour market.

Table 7: Forecast Information

FOR YEAR ENDED	CPI
FY2019	0.00%
FY2020	2.01%
FY2021	2.01%
FY2022	2.00%
FY2023	2.00%
FY2024	2.00%
FY2025	2.00%
FY2026	2.00%
FY2027	2.00%
FY2028	2.00%
FY2029	2.00%

APPENDIX C: Pipeline Capacity

This appendix describes our current capacity determination methodology and sets out our forecast pipeline capacity assessments. Following GTAC going live 1 April 2020, this will be reviewed and any changes required will be included in the 2020 AMP.

North System

PIPELINE LOCATION (DELIVERY POINT OR STATION)	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)			NOTES
		FY19	FY24	FY29	
Tuakau 2	2,252	44,031	42,853	42,531	
Harrisville 2	2,215	27,123	25,095	25,063	
Drury 1	1,197	106,191	103,944	103,104	
Glenbrook	6,500	14,705	14,064	14,001	
Greater Auckland	52,144	43,632	40,184	38,667	1
Hunua	908	108,202	104,103	102,656	
Flat Bush	1,781	89,631	85,559	84,113	
Waitoki	602	4,032	3,783	3,746	
Marsden 1	15,600	2,430	2,245	2,182	
Whangarei	580	2,314	2,138	2,080	
Kauri + Maungaturoto	1,200	1,829	1,758	1,735	
Warkworth	1,567	425	422	420	

Notes:

1. System peak period: 25/06/2018 to 30/06/2018.
2. 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.
3. Rotowaro compression has been modelled at a constant discharge pressure of 84 barg
4. Henderson compression has been modelled at a constant discharge pressure of 84 barg
5. Greater Auckland is a notional Delivery Point, comprising the actual Westfield, Papakura, Bruce McLaren, Waikumete and Henderson Delivery Points

Bay of Plenty

PIPELINE LOCATION (DELIVERY POINT OR STATION)	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)			NOTES
		FY19	FY24	FY29	
Edgecumbe	4,685	6,071	3,124	2,997	
Gisborne	1,438	3,799	3,797	3,795	
Greater Mount Maunganui	2,595	4,600	3,013	1,321	1
Greater Tauranga	1,258	3,585	2,556	1,193	5
Kawerau	2,300	22,816	13,509	12,926	
Kinleith	11,121	32,193	27,571	23,061	
Lichfield	5,900	26,692	21,725	21,788	
Reporoa	1,975	9,199	6,906	6,778	
Rotorua	1,558	2,813	2,014	1,975	
Tirau	1,400	14,841	11,899	10,087	
Whakatane	2,647	5,439	3,416	3,310	

Notes:

1. System peak period: 16/10/2017 to 21/10/2017
2. Kawerau compressor online was assumed online for modelling purposes. Model assumes a fixed outlet pressure of 84 barg and a maximum flow of 2.72 SCMS.
3. For operational reasons the discharge pressure at Pokuru was limited to 74 bar, although compressors are capable to deliver up to MAOP of BoP system
4. Greater Tauranga is a notional Delivery Point, comprising the actual Tauranga and Pyes Pa Delivery Points
5. Greater Mt Maunganui is a notional Delivery Point, comprising the actual Mt Maunganui and Papamoa Delivery Points

Central North System

PIPELINE LOCATION (DELIVERY POINT OR STATION)	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)			NOTES
		FY19	FY24	FY29	
Cambridge	1,850	1,867	1,856	1,845	
Greater Hamilton	7,160	18,032	17,178	16,285	3
Horotiu	816	12,593	11,792	10,957	
Kiwitahi	1,000	2,891	2,643	2,243	
Morrinsville	1,073	3,804	3,558	3,285	
Tatuanui DF	1,600	2,691	2,454	2,211	
Te Rapa Cogen	23,200	12,733	11,863	10,950	
Waitoa	1,100	3,528	3,408	3,287	

Notes:
1. System peak peiod: 20/08/2018 to 25/08/2018.
2. Compression at Rotowaro is modelled at a constant discharge pressure of 84 barg.
3. Greater Hamilton is a notional Delivery Point, comprising the actual Hamilton (Te Kowhai) and Hamilton (Temple View) Delivery Points

Central South System

PIPELINE LOCATION (DELIVERY POINT OR STATION)	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)			NOTES
		FY19	FY24	FY29	
Eltham	600	9,824	9,824	9,823	
New Plymouth	3,238	3,288	3,277	3,265	
Waitara	357	5,526	5,525	5,525	

Notes:
1. System peak period: 25/06/2018 to 30/06/2018.
2. The demand at Pokuru offtake is modelled as being fully interrupted.
3. Mahoenui compression is modelled at a constant discharge pressure of 84 barg.
4. Inlet pressure at Kapuni was set to 84 barg.

