SUBMISSION

Default price-quality paths for gas pipeline businesses from 1 October 2017 to 30 September 2022

Draft reasons paper

First Gas Limited
10 March 2017

Executive Summary

This is the First Gas submission on the "Default price-quality paths for gas pipeline businesses from 1 October 2017 to 30 September 2022: Draft reasons paper" (the draft decisions). The proposed reductions to our forecast operational and capital expenditure for our gas transmission and distribution businesses will negatively impact on our ability to manage risk and provide resilient network services. This submission explains why this is not in the long-term interest of consumers, and recommends improvements for the final DPP reset decisions.

Context for the draft decisions

If implemented, the draft decisions would lead to a significant reduction in our revenue:

- Part of this reduction (around 60 percent) arises from changes in estimating the regulatory Weighted Average Cost of Capital (WACC). The draft decisions implement the WACC input methodologies (IMs), so this element of the price reset is not discussed in any detail in this submission.

- The remainder of the proposed reduction in our revenue comes from decisions that are made through the DPP process – particularly on whether to allow our forecasts of capital expenditure (capex) and operating expenditure (opex) to be funded through our prices. This submission focuses on those decisions.

We appreciate that many of the approaches used at this DPP reset are new, and that the draft decisions reflect the need to test and refine these approaches. The purpose of this submission is to help ensure that the final DPP reset decisions better achieve the purpose of Part 4 of the Commerce Act. While we continue to generally support the intent of changes in approach introduced at this DPP reset, we are firmly of the view that the proposed revenue reductions would lead to outcomes that are not in the long-term interests of consumers.

The DPP reset should enable the risk profile of gas transmission to be effectively managed

A major theme of this submission is that the DPP should provide sufficient revenue to allow regulated businesses to meet regulatory and contractual service standards. In the case of our gas transmission business (GTB), this means enabling First Gas to maintain safety, security and reliability risks at current levels and to discharge our responsibilities as a reasonable and prudent operator (RPO). This includes meeting key regulatory obligations across a number of regulatory frameworks that ultimately require First Gas to provide safe, reliable and efficient delivery of gas to customers.

We submit that the expenditure allowances in the draft decisions would not enable us to provide safe, reliable and efficient delivery of gas to customers. Since taking over the ownership of gas transmission pipelines, First Gas has put considerable effort into developing a strong understanding of network risks and preparing an Asset Management Plan (AMP) that explains the expenditure levels required to appropriately manage these risks. The Commission has disallowed expenditure that is necessary for First Gas to adequately manage identified safety and resilience risks, and we urge the Commission to reconsider its decisions on GTB capex and opex. We provide further evidence of the need for this expenditure in this submission, together with further information to support our forecasts for distribution system growth capex and customer connection capex that has also been disallowed in the draft decisions.

A particular challenge at this DPP reset is that trends based on the historical expenditure of previous owners may not be a good guide to the future expenditure needs facing First Gas. Expenditure levels prior to most asset sales are likely to be lower than ongoing sustainable network needs as the vendors seek to increase the financial returns of the business and make it more attractive to prospective buyers. Vendors are also likely to choose to leave significant investment decisions for the new owner. We believe that the Commission can and should take these factors into account when seeking to understand our forecasts of expenditure needs and establishing fall-backs that enable First Gas to meet customer demands and comply with regulatory requirements.

We recommend changes to the draft decisions to deliver better outcomes for consumers

This submission explains why we consider that the draft decisions are not in the long-term interests of consumers. The reasons for this conclusion fall into two categories:

- **Good regulatory design.** The Commission is applying a more tailored approach to DPP expenditure allowances for the first time – and we expect both the Commission and regulated suppliers will learn from this process. We have identified several areas where the draft decisions create undesirable incentives for suppliers to shift the timing or categorisation of expenditure forecasts presented in AMPs (section 2). We are also concerned about unintended consequences from the average price increase limit proposed by the Commission under our revenue cap with wash-ups (section 5).

- **Prudent and efficient expenditure needs.** This submission provides additional detail to support expenditure that has been disallowed by the Commission (section 3). We also provide a report from an independent expert (Chris Harvey), who has reviewed our expenditure forecasts and supporting information against reasonable industry practice for gas pipelines and the test of only allowing prudent and efficient expenditure to be funded through prices (**Appendix A**).

Transmission Asset Replacement and Renewal capex is needed to maintain a resilient network

The draft decisions provide an allowance of $56.5 million[1] for asset renewal and replacement (ARR) expenditure. This is significantly lower than our forecast in this capex category of $121.9 million (including the White Cliffs realignment).

Given that the Commission has indicated that the White Cliffs realignment is better suited to a Customised Price-quality Path (CPP), the expenditure related to this project should be removed from the review process applied under the DPP. If this approach is not followed, then suppliers may be reluctant to disclose and engage on major expenditure projects due to the risk that DPP allowances immediately revert to historic fall-back levels. We have been open about our views on the timing of White Cliffs expenditure, and it would not be in consumers' interests for that transparency to work against us (which is the outcome delivered by the draft decisions).

Once the White Cliffs realignment is removed from our DPP expenditure forecasts, we are still forecasting a "step up" in ARR capex. This is due to two factors:

- **Gilbert Stream realignment.** We have provided further information to the Commission on this project (available on the Commission's website[2]), and we are confident that the forecast expenditure is prudent, efficient and necessary to ensure continued reliable gas supply; and

- **Increase in programmatic ARR.** The need for this expenditure appears to have been accepted by the Commission's consultants (Strata). However, we have provided additional evidence on programmatic ARR in this submission, since the Commission may not have yet considered justification for the scale of the increase we have forecasted. We firmly consider that a higher level of programmatic expenditure is needed to provide a safe, reliable and efficient transmission network. The details of the key expenditure drivers are provided in section 3, and include essential activities

[1] All figures in real terms, sourced from "Inputs" and "Totals" tabs from *Gas DPP reset – Expenditure model – 10 February 2017*, Commerce Commission, http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/

[2] Gas DPP – First Gas response to Commission questions – 17 February 2017, published on 24 February 2017, http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/

Firstgas

such as undertaking regular in-line-inspections (previously categorised as opex); completing safety and reliability upgrades at aging compressor stations; carrying out geohazard risk mitigation works; replacing equipment that is no longer supported by manufacturers; modifying piping to meet current safety requirements; replacing leaking valves; and replacing parts of the pipeline corrosion prevention system that are more than 40 years old.

Transmission RCMI opex is needed to identify and remediate network risks

The draft decisions provide an allowance for average annual transmission opex of $39.5 million. This is significantly lower than the opex forecast by First Gas of around $42.7 million. The draft decisions also represent a reduction in aggregate opex compared to the historic operating costs incurred by Vector and MDL of $40.1 million (once reclassified in-line inspection costs are removed). The opex category where GTB expenditure was disallowed is RCMI, where our forecast of $85.1 million was reduced to an allowance of $71.2 million in the draft decisions.

We consider that there are compelling reasons to accept our forecast RCMI opex that was disallowed in the draft decisions:

- Part of the apparent increase is due to the reclassification of opex that had been categorised by the previous owner of the Maui pipeline (from ARR opex to RCMI). Given that Vector and MDL had different approaches to classifying this expenditure, we needed to choose one of these categories to apply a consistent approach across our GTB. We selected the RCMI category as it provides a better fit for the type of activity involved and is consistent with the practice followed by most other gas pipeline owners (Vector and GasNet); and

- Part of the increase relates to a more active programme of geohazard assessment and remediation, which is essential to ensuring a resilient gas transmission network. We have provided a better description of the opex budgeted to identify and address geohazard risks, and have provided supporting reports that illustrate that heightened level of activity around geohazards compared with historic levels of expenditure. This expenditure directly relates to mitigating safety, security and reliability risks.

We also strongly believe that a reduction in aggregate opex for gas transmission is not in the long-term interests of consumers, and does not follow good regulatory practice. While the regulatory process should share efficiency gains with consumers over time, it is important that suppliers benefit from any cost reductions for a period to maintain incentives for those savings to be achieved.

We understood that the Commission intended to safeguard against such an outcome through the alternative fall-back of applying the “step and trend” model used in previous DPP resets[3]. However, we understand that the Commission did not in fact apply this alternative fall-back in the draft decisions. We therefore encourage the Commission to reconsider the aggregate levels of opex allowed for our GTB (and other regulated suppliers) to ensure that the opex allowance provided is no lower than the result of the opex step and trend model.

Distribution capex for system growth is needed to meet peak demand

The Commission has proposed an allowance of $3.4 million for system growth capex for our distribution networks, which is significantly lower than our AMP forecast of $16.4 million.

Expenditure in this category is driven by forecast levels of peak demand growth and our system modelling of the peak week by network (presented in our AMP). We understand that peak demand was not used by the

[3] As described in paragraph 4.44 of the draft decisions paper.

Commission/Strata as a metric for analysing the need for growth,[4] so the underlying rationale for investment may not be adequately reflected in the draft decisions.

We clarify the specific initiatives that support our capex forecasts in this category, including our proposed expansion to deliver more capacity in Cambridge. Much of this expenditure relates to costs that were deferred by the previous network owner (Vector), which, as noted above is not surprising given its decision to sell the networks. This deferral has two implications for this DPP reset in creating:

- The need to substantially increase system growth capex over the coming period to meet the future needs of our customers; and
- An artificially depressed baseline for evaluating variances and fall-back levels of expenditure.

We also demonstrate why the forecast capex in our AMP is necessary to meet customer demand in Ruakura and Cambridge that has already been improved. If this expenditure did not proceed then the ability to accommodate future growth and maintain the reliability of the network would be compromised.

We have revised our forecast of distribution customer connections capex to align with CPRG

The Commission has proposed an allowance of $9.8 million for system growth capex for our distribution networks, which is considerably lower than our AMP forecast of $20.5 million.

We see merit in applying a consistent approach to forecasting Constant Price Revenue Growth (CPRG) and the capex required for customer connections. We strongly support the incentives for growth that are provided by the Weighted Average Price Cap (WAPC) form of control for gas distribution, and believe that this is essential to provide the right incentives to get reticulated gas into more homes and businesses. A result of this form of regulatory control is that we have financial incentives to outperform the Commission's connection growth forecasts, which increases the efficiency of our networks.

However, even with a consistent view of growth, the fall-back level of expenditure for this category is too low. Using a connections growth forecast of 0.7% (from the Commission's CPRG model), we have revised our capex forecast to $13.5 million. This increase above historic expenditure levels is driven by our different approach to supporting growth than the previous network owner, including a different capital contributions policy. This is most clearly evidenced by the experience in Papamoa. A large number of new subdivisions in that area were not reticulated with gas, leading an outside company (GasNet) to invest in pipelines. Again, this has the dual effect of requiring a catch-up in expenditure to reticulate gas through subdivisions that have already been built, and artificially depressing the historic baseline used for variance tests and fall-back expenditure levels.

[4] See paragraph C38.2 of the draft decisions.

Summary of DPP expenditure allowances in categories disallowed in draft decisions

The table below summarises the resulting expenditures that we recommend be incorporated into our DPP allowance:

Business area	Category	First Gas AMP forecast ($million)	Draft DPP allowance ($million)	Recommended DPP allowance ($million)
Transmission Opex	Routine corrective maintenance and inspection (RCMI)	85.1	71.2	85.1
Transmission Capex	Asset Replacement and Renewal (ARR)	121.9	56.5	94.6*
Distribution Capex	System Growth	16.4	3.4	16.4
	Customer Connection	20.5	9.8	13.5**

Notes: * excludes expenditure forecast for the White Cliffs realignment
** using CPRG connection growth rate of 0.7%

The tables on the following pages summarise the activities that the higher levels of expenditure presented above will be used to fund and the consequences of not carrying out those activities.

Table A: Requirements for higher capital expenditure – Transmission

Category	AMP Forecast (2018-2022) ($000s)	Draft DPP Decision (2018-2022) ($000s)	Reasons forecast level is prudent and efficient	Impact of under investment (disallowed areas only)	Allowed or fall-back
Asset relocation	**1,780**	**1,592**			**ALLOWED**
• Asset relocations	1,780		Assumes 90% recovery of costs. Allocation is lower than historical expenditure due to a reduction in anticipated relocation requests. Historical levels are high with Transmission Gully and M2PP projects in recent years.		
Asset replacement and renewal	**121,962**	**55,599**			**FALLBACK**
• Pipes	66,088		Increase on historic levels due to White Cliffs, Gilbert Stream and inclusion of intelligent pigging and geo-hazard remediation to increase network resilience	White Cliffs and Gilbert Stream are at risk of coastal erosion which could instigate a critical contingency. Intelligent pigging is a mandatory requirement to continue to operate the pipeline. Failure to address geo-hazard risks can lead to unplanned pipeline outages and potential loss of supply to customers.	
• Compressor stations	18,766		Consistent with historic levels		
• Other stations	22,003		Increase on historic levels in FY18,19 to accelerate the replacement of obsolete regulators, then consistent with historic levels	Failure to replace the obsolete regulators in time would lead to unplanned station outages and potential loss of supply to customers.	

Category	AMP Forecast (2018-2022) ($000s)	Draft DPP Decision (2018-2022) ($000s)	Reasons forecast level is prudent and efficient	Impact of under investment (disallowed areas only)	Allowed or fall-back
• SCADA and communications	2,230		One-off costs to replace master station in FY18, then consistent with historic annual cost	If the obsolete SCADA system fails, First Gas would lose visibility of the system and would not be able to operate safely	
• Special crossings	208		Consistent with historic levels		
• Main line valves	4,115		Increase above historic levels due to replacement and renewal of known valves	Failure to replace known valve problems increases the risk of being able to operate the system safely	
• Heating system	3,689		Consistent with historic levels to continue with annual heater replacement programme		
• Odorisation plant	305		Consistent with historic levels		
• Coalescers	556		Increase above historic levels in FY18 to deal with a specific issue at Kapuni treatment plant which would prevent future pipeline inspection programme	Failure to address the known filtration issue at Kapuni would prevent First Gas from undertaking the next intelligent inspection	
• Metering systems	2,448		Increase above historic levels to replace obsolete meters which has previously been deferred	Failure to replace obsolete meters increases the risk of under recovery of income	
• Cathodic protection	1,368		Increase above historic levels due to known age replacement programme for rectifiers	Failure to replace rectifiers at the end of their expected life increases the risk of pipeline corrosion forming where rectifiers fail without warning, and causes unplanned outages	

Category	AMP Forecast (2018-2022) ($000s)	Draft DPP Decision (2018-2022) ($000s)	Reasons forecast level is prudent and efficient	Impact of under investment (disallowed areas only)	Allowed or fall-back
• Chromatographs	186		Consistent with historic levels		
Consumer connections	**6,000**	**5,975**			**ALLOWED**
• Consumer connection	6,000		This is less than historic levels for FY16 and FY17, which are elevated due to the Henderson compressor station		
Non-network assets	**18,032**	**16,879**			**ALLOWED**
• ICT	15,652		Systems upgrades associated with new business creation but costs are consistent with historic levels		
• Building refurbishment	2,380		Building refurbishment above historic levels, but needed due to earthquake proofing of headquarters site and general condition of office accommodation		
System growth	**16,898**	**13,909**			**ALLOWED**
• Other stations	16,898		Substantial allowance in FY18 of $6.5M for Warkworth upgrade. Remaining upgrades are normal over the period.		
Reliability, safety and environment	**0**	**0**			
TOTAL	**164,672**	**93,954**			

Firstgas

Table B: Requirements for capital expenditure – Distribution

Category	AMP Forecast (2018-2022) ($000s)	Draft DPP Decision (2018-2022) ($000s)	Reasons forecast level is prudent and efficient	Impact of under investment (disallowed areas only)	Allowed or fall-back
Asset relocation	**700**	**694**			**ALLOWED**
• Asset relocations	700		Assumes approximately 85% recovery of costs. Allocation is lower than historical expenditure due to a reduction in anticipated relocation requests.		
Asset replacement and renewal	**18,030**	**18,146**			**ALLOWED**
• Pipes	13,680		Significant planned investment in pre-1985 PE replacement programme and dedicated coupling/steel replacement in Hamilton. Increased investment due to the commencement of the pre-1985 PE programme.		
• Stations	3,720		Replacement of station equipment due to obsolescence and upgrades to CP systems. Allocation is consistent with FY17 historic level.		
• Main line valves	250		Installation of new valves to meet standard requirements. Consistent with FY17 historic level		
• Service pipes	380		Replacement of bridge crossing supports. Lower average investment than FY17 historic level		

Category	AMP Forecast (2018-2022) ($000s)	Draft DPP Decision (2018-2022) ($000s)	Reasons forecast level is prudent and efficient	Impact of under investment (disallowed areas only)	Allowed or fall-back
Consumer connections	**18,838**	**9,820**			**FALLBACK**
• Mains extension	8,195		Increase above historic levels needed to reticulate more subdivisions with gas and ensure that future developments can be accessed from existing networks	Gas networks become further removed from expanding urban boundaries, ultimately leading to lower rates of asset utilisation and fewer options for consumers	
• Domestic connections	9,483		Consistent with growth forecasts from Covec report. Increase relative to historic trend due to changes to capital contributions policy and growth initiatives	Fewer new connections lead to lower rates of asset utilisation and higher network tariffs over time	
• Commercial/industrial connections	940		Consistent with growth forecasts from Covec report. Increase relative to historic trend due to changes to capital contributions policy and growth initiatives	Fewer new connections lead to lower rates of asset utilisation and higher network tariffs over time	
• Easements	220		Consistent with growth forecasts from Covec report. Increase relative to historic trend due to changes to capital contributions policy and growth initiatives	Fewer new connections lead to lower rates of asset utilisation and higher network tariffs over time	
Non-network assets	**2,053**	**1,902**			**ALLOWED**
• ICT	1,633		Systems upgrades associated with new business creation but costs are consistent with historic levels		

Firstgas

Category	AMP Forecast (2018-2022) ($000s)	Draft DPP Decision (2018-2022) ($000s)	Reasons forecast level is prudent and efficient	Impact of under investment (disallowed areas only)	Allowed or fall-back
• Building refurbishment	420		Building refurbishment above historic levels, but needed due to earthquake proofing of headquarters site and state of disrepair		
System growth	**16,410**	**3,352**			**FALLBACK**
• Pipes	13,355		Specific reinforcement identified schemes from system modelling of peak demand. Higher than historic trend due to underinvestment by previous owner in recent years and the particular needs of network areas	Adding new loads would breach minimum pressure standards, affecting consumer appliance performance. Connection requests would need to be declined, leading to fewer options for consumers	
• Stations	3,055		Stations required to support identified reinforcement schemes from system modelling of peak demand. Higher than historic trend due to underinvestment by previous owner in recent years and the particular needs of network areas	Adding new loads would breach minimum pressure standards, affecting consumer appliance performance. Connection requests would need to be declined, leading to fewer options for consumers	
Reliability, safety and environment	**0**	**0**			
TOTAL	**56,031**	**33,914**			

The revenue cap with wash-ups should not cap average price increases

We strongly support the decision made in the IMs review to incorporate a wash-up mechanism to the revenue cap that applies to our GTB.

