Firstgas

GAS TRANSMISSION BUSINESS

Asset Management Plan Update

Year commencing 1 October 2021

First Gas Limited
September 2021

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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 Gas Transmission Asset Management Plan Update (AMP) for 2021.

This year has seen a rapidly evolving energy market, primarily driven by a policy and legislative target of net zero carbon emissions by 2050 and the release of the Climate Change Commission's (CCC) final recommendations to Government. Together these represent a significant challenge to Firstgas but also present new opportunities.

Firstgas is committed to helping New Zealand reach its target of net zero emissions by 2050 and we believe gas has a big part to play in New Zealand's energy future. To achieve this target, while keeping energy prices affordable, we support an approach that involves the decarbonisation of multiple energy distribution channels, including gas networks.

For over two years, Firstgas has had a dedicated workstream investigating net zero carbon gases, such as hydrogen, biomethane, and bioLPG. In March 2021, we released our Hydrogen Feasibility Study. Our research shows that we can introduce hydrogen into the Firstgas pipeline network from 2030 and convert to 100% hydrogen by 2050. This step would reduce New Zealand's energy emissions by nearly 25%. In June 2021, we released a joint Biogas study with Beca, Fonterra and EECA which revealed that biomethane is a viable, untapped solution to decarbonising New Zealand's natural gas network right now, with the potential to replace nearly 20% of New Zealand's total gas usage by 2050. Developing these technologies will help us provide low emissions options for our customers in the future. In fact, 82% of respondents at an AMP webinar we held said they support our work to date on the use of net zero carbon gasses on our network.

Over the past year, Firstgas continued its focus on improving the performance of our network and managing risk, while also enabling system growth and increasing the number of customers connecting to our network. Firstgas has continued to deliver on our significant capital works programme and good progress has been made on the Pariroa defect and Gilbert Stream realignment project to increase the resilience of the transmission network. Our compression strategy continues, albeit with refinements to reflect the policy uncertainty resulting from the release of the CCC's final report. Our priority is to ensure the reliability of our oldest units, as well as reducing emissions and fuel costs.

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. We will continue to invest and maintain our existing gas infrastructure, as well as start to develop our network to be able to service the future demand for net zero carbon gases.We feel that it is in everyone's' interests to use the 2022 – 2027 regulatory control period to start these activities. This will help us maintain stable prices and retain the quality and reliability of our transmission service.

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. Firstgas is proudly connecting with kiwis every day to make sure their energy needs are met right now, and in the future. Investigating innovative technology is part of New Zealand's journey to cutting emissions but we need the sustainability, reliability and affordability of gas to help get us there.

I hope you find the 2021 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

Goodeve

Paul Goodeve
Chief Executive

GLOSSARY

TERM	DEFINITION
AMMAT	Asset Management Maturity Assessment Tool. Results of the AMMAT are published in a full AMP. Any material changes to the asset management maturity rating results between AMPs are published in the AMP update
AMP	Asset Management Plan
Asset grades	Grade 1: means end of service life, immediate intervention required Grade 2: means material deterioration but asset condition still within serviceable life parameters. Intervention likely to be required within three years Grade 3: means normal deterioration requiring regular monitoring Grade 4: means good or as new condition Grade unknown: means condition unknown or not yet assessed
Capex	Capital expenditure – the expenditure used to create new or upgrade existing physical assets in the network, as well as Non-network assets, e.g. IT or facilities
CCC	Climate Change Commission
COO	Chief Operating Officer
CP	Cathodic protection
CPP	Customised Price-Quality Path
CPU	Central Processing Unit
DP	Delivery Point
DPP	Default Price – Quality Path
FEED	Front End Engineering Design
FY2021	Financial year ending 30 September 2021
GDB	Gas Distribution Business
GIC	Gas Industry Company – New Zealand's gas industry co-regulatory body
GIS	Geographical Information System
GM	General Manager
GMS	Gas Measurement System – commonly referred to as a gas meter
GPB	Gas Pipeline Business
GTAC	Gas Transmission Access Code – the proposed single code for the transmission system, that sought to replace the existing two commercial codes, Maui Pipeline Operating Code and the Vector Transmission Code. The project has been discontinued.
GTB	Gas Transmission Business
HSEQ	Health, Safety, Environment and Quality
ICP	Installation Control Point
IMs	Input Methodologies – documents set by the Commerce Commission which promote certainty for suppliers and consumers in relation to the rules, requirements, and processes applying to the regulation under Part 4 of the *Commerce Act 1986*
IS	Information Systems
IT	Information Technology
KGTP	Kapuni Gas Treatment Plant
KPI	Key Performance Indicators
MAHI	Maximo Asset Health Insights
MLV	Main line valve
NZTA	New Zealand Transport Agency
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)
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
PJ	Petajoule (unit of energy). $10^{\wedge 15}$ joules = 1,000 TJ
RAB	Regulated Asset Base
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*.
RTE	Response time to emergencies
SCADA	Supervisory control and data acquisition
TJ	Terajoule (unit of energy) = 10^{12} Joules
UAV	Unmanned aerial vehicle

EXECUTIVE SUMMARY

This is First Gas Limited's (Firstgas) Gas Transmission Asset Management Plan Update (AMP Update) for 2021.

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 a group of companies consisting of Rockgas, Firstgas, Flexgas and Gas Services NZ. Firstgas and Rockgas are consumer brands that supply natural gas and LPG to over 165,000 customers through their gas network of high-pressure transmission pipeline and distribution pipeline in the North Island, 36 local LPG suppliers, and over 180 Refill & Save locations across New Zealand.

Flexgas and Gas Services NZ are energy storage, operations and maintenance brands who make sure gas is delivered safely and continuously. 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

For our gas transmission business, this means that we are focused on transporting gas across the North Island to meet the diverse needs of our customers, be it 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 and starting to develop our network to service the future demand for net zero carbon 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. We will invest where it is economic, given the expected decline in natural gas demand, while ensuring we have the capacity to support the deployment of net zero carbon gases.

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.

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 implementation of our compression strategy this year is a key focus, with our intention to update and simplify an ageing fleet of compressor units, by utilising singular modular compression packages. This approach will improve reliability, security of supply and provide flexibility, allowing units to be relocated to match future changing system loads and opportunities.

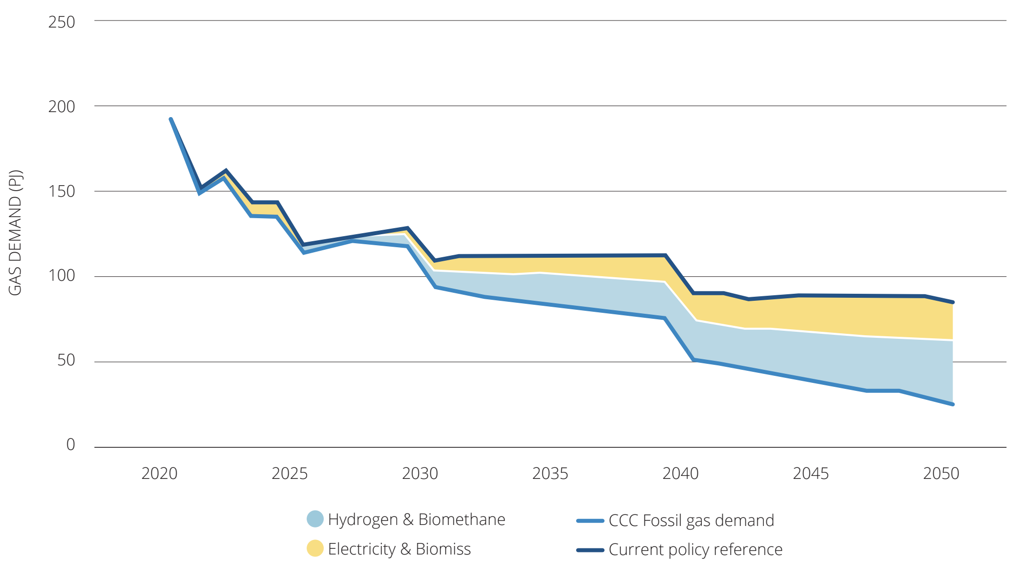
  Our asset management improvement programme also incorporates building on the work we have done in FY2021. The delivery of our Maximo Asset Health Insights (MAHI) application will provide us with a powerful tool to assisting in our planning.
- **A strong culture around health and safety:** Safety is at the forefront of how we approach managing and operating 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.
- **Mitigating and managing risk:** The consideration of risk plays a key role in our asset management decisions. In 2019, the Commerce Commission engaged AECOM to review our risk management practices. This year we requested that AECOM return to review our progress since the 2019 report. We are very pleased with the outcome of AECOM's 2021 report, that highlights our improvements and commitment to continuous improvement around managing risk.

- **Preparing the business for future challenges and opportunities.** We are in a rapidly evolving energy landscape, with significant change driven by New Zealand's legislated target for net zero carbon emissions by 2050 and the release of the Climate Change Commission's (CCC) final advice to Government. Together, these drivers provide significant challenges and opportunities for Firstgas. We are committed to being part of the solution to reduce emissions, while ensuring that gas has ongoing role in New Zealand's energy future.We believe that a more diverse energy portfolio will provide more resilience for our country, as well as be more affordable for all New Zealanders.

  Therefore, we are focused on ensuring we maintain our existing infrastructure to an appropriate standard to meet customer needs, while making economic investments aligned with the expected decline in natural gas. Figure 1 outlines the long-term forecast demand for gas, as modelled by the CCC.

  We are also developing our network to ensure it has the capacity to meet the future deployment of net zero carbon gases. Over the last two years, we have had a significant programme of work underway to investigate the potential for zero carbon gases such as green hydrogen and biogas. Figure 1 highlights the proportion of gas demand that could be met by the introduction of hydrogen and biomethane.

Figure 1: Net Zero Carbon Gases



ACTIVITIES PLANNED FOR THE COMING YEAR

The focus for the coming year (FY2022) 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 2 and Figure 3, with the forecasts from last year's AMP shown in the red line.

The overall impact over the 10-year planning period is a reduction in forecast Capex. We believe that this is prudent given the uncertainty we are facing from the CCC final advice and subsequent government policy, however we also believe that the resulting Capex is consistent with achieving a service standard and maintaining reliability.

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

Changes within the current regulatory period (FY2018 – FY2022)

- Two customer driven connections have been initiated for FY2022 – new dairy factories in Otorohanga and in Tokoroa with a forecast expenditure of $2 million.
- We are moving into the execution phase of the compression strategy. This work will address aging assets and the high maintenance costs associated with two compression sites. We are forecasting an additional $12 million in FY2022 under our compressor expenditure to replace the compressor units.
- Reduced forecast costs for FY2021 resulting from the decision not to proceed with the Gas Transmission Access Code (GTAC) implementation project.

Changes within the regulatory periods 3 and 4

The uncertainty resulting from the CCC's final advice has prompted us to refine our mid to long term planning forecasts through the planning period. This has resulted in an overall reduction in expenditure over the next two regulatory control periods and a 12% reduction in Capex over the ten-year planning period.

The key changes compared to the 2020 AMP are:

- Changes in the delivery plan for the compression strategy. Originally, we had planned to replace compressors at four strategic sites. The programme of work now focuses on two sites, equating to reduction of $60 million in compressor expenditure over the planning period.
- A reduced forecast for customer connections that results in a $5 million reduction over the planning period.
- A reduced forecast for system growth that results a $10 million forecast reduction over the planning period.
- An increase in forecast IT expenditure associated with system security, modernising infrastructure, and key system upgrades of $12 million over the planning period.

Figure 2: Forecast total Capex (all figures in FY2021 prices)

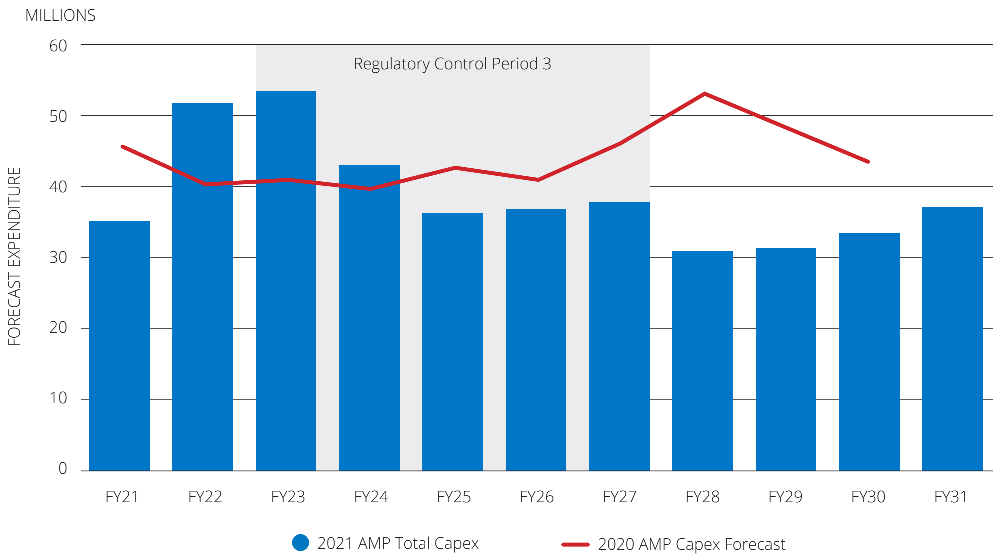
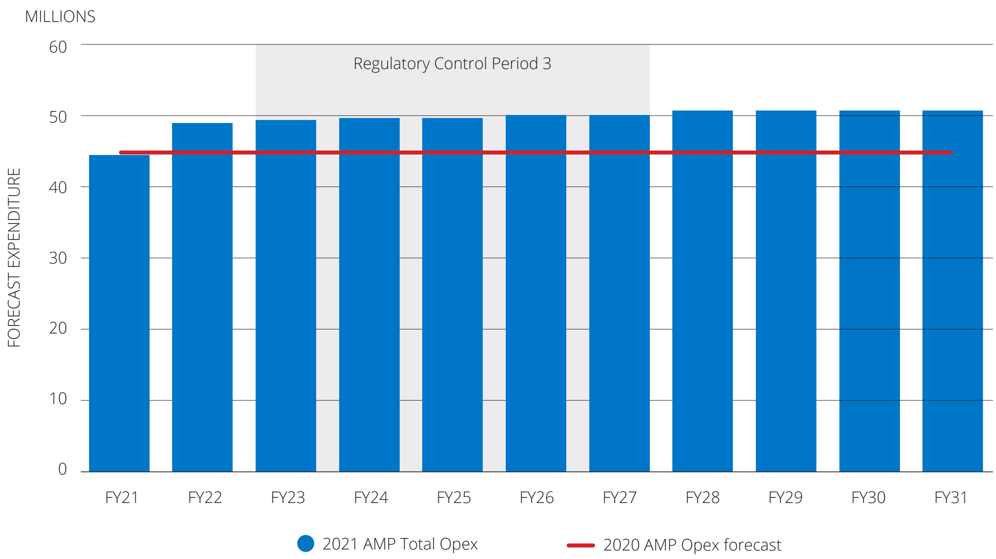


Figure 3: Forecast total Opex (all figures in FY2021 prices)



Operational expenditure forecast

Our forecast operational expenditure (Opex) over the planning period, compared to that Opex published in our 2020 AMP, is set out in Figure 3.

Over the course of the planning period, our base maintenance costs are anticipated to remain steady. The increase in Opex is primarily attributable to higher compressor fuel costs. This increase represents a 11.7% increase in costs over the planning period and is due to tightening market conditions for gas and growing the use of renewable gas (biomethane and hydrogen) over time.

We have included in our Opex forecasts approximately $3.6 million (total) over the planning period for our net zero carbon gas trial programme.

Risk and performance of the transmission system

We have developed a high-level overview of the risk profile of our transmission system and how we anticipate that this will change over the course of the planning period. Overall, our assets are in a good condition, and we anticipate very little change through the next regulatory control period. Our risk management framework provides a methodology to manage our existing risks. Typically, individual risks are assessed in isolation to determine best mitigation measures, but this does not provide easy visibility of cumulative risk where different risks affect a single asset.

To address this approach, we have implemented Maximo Asset Health Insights (MAHI) application that provides an overall asset health score. We can then use the individual risk and overall asset health score to better support our investment decisions.

Measuring performance

A key premise for the AMP Update is that existing reliability, safety, and supply quality levels will be maintained and improved. We have met our required quality standards, as set by the Commerce Commission. All our performance measures are outlined in the year in review section.

1. INTRODUCTION

This is First Gas Limited's (Firstgas) Gas Transmission Asset Management Plan Update (AMP Update[1]) for 2021.

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 2021 AMP Update and provides an overview of the material changes from our AMP published in 2020. We also set out the key regulatory and environment changes that are influencing our gas transmission business.

1. 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 (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 2020 AMP 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 and
8. Contain the information set out in the schedules described in clause 2.6.6 [Schedules 11a, 11b, 12a and 12b].

For a complete understanding of the basis for our asset management decisions over the planning period, we recommend that this AMP Update be read in conjunction with our 2020 AMP.

