Firstgas
A Firstgas Group company

GAS TRANSMISSION BUSINESS

Asset Management Plan Update

Year commencing 1 October 2022

First Gas Limited
September 2022

Disclaimer: The information in this document has been prepared in good faith and represents Firstgas' intentions and opinions at the date of issue. However, Firstgas operates in a dynamic environment (for example, the changing requirements of customers, deteriorating asset condition and the impact of severe weather events) and plans are constantly evolving to reflect the most current information and circumstances.

Importantly, we note that how the Government choses to implement the actions specified in its first Emissions Reduction Plan (ERP) may have a material effect on our asset management strategy and the underlying assumptions we have applied to develop our AMP Update forecasts. Consequently, Firstgas does not give any express or implied assurance about the accuracy of the information or whether Firstgas will fully implement the plan or undertake the work mentioned in the document.

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I OREA TE TUATARA KA PUTA KI WAHO

– Ta Hirini Moko Mead

Translation:

*The Tuatara comes out before it is too late.
A problem is solved by continuing to find solutions.*

MESSAGE FROM THE CHIEF EXECUTIVE OFFICER

Tēnā koutou katoa and welcome to First Gas Limited's (Firstgas) Gas Transmission Asset Management Plan Update (AMP Update) 2022.

This year has seen a rapidly evolving energy market, primarily driven by a legislative target of net zero emissions by 2050 and the release of the Government's first Emissions Reduction Plan (ERP). This plan paves the way for renewable gas and Firstgas Group looks forward to engagement with the gas sector and Government on the development of both the Gas Transition Plan and National Energy Strategy.

Firstgas is part of Firstgas Group and is committed to helping New Zealand reach its target of net zero emissions by 2050. We are a member of the Climate Leaders' Coalition and have spent close to four years investigating the prospects for introducing renewable gas into the New Zealand gas network.

This year we established our Future Fuels team as part of our commitment to the further development and delivery of our Renewable Fuels strategy. We are supporting the development of New Zealand's first large-scale biogas upgrading facility and have been planning for our hydrogen blending trials to establish how existing gas infrastructure can be used to transport green hydrogen.

This past year saw the culmination of two major projects that required a pipeline shutdown: the Gilbert Stream Realignment (moving the pipeline away from coastal erosion), and the Pariroa Buckle Repair (disconnecting the temporary bypass and implementing the permanent repair). I'm extremely proud of these highly challenging and technical projects that were critical for the continued, safe supply of gas to New Zealanders. Key to the project's success were Plant and Platform, Energyworks, Whitaker Civil Engineering and I&D George Contracting as well as many people from across the business who devoted an enormous amount of time and energy into planning and preparing for this work. Thanks also to our transmission customers who worked closely with us.

Firstgas set the objective that stakeholders and customers should be better off than they were before the project commenced. Through outstanding collaboration and innovation, we achieved this and more. In January 2022, during a planned, 55-hour gas outage, the new and existing pipelines were connected 25 hours earlier than expected, avoiding major interruption of the nation's gas supply. Health and safety performance targets were exceeded. Outstanding cultural engagement has enhanced the relationship between Firstgas and local Iwi, Ngāti Tama, a relationship that focuses on empowerment and open communication.

We have also completed over 40 projects that reinforce the reliability of our existing network including the business-as-usual Intelligent Pigging programme and heater refurbishments, and work fronts to combat identified obsolescence like battery chargers and fire detection. The roll out of our Maximo Asset Health Insights (MAHI) application this year has been successful and allows us to better link asset health to risks and improve our asset management planning process.

Looking ahead, we are focused on ensuring gas remains a competitive fuel choice for our customers while operating within the regulated price-quality framework set by the Commerce Commission. It is important for our business to remain proactive and ready to adapt to change. Our customers come first, and we work as one dedicated team to create an industry leading operation. Integrity and respect are integral to our business, and we empower our team to do their jobs safely.

I hope you find the 2022 AMP Update for our gas Transmission business both interesting and informative. We look forward to working with you in the coming year and welcome feedback on this year's AMP Update.

Ngā mihi nui

Paul Goodeve
Chief Executive

GLOSSARY

TERM	DEFINITION
AMP	Asset Management Plan
Asset Condition	At the start of planning period (% of units by grade) – the proportion of each asset class against the asset condition categories (Grade 1 to 4) reflecting the likelihood of short, medium or longer term intervention. GTB are able to apply their own criteria for intervention when populating the table
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
barg	The pressure, in units of bars, above or below atmospheric pressure
Capex	Capital expenditure - the expenditure used to create new or upgrade existing physical assets in the network, as well as non-network assets, e.g. IT or facilities
CCC	Climate Change Commission
CP	Cathodic protection
DP	Delivery Point
DPP	Default Price – Quality Path
ERP	Emissions Reduction Plan
FSA	Formal Safety Assessment risk management process in distribution networks
FY2022	Financial year ending 30 September 2022
GDB	Gas Distribution Business
GIC	Gas Industry Company – New Zealand's gas industry co-regulatory body
GIS	Geographical Information System
GM	General Manager
GPB	Gas Pipeline Business
GTB	Gas Transmission Business
GTP	Gas Transition Plan
HSEQ	Health, Safety, Environment and Quality

TERM	DEFINITION
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
LMS	Learning Management System
MAHI	Maximo Asset Health Insights
Major Incident	Means an uncontrolled event at a major hazard facility that— (a) involves, or potentially involves, specified hazardous substances; and (b) exposes multiple persons to a serious risk to their health or safety (including a risk of death) arising from an immediate or imminent exposure to— (i) 1 or more of those substances as a result of the event; or (ii) the direct or indirect effects of the event. (2) Without limiting subclause (1), an uncontrolled event includes any of the following: (a) escape, spillage, or leakage of a substance: (b) implosion, explosion, or fire.
MBIE	Ministry of Business, Innovation and Employment
MHF	Major Hazard Facilities – are facilities that store and process very large quantities of hazardous substances. These facilities have the potential to generate catastrophic events which could cause harm to people, the environment, and the wider economy
MLV	Main line valve
OATIS	Open Access Transmission Information System
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)

TERM	DEFINITION
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
Planning period	A projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed
Regulatory control period (RCP)	Means the regulatory period for default / customised price-quality regulation applicable to a GTB as specified in a determination made under a S52P of the *Commerce Act 1986*
Residual Risk	Risk remaining after risk treatment activities are implemented
SaaS	Software as a Service
SCADA	Supervisory control and data acquisition
SCE	Safety Critical Element

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EXECUTIVE SUMMARY

This is Firstgas Gas Transmission Asset Management Plan Update (AMP Update) for 2022.

Firstgas owns and operates New Zealand's gas transmission system. Our system transports large volumes of natural gas from production stations in the Taranaki region to distribution networks and large customers across the North Island. We also own and operate more than 4,900 kilometres of gas distribution pipelines, supplying consumers across Northland, Waikato, Central Plateau, Bay of Plenty, Gisborne and Kapiti Coast.

Firstgas is part of Firstgas Group. Headquartered in New Plymouth, Firstgas Group is an umbrella brand consisting of Rockgas, Firstgas, Flexgas and Gas Services NZ. Firstgas Limited and Rockgas Limited (Rockgas) deliver natural gas and supply LPG to over 500,000 customers through their network of high-pressure gas transmission pipelines and distribution pipelines in the North Island, as well as through LPG distribution pipelines in the South Island, 36 local LPG suppliers, and over 180 Refill & Save locations across New Zealand.

Flexgas operates the Ahuroa gas storage facility in Central Taranaki. Gas Services NZ provides operational and maintenance support to all gas infrastructure owners, including other parts of Firstgas Group.

Activities across the Firstgas Group are driven by our vision and mission:

Vision	Proudly leading the delivery of New Zealand's energy needs in a changing world.
Mission	Safely and reliably delivering energy that is affordable and acceptable to New Zealand's families and businesses.

Our gas transmission business is focused on transporting gas across the North Island to meet the diverse needs of our customers. This includes industrial use, power generation, commercial applications or residential use for space heating, water heating and cooking. We are focused on ensuring gas is a competitive fuel choice for our customers, while operating within the regulated price quality framework set by the Commerce Commission. We are starting to develop our network to service the future demand for renewable gases.

KEY DRIVERS FOR OUR TRANSMISSION BUSINESS

This AMP Update focuses on the material changes influencing our planned expenditure and the risk profile of our gas transmission business over the coming years. It focuses on how we intend to manage these assets over the next 10 years (the planning period), with a focus on:

- A commitment to safety for our staff, customers and the general public.
- Being accountable for the performance of our gas transmission system.
- Providing visibility of our investment in the network and upcoming physical works.
- Ensuring ongoing engagement with our stakeholders, staff and contractors.
- Complying with our regulatory obligations.
- Preparing our business for future challenges and opportunities. For a complete understanding of the basis for our asset management decisions over the planning period, read this AMP Update in conjunction with our **2020 AMP**.

Our approach to asset management is guided by an asset management framework that provides a clear "line of sight" from Firstgas Group's vision and mission, down to our company objectives and day to day activities. This framework guides the optimal combination of life cycle activities to be applied across our portfolio of transmission assets, based on their criticality, condition and performance.

There are several key drivers that influence our approach to asset management for our gas transmission business over the ten-year planning period. Firstgas is focused on:

- **Continued performance improvements:** We are focused on the efficiency of how we physically operate our transmission system, as well as the efficiency of our broader business activities. The progression of our updated compression strategy, focussing on network optimisation and accounting for the uncertainty in the future of gas, emission reductions and future fuels is a key activity this year. We will update and rationalise our compressor fleet addressing the increasing challenges of operating and maintaining ageing equipment. This will improve security of supply and operating efficiency.

  Our asset management improvement programme continues to evolve. We have undertaken an ISO55001 gap analysis during late FY2022 to ensure we continue on a recognised asset management path.
- **A strong culture around health and safety:** Safety is at the forefront of how we manage and operate our transmission assets. Maintaining product containment is the primary control that minimises risk to all those who live and work on and around the transmission system. Asset integrity and our asset management practices outlined in this AMP Update are crucial in maintaining safe outcomes.

  As part of Firstgas Group's commitment to reducing our carbon footprint, the Engineering Principles Strategy has been updated to further reduce overall methane emissions associated with operations, incidents and fugitive leaks, and ensure system designs do not limit the potential of renewable gas. We have developed specific strategies for our approach to monitoring, reporting of emissions and methods to reduce emissions over time.

  An emissions estimate model has been developed utilising a global standard model and been refined for Firstgas operating conditions in New Zealand.
- **Mitigating and managing risk:** Risk management plays a key role in our asset management decisions. It is integrated in everything we do, evolving over time to ensure that as a business, we deliver our strategic objectives. The potential impact of major incidents to personnel and public safety remains a key focus. We identify all equipment that can impact on the safety of the transmission pipeline network and take prioritised actions to reduce the likelihood and consequence of risks.
- **Preparing the business for future challenges and opportunities.** The future demand for gas is uncertain, however Firstgas is committed to ensuring that we can safely and reliably deliver energy that is affordable and acceptable to New Zealand families and businesses, both now and into the future while making economic investments aligned with the expected decline in natural gas.

We support the transition to a net zero-carbon future and in May 2022, welcomed the publication of the Government's first Emissions Reduction Plan (ERP). It is encouraging to see the ERP's focus on green hydrogen and biogas as enablers to reducing New Zealand's carbon emissions. Firstgas Group looks forward to engagement with the gas sector and Government on the development of both the Gas Transition Plan (GTP) and National Energy Strategy.

Firstgas Group is playing a leading role in both biogas and hydrogen development in NZ. We are supporting the development of New Zealand's first large-scale biogas facility which will see the injection of biomethane, produced from food waste, into the gas network. We have also undertaken significant work to establish how existing gas infrastructure can be used to transport green hydrogen, with the first blending trials currently being planned.

ACTIVITIES PLANNED FOR THE COMING YEAR

The focus for the coming year (FY2023) remains on providing our customers with a safe and resilient gas transmission system.

Our forecast expenditure (Capex and Opex) over the next ten years is set out in the blue bars in Figure 1 and Figure 2, with the forecasts from last year's AMP shown as the red line.

Capital expenditure forecast

The overall impact across the 10-year planning period is a small reduction in forecast Capex. We will continue to review expenditure to ensure our assets provide value and long-term service in a carbon zero environment supporting the Government's net zero by 2050 target.

The difference between this year's forecast and last year's AMP Update forecast arises from several key projects:

Changes within regulatory control period two (FY2017 – FY2022) relate to:

- Two customer driven connections were planned for FY2022, however, one has been delayed 12 months and the other has chosen an alternative fuel, no longer requiring this gas connection. The total combined project was $1.5 million.
- Expansion of the Warkworth Network has been delayed until at least 2028 and does not feature in the forecast due to its uncertainty. The project value was $4.0 million.
- We developed a Network Optimisation plan, in tandem with the compression strategy to ensure we can achieve the overall objective of modernising our compressor fleet. The compression strategy was underspent by $10.0 million in FY2022. As we move to upgrading and replacing equipment, the spend will increase across the coming regulatory period.

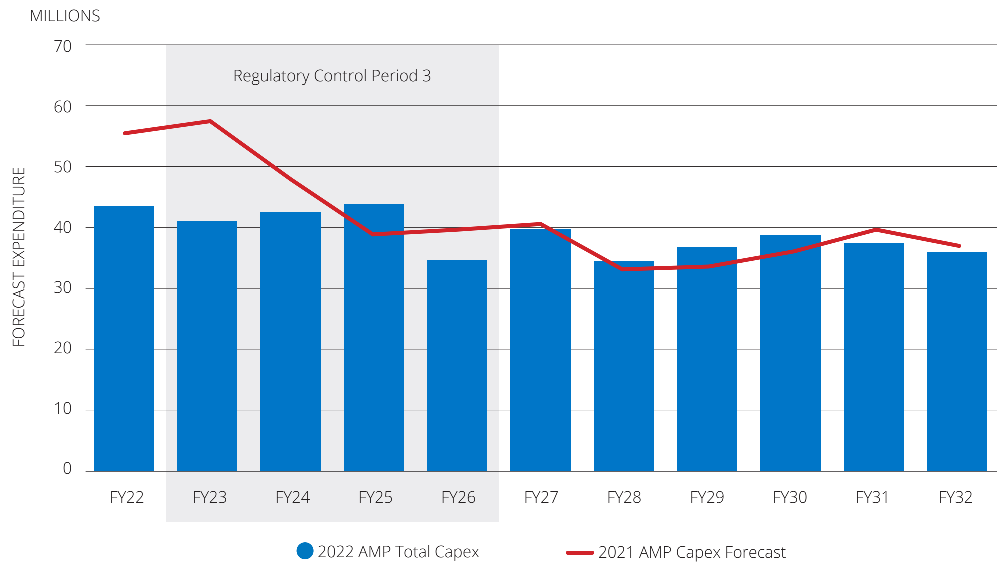
Changes within the regulatory period three (FY2023 – FY2026)[2]:

A review of growth opportunities and the Commerce Commission's final decision on the Default Price-Quality Path (DPP) for the FY2023 – FY2026 period (DPP3) has prompted us to refine our mid term planning forecasts.

Key changes compared to the 2021 AMP Update are:

- Consumer connections has reduced by further 50% or $3.2 million.
- System growth for FY2023 has been reduced by $2 million as the Bremner Road development in Auckland has been delayed, with no indication from the developers of when this might be required.
- Asset replacement and renewal has been contained within the DPP3 allowance and the new Water Bath Replacement Strategy has reduced expected Capex by $4.0 million across the next 10 years.
- Non-network Capex over the next regulatory control period has been reduced by $6.0 million due to Software as a Service (SaaS) recategorisation[3] to Opex.

Figure 1: Forecast total Capex (all figures in FY2022 prices[1])



1. FY2022 prices include the respective weighted average Opex and Capex inflation adjustment (Year ending June) on FY2021 prices as stated in the Commerce Commission Expenditure model V1 published 31 May 2022. https://comcom.govt.nz/__data/assets/excel_doc/0024/284532/Expenditure-model.xlsx
2. The $ figures quoted are in FY2021 values to align with the Commerce Commissions commentary in the Gas Pipeline Businesses Final Reasons Paper for the DPP3 reset. https://comcom.govt.nz/__data/assets/pdf_file/0025/284524/DPPs-for-gas-pipeline-businesses-from-1-October-2022-Final-Reasons-Paper-31-May-2022.pdf
3. SaaS recategorisation was due to a change in accounting rules

Operational expenditure forecast

Our forecast operational expenditure (Opex) over the planning period, compared to the Opex published in our 2021 AMP Update is set out in Figure 2.

Changes within regulatory control period two (FY2017 – FY2022) relate to:

- Actual spend of SaaS recategorised from Capex to Opex of $3 million in FY2022.
- Increased IT operational costs $1.1 million.