In implementing the revenue cap, the draft decisions also intend to apply a cap on average price increases of 10%. While we support the intent of having stable prices, we believe that the mechanism proposed creates more problems than it solves:

- The problem that the average price increase cap aims to solve has been significantly addressed through the revenue cap with wash-ups. The GTB no longer faces permanent reductions in revenue from any decision to moderate price increases by not pricing up to its cap.

- The draft decisions acknowledge that the revenue cap needs to be designed in a way that works with the new transmission access code that we are currently developing. This is particularly difficult given that the new code is still in its formative stages. The Commission can take a significant degree of comfort from the extent of customer input and regulatory oversight from the Gas Industry Company (GIC) in the process of developing the new access code. The ability for First Gas to implement a pricing regime that is not supported by our customers and industry regulator is remote.

- An average price increase limit will not fit with the proposed pricing methodology that we have signalled for the new code – which combines postage stamp prices for daily nominated capacity with auction-based prices for priority rights on daily nominated capacity.[5] However, it is plausible that the revenue collected from different access products could change significantly from year to year while remaining with our overall revenue cap.

We therefore recommend that the Commission does not introduce a limit on average price increases as part of the DPP.

The scale of price changes signalled at this DPP reset warrants a measured approach

We consider that the Commission should seek to minimise disruption caused by the DPP reset and any subsequent CPP process for First Gas. If the Commission is comfortable that forecast levels of expenditure are required to operate as a RPO (regardless of whether a DPP or CPP applies), then those costs should be allowed under the DPP.

A measured approach to resetting the DPP is in consumer's interests because it avoids a reduction in tariffs that does not reflect the long run costs of operating the network, and avoids the situation where First Gas makes sharp cuts in expenditure only to have to contract back resources at a higher cost. We consider that this is also consistent with other DPP decisions, where the Commission has carefully considered the interaction between the DPP and CPP.

We also suggest that significant starting price adjustments (of more than 10%) should be smoothed in over time – perhaps over the first two years of the regulatory period. This maintains the same outcome in present value terms, but allows regulated businesses more time to adjust to lower revenues and leads to less shock to business processes and staffing.

---

[5] See http://www.gasindustry.co.nz/work-programmes/transmission-pipeline-access/developing/gas-transmission-workshop-february-2017/

Table of Contents

1. Introduction

First Gas operates 2,500km of gas transmission pipelines (including the Maui pipeline), and more than 4,800km of gas distribution pipelines across the North Island. These gas infrastructure assets transport gas from Taranaki to major industrial gas users, electricity generators, businesses and homes, and transport around 20 percent of New Zealand's primary energy supply. For further information on First Gas, please visit our website www.firstgas.co.nz.

First Gas welcomes the opportunity to submit on the "Default price-quality paths for gas pipeline businesses from 1 October 2017 to 30 September 2022: Draft reasons paper" dated 10 February 2017 (the draft decisions). The Commerce Commission (Commission) has introduced new regulatory approaches at this default price-quality path (DPP) reset, in particular by setting expenditure allowances based on a low-cost review of supplier AMP forecasts. This DPP reset is also a first for First Gas, as a new company and as the owner of the entire gas transmission network.

The changes introduced at the DPP reset need to be made in a way that ensures that the revenues we earn over the coming regulatory period enable us to provide safe, reliable and efficient gas infrastructure, particularly for our gas transmission business (GTB).

1.1. The draft decision would result in a significant reduction in our revenue

This submission presents our concerns that the revenue reductions that would result from the draft decisions would not achieve regulatory objectives and would not be in the long-term interests of consumers. The draft decisions, if confirmed, would see a reduction in revenue for First Gas of $120 million over the five-year period.

We acknowledge that a portion of this decrease is due to changes in the Commission's estimate of our Weighted Average Cost of Capital (WACC), following regulatory decisions on the WACC percentile and the Input Methodologies (IMs) review decisions released in December 2016. Figure X1[6] of the draft decisions clearly sets out the movement in the WACC due to regulatory decisions and changes in market conditions. In relation to WACC, the DPP reset is simply implementing decisions that have already been made and therefore, we do not discuss those decisions in this submission.

Our concerns with the draft DPP reset decision lie with the considerable difference between our forecasts of required expenditure and the allowed expenditure across our transmission business (capex and opex) and distribution business (capex). The forecast expenditure that has been disallowed in the draft decision is summarised below.

Business area	Category	First Gas forecast ($) [7]	Draft DPP allowance ($)	% Allowed
Transmission Opex	Routine corrective maintenance and inspection (RCMI)	85.1	71.2	84%
Transmission Capex	Asset Replacement and Renewal (ARR)	121.9	56.5	46%
Distribution Capex	System Growth	16.4	3.4	21%
	Customer Connection	20.5	9.8	48%

[6] Page 7 of the draft decisions.

[7] All figures in real terms, sourced from "Inputs" and "Totals" tabs from *Gas DPP reset – Expenditure model – 10 February 2017*, Commerce Commission, http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/

We focus on these areas (although we are prepared to accept the Commission's reasoning in relation to distribution customer connection capex). One of the advantages we see in the approach the Commission has taken to this DPP reset is that it enables us to focus on particular categories of expenditure that have been disallowed. From our perspective, this clearly lowers the costs of regulation relative to a CPP, and we imagine this would be true for other interested parties that can focus their resources on understanding the drivers of expenditure within these categories.

1.2. Structure of this submission

The remainder of this submission proceeds as follows:

- **Section 2** discusses the objectives of a DPP reset, and aspects of the draft decisions that we consider undermine those objectives;
- **Section 3** builds on the information presented in our AMPs to support the level of expenditure we believe should be allowed at this DPP reset. We have also engaged an independent expert, Chris Harvey, to review our AMP and supporting information. Chris Harvey has extensive experience in the gas industry, both distribution and transmission, and has undertaken numerous regulatory reviews in Australia to assess required levels of opex and capex. We summarise the key findings of the expert review in section 3.5 and the full report is attached in **Appendix A**;
- **Section 4** comments on proposed changes to service quality measures under the DPP;
- **Section 5** discusses the proposed implementation of the revenue cap with wash-ups for our GTB, and explains our concerns about introducing a cap on average annual price increases; and
- **Section 6** offers commentary on how the Commission should implement price changes introduced by the DPP reset, particularly given the context of a likely CPP application by First Gas.

We have targeted this submission on elements of the draft decisions that we believe could be improved. As a result, there are several topics in the draft decisions that are not addressed in this submission because we agree with the Commission's proposed approach. These areas include:

- The decision that the White Cliffs project is best addressed through a CPP. We appreciate that the DPP is not well-suited to considering large, complex projects like the White Cliffs realignment. Our remaining concern is to ensure that the processes used in the CPP are appropriate given that the level of expenditure for a Frist Gas CPP is likely to be much lower than other CPP applications considered and discussed to date (Orion and PowerCo).
- The Constant Price Revenue Growth (CPRG) forecasts for our distribution networks. We reviewed the proposed approach to CPRG forecasting as part of the August policy paper and concluded that it is fit for purpose.
- The approach to our acquisition of GasNet's Papamoa assets. We consider that adding the purchase price to our opening RAB is the correct approach to dealing with this small transaction, and is consistent with how the costs would be treated if we had engaged third parties directly to construct the assets.

1.3. Contact details

For any questions regarding our submission, please contact:

Ben Gerritsen
General Manager, Commercial and Regulation
Ben.Gerritsen@firstgas.co.nz
021 911 946

We would also like to extend an invitation to Commissioners, Commission staff, and the Commission's consultants to talk through the material presented in this submission. While we have tried to articulate the points made in this submission clearly, we believe that discussing the material can help to ensure a better understanding of our position.

2. Objectives for setting DPP expenditure allowances

The Commission's draft decisions will have a detrimental impact on First Gas's business. We are concerned that the proposed reductions in expenditure will ultimately increase the risk profile of our gas transmission network – an outcome that is not in the long-term interests of gas consumers.

Before explaining why we think higher levels of expenditure are justified (section 3), we want to ensure clarity on:

- The objectives that the DPP reset aims to achieve (section 2.1), and
- How the process of the DPP reset can best safeguard those objectives (section 2.2).

In this section, we raise specific concerns that the process that the Commission has followed in reviewing expenditure (using variance tests and scrutiny of expenditure forecasts) has unintended consequences that undermine the Commission's regulatory objectives. In particular, we think the Commission needs to guard against creating undesirable incentives for suppliers to prepare expenditure forecasts to maximise regulatory outcomes rather than faithfully presenting network and business needs.

2.1. The objectives that the DPP reset aims to achieve

Commission's stated regulatory objective for the DPP regulatory regime is to:

> *"limit suppliers from earning excessive returns, while maintaining incentives for* ***sufficient investment*** *and to supply services at the* ***level of quality demanded by consumers****."*[8]
> [emphasis added]

Focus on managing the risk profile of gas transmission

In relation to our GTB, we consider that this objective requires expenditure allowances that are consistent with ensuring the risk profile of the gas transmission network complies with all of First Gas's regulatory obligations, including meeting the requirements of the following key regulatory obligations:

- Quality standards as set out in the DPP and the Gas Transmission Information Disclosure Determination 2012 (consolidated in 2015);
- Gas Industry Company (GIC) requirements including the Gas Governance (Critical Contingency Management) Regulations 2008 (CCM Regulations);
- Health and Safety in Employment (Pipelines) Regulations 1999 (Pipelines Regulation), and via the regulation the application of the consensus standard AS/NZS 2885 Pipelines - Gas and Liquid Petroleum; and
- Health and Safety at Work Act 2015 and associated regulation.

Since taking control of the gas transmission network in 2016, First Gas has invested considerable effort into understanding the condition of gas transmission system, assessing the risk profile of the transmission system and ensuring that the management of the GTB aligns with our key regulatory obligations. This work has proceeded across several fronts and has included:

- Recertification under the Pipelines Regulation. This is a prescriptive standard where action is required to keep risks "low" (as defined in AS2885), and if this is not possible to keep risks "as low as reasonably practicable", to maintain operator certification;

8 Para 4.92, page 55 of draft decision.

- Completion of the Safety Management Study process as required under AS/NZS 2885. This process involves a detailed review of risks across the transmission network within a well-defined framework and raises action items that need to be addressed within specified timeframes to ensure that risk levels are within the levels defined with the consensus standard;
- Engaging in the Gas Industry Company (GIC) review of gas transmission security and reliability;[9]
- Consulting individually with major gas users on risks across the gas transmission network and the particular risks that are relevant at their sites;
- Publishing an Asset Management Plan (AMP) that for the first time takes a system-wide view of gas transmission in New Zealand;
- Presenting the outcomes of the AMP to major gas users and other interested parties (GIC, shippers, gas producers); and
- Expert assessment during the due diligence review in the acquisition process of the GTB. These assessments covered asset condition, operations and management practise, operations expenditure and capital expenditure, environmental compliance, and safety compliance. This process identified a number of opportunities for improvement to meet the key regulatory obligations

While we will continue to improve our understanding and management of network risks, we consider that these steps have led to a much better ability to effectively manage risk than existed in the past. Some key takeaways from this work that we think are highly relevant to achieving the DPP regulatory objective are:

- There is no suggestion that current risk position of our GTB is too low (e.g. due to gold plating of the network or unnecessary redundancy) or too high (due to a manifest lack of reliability). However, our risk reviews have identified and prioritised new risks and our stakeholder engagement has encouraged us to address identified risks in a timely way. Most of the concerns raised in our engagement on security and reliability and our AMP relate to how risks are communicated;
- Strong customer support exists for security and reliability. Major gas users highlight security and reliability as among their top priority, and want to ensure a willingness on the part of the transmission owner to invest. A specific example of this desire for maintaining security and reliability is that major gas users are keen to ensure that the current levels of redundancy provided by the Maui and non-Maui systems remain following pipeline realignment and remediation work (such as the White Cliffs project); and
- The Commission proposes to introduce new quality standard under the DPP for major interruptions (we comment on this proposal further in section 4). This new standard is consistent with an increasing focus on managing security and reliability risks, but needs to be adequately funded through DPP expenditure allowances.

[9] http://www.gasindustry.co.nz/work-programmes/pipeline-security-and-reliability/overview/

2.2. How the DPP reset can best achieve these objectives

The Commission's consultants (Strata) developed an expenditure review process for this DPP that incorporated variance tests, materiality checks and AMP evidence assessment tests. This process was undertaken with a view to ensuring the:

> *"Capital and operating expenditure [of the regulated business reflects] the efficient costs that a prudent non-exempt business would require to meet demand in a regulatory period and over the longer team and comply with application regulatory obligations"*.[10]

The expenditure review process used in the draft decisions compares forecast expenditure levels with historic levels disclosed by regulated suppliers. Where expenditure forecasts exceed an accepted baseline (5% above historic levels for opex and 10% for capex), information to support higher levels of expenditure is sought from the AMP, then through supplier requests if required. Where expenditure is not justified, it is reduced to fall-back level.

While we broadly support this expenditure review process, the draft decisions highlight that in some cases a mechanistic application will not best achieve the regulatory objective summarised above. In essence, we believe that the process needs to ensure:

- An appropriate balance between "revealed" funding requirements and legitimate reasons why the past might be different from the future. The weight that is placed on historic baselines may be different for capex and opex, given that historic levels of capex are not such a useful guide to future expenditure needs due to the lumpy nature of required capex;

- Suppliers are encouraged to present unbiased estimates of future expenditure needs in their AMPs. The expenditure review process should not reward suppliers for adjusting the timing or categorisation of expenditure and nor should it penalise suppliers for accurately reflecting network and business expenditure needs; and

- Incentives for efficiency are maintained. The process should allow regulated suppliers to enjoy the benefits of efficiency gains for a period of time to encourage suppliers to actively seek out such efficiency gains for the long-term benefit of consumers.

These outcomes must all be achieved within the low-cost intent of the DPP. We appreciate this is challenging – but is essential for the DPP to operate in the long-term interests of consumers.

We are concerned that the draft decisions inadvertently undermine these outcomes in several respects. In particular, the expenditure review process used in the draft decisions makes it rational for suppliers to move expenditure around (across time and between categories) to deliver different outcomes from the DPP. Rather than engage in such a process, we use this submission as a good faith effort to help improve the regulatory approach.

2.3. Striking the right balance between using historic information and forecasts in the DPP

Historic levels of expenditure are clearly useful in resetting prices. In the absence of other evidence, the costs that have previously been incurred to operate and invest in regulated networks provide a reasonable guide to likely future costs.

However, historic levels of expenditure are not always a good predictor of the level required to meet the quality and service sought by consumers. This is particularly true for capex, which can be lumpy and is generally only well-understood by network owners. For this reason, regulators overseas (such as the

[10] Paragraph 4, *Report on First Gas distribution BAU variance checks and evidence assessment*, Strata Energy Consulting, 31 October 2016.

Australian Energy Regulator in Australia) use a mix of reliance on historic and forecast information when setting opex and capex allowances for a regulatory period.

Historic information is also likely to be less relevant following a change in asset ownership. Expenditure prior to sale is likely to be lower than ongoing sustainable network needs, as the vendor seeks to increase the financial returns of the business to make it more attractive to prospective buyers. The vendor is also likely to prefer high cash returns prior to sale, safe in the knowledge that the impacts of any deferred maintenance will take some time to be revealed.