1.3 PERIOD COVERED BY THE AMP

The AMP Update covers a ten-year forecast period from 1 October 2021 through to 30 September 2031 (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 2021 prices (unless otherwise stated).

The 2021 Firstgas AMP Update was approved by our Board of Directors on 11 August 2021.

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 published in 2020. It describes what we have achieved over the past 12 months, and the key activities for the coming year. 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 2020 AMP for our gas distribution business is available on our Firstgas website.[2]

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[3] and the Ahuroa gas storage[4] facility. Rockgas has over 80 years' experience and provides LPG to 100,000 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.

2. More information on our gas distribution business is available here: https://firstgas.co.nz/about-us/regulatory/distribution/
3. More information on Rockgas: https://rockgas.co.nz
4. 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 2021 AMP Update and relevant 2020 AMP appendices

AMP SUMMARY 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 2020 AMP.

The AMP Update incorporates

- **Appendix A:** Summary of material changes and compliance
- **Appendix B:** Information disclosure schedules
- **Appendix C:** Pipeline capacity determination
- **Appendix D:** Capacity forecasting methodology
- **Appendix E:** Responses to Webinar questions
- **Appendix F:** 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 I	Expenditure overview
Appendix J	Security of supply
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 First Sentier Investors, part of the Mitsubishi UFJ Financial Group. 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.[5]

On 20 April 2016, Firstgas took control of Vector Limited's gas transmission assets (along with Vector's gas distribution assets located outside Auckland). In a separate transaction on 15 June 2016, Firstgas took ownership of Maui Development Limited's gas transmission assets (the Maui pipeline). The creation of Firstgas is the first time that gas transmission assets in New Zealand have had a common owner. 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
- An opportunity to bring new capabilities to our team to drive growth in the use of the gas transmission system
- An ability to operate the gas transmission system and manage our assets in ways that better serve the interests of our customers.

We recognise that for most customers, gas is an optional fuel. Unlike electricity, which is universally used by households and businesses, reticulated natural gas is not a necessity in New Zealand. This means that gas must be cost-effective and will often need to be actively marketed to compete with other energy options. 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

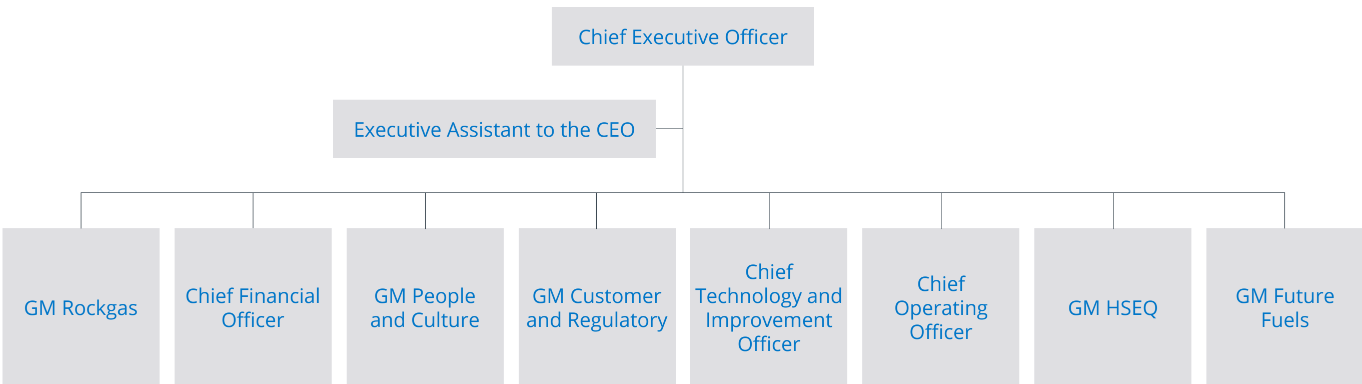
Firstgas has approximately 222 staff, with most staff based in our corporate headquarters in Bell Block, New Plymouth, with small teams located in Wellington, Auckland, Palmerston North and Hamilton. Our Executive team is headed by our Chief Executive Paul Goodeve, with eight direct reports.[6] Our organisational structure is illustrated in Figure 4 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[7] (ex-Vector) transmission pipelines, as set out in Figure 5.

The transmission system is 2,517 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.

Figure 4: Organisation chart



5. More information on First Sentier Investors is available on their website: https://www.firstsentierinvestors.com.au/au/en/institutional/about-us/corporate-profile.htmll\
6. Firstgas reviewed our organisational structure in July 2021.
7. The gas transmission system purchased off Vector Limited in April 2016.

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 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 2021, 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 5: High pressure gas transmission pipelines

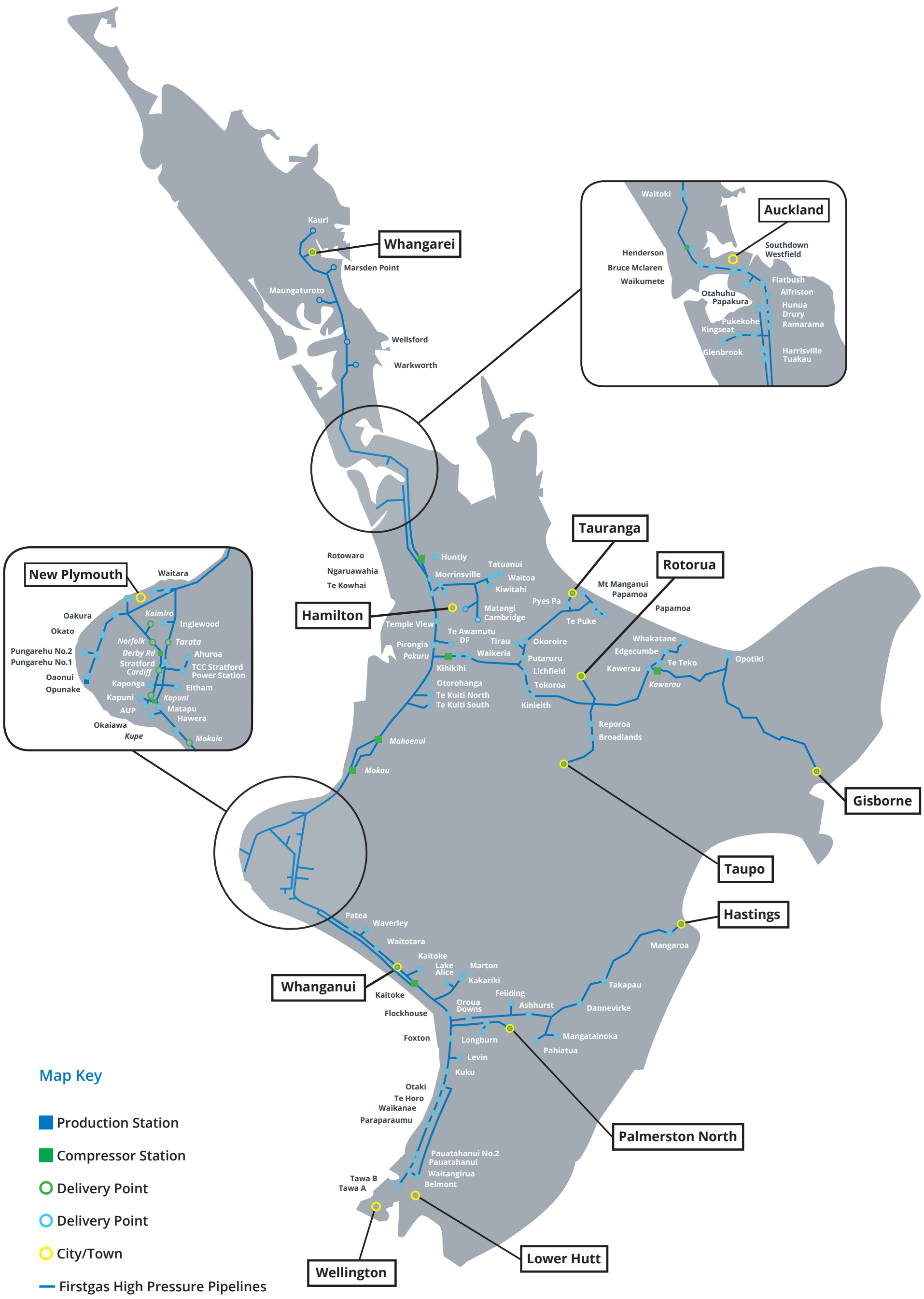


Table 2: Key gas transmission statistics as at 1 June 2021

STATISTIC	VALUE	CHANGE FROM 2020
System length (kilometres)	2,517	3
Compressor stations	9	0
Compressor units	20	0
Delivery points	131	0

The additional three kilometres of the pipeline relates to pipeline installed for the Pariroa Defect bypass, the Transmission Gully project, and other minor works on the system.

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 and 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.
- **Asset Management system:** This system links our corporate objectives and stakeholder needs to specific asset management approaches through our Asset Management Policy. It aligns with the requirements of ISO 55001, the international standard for asset management, and seeks to reflect good practice.
- **Performance measures:** These documents set out the overall asset management performance objectives and the key performance indicators (KPIs) that 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.

AECOM risk management practice review

In May 2019, the Commerce Commission engaged an external expert (AECOM[8]) to assess the risk management practices applied by gas pipeline businesses (GPBs) against an internationally recognised risk management framework.

Figure 6 shows the gap analysis summary from AECOM's 2019 report for Firstgas' transmission business, in terms of asset knowledge, strategic planning processes, asset management practices, information systems and organisational tactics. The report highlights key strengths with the businesses, as well as identifying gaps in the risk management practices. We have used the report to direct our asset management improvement initiatives over the course of the last 18 months.

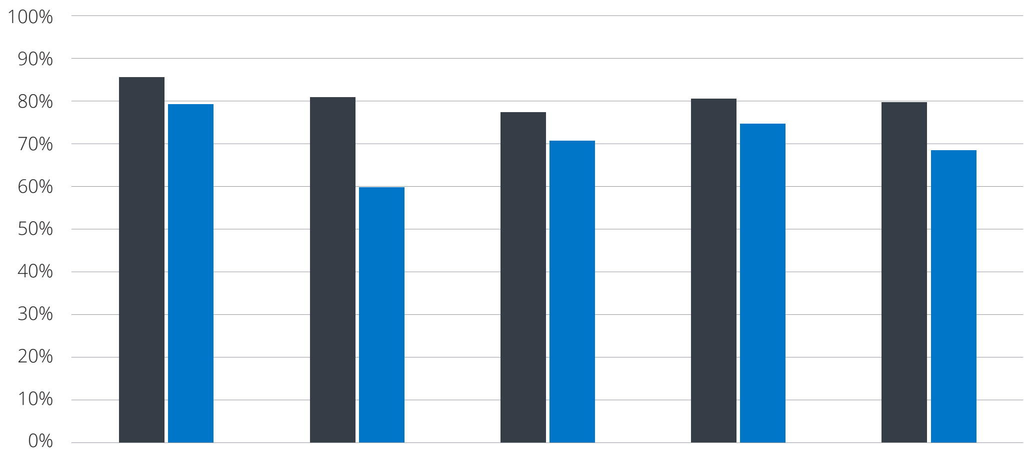
In 2021, we engaged AECOM directly to review our progress since its 2019 report. They have identified several key areas where we have improved:

- More considered application of risk management to the Mangapukatea erosion mitigation strategy
- Alignment of practices between our gas transmission and distribution businesses
- Increased stakeholder engagement
- Increased identification of risk events and velocity of risk resolution through our systems
- Development of formalised strategies to inform major activity classes with risk management an integral part of the strategies
- Capture of additional geospatial information within GIS and use of this to refine strategies and plans.

Based on the 2021 AECOM report, we are now achieving minimum best appropriate practice across all the assessment categories, and near or above best appropriate practice in the areas of asset knowledge and asset management practices.

We also took the opportunity to undertake a high-level review of our Asset Management Maturity assessment (AMMAT) against the outcomes of 2021 AECOM review. We believe that we have met and exceeded our AMMAT target score of 3. This will be formally reviewed with our next full AMP publication.

Figure 6: 2019 AECOM transmission business Gap Analysis Report



	Asset Knowledge	Strategic Planning Processes	Asset Management Practices	Information Systems	Organisational Tactics
Best Appropriate	85%	80%	77%	80%	79%
Current	79%	59%	70%	74%	68%

8. The report is available through the Commerce Commission website https://comcom.govt.nz/regulated-industries/gas-pipelines/gas-pipelines-performance-and-data/summary-and-analysis-of-information-disclosed-by-gas-pipeline-businesses/risk-management-review-of-gas-pipeline-businesses?target=documents&root=176809.

We welcomed the 2021 AECOM review as it gave us an opportunity to demonstrate to an external party how we manage risk and the context of our business, and to also demonstrate the improvements we have made. The review has also informed us of the areas that we can continue to improve on.

Addressing geohazards on our network

The impact of geo-hazards 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 has 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) survey 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 (IMU) 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.
- Drones will be used where efficient to support walking surveys. They are able to cover large distances quickly and across areas that are unsuitable or unable to be accessed by the walking survey team. The walking survey team will review the drone data before submitting the geohazard risks to us in an electronic form that can be loaded into the GIS.

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.

2.5 OUR APPROACH TO HEALTH AND SAFETY

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.

Figure 7: Firstgas First Principles

First Principles

RESPECT THE RISK	UNDERSTAND THE WORK	HARNESS KNOWLEDGE	LISTEN, LEARN, IMPROVE	WORK TOGETHER
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.	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'.	We trust in the expertise of our team to deliver successful work. We move decisions to where the expertise lies.	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.	We value the skills and experiences of different teams and work together to embed HSEQ into successful work.

Asset integrity and our asset management practices outlined in this AMP Update are, therefore, crucial in maintaining safe outcomes.

Firstgas understands that one of the key factors in HS&E excellence is leadership and accountability. Leadership is required from all layers across the organisation, 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.

2.6 CHANGES IN THE REGULATORY AND POLICY ENVIRONMENT

This year has seen a rapidly evolving energy market, primarily driven by the Government's legislative target of net zero carbon emissions by 2050, the release of the Climate Change Commission's (CCC) final recommendations to Government and a large suite of climate change policies and measures being drafted by government agencies. Together these factors represent a significant challenge to Firstgas, with an expected decline in natural gas over the long-term, as modelled by the CCC. However, the changes present new opportunities for the business, with the deployment of net zero carbon gases such as green hydrogen and biogas.

This is occurring at a time when Firstgas is also approaching the next DPP reset for both our gas transmission and distribution business, where the Commerce Commission will set our price quality path for 2022 – 2027. The Commission must also complete a review of the underlying Input Methodologies (IMs) for regulated energy businesses by December 2023. The outcome of these two regulatory workstreams will impact the forecast expenditure that we have set out in this AMP Update.

Swift Government action to address climate change

The Climate Change Commission (CCC) released its final advice in June 2021, setting out the first package of advice to Government on the actions it must take to reach 2050 target. This final advice was informed by extensive consultation with stakeholders and the public, with the CCC receiving over 15,000 submissions. A copy of Firstgas Group's submission to the CCC is available on our website **here**.

In its final report, the Commission has removed the proposed ban on new gas connections, and its initial recommendation to replace gas appliances with electric alternative. We strongly opposed these measures in the CCC's initial report as we believe that the CCC should look to rule options in, rather than out with seeking to reduce emissions.

The CCC's final report now focuses on determining how to best eliminate fossil gas use in residential, commercial, and public buildings, proposing action such as:

- Setting a date to end the expansion of pipeline connections to safeguard consumers from the costs of locking in new fossil gas infrastructure
- Evaluating the role of low-emission gases as an alternative use of pipeline infrastructure
- Determining how to transition existing fossil gas users to low emissions alternatives.

The final report recommends Government sets a target for 50% of all energy consumed comes from renewable sources by the end of 2035; supports the development of bioenergy and hydrogen; and evaluates the role of biogas and hydrogen as an alternative use of pipeline infrastructure.

Firstgas commended the CCC for retaining energy options in its final advice to government and acknowledging the important role of net zero carbon gas may have in reducing New Zealand's carbon emissions by 2050. We also support the CCC's recommendation that Government commits to delivering a national energy strategy to decarbonise the system in collaboration with energy-system stakeholders. The Government now has until the end of this year to respond to the CCC report and set the first three emissions budgets for New Zealand.