Frankley Road System

PIPELINE LOCATION (DELIVERY POINT OR STATION)	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)			NOTES
		FY19	FY24	FY29	
Ammonia-Urea Plant (AUP)	22,500	20,863	15,073	22,416	7
KGTP Maui Bypass	25,000	17,645	12,426	47,366	
TCC+Strat Power+Strat storage	170,000	27,079	18,079	82,079	

Notes:

1. System peak period: 07/05/2018 to 12/05/2018.
2. The gas pressure at Frankley Road is modelled as 44 barg entering this system.
3. TCC (64,000 GJ/day contractual capacity) anticipated to be closed down by 2029. No growth of Stratford Power assumed.
4. The pressure at Frankley Road equals the pressure in the Maui Pipeline.
5. Stratford 2 supplies the Stratford "peaker" power station. FGL delivers gas there at pipeline (ie unregulated) pressure
6. Ammonia-Urea (AUP) comprises the Ballance 8201 (fuel) and 9626 (process gas) Delivery Points. FGL aims to deliver gas at both DPs at not less than 29 barg.
7. Stratford 3 is for the Ahuroa underground gas storage facility

South System

PIPELINE LOCATION (DELIVERY POINT OR STATION)	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)			NOTES
		FY19	FY24	FY29	
Belmont	6,469	9,319	9,189	9,060	
Feilding	860	4,435	4,421	4,408	
Hastings	7,347	7,508	7,469	7,432	7
Hawera	1,552	34,076	33,809	33,528	6
Levin	1,150	5,290	5,265	5,240	
Longburn	899	6,823	6,803	6,785	
Marton	900	5,197	5,195	5,194	
Pahiatua	3,634	4,428	4,406	4,384	
Palmerston North	4,291	4,252	4,233	4,216	
Greater Kapiti	707	9,911	9,826	9,742	
Tawa	10,044	3,853	3,853	3,853	
Greater Waitangirua	1,467	10,213	10,129	10,047	8
Whanganui	4,314	33,094	32,836	32,566	

Notes:

1. System peak period: 03/09/2018 to 08/09/2018
2. The calculation of Uncommitted Operational Capacity at Tawa is based on pressures being limited to 14 barg. Although not defined in the Gas Transmission Security Standard, 14 barg is the minimum accepted pressure for distribution.
3. Kapuni compression is modelled at a constant discharge pressure of 84 barg
4. Kaitoke compression is modelled at a constant discharge pressure of 84 barg
5. Greater Kapiti is a notional DP which also includes Waikanae 2
6. Greater Waitiangirua is a notional Delivery Point, comprising the actual Waitangirua and Pauatahanui 1 Delivery Points

Maui System

PIPELINE LOCATION (DELIVERY POINT OR STATION)	MAXIMUM OFFTAKE	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)			NOTES
		FY19	FY24	FY29	
Te Awamutu DF	1,243	45,627	24,535	7,064	
Te Kuiti South	420	3,909	2,867	2,764	
Rotowaro	60,656	129,345	121,843	117,136	
Pokuru 1	20,056	69,609	54,713	43,437	
Bertrand Road	105,248	344,753	247,032	148,383	
Huntly Power Station	99,282	296,931	187,918	124,863	

Notes:

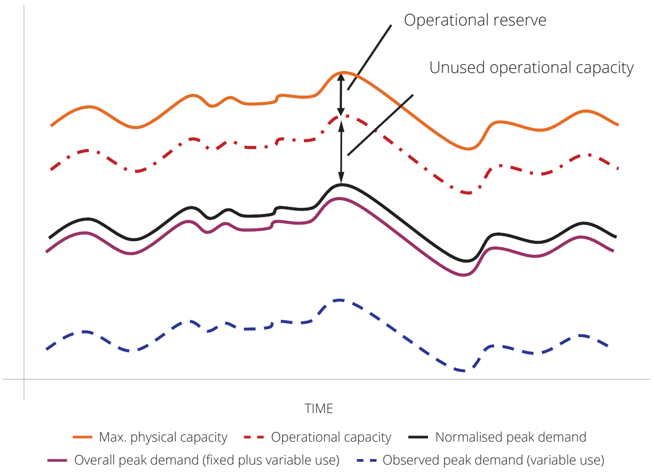
1. System peak period: 29/01/2018 to 02/02/2018.
2. On the Maui system, contractual capacity is obtained by nominations, not by an annual reservation. The Maximum Off-take shown at each location is the actual off-take on the first day of the system peak period.
3. A 46 barg source pressure has been assumed at Oaonui Production Station
4. Mokau compression has been modelled at a constant discharge pressure of 56 barg
5. 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.