In the case of our GTB, we note that the AMPs published by previous owners also forecast that higher levels of expenditure were required. While in some cases expenditure did increase (such as capital expenditure on the Maui pipeline), the previous owners generally underspent relative to forecast. In contrast, we are already spending capital in line with our forecast for 2016/17. As a result, we expect our opening RAB to be around $930 million, which is higher than the value used by the Commission in the draft decisions ($913 million). We are happy to provide more information to inform an accurate assessment of our opening RAB.

In this circumstances, we consider that historic expenditure levels are less relevant for assessing the efficient future expenditure needs of our transmission and distribution businesses (particularly for capex). It should be clear to the Commission that First Gas is taking a very different approach to network investment than previous owners – and in many areas we are having to complete projects that were deferred due to the sale process. We are currently on track to deliver capital expenditure across our regulated business of close to $50 million this year (compared with $30 million last year). In section 3 of this submission, we highlight specific instances where the change of ownership has made historic expenditure levels a less useful guide for future expenditure needs.

2.4. Ensuring that AMPs present unbiased estimates of future expenditure needs

The Commission's expenditure review process uses the information presented in AMPs. We believe this is a positive step in helping to tailor the DPP to the circumstances facing particular suppliers. However, this approach creates the risk that AMPs are prepared to maximise the outcomes from a DPP reset, rather than to present an accurate assessment of expenditure needs. While this risk is lower at this DPP reset (since suppliers did not know the full details of the Commission's approach when AMPs were prepared), the decisions that the Commission makes at this review will influence how suppliers prepare future AMPs.

We have identified the following problems with the way that AMP forecasts have been used in the expenditure review process:

- **Impact of large projects**: Including large capital projects can tip expenditure forecasts over the (undefined) level that is appropriate under the DPP, and thereby force an expenditure category to the fall-back level. This outcome appears to hold even where higher "programmatic" (non-project) levels of spend in the category are adequately supported. This has occurred for our transmission Asset Replacement and Renewal (ARR) capex, where two larger projects (White Cliffs and Gilbert Stream) have not been allowed under the draft decisions and the fall-back level of expenditure has been used. This outcome may make suppliers reluctant to propose significant projects, even though they are genuinely required, if they are considered to require a higher burden of proof than programmatic expenditure or to pose a risk to programmatic expenditure that is well supported. Alternatively, it may encourage suppliers to alter the proposed timing of major projects to ensure it is not caught within the upcoming regulatory period or to use an expenditure category where the risk is better managed. This is not in consumers' interests, who should be able rely on the accuracy of the information presented in AMPs for their business planning purposes; and

- **Differing application of expenditure categories**: The use of capex and opex "categories" in AMPs is not a straightforward practice and it varies considerably between regulated suppliers. This creates particular issues for First Gas because previous asset owners (Vector and MDL) have used different categories for the same expenditure, and for consistency we need to select one category. The issues with categories are illustrated by the vastly different category-level expenditure of different suppliers presented in Attachment D of the draft decisions – for example, with Powerco being the only supplier to use Asset Renewal and Replacement opex (we note that this category was also used by the former owner of the Maui pipeline, MDL). This issue has directly impacted on the opex allowance for our GTB in the draft decisions because the fall-back level of Routine and Corrective Maintenance and Inspection (RCMI) opex used by the Commission does not include MDL's past ARR that we have re-categorised as RCMI.

We encourage the Commission to take a flexible approach to the expenditure review process and to resolve these issues in its final decisions.

2.5. Maintaining incentives for efficient operating expenditure

As noted above, we accept that the reasons to link expenditure allowances to historic expenditure are likely to be stronger for opex than capex. We consider that capex is better suited to a process that involves scrutiny of AMP forecasts, whereas opex may be better suited to analysis at an aggregate level and through the application of a "step and trend" type model. Opex levels are revealed over time and are more stable than capex. An analysis of opex at a category level also does not provide much insight into cost drivers due to the different approaches taken to categorise opex. Opex categorisation is subjective and likely to change over time with changes in treatment and allocation.

The aggregate level of opex provided through the DPP is important, and we do not see the merit in providing aggregate opex allowances that are lower than historical levels. We understood that the application of the alternative fall-back of applying the Commission's "step and trend" opex model (described at paragraph 4.44 of the draft decisions) would ensure adequate opex levels. We were therefore surprised to discover that the draft decisions proposed a reduction in allowed opex for our GTB relative to the amounts historically spent by Vector and MDL. This appears to be explained in the opex step and trend model released by the Commission that states that "the methodology is not used in the draft determination".

Our analysis of opex (presented in Table 1 below) suggests that the draft decisions allow 99% of historic opex levels and 92% of our forecast. The results of the step and trend model appear very close to our forecast of aggregate opex. After reclassified in-line inspection costs are removed, the step and trend model suggests opex levels in 2018 of $42.8 million.[11] While we continue to believe that elevated levels of opex are supported for our GTB (as explained in section 3.2 of this submission), we believe that the Commission should also apply its step and trend model as an alternative fall-back if the aggregate opex allowance is lower than the step and trend model.

[11] This has been calculated by taking the estimated First Gas transmission opex in the 'Output' tab of the step and trend model for 2018 of $43.9 million and subtracting annual in-line inspection costs of $1.1 million.

Table 1: Analysis of aggregate transmission opex

Transmission opex categories	Annual historical average (last 3 available years, 2013-2015)	Annual average AMP forecast (2018-2022)	Annual Average Allowed DPP Draft Decision (2018-2022) (Appendix D Draft Decision)	% Allowed of historic opex	% Allowed of forecasts
ARR	0	0	0		
Business support	4,335	12,045	12,204	282%	101%
RCMI	13,106[12]	17,026	14,234	100%	84%
Service interruptions, incidents and emergencies	598	652	652	109%	100%
System operations and network support	17,902	7,309	7,289	41%	100%
Compressor fuel	3,784	4,951	4,400	116%	89%
Land management and other activities	373	750	741	199%	99%
Total transmission opex	**40,097**	**42,733**	**39,521**	**99%**	**92%**

[12] We have adjusted the annual historic average RCMI figure (originally $14,251,000) to exclude the annual historic average cost of in line inspection (estimated at $1,144,505, based on actual incurred costs), as this expenditure has been re-categorised as ARR capex in our AMP. This ensures a "like for like" comparison.

2.6. Summary of recommended changes to achieve regulatory objectives

In summary, First Gas recommends that the processes applied in reaching final DPP decisions are adjusted to:

- Adopt approaches that generally place less importance on historical expenditure levels, particularly for capex;
- Exclude expenditure forecasts of major projects considered most appropriate for a CPP from the DPP expenditure review process;
- Review expenditure categories to ensure comparability across years, and be prepared to aggregate categories where suppliers have categorised expenditure differently (such as First Gas changing MDL ARR opex to RCMI opex); and
- Use the results of the Commission's aggregate "step and trend" opex model as a lower bound for opex allowances maintain adequate incentives and rewards for efficiency.

3. Evidence on forecast expenditure disallowed in draft decision

In the draft decisions, the Commission proposes not to allow the level of expenditure forecast by First Gas across four expenditure categories and instead bases proposed expenditure allowances on past expenditure levels for:

- Transmission asset replacement and renewal (ARR) capex;
- Transmission routine and corrective maintenance and inspection (RCMI) opex;
- Distribution system growth capex; and
- Distribution consumer connection capex.

This section explains why we consider that our expenditure forecasts achieve the objectives set out in section 2 of this submission – that is, that our forecast expenditure levels are a prudent and efficient way to deliver gas transmission and distribution services across our networks. In the first three of these categories, we maintain the view set out in our AMP that the forecast expenditures are necessary to manage the risks across our network, meet our customers' growth requirements, and therefore (with the exception of the White Cliffs realignment) should be allowed into the DPP by the Commission. In the fourth category (distribution consumer connection capex), we have adjusted our forecast to align with the Commission's modelling of new connections to set our weighted average price cap.

We are happy to engage further with the Commission and Strata on any of the additional information provided on opex and capex forecasts.

3.1. Disallowed asset replacement and renewal (ARR) capex for gas transmission

The Commission has disallowed our forecast level of ARR capex, raising particular concerns with two projects:

- Gilbert Stream remediation project; and
- White Cliffs realignment.

These two projects were considered individually by the Commission because of their relatively large level of expenditure and project uncertainties. Gilbert Stream was not accepted due to insufficient information and White Cliffs was not accepted because the Commission considered it to be better suited to the level of scrutiny involved in a customised price-quality path (CPP).

This draft decision proposes a considerable decrease in our ARR expenditure, with the Commission allowing 46% of our forecast expenditure (in real terms, as outlined in the table below).

Table 2: Forecast and proposed allowances for ARR capex[13]

Year ending	2018	2019	2020	2021	2022
First Gas forecast ARR capex ($000)	32,359	20,022	18,442	16,444	34,695
Commission's proposed fall-back ARR capex ($000)	11,793	12,072	11,293	10,661	10,741

3.1.1. Use of fall-back determined by inclusion of large capex projects

As outlined in section 2 of this submission, large projects can alter the outcomes of the Commission's expenditure review process, and can drive an expenditure category down to the fall-back allowance even though a higher "programmatic" baseline of expenditure may be justified. This clearly is the case for the application of the expenditure review process to First Gas's ARR capex.

Even though the Commission has acknowledged that the White Cliffs project is best suited to a CPP, it has still included the White Cliffs expenditure within the total ARR expenditure that was scrutinised through the expenditure review process. As the Commission deemed that White Cliffs (and Gilbert Stream) were not adequately supported by the evidence presented in our AMP, the Commission has proposed to use the fall-back allowance for our ARR capex.

For the reasons provided in section 2 of this submission, we recommend that the Commission excludes the expenditure forecasts relating to the White Cliffs realignment from the DPP expenditure review process, since this project is considered most appropriate for a CPP. The table below details the costs and sequencing of the White Cliffs remediation project.

Table 3: White Cliffs expenditure during regulatory period

Year ending	2018	2019	2020	2021	2022
Ex-MDL transmission line ($000)	4,100	250	250	250	12,600
Ex-Vector transmission line ($000)	2,500	250	250	250	7,650
TOTAL ($000)	6,600	500	500	500	20,250
Total over regulatory period ($000)					**28,350**

[13] All figures in real terms, sourced from "Inputs" and "Totals" tabs from *Gas DPP reset – Expenditure model – 10 February 2017*, Commerce Commission, http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/

3.1.2. Evidence for Gilbert Stream

As noted in Commission's draft decision, First Gas had insufficient time to provide information on the Gilbert Stream project, and subsequently this project has not been accepted into our ARR capex. First Gas received an information request on 3 February 2017, and our response was published on 24 February 2017 Commission website.[14] Our response provided information outlining:

- The risk analysis and evidence underpinning this investment, incorporating a survey report showing the degree of cliff erosion over time;
- An options study report analysing a number of alternative solutions and identifying our preferred solution;
- Detail on how we have consulted with industry and consumers on this project; and
- Economic analysis undertaken to consider scale of a failure.

Our response also provided a breakdown of our capex with and without three major projects – Gilbert Stream, White Cliffs and the Henderson compressor project (a growth project to meet additional gas demand at the Marsden Point refinery).[15] This should enable the Commission to isolate the impact of major projects, and separately consider the efficiency of other elements of expenditure within each category.

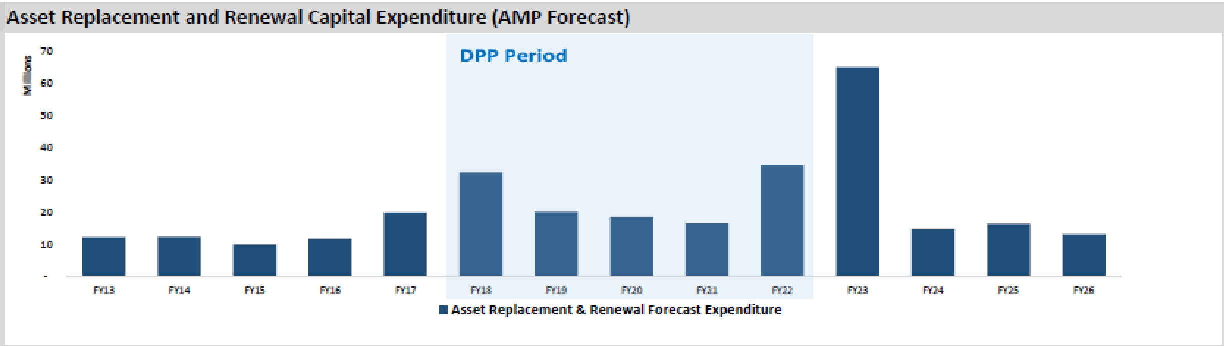
We consider that the information on Gilbert Stream provides a robust evidence base to demonstrate the necessity of this project and how it will cost-effectively address the risk on this area of the network.

3.1.3. Evidence for "programmatic" ARR capex

By applying a mechanistic approach to category-level expenditure, the Commission has not considered whether the underlying level of expenditure (excluding White Cliffs and Gilbert Stream) meets the expenditure objective and should therefore be allowed into the DPP.

The graphs below demonstrate the impact of excluding the White Cliffs and Gilbert Stream projects on our forecasts of ARR expenditure.

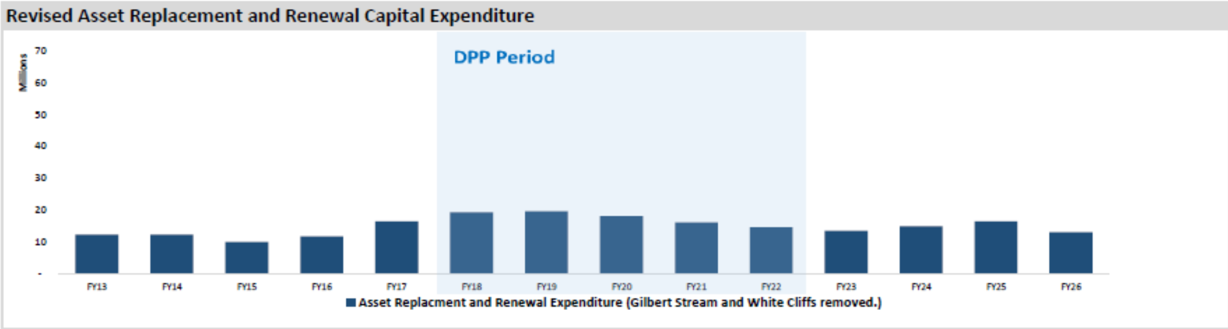
Figure 1: ARR capex profile including major projects



[14] *Gas DPP – First Gas response to Commission questions – 17 February 2017,* Commerce Commission website, http://www.comcom.govt.nz/regulated-industries/gas-pipelines/gas-default-price-quality-path/2017-2022-gas-dpp/

[15] Two of these graphs have been included in the prior section.

Figure 2: ARR capex profile excluding major projects



While forecast expenditure is clearly much lower in this category when major projects are excluded, the remaining programmatic expenditure still represents an increase of more than 10% over the low historic baseline used in the draft decisions (FY13, FY14 and FY15). In Strata's letter to the Commission, they note that:

> *"The AMP evidence explained the ARR capex forecasts and the priorities for ARR planning. The Asset fleet section of the AMP was thorough and linked planning to capex forecasts. All variances from asset condition assessment were satisfactorily explained. The projects that significantly contribute to ARR forecasts are well described and have forecasts attributed to them."*[16]

It would therefore appear that Strata is supportive of the evidence we have provided for the "programmatic" ARR capex, and we therefore expect that if this expenditure is considered in isolation of major projects that it would be accepted. However, since the Commission may not have yet considered justification for the scale of the increase, we have forecasted we have provided further information on our programme of ARR expenditure by:

- Identifying expenditure by sub-category, and noting the areas that are above the historic average (see **Appendix B**); and
- Summarising in the table below (with more detail provided in **Appendix C**) the particular projects that drive each of these increases.

We consider that this expenditure is in line with that expected from a reasonable and prudent operator seeking to manage the risk profile of the gas transmission network, in line with the key regulatory obligations identified in section 2.

---

[16] Paragraph 45 of Appendix 1, *Report on First Gas transmission BAU variance checks and AMP evidence assessment*, Strata Energy Consulting, 16 November 2016.

Table 4: Summary of breakdown of "programmatic" ARR capex

Category	Explanation and size of change over regulatory period (2017-22)	
Pipelines	Re-categorisation of in-line-inspection from RCMI opex to capex (consistent with typical pipeline industry practice) has increased expenditure	$8.2 million[17]
	Completion of 2-3 geohazard remediation projects per year (further detail of geohazard costs are provided in relation to transmission opex disallowed in draft decisions)	$17 million
	Inclusion of off-pipeline capital expenditure, an item that had not been included in prior owner's forecast expenditure, to ensure reasonable ground access to the pipeline is maintained	$1.2 million
Compressors	Improvements to the Rotowaro compressor station turbine package fire and gas detection equipment to ensure safety and reliability	$1.2 million
	Replacement of obsolete gas detection systems in reciprocating compressor buildings to ensure safety and compliance. Forecast expenditure was not included in previous forecasts	$1.0 million
	Replacement of four compressor station gas cooler units driven by remaining life reviews undertaken by external consultants to ensure reliability and compliance	$3.4 million
Other stations	Acceleration and completion of a five-year replacement programme for all Grove 80 regulators, due to the vendor advising First Gas that soft parts would no longer be made to ensure reliability	$3.4 million
	Upgrading all pig traps to minimum required standards to ensure safety and compliance	$3.6 million
	Replacement and upgrading of station security and fencing to the minimum standard to ensure reliability	$1.1 million
	Replacement of leaking station values to ensure safety	$2.8 million
SCADA and communications	Replacement and upgrading of the SCADA master system to ensure reliability	$1.2 million
Main line valves	Refurbishment programme to extend the service life of existing mainline valves in addition to the continued programme to install remote actuation equipment to ensure reliability and safety	$1.8 million
Heating systems	Slight increase above average historic expenditure due to the need to refurbish some larger heaters (the unit cost for refurbishment is based on heater size) and upgrade heater control systems to ensure reliability	$3.7 million
Cathodic protection	Installation of replacement transformer rectifier and intelligent power supply assemblies to ensure reliability and compliance. A significant portion of the rectifiers are in excess of 40 years old and due for replacement during the next 5 years	$1.4 million

The scale of increase in ARR capex over the historic average can be justified by the requirements to meet the key regulatory obligations, with a clear focus on safety, reliability of gas deliveries and compliance to New Zealand legislation.