Firstgas is already seeing the release of several Government consultation documents on areas that directly impact on our businesses and the likely future demand for natural gas. For example:

- The Ministry for the Environment (MfE) has consulted on phasing out fossil fuels in process heat by using National Environmental Standards (NES) or National Policy Statements (NPS) under the *Resource Management Act 1991*.[9]
- MfE is also consulting on changes to the New Zealand Emissions Trading Scheme (ETS), which will enable carbon prices to better align with carbon budgets.[10]
- The Ministry of Business, Innovation and Employment (MBIE) is working with the Energy Efficiency and Conservation Authority (EECA) to improve process heat's energy efficiency and increase renewable energy.[11] MBIE is expected to release the draft Emissions Reduction Plan for the heat, industry and power sector component of the energy sector later this year.
- The Government is preparing to reform the *Resource Management Act 1991* (RMA), seeking to replace is with three new acts. At the time of writing, parliament was consulting on its proposed Natural and Built Environments Act (NBA) that would provide for land use and environmental regulation and be the primary replacement for the RMA)

9. *Phasing out fossil fuels in process heat*, Ministry for the Environment, April 2021, https://consult.environment.govt.nz/climate/phasing-out-fossil-fuels-in-process-heat/supporting_documents/phasingoutfossilfuelsinprocessheat.pdf
10. Proposed changes to NZ ETS and SGG levy regulations 2021, Ministry for the Environment, April 2021, https://consult.environment.govt.nz/comms/proposed-nz-ets-changes2021/supporting_documents/proposedchangestoNZETSandSGGlevyregulations2021.pdf
11. Consultation on this was undertaken through *Discussion Document: Accelerating renewable energy and energy efficiency*, MBIE, December 2019, https://www.mbie.govt.nz/dmsdocument/10349-discussion-document-accelerating-renewable-energy-and-energy-efficiency

- The Gas Industry Company (GIC) is undertaking a market investigation into role of gas in supporting the energy transition and the fitness of current market, commercial and regulatory settings to support decarbonisation (at request of the Minister for Energy and Resources).[12]

Firstgas is actively engaging 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. We are also outlining and demonstrating the potential for net zero carbon gases in our transition to net zero emissions and advocating for policy settings that will support this opportunity.

Impact on upcoming DPP reset and IMs review

Government action on climate change policy is occurring at the same time as the Commerce Commission is preparing to commence two key work streams:

- The DPP reset for gas pipeline businesses for the next regulatory control period (2022 – 2027). Decisions on our price-quality path will need to be determined by the end of May 2022.
- A review of the Input Methodologies for GPBs, electricity distribution businesses and airports. This IMs review must be completed by December 2023.

To help guide this work, the Commission released an open letter seeking views on emerging issues for electricity networks, gas networks and airports in relation to Part 4 regulation under the *Commerce Act 1986*. The Commission wanted to understand how it should prioritise these issues when planning its work programme in the near term. Our submission on this open letter outlined the emerging issues we see facing the gas sector, and why in our view the existing regulatory rules are no longer fit for purpose for the environment we face in the upcoming regulatory control period. We outlined to the Commission our view that the next DPP reset for GPBs (2022 – 2027) should focus on ensuring three outcomes:

1. Reducing the risk of future price escalation and economic asset stranding
2. Continuing to provide sufficient incentives to invest to maintain reliable gas infrastructure
3. Preserving the option of using gas infrastructure for net zero carbon gases in the future

The Commission released its DPP reset process and issues in paper in early August 2021. Firstgas welcomes the opportunity to engage with the Commission and stakeholders throughout this process and discuss how we can ensure a regulatory framework that supports New Zealand's transition to net zero carbon emissions and the opportunities for net zero carbon gases.

12. *Gas Market Settings Investigation consultation paper*, Gas Industry Company, May 2021, https://www.gasindustry.co.nz/work-programmes/gas-market-settings-investigation/developing-2/consultation-3/document/7263

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.

We support the transition to a zero-carbon emissions future and welcomed the recent release of the Climate Change Commission's (CCC) final report, outlining the actions that are needed for New Zealand to obtain zero-carbon by 2050. We consider that net zero carbon gases will play a part in this transition – gas plays a role in all future energy scenarios modelled and provides greater resilience to New Zealand's energy portfolio through diversification with green hydrogen and biogas. We have discussed these opportunities with government departments and await the release of the Government's response to the CCC final report.

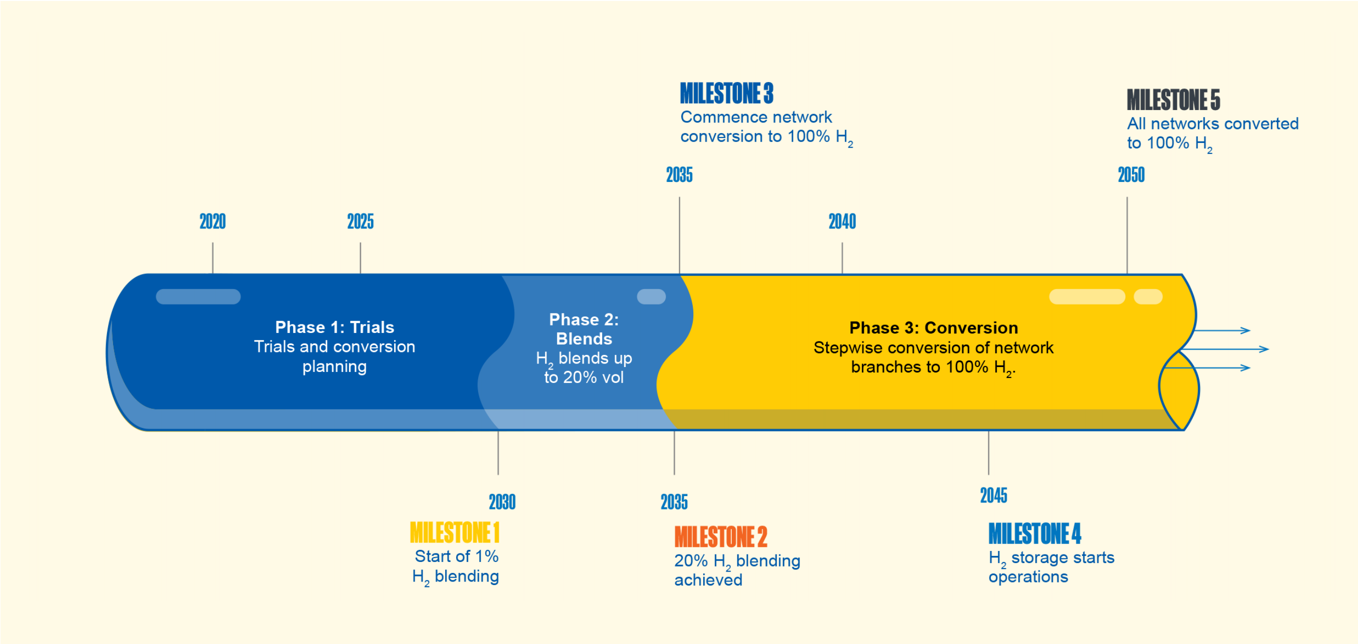
Firstgas has established a work programme to explore the potential for net zero carbon gases and how we can develop our network to be able to service this future demand.

3.2 HYDROGEN

In March 2021, we released our report[13] into whether green hydrogen can be used in New Zealand and transported via the existing gas pipeline network. Our report concluded that hydrogen is viable in a zero carbon energy system and that it is feasible to convert Firstgas pipelines to hydrogen — initially as a blend, and then to 100% in the future.

The next phase of our work is to begin live trials of hydrogen.

- **Phase 1** 2020 – 2030 Trials and conversion planning
- **Phase 2** 2030 – 2035 Blends hydrogen up to 20% volume
- **Phase 3** 2035 – 2050 Conversion of network branches up to 100% hydrogen.

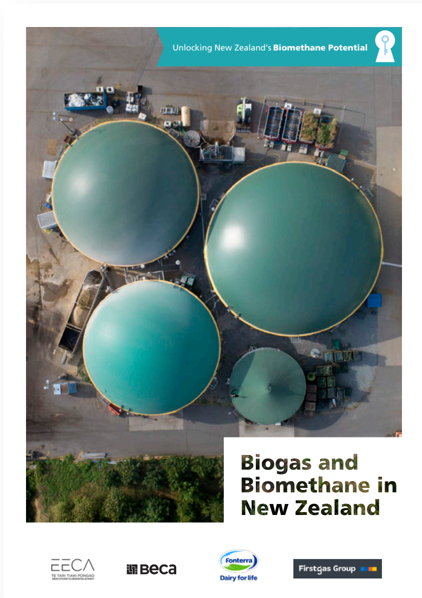


3.3 BIOMETHANE

In addition to hydrogen, we believe that biomethane will also form part of the transition to net zero carbon 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. The technology for biomethane production is mature and with treatment, biomethane can be used as a direct replacement for methane in our gas pipeline.

In June 2021, we released a joint Biogas study[14] with Beca, Fonterra and EECA which revealed that biomethane is a viable, untapped solution to decarbonising New Zealand's natural gas network right now, with the potential to replace nearly 20% of New Zealand's total gas usage by 2050.

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.



13. Bringing Zero Carbon Gas to Aotearoa: Hydrogen Feasibility Study – Summary Report, Firstgas Group, 29 March 2021, https://gasischanging.co.nz/our-path-to-zero-carbon-gas/hydrogen-trial-results/
14. Biogas and Biomethane in New Zealand. The report is available through the Beca website: https://www.beca.com/ignite-your-thinking/ignite-your-thinking/july-2021/biogas-and-biomethane-in-nz-report

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 2021 AMP Updates and on relevant aspects of the 2022 DPP reset process, 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 structured workshops with stakeholders to discuss our work to date on GTAC implementation, the GTAC review, and our subsequent decision not to proceed with the GTAC.
- Held bilateral meetings with individual shippers to get a more thorough understanding of their views. This has provided an opportunity for them to engage with us in an open manner that has helped shape a path forward on projects.
- Attended 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 and respective views on key government workstreams.
- Held regular meetings with our large gas users to better understand their business requirements and how we can best service them.
- Commenced periodic meetings with gas producers to discuss relevant issues and opportunities from improvement around gas quality and compliance with the gas specification.
- Increased 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.
- Conducted ongoing stakeholder engagement with customers, landowners, local Iwi and community was undertaken to regularly update these groups on the Gilbert Stream realignment and Pariroa projects.

4.2 AMP 2021 WEBINAR BRIEFING

In a first for our gas transmission business, Firstgas held a webinar in June 2021 to update stakeholders on the preparation of our 2021 AMP Updates (for both our gas transmission and distribution businesses). During this session, we provided an overview of the activities that we see as shaping the next 12 months and beyond, covering:

- The Pariroa and Gilbert stream projects
- Our compression strategy
- IT expenditure
- The "Gas is Changing" strategy and the possibilities of using our networks to distribute net zero carbon gas, such as green hydrogen and biogas in the future
- The upcoming DPP reset for 2022 – 2027.

The webinar was interactive, with attendees able to ask questions and respond to polling questions raised in the session. Figure 8 sets out insights we gained from the live polling and **Appendix E** outlines the questions and answers addressed during webinar.

A recording of the webinar is available **here**.

What has changed as a result of stakeholder feedback?

Firstgas has used the feedback and comments from our stakeholder consultation to inform the preparation of the final 2021 AMP Updates. From what we have heard is that our stakeholders want to see us continue to provide a reliable and sustainable network that is clearly oriented towards the future to ensure gas remains an important part of New Zealand's net zero carbon energy mix.

Figure 8: Polling questions and results

ATTENDEES QUESTIONS — 39 STAKEHOLDER RESULTS

Which **one** of these outcomes is most important to you/what should Firstgas' core focus be?

- Safety
- Reliability
- Price/Cost
- Risk

Reliability received the most votes. Followed evenly by safety, price/cost and risk.

Of the areas discussed in today's webinar, which is the one that you would like to see **more** emphasis from Firstgas?

- Gas is changing
- Growth and customer connections
- Compression strategy
- Geohazards
- IS and security of corporate information
- None

Gas is changing ranked highest. Others mixed.

Of the areas discussed in today's webinar, which is the one that you would like to see **less** emphasis from Firstgas?

- Gas is changing
- Growth and customer connections
- Compression strategy
- Geohazards
- IS and security of corporate information
- None

All answers split. 'None' slightly higher (50%). IS / security and Growth slightly lower.

Do you support our work to date on the use of net zero carbon gases in our network?

- Yes, I support it
- I only support some of it
- No, I do not support it
- Unsure

Yes came out the highest (82%). Two were unsure. None voted 'no.'

How do you find Firstgas' level of communication and engagement with you?

- Too sparse, I would like to hear from you more regularly
- About right, I am happy as is
- Too much, I would like to hear from you less

The majority think it is **about right and happy**. Two voted that they would prefer more.

4.3 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 and distribution 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 and work practices around our pipelines. It also seeks feedback from our stakeholders to improve the way we work with them, how we communicate, the key messages and how we manage the impact of our work activities on their land.

We continue to re-examine and improve our stakeholder management and create new ways of engaging with stakeholders to grow and sustain long lasting relationships that benefit all parties.

Fostering strong relationships

In 2021, Ngāti Tama iwi and the Firstgas Group have developed a strong and collaborative relationship that has enabled the iwi to reconnect with their ancestral land. The $13 million Gilbert Stream project near Pukearuhe in North Taranaki involves moving 370 metres of high-pressure gas pipeline inland because of cliff erosion. The pipeline travels through the iwi's ancestral land and Ngāti Tama's involvement has led to the discovery of artefacts from an historical Maori settlement along the coastline.

> *"I genuinely appreciate the respect they have* ***demonstrated.*** *It was new for Ngāti Tama to work with Firstgas and contractors, Whitaker Civil Engineering and Energy Works, and it was a new concept for them too.* ***We have established a healthy working relationship*** *with Firstgas, also with the other contractors on site".*
>
> *Tāngata Tiaki – Cultural Monitor of Ngāti Tama Rae-Hinerau Wetere*

Figure 9: Engaging with local communities carrying out riparian planting

4.4 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.

5. YEAR IN REVIEW

This section provides an overview of Firstgas' major projects and initiatives over the past year ending 30 September 2021 (FY2021). We review our forecast expenditure against the plans stated in our 2020 AMP 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 variance in expenditure for FY2021 relates to the decision not to proceed with the GTAC project. Following a review of the project, it was confirmed with stakeholders that the project would be discontinued, and no additional expenditure is forecast under the existing project.

Our Opex forecast for FY2021 is aligned with what was published in the 2020 AMP.

Figure 10: Total Capex in FY2021 versus forecast expenditure in 2020 AMP

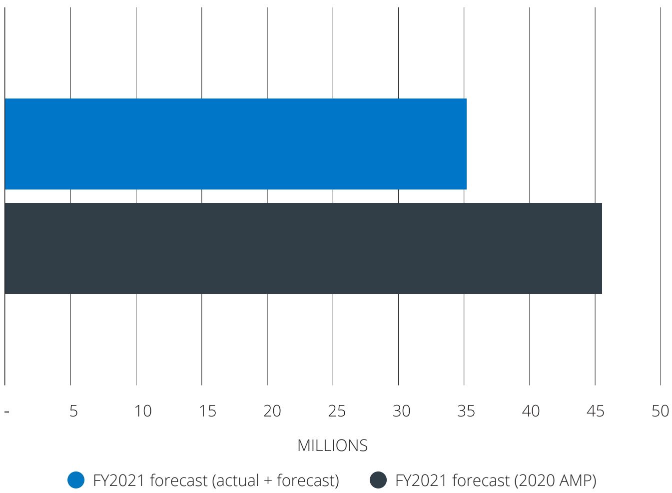
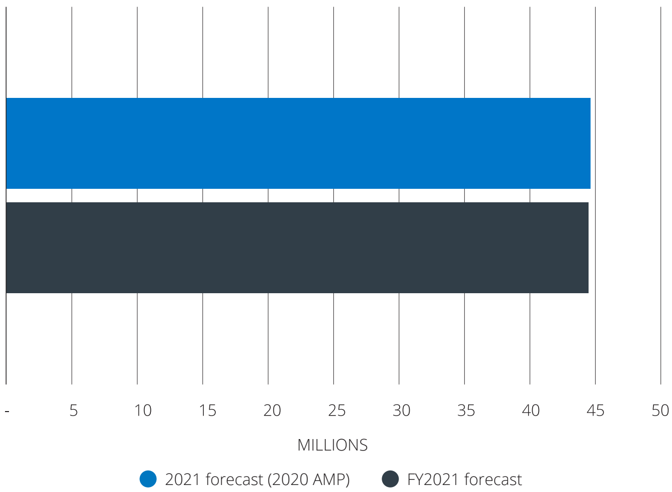