Changes within the regulatory period three (FY2023 – FY2026)[4]:

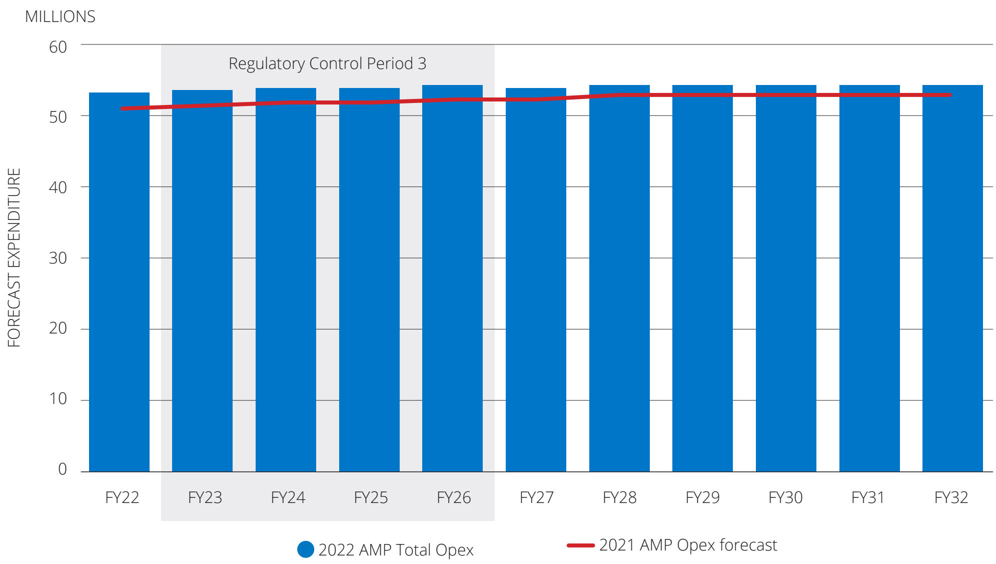
- Over the course of the planning period our base maintenance costs are anticipated to remain steady but will require further review as alternative fuels are introduced into the network.
- There is an allowance approved for regulatory control period three of $0.2 million per annum for our renewable gases trial programme. Firstgas anticipate significantly higher spend will be required. Only the regulatory allowance is included in our AMP forecast.
- Capex has been reduced as a result of the recategorisation of SaaS as Opex. There has been no uplift in business support Opex for regulatory control period three. The costs ($1.88 million per annum) for SaaS have been added to our AMP forecast.

Risk and Performance of the Transmission System

We will continue to develop and implement our asset strategies and explore the use of innovative tools and technology that will help drive our proactive approach to address and mitigate the risks, condition, and performance issues in our transmission network. Further development and integration of Maximo Asset Health Insights (MAHI), identification of safety critical equipment and other reliability initiatives into our asset lifecycle activities will improve our decision-making and ensure we continue to meet our quality standards.

To ensure that existing reliability, safety and supply quality levels will be maintained and improved across our transmission network, Firstgas has established a series of Key Performance Indicators (KPI) that we regularly monitor and annually report against. We are meeting the Commerce Commission's quality standards and will continue to investigate opportunities to improve our performance. All our performance measures are outlined in the year in review section 5.4.

Figure 2: Forecast total Opex (all figures in FY2022 prices[5])



4. The $ figures quoted are in FY2021 values to align with the Commerce Commissions commentary in the Gas Pipeline Businesses Final Reasons Paper for the DPP3 reset. https://comcom.govt.nz/__data/assets/pdf_file/0025/284524/DPPs-for-gas-pipeline-businesses-from-1-October-2022-Final-Reasons-Paper-31-May-2022.pdf
5. FY2022 prices include the respective weighted average Opex and Capex inflation adjustment (Year ending June) on FY2021 prices as stated in the Commerce Commission Expenditure model V1 published 31 May 2022. https://comcom.govt.nz/__data/assets/excel_doc/0024/284532/Expenditure-model.xlsx

1. INTRODUCTION

This is Firstgas Gas Transmission Asset Management Plan Update (AMP Update[6]) for 2022.

Firstgas owns and operates all 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 the operations of our business.

This section outlines the purpose, scope and structure of our 2022 AMP Update and provides an overview of the material changes from our AMP Update published in 2021. We also set out the key regulatory and environment changes that are influencing our gas transmission business.

6. Section 2.6.3 of the *Gas Transmission Information Disclosure determination 2012* provides guidance on when an AMP Update can be published.

1.1 PURPOSE OF THE AMP UPDATE

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

In addition, we are using this opportunity to update all our stakeholders on our progress against the 2021 AMP Update and to outline our key areas of focus for the year ahead. We see the release of this AMP Update as one part of our ongoing engagement with our stakeholders and customers, and it provides an important way in which our customers can evaluate the value being delivered by our capital programme.

1.2 ALIGNMENT WITH REGULATORY REQUIREMENTS

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

1. Relate to the gas transmission services supplied by the GTB.
2. Identify any material changes to the network development plans disclosed in the last AMP under clause 14 of Attachment A3 or in the last AMP update disclosed under this clause.
3. Identify any material changes to the lifecycle asset management (maintenance and renewal) plans disclosed in the last AMP pursuant to clause 15 of Attachment A or in the last AMP update disclosed under this clause.
4. Provide the reasons for any material changes to the previous disclosures in the Report on Forecast Capital Expenditure set out in Schedule 11a and Report on Forecast Operational Expenditure set out in Schedule 11b.
5. Provide an assessment of transmission capacity as set out in clause 8 of Attachment A.
6. Identify any material changes related to the legislative requirements as set out in clause 3.6 of Attachment A.
7. Identify any changes to the asset management practices of the GTB that would affect a Schedule 13 Report on Asset Management Maturity disclosure.
8. Contain the information set out in the schedules described in clause 2.6.6 [Schedules 11a, 11b, 12a and 12b].

For a complete understanding of the basis for our asset management decisions over the planning period, we recommend that this AMP Update be read in conjunction with our 2020 AMP summary document and appendices which are available on our website **here**.

1.3 PERIOD COVERED BY THE AMP

The AMP Update covers a ten-year forecast period from 1 October 2022 through to 30 September 2032 (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 2022 prices[7] (unless otherwise stated).

The 2022 Firstgas AMP Update was approved by our Board of Directors on 29 July 2022.

1.4 STRUCTURE OF THE AMP UPDATE

The AMP Update is a standalone document that provides an overview of the material changes from the AMP Update published in 2021. It describes what we have achieved over the past 12 months (FY2022), and the key activities for the coming year (FY2023). It also provides a summary of our forecast expenditure over the next 10 years. We have designed this document for those customers and stakeholders who want a concise overview of our asset management plans for the next 10 years.

Firstgas Group

Our broader business

Firstgas also owns and operates more than 4,900 kilometres of gas distribution pipelines. Our distribution network services approximately 66,000 consumers across Northland, Waikato, Central Plateau, Bay of Plenty, Gisborne and Kapiti Coast. Our gas distribution business is also regulated under Part 4 of the *Commerce Act 1986* and the 2022 AMP Update for our gas distribution business is available on our Firstgas website.[8]

Firstgas is part of the wider Firstgas Group. The Firstgas Group owns energy infrastructure assets across New Zealand through our affiliate Gas Services NZ Limited (GSNZ), a separate business with common shareholders that owns Rockgas[9] and the Ahuroa gas storage[10] facility. Rockgas Limited has over 80 years' experience and provides LPG to 500,000 customers throughout New Zealand. It is New Zealand's largest LPG retail business and supplies its customers with LPG from both domestic and imported sources. The Ahuroa gas storage facility (trading as Flexgas Limited) is New Zealand's only open access gas storage facility.

7. FY2022 prices include the respective weighted average Opex and Capex inflation adjustment (Year ending June) on FY2021 prices as stated in the Commerce Commission Expenditure model V1 published 31 May 2022 https://comcom.govt.nz/__data/assets/excel_doc/0024/284532/Expenditure-model.xlsx
8. More information on our gas distribution business is available here: https://firstgas.co.nz/about-us/regulatory/distribution/
9. More information on Rockgas: https://rockgas.co.nz
10. More information on Flexgas Limited: https://flexgas.co.nz/

For greater detail on the gas transmission business, we recommend that readers refer to the detailed appendices published with our 2020 AMP. The list of these appendices is set out in Table 1 below.

Table 1: Structure of our 2022 AMP Update and relevant 2020 AMP appendices

2022 AMP UPDATE	
A standalone document that provides an overview and summary of the activities we have undertaken over the past 12 months and includes any material changes to the 2021 AMP Update. The AMP Update incorporates – **Appendix A:** Summary of material changes and compliance – **Appendix B:** Information disclosure schedules – **Appendix C:** Pipeline capacity – **Appendix D:** Pipeline Capacity Determination – **Appendix E:** Director certificate	
RELEVANT 2020 AMP APPENDICES	
Standalone appendices in one consolidated document	
Appendix A	Glossary
Appendix C	Network overview
Appendix D	Asset details
Appendix E	System schematics
Appendix F	System development
Appendix G	Security of supply
Appendix H	Asset management approach
Appendix J	Expenditure overview
Appendix K	Maintenance schedules
Appendix L	Significant projects

2. OVERVIEW OF FIRSTGAS

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

2.1 CORPORATE STRUCTURE OF FIRSTGAS

Firstgas is owned by funds associated with Igneo Infrastructure Partners, which is part of the First Sentier Investors group, who in turn is part of the Mitsubishi UFJ Financial Group (MUFG). First Sentier Investors is a long-term infrastructure investor with experience in the regulated utility sector with assets across Europe, the United Kingdom, Asia, and New Zealand.[11]

The creation of Firstgas in 2016 is the first time that gas transmission assets in New Zealand have had a common owner, alongside an extensive distribution network. We believe that common ownership is delivering three distinct advantages for gas industry participants and consumers:

- A strong commercial interest in maximising the competitiveness of gas.
- To bring new capabilities to our team to capitalise on opportunities in the use of the gas transmission system and gas distribution network.
- An ability to operate the gas transmission system and the gas distribution network and manage our assets in ways that better serve the interests of our customers.

We remain focused on actively promoting the use of gas and ensuring work signalled in our AMP Update maximises the value obtained from our gas transmission system.

Firstgas Board

Firstgas is governed by a Board of Directors, chaired by Mark Ratcliffe. 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

Firstgas has approximately 282 staff (excludes Rockgas staff), with most staff based in our corporate headquarters in Bell Block, New Plymouth, with small teams located in Wellington, Auckland, Palmerston North and Hamilton.

Our Executive team is headed by our Chief Executive Paul Goodeve, with seven direct reports.[12] Our organisational structure is illustrated in Figure 3 below.

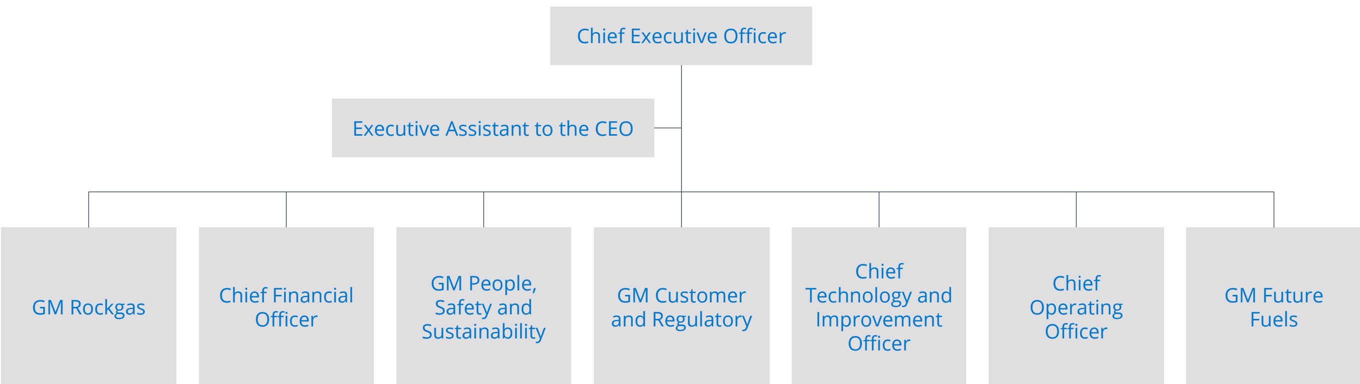
2.3 FIRSTGAS TRANSMISSION SYSTEM

Firstgas 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[13] (ex-Vector) transmission pipelines, as set out in Figure 4 below.

The transmission system is 2,516 kilometres in length, with approximately 137 kilometres installed in urban areas and the remainder in rural areas. The nominal internal diameter of the pipelines ranges from 50mm to 850mm, with the majority installed below ground. The pipelines connect 252 stations that contain a range of equipment designed to receive, transmit and deliver gas safely and efficiently to customers.

The assets were constructed and commissioned in accordance with the appropriate standards applicable at the time. From the mid-1960s to the mid-1980s, assets were constructed to codes and standards under United States Minimum Federal Safety Standards for Gas Lines – Part 192, United States Department of Transport and United Kingdom Institute of Petroleum. From the

Figure 3: Organisation chart



11. More information on First Sentier Investors is available on their website: https://www.firstsentierinvestors.com.au/au/en/institutional/about-us/corporate-profile.html
12. Firstgas reviewed its organisational structure July 21
13. The gas transmission system purchased off Vector Limited in April 2016.

mid-1980s and into the 1990s, assets were constructed to the New Zealand gas pipeline code, NZS 5223 - Code of Practice for High Pressure Gas and Petroleum Liquids pipelines. In the late 1990s, the AS 2885 Pipelines – Gas and Liquid Petroleum suite of standards was adopted.

The key statistics for the gas transmission system as of 30 June 2022, are set out in Table 2.

For a full overview of the gas transmission system, please refer to the 2020 AMP **Appendix C – Network overview**.

Figure 4: High pressure gas transmission pipelines

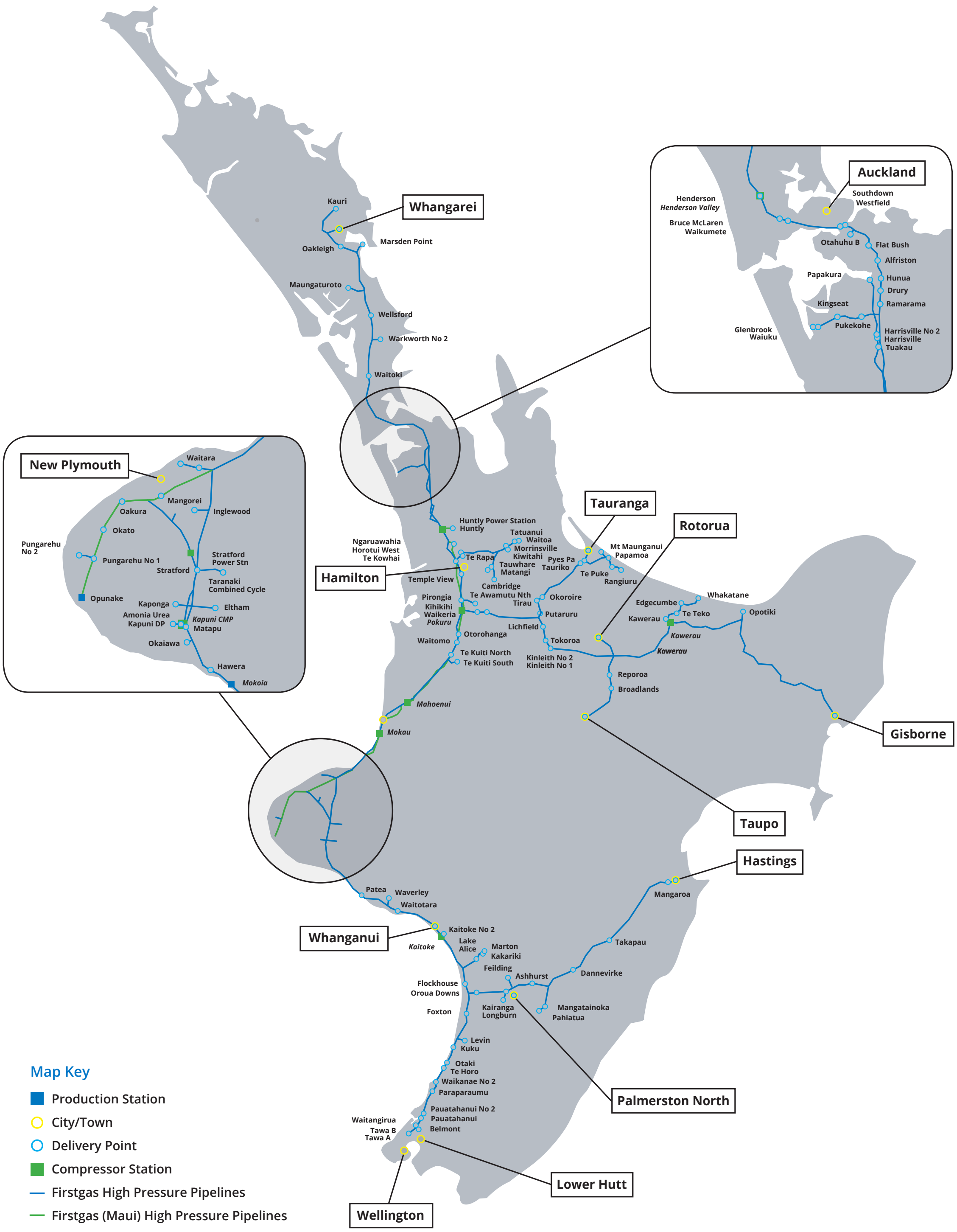


Table 2: Key gas transmission statistics as at 1 June 2022

STATISTIC	VALUE	CHANGE FROM 2021
System length (kilometres)	2,516	-1
Compressor stations	9	0
Compressor units	20	0
Delivery points	131	0

The reduction of 1 kilometre of the pipeline relates to the bypass pipeline installed for the Pariroa Defect that was removed during the January 2022 remedial work.

Asset categories

The Gas transmission system is made up of several distinct asset types. We use several categories to organise our asset base.