[17] The timing schedule for pigging means that we require greater levels of in-line-inspection per year over the forecast period ($1.6 million), than was undertaken in the three-year period used to calculate the historic average.

3.1.4. Recommended approach and outcomes for ARR capex

Given the information that we have provided to justify our ARR capex, we recommend that the Commission:

- Remove the White Cliffs project from the ARR capex category, on the grounds that all parties accept that this will be applied for and scrutinised under a CPP;
- Re-run the remaining ARR expenditure through the expenditure review process, incorporating the additional information provided in response to the Gilbert Stream information request and in this submission; and
- Accept all non-White Cliffs ARR expenditure forecast for the DPP period as a prudent and efficient response to identified network risks. This will increase the ARR capex allowance over the 5 year DPP period from $56.5 million to $94.6 million (compared to our original forecast of ARR capex of $121.9 million, which included work on the White Cliffs realignment).

3.2. Disallowed routine corrective maintenance and inspection (RCMI) opex for gas transmission

The Commission has disallowed our forecast level of RCMI opex for gas transmission and applied the fall-back allowance based on historic expenditure in this category. We have already explained (in section 2) our view that the resulting outcome of an aggregate opex allowance that is below the historic average is not in the long-term interests of consumers. This section provides further support specifically on our forecasts of RCMI opex.

In its letter to the Commission, Strata concluded that our:

- "Explanations for the increased opex from 2019 onwards [were] confusing and not compelling"; and
- Reasoning for the increase in geohazard remediation costs were "not properly explained" and noted concerns about the timing of our geohazard assessment and remediation activity.[18]

The Commission's draft decision allows 84% of our forecast level of expenditure in the RCMI category. Table 5 below outlines the scale of the proposed change across the regulatory period.

Table 5: Forecast and proposed allowances for RCMI opex

Year ending	2018	2019	2020	2021	2022
First Gas forecast RCMI opex ($000)	17,391	17,280	17,252	16,474	16,741
Commission's proposed fall-back RCMI opex ($000)	14,193	14,272	14,242	14,255	14,286

[18] Question 1.1 of table, *Report on First Gas transmission supplier evidence assessment responses*, Strata Energy Consultant, 28 November 2016.

There are two components to our submission that our forecast of RCMI expenditure should be allowed, which are discussed in detail below:

- The forecast increase in RCMI expenditure is partly explained by re-categorisation of MDL opex, along with an increase in expenditure in this category relative to what MDL had spent due to the inclusion of off-pipeline assets that need to be maintained; and
- Our estimated geohazard costs are necessary to manage the risk profile of our network.

3.2.1. Reclassified MDL expenditure and increase in expenditure between 2019 and 2021

Strata noted that our RCMI forecast expenditure for the Maui pipeline (up to $930,000 per annum) is considerably higher than MDL's previous forecast of $510,000 per annum.

Part of this variance (around $800,000 over the regulatory period) is simply a re-categorisation of costs previously categorised by MDL as ARR opex. This re-categorisation provides a better fit with the nature of the activity and also aligns with the approach generally taken by other regulated suppliers, who do not use the opex ARR category (with the exception of PowerCo). As part of the AMP issued by MDL, the ARR opex included several allocations of work still to be identified. First Gas has subsequently identified these work areas and prepared individual cost estimates for each work area.

One of the most material changes from MDL's AMP was the identification of maintenance requirements for unrecorded off-pipeline assets. These previously unrecorded assets were identified during the geohazard assessments for the ex-MDL pipelines following the Pukearuhe incident in 2011, and from the mandated Safety Management Studies which occurred in 2016. These off-pipeline assets include items such as access tracks, retaining walls, wooden flumes, culverts, drainage systems, weathering monitoring stations and retired land blocks around easements. Ongoing maintenance and management of these assets is essential in ensuring First Gas continues to meet its key regulatory obligations.

This additional opex is required to maintain these off-pipeline assets to an appropriate standard.

Appendix D details the items that MDL had included in its AMP accounting for approximately $510,000 per annum, and the additional expenditure items that First Gas has included for both off-pipeline assets and some addition annual maintenance expenditure items that have recently been identified. This appendix provides a clear line of sight from the figures forecast by MDL to the First Gas forecast of approximately $930,000 per year, and explains the need for additional expenditure in this area.

3.2.2. Geohazard costs

Our AMP forecast the following expenditure profile for geohazard assessment (to identify areas where land movement and coastal erosion might impact on pipeline integrity) and geohazard rectification (to remediate areas where risks are assessed as being greater than threshold levels required by AS/NZS 2885). This expenditure results from a new programme to better understand and manage geohazard risks, and is therefore not reflected in historic expenditure profiles.

Table 6: Expenditure profile for geo-hazard assessment and remediation

	Forecast	DPP forecast				
	FY17	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Geo-hazard assessment	$319,300	$319,300	$319,300	$319,300	$319,300	$319,300
Geo-hazard remediation	$0	$847,175	$839,450	$847,175	$850,780	$853,670
Total	**$319,300**	**$1,166,475**	**$1,158,750**	**$1,116,475**	**$1,170,080**	**$1,172,970**

As noted above, Strata concluded that we did not fully explain our methodology for undertaking geohazard remediation following assessment and investigation. Strata was unsure about the timing of the proposed work, noting that:

> *"Strata would expect the remediation, if any, to prudently follow the assessment and considers it unlikely that remediation would be conducted at the same time as the incomplete assessment is occurring."*[19]

Strata concluded that First Gas had forecast $1.13 million for geohazard remediation, in addition to geohazard assessment costs. However, this is a misunderstanding, since only around $850,000 of geohazard remediation opex is triggered each year following geo-hazard assessments. The forecast of $1.13 million covered both assessment and remediation).

It is important to clarify that geohazard assessment is not a single investigation that only triggers a programme of remedial action once it is completed. Rather, the expenditure is made up many investigations across the gas transmission network that will be undertaken over a ten-year period. **Appendix E** outlines First Gas's 10-year activity schedule for transmission pipelines, including the current assessed risk level of each pipeline.

As each investigation is completed and reported against, a number of actions are triggered in order to mitigate the potential risks. Some of these actions will be identified as capex and planned for in the ARR capex expenditure forecast, such as:

- Pipeline realignment work;
- Pipeline recoating; and
- Installation of associated remediation assets such as drainage.

Other risk mitigation actions will be treated as opex and planned for in the RCMI forecast, such as:

- Excavation to de-stress the pipeline;
- Installation of temporary monitoring equipment; and
- Creation of new routine monitoring programmes to track changes such as slope movements and cliff erosion.

---

[19] Page 2, *Report on First Gas transmission supplier evidence assessment responses,* Strata Energy Consulting, 28 November 2016.

The first year of the activity schedule in **Appendix E** is the current full year (2016/17), shown in the above expenditure table where no remedial action is undertaken. Remediation opex then starts in the following year – 2017/18). This scheduling allows for the pipeline geo-hazard risk reports to be written, published, considered and actioned.

We note that while the impact to the pipeline is being established and the work scope defined, the site may need to have a temporary monitoring regime established to ensure a timely response to any changes in risk. Examples of short-term monitoring include:

- Unmanned Aerial Vehicle (UAV) flights;
- GIS surveys on land movement;
- Increased line walking patrols; and
- Rainfall and GIS survey marker post monitoring.

All of these activities are classified as opex and are essential to managing the risk profile of the network and responding in a timely way to identified risks.

Example of geohazard pipeline risk reports

Following the Pukearuhe Incident in 2011,[20] the Maui pipeline was risk surveyed to identify if there were any further areas of geohazard concern. The activity schedule in **Appendix E** details all the First Gas pipeline surveys to be undertaken for the first time, including resurveys of the Maui pipeline that was completed in 2013/14.

We also provide an example of an individual geohazard risk report in **Appendix F**. This report addresses the Huntly offtake to the Huntly Power Station line (403 pipeline) and identifies 25 individual risks. First Gas is currently planning to remediate one of the high risks identified in this report through capex in the 2016/17 financial year. Appendix B of this report outlines how a number of prudent mitigations can be put in place through increased monitoring, rather than excavation and repair. This pipeline has been identified on the activity schedule to be re-surveyed in 2019, due to the types of risks previously found.

Periodic review of the First Gas geohazard register enables us to amend monitoring regimes, based on data fed back from the long-term monitoring plans. We also report the status and progress of addressing geohazard risks to our Board each month. We have included an example of a geo-hazard Board report in **Appendix G**.

Justification of geohazard remediation costs

Strata noted that First Gas provided no explanation of its recent experience that informed the forecast costing of geohazard remediation.

In explaining our approach to estimating the costs of remediation, it is important to understand that expenditure on geohazard remediation is not easily predicted and relies heavily on historical costs incurred. However, given the quantum of recent historical geohazard remediation, the forward expected activity levels are not predicted to materially change. We have therefore estimated forecast expenditure for geohazard remediation based on the average historical expenditure from recent geohazard remediation work. We outline our approach in **Appendix H**, explaining why we consider the figure of $850,000 per year for remediation to be a reasonable, evidence-based estimate of future costs.

[20] Where a geohazard feature was found to be the root cause of the pipeline failure.

3.3. Disallowed system growth capex for gas distribution

The Commission proposes to disallow our forecast of distribution system growth capex and reduce the expenditure to the much lower fall-back allowance (see table below).

Table 7: Forecast and proposed allowances for system growth capex

Year ending	2018	2019	2020	2021	2022
First Gas forecast system growth capex ($000)	3,723	1,756	4,096	2,795	4,040
Commission's proposed system growth capex ($000)	670	670	670	670	670

As with the customer connections capex (described below), Strata is:

- Unconvinced of the drivers justifying the step change between 2016 and 2017, and the sustained increases between 2018 to 2022;
- Not convinced that the population forecasts used by First Gas reflect the growth in Tauranga, Hamilton and the Kapiti Coast.

Concerns are also raised with projects planned by First Gas for the Cambridge network and there is confusion around whether these are the same projects discussed by the previous network owner (Vector) in its 2015 AMP.

We remain of the view that the system growth capex forecasts presented in our AMP represent prudent and efficient levels of expenditure to accommodate future growth. The draft decisions do not appear to recognise that system growth capex is driven by peak demand (rather than customer connections or gas conveyed). Our modelling of peak demand supports our proposed expenditure plans. The expenditure required in Cambridge and other parts of the network where growth capex was deferred by the previous owner (Vector) is also needed and valuable for customers. These issues are explained in more detail below.

3.3.1. Peak load forecast drives system growth capex

In the draft decisions, the Commission notes that the key drivers of system growth are:

> *"volume of gas supplied or forecast to be supplied, the number of ICPs connected and the length of the pipelines or systems used to meet demand, compared to capex and opex".*[21]

This is incorrect. The key driver for system growth capex is peak load. Peak growth is driven by the specific characteristics of the individual network, including the mix of residential, commercial and industrial customers, the efficiency of gas appliances, weather conditions, and the resulting diversity of demand. The peak forecasts presented in our AMP are based on flow modelling across our networks by on an extrapolation of historic trends and known significant changes to load (additions and closures). First Gas reviews "peak week" forecasts for each network annually, and now has a 20-year trend line that informs our system growth capex forecasts.

This point was clearly picked up through the independent review of our AMP, as outlined in section 3.5 below and **Appendix A**. We acknowledge that the drivers of system growth capex could have been better articulated in our AMP and supporting evidence.

[21] Paragraph C38.2 of the draft decision.

3.3.2. Clarification of works on the Cambridge network

Information provided by First Gas in late 2016 did not clearly demonstrate that the planned network reinforcement expenditure for the Cambridge network was justified, nor was the same project deferred by Vector in its AMP. We provide further information to the Commission to address this confusion:

- The Cambridge reinforcement project was first outlined in Vector's 2015 AMP in section 5.10.10.4, where two options were put forward (see **Appendix K**). This section of the AMP stated that one of the options, IP20 pipeline, had been selected and included in Vector's 10-year planning period;
- The Cambridge reinforcement project was later discussed in section 5.15 of Vector's 2015 AMP, with only the preferred option (IP20) outlined at a stated cost of $3.753 million. This section of the AMP outlined how the project had originally been planned for 2019/20 but had been brought forward to accommodate a new large potential load request in the area (a glasshouse seeking gas of approximately 270 m^3/hr);
- The new load request was approved to progress in July 2015, then subsequently deferred by the customer. Vector then deferred this reinforcement project.

First Gas's decision around the timing of the Cambridge reinforcement project was driven by the forecast peak demand growth rate in this area, the Cambridge network model and the design of the proposed reinforcement scheme, as attached in **Appendix K**. This information enabled First Gas to determine that:

- The trigger point for any new investment (to avoid system failure) is 1,360 m^3/hr;
- Without any exceptional load, the Cambridge network should be reinforced in 2022; and
- If the approved glass house project progresses, the reinforcement must be brought forward and completed more urgently.

Given this analysis, First Gas proposed in our 2016 AMP[22] to proceed with Vector's deferred project in 2021/22 at a cost of $3.753 million. Subsequent to the release of the 2016 AMP, we were made aware that as of November 2016, the glass house project has been proposed again. We have recently accepted the customer's load request,[23] so we will need to accelerate this reinforcement project.

3.3.3. Completion of other projects previously deferred

In addition to the deferred Cambridge project, a number of other system growth projects were deferred by Vector in 2015/16 but are included within First Gas's work programme and growth forecasts. We provide information on these projects in **Appendix L**, noting how they have mapped across from Vector's AMP to our work programme. The completion of these seven projects aligns with our strategy of growing the distribution business and accounts for approximately $8.6 million of capex over the regulatory period.

The deferral of these projects has had the compounding negative effect of reducing the historic average expenditure level for this individual expenditure category, the aggregate total capex programme, as well as increasing our forecasted expenditure in the first few years of the next regulatory period. The fall-back allowance is therefore artificially lower than would have been expected if the seven projects had been completed as planned. The deferral of these projects has also now made the projects even more pressing, with growing demand on these networks requiring a response to maintain the quality of supply.

[22] Section 8.3 of our 2016 AMP.

[23] First Gas accepted the load request on 22 February 2017.

3.3.4. Current system growth projects underway to meet demonstrated customer needs

System growth projects are essential to support growth in our distribution network areas. If these projects are not completed in a timely manner, it could put the operation of the network outside of the standard operating parameters, and in the worst cases, cause interruptions to customers.

Across our distribution networks, there are two areas that have customer loads already approved based on the reinforcement work included within the system growth area of the AMP. These areas are Ruakura (in Hamilton) and Cambridge (described above). In Ruakura, an existing customer would not have been able to upgrade its facilities to meet their growth requirements without assurance that First Gas will be proceeding with the planned projects in the Hamilton area. The AMP was used as evidence to the customer of our plans in the area and to assure them of the ability of our network to continue to support the existing load and meet the organic growth.

If the customer proceeded with the upgrade, and First Gas did not complete the scheduled Hamilton work (which includes the already underway Te Kowhai projects), the security of the supply in the Ruakura area would be compromised. The deferral of projects in the Hamilton area in the last couple of years has put system growth projects onto the critical path.

Cambridge also has a similar time critical nature to the work. We recently approved three customer loads for the area to meet the requirements of a glass house facility,[24] a medium-large subdivision and a poultry factory. The remaining system peak capacity was equivalent to one of these loads, not all three. If First Gas is committed to the system growth work, then we would have had two unpalatable options for the Cambridge network:

- Reject the loads of at least two, if not all three of the consumers above, or
- Allow the connections and put the continual operation of the network during system peaks in jeopardy.

These options are neither practical nor in the long-term interests of consumers. By investing to enable growth, we expect to increase utilisation of our network assets and ultimately reduce network our tariffs over time.

The customers in Ruakura and Cambridge discussed above are not large industrial facilities that were unforeseen and put strain on the system, but rather organic growth opportunities for our network that we need to respond to. The rate of growth varies across our network, and we prudently plan system growth projects to defer capex until it is required, without compromising the ongoing provision of gas to end consumers (both existing and new).

3.3.5. GasNet investment a response to unmet system demand

First Gas's recent acquisition of pipelines from GasNet Limited in Papamoa East (Wairakei) provides an important example of how we are actively supporting growth in our distribution business in a way that is demonstrably different to the previous owner. We believe that this change in approach needs to be reflected in the historical levels of expenditure used as a baseline and incorporated into the Commission's allowance of our future investment needs.