APPENDIX D: CAPACITY FORECASTING METHODOLOGY

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

For our modelling analysis we use Synergi version 4.8.0 software, which is a leading, internationally recognised product, produced by DNV GL.

Figure D1: Overview schematic for pipeline capacity determination



The steps to determine pipeline capacity are as follows:

- Determine the time period sufficient to reveal the pipeline's performance, in particular the cycle of pressure depletion and recovery.
- Obtain actual demand profiles for variable demands during the selected time period.
- Determine "fixed" demands.
- Normalise the variable demand profiles to reflect the long-term trend.
- Run the model to determine the maximum physical demand that can be sustained without breaching the System Security Standard.
- Allow for an "operational reserve" to cover severe winter demands as well as an appropriate "survival time" for the pipeline. This establishes the available "operational capacity".

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 – Time

The peak demand period relevant to the determination of physical pipeline capacity should be the period of greatest demand from the pipeline where pipeline pressures:
(a) do not fall below the minimum acceptable level at any point; and (b) following any depletion, recover to at least their starting levels.[20] For most pipelines the peak demand period is usually a sequence of high demand days (which may or may not include the peak demand day).

Peak demand on our pipelines occurs during the working week. Overall demand on most pipelines (although not necessarily at all delivery points) is invariably lower on weekends. For this reason, modelling is generally based on the 5 days (Monday-Friday, inclusive) in which the highest aggregate demand occurs (the "five-day peak[21]").

At the start of the 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 in the pipeline will fall[22]. To determine the pipeline's sustainable capacity, pressures must fully recover.

It is noted that in many international gas regimes, peak demand profiles are considered over a 24-hour period only, and gas consumption is limited to ensure that pressures fully recover within this period. We have evaluated that, but as it would materially reduce the transmission capacity that could be allocated and, given that the system can still be operated within prudent operating levels, we have decided to maintain the five-day peak approach. Our system security standard reflects this operating approach.

Step 2 – Observed (Variable) Peak Demand

The second step in a physical capacity determination is to assemble gas demand profiles[23] by observing actual variable demand patterns during the five-day peak (or, potentially, other peak demand period) for all delivery points on the pipeline. Generation loads are excluded at this point as they are assumed to be fixed.

This effectively captures the actual diversity in the demands from the pipeline including, in the case of delivery points supplying

20. Indicating that a further such peak demand period would be sustainable.
21. The Saturday and Sunday immediately following are also modelled in order to check that pressures recover sufficiently before the start of the next week. Hence any reference in this paper to modelling the five-day peak should be understood to mean that the relevant 7 days are considered.
22. 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 a number of 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).
23. 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.
24. The counterfactual is that, if we used gas demand profiles representing the peak demand of each individual delivery point on the pipeline, it would need to apply "artificial" diversity factors.
25. As discussed in the System Security Standard.

distribution networks, the diversity exhibited by often large populations of individual gas consumers. The benefit of this approach is that, for the purpose of determining the available physical capacity of a pipeline, we do not need to forecast diversity.[24] The implicit assumption being that this is the best predictor of diversity to apply when modelling usage at a level that hits the maximum physical limits of the system. Accordingly, the physical capacity determination is based on the most recent observed five-day peak, as this best reflects the latest demand profile on a pipeline.

This approach does mean, however, that should capacity be allocated equivalent to a pipeline's maximum physical capacity then, if all shippers simultaneously consumed their full contractual gas capacity, this could exceed the pipeline's physical capacity leading to a critical contingency event.[25]

Future demand profiles may differ from those previously observed, which in severe cases could also cause the pipeline's physical capacity to be exceeded.

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

Dairy factories' peak demand periods do not generally coincide with the five-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. Other large directly-connected customers (excluding power stations) are modelled as variable loads according to their actual demand during the five-day peak, unless their demand in that period was so unusually low as to justify an adjustment factor being applied to simulate more typical operation.

Step 3 – Overall Modelled Peak Demand

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

Currently, only power stations are treated as fixed loads. While their demand is not literally fixed, when power stations are operating at maximum generating capacity, they represent both near-constant and very substantial loads on the relevant pipeline. Power stations can operate at full capacity at any time of the year. Even if they were not actually operating at peak load during the five-day peak, it is clear that they could. Accordingly, we model each power station's demand as its maximum contractual entitlement rather than its actual demand in the five-day peak.

Step 4 – Normalised Peak Demand

The 4th step in the capacity determination process is to "normalise" five-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[26] this annual variance correlates closely with winter weather patterns, predominantly delivery points to distribution networks which supply large numbers of smaller consumers (amongst others).