Table 3: Asset categories for gas transmission

ASSET CATEGORY	DESCRIPTION
Pipelines	Our high-pressure pipelines are constructed from steel with wall thickness and material grades specified by appropriate design codes.
Special crossings	Special crossings encompass a variety of crossings installed during pipeline construction. The designs include: – Aerial self-supporting pipelines – Pipelines supported by aerial trussed structures – Buried cased crossings where the pipeline is contained in a concentric steel sleeve – Pipelines supported on flexible bearings.
Cathodic protection (CP) system	In addition to their external coating, pipelines are connected to an impressed current CP system. This provides secondary protection against corrosion at coating breaches by holding the pipeline at a negative voltage relative to the ground.
Off-pipeline assets (on and off easement)	Transmission pipelines are managed through easements. However, in some areas there may be additional assets that are not located within the easement. These are referred to as off-pipeline assets and are predominantly civil construction type assets. These assets may include the following: retired land blocks, access tracks and culverts, crib or retaining walls, fencing and drainage, ground water monitoring equipment and land movement monitoring equipment.
Main line valves	Main line valves (MLVs) are designed to automatically isolate pipeline sections when pipeline failure occurs. MLVs are positioned at maximum intervals of 32 kilometres throughout the length of the gas transmission system except in the Auckland metropolitan area. In Auckland, MLVs are nominally spaced at 13-kilometre intervals due to the higher consequence of pipeline failures.
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 strategic locations on the transmission system
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.

ASSET CATEGORY	DESCRIPTION
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.
Pipeline Inspection Gauges (PIG) launchers and receivers	Pipeline Inspection Gauges (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.
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.

Further information on asset categories is set out in the **2020 AMP Appendix C – Network Overview**.

2.4 OUR ASSET MANAGEMENT APPROACH

Firstgas' 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 KPIs that Firstgas 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 AMP Update captures 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 **2020 AMP Appendix H – Asset Management Approach**.

Addressing risks on our Transmissions 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 network 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 Firstgas 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 planning ensures that 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 Firstgas to ensure a consistent approach in recognising and reporting events.

Given the potentially severe nature of failures on the gas transmission system (particularly loss of containment), appropriate and effective risk management is integral to our day-to-day operations. 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 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 risks 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.

Addressing geohazards on our network

The impact of geo-hazards on our transmission network and how this translates to pipeline integrity risk remains a key focus for Firstgas. Geo-hazard is the term we use for land instability events, such as landslides, erosion or movement of rocks or debris, that have the potential to affect the integrity of transmission pipelines.

Due to advances in technology, software and data management tools we have improved our current approach in the following ways in order to capture all potential geohazards, assess the risk to the transmission pipeline and define mitigation measures to prevent failure:

- Light Detection and Ranging (LiDAR) surveys will be used across all pipeline easements to firstly baseline the ground level and then detect very small ground level changes, which may be related to geohazards or other third-party interference. LiDAR survey information will be able to be loaded into Geographic Information System (GIS).
- We will identify geohazard features which are impacting the gas pipeline using strain monitoring information, obtained during regular intelligent inline inspection (ILI) surveys. These surveys will utilise an inertial mapping unit to identify regions of high bending strain on the pipeline.
- Line walking surveys will be undertaken on all pipelines where ILI with bending strain analysis is not possible.

Pipeline risks will be evaluated in the asset risk system and actions to mitigate the risk will be identified. Where a pipeline risk is sufficiently high and the mitigation solution will take a number of months or years to complete and interim mitigation measures will not reduce the risk to an acceptable level, then an "Emergency Response Plan" will be developed, to be able to respond immediately if the risk escalates. The action to develop an Emergency Response Plan will be recorded against the risk, with an agreed timeframe to complete.

Utilising Strategic data analysis

The ability to overlay outcomes from our Safety Management Studies, the impact of land use changes and identification of geohazards in a layered approach has resulted in the pipeline piggability upgrade work that has been previously signalled in prior AMPs. The physical works are planned for completion from late FY2022 into early FY2023 enabling the first of the newly piggable sections to be run mid FY2023. This will increase the ILI coverage from 71% to 86% of the transmission system, with a target of 90% by FY2025 with further engineering work and inspection.

Identification of Safety Critical Equipment

Safety is top of mind in everything we do and is critical to the ongoing sustainable operation of our business. Avoiding and reducing the impact of major incident on personnel safety remains a key focus for Firstgas.

Firstgas are developing the identification and management requirements of safety critical elements (SCEs) using Formal Safety Assessment (FSA), Major Hazard Facilities regulations (MHF regulations) and Good Practice Guidelines as a basis and guidance. This will enable us to identify and apply the appropriate controls and mitigation barriers, and have governance process in place to help reduce the risk of major incident and its consequences.

The safety critical element development is underway, and we anticipate its completion by the end of the calendar year.

2.5 OUR APPROACH TO HEALTH, SAFETY AND ENVIRONMENT

Safety is at the forefront of how we approach managing and operating our assets. There are hazards involved in the transmission and distribution of a flammable product such as natural gas. We take a systematic approach to ensure that the hazards and risk can be controlled and mitigated to an appropriate level. The asset integrity and our asset management practices outlined in this AMP Update illustrate how we mitigate risks and maintain safe outcomes. From maintaining containment of our product through to the Health and Safety leadership and accountability that underpins our culture.

Firstgas has a strong culture for ensuring safety. It is at the core of everything we do and extends beyond ensuring our people are safe in the field. Consideration of safety is at the forefront whether we are designing new assets, developing maintenance plans, executing work in the field, operating the network, or having the appropriate emergency response plans.

Maintaining product containment is one of the primary controls that minimises risk to both workers and the public. Asset integrity and our asset management practices outlined in this AMP Update are, therefore, crucial in maintaining safe outcomes.

Leadership

Firstgas understands that one of the key factors in Health, Safety and Environment excellence is leadership and accountability. Leadership is required from all layers across the organisation,

Figure 5: Firstgas First Principles

First Principles

RESPECT THE RISK

We respect the risks of the work we do and commit to managing high risks with care and thoroughness. We keep the risk discussion alive – always vigilant.

We stop if we're not sure.

UNDERSTAND THE WORK

We take time to understand the reality of how work is done.

We understand that people are not perfect – we take ownership of our work and our mistakes and respond fairly to others'.

HARNESS KNOWLEDGE

We trust in the expertise of our team to deliver successful work.

We move decisions to where the expertise lies.

LISTEN, LEARN, IMPROVE

We look for improvement opportunities and take ownership to make them happen.

We are comfortable speaking up and do not judge issues raised by others.

WORK TOGETHER

We value the skills and experiences of different teams and work together to embed HSEQ into successful work.

but the expectation and drive around leadership starts at the top. We have developed a set of First Principles that outline our approach to achieving healthy and safe work within Firstgas. The First Principles provide guidance on how we work rather than provide a prescriptive set of rules. Our First Principles are used as a basis for discussion when making decision about our work and ensuring that expectations are met.

Methane Emission Reduction Plan

In October 2021, the New Zealand government announced that New Zealand would significantly increase its contribution to the global effort to tackle climate change by reducing net greenhouse emissions by 50 percent (below gross 2005 levels) by 2030.

In November 2021, the New Zealand Government attended the United Nations Climate Change Conference (COP26) in Glasgow UK, where they agreed to sign on to the "Global Methane Pledge". Participants joining the Pledge agree to take voluntary actions to contribute to a collective effort to reduce global methane emissions by at least 30 percent from 2020 levels by 2030, which could eliminate over 0.2 degrees C warming by 2050.

Methane is a powerful but short-lived climate pollutant that accounts for about half of the net rise in global average temperature since the pre-industrial era. Rapidly reducing methane emissions from energy, agriculture and waste can achieve near term gains in our efforts in this decade. It is regarded as the single most effective strategy to keep the goal of limiting global warming to 1.5 degrees C within reach, while yielding co-benefits including improving public health and agricultural productivity.

We have developed an approach to estimate more accurately the sources of methane emissions from all our assets with a view to identifying the major contributors and developing solutions to these issues. These solutions are currently being planned for delivery over the coming years and the impact of these improvements demonstrates that a 30% reduction target is achievable.

2.6 CHANGES IN THE REGULATORY AND POLICY ENVIRONMENT

This year, the Government released New Zealand's first Emissions Reduction Plan (ERP) and the first three supporting emissions budgets out to 2035. This plan is the culmination of the extensive work undertaken by the Climate Change Commission and numerous government departments, with input from businesses such as ourselves, stakeholders and the public. We support the direction signalled in the ERP, with the development of a specific Gas Transition Plan, and a broader National Energy Strategy. This approach will ensure that there is a considered transitional pathway for the natural gas industry, while supporting the development of alternative renewable gas such as green hydrogen and biogas. We look forward to continued engagement with Government officials and the energy sector, as we progress the first ERP and the supporting policies for the energy sector.

Alongside a rapidly changing policy environment, the Commerce Commission has completed its DPP reset for all gas pipeline businesses. To deal with the uncertainty, the Commission has set a four-year regulatory control period. It has also introduced an accelerated depreciation mechanism, to better reflect the expected remaining economic lives of the networks. The outcome of this DPP reset has been factored into the forecast expenditure that we have set out in this AMP Update.

The Commission is now commencing a review of the underlying Input Methodologies (IMs) for regulated energy businesses. This review is expected to canvass a wide range of issues, as the regulated energy sector deals with the uncertainty it faces through the energy transition. This review must be completed by December 2023 and will impact on future AMPs as we transition our business.

Release of first Emissions Reduction Plan (ERP)

In May 2022, the Government released its first Emissions Reduction Plan (ERP) and the first three carbon budgets (2022 – 2025, 2026 – 2030, 2031 – 2035). The plan sets out the policies and investments proposed to reduce emissions to align with the budgets– which call for a 10% reduction in emissions by 2025, a 25% reduction by 2030, and a 40% reduction by 2035. This plan is the Government's response to the Climate Change Commission's final report released in June 2021 and incorporates the extensive feedback that the Government received on its draft ERP consultation paper.

Firstgas supports the release of the ERP. Of particular interest to our business is the development of gas transition plan by the end of 2023. This will set out a transition pathway for the gas industry, explore opportunities for renewable gases, and ensure an equitable transition. This work is being led by the Gas Industry Company (GIC) and the Ministry of Business, Innovation and Employment (MBIE), with a terms of reference publicly released. This transition plan is intended to feed into the broader National Energy Strategy, which will address the strategic challenges in the energy sector.

The ERP also outlines actions to support the development of low-emissions fuels. We support the development of a hydrogen roadmap by 2023, investigations into bioenergy supply options, and the review of hydrogen regulatory settings to ensure they are fit for purpose. The ERP importantly does not contain a ban on new gas or LPG connections. The Minister of Energy and Energy Resources is quoted as saying "the preference now is to repurpose gas infrastructure for low-carbon gases rather than banning new connections". We welcome this statement and look forward to engaging with government, stakeholders and the public on how we can plan for a smooth transition away from natural gas, while still providing a secure and safe service and exploring the opportunities for renewable gases.

Firstgas has continued to engage on a broad range of Government consultation documents that directly impact on our businesses and the likely future demand for natural gas. For example:

- The GIC has continued its work on improving information disclosure within the gas sector, with a proposal to introduce new gas governance rules for the disclosure of gas production and gas storage facility outage information.
- The GIC has also published its final report on the Gas Market Settings Investigation, as requested by the Ministry of Energy & Resources. This report outlines two key actions areas, and several supporting workstreams, to ensure that the gas industry arrangements remain fit for purpose through the transition.
- Firstgas provided input into the Infrastructure Commission's Infrastructure Strategy, Rautaki Hanganaga o Aotearoa. We encourage the Commission to encourage the circular economy, including the option for biogas production from waste.
- MBIE has consulted on the definition of Energy Hardship, with Firstgas providing input on how this definition can best consider gas consumers.
- The Ministry for the Environment has consulted on numerous aspects of the Emissions Trading Scheme, as it refines the operation of the ETS to better support the transition to net zero.

Firstgas will continue to engage with government officials on these work streams to ensure that the role and benefits of natural gas in New Zealand's energy mix is reflected in the government's policies, as well as advocating for policy settings to support the opportunities for renewable gases.

DPP reset for 2022 – 2026

At the end of May 2022, the Commerce Commission announced its decisions for the DPP reset for gas pipeline businesses for the next regulatory control period (2022 – 2026). The DPP decision was informed by a series of consultations with the sector, where all parties could discuss the issues, and increasing uncertainty facing the gas sector. The key decisions made as part of DPP3[14] included:

- Setting the length of the regulatory period at four years to enable the Commission to review price-quality settings at the earliest opportunity after further government energy policy initiatives are scheduled to be announced.
- Shortening asset lives to better reflect the expected remaining economic lives of the networks.
- Smoothing price increases over the regulatory period to minimise the impact of price rises on consumers of gas pipeline services.
- Allowing some Opex for the investigation of blended gases in networks, recognising that this could benefit consumers of gas pipeline services.
- Providing expenditure reopeners for GPBs to seek additional funding for unforeseen growth or risks that affect safe and reliable gas supply.

We are aware of the potential impact of this decision on consumer gas prices and will be carefully considering how we balance the Commission's decision and the challenges being faced by New Zealanders. We are confident that gas is still a cost-effective option for New Zealanders.

Upcoming IMs review

The Commerce Commission has commenced its review of the Input Methodologies for GPBs, electricity distribution businesses and airports. The IMs must be reviewed every seven years, with this review due to be completed by December 2023. All sectors are facing uncertainty and different challenges and opportunities, that will influence the matters that should be considered through this review.

To start the process, the Commission has released its first two consultation papers on the IMs review:

- Process and issues paper that sets out key topics for the IMs review, the issues the Commission have identified to date relating to those topics, and the details of the process by which it intends to complete the review.
- Draft framework paper that describes the framework the Commission intend to apply in reaching its decisions on the IMs review.

14. Commerce Commission final decision paper is available on their website: https://comcom.govt.nz/__data/assets/pdf_file/0025/284524/DPPs-for-gas-pipeline-businesses-from-1-October-2022-Final-Reasons-Paper-31-May-2022.pdf

We believe it is key for the Commission and the regulated sectors to properly canvass the issues it is facing, before considering what IMs amendments are required. We also believe that it will be important for the Commerce Commission to liaise closely with the Ministry of Business, Innovation and Employment (MBIE) and the Gas Industry Company (GIC) so that we develop a common understanding of the impact of the GTP and the Energy Strategy. As with the DPP reset, Firstgas remains focused on advocating for IMs settings that:

1. Reduce the risk of future price escalation and economic asset stranding.
2. Continue to provide sufficient incentives to invest to maintain reliable gas infrastructure.
3. Preserve the option of using current gas infrastructure for renewable gases in the future.

We look forward to engagement with the Commission and stakeholders throughout the IMs process, as we discuss how we can ensure a regulatory framework that supports New Zealand's transition to net zero emissions.

3. PREPARING THE BUSINESS FOR THE FUTURE

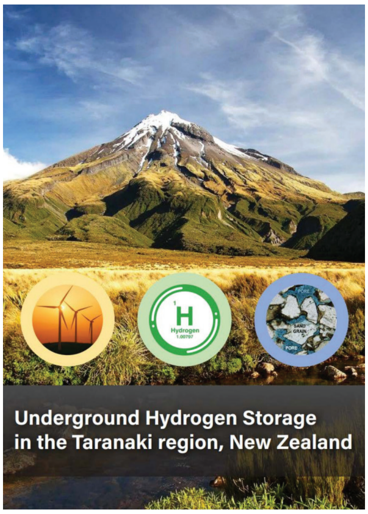
Firstgas is committed to ensuring that we can safely and reliably deliver energy that is affordable and acceptable to New Zealand's families and businesses, both now and into the future.

3.1 WORK PROGRAMME ESTABLISHED ON RENEWABLE GASES

Firstgas Group is playing a leading role in investigating and trialling hydrogen, biogas and other new fuels which are a necessary partner to the electricity grid in decarbonising New Zealand's energy supply. We are supporting the development of New Zealand's first large-scale biogas facility which will see the injection of biogas, produced from food waste, into the gas network. We have also undertaken significant work to establish how existing gas infrastructure can be used to transport green hydrogen, with the first blending trials being planned and includes identification of the network location, work with appliance suppliers, retailers and installed appliances at premises.

We also appointed our Future Fuels General Manager in April 2022 to lead the Company's new Future Fuels team, as part of our commitment to the further development and delivery of our Renewable Fuels strategy. With this team in place, Firstgas Group will work with the sector and Government on the Gas Transition Plan and National Energy Strategy.

3.2 HYDROGEN



Green Hydrogen storage in Taranaki[15]

Following the release of our hydrogen pipeline study in March last year, we are in the planning stages of our first hydrogen pipeline trial. Our plan is to decarbonise the gas pipeline network by blending up to 20% hydrogen into the natural gas network from 2030, with conversion to 100% hydrogen by 2050. This would provide emissions reductions for all gas users while continuing to use existing pipeline and gas infrastructure.

In early 2022, we commissioned research by the University of Canterbury, to investigate the potential of existing underground gas storage to store green hydrogen. This research has identified seven depleted oil and gas reservoirs in Taranaki that are potential candidates to store large volumes of clean energy underground in the form of green hydrogen.

Fortescue Future Industries and Firstgas to investigate[16]

FORTESCUE FUTURE INDUSTRIES | Firstgas Group

It means that hydrogen would not only be delivered to New Zealand users, but done so through existing infrastructure, making it an efficient way for New Zealand to achieve its wider zero emissions targets. We are considering the further testing and programmes of work recommended by this report to progress large-scale hydrogen storage in New Zealand. This will be a key enabler to unlock the full potential benefits that green hydrogen can offer.