The previous network owner in this area (Vector) did not grow the network into the substantial subdivisions in the area, nor begin the process of future-proofing the supply for the substantial growth in the area. We understand that at the request of developers in the area, GasNet filled the void that had been left and invested in system growth (200mm trunk main MP4) and installing subdivision 32/50mm pipe (classified as customer connections capex in our AMP). We estimate that 89% of GasNet's investment in Papamoa was

[24] As discussed in section 3.3.2.

directed at system growth, with the remaining 11% on subdivision pipe. We have subsequently purchased these assets from GasNet to complement our existing networks in the area.

For accuracy in determining historical expenditure, it is important that the value of these ex-GasNet pipelines are included in the historical expenditure levels. We consider that expenditure that occurred within the network area to meet the needs of consumers (whether completed by the incumbent owner or a third-party), should be included in the baseline of the historical capex required to meet consumer's needs.

3.3.6. Recommend allowing the forecast expenditure

We recommend that the Commission allow the forecast levels of expenditure for system growth capex. We consider that the information provided above and in the appendices to this submission:

- Clarifies the driver for growth in this capex category (peak load, at a network level);
- Gives a clearer line of sight to demonstrate how Vector's deferred projects have been incorporated into our AMP and the timing of the investments;
- Demonstrates why the deferral of projects by the prior network owner has both artificially lowered the historic average expenditure below what would be considered efficient/prudent, and has made the system growth projects now even more pressing to address growth in these networks; and
- Demonstrates why the forecast capex in our AMP is necessary to meet already approved customer demand in Ruakura and Cambridge. If this expenditure was not to proceed, it would put considerable strain on the reliability of the network; and
- Suggests revisions to the historic baseline used to evaluate forecast levels of expenditure to incorporate investments made by GasNet.

3.4. Disallowed customer connections capex for gas distribution

Strata recommended that the Commission not accept our forecast customer connections capex for the 2017/22 DPP reset period due to:

- The reliance placed on Covec's Auckland forecasts for non-Auckland networks; and
- Insufficient information to justify the drivers for the step change between 2016 and 2017, and the sustained increases between 2018 to 2022.

The Commission has subsequently set the customer connection capex at the fall-back allowance, as outlined in table below.

Table 8: Forecast and proposed allowances for customer connections capex

Year ending	2018	2019	2020	2021	2022
First Gas forecast customer connections capex ($000)	3,783	3,801	4,047	4,298	4,570
Commission's proposed fall-back customer connections capex ($000)	1,964	1,964	1,964	1,964	1,964

3.4.1. Evidence that the historic baseline expenditure for customer connections is too low

First Gas considers that there are strong reasons to allow a higher level of expenditure for customer connections. We believe that the historic baseline for customer capex used in the draft decisions is artificially suppressed by:

- The prior owner's historic capital contributions policy, which sought to recover much of the connection cost upfront, rather than through the RAB; and
- The prior owner's proven unwillingness to lay gas mains in new subdivisions (as demonstrated by the investments made by GasNet in Papamoa, subsequently acquired by First Gas);

We also provide the Commission with the correct Covec report used for our forecasting, which shows clearly non-Auckland growth assumptions. We discuss each of these points below.

Capital contributions policy

The main driver for the change in expenditure levels in this DPP period relates to the capital contribution policy adopted by First Gas, most importantly at the subdivision developer level. The previous owner required a full contribution upfront, with a rebate policy per ICP connection to the developer. This required a substantial cash investment from developers and allocates the risk of uptake of new connections to developers. First Gas uses a contribution policy that we understand is more comparable to other gas distribution businesses (GasNet and PowerCo), where we determine the minimum economic contribution required by the developer and only seek that level of capital contribution.

This approach delivers two outcomes that are important for understanding future investment needs:

- Higher uptake rate of gas network deployment by developers
- A lower level of capital contributions per development.

In our key growth areas (such as Tauranga), we have found that the uptake rate of gas for new subdivisions had dropped dramatically over the past 5 years. While there will be several reasons for this trend, the initial revision to our capital contribution policy described above has resulted in an immediate uplift in acceptance rates by developers.

Investing in subdivision infrastructure opens growth opportunities for First Gas, but it also has benefits to consumers in delivering a more stable and robust network through looping and providing multiple sources of supply. This investment also ensures that the network is able to expand into future growth areas, where new customers will contribute towards existing asset costs. The previous owner's approach, including its capital contributions policy, led to parts of the network becoming isolated from areas earmarked for future growth. Simply put, under-investment now puts the access to reticulated natural gas in future growth areas at risk.

Covec report for non-Auckland forecast growth

We draw the Commission's attention to the Covec report summary provided in **Appendix I**. This is the correct Covec report used by First Gas for its forecasts and clearly shows non-Auckland growth assumptions, with low, medium and high case projections. As stated previously in the 2016 AMP,[25] First Gas selected the medium case for non-Auckland when building up the overall capex required.

3.4.2. Consistent approach to forecasting growth for customer connections

We see merit in applying a consistent approach to forecasting Constant Price Revenue Growth (CPRG) and the capex required for customer connections. This creates internal consistency in the DPP reset. Our AMP connection growth forecasts are higher than the forecasts incorporated in the Commission's CPRG model, although as the Commission notes[26] using our forecast connections growth would only lead to a small change in CPRG.

We strongly support the incentives for growth that are provided by the Weighted Average Price Cap (WAPC) form of control for gas distribution, and believe that this is essential to provide the right incentives to get reticulated gas into more homes and businesses. A result of this form of regulatory control is that we have financial incentives to outperform the Commission's connection growth forecasts, which increases the efficiency of our networks.

While we can align our forecasts of connection growth with the CPRG, this expenditure category also includes subdivision mains extensions. This component of our forecast is not solely determined by estimated connections over the regulatory period, and in fact shares some of the characteristics of system growth capex. For the year starting 1 October 2017, First Gas has to date committed to $1.3 million of projects to reticulate new subdivisions at the request of developers. We happy to provide the Commission with further information on our FY2017 expenditure to date on subdivisions/mains extensions and the level of uptake from developers. Adjusted expenditure forecast for customer connection capex

Using a connections growth forecast of 0.7% (consistent with the Commission's CPRG model), we have revised our capex forecast to $13.5 million over the regulatory period (our analysis is provided in **Appendix J**). We therefore recommend that the Commission allows this amount for customer capex for the 2017/22 DPP reset period.

3.5. Findings from an independent review of forecast expenditure

In response to the Commission's draft decisions to disallow a significant proportion of our capex and opex, First Gas engaged an independent expert to review the reasonableness of our expenditure forecasts. This independent expert (Chris Harvey) was asked to consider, based on his experience in the gas pipelines industry and his involvement in regulatory processes in Australia, whether the the operating and capital expenditure forecasts First Gas prepared (in areas disallowed by the Commission) are:

- Reasonable, prudent, and generally consistent with industry practice observed elsewhere (e.g. in Australia); and
- Consistent with managing asset risks at current levels.

The independent expert's report found that:

- In his view, First Gas's opex and capex forecasts are based on good industry practice, both in asset management and expenditure forecasting. Not only is the approach appropriate, but also the

[25] Section 5.7.2, First Gas 2016 Distribution AMP.

[26] See paragraph 6.30 of the draft decisions.

forecasts themselves are reasonable and consistent with the expenditure objective established under the legislation and set out in paragraph 4.30 of the Commission's draft decisions paper;

- He reached this conclusion for the following categories of expenditure for our gas transmission and distribution networks:

Category	Reasoning
Gas transmission	
Asset renewal and replacement (ARR) capex	Once the White Cliffs and Gilbert Stream projects are addressed – White Cliffs through a CPP process and Gilbert Stream accepted as a result of the comprehensive information provided to the Commission by the First Gas on 17 February 2017 – the remaining ARR capex is adequately explained in supplementary information provided by First Gas and, in his view (and it appears Strata's), reasonable and meets the expenditure objective.
Routine and corrective maintenance and inspection (RCMI) opex	Comparisons of forecast opex with the Commissions' threshold (three-year average plus five per cent) at a opex category level are problematic, and especially so for First Gas, given the changes to cost allocation to opex categories since acquisition of the network and pipeline assets of Vector and MDL. However, to provide a positive rather than a negative basis for assessing the RCMI forecast, he has reviewed First Gas's explanations for the increase against the Commission's threshold and finds them a reasonable and consistent with the expenditure objective.
Gas distribution	
System growth capex	The peak demand forecast that the System Growth capex was based on was appropriate and the resulting timing and scope of System Growth projects was therefore appropriate. There are plausible and reasonable explanations for the significant increase in growth capex and the projects, costs and timing resulting from First Gas's AMP and forecasting process were therefore reasonable and consistent with the expenditure objective.
Customer connections capex	First Gas recognises the value of consistency between the new connection forecast for the purposes of forecasting distribution capex and that used in the constant price revenue growth model. This leads to two available economic forecasts: First Gas's based on Covec's 2104 forecast and the Commission's based on Concept Consulting's model. First Gas have elected to accept the Commission's modelling. This is reasonable given that the Commission's forecast is more recent and provides a stronger incentive for growing revenue. On this basis, it is reasonable and consistent with the expenditure objective for First Gas to revise its new connection capex forecast to be based on the Commission's new connection forecast;

A copy of Mr Harvey's CV and the full report is attached in **Appendix A**. We are also happy to make Mr Harvey available to meet with the Commission and its consultants to discuss his findings.

3.6. Revised expenditure table

Based on the information presented in this submission and support by the points in the independent expert report, we propose that the Commission allow the following recommended allowances for expenditure:

Business area	Category	First Gas AMP forecast ($million)	Draft DPP allowance ($million)	Recommended DPP allowance ($million)
Transmission Opex	Routine corrective maintenance and inspection (RCMI)	85.1	71.2	85.1
Transmission Capex	Asset Replacement and Renewal (ARR)	121.9	56.5	94.6*
Distribution Capex	System Growth	16.4	3.4	16.4
	Customer Connection	20.5	9.8	13.5**

Notes: * excludes White Cliffs
** using CPRG connection growth rate of 0.7%

This level of expenditure will enable First Gas to adequately manage the risk profile of both our transmission and distribution as sought by our customers, reflects expenditure to enable First Gas to meet its key regulatory obligations, in line with reasonable practice internationally, and for the gas distribution network, will enable First Gas to empower greater utilisation of gas in networks where growth is forecast.

We consider that the proposed allowance for customer connection capex for our distribution network ensures a consistent approach to forecasting Constant Price Revenue Growth (CPRG) and the capex required for customer connections, while still setting expenditure at a level that matches First Gas's philosophy and approach to distribution network development.

3.7. Changes to insurance costs

First Gas has been advised that we will be facing an increase in insurance costs following the 2016 Kaikoura earthquakes. We expect to have clarity on the actual costs on or around 20 March 2017, but current indications are that we face a 30% increase in our premiums. This increase appears to be due to an assessed increase in the replacement value of our regulated assets, the results of a comprehensive risk assessment, and prevailing insurance market conditions.

We will provide confirmed details in our cross-submission, but wanted to bring this issue to the attention of the Commission early to ensure that our opex allowance or pass-through costs adequately fund responsible insurance practices. We anticipate that this issue will also apply to other regulated suppliers, although we understand that we are the first gas pipeline since the earthquakes to go to market for insurance.

We also understand that the Commission addressed this issue through the DPP reset for electricity distribution businesses after the Canterbury earthquakes.

4. Quality path

The Commission has proposed to retain the existing quality standard for both transmission and distribution networks – the response time to emergencies (RTE). As outlined in our 28 September 2016 submission,[27] we support the retention of this quality standard as gas suppliers have well supported systems to already capture this information and report on the standard. We also support the proposed improvements to clarify the requirements around RTE, by moving away from a quality standard formulae to a description of equivalent effect and to extend the exemption timeframe from 30 days to 45 days. This is a pragmatic response to the evidence presented by suppliers on the workability of the exemption.

The Commission also proposes to introduce a new standard to avoid any major interruptions on the gas transmission network, a key concern raised by the Major Gas Users Group (MGUG). As previously noted, we have strong existing incentives to deliver this level of service – so the effect of the new standard is to add another consequence of any failure to ensure supply. This further reinforces the need to adequately fund expenditure to manage security and reliability risks.

4.1. New standard on major interruptions

We appreciate the Commission's analysis of this new proposed quality standard, and we consider that the approach generally balances the needs of consumers with the cost to First Gas of measuring and reporting against this new standard. We support:

- The link to the existing critical contingency management (CCM) regulations overseeing such major interruptions;
- The intent to avoid the capture of negligible interruption events; and
- The exclusion of interruptions caused by disruptions upstream of the transmission system.

However, we recommend improvements to the definition of "major interruptions" as defined in section two of the draft determination. The Commission proposes to define a major interruption as:

> *"any declaration of a Critical Contingency caused or contributed to by an incident on the transmission system, which results in curtailment directions being issued in respect of any band beyond Band 1".*[28]

We recommend that the curtailment band threshold referred to in this definition should be "beyond Band 2". Bands 1 and 2 in the CCM Regulations cover the "Large Consumers" directly connected to the transmission system who are capable of consuming more than 15TJ/Day. As there are only a small number of Large Consumers who use a large quantity of gas, they logically become the first load to be curtailed by the CCO. While dependent on the exact circumstances of the event giving rise to the critical contingency, we consider such curtailment should be enough to stabilise pressure and line pack levels without the need to disrupt the greater number of consumers that fall within Band 3 onwards.

The only distinction between Bands 1 and 2 is availability of an alternative fuel capability (such as coal at Huntly Power Station). Prior to the update of the CCM Regulations that came into effect in March 2014, this distinction was recorded in the Regulations as Bands 1a and 1b. Therefore, we suspect that the current reference to "beyond Band 1" might have been as a result of an earlier version of the CCM Regulations being reference.

[27] *Submission on policy for setting price paths and quality standards in DPP for gas pipeline services from 1 October 2017*, First Gas Limited submission to the Commerce Commission, 28 September 2016.
[28] Paragraph 7.32 of the draft decisions.

A “beyond Band 2” threshold would also align with the trigger for “public statements” that are required to be made by the owner of the asset that has caused or contributed to the Critical Contingency.[29]

4.1.1. Interruptions caused by third parties

We remain concerned with the Commission’s decision to include interruptions caused by third parties within the standard’s definition. We remain of the view (as set out in our prior submission[27]) that these events are largely outside of our control. Nevertheless, we expect that the cause of the interruption and the extent of First Gas’s role in the event will be fully explained through the Commission’s proposed reporting obligation and this will inform any enforcement actions.

4.1.2. Reporting obligations

We are pleased that the Commission has decided that the reporting obligation should not contain:

- Information on the number of customers affected by the interruption; and
- The supplier’s best estimate of the cost of the interruption to consumer.

The Commission is proposing that a GTB must provide a report covering the specified information[30] within 50 working days (10 weeks). We are concerned that this timeframe is not sufficient. During and following critical contingency, First Gas (as the transmission system operator) is required to:

- Remedy the cause of the major interruption to safely restore the gas supply;
- Support the Critical Contingency Operator (CCO) with compiling an Incident Report, which under section 64 of the CCM regulations must be undertaken within 5-business days of the termination of the event;
- Support the CCO to generate a Performance Report, which under section 65 of the CCM regulations must be completed within 30 Business Days of the termination of a critical contingency event;
- Calculate the critical contingency imbalances and price (CCM Regulations allow approximately 2 months);
- Engage in more in-depths specialised studies if required (e.g. geotechnical, environmental, economic, metallurgical etc); and
- Generally, deal with the aftermath of a significant event.

We agree with the Commission’s proposal to enable the GTB to reference the CCM report,[31] however, there will still be a level of additional information that will need to be complied for the Commission (such as revenues from unearned services). Experience from the 2011 incident has shown that it took considerable time for reports to be finalised with all the required information summarising the incident. We also understand that there was an agreement between the CCO and GIC to extend the timeframe for submitting the Performance Report.

It is also unclear whether the 50 working days will be measured from the beginning or resolution of the major interruption. If measured from the beginning, we note that First Gas resources will primarily be focused on resolving the incident then complying with the requirements CCM regulations, before staff can freed up to

[29] See sections 54A and section 2 of Schedule 5 of the CCM Regulations.

[30] Paragraph 9.5 of the draft Gas Transmission Services Default Price-Quality Path Determination 2017.

[31] Paragraph 7.40 of the draft decisions.

contribute to the Commission's proposed reporting obligation. In line with the CCM regulations, we recommend that the determination explicitly starts from "the termination of the major interruption".

We appreciate that the draft determination incorporates an extension clause (clause 9.7). However, given the concerns and existing obligations we have outlined above, we consider that it would be prudent to extend the reporting obligation to at least 60 working days.

4.1.3. Enforcement of breaches

The Commission has proposed that:

> *"while every interruption that meets the definition set out above in paragraph 7.32 will be a breach of the quality standard, not every breach will trigger the same enforcement response."*[32]

We consider that this creates a considerable degree of uncertainty and risk for our business. Rather than declaring every major interruption a breach of the DPP, we prefer the Commission's alternative proposal that would not see a breach declared if:

- The GTB can demonstrate to the Commission that it took all actions aligned with reasonable industry practice (a reasonableness criteria); or
- The GTB can demonstrate to the Commission that the major interruption was beyond the reasonable control of the GTB.