Figure 10: Total Opex in FY2021 versus forecast expenditure in 2020 AMP



5.2 SIGNIFICANT ACTIVITIES UNDERTAKEN IN FY2021

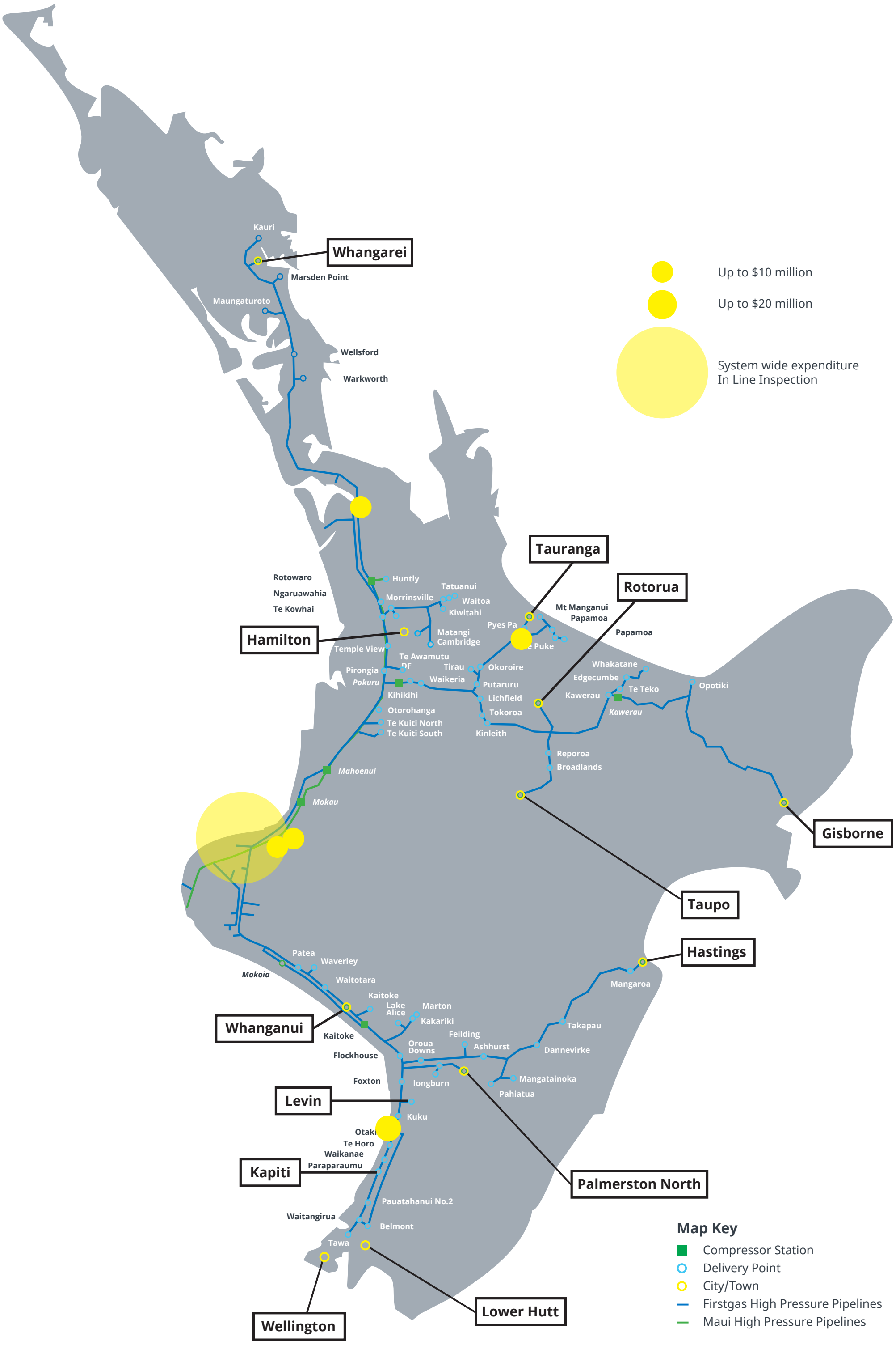
Firstgas has continued to deliver the significant capital works programme set out for this regulatory control period (1 October 2017 – 30 September 2022). Figure 11 outlines the most significant projects that were delivered during the last 12 months. These projects were outlined in the 2020 AMP.

Figure 11: Significant projects undertaken in FY2021

SIGNIFICANT PROJECTS

INCREASING RESILIENCE OF THE NETWORK

Figure 12: Locations of significant projects undertaken in FY2021



Gilbert Stream Realignment Project

The Gilbert Stream realignment project addresses an 80-metre section of the 400 Line at Pukearuhe, North Taranaki this is threatened by marine erosion of the cliff face. The project requires that a section of the pipeline is re-aligned and commenced in 2017.

Over the course of FY2021, the focus has been on the completion of the civils works associated with the project. There has been a significant amount of work required to construct the two-metre diameter culvert to divert the path of the Gilbert stream. The final tie ins to complete the project are scheduled to be completed during Auckland Anniversary weekend in January 2022.

Pariroa Feature Defect

The Pariroa project addresses a buckle on the 400 pipeline between Frankley Road and Mokau compressor station approximately 9.3 km south of Mokau compressor station. This buckle was identified through pipeline pigging on the line during April 2018 and is located close to a previously identified pipeline strain site at an active and complex landslide.

The project was split into 2 phases, with phase 1 responding to the immediate risk (potential loss of containment).

This work was undertaken in 2018 and included:

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

During FY2021, we have completed a study to understand the mechanism under which the pipeline was deformed and to inform us on the remediation required to stabilise the area. This information was necessary prior to the execution of the long-term solution for the project.

In the year ahead section, we provide more detail on the works planed for FY2022.

In Line Inspection

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 pigging is conducted

Figure 13: Progress photos at Gilbert Stream

Figure 14: Pictures of the Pariroa project

at ten yearly intervals. For all our piggable pipelines, it is a requirement from our pipeline certifier that we conduct the pigging at our specified intervals to maintain our certificate of fitness.

Through the course of FY2020, we have conducted intelligent pigging on the 100 series pipelines in the southern system, 200 series pipelines between Taranaki and Hamilton and on the 500 series pipelines in the Bay of Plenty system.

Infrastructure Relocations – Murphy Road

There is currently a residential development underway in the Flat Bush area of Auckland. The Firstgas owned and operated 400 pipeline in the Flatbush area is currently in an easement that runs through a large section of the area for development. The developer has requested that Firstgas relocate the existing pipeline to allow for progression of the development. This project was identified in 2017. However, with these types of projects we work with the developers and their schedules to deliver the relocation of the work.

Tauriko Growth

Growth within the Tauranga area has prompted the development of the Tauriko Business Estate (TBE). New Zealand's only manufacturer of gypsum plasterboard, drywall systems and associated products, will be relocating to Tauriko.

To support this increased demand, Firstgas is developing a new delivery point. The customers is expected to commence manufacturing operations in 2023, with gas required in 2022 for commissioning purposes.

Pig Trap Modifications

Firstgas has embarked on a programme to upgrade our pigging facilities to ensure they are aligned with industry good practice.

Pipeline pigging is an essential asset management activity. Pigging of the pipelines allows us to carry out assess the condition of the pipeline by allowing us to conduct maintenance and inspection activity without stopping the flow of gas. Firstgas uses a tool referred to as a 'PIG' (Pipeline-Inspection-Gauge) that is inserted into the pipeline at dedicated launch and receive locations.

Our fleet of PIG launchers and receivers currently have varied configurations that reflect what was best practice at the time they were manufactured. We are now looking to move to standardised designs for our facilities, considering current pigging technologies and configurations.

Part of the programme also involves upgrades to our pigging launchers and receivers. We are continuing with this planned programme of pigging facilities upgrades in FY2021. The plan includes eight projects in different regions such as Auckland, Waikato, Hawke's Bay, Taranaki and Manawatu.

Compression Strategy

During FY2021, Firstgas has continued to refine its compression strategy for the transmission system. We have undertaken a strategic compression operating regime review to determine how we can best to meet the needs of our customers, standardise and modernise our compression fleet, while ensuring we have the flexibility to accommodate changes to the network in an efficient manner.

Our compression strategy is focused on achieving the following objectives:

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

Despite the uncertainty and opportunities facing our business, we believe that the objectives for this work remain unchanged. However, the delivery of the strategy has been refined and is now focused on responding to reliability issues and operational costs at key compression sites:

More information is available in our year ahead section.

Gas Transmission Access Code (GTAC)

In 2021, the Board of Firstgas Group made the difficult decision to permanently discontinue implementation of the GTAC project. This was due to changes in the external environment coupled with technical challenges.

The GTAC was conceived as a single set of transmission arrangements to replace the two existing transmission operating codes – the Maui Pipeline Operating Code and the Vector Transmission Code. Work on its development began in 2016, during a period of relatively plentiful gas supply and high gas demand for electricity generation. Accordingly, the design of the GTAC was heavily influenced by the perceived need to anticipate and manage capacity constraints.

Since that time, both the operating and policy environments have changed. The industry has moved to a more constrained gas supply position, and there appears to be little prospect of capacity constraints eventuating. Further, it seems clear that the industry will need to keep evolving in response to the policy environment and Government direction to reduce energy sector emissions. These factors suggest that transmission arrangements will need to evolve for instance, to support the use of net zero carbon fuels or to cater for peak generation loads.

Alongside these factors, a review of GTAC and our software vendors uncovered several technical and design challenges that would add significant cost, complexity and risk to appropriately address. The decision to not proceed with the project was communicated with all stakeholders and discussions help on how to evolve the existing commercial codes for the coming year.

No additional expenditure is now expected on this project with historical expenditure having been written off .

5.3 ASSET MANAGEMENT IMPROVEMENT PROGRAMME

In FY2021, we successfully rolled out our Maximo Asset Health Insights (MAHI) application dashboard and started linking asset health to risks and our asset management planning process.

The MAHI application uses several metrics as an input into the software, such as records of outstanding maintenance activities, individual risks items associated with the assets and condition of assets. This information collectively is used to derive an overall health score that is used to support our decisions when developing workplans and prioritising activities.

The asset health index provides a line of sight to expenditure profiles. In other words, expenditure is linked to our assessment of asset condition, targeting our spend to the areas that we believe are needed to reduce risk and maintain asset reliability. As well as providing insights when planning for the work activities, the application provides a geographical presentation of the asset health that will enable more efficient planning for the delivery of work.

Maximo Asset Management Planning Tool

The development of the Asset Management Planning tool in Maximo to support our capital expenditure programme has enabled better risk management data recording and reporting in terms of risk mitigation actions and projects are being recorded against the asset. This means any asset integrity / process safety risk issues requiring capital work have a Risk Item Register (RIR) record entered against the asset which then feeds into the asset management planning process.

Risk Management

Risk management is at the core of what we do. We have evaluated the different risks that our assets are exposed to establish inherent and residual risk profiles – this is essentially the risks before (inherent) and after (residual) we have controls in place to control risk escalation.

We have collated our asset classes health and risk data. The extract of the key assets below in Figure 17 includes the following indicators:

- **Inherent risk:** Risk identified without risk controls implemented
- **Current residual risk:** Risk remaining after risk treatment controls are implemented
- **Current asset health:** It is the health index calculated based on condition, performance and risk. These are each rated using three colours such as green (good), amber (fair) and red (poor) representing different state of health
- **Post RCP3 residual risk:** The level of remaining risk anticipated with the current controls in place

Figure 15: MAHI showing Transmission asset health (good, fair, and poor) and locations on the map

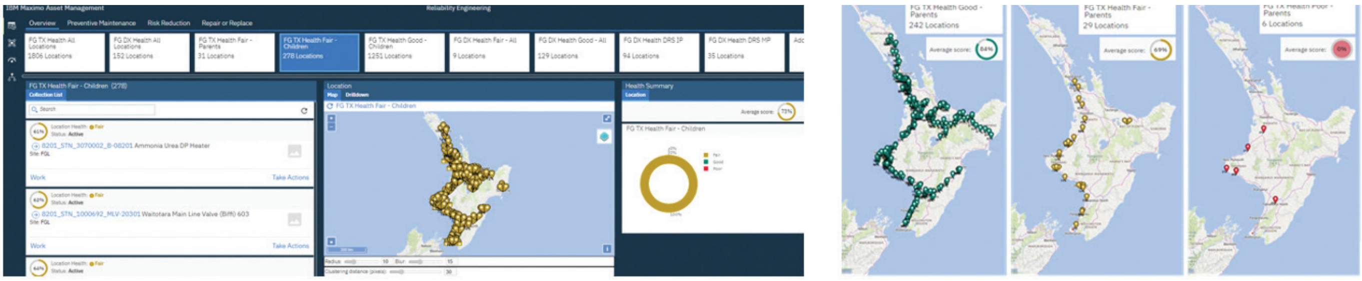


Figure 16: Linking Maximo (RIR) Risk Item Register to Asset Management Planning Tool

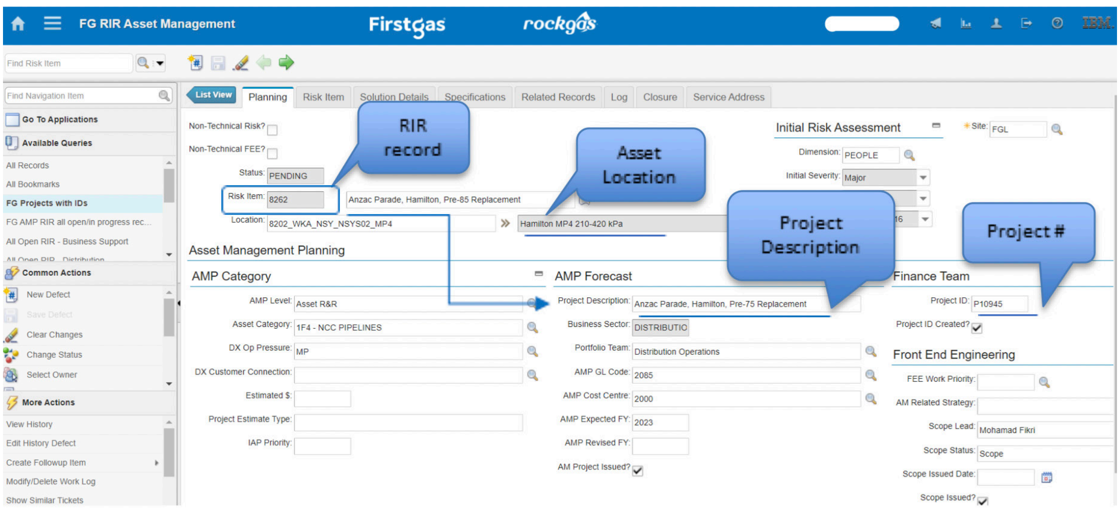
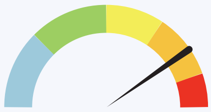
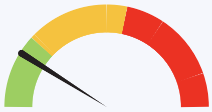
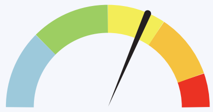


Figure 17: Asset health, risk and forecast expenditure

ASSET	INHERENT RISK	CURRENT RESIDUAL RISK	CURRENT ASSET HEALTH	POST RCP 3 RESIDUAL RISK & EXPENDITURE FORECAST	10 YEAR PLANNING PERIOD RESIDUAL RISK & EXPENDITURE TREND
Transmission Network				 RCP FORECAST $210 million RCP EXPENDITURE PROFILE 	 PLANNING PERIOD FORECAST $450 million 10-YEAR FORECAST TREND

- **Post planning period residual risk:** The level of remaining risk anticipated relative to aging, obsolescence, and performance issues of some of our assets.

Currently we have a stable risk profile with very little change through the planning period. In the long-term we anticipate that there will be an increase in our risk profile driven primarily through ageing asset.

In the year ahead section, we discuss our plans to refine this data and incorporate criticality to the asset health data.

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:

- Our compressor availability has improved over the course of the year, and we are very close to meeting our target.
- Our compressor reliability has dropped; however the implementation of the compression strategy is anticipated to improve both reliability and availability
- We have had a single non-compliance during our last Lloyds Audit in relation to a delay in completing the In-line Inspection of the 200 and 400 pipelines. A contingency plan will be developed to monitor the structural integrity in the interim.

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

Table 4: Key Performance Indicator Trend table

KEY PERFORMANCE INDICATORS	FY2020	FY2021 TARGET	CURRENT TREND[15]
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[16] – 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	93.8%	**>97%**	
Lloyds annual audit non-compliance	1	**0**	
Compressor availability	94[17]%	**>95%**	

15. The arrow direction compares data between FY2020 and FY2021, if there was an increase, decrease or steady trend. The arrow colour indicates how close is the KPI to the FY2021 target.
16. 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.
17. Percentage based on the average of the first 9 months of financial year FY2021

6. YEAR AHEAD

This section sets out the areas of focus for Firstgas over the coming year commencing 1 October 2021, which is the final year of current regulatory control period (2017 – 2022). The focus remains on providing our customers with a safe and resilient transmission system, while maturing and optimising our approach to asset management.

6.1 SIGNIFICANT ACTIVITIES FOR FY2022

Figure 18 sets out the major activities we plan to undertake throughout FY2022.

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. Through our analysis, we estimate limited change in the short-term to our expenditure forecasts from what was published in the 2020 AMP.

As we move into the next regulatory control period (FY2023 to FY2027), we do anticipate reduced expenditure for the transmission system. The two areas that account for these reductions are:

- Reduced forecasts relating to growth and customer connections
- A change to the delivery of the compression strategy, where the focus will be on two compression sites, Rotowaro compressor station and Kapuni gas treatment plant.

This has resulted in a reduction of anticipated Capex of approximately $49 million over the planning period.

Figure 19 outlines each of the significant projects for the year ahead and the location of these projects.