This year, Firstgas Group signed a non-binding Memorandum of Understanding with Fortescue Future Industries to identify opportunities to produce and distribute green hydrogen to tens of thousands of homes and businesses in New Zealand. Working with Fortescue marks an important step in Firstgas' development and scale-up of renewable fuels and we are excited about the opportunities this presents.

3.3 BIOMETHANE

In addition to hydrogen, we believe that biomethane will also form part of the transition to renewable gases. Production and utilisation of biomethane via digestion of organic wastes and processing the raw biogas creates benefits for gas users, waste generators, asset owners, their communities and the environment.

Turning kerbside waste into renewable gas[17]

The technology for biomethane production is mature and with treatment, biomethane can be used as a direct replacement for methane in our gas pipeline. Collaboration is the key to successful uptake of biomethane. It will require cooperation across industries, communities and both the private and public sector to reach its full potential.

Last year we announced our plans to upgrade and inject the biogas produced at Ecogas' first large scale anaerobic digestion facility in Reporoa. A first for New Zealand, this plant will transform Auckland's kerbside food waste into a valuable source of renewable gas for homes and businesses, allowing gas users to enjoy the benefits of this renewable gas in their existing appliances while reducing emissions.

15. Research reveals hydrogen storage potential in Taranaki to support growth in renewable electricity | Gas is changing
16. Fortescue Future Industries and Firstgas to investigate green hydrogen | Gas is changing
17. Firstgas and Ecogas to turn kerbside waste into renewable gas for use in homes and businesses | Gas is changing

4. STAKEHOLDER ENGAGEMENT

Firstgas recognises the importance of regular engagement with our major gas users, shippers and other parties who rely on the consistent and safe delivery of gas to maintain their productivity and business. Our primary focus is to inform and consult with our customer, with four underlying objectives for this engagement:

- Understanding our customers' views and preferences for investment and asset maintenance strategies, services, and pricing decisions.
- Informing and consulting customers on the development of our 2022 AMP Update and on relevant aspects of the DPP3 reset decision so that our plans and decisions are informed by our customers' views.
- Laying the foundation for future engagement with customers on issues for the 2023 Input Methodologies (IMs) review, future regulatory and government policy processes, and key operational decisions.
- Taking tangible steps on a longer-term journey of making our business more customer centric and focusing on the issues that matter to customers, with customer engagement ultimately becoming part of our business-as-usual process.

4.1 ENGAGEMENT ACTIVITIES WITH TRANSMISSION STAKEHOLDERS

During the last year, we have undertaken the following activities with our stakeholders and customers:

- Held bilateral meetings with individual shippers to get a more thorough understanding of their views and priorities.
- Circulated periodic stakeholder updates which are described as an occasional series of dispatches on noteworthy transmission topics. One of the most recent editions provided an update on work recently completed on the IT systems that we use to support the commercial operation of the gas transmission system (e.g., metering validation, OATIS etc.).
- Continued to attend quarterly meetings of the Major Gas Users Group (MGUG) to share our detailed operational plans and to gain their feedback on these plans. We also used these opportunities to discuss our common areas of interest on the issues facing the gas sector, such as the ERP and the work towards a Gas Transition Plan.
- Firstgas, alongside Vector and Powerco, is a member of the Gas Infrastructure Futures Working Group. This group was set up to enable a collaborative approach to the challenges of the energy transition and has produced in depth analysis for the gas infrastructure sector, which will help inform the government's response to climate change. Government officials and MGUG are both observers on this group and have helped to test the group's thinking. The report is available via this **link**.
- Continued periodic meetings with gas producers to discuss relevant issues and opportunities for improvement around gas quality and compliance with the gas specification.
- Continued our engagement with EmsTradepoint, the wholesale gas market operator. We regularly contribute to their operations working group, which helps us understand how gas trading affects the competitiveness of the New Zealand gas market.
- We sought feedback from Shippers on our provisional prices for FY2023. Shippers and gas users had previously indicated a preference for more variable prices, so we included a set of Alternative Prices with an increased variable component for comment.
- Participated in monthly meetings with the newly appointed Critical Contingency Operator (CCO) to discuss relevant issues and ensure readiness for responding to any potential critical contingency events.
- Provided Transmission System Owner (TSO) input into the CCO's annual training sessions, which were attended by Shippers, Large Consumers, Retailers, Producers and gas distributions companies.
- Firstgas teamed up with Australia's Future Fuels Cooperative Research Centre (FFCRC) to present a technically focused webinar to stakeholders wanting to gain insight into FFCRC's research on Hydrogen use and what this means for commercial and industrial appliances.

4.2 LAND AND PLANNING STAKEHOLDER MANAGEMENT

Firstgas' Land and Planning team focuses on building and sustaining stakeholder relationships, and where appropriate, partnerships with landowners, iwi, councils, developers, contractors, and other interested parties for the protection of people and the transmission pipeline networks.

To manage this, our stakeholder management and engagement strategy guides the framework for successful and sustainable stakeholder relations. Firstgas approaches every engagement with a stakeholder as an opportunity to improve relationships with them and this is a process that needs to be well managed. Firstgas has a stakeholder liaison programme that educates and supports the safe living, operating and work practices around our pipelines.

Key areas of focus are new ways to maintain and improve relationships with our stakeholder using technology and more interactive communications.

Enabling and protecting our ability to operate and maintain the pipeline network is also a focus. Much effort is being placed in the review and submission process for Council Plans to ensure our ongoing ability to operate and adapt the network. This is supported by the work to protect our pipeline easement rights through establishment and negotiation of additional rights.

4.3 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.

From our perspective, situations of conflicting interests are best managed by:

- Clearly identifying and analysing stakeholder conflicts (existing or potential).
- 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 transmission 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.

Iwi and community key to successful pipeline project

Firstgas, in collaboration with specialised contractors, local Iwi Ngati Tama and local community achieved the first-ever replacement of a section of the Māui gas pipeline in January 2022. The successful completion of this significant piece of work, ensured the continued security of the natural gas supply to over a million Kiwis across the North Island.

Firstgas worked closely with Ngāti Tama and with the local community who were affected by the project. Firstgas worked hard to minimise the disruption to the residents and landowners living nearby the locations, holding community meetings and providing information about what to expect during the weekend, along with support over the weekend of the project.

Firstgas aimed to establish a more harmonious relationship with Ngāti Tama that would endure well beyond the scope of this project and achieved that and more. The people working for Firstgas gained knowledge that enables them to respond appropriately to Ngāti Tama (and indeed any iwi) from a cultural perspective.

Firstgas works in partnership with Ngati Tama to enable the Iwi to reconnect to their whenua (land).

From right to left: Toka Walden, Rae Hinerau Wetere, Nigel Maxwell (Firstgas) and Ivan Bruce Archaeologist in front of a kumera pit uncovered during excavation.

"The way we handle community relations has fundamentally changed. We're proactively rather than passively engaging with the community…", said Kevin Stretton, Engineering and Projects Manager for Firstgas.

"Some amazing things have developed from working with Firstgas," Rae-Hinerau Wetere, Cultural Monitor (Kaitiaki) on the realignment project for Ngāti Tama

5. YEAR IN REVIEW

This section provides an overview of Firstgas' major projects and initiatives over the past year ending 30 September 2022 (FY2022). We review our forecast expenditure against the plans stated in our 2021 AMP Update and discuss the variances in activities undertaken.

5.1 EXPENDITURE SUMMARY

Firstgas is committed to maintaining a safe and resilient network, and the activities we have undertaken over the last year reflect that commitment.

The major variances in FY2022 Capex relate to not proceeding with two customer connections, delayed expansion of the Warkworth network beyond 2028 and an underspend against the Compressor Strategy due to undertaking a further review, considering network optimisation and emissions reduction. Opex was affected by re-categorisation of SaaS and an increase in IT licencing costs and overheads.

Figure 6: Total Capex in FY2022 versus forecast expenditure in 2021 AMP

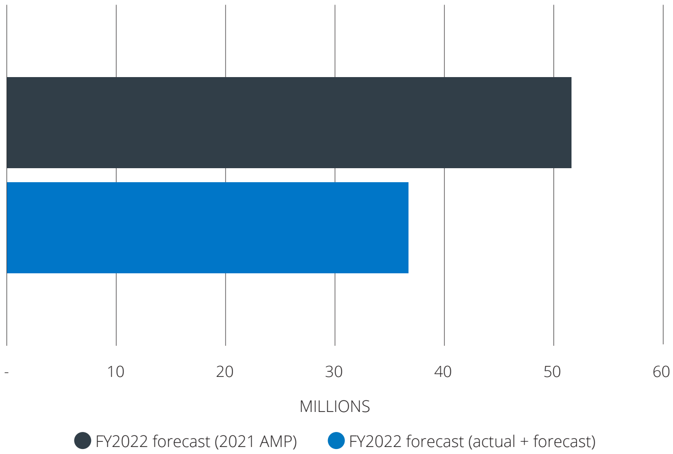
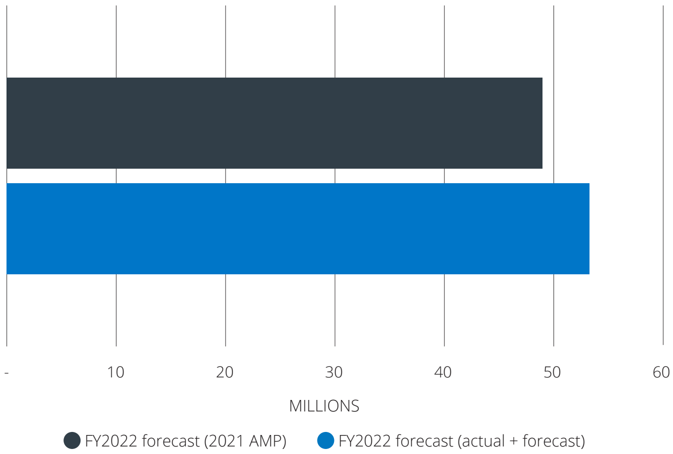


Figure 7: Total Opex in FY2022 versus forecast expenditure in 2021 AMP



5.2 SIGNIFICANT ACTIVITIES UNDERTAKEN IN FY2022

Firstgas has continued to deliver the significant capital works programme set out for this regulatory control period (1 October 2017 – 30 September 2022). Figure 8 outlines the most significant project spend that was delivered during the last 12 months. These projects were outlined in the 2021 AMP Update.

Figure 8: Significant projects undertaken in FY2022

SIGNIFICANT PROJECTS

INCREASING RESILIENCE OF THE NETWORK

$1.8 million
REALIGNMENT
Gilbert Stream realignment project

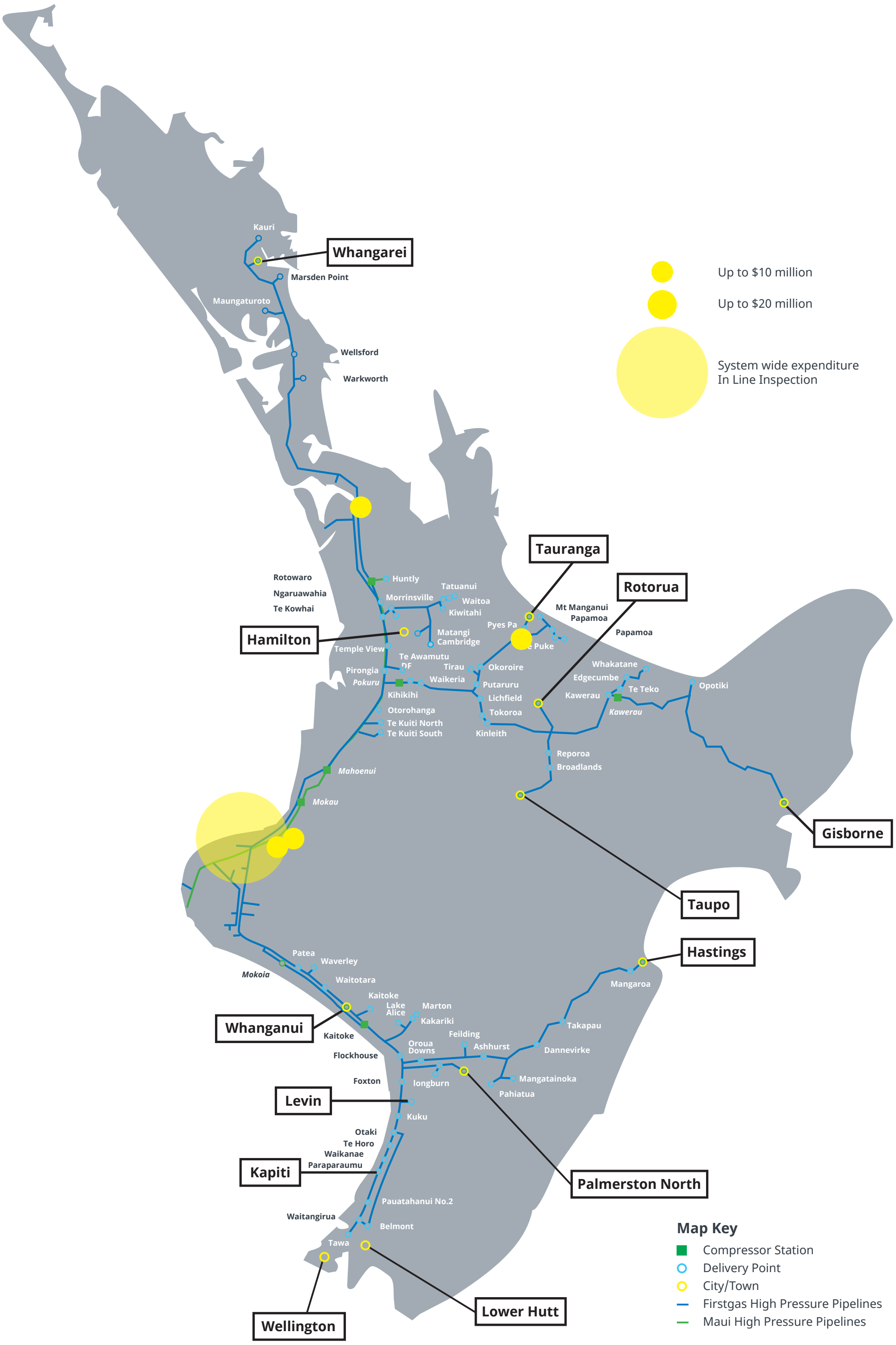
$2.7 million
INSPECTION
In Line Inspection (ILI)

$0.8 million
GROWTH
Tauriko growth

$2.5 million
MODIFICATIONS
Pig trap and Piggability modifications

$1.6 million
REMEDIATION
Pariroa feature defect repair

Figure 9: Locations of significant projects undertaken in FY2022



Gilbert Stream Realignment Project

The Gilbert Stream realignment project replaced an 80-metre section of the 400 pipeline at Pukearuhe, North Taranaki that addressed a threat from marine erosion, and ultimately a risk to the continuity of supply. Firstgas successfully connected the new section of pipeline (customer critical) on the weekend of 28 – 30 January 2022, as planned and a day ahead of schedule.

Firstgas commenced planning of this project in 2017. The realignment connection works were carried out simultaneously with the works at the Pariroa defect repair location so that only one pipeline outage was required.

Firstgas were involved in significant planning and stakeholder engagement as this project was reducing gas supply over the outage period.

Critical field work has concluded however, the project completion activities are still in progress and will continue into FY2023.

Clear communication

The response from our customers to this outage was incredibly positive:

"...well executed and communicated repair..."

"Firstgas and your contractors should be extremely proud of the way this project was planned, communicated and executed. Outstanding effort"

"....congratulations on completing such a big project. We were particularly impressed with the communications and updates that were sent once the work began. It was great to see how things were tracking as well as having the expected completion time set out"

Pariroa Feature Defect Repair

The Pariroa defect project replaced a buckled section of the 400 pipeline approximately 9.3 kilometres south of the Mokau compressor station. The buckled section, caused by land movement, introduced the risk of a major gas leak due to the weakening of the pipeline.

Firstgas split this project in to two phases:

- Firstgas removed the original risk identified through intelligent pigging in 2018, by installing a bypass line.
- The final reconnection (customer critical) of the repaired section was successfully completed on the weekend of 28 – 30 January 2022, as planned and a day ahead of schedule.

Reinstating the pipeline now allows for inspection (ILI) of this pipeline section.

By linking this work with the Gilbert Stream project, we were able to carry out both pieces of work within one outage of the pipeline. We were involved in significant planning and stakeholder engagement as this project was reducing gas supply over the outage period.

While critical field work has concluded, project completion activities are still in progress and will continue into FY2023.

Figure 10: Re-alignment at Gilbert Stream

Gilbert Stream South tie-in. Existing line, now cut, is running left to right, and new green pipeline about to be lifted into place.

Figure 11: Replacement line at Pariroa

Pairoa North tie-in, with header and bypass removed and new section (in green) being lifted in to place, ready for welding.

In Line Inspection

Pipeline intelligent pigging is an essential asset management activity. Intelligent pigging of the pipelines allows us to assess the condition of the pipeline by allowing us to conduct internal inspection without stopping the flow of gas. Firstgas uses a tool referred to as a pig that is inserted into the pipeline at dedicated launch and receive locations. Gas flow is used to propel the pig through the pipeline.

Pigs can either be used for maintenance cleaning operations or for In Line Inspection (ILI), whereby the tool is fitted with banks of sensors. These are used to record pipeline condition data such as wall thickness and the location of defects. Running this data through an assessment tool is then able to produce condition reports on the pipeline.