The Commission will appreciate that there are reputational impacts for our business of having breaches recorded against our quality path. We do not consider it appropriate to suffer a loss of reputation where we have demonstrably acted as a RPO in managing and responding to network risks.

4.2. Link between new quality standard and price path reset

The introduction of a new quality standard introduces an additional consequence arising from critical contingency events that we will need to manage. This underscores the importance of ensuring adequate levels of funding to ensure that we can deliver on this quality standard and maintain a resilient gas transmission network. It also creates the need to retain the balance between the level of quality sought and the level of quality that consumers pay for. In other words, service quality requirements reflected in the quality path need to be adequately compensated through the price path.

With the Commission's proposed decisions at this DPP reset to disallow significant expenditure forecast by First Gas, we face the risk of having new consequences from not meeting quality standards without adequate funding to do so. This outcome would clearly not be in the long-term interests of consumers, who want risk to be well-managed through efficient expenditure.[33]

[32] Paragraph 7.51 of the draft decision.

[33] *Cross-submission on policy for setting price paths and quality standards in DPP for gas pipeline services from 1 October 2017*, First Gas Limited cross-submission to the Commerce Commission, 12 October 2016.

5. Implementing the revenue cap with wash-ups

In the IMs reviews, the Commission decided to change the form of control that applies to gas transmission to a "pure" revenue cap (i.e. where any under- or over-recovery of revenue is washed up in subsequent years). We supported this change on the basis that it better achieves the regulatory intent of our revenue cap to not allocate transmission demand risk to First Gas (given our limited control over the gas consumption decisions of parties like Methanex and electricity generators in particular). Another significant advantage of the pure revenue cap is to limit the commercial impacts of changing the transmission pricing methodology, which will take place as part of the current initiative to develop a single gas transmission access code.

The decisions made as part of the DPP reset provide further detail on how the Commission proposes to implement the pure revenue cap. This is more complex than it first appears, and has very high risks of unintended consequences that undermine the purpose of moving to a pure revenue cap. In our view, the best way to avoid unintended consequences is to make the mechanics of the revenue cap as straightforward as possible, without unnecessarily complex or onerous compliance requirements.

We consider that the proposed cap on average price increases is not required because it solves what is now a largely historical problem, and would in fact create more problems than it solves in restricting the flexibility of future pricing arrangements under the new access code.

5.1. Proposed cap on average price increases

We understand that as part of the DPP reset, the Commission is proposing to make three decisions in relation to average price increases:

- To cap the level of annual average increase in prices;
- To set the cap at 10 percent; and
- To apply the cap across pricing categories/revenue classes (currently reserved capacity, throughput fees, overrun charges, and Maui tariffs 1 and 2).

We understand that this proposal responds to concerns that have been raised about significant year-on-year prices increases (of around 20%) implemented under the Vector Transmission Code (VTC), following the closure of Auckland power stations in 2015.

We agree that there is value in having greater price stability and not having users experience significant, unbudgeted increases in their transmission prices. However, we think that the introduction of a pure revenue cap in itself addresses this problem by ensuring that the regulated supplier does not forego revenue by smoothing price increases over several years. In other words, placing a cap on average price increases is trying to solve a problem that no longer exists.

5.2. Unintended consequences of the proposed cap on average price increases

More fundamentally, we are concerned that introducing a cap on average price increases is likely to create new problems that could undermine the value of the pure revenue cap. The full extent of those problems is difficult to predict given that the transmission pricing methodology that will accompany the new code has not yet been developed. However, we consider that an average price limit would not be consistent with the high-level design of the pricing methodology we have outlined to date and that preventing more efficient pricing would not be in the interests of consumers.

Our thinking on pricing under the new code is intimately linked to the access products that we will sell to shippers – as we have previously stated access and pricing go "hand in glove". Responding to several years of work in the gas industry, we have decided upon an access regime that allows parties to access daily transmission capacity through nominations across different geographic zones (to be defined). Shippers will also have the ability to purchase priority rights for their nominations. We believe that this system provides the right mix of flexibility (by allowing shippers to manage the distinct daily, weekly and seasonal demands of their customers) and certainty (by providing access to priority rights to parties that place value on that status). Further details of our proposals for the new code are available on the Gas Industry Company website. [34]

One immediate challenge is that none of the proposed new price categories are the same as the price categories that currently exist under the VTC and Maui Pipeline Operating Code (MPOC). This will create a transition issue in complying with an average price increase limit in the year that the new code is introduced (currently scheduled for 1 October 2018, the second year of the coming DPP period), since all of the price categories will be set to zero.

We do not think this should raise particular concerns from the Commission, since the process of agreeing the new code involves extensive customer and stakeholder consultation and is subject to the regulatory oversight of the Gas Industry Company. The need to achieve a substantial degree of consensus on what the new code looks like means that we have strong incentives not to create materially adverse pricing outcomes for particular parties.

Ignoring this transition issue, we see a longer term problem with an average price increase limit under the new access code. In an effort to ensure efficient prices, we are proposing to run regular auctions for priority rights. A major advantage of an auction-based system is that it enables prices to better align with available service capacity on the transmission network – which is one of the pricing principles that the Commission encourages us to achieve.[35] But the result of this market-based pricing is that we will have very little control over how the revenue earned from auctions varies from year to year – and as a result, how the revenue required from other tariffs (primarily daily nominated capacity) will need to adjust. This is by design. It is entirely efficient for the prices of priority rights to increase as capacity becomes scarce and then fall once the prospect of congestion abates (either through demand response or the addition of capacity).

As we understand it, the average price increase cap would bind if we ever proposed to increase the average price of daily nominated capacity by more than 10%. However, if auction revenue is expected to fall by a significant amount in any year (which is entirely plausible), then an increase in the price of daily nominated capacity will be required and will be an efficient way to earn our regulated revenue.

5.2.1. Worked example of potential problems with average price cap

To support our points above, we have provided a worked example that shows variations in the proportion of revenue recovered via daily nominated capacity and priority rights.

In this example, the average price increase cap has been breached twice. In Year 3 this is because the revenue expected from priority rights has decreased from the amount expected in Year 2. In Year 5 this is because a higher total revenue needs to be collected – and no more revenue is expected to come from auctions of priority rights than was expected in the prior year.

[34] See http://www.gasindustry.co.nz/work-programmes/transmission-pipeline-access/developing/gas-transmission-workshop-february-2017/

[35] The Pricing Principles specified in clause 2.5.2 of the Input Methodologies state that Prices are to signal the economic costs of service provision, by having regard, to the extent practicable, to the level of available service capacity.

	Year 1	Year 2	Year 3	Year 4	Year 5
FAR	100	100	100	100	100
Wash-up carried forward from t-2	-	-	5	-10	-
Far (with wash-up)	100	100	105	90	100
Forecast revenue DNC	90	80	100***	80	90***
Forecast Revenue PR	10	20	5	10	10
Actual Revenue DNC	90	80	100	80	90
Actual Revenue PR	5	30	5	10	10
Difference to be washed up	5	-10	-	-	-

*** denotes a breach to the 10% average price increase cap proposed in the draft decisions

5.3. Recommended approach and summary

While we understand the value of price stability, for the reasons explained above we recommend that the Commission does not specify a cap on average price increases at this DPP reset. In essence, we consider:

- The proposal to cap average price increases solves a problem that no longer exists. Since we have a wash up, we don't immediately forego revenue not collected and therefore can make rational commercially-based decisions on when it is best to collect revenue given the desire to maintain customer goodwill and enable the use of gas;
- Safeguards to price volatility are provided through other processes – particularly code redevelopment and consultation on the transmission pricing methodology that will accompany the new code;
- The new code may well carry over none of the price categories that currently exist, which creates a transition issue; and
- The risk of unintended consequences in applying the average price increase cap is high – particularly when we are still in a formative stage of developing the new code. The draft decisions appear likely to undermine our current thinking on selling priority rights to capacity through auctions, since revenue fluctuations from auctions will affect revenue from priced products year on year. This would be disappointing given that one of the reasons for introducing a pure revenue cap was to accommodate tariff restructuring and specifically the use of capacity auctions on the transmission system.

6. DPP implementation

If confirmed, the proposed reduction in expenditure will require First Gas to reprioritise work that can be done on the transmission and distribution networks to conform with the Commission's allowances. A change in our risk profile is not likely to align with our customer expectations and it is not in our customers' interests for prices to be artificially depressed for a couple of years, only to have them raised through a CPP.

We therefore recommend that the starting price adjustments for our regulated businesses (particularly our GTB) is implemented over two years to:

- Give suppliers opportunity to adjust to the new price path;
- Allow First Gas the opportunity to incorporate those adjustments into its CPP application process. We expect to gain a better understanding of specific expenditure needs through that process, and could get more value out of it if we didn't have to respond to revenue reductions so quickly;
- Manage the situation where sharp revenue reductions under the DPP are immediately offset by increased revenue under the CPP. In a view, a more moderate path from current revenue to the CPP would be in everyone's interests.

All adjustments would result in the same present value outcome, but taking two years (rather than a single jump) would provide more opportunity for a measured and efficient response.

We also note the need for a more flexible approach to the CPP process, which we understand will be considered later this year as part of the input methodologies review. Given the nature of the expenditure that is likely to form part of any CPP application by First Gas, we believe the process should enable us to adjust our expenditure as project requirements and opportunities warrant. This may take the form of having individual well-defined projects or categories of projects approved through a CPP application, with actual investment levels and timeframes contingent on the availability of further information.

7. Appendices

The following appendices are provided with our submission:

Appendix A:	Independent expert review from Chris Harvey
Appendix B:	Summary of ARR expenditure forecasts and allowances
Appendix C:	Breakdown of ARR capex
Appendix D:	Breakdown of prior MDL expenditure reallocated by First Gas to RCMI
Appendix E:	10-year activity schedule
Appendix F:	Maui pipeline (403 line) Assessment of geohazard features
Appendix G:	Example of First Gas Board report on geohazard risks
Appendix H:	Calculation of geohazard remediation costs
Appendix I:	Covec report on growth forecasts
Appendix J:	Revised customer connection capex forecasts
Appendix K:	Cambridge options, network growth rate and network failure flow
Appendix L:	Vector projects mapped to First Gas

Appendix A: Independent expert review from Chris Harvey

Report

Review of First Gas's opex and capex forecasts

For its Default Price-Quality Path (DPP) reset determination for 1 October 2017 to 30 September 2022

March 2017

Table of Contents

Review of First Gas's Opex and capex forecasts in the context of Review of Default Price-quality Paths by the New Zealand Commerce Commission

1 Executive summary

1. I have been requested by First Gas Limited to review its operating expenditure (opex) and capital expenditure (capex) forecasts currently being assessed by the New Zealand Commerce Commission (NZCC or the Commission) as part of its reset of default price-quality paths (DPP) for gas pipeline businesses. The purpose of this work is to provide an independent view of the forecasts and, in particular, to comment on areas that the regulator has proposed not to accept certain elements of First Gas's forecast expenditure and substitute in its fall-back allowance.

2. I have used a range of documents and supplementary information provided by First Gas, including that from the Commission and its consultant, Strata Energy Consulting (Strata), to form my views about First Gas's opex and capex – within the limits of scrutiny expected as part of the Commerce Commission's "low cost" DPP review. My view is that First Gas's opex and capex forecasts are based on good industry practice, both in asset management and expenditure forecasting. Not only is the approach appropriate, but also the forecasts themselves are reasonable and consistent with the expenditure objective established under the legislation and set out in paragraph 4.30 of the Commission's Draft Reasons Paper.

3. I have reached this conclusion for the following categories of expenditure for the respective assets (distribution and transmission):

   - **Transmission capex**
     - **Asset Renewal and Replacement (ARR)** – Once the White Cliffs and Gilbert Stream projects are addressed – White Cliffs through a CPP process and Gilbert Stream accepted as a result of the comprehensive information provided to the Commission by the First Gas in February 2017 – the remaining ARR capex is adequately explained in supplementary information provided by First Gas and, in my view (and it appears Strata's), reasonable and meets the expenditure objective.
   - **Transmission opex**
     - Routine and corrective maintenance and inspection (RCMI) – My view is that comparisons of forecast opex with the Commissions' threshold (three-year average plus five per cent) at a opex category level are problematic, and especially so for First Gas, given the changes to cost allocation to opex categories since acquisition of the network and pipeline assets of Vector and MDL. However, to provide a positive rather than a negative basis for assessing the RCMI forecast, I have reviewed First Gas's explanations for the increase against the Commission's threshold and find them a reasonable and consistent with the expenditure objective.
   - **Distribution capex**
     - **System Growth** – The demand forecast that the System Growth capex was based on was appropriate and the resulting timing and scope of System Growth projects was therefore appropriate. There are plausible and reasonable explanations for the very significant increase in growth capex and the projects, costs and timing resulting from First Gas's AMP and forecasting process were therefore reasonable and consistent with the expenditure objective.
     - **New connections** – Application of Covec's forecast of connections for non-Auckland gas networks to historically derived unit connection costs is consistent with good industry practice. However, I also note that First Gas, in recognising the need for consistency between the new connection forecast for the purposes of forecasting new connection capex and that used in the constant price revenue growth model, accepts that the

forecasts need to be the same. There are two available economic forecasts: First Gas's based on Covec's 2104 forecast and the Commission's. First Gas has elected to accept the Commission's. This is a reasonable course, on the assumption that the Commission's forecast is more recent than 2014 and it provides a better incentive for growth in the revenue path. On this basis it is reasonable and consistent with the expenditure objective for First Gas to revise its new connection capex forecast to be based on the Commission's new connection forecast.

2 Report brief

4. I have been requested by First Gas Limited to review its operating expenditure (opex) and capital expenditure (capex) forecasts currently being assessed by the New Zealand Commerce Commission (NZCC or the Commission) as part of its reset of default price-quality paths (DPP) for gas pipeline businesses. The purpose is to provide an independent view of the forecasts and, in particular, to comment on areas that the regulator has proposed not to accept certain elements of First Gas' forecast and substitute its own fall-back.

5. The review requires an assessment of First Gas's Asset Management Plans (AMP) for its transmission pipeline network and distribution network, as these form the basis of the capex and opex forecasts. In particular, it has involved assessment of the approach to asset management and the methodology used for expenditure forecasting to determine whether:

   - these are consistent with good industry practice and the expenditure objectives under the legislation, and
   - the forecasts themselves are reasonable given my experience with the gas industry in other jurisdictions.

6. My credentials for undertaking this review arise out of my training in engineering and my extensive experience in the gas industry, both gas distribution and gas transmission. This has included a range of roles covering technical, commercial, general management and economic regulation and advisory. I have had extensive experience with regulatory reviews that have included assessment of opex and capex, both in my roles as regulatory manager and as advisor to regulated businesses. In addition, my roles managing a gas network and transmission pipeline together with my experience developing the Australian Pipelines and Gas Association's (APGA) Pipeline Engineer Competency System have provided relevant additional experience. My curriculum vitae is provided in Appendix 1.

3 Review methodology

7. The process I have adopted has been to review and analyse the following documents:

   - Information Disclosure Determinations 2012 – (consolidated in 2015) for transmission and distribution
   - First Gas's distribution and transmission AMPs 2016/17
   - Strata's reports on First Gas transmission and distribution BAU variance checks and AMP evidence assessment
   - First Gas's response to Questions for Supplier evidence stage of forecasting expenditure process covering both distribution and transmission
   - Strata's reports on First Gas supplier evidence assessment responses for transmission and distribution
   - Strata's Dashboard spreadsheets for transmission and distribution
   - The NZCC's Draft Reasons Paper on gas pipeline businesses from 1 October 2017 to 30 September 2022 (dated 10 February 2017)
   - First Gas - Supplier expenditure questions - 17 Feb 17_FGL response, including appendices
   - First Gas's draft submission in response to the NZCC's Draft reasons paper

8. Where there have been gaps in the information, I have requested First Gas to fill those gaps. This has included discussions with First Gas staff to clarify the nature of the information requested.

9. Supplementary information I have received is listed in Appendix 2.

10. Based on this information I have formed a view about the appropriateness of First Gas' approach to asset management as set out in its Asset Management Plans and the validity of it expenditure forecasting methodologies which have led to a view about the reasonableness – or otherwise – of First Gas' opex and capex forecasts.

11. My focus has, in the main, been on those areas of expenditure that the Commission proposes to not accept and substitute its own forecast in the form of the fall-back allowance.

4 Comments on First Gas's capex and opex forecasts methodologies and its AMP approach

4.1 Approach to asset management

12. First Gas has produced AMP's for both its distribution and transmission businesses. This is in line with the requirement of the NZCC under Part 4 of the Commerce Act 1986. Perhaps more importantly, well developed asset management plans are a major element of sound management of infrastructure assets such as gas distribution networks and gas transmission pipelines. The asset management plan together with its associated asset management policy and asset management strategy is an essential means to gaining confidence that an infrastructure asset is being managed in a way that will deliver the required outcomes in a safe, environmentally sustainable, efficient and effective manner.