Figure 18: Significant projects for FY2022

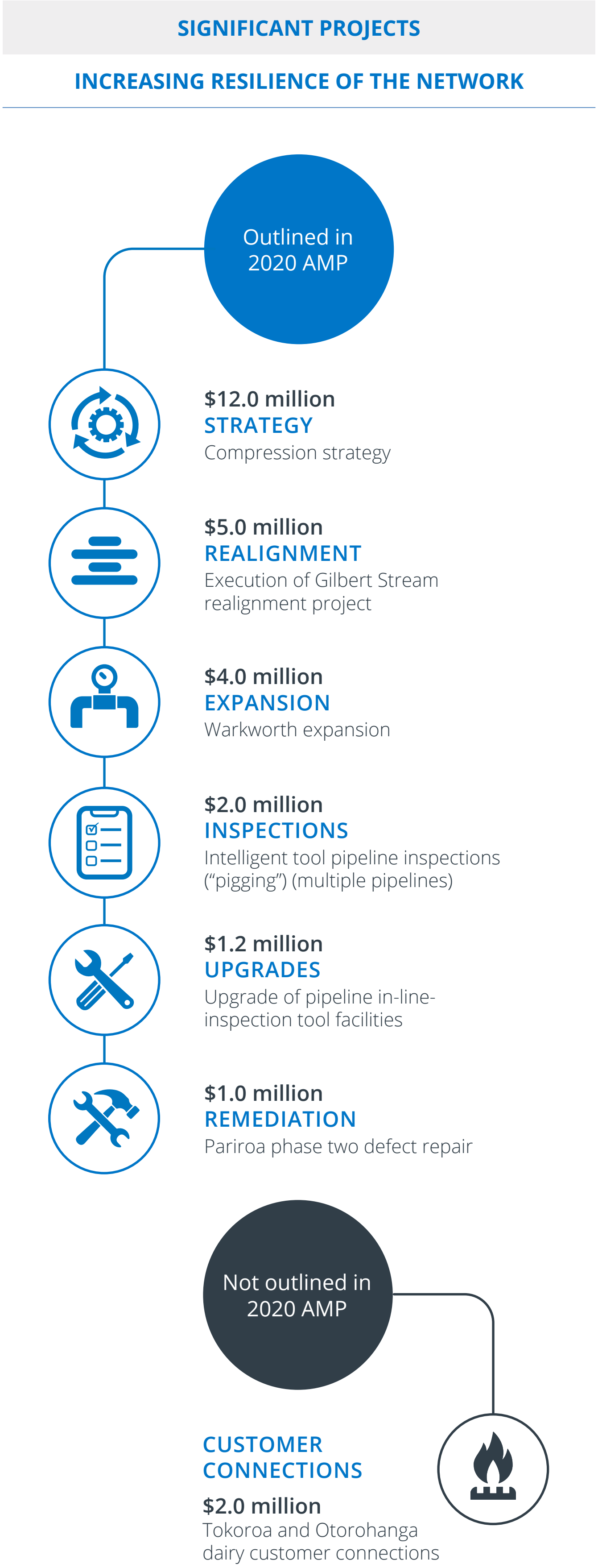
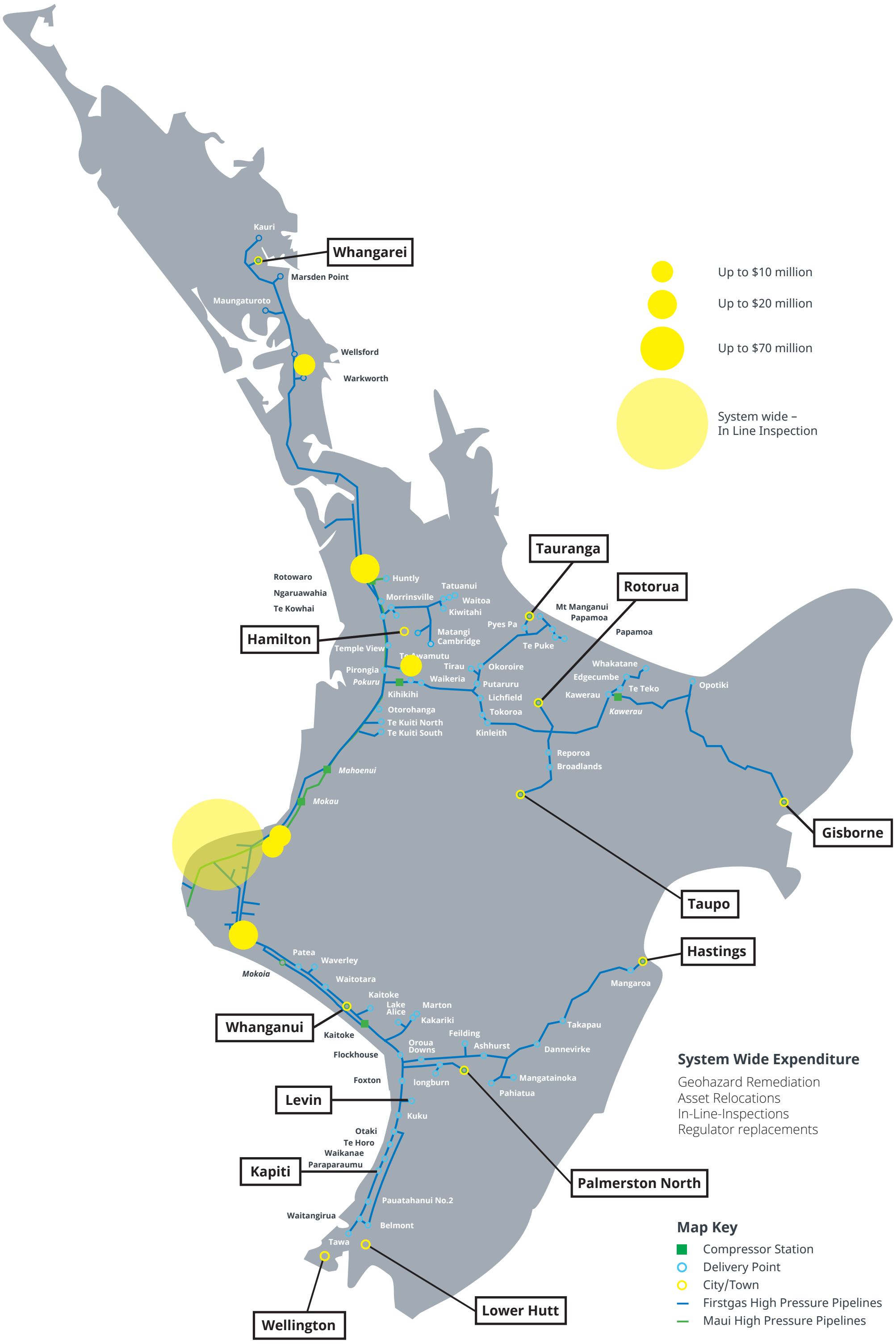


Figure 19: Largest Capex projects



System Wide Expenditure

Geohazard Remediation
Asset Relocations
In-Line-Inspections
Regulator replacements

Map Key

- Compressor Station
- Delivery Point
- City/Town
- Firstgas High Pressure Pipelines
- Maui High Pressure Pipelines

Gilbert Stream Realignment

The Gilbert Stream realignment project addresses an 80-metre section of the 400Line at Pukearuhe, North Taranaki that is threatened by marine erosion of the cliff face. The project requires a section of the pipeline be re-aligned.

Civil works to construct the culvert will be completed in mid-2021. Following the completion of the civils phase, our efforts will shift to pipeline construction. The pipeline design incorporates a buried pipeline along the culvert and requires a considerable amount of recontouring of the area.

The methodology for the tie-in of the new realigned sections requires a cold cut that will involve the shutdown of the Maui pipeline. This tie-in process is planned to occur on Auckland Anniversary weekend, 29 – 31 January 2022. More details regarding the planned shutdown will be communicated over the coming months.

Phase 2 addressing the Pariroa Buckle

The Pariroa project addresses a buckle on the 400 pipeline between Frankley Road and Mokau compressor station approximately 9.3 kilometre south of Mokau compressor station. This buckle was identified through pipeline pigging on the line during April 2018 and is located close to a previously identified pipeline strain site at an active and complex landslide. Phase 1 of the project focused on addressing the immediate risk and involved installing a temporary bypass. This work was completed in 2019.

Phase 2 of the project focusses on development of long-term solution to the defect. As noted in the section above, we have completed a study to understand the mechanism under which the pipeline was deformed and to inform us on the remediation required to stabilise the area. In FY2022, we now intend to undertake the following work:

- Ground stabilisation, which will include construction of subsurface drainage within the existing pipeline easement to lower ground water levels and stabilise the landslide
- Installation of a new section of 750mm pipeline, destressing the pipeline and removal of the bypass.

The planned tie-in work will be completed at the same time as the Gilbert stream realignment project. This is scheduled over Auckland anniversary weekend in 2022 to minimise disruption to our customers.

Figure 20: Progress of the Gilbert Stream Project

▲ *Civil earthworks associated with the Gilbert Stream Project*

Compression Strategy

Work during FY2022 will focus on execution of the compression strategy at key compressor sites. Front end engineering studies are underway that will identify the optimum configuration that will deliver on our objectives, whilst still providing a degree of flexibility to respond to future changes.

Over recent years, some sites have performed poorly, generally due to their age, indicating that they are close to, and in some cases have reached the end of their useful life. Not only is the reliability becoming an issue to maintain our service levels, but some units are also now obsolete, making it more and more difficult to obtain replacement parts for failed components.

The number and regularity of failures at some sites has now reduced availability to such an extent, that these compressor units can no longer be considered to be fit for purpose.

As part of our analysis as part of our compression strategy we have concluded that it will be preferable to install electric drives rather than gas drives on the new compressors to allow improved capacity ramp up and down as well as significant CO_2 emissions savings.

A high-level comparison of electric motor and gas engine drives for new compressors is shown in Table 5.

Using a single design range allows for most parts to be interchangeable, maintenance training and support to be simplified and allows for the potential interchangeability of complete skid mounted units, should the need arise.

Table 5: Electric drive vs gas driven engine comparison

	ELECTRIC MOTOR	GAS ENGINE
Fuel/power cost	×	✓
Emissions	✓	×
Efficiency	✓	×
Extra flow capacity	✓	×
Availability	✓	×
OPEX	✓	×
Noise	✓	×
Safety	✓	×
Package cost	✓	✓

Intelligent Pigging

Pipeline pigging is an essential asset management activity. Pigging of the pipelines allows us to carry out assess the condition of the pipeline by allowing us to conduct maintenance and inspection activity without stopping the flow of gas. Firstgas uses a tool referred to as a 'PIG' (Pipeline-Inspection-Gauge) 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 PIG tool is fitted with banks of sensors. These are used to record pipeline condition data such as wall thickness, or locations of defects. Running this data through an assessment tool is then able to produce condition reports on the pipeline.

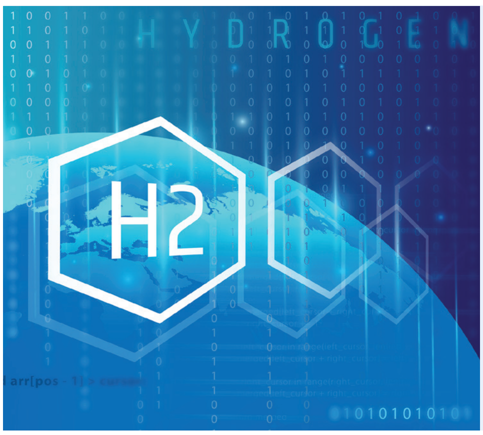
The frequency of our intelligent pigging programme is driven by our Pipeline Integrity Management Plan. Typically for pipelines that transit urban area or are in areas that pose an increased risk, the intelligent pigging will be conducted at five yearly intervals. For pipelines that transit rural areas or are not exposed to elevated potential for risk, the 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 pigging at our specified intervals to maintain our certificate of fitness.

Through the course of FY2022, we are planning to conduct intelligent pigging in the Bay of Plenty region, Hastings, Manawatu, and the Waikato regions.

Customer Connections

Firstgas' has been working with the developers of two new dairy processing facilities in the South Waikato that want to connect to a natural gas supply. The first is being developed by Happy Valley Nutrition (HVN), an ASX-listed company that is investing in a new infant formula manufacturing plant near Otorohanga. The second is being developed by Olam, one of the largest international dairy processors. Both sites will require delivery point to be constructed to meet the demand.

- A new delivery point will be constructed at Otorohanga to supply the HVN plant
- A delivery point will be constructed at Kinleith scraper station to supply the Olam plant



Our Hydrogen Trials

Transitioning to net zero carbon gases is important if we want to reduce New Zealand's carbon emissions and hydrogen has a big part to play in this change. The release of our Hydrogen Pipeline Trial Study set the foundation for our ongoing delivery work on hydrogen. Work to date has been centred around table-top studies and investigation of the feasibility of Hydrogen. The next step will be introducing hydrogen into our networks, through field-based trials.

We have a number of sites that we are currently evaluating to build our off-grid testing, we are planning to design and install blending and metering equipment to introduce hydrogen into the gas. These trials and demonstrations will act to build our experience and confidence in hydrogen.

6.2 CONTINUING OUR ASSET MANAGEMENT IMPROVEMENT PROGRAMME

Following the successful MAHI implementation, we are now looking at how we can better link our asset criticality information with our risk and health and feed this into our planning processes.

The asset criticality information (an indication of the importance of the asset) will be used in conjunction with the health and risk information to assist with prioritising our activities. In other words, expenditure is linked to our assessment of asset condition, the risk associated with the assets, and the importance of the assets. We target our spend to the areas we believe it is most needed to reduce risk and maintain asset reliability.

The two main features of the framework are the "health" and "criticality" related to an asset.

- **Asset health** is a measure of the useful remaining life of an asset and a key factor in the likelihood of asset failure.
- **Asset criticality** is a measure of the potential consequence because of an asset failure and is a key determinant in quantifying the loss associated with the failure.

Health indices change over time as attributes that affect the probability of asset failure change, such as the physical condition or operating conditions. Criticality indices may change over time when network attributes change, such as the demand supplied or the network configuration. By linking the health and criticality we can better prioritise our investment planning.

Other asset management improvement initiatives we are undertaking include:

- Finalising our asset criticality framework
- Expanding our long-term planning to the wider business
- Delivery of an Integrated Activity plan to facilitate concurrent planning within the business.

Asset condition (Schedule 12A)

Schedule 12a (report on asset condition) provides a high-level overview of the asset condition rating as per the Commerce Commission's grading categories[18]. Our asset management strategies and expenditure are targeted to addressing instances where the condition rating is falling below the required standard. Assessing asset condition is a dynamic process and gradings will change as the assets age or as specific issues are identified.

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

- **Compressors (7% are classified as grade 1):** Our emphasis is the delivery of compressor upgrades for KGTP and Rotowaro. This will address an aged unit at KGTP and drive cost reductions at the Rotowaro compressor station.
- **Gas fired heaters (29% are classified as grade 1):** An ongoing inspection program will assess the condition of the heaters over the course of its service life. Replacements will be based on condition following planned inspections and end of service life assessments.
- **Metering systems (20% of ultrasonic meters and 36% of rotary meters are classified as grade 1):** Meter replacements are an ongoing programme throughout the AMP Update period. Over the next five years, we anticipate that 10% - 20% of the meters will be replaced. This replacement programme is based on age of the existing meters. Performance will be monitored to ensure that the replacement programme is targeted to the meters where performance issues warrant the replacement.
- **SCADA and communications, remote terminal units:** A programme to replace the Central Processing units component within the remote terminal unit (RTU) has resulted in the extension of life of all the RTUs at a significantly reduced cost than replacing the entire RTU.

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

Figure 21: Criticality and Asset Health Framework

HEALTH CRITICALITY MATRIX		ASSET HEALTH BAND				
		BAND 1	BAND 2	BAND 3	BAND 4	BAND 5
CRITICALITY	C1	25	23	18	13	8
	C2	24	20	15	10	7
	C3	22	19	14	9	3
	C4	21	16	11	5	2
	C5	17	12	6	4	1

18. 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 22.

The chart above represents our planned Capex for the planning period compared to the forecast Capex published in our 2020 AMP. The variances are attributed to several key projects:

Changes within the current regulatory period (FY2018 – FY2022)

- Two customer driven connections have been initiated for FY2022 –new dairy factories in Otorohanga and in Tokoroa with a forecast expenditure of $2 million
- We are moving into the execution phase of the compression strategy. This work will address aging assets and the high maintenance costs associated with two compression sites. We are forecasting an additional $12 million for compressor replacements.
- Reduced forecast costs for FY2021 resulting from the decision not to proceed with the Gas Transmission Access Code (GTAC) implementation project.