The frequency of our intelligent pigging programme is driven by our Pipeline Integrity Management Plan. Typically for pipelines that transit urban area or are in areas that pose an increased risk, the intelligent pigging will be conducted at five yearly intervals. For pipelines that transit rural areas or are not exposed to elevated potential for risk, the intelligent pigging is conducted at ten yearly intervals. For all our piggable pipelines, it is a requirement from our pipeline certifier (Lloyds) that we conduct the intelligent pigging at our specified intervals to maintain our certificate of fitness.

Through the course of FY2022, we have conducted intelligent pigging on the 100 series pipelines between Taranaki and Wellington, 200 series pipelines between Taranaki and Hamilton, on the 500 series pipelines in the Bay of Plenty system and on the 700 series pipeline between Feilding and Hastings. Several delays have pushed the commencement of the 700 and 500 lines towards the end of FY2022 with $0.7 million of these costs now expected in FY2023.

Pig Trap Modifications

The pig trap modification programme has continued, with 7 sites completed during FY2022. This will allow pigging of the 503, 505 and 508 pipelines in FY2023. The plan is continuing over the next five years with:

- The 421, 434, 435, 702 pipelines scheduled for pigging in FY2024.
- The 308, 402, 437, 502, 507 pipelines scheduled for pigging in FY2025.
- The 110 pipeline completed for pigging in FY2026.
- Concluding with the 104 and 306 pipelines completed for pigging in FY2027.

Tauriko Growth

To support the increased demand in Tauranga due to the development of a manufacturing plant, Firstgas is developing a new delivery point. The customer is expected to commence manufacturing operations in 2023, with gas required in 2022 for commissioning purposes.

Compression Strategy

During FY2022, Firstgas has continued to refine its compression strategy for the transmission system. We have undertaken a strategic network compression review to determine how we can best meet the needs of our customers' and with the most appropriate use of the system to achieve reliable, safe and economic supply. This focus on network optimisation is driving us to standardise and modernise our compression fleet – while ensuring we have the flexibility to accommodate changes to the network in an efficient manner.

Our network optimisation strategy is focused on these objectives:

- Ensure the security standard for normal operations is met across the entire network.
- Ensure sufficient line pack at all times to meet the time to failure criteria set out in the Critical Contingency Regulations
- Have a balanced compression load across the system.

Our compression strategy is focused on these objectives:

- Maintaining / improving reliability.
- Reducing costs (fuel, maintenance, capital).
- Reducing emissions.

Electricity supply limitations at Kaitoke have determined Electric drive compressor units will not be suitable at this location. Electric drive compressors are still preferable when supply can be assured at a reasonable price. More information is available in our year ahead section.

5.3 ASSET MANAGEMENT IMPROVEMENT PROGRAMME

Over the last year, several activities have been initiated to improve our asset management practices and to ensure we continue to meet our asset management objectives. The improvement programme is aligned with our strategy focus on asset management and included work on the flowing areas:

Asset Management Gap Analysis and Maturity Assessment

Firstgas engaged a third-party consultant to objectively assess our asset management practices based on the international Asset Management Standard, ISO55001. The consultant reviewed existing information relevant to asset management framework and processes, procedures, and information, and supplemented these findings with a series of on-site meetings and discussions with relevant staff.

Firstgas is awaiting the final report and will put a plan in place to address recommendations to increase the maturity of our Asset Management System.

Our goal is to improve and develop a high-quality Asset Management system which will enable us to demonstrate that risks and costs associated with the management of assets are fully and properly considered and optimised.

Learning Management System (LMS)

A Learning Management System has been selected as a solution to consolidate training requirements, delivery and tracking within the Firstgas Group and major contractors. This will ensure that Firstgas Group meets its statutory obligations around training and competency in an efficient and effective manner, as well as provides a suitable central platform to deliver training to staff which is currently occurring in multiple systems. A market evaluation was conducted to select a suitable provider for a solution and implementation is underway.

Implementation will continue into next year with system launch to the business anticipated by Q2 of FY2023.

5.4 PERFORMANCE OF THE TRANSMISSION SYSTEM

A key premise for the AMP Update is that existing reliability, safety, and supply quality levels will be maintained and improved. We have set targets to help drive performance improvements and measure our progress in delivering reliable, safe, and high-quality service (these targets are detailed in **2020 AMP – Appendix H**).

We have continued to meet the quality standards set by the Commerce Commission. We note that:

- Maintaining the reliability of an ageing compressor fleet continues to be challenging. Security of supply is ensured by the availability of redundancy across the network. The implementation of the network optimisation and compressor replacement strategy will improve both security of supply and efficiency of operation.
- We have had two non-compliances during our last Lloyds Audit. These relate to a delay actioning 500 Line SMS findings (which is still in progress) and an overdue 5-year review of the Pipeline Integrity Management Plan, which has now been completed.

Additional information regarding our KPI's and targets is contained in **Appendix H** of the **2020 AMP**.

Table 6: Key Performance Indicator Trend table

KEY PERFORMANCE INDICATORS	FY2021	FY2022 TARGET	TREND[18]
Safety-lost time injuries	0	**0**	▶
Response time to emergencies less than 3 hours (Commerce Commission quality standard)	100%	**100%**	▶
Unplanned interruptions	0	**0**	▶
Major interruptions (Commerce Commission quality standard)	0	**0**	▶
Environmental[19] – instances of non-compliance with all	0	**0**	▶
Asset Management Maturity Assessment	3.0	**3**	▲
Public reported escapes and gas leaks	4	**<5**	▶
Compressor reliability	85%	**>97%**	▼
Lloyds annual audit non-compliance	2	**0**	▼
Compressor availability	94.7%[20]	**>95%**	▲

18. The arrow direction compares data between FY2021 and FY2022, if there was an increase, decrease or steady trend. The arrow colour indicates how close is the KPI to the FY2022 target.
19. We have a policy aim of providing a safe and reliable gas supply to our customers in a manner that minimises our impact on the environment. We are committed to comply with all legislative requirements and where possible exceed them.
20. Percentage based on the average of the first 9 months of financial year FY2022

6. YEAR AHEAD

This section sets out the areas of focus for Firstgas over the coming year commencing 1 October 2022, which is the start of DPP3 (FY2023 – FY2026). The focus remains on providing our customers with a safe and resilient transmission system, while maturing and optimising our approach to asset management.

6.1 SIGNIFICANT ACTIVITIES FOR FY2023

Irrespective of the uncertainty and opportunities facing the gas sector, we have a responsibility to maintain our assets at an appropriate level to ensure we safely and reliably operate the transmission system.

Our expenditure has been reduced for the transmission system for the DPP3 period (FY2023 to FY2026). The areas that account for these reductions include:

- Further reduced forecasts relating to growth and customer connections $4.8 million.
- Implementation of new strategies (Water Bath Replacement, Meter Replacement) and the conclusion of several upgrade programmes has resulted in a $4.0 million reduction in Asset Replacement and Renewal over this regulatory period.

Figure 12 sets out the major activities we plan to undertake throughout FY2023.

Figure 12: Significant projects for FY2023

SIGNIFICANT PROJECTS

INCREASING RESILIENCE OF THE NETWORK

Outlined in the 2022 AMP Update

$7.5 million
STRATEGY
Network Optimisation and Compression strategy

$3.2 million
REPLACEMENT
SCADA Master Station Replacement

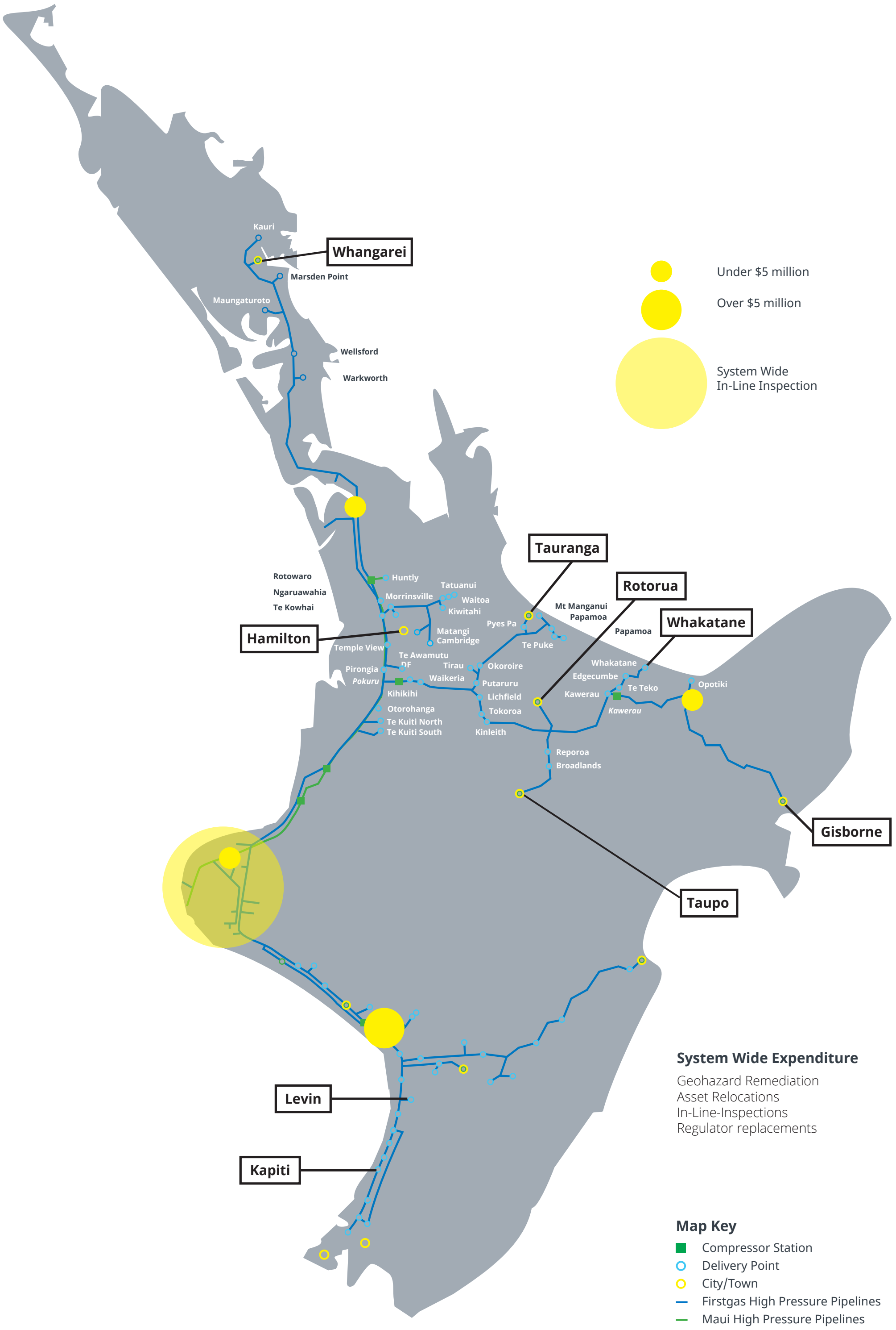
$2.9 million
INSPECTIONS
Intelligent tool pipeline inspections ("pigging") (300, 403, 430, 800 pipelines), includes $0.7 million delayed from FY2022 (500 and 700 pipelines)

$1.9 million
INSPECTIONS
Intelligent tool pipeline inspections ("pigging) of newly piggable 303, 505 and 508 lines

$1.0 million
UPGRADE
Upgrade of pipeline in-line-inspection tool facilities

$1.6 million
REALIGNMENT
200 Line Drury Kiwirail Realignment

Figure 13: Location of significant projects for FY2023



Network Optimisation and Compressor Replacement Strategy

The strategy and planning work for this project started in 2022 and will continue during FY2023. The focus will be on implementation of the Network Optimisation plan and execution of the Compressor Replacement strategy at a limited number of critical compressor sites. Detailed design work has progressed well. We expect to order long lead compressor items early in FY2023, as well as finalising design and site works to ensure an efficient installation and commissioning of new compressors.

SCADA Master System Replacement

Firstgas will be replacing its SCADA master system as the platform currently used by Firstgas for its SCADA management has been identified by the supplier as end of life.

We expect to select a suitable product and supplier in FY2023, with deployment in FY2024 and FY2025.

Intelligent Pigging

Through the course of FY2023, we are planning to conduct intelligent pigging in the Bay of Plenty region, Taranaki, Huntly Offtake and north of Auckland, as well as concluding any remaining FY2022 programmes on the 700 line to Hawkes Bay and 500 line across southeast Waikato.

In FY2023 we have scheduled the inaugural intelligent pigging of the 303, 505 and 508 pipelines as a direct result of the piggability upgrades completed to date.

6.2 CONTINUING OUR ASSET MANAGEMENT IMPROVEMENT PROGRAMME

We will continue developing our overall asset management framework, asset management system elements and documentation while also looking at improving the way we use our existing IT systems and technology. The key asset management improvement activities for FY2023 include:

- ISO 55001 gap assessment, where we engaged a consultant to review our systems in line with ISO 55001 and provide recommendations for improvement. The report is pending and we will create a roadmap to develop an improvement plan to address the recommendations.
- Embedding of Maximo Asset Health Insights (MAHI) into our asset management planning process. We intend to analyse those transmission assets where the health calculation parameters have been exceeded. We will confirm the quality and correctness of data, validate the calculation, and implement any improvements identified in the review.
- Implementation of a Learning Management Solution (LMS) continuing into next year with system launch to the business anticipated by Q2 of FY2023.

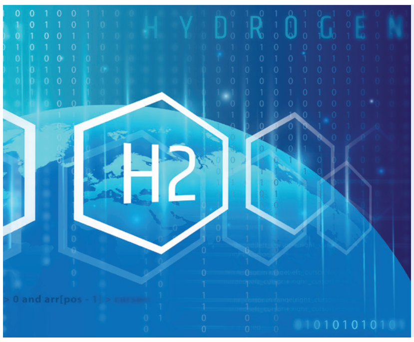
Asset condition (Schedule 12a)

Schedule 12a (report on asset condition) provides a high-level overview of the asset condition rating as per the Commerce Commission's grading categories[21]. 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.

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

- **Compressors (50% of reciprocating engine driven are classified as grade 1):** The existing reciprocating compressors at Rotowaro CS will require major overhauls within the next 5 years. However, implementation of the Network Optimisation and Compressor Replacement strategies will affect the rate and requirement of major overhauls and actual replacement quantities. The compressor replacement strategy will replace two current fleet reciprocating compressors within the next 5 years.
- **Metering systems (57% of ultrasonic meters, 10% of rotary meters and 15% of turbine meters are classified as grade 1):** Meter replacements are an ongoing programme throughout the planning period. Over the next five years, we anticipate that 40% of the meters will be replaced. The Meter Replacement Strategy sets the performance criteria to ensure that the replacement programme is targeted to the meters where performance issues warrant the replacement.
- **Cathodic protection (25% are classified as grade 1):** A programme to replace the rectifier units is underway with 21% identified within the next 5 years.
- **Chromatographs (60% are classified as grade 1):** All Chromatographs will be replaced in the next 5 years.

Further detail on the condition, risks and issues, and planned activities can be found in our **2020 AMP Appendix C Network overview**.



Our Hydrogen Trials

Firstgas is working with other gas network owners on investigating how we can transition our networks to transport hydrogen as a core objective for the industry. The release of our Hydrogen Pipeline Trial Study set the foundation for our ongoing delivery work on hydrogen. Work is now underway to prepare small sections of our network for limited trials of hydrogen blends, before we move to larger parts of our network.

We are closely coordinating with industry stakeholders and will release further information on our trial work as we progress.

21. When Firstgas 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.

7. EXPENDITURE FORECASTS

Through the improvements we have made to our risk management and development of our MAHI application, we are now in a better position to develop longer-term plans based on asset health, criticality, and trends in risks.

7.1 CAPEX FORECAST

Our forecast Capex spend over the next ten years is set out in Figure 14, with forecast from last year's AMP Update shown in red line. There are changes to the profile and the total Capex within the current DPP period from that set out in our 2021 AMP Update.

Changes within regulatory control period two (FY2017 –FY2022):

- The cancellation and delay of two new industrial plant customers projects in FY2022 of approximately $1.5 million.
- Turndown of the Warkworth expansion putting a hold on investment of $4.0 million.
- Further refinement of the Compression Optimisation and Replacement Strategy and consideration of the Government's emissions reduction plan slowed the expected spend by $10.0 million.

Changes over regulatory control period three (FY2023 – FY2026)[22]:

The scrutiny of our expenditure through the DPP3 reset has resulted in an overall reduction in the expenditure for the next two regulatory control periods and a 10.8% reduction in Capex over the next four-year planning period.