13. First Gas' AMP reflects good industry practice in both the gas distribution and gas transmission industries. They are comparable to those of gas distribution and gas transmission businesses in Australia. In some respects, they provide greater levels of detail than some I have been aware of. This may, in part, be because of the requirements for asset management plans set out by the NZCC and their role in the DPP reset process.

14. A key element of First Gas's approach to asset management is its reliance on the two standards that provide the basis for safe, reliable, environmentally sustainable and efficient design construction and operation of gas networks and pipelines in Australia and New Zealand. The applicable Standards are AS/NZS 4645 for distribution networks and AS/NZS 2885 for gas pipelines (transmission). A core element of both of these standards is the management of safety, environmental issues and supply reliability through a rigorous approach to risk management. In the case of AS/NZS 4645 it is through the process of Formal Safety Assessments; and in the case of AS/NZS 2885 it is the process of Safety Management Studies. Both of these processes are applied to each stage of an asset's life through design, construction, commissioning, operation and maintenance and suspension and abandonment.

15. This risk-based approach is essential to good practice in gas asset management. It provides the basis for determining priorities to be given to each category of capex and opex. Risk by nature carries the concept of uncertainty and a risk-based approach provides a sound framework for managing uncertainty.

4.2 Approach to expenditure forecasting

4.2.1 Comments about First Gas's expenditure forecasting

16. First Gas' approach to forecasting of opex and capex generally reflects accepted good industry practice. For capex for all of its assets it has undertaken a bottom-up build based on historic activity levels , added new activities that have step changes in activity, then used historical average costs to forecast regulatory period expenditure. For distribution opex, this forecast comprises what has been called in Australia the base-step-trend model, where the base is the quoted price for its opex undertaken by its contractor, Electrix, supplemented by a detailed budget for network support expenditure for 2017. For transmission opex it has based its forecast on historic activity levels and added step changes in activity as required.

17. In the context of regulatory reviews/resets, typically the base year of a base step trend forecast is the year is two years prior to the first year of the regulatory period, but this is not universally so. The use of the year two years prior seeks to reflect the incentive properties in the price path incentive regulation, recognising that the regulated business has an interest in reducing its opex over the regulatory period and the year prior to the next regulatory period will not be an actual cost but a forecast.

18. It is important to note that in taking over Vector and MDL's assets, First Gas has adopted a different allocation of costs both between capex and opex and between opex categories. This arose, in part, because of the different treatment of expenditure between the Vector and MDL businesses and consistency was required across all of First Gas's assets for effective management of them.

19. First Gas's approach to capex requirements forecasting also reflects good industry practice, determining what expenditure is needed through its AMP, in particular through its risk management framework applied to each category of expenditure and each asset class/fleet.

20. Its approach to capex cost estimation reflects good industry practice, applying a bottom up estimate approach, and applying an appropriate method to each type of expenditure:

    - program based – using volumes and historically derived unit rates or historic averages where volumes are not predictable;
    - project-based – applying standard project cost estimating tools, which utilise recent cost experience in deriving the estimates of cost elements;
    - ICT – similar to project based with a strong reference to actual costs of similar hardware and software; and
    - Building – using standard unit rates for floor area and services.

4.2.2 Comments about NZCC's approach to expenditure forecasting

21. NZCC's approach to evaluating opex is to apply a three-year average plus five per cent margin as a threshold for more in depth assessment. The three-year average also acts as a fall-back in the event that costs in excess of the threshold are inadequately justified. The Commission applies this at both the overall level and at the opex category level, but appears to focus on the individual category level.

22. Historic benchmarking of individual opex categories is generally a problematic exercise, because opex categories vary between businesses and inclusions in categories can change with time, even for the same business, as a result of regular internal reorganisations. First Gas has identified that its approach to allocation of costs to opex categories is different from previous asset owners (Vector and MDL) ensuring that any comparison of opex at the category level is at best uncertain, if not simply inaccurate, and should not be used to assess the prudent and efficient level of opex, because it is not a true "apples for apples" comparison.

23. Moreover, where the total quantum of opex is the same as the three-year average, but where there is also a reallocation of costs to each category, there is a risk that categories that are less than the historic average will be captured while those above the historic average may be truncated. It is important that the Commission is aware of this possibility f "cherry picking" and avoids this unintended consequence of its approach to assessing opex.

24. The Commission's approach to assessing capex using the historic average of three years with a 10 per cent margin as a threshold and fall-back makes some practical sense as a mechanism to keep the regulatory review process low cost. However, it needs to be recognised that the 10 per cent margin is arbitrary and that capex programs are inherently lumpy, and even regular capex typically has frequencies of much longer than 3 years. Variations from year to year can swing significantly, by as much as 50 per cent or more, and even taking a three-year average is not sufficient to smooth out these movements or be representative of the long term capex program.

The use of the three-year average plus 10 per cent margin threshold has no empirical basis and has potential to create perverse incentives for businesses to smooth capex away from when it is most efficient to be incurred and most needed for effective risk management. This means that the follow up process of assessing capex programs that exceed the threshold needs to be sufficiently detailed to ensure capex that is needed is not rejected from the capex forecast.

25. In fact, it is likely that at most regulatory resets, a gas distribution or transmission business's prudent and efficient capex will exceed the threshold of the three-year average plus 10 per cent in capex categories that are inherently lumpy. As a result, the Commission and its consultants will, for a large proportion of resets, need to investigate some categories of capex for gas network and pipeline infrastructure in depth. Even with the largest capex projects removed, there is likely to be natural variation in capex requirements that exceeds the arbitrary threshold set by the Commission.

5 Specific issues – aspects of capex and opex not accepted

26. In the Draft Reasons the Commission proposes not to accept First Gas' capex for system growth and new connections for the distribution business, and the RCMI opex and the asset renewal and replacement. (ARR) capex for its gas transmission business. It also proposes to exclude White Cliffs, ad Gilbert Stream from ARR capex and apply the standard fall-back. The following provides reasoning as to why I consider that First Gas's forecast capex for these categories is reasonable and reflects the expenditure objective set out in paragraph 4.30 of the NZCC's Draft Reasons.

5.1 Transmission

5.1.1 Asset renewal and replacement

27. Section 6.2 and 8.5 of First Gas's Transmission AMP set out the requirements for ARR capex, which cover the full range of asset classes (or asset fleets) in the First Gas transmission pipeline network. There are two large projects that involve realignment of pipeline sections that are in close proximity to coastal erosion at White Cliffs and near Gilbert Stream.

28. While Strata accepted forecast costs of the two realignment projects the Commission has proposed not to accept them, but would consider White Cliffs as part of a Customised Price-Quality Path (CPP) with investigation costs being added to the opex forecast as part of its fall-back. It has also proposed applying the standard fall-back to the remainder of the ARR expenditure.

29. It is reasonable that a project of the size of the White Cliffs project should be the subject of a CPP, given the extensive investigation, project planning and cost estimation required and the need for more exacting scrutiny of the prudence and efficiency of the forecast cost.

30. First Gas provided responses to supplementary questions from the Commission on 17 February 2017. These questions and answers addressed details around the justification for the Gilbert Stream project and the forecast expenditure for the three major projects: Gilbert Stream pipeline realignment, White Cliffs pipeline realignment and the Henderson Compressor Project.

31. The responses to the Commission's questions were comprehensive and provided a clear view as to why the proposed Gilbert Stream project was needed and was the most appropriate project, based on an evaluation of four options from a risk management and economic perspective. The cost estimates were at the appropriate level for an options analysis. I expect that they would have an accuracy of +/- 30 per cent, even with a 20 per cent contingency allowance. My experience with gas infrastructure projects is that estimates at this level tend to underestimate, rather than overestimate, the actual cost, largely because of factors, unable to be identified until detailed design, that can affect the scope of the project or simply add costs that could not be foreseen.

32. Given this information, it is reasonable for the Commission to accept the forecast capex for the Gilbert Stream as meeting the requirements of the expenditure objective.

33. Strata formed the view that the remaining ARR capex was well supported and should be accepted[1]. It is unclear if it is simply a mechanical application of the fall-back or it is as a result of some further consideration of the ARR capex with the White Cliffs and Gilbert Stream projects removed, but in its Draft Reasons the Commission proposes to reduce the remainder of AAR capex to the standard fall-back (10 per cent above the three-year average). Consistent with my comments in Section 4.2 paragraph 24 and 25, the fall-back is both arbitrary and unsatisfactory as a basis for forecasting lumpy capex. Bottom up estimates of capex are, by nature, lumpy and irregular and are not well benchmarked by the three-year average – or any historic average.

34. I have reviewed additional information provided by First Gas. This comprised (i) explanations of expenditure that is additional to that made in recent history and includes a reallocation of in-line inspection from opex to capex[2] and (ii) a review of its forecast capex model[3], which captures every item of capex used to develop the bottom up build of the forecast. Significant items of new or increased expenditure were:

    - Re-categorisation of in-line inspection from RCMI opex. – It is generally industry practice to capitalise in-line inspections - $8,200,000
    - Geohazard remediation – There is clearly a need for this expenditure of $17,000,000 and the forecasting basis is reasonable
    - Replacement of compressor station cooling fans – This is based on external consultant's advice and can reasonably be expected for aging gas coolers – $3,400,000
    - Replacement of Grove 8 regulators – Due to loss of vendor support - $3,400,000
    - Upgrading of pig traps to required standards – clearly needed – $3,600,000
    - Heating systems refurbishment and controls upgrade – larger heaters resulting in an increase over previous years - $3,700,000

35. It would be more appropriate, if the Commission has any residual concerns about the proposed ARR capex, that it ask its advisors, Strata, to review the same material as I have to make an assessment of their reasonableness, in the light of the processes set out by First Gas in its AMP in deriving the project list. Having done so I am satisfied that the ARR capex net of the White Cliffs and Gilbert Stream projects is appropriate and consistent with prudent and efficient practice.

5.1.2 Routine and corrective maintenance and Inspection

36. Sections 6.4.2 and 8.8.2 set out First Gas's approach to routine and corrective maintenance and inspection (RCMI) and its forecast, which shows a step up in opex when compared to 2016 expenditure and the three-year average for 2013 – 2015.

37. Strata has recommended against accepting First Gas' forecast opex following a request for evidence from First Gas, because it finds explanations for the increased opex, particularly from 2019 onwards, are confusing and not compelling. In particular, it has the following concerns:

    - Re-categorisation of MDL's ARR expenditure to RCMI by $930,000, which is inconsistent with MDL's historic ARR expenditure of $510,000
    - Geohazard management costs are somewhat ambiguous as the AMP explains that it relates to the step up in RCMI in 2017, whereas in First Gas' responses to NZCC questions[4] it explains that there is an ongoing expenditure on geo-hazard management from 2017. It appears that

[1] Report on First Gas transmission BAU variance checks and AMP evidence assessment, Strat Energy Consulting, 16 November 20916, para 45

[2] First Gas Response to Draft Default Price Path Decision from the Commerce Commission, Section 3.1, Appendices B and C

[3] AMP - Consolidated Model – GTBCapex – As published.xlxs

[4] NZCC – Gas DPP Reset 2017 – Questions for supplier evidence stage of forecasting expenditure process

Strata is unclear about whether the costs include remediation and when it will occur in relation to the associated investigation.

38. The issues that Strata has with the RCMI opex are, in part, a consequence of attempting to look at opex at the category level, for the reasons enumerated in Section 4.2 at paragraph 21, namely that comparison of opex at cost category level is problematic and especially when there has been a change of ownership and associated change in cost allocation. As identified in section 4.2.2, paragraph 21, I believe that comparisons should only be done at the aggregate opex level, unless there is a demonstrably consistent approach to opex cost categorisation over time.

39. I note that the approach adopted by the NZCC results in a reduction of $576,000[5] in overall opex (after adjustment for in-line inspection expenditure) against the 2013-15 average for the combined Vector and MDL transmission assets. This arises out of the application of the three-year plus 10% margin threshold at the opex category level. In doing so the Commission is capturing the opex for categories where opex has reduced and truncating it in the RCMI category. This is both inappropriate and unreasonable, and more importantly it results in a level of opex less than is required for the prior years and is therefore likely to be less than that required for prudent and efficient operation of the pipeline networks.

40. Having said that, I have requested First Gas to provide me with a clear explanation about why the costs have increased for the RCMI category[6], to provide confidence about whether the costs have increased significantly and, if so, why.

41. That additional information together with that in its response to questions from Commission provides a reasonable, complete explanation of the basis of the $930,000 addition to RCMI[7] for what had previously been treated as ARR opex by MDL and additional work that had not been identified by MDL that is necessary for proper maintenance of the MDL assets. First Gas has provided a detailed build up of the costs included in the addition to RCMI from the MDL pipeline ARR opex[8] and the make-up of the costs is well substantiated. Similarly, in respect of geohazard management its explanation of the make-up of the expenditure between investigation and remediation is clear and costs well substantiated. In particular, Strata's concern about the timing of investigation and remediation as part of a 10-year rolling program is clearly explained. The amounts estimated for these activities are reasonable.

42. Once these and other costs identified by First Gas in its response to questions from the Commission,[9] the remaining difference between the three-year average is less than or equal to the five per cent margin (See Appendix 3). Importantly, if the average is moved forward by one year the costs fall to the level of the three-year average, calling into question the representativeness of 2013 for the purposes of setting the benchmark, and possibly the three-year average, given its apparent volatility.

5.2 Distribution

43. First Gas's approach to forecasting system growth and customer connection capex reflects good industry practice. It would appear that some of the reasons for not accepting the capex in these categories may reflect a lack of familiarity with the demand forecasts that have been used to derive opex, capex and constant price revenue growth (CPRG) and prices.

44. It seems worthwhile to spell out the three forecasts used by First Gas and their different applications. These are:

---

[5] First Gas Response to Draft Default Price Path Decision from the Commerce Commission, Section 2.5

[6] First Gas Response to Draft Default Price Path Decision from the Commerce Commission, Appendices D,E,F,G,H and Email and spreadsheet - L Treadway - First Gas Transmission expenditure forecast analysis (005).xlsx
Email L Treadway re OPEX Activities

7 GAS DPP RESET 2017 – QUESTIONS FOR SUPPLIER EVIDENCE STAGE OF FORECASTING EXPENDITURE PROCESS

8 First Gas Response to Draft Default Price Path Decision from the Commerce Commission, Appendices D

9 GAS DPP RESET 2017 – QUESTIONS FOR SUPPLIER EVIDENCE STAGE OF FORECASTING EXPENDITURE PROCESS, November 2016

- **Annual energy quantity forecast (TJ per annum transported)** – used for converting revenue requirement into the energy component of prices. This is typically based on a forecast of customer numbers and average annual usage for each customer class. The new connections forecast will be an input to this forecast. These may be forecast at a global level, but in some cases may be broken down by geographic area.
- **Peak load forecast (peak hourly demand GJ/hr)** – used for planning System Growth capex (perhaps more accurately, system capacity expansion capex) and determining timing of system capacity expansions for pipeline and station additions/enhancements. Peak load rather than annual quantities are required because this is the basis of sizing station equipment and capacity modelling of sub-networks. By nature, it is essential that this be undertaken at the sub-network level, because the peak demand growth will be geographically specific to each network, reflecting the mix of customers between residential, commercial and industrial, all of which have very different load characteristics and growth patterns. This, like most forecasts, is based on an extrapolation of the historic peak demand growth adjusted for known factors that are likely to affect the forecast, such as addition of major industrial customers or significant new estate developments. This approach to peak demand forecasting is good industry practice.
- **Network connection forecasts (Customer numbers and annual demand size)** – Typically these forecast are undertaken by economic forecasting consultancies. These sorts of estimates tend to reflect broad economic parameters, such as population growth, GDP and housing forecast. This is used for forecasting connections capex, and estimation of annual energy quantity forecast. For larger networks, which are predominantly urban, typically a single forecast is undertaken applicable to all geographic regions. Where there is a substantial number of diverse geographic regions, such as for First Gas, the forecast is made for each of the regions and aggregated.

45. Because each of these forecasts is undertaken separately and using different bases, the linkages between them are not direct and it is normal that growth rates for each of these differ, reflecting differences in load characteristics (mainly load factor) and the new connection consumption patterns relative to consumption patterns of existing customers. One notable trend is that energy appliances are becoming more efficient, thereby reducing average annual energy quantity per customer, while increasing peak demand. The result is that peak demand grows at a faster rate than annual quantities. This is also seen in electricity markets, but for different reasons.

46. A better understanding of the nature of each of these forecasts, their bases and application provides a better understanding of demand-based capex forecasting.

5.2.1 System growth capex

47. Sections 5.1 - 5.6 and 5.8 of First Gas' Distribution Network AMP provide a thorough explanation of the processes it uses for planning for and forecasting of capacity expansion (i.e. system growth) of the distribution network. The methodology described reflects good industry practice as I have found among First Gas' Australian peers. It is this methodology and process that necessarily drives the forecast, and it is essential for maintenance of reliable supply that it does.

48. First Gas' planning for needed expansions is based on the second type of forecast (peak load forecast). This is set out in detail in Appendix E of the AMP providing the individual sub-network peak demand forecasts, which are aggregated into a whole of system forecast, by applying a historically derived diversity factor. There are particular aspects of the peak demand forecasting methodology that make it different from the other two forecasts and are worth reiterating:

- A peak demand forecast is developed for each sub-network, so that it reflects the actual peak demand and the particular circumstances of the relevant sub-network and its customer group that influence it. It is this peak demand that must flow through the stations and pipeline network.