A capacity allocation requires an understanding of the underlying demand growth trend. To determine this trend, it is necessary to normalise annual demand fluctuations that are caused by unpredictable external events (such as unexpected temperature levels). This normalisation is done by adjusting the relevant observed five-day peak profile to the average trend in five-day peak values observed over time. Such an adjustment can be both upwards (in a milder-than-average year, where peak consumption was lower than the long-term trend), or downwards (in a colder-than-average year, where peak consumption was higher than the long-term trend). The adjustment is applied to the five-day peak demand profile by means of a single multiplication factor: in other words, the shape of the consumption profile remains as observed, but the actual hourly consumption levels are moved up or down as determined by the normalising factor.

If relevant, where the five-day peak is not predominantly weather-driven, other adjustment factors are applied.

Step 5 – Maximum Physical System Capacity

The 5th step is to determine the maximum physical capacity that a pipeline system can deliver, based on the most recent five-day peak demand profiles (normalised where appropriate) and including fixed loads.

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

Modelling to determine the maximum physical capacity of a pipeline system necessitates simulating increased demand. This involves applying one or more of the following three methods at a delivery point to a pipeline, or more than one delivery point in certain cases:

- Applying a factor to the (normalised) five-day peak.
- Adding a constant flow rate to the (normalised) five-day peak.
- Configuring a separate flow profile that adds to the (normalised) five-day peak.

The method(s) used depends on the scenario being modelled, the information available and whether the modelling is being undertaken to provide an indication of the general level of unused physical capacity on the pipeline, or in response to a specific request from a shipper.

26. The Bay of Plenty pipeline does not display a strong overall winter peak.

Method 1 is the most commonly used. The factor is increased to the point immediately before the system security standard would be breached, which is usually when an unacceptably-low minimum pressure occurs at a delivery point on the pipeline.

Method 2 is used to simulate fixed demand.[27] The fixed flow rate is increased until the maximum flow rate short of breaching the system security standard is found.

Method 3 is used to simulate a different flow profile from the observed five-day peak. Having determined the "base" profile, an increasing factor is applied to it until the point immediately before the system security standard would be breached.

When modelling "organic growth", generally a relatively small percentage increase in demand is expected to more or less follow the existing flow profile, and thus method 1 is used.

Method 1 can also be used to give an indication of spare capacity where that is very large (in other words, where the factor is a large number, 5, 10 or 20.) It would need to be borne in mind, however, that if such a large new load were to materialise, it might well exhibit a flow profile materially different from the existing one, which might change the factor.

Method 2 is often used as a first, conservative go/no-go test of a pipeline's ability to supply a new load. For example, a prospective new load might be set at a constant flow rate, set at the rate of its maximum hourly quantity (MHQ). If the pipeline can sustain that, then there is most likely no need for more refined or realistic modelling.

Method 3 can be used where the flow profile of a new load is known and is materially different from the profile of the existing load. Another use might be to test additional load complying with contractual criteria of MHQ and maximum daily quantity ("MDQ"), on a continuous basis, so as to be sure of the amount of additional contractual capacity that could be allocated at the delivery point.

Step 6 and 7 – Operational Capacity and Operational Reserve

Prudent operation of a gas transmission pipeline system requires that it is not operated at a level exceeding its maximum physical capacity. As a reasonable and prudent operator, we must operate the pipeline at "safe" levels, including ensuring that the system security standard is not breached in a manner other than as a result of events beyond our reasonable control.

The "safe" level of physical capacity is termed the "operational capacity" of a pipeline system. It is determined by reducing the maximum physical capacity by an amount known as the "operational reserve". 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.[28] We have adopted a one-in-20 year winter incidence (i.e. severity) level to ensure that transmission capacity shortfalls do not occur at an unacceptably high frequency. While this is our current standard, and is a common standard in many other jurisdictions, future economic testing may identify a requirement to revise this.
- **Survival time:** compression is a key to increasing capacity on most pipeline systems. Our compressor stations are designed with N-1[29] redundancy (as set out in the system security standard). However, a redundant compressor may also fail, or fail to start,[30] and additional time therefore needs to be allowed during which such a failure may be remedied – the so-called survival time. This margin is determined based on 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 has to be determined for each pipeline individually. This also applies to any pipeline where the five-day peak is not determined by winter conditions.

Step 8 – Unused Operational Capacity

The amount of the operational capacity that shippers are not currently using represents additional gas that could have been conveyed through the pipeline system to delivery points during the five-day peak without reasonably being expected to result in a breach of the System Security Standard, even in the event of a one-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.

It is necessary to distinguish "unused" operational capacity from "uncommitted" operational capacity.

27. 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.
28. 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.
29. 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.
30. 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.

APPENDIX E: DIRECTOR CERTIFICATE

Certification for Year beginning Disclosures

Clause 2.9.1

We, Philippa Jane Dunphy and Euan 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.

(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.

Director	**Director**
14 August 2019	14 August 2019
Date	**Date**