The key changes compared to the 2021 AMP Update are:

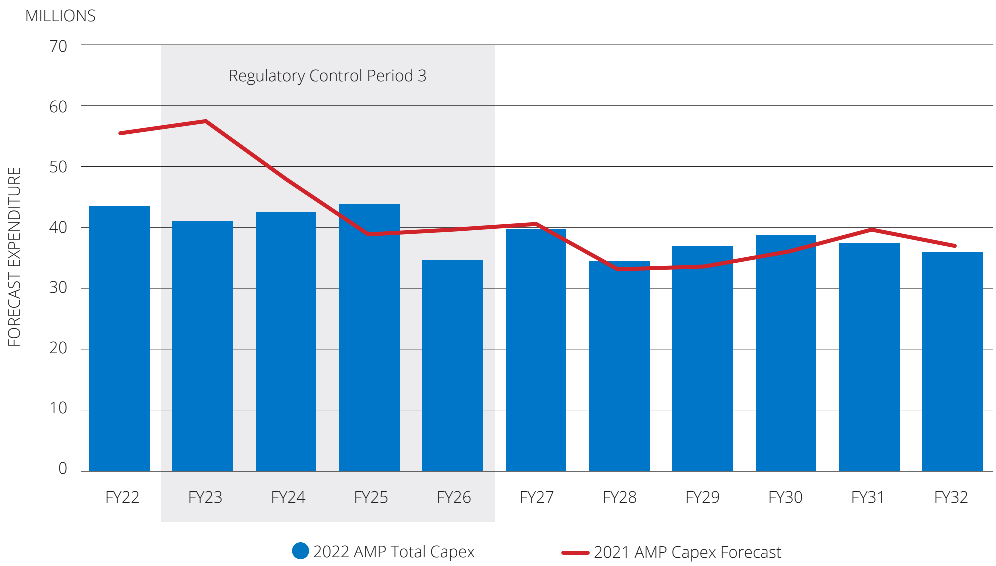
- A reduced forecast for customer connections that results in a $2.8 million reduction over the regulatory control period.
- A reduced forecast for system growth that results in a $2.0 million forecast reduction over the regulatory control period.
- A reduced forecast for non-network assets of $6.0 million over the regulatory control period for SaaS recategorisation.

Largest Capex projects going forward

We have continued to incorporate the high-level heat map that shows the largest Capex projects planned for the next ten years (FY2023 to FY2032) in our AMP Update. This heat map is part of the related party transaction information disclosure requirements. Figure 11 sets out the location of the largest projects, with greater detail in the 10 Year Capex Forecast Table below.

All network Capex is forecast to be completed by our related party, Gas Services New Zealand Limited (GSNZ) under an operations and management agreement (O&M) between Firstgas and GSNZ. This O&M agreement was entered into with the change in ownership of the distribution business in 2016 and will be reviewed before September 2022.

Figure 14: Forecast total Capex (all figures in FY2022 prices)



22. The $ figures quoted are in FY2021 values to align with the Commerce Commissions commentary in the Gas Pipeline Businesses Final Reasons Paper for the DPP3 reset. https://comcom.govt.nz/__data/assets/pdf_file/0025/284524/DPPs-for-gas-pipeline-businesses-from-1-October-2022-Final-Reasons-Paper-31-May-2022.pdf

10 Year Capex Forecast

Over the last few years, the focus for Firstgas has been the immediate Capex programme that was detailed in the previous AMPs and ensuring we can deliver on what is required. As we have started maturing our asset management planning, we are able to extend the horizon beyond the current regulatory control period and focus on the longer-term planning for the assets.

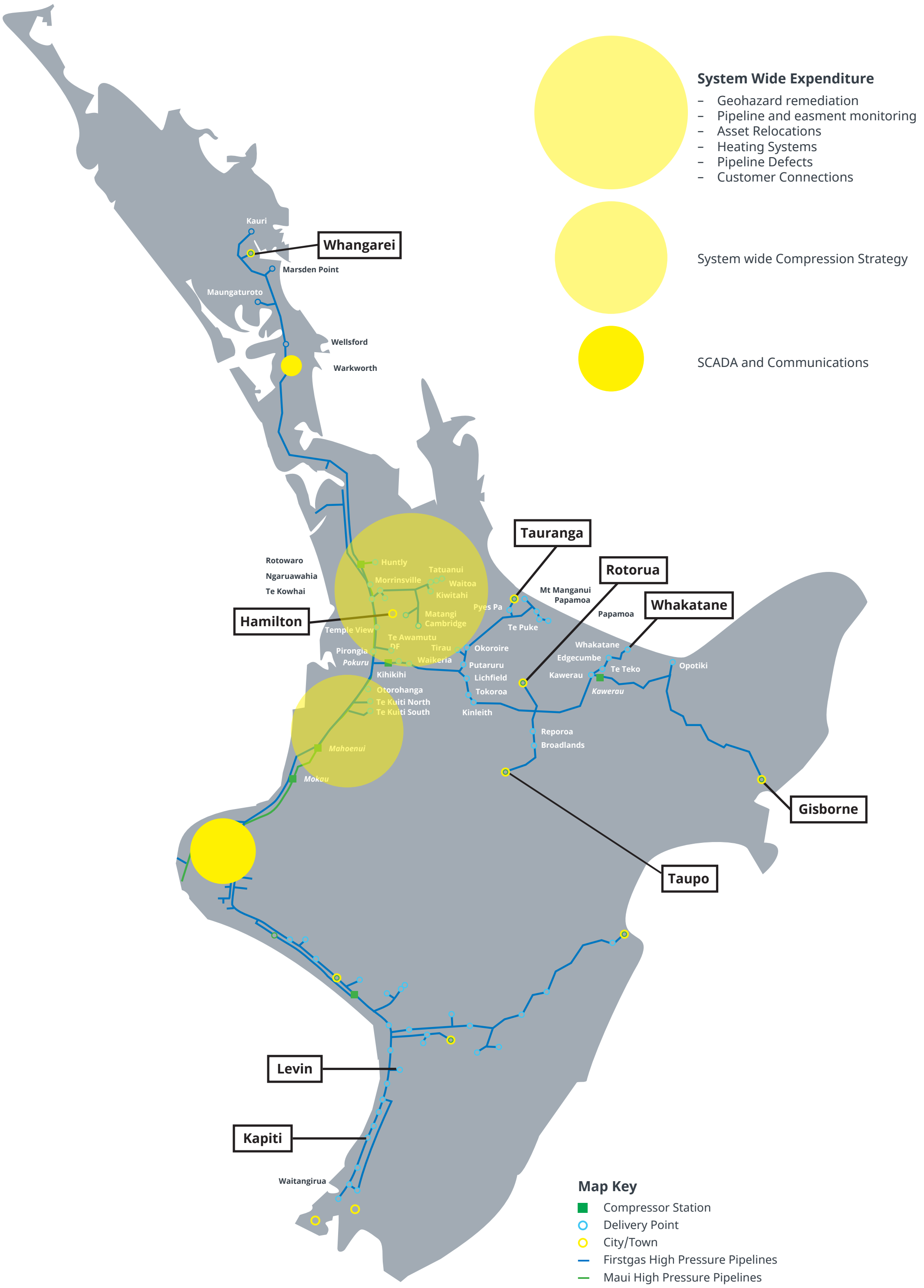
Significant spend areas are listed below and are a mixture of programmed replacements and targeted areas for upgrade and replacement.

Table 5: Description of largest Capex projects

PROJECT	DESCRIPTION	REGION	COST (CONSTANT FY2022 $)	PERIOD
Geohazard Risk remediation	Risk Remediation project resulting from geo-technical hazards	System Wide	$47.2 million	FY23 – FY32
Compression Strategy	Upgrade and standardisation of aging fleet of compressors	Strategic Compression Sites	$32.1 million	FY23 – FY26
Pipeline Condition Monitoring	Pipeline pigging operations	System wide	$31.1 million	FY23 – FY32
Asset Relocations	Relocation of infrastructure	System wide	$21.4 million	FY23 – FY32
Heating Systems	Cost associated with inspection, overhaul and replacement of Water bath heaters	System wide	$10.7 million	FY23 – FY32
Pipeline Defects	Forecast cost to effect repairs associated with pipeline defects identified through increased inline inspections or other condition monitoring	System wide	$11.8 million	FY23 – FY32
Customer Connections	Supporting connecting new customers	System wide	$9.4 million	FY23 – FY32
SCADA and Communications	Upgrade and replacement of SCADA Master sever and obsolete field units	System wide	$26.8 million	FY23 – FY32

The map below 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 2023.

Figure 15: FY2022 Capex expenditure 10-year planning



7.2 OPEX FORECAST

The forecast Opex over the planning period is set out in the blue bars in Figure 16, with forecast from last year's AMP Update shown in red line. There was a change in Opex spend in regulatory control period two (FY2017 – FY2022). The variance was attributed to:

Changes within regulatory control period two (FY2017 – FY2022) relate to:

- Actual spend of SaaS re-categorised from Capex to Opex $3 million for FY2022.
- Increased IT operational costs $1.2 million.

Changes over regulatory control period three (FY2023 – FY2026)[23]:

Over the course of the planning period, our base maintenance costs are anticipated to remain steady. However, the costs will require further review as renewable gases are introduced into the network.

- There is an allowance approved for regulatory control period three of $0.2 million per annum for our renewable gases trial programme. Firstgas anticipate significantly higher spend will be required. Only the regulatory allowance is included in our AMP forecast.
- Capex has been reduced as a result of the recategorisation of SaaS as Opex. There has been no uplift in Business support Opex for regulatory control period three. The costs ($1.88 million per annum) for SaaS have been added to our AMP forecast.

Largest Opex spend categories going forward

We have also continued to incorporate the high-level heat map that shows the largest Opex projects planned for the next ten years (FY2023 to FY2032) in our AMP Update. This heat map is part of the related party transaction information disclosure requirements. Figure 13 sets out the location of the planned Opex spend, with greater detail in the 10-year Opex Forecast Table 6.

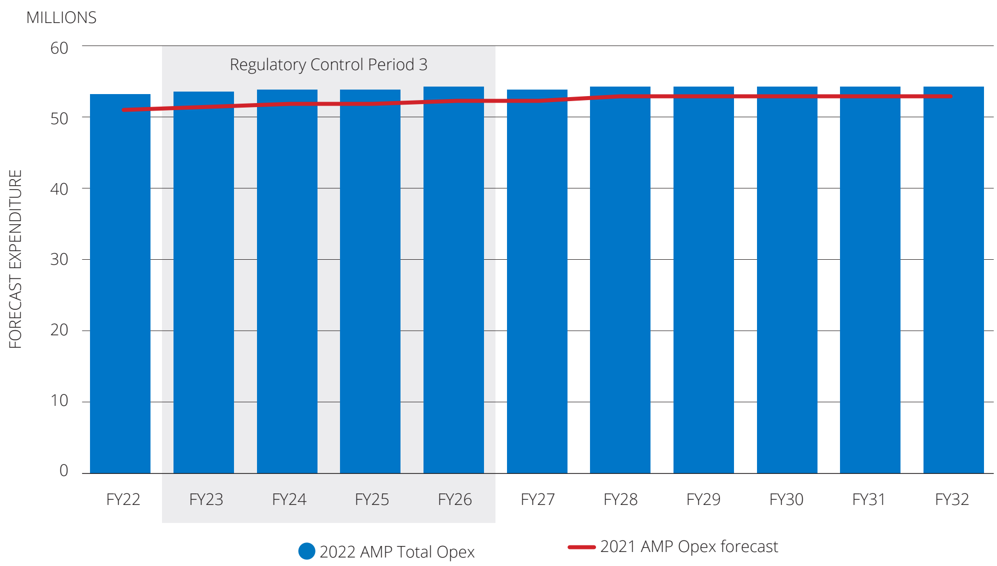
Firstgas does not have specific Opex projects planned for the period. Instead, we have provided the total Opex expenditure. Where it has been possible, we have specified the level of Opex allocated to each region within our network.

10 Year Opex Forecast

Our planned Opex expenditure has been relatively stable in the preceding years. Where possible we have focussed on driving for savings and efficiencies in our Opex costs.

Table 6 presents areas that have the highest operational expenditure through the planning period.

Figure 16: Forecast total Opex (all figures in FY2021 prices)



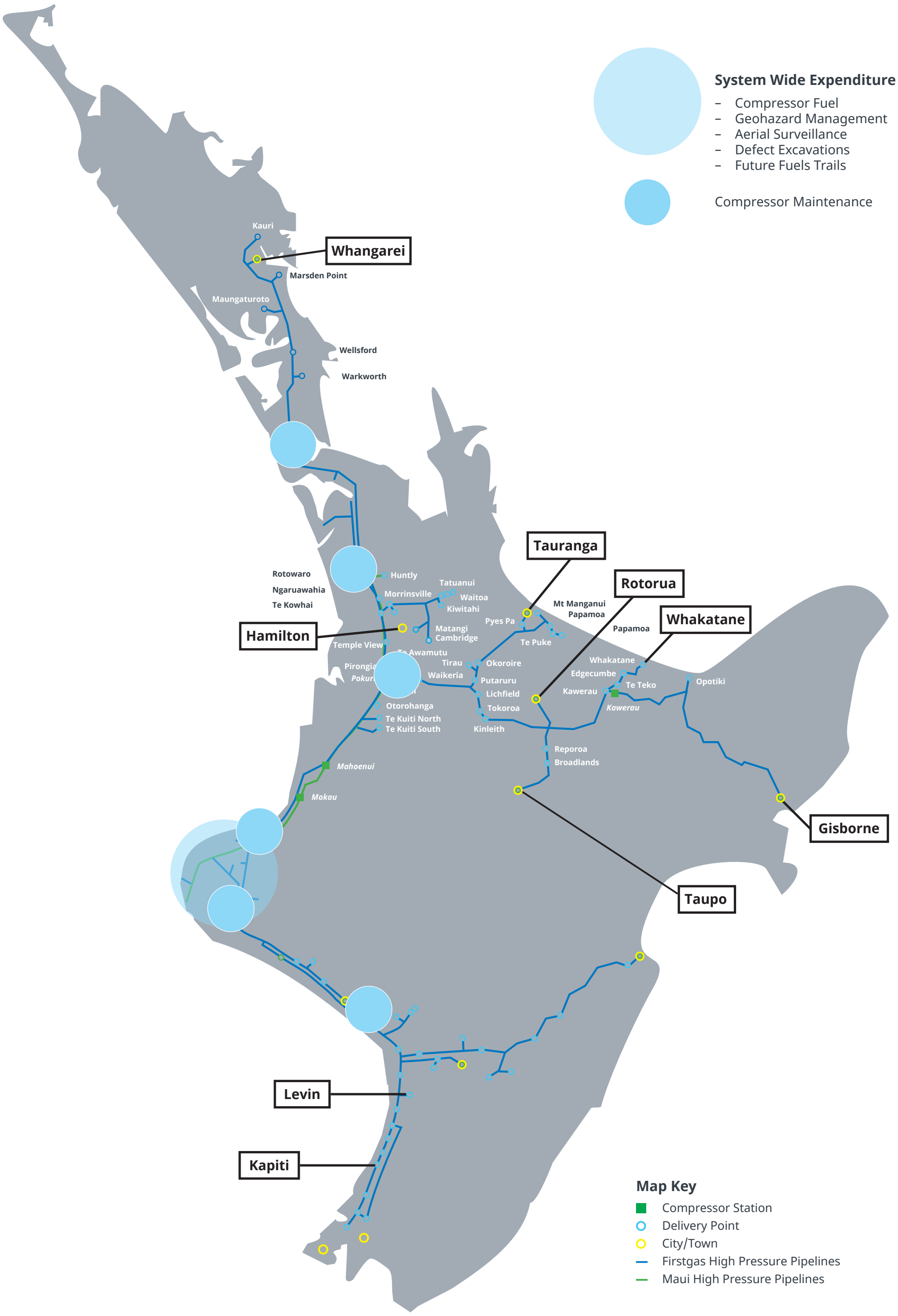
23. The $ figures quoted are in FY2021 values to align with the Commerce Commissions commentary in the Gas Pipeline Businesses Final Reasons Paper for the DPP3 reset. https://comcom.govt.nz/__data/assets/pdf_file/0025/284524/DPPs-for-gas-pipeline-businesses-from-1-October-2022-Final-Reasons-Paper-31-May-2022.pdf

A breakdown of the Opex by region is provided in 10 year Opex Forecast table below and more detail can be found in the 2020 AMP.

Table 6: Opex costs

CATEGORY	DESCRIPTION	REGION	COST (CONSTANT FY2022 $)	PERIOD
Compressor Fuel costs	We are facing an increased cost for our ongoing compressor fuel requirements. The compression strategy may offset some of these costs in the future. When the opportunity presents itself, we will look to source low-carbon compressor fuel gas	System wide	$87.8 million	FY23 – FY32
Aerial Surveillance	Aerial surveillance is a key activity to detect changes in environment through which pipelines traverse. It is also used as a method to monitor any third-party interference along the easement corridor. Helicopters are now the preferred flight method and incur higher running costs	System wide	$13.2 million	FY23 – FY32
Kapuni Gas Treatment Plant	Ongoing maintenance requirements to ensure reliability. KGTP compressors are strategic for the 100 and 200 pipelines	Taranaki region	$12.5 million	FY23 – FY32
Geohazard management	Ongoing maintenance costs associated with identifying, assessing, and monitoring geotechnical issues on the system	System wide	$9.4 million	FY23 – FY32
Defect excavations	Pipeline coatings are the primary protection against corrosion. Each year several defects are excavated to carry out coating remediations	System wide	$5.2 million	FY23 – FY32
Rotowaro Compressor Station	Ongoing maintenance requirements to ensure reliability. Rotowaro compressors are strategic for the northern transmission system	Waikato region	$5.2 million	FY23 – FY32
Renewable gas Trials	In order to take the first steps towards replacing natural gas with hydrogen by utilising the existing gas infrastructure, it must be demonstrated that there are no adverse effects to gas consumers or gas transportation assets. This allocation is included in the forecast to support these trials	System wide	$0.8 million	FY23 – FY26
Mokau Compressor Station	Ongoing maintenance requirements to ensure reliability. Mokau compressors are strategic for the 400 pipeline	Taranaki region	$3.1 million	FY23 – FY32
Henderson Compressor Station	Ongoing maintenance requirements to ensure reliability. Henderson compressors are strategic for the 430 pipeline	North Auckland region	$2.7 million	FY23 – FY32
Kaitoke Compressor Station	Ongoing maintenance requirements to ensure reliability. Kaitoke compressors are strategic for the 100 and 600 pipelines	Manawatu – Whanganui region	$2.1 million	FY23 – FY32

Figure 17: FY2022 Opex expenditure 10-year planning



All network Opex and system operations and network support Opex is forecast to be completed by our related party, GSNZ under an operations and management agreement between Firstgas and GSNZ. This O&M agreement was entered into with the change in ownership of the distribution business in 2016 and will be reviewed before September 2022.