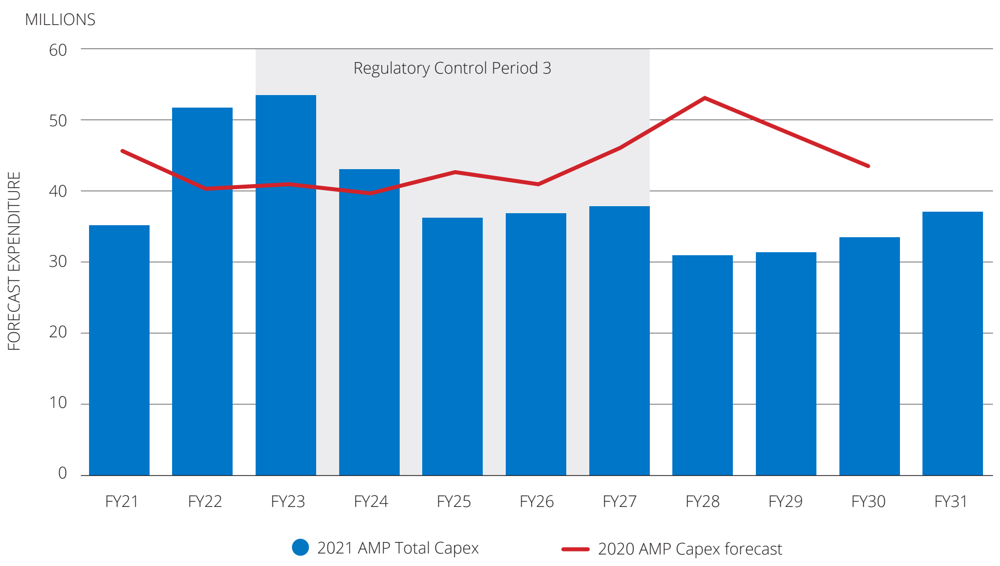
Changes over the next two regulatory periods (FY2023 – FY2032)

The uncertainty resulting from the CCC's final advice has prompted us to refine our mid to long term planning forecasts for the planning period. This has resulted in an overall reduction in the expenditure for the next two regulatory control periods and a 12% reduction in Capex over the ten-year planning period.

The key changes compared to the 2020 AMP are:

- Changes in the delivery plan for the compression strategy. Originally, we had planned to replace compressors at four strategic sites. The programme of work now focuses on two sites, equating to reduction of $60 million in compressor expenditure over the planning period.
- A reduced forecast for customer connections that results in a $5 million reduction over the planning period
- A reduced forecast for system growth that results a $10 million forecast reduction over the planning period.
- Increase in expenditure to deliver improved security, supporting Firstgas Group strategy and operational needs.

Figure 22: Forecast total Capex (all figures in FY2021 prices)



19. Regulatory control period four runs from FY2028 through to FY2032.

7.2 OPEX FORECAST

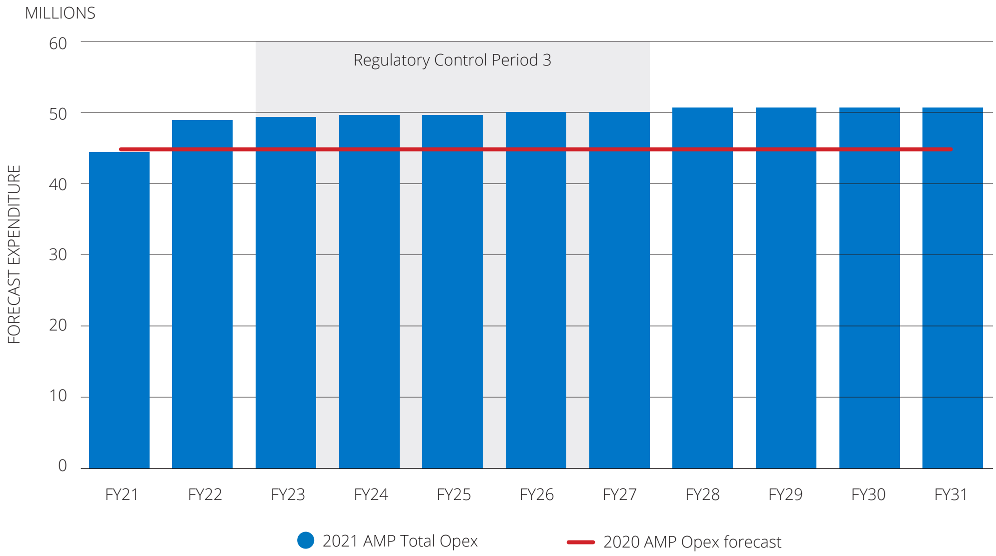
The forecast Opex over the next planning period is set out in Figure 23. There is no significant change in ongoing Opex from that set out in 2020 AMP.

Over the course of the planning period, our base maintenance costs are anticipated to remain steady. The increase in OPEX is primarily attributable to higher compressor fuel costs.

This increase represents a 11.7% increase in costs over the planning period and is due to tightening market conditions for gas and growing the use of renewable gas (biomethane and hydrogen) over time.

The changes within regulatory control period three and four[19] relate to an increase in network expenditure of approximately $4 million (total) over the next two regulatory control periods for our net zero-carbon gas trial programme.

Figure 23: Forecast total Opex (all figures in FY2021 prices)



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 6: Material changes in work programmes

ACTIVITY	2020 AMP	2021 AMP UPDATE	RISK
Gilbert Stream realignment project	Works planned to be completed autumn / winter of FY2021.	Final tie-ins planned to be completed over Auckland Anniversary weekend January 2022	The site has regular monitoring to ensure there is no change to the risk profile. Emergency response plan developed to enable us to react if required. Since the initiation of the project there has been no increase in risk. The planned ties-in in 2022 is a better outcome for customers as only one shutdown will be required to tie in the Gilbert Stream project and the Pariroa project.
Pariroa defect repair	Phase 2 of the activities planned for completion in FY2020, includes re instatement of the 750mm pipe section and land stabilisation	Phase 2 of the activities planned for completion in FY2022, includes re instatement of the 750mm pipe section and land stabilisation	No increase in risk, better outcome for customers as only one shutdown will be required to tie in the Gilbert Stream project and Pariroa project
Compression strategy	Planned to upgrade four compressor sites over the planning period (10 years)	Compression strategy refined and is focussed on 2 strategic sites.	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 relation to 2 dairy factory connections Forecast included $19million over planning period to facilitate customer connections	Included $2m forecast to enable customers to connect to the Transmission system Forecasts have been reduced. $13.7million forecast over planning period to facilitate customer connections	Unable to meet customer demand, and provide gas services and system growth
ICT 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	Increase in expenditure to deliver improved security, supporting Firstgas Group strategy and operational needs
System Growth	Forecast included $19.5million to facilitate system growth	Forecast reduced $9.1million included in forecast to facilitate system growth	Unable to meet customer demand, and provide gas services and system growth

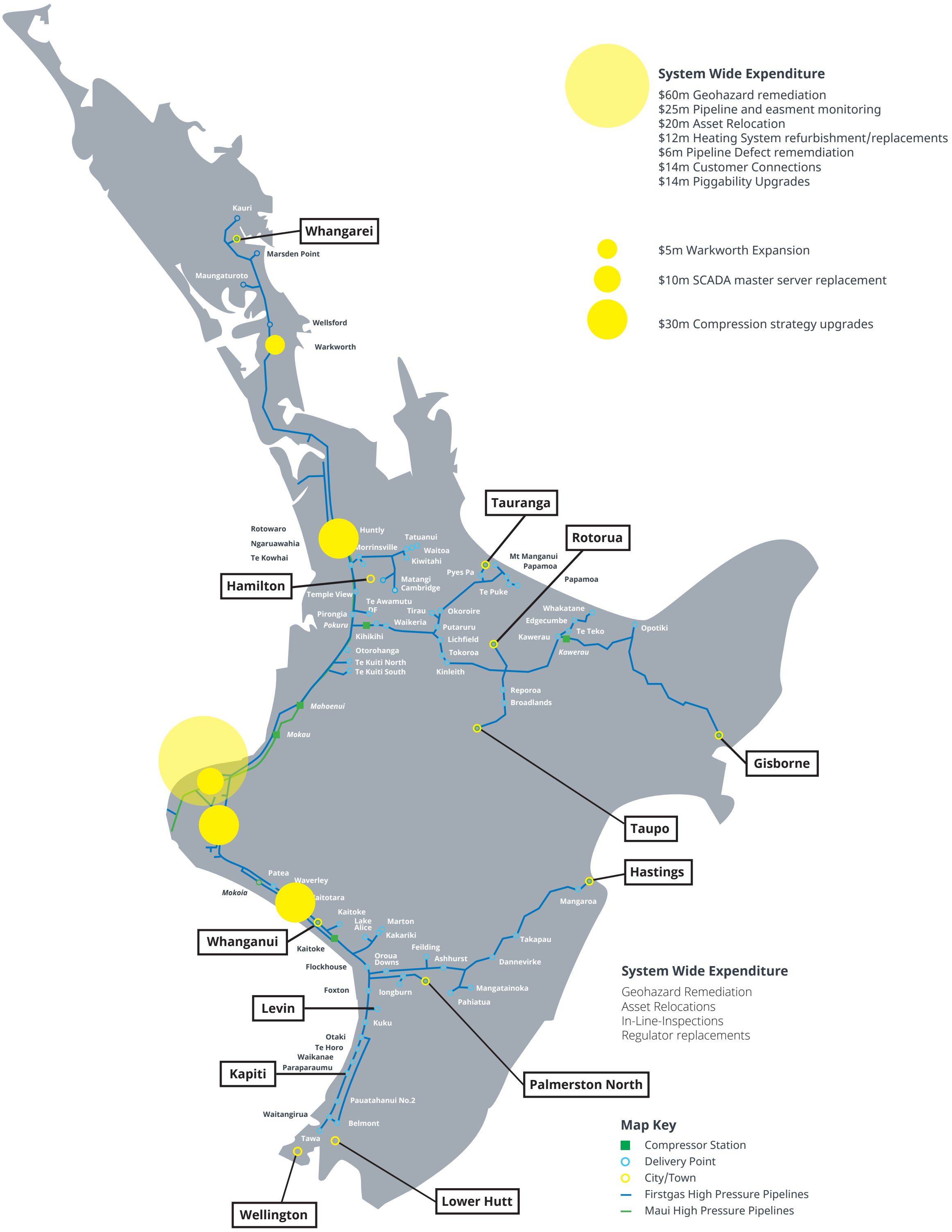
10 Year Capex Forecast

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 (2017 – 2022) 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 7: Capex costs

PROJECT	DESCRIPTION	REGION	COST (CONSTANT $)	PERIOD
Geohazards Risk remediation	Risk Remediation project resulting from geo-technical hazards	System Wide	$57m	FY2022 – FY2031
Compression Strategy	Upgrade and standardisation of ageing fleet of compressors	Strategic Compression sites	$30m	FY2022 – FY2025
Pipeline and easement Condition monitoring	Pipeline pigging operations and easement UAV surveillance	System Wide	$25m	FY2022 – FY2025
Asset Relocations	Relocation of Infrastructure	System Wide	$20m	FY2022 – FY2031
Heating system	Cost assocateid with overhaul and replacement of Water bath heaters	System Wide	$12m	FY2022 – FY2031
Pipeline Defects	Foreast cost to effect repairs assocaited with pipeline defects identified through Inline inspections or other condition monitoring	System Wide	$6m	FY2022 – FY2031
Customer connections	Supporting connectinsg new customers	System Wide	$14m	FY2022 – FY2031
Piggability Upgrades	Upgrading facilities and or pipelines to enable pigging operatons	System Wide	$14m	FY2024 – FY2031
SCADA and Communications	Uppgrade and reaplcement of SCADA master server	North Taranaki	$10m	FY2022 – FY2024
Warkworth Expansion	Increasing pipeline capacity to meet increase in demand	Northern System	$5m	FY2022 – FY2023

Figure 24: FY21 capex expenditure 10 year planning



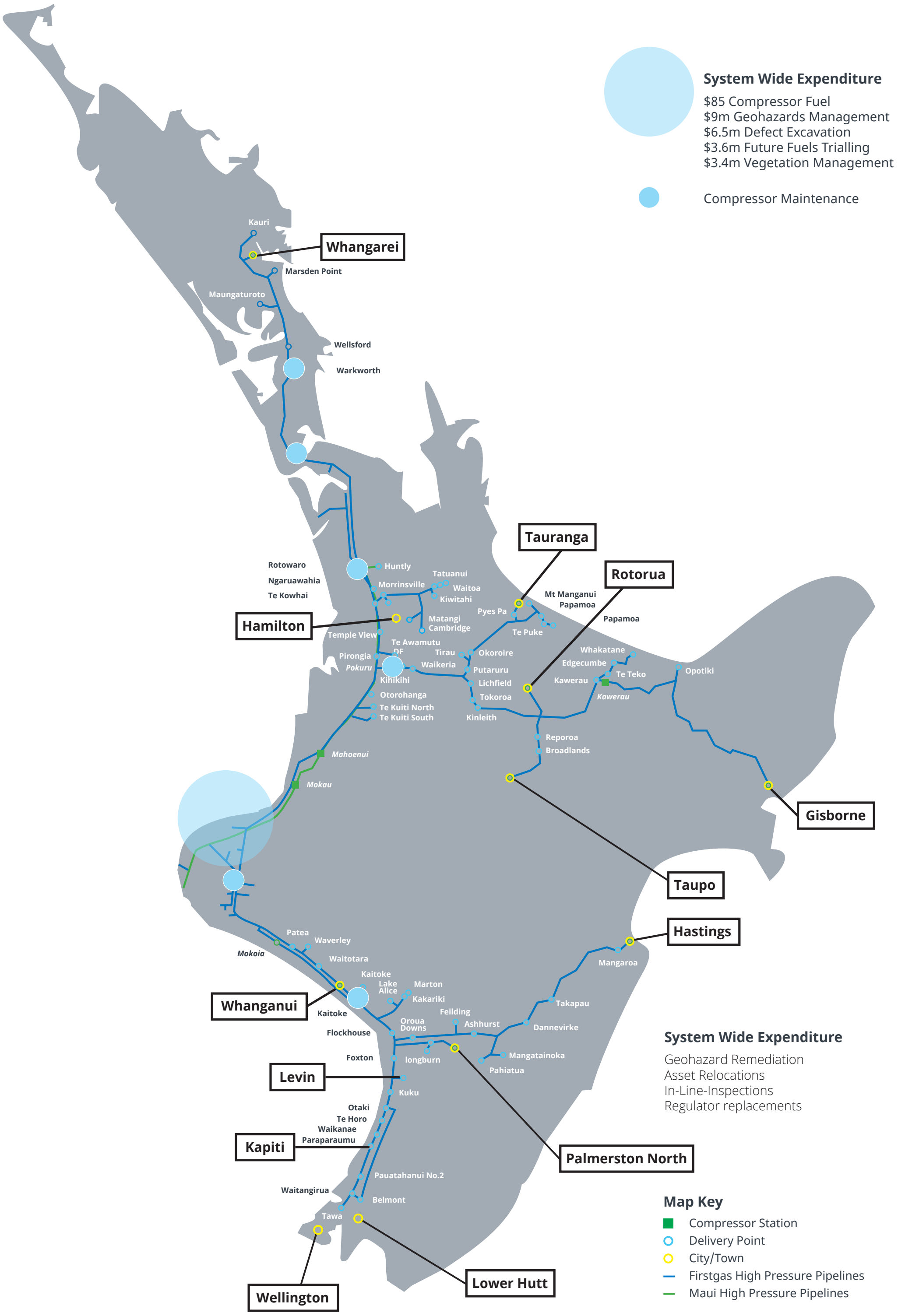
10 Year Opex Forecast

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. The table presents areas that have the highest operational through the planning period.

Table 8: Opex costs

CATEGORY	DESCRIPTION	REGION	COST (CONSTANT $)	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 oppertunity presents itself we will look to source low-carbon compressor fuel gas in the future.	System Wide	$85m	FY2022 – FY2031
Kapuni Gas Treament Plant	Ongoing Maintenance requirements to ensure reliability. KGTP compressors are strategic for the 100 and 200 piplines	Taranaki Region	$11m	FY2022 – FY2031
Geohazard management	Ongoing maintenance costs assocaited with identifying, assessing and monitoring geotechnical issues on the transmission system.	System Wide	$9m	FY2022 – FY2031
Defect Excavation	Pipeline coatings are the primary protection against corrosion. Each year several defects are excavated to carry our coating remedations	System Wide	$6.5m	FY2022 – FY2031
Rotowaro Compressor Station	Ongoing Maintenance requirements to ensure reliability. Rotowaro compressor station is a strategic compressor station for the northern system.	Waikato region	$5.6m	FY2022 – FY2031
Future Fuels Trials	In order to take the first steps towards replacing natural gas with hydrogen by utilising the existing gas tranmssion and distribution assets. 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	$3.6m	FY2022 – FY2031
Vegetation Management	Operational costs associated with management of vegetation in pipeline easements	System Wide	$3.4m	FY2022 – FY2031
Mokau Compressor Station	Ongoing maintenance is required on our assets to ensure reliability. Mokau compressor station is a strategic compressor site to the 400 pipeline	Northern Taranaki	$3m	FY2022 – FY2031
Henderson Compressor Stattion	Ongoing maintenance is required on our assets to ensure reliability.	North Auckland	$2.6m	FY2022 – FY2031
Kaitoke Compressor station	Ongoing maintenance is required on our assets to ensure reliability. Kaitoke compressot station is a strategic site for the 100 and 600 pipelines, providing additional compression for the southern section of the transmission system	Manawatu – Whanganui region	$2m	FY2022 – FY2031

Figure 25: Opex expenditure 10 planning period



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 2020 AMP and includes our signed director certificate.