7.3 MATERIAL CHANGES

We plan our Capex work programme based on the best information that we have available at the time. However, we need to remain flexible and able to respond to any changes, as the year progresses.

Table 7: Material changes in work programmes

Activity	2020 AMP	2021 AMP Update	2022 AMP UPDATE	Risk
Compression strategy	Planned to upgrade four compressor sites over the planning period (10 years)	Compression strategy refined and is focussed on 2 strategic sites.	Compression strategy continues to be refined. The focus remains on two strategic sites however, the expected spend profile is expected to be delayed – overall $4.5 million reduction in DPP3 allowance	Reduced the risk of stranded assets whilst addressing reliability issues and high maintenance and operation costs. Long term increase in risk around reliability due to aging fleet.
Customer connections	No reference to committing to expenditure forecast in relation to 2 factory connections Forecast included $19 million over planning period to facilitate customer connections	Included $2 million forecast to enable customers to connect to the transmission system Forecasts have been reduced. $13.7 million forecast over planning period to facilitate customer connections	Forecast reduced by $3.2 million in accordance with the final DPP3 allowance	Unable to meet customer demand, and provide gas services and system growth
System Growth	Forecast included $19.5 million to facilitate system growth	Forecast reduced $9.1 million included in forecast to facilitate system growth	Warkworth expansion not required yet, project on hold $4 million reduction No change to remaining allocation	Unable to meet customer demand, and provide gas services and system growth
Non-Network IT expenditure	$40 million (excl. GTAC project) forecast to be spent over the course of the planning period	$52 million forecast expenditure over the planning period	$6 million reduction in forecast expenditure over regulatory control period three as a result of SaaS recategorisation	Increase in expenditure to deliver improved security, supporting Firstgas Group strategy and operational needs
Non-Network Property expenditure			$5 million increase in FY2025 forecast for additional storage facility	

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 2021 AMP Update and includes our signed director certificate.

APPENDIX A: SUMMARY OF MATERIAL CHANGES AND COMPLIANCE

The table below:

- Summarise the material changes in our asset management plan, as compare with our 2021 AMP Update.
- Demonstrates our compliance with the requirements for an AMP Update, as set out in the *Gas Transmission Information Disclosure Determination 2012* (ID Determination).

Table 9: 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 Firstgas' gas transmission business. Information on the Firstgas distribution business (GDB) can be found in the separate Distribution 2022 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	**Material changes from the 2021 AMP:** Material changes from the 2021 AMP Update: Two industrial customer connections were included in the FY2022 budget that did not go ahead: – One connection was cancelled ($1.0 million). – One connection is delayed ($0.5 million). Warkworth expansion delayed beyond 2028 ($4.0 million).
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	**Material changes from the 2021 AMP:** Execution of the Compression strategy for FY2022 was delayed so that we could undertake a further review to incorporate network optimisation and address the Government Emissions Reduction Plan. The impact of this delay was $10.0 million underspend in FY2022.
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 has been a decrease in Capex over DPP 3 period of $19 million[24]. This reduction in costs is attributed to: – A reduced forecast for customer connections that results in a $2.8 million reduction over the period. – A reduced forecast for Bremner Road, Auckland system growth that results in a $2.0 million forecast reduction over the period. – A reduced forecast of $4.0 million over the period for Asset Replacement and Renewal due to an improved Water Bath Heater Replacement Strategy and containment of spend within the DPP3 allowance. – A reduced forecast for non-network assets of $6.0 million over DPP3 for SaaS re-categorisation from Capex to Opex and a further $2.0 million to contain the spend within the DPP3 allowance. – An increase forecast for non-network assets of $5.0 million in FY2025 for a new storage facility. There has been no uplift in Business support Opex as a result of the reduction in Capex for SaaS recategorisation. The costs ($1.88 million per annum) for SaaS have been added to our AMP forecast.[25] There is an Opex allowance approved for regulatory control period three of $0.8 million reduced from $1.6 million for the renewable gases trial programme.

24. The $ figures quoted are in FY2021 values to align with the Commerce Commissions commentary in the Gas Pipeline Businesses Final Reasons Paper for the DPP3 reset. https://comcom.govt.nz/__data/assets/pdf_file/0025/284524/DPPs-for-gas-pipeline-businesses-from-1-October-2022-Final-Reasons-Paper-31-May-2022.pdf
25. The $ figures quoted are in FY2021 values to align with the Commerce Commissions commentary in the Gas Pipeline Businesses Final Reasons Paper for the DPP3 reset. https://comcom.govt.nz/__data/assets/pdf_file/0025/284524/DPPs-for-gas-pipeline-businesses-from-1-October-2022-Final-Reasons-Paper-31-May-2022.pdf

ID REQUIREMENT	DISCUSSION
Clause 2.6.5 (5) Provide an assessment of transmission capacity as set out in clause 8 of Attachment A	There has been no Material Changes to Transmission Capacity determination. The Assessment is included in **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
Clause 2.6.5 (7) Identify any changes to the asset management practices of the GTB that would affect a Schedule 13 Report on Asset Management Maturity disclosure	There are no material changes in Asset Management practices that affect Schedule 13 Report on Asset Management Maturity disclosure
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.	The Information Determination Disclosure templates are included in the AMP Updates as **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

Schedule 11a: Report on forecast capital expenditure

Company Name	**First Gas Ltd**
AMP Planning Period	**1 October 2022 – 30 September 2032**

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			*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 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**	**30 Sep 32**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (nominal dollars)**										
10		Consumer connection	34	767	782	798	813	1,185	1,209	1,233	1,258	1,283	1,309
11		System growth	2,648	548	558	570	581	572	584	595	607	620	632
12		Asset replacement and renewal	31,613	32,714	35,658	32,667	28,996	30,750	24,432	24,365	28,563	32,802	32,779
13		Asset relocations	1,625	2,976	2,158	1,994	2,034	2,371	2,418	2,466	2,516	2,566	2,617
14		Reliability, safety and environment:											
15		Quality of supply											
16		Legislative and regulatory											
17		Other Reliability, Safety and Environment	520	548	558	570	581	593	605	617	629	642	654
18		**Total reliability, safety and environment**	520	548	558	570	581	593	605	617	629	642	654
19		**Expenditure on network assets**	36,440	37,553	39,714	36,599	33,005	35,471	29,248	29,276	33,573	37,913	37,991
20		Expenditure on non-network assets	6,907	4,229	4,141	9,707	4,462	8,083	9,387	12,915	11,656	6,607	5,740
21		**Expenditure on assets**	43,347	41,782	43,855	46,306	37,467	43,554	38,635	42,191	45,229	44,520	43,731
22													
23	*plus*	Cost of financing	370	357	375	395	320	372	330	360	386	380	373
24	*less*	Value of capital contributions	1,463	2,679	1,942	1,794	1,830	2,134	2,176	2,220	2,264	2,309	2,356
25	*plus*	Value of vested assets											
26		**Capital expenditure forecast**	42,254	39,460	42,288	44,907	35,957	41,792	36,789	40,331	43,351	42,591	41,748
27													
28		Assets commissioned	35,048	33,782	35,459	37,439	30,294	35,215	31,237	34,114	36,570	35,996	35,359
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 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**	**30 Sep 32**
32			**$000 (in constant prices)**										
33		Consumer connection	34	752	752	752	752	1,074	1,075	1,074	1,074	1,074	1,074
34		System growth	2,648	537	537	537	537	537	518	518	518	518	518
35		Asset replacement and renewal	31,613	32,073	34,273	30,784	26,787	27,585	21,695	21,211	24,379	27,447	26,890
36		Asset relocations	1,625	2,918	2,074	1,879	1,879	2,147	2,147	2,147	2,147	2,147	2,147
37		Reliability, safety and environment:											
38		Quality of supply	-	-	-	-	-	-					
39		Legislative and regulatory	-	-	-	-	-	-					
40		Other Reliability, Safety and Environment	520	537	537	537	537	537	537	537	537	537	537
41		**Total reliability, safety and environment**	520	537	537	537	537	537	537	537	537	537	537
42		**Expenditure on network assets**	36,440	36,817	38,173	34,489	30,492	31,880	25,972	25,487	28,655	31,723	31,166
43		Expenditure on non-network assets	6,907	4,147	3,981	9,147	4,123	7,321	8,336	11,243	9,948	5,529	4,709
44		**Expenditure on assets**	43,347	40,964	42,154	43,636	34,615	39,201	34,308	36,730	38,603	37,252	35,875
45	**Subcomponents of expenditure on assets (where known)**												
46		Research and development											

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
	for year ended	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26	30 Sep 27	30 Sep 28	30 Sep 29	30 Sep 30	30 Sep 31	30 Sep 32
Difference between nominal and constant price forecasts		**$000**										
Consumer connection		-	15	30	46	61	111	134	159	184	209	235
System growth		-	11	21	33	44	35	66	77	89	102	114
Asset replacement and renewal		-	641	1,385	1,883	2,209	3,165	2,737	3,154	4,184	5,355	5,889
Asset relocations		-	58	84	115	155	224	271	319	369	419	470
Reliability, safety and environment:												
Quality of supply		-	-	-	-	-	-	-	-	-	-	-
Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
Other Reliability, Safety and Environment		-	11	21	33	44	56	68	80	92	105	117
Total reliability, safety and environment		-	11	21	33	44	56	68	80	92	105	117
Expenditure on network assets		-	736	1,541	2,110	2,513	3,591	3,276	3,789	4,918	6,190	6,825
Expenditure on non-network assets		-	82	160	560	339	762	1,051	1,672	1,708	1,078	1,031
Expenditure on assets		-	818	1,701	2,670	2,852	4,353	4,327	5,461	6,626	7,268	7,856

11a(ii): Consumer Connection

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26	30 Sep 27
*Consumer types defined by GTB**		**$000 (in constant prices)**					
Happy Valley (Otorohanga)		34					
Other Consumer connections			752	752	752	752	1,074
** include additional rows if needed*							
Consumer connection expenditure		34	752	752	752	752	1,074
less Capital contributions funding consumer connection			-	-	-	-	-
Consumer connection less capital contributions		34	752	752	752	752	1,074

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Pipes	2,148	193	-	408	408	268
Compressor stations	-	-	-	-	-	-
Other stations	500	344	537	129	129	269
SCADA and communications	-	-	-	-	-	-
Special crossings						
System growth expenditure	2,648	537	537	537	537	537
less Capital contributions funding system growth						
System growth less capital contributions	2,648	537	537	537	537	537

11a(iv): Asset Replacement and Renewal

	for year ended	*Current Year CY* 30 Sep 22	*CY+1* 30 Sep 23	*CY+2* 30 Sep 24	*CY+3* 30 Sep 25	*CY+4* 30 Sep 26	*CY+5* 30 Sep 27
		$000 (in constant prices)					
	Pipes	12,100	10,640	7,831	8,218	9,865	13,673
	Compressor stations	11,475	10,280	14,480	9,931	7,515	5,368
	Other stations	4,850	4,814	4,390	7,404	7,247	5,368
	SCADA and communications	550	3,793	5,314	3,543	429	1,647
	Special crossings	88	47	47	47	47	47
	Components of stations (where known)						
	Main-line valves	650	574	670	420	537	537
	Heating system	650	859	590	322	322	215
	Odorisation plants	89	95	96	96	107	107
	Coalescers	300	54	54	54	54	54
	Metering system	613	713	567	567	567	387
	Cathodic protection	248	97	97	97	97	97
	Chromatographs	-	107	137	85	-	85
	Asset replacement and renewal expenditure	31,613	32,073	34,273	30,784	26,787	27,585
less	Capital contributions funding asset replacement and renewal						
	Asset replacement and renewal less capital contributions	31,613	32,073	34,273	30,784	26,787	27,585

11a(v): Asset Relocations

	Project or programme*	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26	30 Sep 27
	400Line SH3 Rapanui Crossing Remediation	365					
	402Line Recoat and protection Evolution Drive	72					
	402Line Terapa Realignment (POAL)	14					
	400LIne Realignment Short Route Development		1,294				
	200Line Drury Realignment (Kiwirail)	148	1,624				
	** include additional rows if needed*						
	All other projects or programmes - asset relocations	1,026	-	2,074	1,879	1,879	2,147
	Asset relocations expenditure	1,625	2,918	2,074	1,879	1,879	2,147
less	Capital contributions funding asset relocations	1,463	2,626	1,867	1,691	1,691	1,932
	Asset Relocations less capital contributions	163	292	207	188	188	215

11a(vi): Quality of Supply

	Project or programme*	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26	30 Sep 27
	** include additional rows if needed*						
	All other projects or programmes - quality of supply						
	Quality of supply expenditure	-	-	-	-	-	-
less	Capital contributions funding quality of supply						
	Quality of supply less capital contributions	-	-	-	-	-	-

11a(vii): Legislative and Regulatory

Project or programme*						
** 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 22	*CY+1* 30 Sep 23	*CY+2* 30 Sep 24	*CY+3* 30 Sep 25	*CY+4* 30 Sep 26	*CY+5* 30 Sep 27
Project or programme*	**$000 (in constant prices)**					
Minor Management of Technical Change	150					
** include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment	370	537	537	537	537	537
Other reliability, safety and environment total	520	537	537	537	537	537
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	520	537	537	537	537	537

11a(ix): Non-Network Assets

Routine expenditure

Project or programme*	**$000 (in constant prices)**					
ICT	5,608	2,579	2,621	2,498	2,321	3,784
Vehicles	560	613	613	613	613	613
Property	389	418	210	5,499	652	2,387
Plant and Equipment	350	537	537	537	537	537
** include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	6,907	4,147	3,981	9,147	4,123	7,321

Atypical expenditure

Project or programme*						
** include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	-	-	-	-	-
Expenditure on non-network assets	6,907	4,147	3,981	9,147	4,123	7,321

Schedule 11b: Report on forecast operational expenditure

Company Name	First Gas Ltd
AMP Planning Period	1 October 2022 – 30 September 2032

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

	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 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**	**30 Sep 32**
Operational Expenditure Forecast	**$000 (in nominal dollars)**										
Service interruptions, incidents and emergencies	578	813	829	846	863	880	898	916	934	953	972
Routine and corrective maintenance and inspection	14,636	15,869	16,186	16,510	16,840	17,177	17,520	17,871	18,228	18,593	18,964
Asset replacement and renewal											
Compressor fuel	4,727	8,323	8,707	8,881	9,625	9,817	10,603	10,815	11,031	11,252	11,477
Land management and associated activity	1,708	1,711	1,745	1,780	1,816	1,852	1,889	1,927	1,966	2,005	2,045
Network opex	21,649	26,716	27,467	28,017	29,144	29,726	30,910	31,529	32,159	32,803	33,458
System operations	3,540	3,677	3,751	3,826	3,902	3,980	4,060	4,141	4,224	4,308	4,394
Network support	6,496	4,654	4,746	4,841	4,938	4,460	4,549	4,640	4,733	4,827	4,924
Business support	21,443	19,537	19,928	20,326	20,733	21,147	21,570	22,002	22,442	22,890	23,348
Non-network opex	31,479	27,868	28,425	28,993	29,573	29,587	30,179	30,783	31,399	32,025	32,666
Operational expenditure	53,128	54,584	55,892	57,010	58,717	59,313	61,089	62,312	63,558	64,828	66,124

	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 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**	**30 Sep 32**
	$000 (in constant prices)										
Service interruptions, incidents and emergencies	578	797	797	797	797	797	797	797	797	797	797
Routine and corrective maintenance and inspection	14,636	15,557	15,557	15,557	15,557	15,557	15,557	15,557	15,557	15,557	15,557
Asset replacement and renewal											
Compressor fuel	4,727	8,160	8,369	8,369	8,892	8,892	9,415	9,415	9,415	9,415	9,415
Land management and associated activity	1,708	1,678	1,678	1,678	1,678	1,678	1,678	1,678	1,678	1,678	1,678
Network opex	21,649	26,192	26,401	26,401	26,924	26,924	27,447	27,447	27,447	27,447	27,447
System operations	3,540	3,605	3,605	3,605	3,605	3,605	3,605	3,605	3,605	3,605	3,605
Network support	6,496	4,563	4,562	4,562	4,562	4,039	4,039	4,039	4,039	4,039	4,039
Business support	21,443	19,154	19,154	19,154	19,154	19,154	19,154	19,154	19,154	19,154	19,154
Non-network opex	31,479	27,322	27,321	27,321	27,321	26,798	26,798	26,798	26,798	26,798	26,798
Operational expenditure	53,128	53,514	53,722	53,722	54,245	53,722	54,245	54,245	54,245	54,245	54,245
Subcomponents of operational expenditure (where known)											
Research and Development											
Insurance											