APPENDIX A: SUMMARY OF MATERIAL CHANGES AND COMPLIANCE

The table below:

- Summarises the material changes in our asset management plan, as compared with our 2020 AMP.
- 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' Transmission business. Information on the Firstgas' distribution business (GDB) can be found in the separate distribution 2021 AMP Update.[20]
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 FY2020 AMP:** Two customer connections have been included in the FY2022 forecast. Gas supply will be provided to two dairy factories, one in Otorohanga and one in Tokoroa. In the year ahead section we reference the projects.
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 FY2020 AMP:** The execution of the Compression strategy has been included in the FY2022 and FY2023 forecasts. Anticipated compression strategy expenditure that was planned from FY2024 - FY2029 has been removed from the forecast. The net result is a $70 million reduction in forecast expenditure over the planning period.
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.	**Material changes from the FY2020 AMP:** There has been an increase in forecast compressor fuel Opex costs. Compressor fuel usage is not anticipated to increase, the cost to purchase fuel is anticipated to increase. There has been a decrease in Capex over the planning period of $60 million. This reduction in costs is due to: – $60 million reduction in compressor replacement and renewal costs – $10 million reduction expected system growth expenditure – $5million reduction in customer connection expenditure – $12 million increase in non-network expenditure on system security for our information systems. Further information on material changes in expenditure is available in the year ahead section.

20. Information on Firstgas' distribution business is available here: https://firstgas.co.nz/about-us/regulatory/distribution/

ID REQUIREMENT	DISCUSSION
Clause 2.6.5 (5) Provide an assessment of transmission capacity as set out in clause 8 of Attachment A.	See **Appendix C**.
Clause 2.6.5 (6) Identify any material changes related to the legislative requirements as set out in clause 3.6 of Attachment A.	There have been no material changes to the legislative requirements directly affecting management of the assets as set out in clause 3.6 of Attachment A.
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) There are no material changes in Asset Management practices that affect Schedule 13 Report on Asset Management Maturity disclosure.	See **Appendix B**.
Clause 2.6.6 Subject to clause 2.13.2, before the start of each disclosure year, each GTB must complete and publicly disclose each of the following reports by inserting all information relating to the gas transmission services supplied by the GTB for the disclosure years provided for in the following reports: 1. The Report on Forecast Capital Expenditure in Schedule 11a. 2. The Report on Forecast Operational Expenditure in Schedule 11b. 3. The Report on Asset Condition in Schedule 12a. 4. The Report on Forecast Demand in Schedule 12b.	See **Appendix B**.
Clause 2.7.2 Before the start of each disclosure year, every GTB must complete and publicly disclose the Mandatory Explanatory Notes on Forecast Information in Schedule 14a by inserting all relevant information relating to information disclosed in accordance with clause 2.6.6.	See **Appendix B**.

APPENDIX B: INFORMATION DISCLOSURE SCHEDULES

Schedule 11a: Report on forecast capital expenditure

Company Name	**Firstgas**
AMP Planning Period	**1 October 2021 – 30 September 2031**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

GTBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref													
7			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		for year ended	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (nominal dollars)**										
10	Consumer connection		339	2,777	1,457	1,486	1,515	1,546	1,577	1,149	1,172	1,195	1,219
11	System growth		1,050	2,701	2,601	531	541	552	563	574	586	598	609
12	Asset replacement and renewal		24,892	37,713	41,691	29,593	27,566	29,457	29,603	23,337	23,277	27,268	31,298
13	Asset relocations		491	2,040	2,081	2,122	2,165	2,208	2,252	2,297	2,343	2,390	2,438
14	Reliability, safety and environment:												
15	Quality of supply		-	-	-	-	-	-	-	-	-	-	-
16	Legislative and regulatory			-	-	-	-	-	-	-	-	-	-
17	Other Reliability, Safety and Environment		316	530	520	531	812	828	845	574	586	598	609
18	**Total reliability, safety and environment**		316	530	520	531	812	828	845	574	586	598	609
19	**Expenditure on network assets**		27,087	45,762	48,349	34,263	32,600	34,591	34,840	27,932	27,964	32,048	36,174
20	Expenditure on non-network assets		8,147	6,862	7,302	11,256	6,500	6,024	7,583	7,365	8,509	7,967	8,909
21	**Expenditure on assets**		35,233	52,624	55,651	45,518	39,100	40,615	42,423	35,297	36,473	40,015	45,083
22													
23	*plus* Cost of financing		301	451	477	390	335	348	373	352	353	384	428
24	*less* Value of capital contributions		442	1,836	1,873	1,910	1,948	1,987	2,027	2,068	2,109	2,151	2,194
25	*plus* Value of vested assets		-	-	-	-	-	-	-	-	-	-	-
26	**Capital expenditure forecast**		35,093	51,238	54,255	43,998	37,487	38,976	40,769	33,582	34,717	38,248	43,317
27													
28	Assets commissioned		28,536	42,672	45,123	36,932	31,745	32,973	35,348	33,322	33,421	36,364	40,542
29													
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31		for year ended	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**
32			**$000 (in constant prices)**										
33	Consumer connection		339	2,723	1,400	1,400	1,400	1,400	1,400	1,000	1,000	1,000	1,000
34	System growth		1,050	2,648	2,500	500	500	500	500	500	500	500	500
35	Asset replacement and renewal		24,892	36,974	40,072	27,886	25,467	26,680	26,287	20,317	19,867	22,817	25,675
36	Asset relocations		491	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
37	Reliability, safety and environment:												
38	Quality of supply		-	-	-	-	-	-	-	-	-	-	-
39	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
40	Other Reliability, Safety and Environment		316	520	500	500	750	750	750	500	500	500	500
41	**Total reliability, safety and environment**		316	520	500	500	750	750	750	500	500	500	500
42	**Expenditure on network assets**		27,087	44,865	46,472	32,286	30,117	31,330	30,937	24,317	23,867	26,817	29,675
43	Expenditure on non-network assets		8,147	6,727	7,018	10,606	6,005	5,456	6,733	6,412	7,263	6,666	7,309
44	**Expenditure on assets**		35,233	51,592	53,490	42,893	36,122	36,786	37,670	30,728	31,129	33,483	36,984
45	**Subcomponents of expenditure on assets (where known)**												
46	Research and development												

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
47												
49	for year ended	30 Sep 21	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26	30 Sep 27	30 Sep 28	30 Sep 29	30 Sep 30	30 Sep 31
50	**Difference between nominal and constant price forecasts**	**$000**										
51	Consumer connection	-	54	57	86	115	146	177	149	172	195	219
52	System growth	-	53	101	31	41	52	63	74	86	98	109
53	Asset replacement and renewal	-	739	1,619	1,707	2,099	2,777	3,316	3,021	3,410	4,451	5,623
54	Asset relocations	-	40	81	122	165	208	252	297	343	390	438
55	Reliability, safety and environment:											
56	Quality of supply	-	-	-	-	-	-	-	-	-	-	-
57	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
58	Other Reliability, Safety and Environment	-	10	20	31	62	78	95	74	86	98	109
59	**Total reliability, safety and environment**	-	10	20	31	62	78	95	74	86	98	109
60	**Expenditure on network assets**	-	897	1,877	1,976	2,483	3,261	3,903	3,616	4,097	5,232	6,499
61	Expenditure on non-network assets	-	135	284	649	495	568	849	953	1,247	1,301	1,601
62	**Expenditure on assets**	-	1,032	2,161	2,625	2,978	3,829	4,753	4,569	5,344	6,532	8,099

11a(ii): Consumer Connection

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
64	for year ended	30 Sep 21	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26
65	*Consumer types defined by GTB**	**$000 (in constant prices)**					
66	400 Pipeline Otorohanga Happy Valley Dairy plant	330	1,773	-	-	-	-
67	Marsden Pt DP Upgrade	0	-	-	-	-	-
	Mangorei DP Customer Connection	0	-	-	-	-	-
68	Waikeria DP upgrade	0	-	-	-	-	-
69	Tokoroa DP Olam Supply	1	400	-	-	-	-
	Henderson CS gas capacity increase	8	-	-	-	-	-
	Tauriko DP		400				
	Taranaki Receipt point conversion						
70	Customer connections	-	150	1,400	1,400	1,400	1,400
71	** include additional rows if needed*						
72	**Consumer connection expenditure**	339	2,723	1,400	1,400	1,400	1,400
73	*less* Capital contributions funding consumer connection	-	-	-	-	-	-
74	**Consumer connection less capital contributions**	339	2,723	1,400	1,400	1,400	1,400

11a(iii): System Growth

Row		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
76	Pipes	460	2,148	2,000	-	-	-
77	Compressor stations	-	-	-	-	-	-
78	Other stations	590	500	500	500	500	500
79	SCADA and communications	-	-	-	-	-	-
80	Special crossings	-	-	-	-	-	-
81	**System growth expenditure**	1,050	2,648	2,500	500	500	500
82	*less* Capital contributions funding system growth						
83	**System growth less capital contributions**	1,050	2,648	2,500	500	500	500
84							

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
85	for year ended	30 Sep 21	30 Sep 22	30 Sep 23	30 Sep 24	30 Sep 25	30 Sep 26
86	**11a(iv): Asset Replacement and Renewal**						
87		**$000 (in constant prices)**					
88	Pipes	14,599	12,100	11,100	11,600	15,100	14,100
89	Compressor stations	2,007	16,835	15,500	2,000	2,000	3,000
90	Other stations	3,790	4,850	5,900	5,500	5,500	5,500
91	SCADA and communications	462	550	3,534	6,950	1,300	400
92	Special crossings	-	88	44	44	44	44
93	*Components of stations (where known)*						
94	Main-line valves	508	650	612	612	391	500
95	Heating system	2,321	650	2,385	385	385	2,457
96	Odorisation plants	455	89	89	89	89	100
97	Coalescers	0	300	50	50	50	50
98	Metering system	382	613	689	439	439	439
99	Cathodic protection	184	248	90	90	90	90
100	Chromatographs	183	-	79	128	79	-
101	**Asset replacement and renewal expenditure**	24,892	36,974	40,072	27,886	25,467	26,680
102	*less* Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
103	**Asset replacement and renewal less capital contributions**	24,892	36,974	40,072	27,886	25,467	26,680
104	**11a(v): Asset Relocations**						
105	**Project or programme***						
106	402Line Te Rapa Realignment – POAL	183					
107	402line recoat and protection	47					
108	Transmission Gully Pipeline relocations	53					
109	400line SH3 Rapanui Crossing Remediation	67					
	200 Line Ladies Mile Pipeline Realignment	73					
	Murphys road Re-alignment	52					
110	800 Pipeline Tauriko Business Estate Re-alignment	15					
111	** include additional rows if needed*						
112	All other projects or programmes - asset relocations		2,000	2,000	2,000	2,000	2,000
113	**Asset relocations expenditure**	491	2,000	2,000	2,000	2,000	2,000
114	*less* Capital contributions funding asset relocations	442	1,800	1,800	1,800	1,800	1,800
115	**Asset Relocations less capital contributions**	49	200	200	200	200	200
116	**11a(vi): Quality of Supply**						
117	**Project or programme***						
118							
119							
120							
121							
122							
123	** include additional rows if needed*						
124	All other projects or programmes - quality of supply						
125	**Quality of supply expenditure**	-	-	-	-	-	-
126	*less* Capital contributions funding quality of supply						
127	**Quality of supply less capital contributions**	-	-	-	-	-	-
128							

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	-	-	-	-	-	-

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**

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

Project or programme*	$000 (in constant prices)					
Minor Management of Technical Change	152					
Compressor Critical spares	164					
	-					
** include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment		520	500	500	750	750
Other reliability, safety and environment total	316	520	500	500	750	750
less Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
Other reliability, safety and environment less capital contributions	316	520	500	500	750	750

11a(ix): Non-Network Assets

Routine expenditure

Project or programme*	$000 (in constant prices)					
ICT	5,686	5,608	5,752	4,441	4,327	4,162
Vehicles	897	380	571	571	571	571
Property	1,264	389	196	5,095	607	224
Plant and equipment	301	350	500	500	500	500
	-	-	-	-	-	-
** include additional rows if needed*						
All other projects or programmes - routine expenditure	-	-	-	-	-	-
Routine expenditure	8,147	6,727	7,018	10,606	6,005	5,456

Atypical expenditure

Project or programme*						
** include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	-	-	-	-	-
Expenditure on non-network assets	8,147	6,727	7,018	10,606	6,005	5,456

Schedule 11b: Report on forecast operational expenditure

Company Name	**Firstgas**
AMP Planning Period	**1 October 2021 – 30 September 2031**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

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

sch ref												
7												
8		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
9	for year ended	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**
10	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
11	Service interruptions, incidents and emergencies	732	777	793	809	825	841	858	875	893	911	929
12	Routine and corrective maintenance and inspection	13,932	15,169	15,473	15,782	16,098	16,420	16,748	17,083	17,425	17,773	18,129
13	Asset replacement and renewal											
14	Compressor fuel	5,208	7,956	8,115	8,490	8,659	9,385	9,572	10,338	10,545	10,756	10,971
15	Land management and associated activity	1,541	1,636	1,668	1,702	1,736	1,771	1,806	1,842	1,879	1,917	1,955
16	**Network opex**	21,414	25,538	26,049	26,782	27,318	28,416	28,985	30,139	30,742	31,356	31,983
17	System operations	3,312	3,515	3,585	3,657	3,730	3,805	3,881	3,958	4,038	4,118	4,201
18	Network support	3,807	4,041	4,538	4,628	4,721	4,815	4,912	5,010	5,110	5,212	5,316
19	Business support	15,790	16,758	17,093	17,435	17,784	18,139	18,502	18,872	19,250	19,635	20,027
20	**Non-network opex**	22,909	24,313	25,216	25,720	26,235	26,759	27,294	27,840	28,397	28,965	29,544
21	**Operational expenditure**	44,323	49,852	51,265	52,502	53,553	55,176	56,279	57,979	59,139	60,321	61,528
22		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
23	for year ended	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**
24		**$000 (in constant prices)**										
25	Service interruptions, incidents and emergencies	732	762	762	762	762	762	762	762	762	762	762
26	Routine and corrective maintenance and inspection	13,932	14,872	14,872	14,872	14,872	14,872	14,872	14,872	14,872	14,872	14,872
27	Asset replacement and renewal	-	-	-	-	-	-	-	-	-	-	-
28	Compressor fuel	5,208	7,800	7,800	8,000	8,000	8,500	8,500	9,000	9,000	9,000	9,000
29	Land management and associated activity	1,541	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604	1,604
30	**Network opex**	21,414	25,038	25,038	25,238	25,238	25,738	25,738	26,238	26,238	26,238	26,238
31	System operations	3,312	3,446	3,446	3,446	3,446	3,446	3,446	3,446	3,446	3,446	3,446
32	Network support	3,807	3,961	4,361	4,361	4,361	4,361	4,361	4,361	4,361	4,361	4,361
33	Business support	15,790	16,429	16,429	16,429	16,429	16,429	16,429	16,429	16,429	16,429	16,429
34	**Non-network opex**	22,909	23,837	24,237	24,237	24,237	24,237	24,237	24,237	24,237	24,237	24,237
35	**Operational expenditure**	44,323	48,874	49,274	49,474	49,474	49,974	49,974	50,474	50,474	50,474	50,474
36	**Subcomponents of operational expenditure (where known)**											
37	Research and Development											
38	Insurance											

39			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40		for year ended	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**	**30 Sep 27**	**30 Sep 28**	**30 Sep 29**	**30 Sep 30**	**30 Sep 31**
41	**Difference between nominal and real forecasts**		**$000**										
42	Service interruptions, incidents and emergencies		-	15	31	47	63	79	96	113	131	149	167
43	Routine and corrective maintenance and inspection		-	297	601	910	1,226	1,548	1,876	2,211	2,553	2,901	3,257
44	Asset replacement and renewal		-	-	-	-	-	-	-	-	-	-	-
45	Compressor fuel		-	156	315	490	659	885	1,072	1,338	1,545	1,756	1,971
46	Land management and associated activity		-	32	65	98	132	167	202	238	275	313	351
47	**Network opex**		-	501	1,012	1,545	2,080	2,679	3,247	3,901	4,504	5,119	5,746
48	System operations		-	69	139	211	284	359	435	512	592	672	755
49	Network support		-	79	176	267	360	454	550	648	749	851	955
50	Business support		-	329	664	1,006	1,354	1,710	2,073	2,443	2,820	3,205	3,598
51	**Non-network opex**		-	477	979	1,483	1,998	2,523	3,058	3,604	4,160	4,728	5,308
52	**Operational expenditure**		-	977	1,991	3,028	4,078	5,201	6,305	7,505	8,664	9,847	11,054

Schedule 12a: Report on asset condition

Company Name	**Firstgas**
AMP Planning Period	**1 October 2021 – 30 September 2031**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref

				Asset condition at start of planning period (percentage of units by grade)						
7										
8	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
9	Pipes	Protected steel pipes	km	-	1.19%	37.73%	61.08%	-	3	-
10	Pipes	Special crossings	km	-	2.00%	98.00%	-	-	3	-
11	Stations	Compressor stations	No.	-	22.22%	77.78%	-	-	3	
12	Stations	Offtake point	No.	-	4.55%	94.70%	0.76%	-	3	
13	Stations	Scraper stations	No.	-	-	100.00%	-	-	3	
14	Stations	Intake points	No.	-	-	100.00%	-	-	3	
15	Stations	Metering stations	No.	-	-	100.00%	-	-	3	
16	Compressors	Compressors—turbine driven	No.	-	50.00%	50.00%	-	-	3	
17	Compressors	Compressors—electric motor driven	No.	-	-	100.00%	-	-	3	
18	Compressors	Compressors—reciprocating engine driven	No.	7.14%	-	92.86%	-	-	4	14%
19	Main-line valves	Main line valves manually operated	No.	-	10.67%	89.33%	-	-	3	
20	Main-line valves	Main line valves remotely operated	No.	-	-	100.00%	-	-	3	
21	Heating systems	Gas-fired heaters	No.	28.57%	28.57%	41.90%	0.95%	-	3	12%
22	Heating systems	Electric heaters	No.	-	-	100.00%	-	-	4	
23	Odorisation plants	Odorisation plants	No.	-	18.18%	81.82%	-	-	3	
24	Coalescers	Coalescers	No.	-	-	100.00%	-	-	3	
25	Metering systems	Meters—ultrasonic	No.	20.00%	30.00%	50.00%	-	-	4	20%
26	Metering systems	Meters—rotary	No.	36.07%	13.11%	34.43%	16.39%	-	4	20%
27	Metering systems	Meters turbine	No.	64.94%	11.69%	20.78%	2.60%	-	4	20%
28	Metering systems	Meters—mass flow	No.	-	-	100.00%	-	-	3	
29	SCADA and communications	Remote terminal units (RTU)	No.	-	-	100.00%	-	-	3	
30	SCADA and communications	Communications terminals	No.	-	33.33%	66.67%	-	-	4	33%
31	Cathodic protection	Rectifier units	No.	-	20.41%	79.59%	-	-	3	
32	Chromatographs	Chromatographs	No.	-	54.55%	36.36%	9.09%	-	4	

Company Name	**Firstgas**
AMP Planning Period	**1 October 2021 – 30 September 2031**

SCHEDULE 12b: REPORT ON FORECAST DEMAND

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

sch ref

12b(i): Connections

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**
Connection types defined by GTB						
Distribution System		3	-	1	1	-
Direct Connect		-	-	-	-	1
Bi-directional		1	1	-	-	-
Receipt Point		-	-	-	-	-
** include additional rows if needed*						
Connections total	-	4	1	1	1	1

12b(ii): Gas conveyed

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**30 Sep 21**	**30 Sep 22**	**30 Sep 23**	**30 Sep 24**	**30 Sep 25**	**30 Sep 26**
Intake volume (TJ)	152,341	149,127	149,127	149,127	149,127	149,127
Quantity of gas delivered (TJ)	152,341	149,127	149,127	149,127	149,127	149,127
Gas used in compressor stations (TJ)	676	676	676	676	676	676
Gas used in heating systems (TJ)	123	123	123	123	123	123
Total gas conveyed (TJ)	153,140	149,926	149,926	149,926	149,926	149,926

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
FY2021	0.00%
FY2022	2.00%
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%

APPENDIX C: PIPELINE CAPACITY

Table 10: North Pipeline Capacity Forecast

DELIVERY POINT		AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
			FY2021	FY2026	FY2031
Tuakau 2		3,622	41,744	41,661	19,033
Harrisville 2		1,453	37,007	35,765	35,765
Ramarama		86	14,212	14,365	14,364
Drury 1		669	115,396	120,521	120,047
Pukekohe		235	53,183	49,943	49,802
Glenbrook		7,100	137,279	24,224	24,191
GREATER AUCKLAND	Total for Greater Auckland	43,030	49,287	60,296	59,280
	Bruce McLaren	1,957	6,775	8,365	8,311
	Henderson	2,912	10,081	12,052	11,872
	Papakura	11,112	38,474	38,270	38,088
	Waikumete	5,087	17,612	23,420	23,044
	Westfield	21,963	49,287	60,296	59,280
Hunua (Three DPs)		1,513	84,663	139,731	139,202
Flat Bush		1,622	81,115	106,228	105,736
Waitoki		1,584	3,022	16,472	17,442
Marsden (Both DPs)		14,818 (18 after 2022)	1,544	16,172	16,088
Whangarei		428	2,290	10,148	10,131
Kauri + Maungaturoto		2,500	2,238	8,631	8,614
Alfriston		50	13,727	13,810	13,809
Waiuku		221	19,715	19,430	19,348
Warkworth 2		1,555	729	13,138	13,081

Notes:

- The peak week was the week ending the 5 July 2020.
- 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.
- Westfield uncommitted operational capacity limited by Greater Auckland uncommitted operational capacity.
- Aggregate Contractual Capacity is apportioned to Bruce McLaren, Henderson, Papakura, Waikumete and Westfield in proportion to the operational capacity for these delivery points during FY 2021.
- New Zealand Refining assumed shut down after FY2022 with only a small residual load.
- New 100NB pipeline for Warkworth 2 to be constructed and operational in FY2022.

Table 11: Bay of Plenty Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2021	FY2026	FY2031
Broadlands	173	2,751	2,692	2,973
Edgecumbe (Both DPs)	4,650	1,652	1,544	1,578
Gisborne	1,134	3,240	3,236	4,545
Mount Maunganui	2,329	3,498	1,424	2,315
Tauranga (Includes Pyes Pa)	910	1,955	1,205	1,932
Kawerau (Three DPs)	1,867	10,949	10,422	10,598
Kihikihi	182	114,944	96,987	148,435
Kinleith (Both DPs)	12,606	27,333	25,687	26,084
Lichfield (Both DPs)	5,750	22,197	22,023	22,045
Opotiki	34	3,523	3,469	4,572
Putaruru	301	32,029	17,156	20,580
Rangiuru	226	886	875	886
Reporoa	1,964	3,489	3,425	3,454
Rotorua	989	2,134	2,102	2,109
Taupo	285	2,784	2,728	2,888
Tauriko	3,300 (est'd)		2,053	2,675
Te Puke	85	2,478	1,046	1,491
Tirau (Both DPs)	12	15,982	8,498	15,232
Tokoroa	357	27,321	25,731	30,142
Waikeria	58	43,926	35,272	40,930
Whakatane	3,631	2,107	2,008	2,038

Notes:

- The peak week for this system was the week ending 27 October 2019.
- 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 estimated demand at a new Delivery Point is being constructed near Tauriko (on the line to Tauranga/Mt Maunganui) has been included in 2026 and 2031, at 3,300 GJ/day.

Table 12: Central North Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2021	FY2026	FY2031
Cambridge	1,711	2,172	2,160	2,148
Greater Hamilton	5,138	24,848	23,857	22,794
Horotiu	2,744	14,343	13,459	12,517
Kiwitahi	1,000	4,259	3,970	3,671
Morrinsville	470	4,993	4,758	4,517
Tatuanui	1,500	4,051	3,487	3,215
Te Rapa Cogen	23,200	17,654	16,589	15,467
Waitoa	1,143	4,332	4,185	3,887

Notes:

- The peak week was the week ending 28 August 2020.
- 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)		
		FY2021	FY2026	FY2031
Eltham	622	9,394	9,394	9,393
Inglewood	97	9,969	9,967	9,966
Kaponga	6	5,008	5,008	5,008
New Plymouth	2,674	3,617	3,603	3,588
Stratford	252	59,063	58,934	58,800
Waitara	300	5,249	5,249	5,249

Notes:

- The peak week, with Pokuru 2 offtake excluded, was the week ending 3 July 2020.
- 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)		
		FY2021	FY2026	FY2031
Ashhurst	21	Nil	5,621	5,210
Belmont	5,347	Nil	3,832	3,552
Dannevirke	163	Nil	8,679	8,245
Feilding	865	Nil	3,280	3,162
Foxton	100	Nil	4,194	3,913
Hastings (Both DPs)	6,673	Nil	4,580	4,427
Hawera (Both DPs)	726	Nil	49,141	47,792
Kaitoke	97	Nil	2,619	2,625
Kakariki	295	Nil	6,456	6,374
Greater Kapati	401	Nil	2,458	3,199
Lake Alice	123	Nil	3,227	3,180
Levin	773	Nil	4,307	4,167
Longburn	512	Nil	4,415	4,264
Manaia	59	Nil	3,485	3,484
Mangaroa	102	Nil	4,981	4,724
Marton	817	Nil	5,402	5,307
Otaki	55	Nil	4,373	4,061
Pahiatua (Both DPs)	890	Nil	16,448	13,608
Palmerston North	3,229	Nil	3,542	3,400
Patea	42	Nil	36,782	42,501
Takapau	409	Nil	6,439	5,948
Tawa (Both DPs)	8,873	Nil	3,832	3,571
Greater Waitangirua	1,230	Nil	4,088	3,851
Waitotara	126	Nil	24,220	24,204
Whanganui	4,081	Nil	42,893	41,298
Waverley	1	Nil	908	908

Notes:

- The South System's Peak week was the week ending 3 July 2020.
- 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. This has been reassessed since the 2020 AMP.

F2021:

- 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 between Hawera Delivery Point and Kaitoke Compression is out of service.

FY2026 and FY2031:

- 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 is reinstated and regulated to 68 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)		
		FY2021	FY2026	FY2031
Ammonia-Urea Plant	22,500	12,580	19,002	19,002
Kaimiro DP	-	55,109	89,535	89,535
Kapuni (Lactose	-	11,861	14,940	14,940
Kapuni GTP	25,000	44,062	83,458	83,458
TCC + Stratford 2 + Stratford 3	170,000	40,912	40,912	40,912

Notes:

- The peak week was the week ending 19 July 2020.
- 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 2025.

Table 16: Maui System Pipeline Capacity Forecast

DELIVERY POINT	AGGREGATE CONTRACTUAL CAPACITY (GJ/DAY)	UNCOMMITTED OPERATIONAL CAPACITY (GJ/DAY)		
		FY2021	FY2026	FY2031
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:

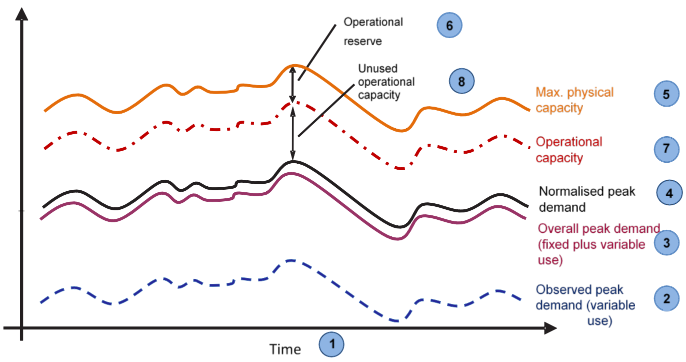
- The peak week for this system was the week ending 1 March 2020.
- On the Maui System, each Shipper's capacity for a day is its approved nominated quantity for that day, i.e., Shippers do not have rights to firm capacity. Therefore, "Aggregate Contractual Capacity" does not apply on the Maui System 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 Pukearuhe bypass line is a temporary installation which imposes some restriction on the pipeline. It has been allowed for in the 2021 forecasting but has been assumed to be replaced with full size pipe by FY2025.
- Pipeline capacity was not determined for Okato or Ngaruawahia because of their low demand.

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 26: 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

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.[21]

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[22]").

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 . 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[24] 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.[25] 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.

21. Indicating that a further such peak demand period would be sustainable.
22. 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.
23. Meaning that, while the pressure at different points in the pipeline will cycle up and down within a day, the minimum and maximum levels reached may trend lower from day to day. This may occur for several reasons, including operational reasons, coincident peak demand being higher than anticipated or shippers exceeding their capacity entitlements. Where there is compression at the inlet to a pipeline, First Gas generally operates it in a constant pressure mode (maintaining inlet pressure at relatively constant level).
24. 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.
25. 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.[26]

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[27] 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.[28] 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 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.

26. As discussed in the System Security Standard.
27. The Bay of Plenty pipeline does not display a strong overall winter peak.
28. 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.

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[29]. 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[30] redundancy (as set out in the system security standard). However, a redundant compressor may also fail, or fail to start,[31] 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.

29. 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.
30. 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.
31. 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: WEBINAR FEEDBACK AND QUESTIONS

Table 17 below sets out the questions raised during the June 2021 webinar with stakeholders and our responses to their queries.

Table 17: Q & As from June 2021 stakeholder webinar

QUESTIONS / FEEDBACK FROM STAKEHOLDERS	OUR RESPONSE AND ACTIONS TO OUR STAKEHOLDER FEEDBACK
How can there be 100% hydrogen distributed in your pipelines in 2040's, when there is likely to still be a core demand for the supply of natural gas?	Our hydrogen trial report shows a possible sequence of converting the gas networks – starting at the outer extremities and working in towards Taranaki. The idea is that those parts of the network with high levels of remaining natural gas demand in 2040 would go relatively later, while those areas with higher demand for hydrogen would go earlier. Actual sequencing decisions will not need to be made for some time to come.
Rod Carr said you should get on with it [action to address climate change and work on zero carbon fuels]. Is Firstgas getting on with it?	Yes. Firstgas has a programme of work to explore the transport of net zero carbon gases through our existing gas infrastructure. Firstgas, along with Beca, Fonterra and EECA has released a joint Biomethane Study that reveals biomethane is a viable, untapped solution to decarbonising New Zealand's residential natural gas network right now. Biomethane has the potential to replace more than 16% of New Zealand's total gas usage by 2050. We also recently released our Hydrogen Feasibility Study that shows that we can introduce hydrogen into the Firstgas pipeline network from 2030 and convert to 100% hydrogen by 2050. Work is now progressing to commence a hydrogen pipeline trial. See section 3 of this AMP Update and our website **www.gasischanging.co.nz**.
What is the cost impact of moving to 100% hydrogen?	The Hydrogen Feasibility Study covers the estimated network costs for gas distribution system conversion. The study suggests that there not much cost impact over and above historical levels of asset replacement and renewal. The study does not cover the full gas transmission system conversion. There are still outstanding research programmes internationally that will help to inform those cost estimates (specifically around high grade steel performance). Consumer cost impacts will be mainly driven by the cost of hydrogen production. The hydrogen study contains some cost projections. However, these are conservative when compared with targets announced overseas, such as the Australia A$2/kg target and the US DOE 'Earthshot' target of US$1/kg by 2030.
The original plan for expenditure on the compressor strategy was $100 million [as stated in the 2020 AMP]. Will that money be spent elsewhere?	No. Our forecast for compression expenditure over the planning period has reduced and has not been reallocated elsewhere.

QUESTIONS / FEEDBACK FROM STAKEHOLDERS	OUR RESPONSE AND ACTIONS TO OUR STAKEHOLDER FEEDBACK
Will the January 2022 shut down [for the Pariroa and Gilbert Stream projects] limit [gas] supply and what are the measures for rationing supply?	Firstgas will be relying on provisions under our existing transmission codes[32] and associated contracts to ensure that gas injection and offtakes are done in the manner requested and required to successfully complete the scheduled work on both the Gilbert Stream realignment and Pariroa tie-in projects. Firstgas is requesting that the largest gas users on the affected parts of the transmission system stop using gas for the duration of the tie-in process. We are also working with other large users to explore any opportunities they may have to minimise gas usage during the period, including using the time to
Why is the IS security maturity model still the same as in 2017?	The IS model shown was to illustrate an improvement based on the 2017 IS security maturity model and assessment. The original improvement programme spanned three years. A new assessment has already been completed and is based on a 2021 maturity model. The ongoing information security investment will be based on this 2021 maturity model. This new programme will also span multiple years.
Will cost of the OATIS replacement feature in [Firstgas' forecast expenditure] upcoming DPP [reset for 2022 – 2027]?	Yes. The costs associated with the OATIS replacement are factored in as part of the normal technology lifecycle costs and included in our Non networks assets category.
Any insights on the proposed tariffs [for gas transmission customer for the year starting 1 October 2021, FY2022]?	We have undertaken consultation with consumers about the proposed transmission tariffs for the upcoming gas year (starting 1 October 2022), under both the Vector Transmission Code and the Maui Pipeline Operating Code. A letter was sent to all customers outlining the increase in tariffs, and the factors driving these increases. Feedback on the proposed tariffs closed on 18 June 2021. The final tariffs for gas transmission will be published on 2 August 2021 (Maui pricing) and 1 September 2021 (Vector Transmission Code pricing). Any feedback on the proposed tariffs will be incorporated into the Transmission Pricing Methodology for FY2022.

32. The Maui Pipeline Operating Code and the Vector Transmission Code

APPENDIX F: DIRECTOR CERTIFICATE

Certification for Year beginning Disclosures

Clause 2.9.1

We, Mark Adrian Ratcliffe and Fiona Ann Oliver, being directors of Firstgas 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 t hat 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

11 August 2021

Date

Director: Fiona Ann Oliver

11 August 2021

Date