	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 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**	**30 Sep 32**
Difference between nominal and real forecasts	**$000**										
Service interruptions, incidents and emergencies	-	16	32	49	66	83	101	119	137	156	175
Routine and corrective maintenance and inspection	-	312	629	953	1,283	1,620	1,963	2,314	2,671	3,036	3,407
Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
Compressor fuel	-	163	338	512	733	925	1,188	1,400	1,616	1,837	2,062
Land management and associated activity	-	33	67	102	138	174	211	249	288	327	367
Network opex	-	524	1,066	1,616	2,220	2,802	3,463	4,082	4,712	5,356	6,011
System operations	-	72	146	221	297	375	455	536	619	703	789
Network support	-	91	184	279	376	421	510	601	694	788	885
Business support	-	383	774	1,172	1,579	1,993	2,416	2,848	3,288	3,736	4,194
Non-network opex	-	546	1,104	1,672	2,252	2,789	3,381	3,985	4,601	5,227	5,868
Operational expenditure	-	1,070	2,170	3,288	4,472	5,591	6,844	8,067	9,313	10,583	11,879

Schedule 12a: Report on asset condition

Company Name	**First Gas Ltd**
AMP Planning Period	**1 October 2022 – 30 September 2032**

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	-	3.87%	94.84%	1.29%		3	-
10	Pipes	Special crossings	km	-	4.00%	96.00%	-		3	-
11	Stations	Compressor stations	No.	-	84.21%	15.79%	-		3	-
12	Stations	Offtake point	No.	0.57%	14.94%	84.48%	-		3	-
13	Stations	Scraper stations	No.	-		100.00%	-		3	-
14	Stations	Intake points	No.	-	16.00%	84.00%	-		3	-
15	Stations	Metering stations	No.	-	-	100.00%	-		3	-
16	Compressors	Compressors—turbine driven	No.	28.57%	28.57%	42.86%	-		3	-
17	Compressors	Compressors—electric motor driven	No.	-	-	100.00%	-		3	-
18	Compressors	Compressors—reciprocating engine driven	No.	50.00%	20.00%	30.00%	-		4	14%
19	Main-line valves	Main line valves manually operated	No.	-	1.79%	98.21%	-		3	-
20	Main-line valves	Main line valves remotely operated	No.	-	-	100.00%	-		3	-
21	Heating systems	Gas-fired heaters	No.	0.63%	0.63%	88.68%	10.06%		3	1%
22	Heating systems	Electric heaters	No.	-	-	100.00%	-		4	-
23	Odorisation plants	Odorisation plants	No.	-	-	100.00%	-		3	-
24	Coalescers	Coalescers	No.	-	-	100.00%	-		3	-
25	Metering systems	Meters—ultrasonic	No.	57.14%	-	42.86%	-		4	80%
26	Metering systems	Meters—rotary	No.	10.32%	-	87.10%	2.58%		4	23%
27	Metering systems	Meters turbine	No.	4.53%	0.82%	76.54%	18.11%		4	11%
28	Metering systems	Meters—mass flow	No.	25.00%	-	75.00%	-		4	50%
29	SCADA and communications	Remote terminal units (RTU)	No.	2.37%	52.13%	39.81%	5.69%		3	5%
30	SCADA and communications	Communications terminals	No.	40.00%	-	60.00%	-		4	100%
31	Cathodic protection	Rectifier units	No.	25.00%	-	75.00%	-		3	21%
32	Chromatographs	Chromatographs	No.	60.00%	-	40.00%	-		4	100%

Schedule 12b: Report on forecast demand

Company Name	**First Gas Ltd**
AMP Planning Period	**1 October 2022 – 30 September 2032**

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

7 **12b(i): Connections**

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9	for year ended	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**
10	**Connection types defined by GTB**						
11	Distribution System	1		1	1		
12	Direct Connect					1	
13	Bi-Driectional		1				
14	Receipt Point		-	-	-	-	-
15	Receipt Point (Future Fuel)		1				
16	** include additional rows if needed*						
17	**Connections total**	1	2	1	1	1	-

19 **12b(ii): Gas conveyed**

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
21	for year ended	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**
23	Intake volume (TJ)	144,557	158,176	158,390	159,404	159,417	159,431
24	Quantity of gas delivered (TJ)	144,005	157,276	157,490	158,503	158,517	158,531
25	Gas used in compressor stations (TJ)	658	658	658	658	658	658
26	Gas used in heating systems (TJ)	112	112	112	112	112	112
27	**Total gas conveyed (TJ)**	144,776	158,046	158,260	159,274	159,288	159,301

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.

FOR YEAR ENDED	CPI
FY2022	0.00%
FY2023	2.00%
FY2024	2.00%
FY2025	2.00%
FY2026	2.00%
FY2027	2.00%
FY2028	2.00%
FY2029	2.00%
FY2030	2.00%
FY2031	2.00%
FY2032	2.00%

APPENDIX C: PIPELINE CAPACITY

Table 10: North Pipeline Capacity Forecast

	DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
			FY2022	FY2027	FY2032
	Tuakau 2	1,296	39,179	39,092	39,005
	Harrisville 2	1,482	39,226	39,226	39,226
	Ramarama	137	15,378	15,356	15,336
	Drury 1	1,087	117,734	117,061	116,225
	Pukekohe	345	53,847	53,730	53,623
	Glenbrook	6,764	22,550	22,511	22,475
GREATER AUCKLAND	Total for Greater Auckland	49,463	65,024	63,615	62,221
GREATER AUCKLAND	Bruce McLaren	1,535	9,608	9,517	9,435
GREATER AUCKLAND	Henderson	3,755	15,438	15,080	14,755
GREATER AUCKLAND	Papakura	7,914	40,748	40,663	40,578
GREATER AUCKLAND	Waikumete	6,238	26,396	25,782	25,216
GREATER AUCKLAND	Westfield	30,021	65,024	63,615	62,221
	Hunua (Three DPs)	738	134,772	134,059	133,345
	Flat Bush	1,588	103,862	103,077	102,350
	Waitoki	888	23,946	23,750	22,978
	Marsden	29	14,476	14,402	14,327
	Whangarei	560	9,750	9,708	9,664
	Kauri + Maungaturoto	5,000	7,408	7,345	7,281
	Alfriston	41	11,739	11,736	11,734
	Waiuku	188	12,030	12,012	11,994
	Warkworth 2	1,571	1,346	1,345	1,344

Notes:

- The peak week was the week ending the 15 August 2021.
- Negligible demand was observed at the Wellsford and Kingseat Delivery Points during the North System's peak week. Pipeline capacity was not determined for those sites.
- Contractual capacity is allocated to Kauri and Maungaturoto collectively.
- Rotowaro compression was modelled running continuously with a constant discharge pressure of 84 barg.
- Henderson compression was modelled running continuously with a constant discharge pressure of 84 barg.
- Aggregate Contractual Capacity is apportioned to Bruce McLaren, Henderson, Papakura, Waikumete and Westfield in proportion to the operational capacity for these delivery points during FY2022.
- New Zealand Refining's offtake was much reduced during FY2022 because they could not obtain the gas they wanted. Since they have now shut down as announced earlier, capacity data for FY2022 reflects zero New Zealand Refining offtake.

Table 11: Bay of Plenty Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2022	FY2027	FY2032
Broadlands	213	4,010	3,997	3,985
Edgecumbe (Both DPs)	4,597	4,233	4,200	4,169
Gisborne	1,353	4,071	4,069	4,068
Mount Maunganui	2,768	1,340	1,211	1,080
Tauranga (Includes Pyes Pa)	1,458	1,566	1,549	1,297
Kawerau (Three DPs)	2,210	12,965	12,821	12,685
Kihikihi	348	138,332	121,350	101,218
Kinleith (Both DPs)	11,207	45,930	41,845	33,762
Lichfield (Both DPs)	5,750	22,027	21,848	21,828
Opotiki	26	3,874	3,857	3,840
Putaruru	103	24,869	21,378	17,302
Rangiuru	200	862	862	794
Reporoa	2,016	8,591	8,557	8,530
Rotorua	1,425	2,723	2,715	2,706
Taupo	539	6,024		
Tauriko	3,300	2,783	2,213	1,633
Te Puke	266	1,442	1,118	790
Tirau (Both DPs)	1,450	13,081	13,901	11,792
Tokoroa	454	36,414	36,111	31,790
Waikeria	99	94,238	84,804	74,007
Whakatane	3,647	1,763	1,742	1,721

Notes:

- The peak week for this system was the week ending 11 October 2020.
- Negligible demand was observed at Okoroire and Te Teko Delivery Points during the peak week. Pipeline capacity was not determined for those sites.
- Pokuru compression was modelled running continuously with a constant discharge pressure of 74 barg.
- Kawerau compression was modelled running continuously with a constant discharge pressure of 84 barg.
- The Rangiuru lateral is operated as a distribution IP main. The minimum acceptable pressure at the inlet to the Rangiuru Delivery Point has been taken as 10 barg. Although not defined in the Gas Transmission Security Standard, 10 barg is the minimum accepted pressure for distribution.
- The estimated demand at a new Delivery Point is being constructed near Tauriko (on the line to Tauranga/Mt Maunganui) has been included at 3,300 GJ/day.
- A large-scale biogas project is now underway at Broadlands. This is expected to inject the biogas into Reporoa to Taupo pipeline to supplement gas supply from FY2023 onwards. To facilitate this project, it is proposed to operate the Reporoa to Taupo pipeline at less than 20 bar g. Normal transmission operating pressure wouldn't be restored unless the demand for capacity on this section of the pipeline requires it.

Table 12: Central North Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2022	FY2027	FY2032
Cambridge	2,026	1,322	1,541	1,471
Greater Hamilton	7,467	17,855	18,710	17,392
Horotiu	1,568	11,281	11,281	11,665
Kiwitahi	1,000	3,177	3,177	3,626
Morrinsville	1,050	3,093	3,093	1,720
Tatuanui	1,500	2,853	2,853	2,753
Te Rapa Cogen	23,200	12,533	12,533	15,467
Waitoa	1,447	3,319	3,319	5,025

Notes:

- The peak week was the week ending 15 August 2021.
- Compression at Rotowaro was modelled running continuously with a constant discharge pressure of 84 barg.

Table 13: Central South Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2022	FY2027	FY2032
Eltham	593	7,885	7,065	5,733
Inglewood	147	6,406	9,926	5,525
Kaponga	8	2,853	3,518	2,680
New Plymouth	3,712	1,351	3,301	2,128
Stratford	357	21,190	30,908	45,376
Waitara	389	2,706	6,490	5,090

Notes:

- The peak week, with Pokuru 2 offtake excluded, was the week ending 18 July 2021.
- Pokuru offtake was set to zero during modelling.
- Compression at Mahoenui was not running during modelling.
- Kapuni compression was modelled running continuously with a constant discharge pressure of 84 barg.

Table 14: South Pipeline System Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2022	FY2027	FY2032
Ashhurst	38	3,223	2,887	2,534
Belmont	6,154	3,121	2,725	2,419
Dannevirke	227	3,583	3,210	2,814
Feilding	996	2,780	2,525	2,167
Foxton	150	2,630	2,211	1,917
Hastings (Both DPs)	6,363	4,373	4,034	3,653
Hawera (Both DPs)	1,393	31,915	26,882	28,430
Kaitoke	89	3,606	3,585	3,603
Kakariki	249	2,782	2,336	2,022
Greater Kapiti	897	2,874	2,591	2,398
Lake Alice	147	3,056	2,563	2,232
Levin	1,087	2,702	2,271	1,956
Longburn	764	3,069	2,596	2,251
Manaia	74	5,910	5,908	5,907
Mangaroa	88	3,354	2,988	2,600
Marton	855	2,135	1,742	1,468
Otaki	84	2,552	2,173	1,891
Pahiatua (Both DPs)	3,205	2,204	1,997	1,832
Palmerston North	4,046	2,261	2,044	1,882
Patea	90	27,571	21,555	24,268
Takapau	350	2,918	2,573	2,223
Tawa (Both DPs)	11,281	4,738	4,319	3,991
Greater Waitangirua	2,055	2,679	2,343	2,102
Waitotara	74	5,034	3,484	4,283
Whanganui	4,725	18,717	12,245	15,846
Waverley	1	908	907	907

Notes:

- The South System's Peak week was the week ending 19 September 2021.
- The calculation of Uncommitted Operational Capacity at Tawa is based on the minimum acceptable pressure at the inlet to both Tawa A and B being 10 barg. Although not defined in the Gas Transmission Security Standard, 10 barg is the minimum accepted pressure for distribution.
- Kapuni compression was modelled running continuously with a constant discharge pressure of 84 barg.
- Kaitoke compression was modelled running continuously with a discharge set pressure of 84 barg.
- 600 looping line regulated to 66 barg between Hawera Delivery Point and Kaitoke Compression.

Table 15: Frankley Road Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2022	FY2027	FY2032
Ammonia-Urea Plant	22,500	449	18,795	18,795
Kaimiro DP	0	25,194	153,129	153,129
Kapuni (Lactose	0	2,650	11,184	11,184
Kapuni GTP	25,000	26,215	78,686	78,686
TCC + Stratford 2 + Stratford 3	0	4,835	68,834	68,834

Notes:

- The peak week was the week ending 13 June 2021.
- While there are major sources of gas near the centre of the pipeline (Ahuroa) and at its southern end (Kupe), Ahuroa is not a continuous source while Kupe has an annual shutdown. Nor can either of these sources supply total demand on the pipeline. Modelling was therefore based on all gas entering the pipeline at Frankley Road, at a constant pressure of 44 barg, since that is more informative in relation to pipeline capacity.
- TCC refers to the DP for the Taranaki combined-cycle power station, Stratford 2 is the DP for the Stratford Peaker power station and Stratford 3 is the DP for the Ahuroa underground storage facility.
- The Taranaki Combined Cycle power station is anticipated to be closed by 2023.

Table 16: Maui System Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2022	FY2027	FY2032
Huntly Town	86	207,687	191,527	178,564
Pirongia (Three DPs)	1,577	150,011	147,454	142,942
Otorohanga	24	236,757	234,903	218,654
Ngaruawahia	10	191,510	177,408	166,522
Te Kuiti North	116	3,873	3,844	3,817
Te Kuiti South	654	8,295	8,260	8,231
Oakura	20	4,876	4,858	4,843
Mangorei	24,572	413,382	389,515	370,337
Rotowaro	101,124	243,691	221,522	203,869
Pokuru 1	25,764	241,737	220,613	204,158
Bertrand Road	101,396	277,447	258,373	243,399
Huntly Power Station	95,991	148,046	139,642	349,812

Notes:

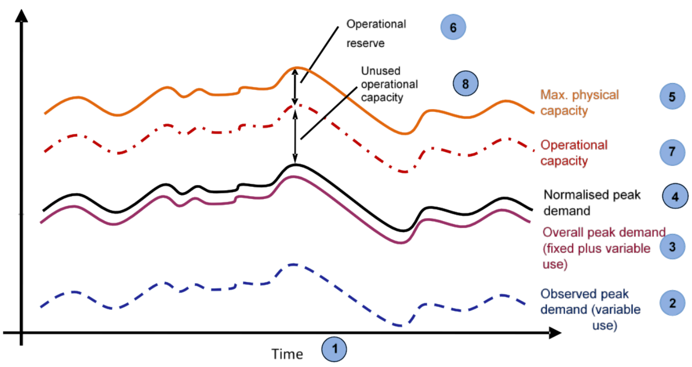
- The peak week for this system was the week ending 11 October 2020.
- On the Maui System, each Shipper's capacity for a day is its approved nominated quantity for that day, i.e., Shippers do not have rights to firm capacity. Therefore, "Aggregate Contractual Capacity" does not apply on the Maui System as it does on other pipeline systems.
- The table instead shows:
- "Peak Demand", i.e., the GJ taken on the first day of the system peak period at each Delivery Point, and
- "Operational Capacity" (i.e., the aggregate pipeline capacity available to each Delivery Point during the system peak period).
- Maui pipeline assumed running at a constant pressure of 46 barg at the Oaonui Production Station end.
- Mokau compression was modelled running continuously with a constant discharge pressure of 61 barg.
- The restriction of the Pukearuhe bypass line has been repaired in FY2022.

APPENDIX D: PIPELINE CAPACITY DETERMINATION

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

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

Figure 10: Overview Schematic for pipeline capacity determination



The steps to determine pipeline capacity are as follows:

- Select the time period that reveals the pipeline's peak demand cyclical performance, from pressure depletion to pressure 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 period

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.[26]

For most pipelines, the peak demand period is usually a sequence of high demand days (that 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[27]").

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[28]. 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 this method, 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[29] 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 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.[30] 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.

26. Indicating that a further such peak demand period would be sustainable.
27. 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 5-day peak should be understood to mean that the relevant 7 days are considered.
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. 27.
28. This may occur for several reasons, including operational reasons, coincident peak demand being higher than anticipated or shippers exceeding their capacity entitlements. Where there is compression at the inlet to a pipeline, First Gas generally operates it in a constant pressure mode (maintaining inlet pressure at relatively constant level).
29. 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.
30. 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.

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.[31]

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, they might in the future. 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 fourth 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[32] 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 out 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 fifth 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.

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.[33] 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 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

31. As discussed in the System Security Standard.
32. The Bay of Plenty pipeline does not display a strong overall winter peak.
33. 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.

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, 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[34]. 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[35] redundancy (as set out in the system security standard). However, a redundant compressor may also fail, or fail to start,[36] 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 must 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.

34. 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.
35. 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.
36. 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

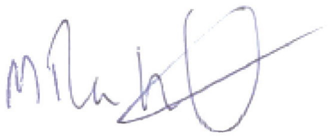
Clause 2.9.1

We, Mark Adrian Ratcliffe and Fiona Ann Oliver, 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: Mark Adrian Ratcliffe

Date: 29 July 2022

Director: Fiona Ann Oliver

Date: 29 July 2022