- It is based on the historic trend of peak load growth for that particular network and is extrapolated to become the forecast.
- The extrapolated historic trend is adjusted for known factors that may cause a deviation from the trend, such as large industrial load additions or subtractions and residential load growth expectations due to new estate development.

49. As already identified, this approach is good industry practice and provides a robust basis for planning capacity expansions, be it for gate stations, district regulators, pipeline additions or pressure upgrades.

50. What is noticeable about First Gas's forecast capex is that there is a very significant increase from 2017 above the 2013-15 average ($609,000) and even the 2014-16 average ($759,000), while the average for the six years 2016-2022 is $3,394,000 an increase of 350 per cent with peaks in 2017, 2020 and 2022 of approximately $4,000,000. Post-2022 the forecast reduces to a stable (not lumpy or large) at a higher level than prior to 2017 (2023-26: average $1,806,000). So that while the process used by First Gas is robust and the basis of considerable confidence in the resulting forecast, the steep and sustained increase must lead to questions about why the increase is present.

51. Strata[10] appears to have recommended non-acceptance of First Gas' System Growth for the following reasons:

    - the AMP does not provide a clear link between the expansions for each sub-network in section 5.8 of the AMP and the annual amounts in the capex forecast. It is particularly concerned about the lack of clarity around the rolling forward of System Growth projects from the Vector AMPs – in particular the Cambridge sub-network projects – and the lack of support for First Gas' assertions about high levels of residential growth in the Tauranga, Hamilton and Kapiti regions;
    - what appears to be confusion about the lack of connection between connection growth forecast and the peak demand forecast; and
    - a lack of rationale for the difference between the forecast of ICP growth of 1 per cent, which appear to be sourced from the NZCC's constant price revenue growth (CPRG) model and the ICP growth in the Covec forecast.

52. Once it is understood that the relevant forecast for purposes of System Growth capex is the peak load forecast for each sub-network (on the assumption that the most prudent option has been chosen and efficiently costed) the projects identified to ensure continued supply and their respective timings are the inevitable consequences of that forecast. That is, when the current capacities of stations and pipe networks for each sub-network become insufficient to meet the forecast peak load a capacity expansion is required. This establishes the timing of the expansion and the options analysis determines the most prudent response. Accordingly, many of Strata's concerns and reasons for rejecting the System Growth capex forecasts, to my mind, should be substantially resolved.

53. However, the steep increase in system growth capex over the 2017-22 period means that the forecast could not be accepted *prima facie*, simply because First Gas has a good process for deriving its system growth capex requirements. The reasons for the increases needed to be investigated and the details of the forecast needed to be tested. To satisfy myself that the increases are plausible and reasonable, I requested further information about the reasons for the increase. It appears that the prior owner, Vector, had been limiting capex prior to sale of its non-Auckland distribution networks with the result that it had managed to keep system growth capex to a minimum, leaving several of the networks very close to capacity during the winter

[10] Strata Energy Consulting, Report on First Gas distribution supplier evidence assessment responses, 28 November 2016

peaks of 2015 and 2016. This had the dual effect of depressing the historic average and creating the need to catch up in succeeding years 217 and 2018.

54. I also reviewed the system growth capex program from First Gas's forecast model against the AMP sections 5.8, Section 8.3 and Appendix F to satisfy myself that there is a clear relationship between the content of the AMP and the system growth capex forecast. Appendix F is well laid out providing a comprehensive assessment of the state of capacity of each of First Gas's sub-networks. A majority of the sub-networks (30 out of 39 sub-networks) do not have any requirement for system growth capex in the ten year period to 2026. For the remainder of the nine sub-networks requiring system growth capex, only five involve expenditure significantly in excess of $1,000,000; two are for about $1,000,000 and two well less than $1,000,000. The forecast model faithfully reflects the described requirements in Section 5.8 and Appendix F. I extracted the relevant elements of the forecast from the capex model as part of this process and it is included in Appendix 4.

55. For a network the size of First Gas's (RAB is $128,000,000) system growth capex of just $600,000 to $700,000 is disproportionately low at 0.5 per cent of the asset value. This low level of system growth capex in 2013-2016 is clearly unsustainable. The increase in system growth capex in FY17/18 reflects a pent up capex requirement at the time of the sale of the network to First Gas and the large amounts of capex required from 2019-22 are simply a result of peak demand growth running into the limits of the existing capacity on a number of the larger sub-networks conincidentally. The average expenditure for 2016-2026 is $2,759,000 (2.1 per cent of the RAB) and I consider this a more sustainable proportion of the RAB given its ongoing growth prospects.

56. Having reviewed the supplementary information provided by First Gas about timing and cost of each of the system growth projects and, in particular, for Cambridge, Tauranga, Hamilton and Kapiti, I am satisfied about the explanations as to the significant increase in system growth capex.

57. When the specific forecast projects, costs and timings are taken together with the soundness of the forecasting methodology used by First Gas for System Growth capex, the forecast capex can be seen to be soundly based and consistent with the expenditure objective. It can also be said that the level of expenditure in the years prior to 2017 are well less than what I would be expect for a network with the continuing growth that has been observed, and consequently forecast, by First Gas.

5.2.2 New connection capex

58. Section 5.7 of First Gas' AMP sets out First Gas's approach to managing new connections and its methodology for forecasting New Connection capex. Central to this forecast is the number of new connections forecast to be made. First Gas (consistent with good industry practice) has sought the advice of Covec, which is a firm whose expertise includes economic forecasting and market analysis.

59. The new connection capex forecast is derived as the number of connections multiplied by the historic average of unit cost per connection for each connection type (subdivision/mains extensions, residential connections, commercial connections and easement costs).

60. Strata's concern about the connection numbers forecast appears to arise from its understanding that First Gas has applied a forecast that was only intended for the Auckland area, commissioned by Vector. I have requested that First Gas provide me with the Covec forecast to assess its suitability for forecasting First Gas' network connections all of which are outside of Auckland.

61. The Covec 2014 forecast provided by First Gas clearly forecasts new connection growth for the networks outside of Auckland and provides a sound basis for the new connection capex forecast. It appears that Strata did not have this information. The only downside with the Covec forecast

is that it was published in April 2014 and will not reflect actual changes since 2013 nor take into account new developments that are beginning to emerge.

62. First Gas has recognised that the new connections forecast must be the same used for the constant price revenue growth (CPRG) as for forecasting new connection capex, and that there are two forecasts of new connections: the Covec 2014 forecast and the Commission's. It has elected to adopt the Commission's as providing stronger incentives to grow the network

63. I consider this a reasonable course to take and that the new connections capex forecast that results has a sound basis that is consistent with the expenditure objective.

6 Summary conclusions

64. Having reviewed the initial information provided by First Gas (see section 3, paragraph 4) and supplementary information (See Appendix 2) requested from First Gas I have been satisfied – within the limits of scrutiny expected as part of the Commerce Commission's "low cost" DPP review – that First Gas's opex and capex forecasts are based on good industry practice, both in asset management and expenditure forecasting, I am also of the view that the forecasts themselves are reasonable and consistent with the expenditure objective establish under the legislation and set out in paragraph 4.30 of the Commissions Draft Reasons Paper.

65. I have reached this conclusion for the following categories of expenditure for the respective assets (distribution and transmission):

- **Transmission capex**
  - **Asset Renewal and Replacement (ARR)** – Once the White Cliffs and Gilbert Stream projects are addressed – White Cliffs through a CPP process and Gilbert Stream accepted as a result of the comprehensive information provided to the Commission by the First Gas in February – the remaining ARR capex is adequately explained in supplementary information provided by First Gas and, in my view (and it appears Strata's), reasonable and meets the expenditure objective.
- **Transmission opex**
  - Routine and corrective maintenance and inspection (RCMI) – My view is that comparisons of forecast opex with the Commissions' threshold (three-year average plus five per cent) at a opex category level are problematic, and especially so for First Gas, given the changes to cost allocation to opex categories since acquisition of the network and pipeline assets of Vector and MDL. However, to provide a positive rather than a negative basis for assessing the RCMI forecast, I have reviewed First Gas's explanations for the increase against the Commission's threshold and find them a reasonable and consistent with the expenditure objective.
- **Distribution capex**
  - **System Growth** – The demand forecast that the System Growth capex was based on was appropriate and the resulting timing and scope of System Growth projects was therefore appropriate. There are plausible and reasonable explanations for the very significant increase in growth capex and the projects, costs and timing resulting from First Gas's AMP and forecasting process were therefore reasonable and consistent with the expenditure objective.
  - **New connections** – Application of Covec's forecast of connections for non-Auckland gas networks to historically derived unit connection costs is consistent with good industry practice. However, I also note that First Gas, in recognising the need for consistency between the new connection forecast for the purposes of forecasting new connection capex and that used in the constant price revenue growth model, accepts that the forecasts need to be the same. There are two available economic forecasts: First Gas's based on Covec's 2104 forecast and the Commission's. First Gas has elected to accept the

Commission's. This is a reasonable course, on the assumption that the Commission's forecast is more recent than 2014 and it provides a better incentive for growth in the revenue path. On this basis it is reasonable and consistent with the expenditure objective for First Gas to revise its new connection capex forecast to be based on the Commission's new connection forecast.

Appendix 1 – Curriculum Vitae – Chris Harvey

Resume and Capabilities

Address: 27 McRae Place, Nth Turramurra
Telephone: (02) 9144 2783
Mobile: 0402 060 499
Email: chris@chrisharveyconsulting.com.au

Key Areas of Expertise

- Energy utility regulation and policy
- Regulatory economics and analysis
- Weighted average cost of capital
- Strategy analysis and development for regulated energy utilities
- Gas industry background - technical, commercial and regulatory – particularly pipelines and networks and some upstream
- Commercial strategy for energy and infrastructure businesses
- Commercial due diligence for gas infrastructure businesses

Qualifications

University: Bachelor of Engineering (Chemical)

Career summary

2008 – present	*Chris Harvey Consulting* – Self employed consultant providing advice and project management in relation to energy policy and regulation matters, and developing a competency-based system for pipeline engineers
1998 – 2008	*AGL/Alinta/Jemena* – A range of senior roles in economic regulation of energy utilities
1993 – 1998	*AGL* - Leading two operating businesses – a gas network and a gas pipeline
1986 – 1993	*AGL* – Technical/commercial management roles
1980 – 1986	*AGL* - Various technical and graduate program roles

Professional Associations

Member Institution of Chemical Engineers (Chartered Engineer)

Member Society of Petroleum Engineers

Member, Australian Institute of Company Directors

Chris Harvey Consulting

2008 – present *Principal*

Assignments:

- Assistance with development of Access Arrangement proposals for Jemena Gas Networks and ActewAGL Distribution – focus on opex and capex
- Assistance with development of capex submission for Jemena Gas Networks Access Arrangement
- Advice on the costs, benefits and likelihood of a coverage application for an unregulated pipeline
- Due diligence advice on a pipeline acquisition project
- Preparing a report for the Department of Resources Energy and Tourism on the potential application of Energy Efficiency Opportunities legislation to gas distribution networks and transmission pipelines
- A review of the benefits of applying for Light Regulation under the National Gas Law and Rules for a distribution business
- Contribution to APIA submissions to the AEMC on its review of Rate of Return provisions of the National Gas Law
- Contribution to APIA submissions to the Expert Panel on Limited Merits Review for the Senior Council on Energy and Resources
- Advice on the commercial viability of offering gas storage services in the Victorian gas market
- Contribution to the joint industry association submissions to the AER for its WACC parameter review
- Project managing preparation of supporting information on behalf of Jemena Asset Management as part of its contribution to ActewAGL Distribution's Access Arrangement and subsequent support for the regulatory review process
- Project Management of the Australian Pipeline Industry Association's project developing a Pipeline Engineer training program
- Training session for DRET on WACC in the context of energy regulation
- Advising a bidder for UED's request for proposal for asset services on strategic commercial and regulatory matters
- Advising an asset management company on its alliancing strategy with regulated businesses
- Miscellaneous brief assignments advising on the National Gas Law/National Gas Rules
- Contributions to the AEMC review on the use of Total Factor Productivity for price regulation of energy utilities
- Miscellaneous assignments assisting with submissions to the AER as part of Access Arrangement reviews
- Advising bidder on SP Ausnet's request for proposal for operational and capital construction services for its gas and electricity distribution businesses
- Assistance in preparing submissions to AEMC's consideration of Rule change proposals from the AER and EURCC on the cost of capital and operating and capital expenditure issues
- Advice to a pipeline owner about development of tariffs consistent with those that would determined by the AER under the National Gas Law and Rules

Alinta Ltd/Jemena Ltd

2006 – 2008 *Manager Asset Regulation and Strategy*

Responsible for:

- Regulatory management of Alinta's NSW Gas Network and Pipelines (EGP, TGP and QGP) including regulatory reviews (ie access arrangement reviews).
- Provision of strategic regulatory advice to asset owning clients both for in-house assets and for clients whose assets Alinta provided asset management services.
- Development of Alinta's positioning and advocacy on MCE reforms, including the response to the legislation for the revise Gas Access Regime, and gas market developments.
- Provision of support to other regulatory managers on analytical and strategic matters including the regulated rate of return as part of regulatory reviews.
- Positioning and advocacy on a major review of the regulated rate of return for the electricity industry by the AER.
- Provision of regulatory and strategic commercial advice on business development and acquisition projects
- Representing Alinta's interests on ENA and APIA regulatory affairs committees.

Achievements:

- Major changes from the initial draft Gas Access legislation to final legislation, which commenced on 1 July 2008.
- Significant contribution to the development of a joint industry submission to the Australian Energy Regulator's Issues Paper on the regulated rate of return.
- Significant contribution to arguments on the regulated rate of return for Multinet Gas in the review of its access arrangement by the ESCV in 2007.
- Removal of coverage (regulation) with a 3 year exemption from coverage of the QGP as part of the reforms to the Gas Access Regime.

The Australian Gas Light Company

2004 to 2006 *Manager Regulatory Development* (transferred to Alinta as part of the sale of infrastructure assets by AGL)

Responsible for:

- Representing AGL's interests on the APIA regulatory affairs committee and liaison with the ENA secretariat.
- Development of AGL's position and advocacy on reforms being undertaken by the Ministerial Council on Energy – including the review of the Gas Access Regime and other key reforms.
- Advocacy for the continued acceptance of the need for merits review of regulators' decisions.
- Support of on strategic regulatory issues including the regulated rate of return, benchmarking of operating expenditure and new approaches such as Total Factor Productivity.
- Development of AGL's positioning and advocacy on the private involvement in the Water Industry in NSW.

Achievements:

- Significant input to the energy network and pipeline industries' positions and advocacy to the Ministerial Council on Energy – including improvements to the current regime.
- Retention of merits review for gas and provision for electricity transmission and distribution.
- An acceptable rate of return for electricity distributors in the 2005 Victorian electricity distribution price review.

- Significant contribution to the conceptual and practical development of the Water Industry Competition Act in NSW. This included NSW Government seeking the views of AGL (and later Alinta).

2002 to 2004 *Manager Regulatory Affairs, Pipelines*

Responsible for:

- Advice on and management of economic regulation affecting pipelines owned and operated by Australian Pipeline Trust (APT) now APA Group, primarily oriented around economic regulation.
- Project management of Access Arrangement Reviews for APT's pipelines.
- Project management of applications for revocation of coverage of APT's pipelines.
- Recommending and advocacy of APT's position on Ministerial Council on Energy reforms, in particular the review of the Gas Access Regime by the Productivity Commission.
- Representing APT's interests on APIA's Regulatory Affairs Committee.
- Project management of APT's appeals (Merits Reviews) of regulatory decisions (Moomba-Sydney Pipeline Access Arrangement decision by the ACCC and partial revocation decision for the MSP by Commonwealth Minister).
- Leadership of a support team for the AGL's regulatory group.

Achievements:

- Satisfactory result on Access Arrangements for Amadeus to Darwin Pipeline.
- Completion of Access Arrangement for Moomba – Sydney Pipeline (MSP) Access Arrangement.
- Successful appeal (merits review) of ACCC decision on MSP Access Arrangement.
- Partial revocation of coverage (regulation) of the MSP.
- Revocation of coverage of the Darwin City Gate to Berrimah Pipeline.

1998 to 2002 *Manager Regulatory Affairs, Gas Networks*

Responsible for

- Managing economic regulation affecting AGL's Gas Network interests.
- Project management of AGL Gas Networks Access Arrangements in NSW and the ACT (now ActewAGL Distribution).
- Presenting at regulators hearings and forums, negotiation with the regulators (IPART and ICRC), coordination and preparation of submissions to regulators, management of consultants (AGL's and the regulators).
- Managing miscellaneous regulatory issues and reviews as they arise.
- Keeping current with the regulatory environment and influencing it where appropriate.

Achievements:

- Successful completion of two Access Arrangements spanning a two-year period with sound regulatory capital bases set into the future, establishing underlying value of the businesses.
- Successful outcomes in a review of licensing arrangements for NSW energy businesses.
- Presenting AGL Gas Network's position on IPART's review of energy licensing in NSW. This resulted in a sensible rationalisation of licensing arrangements and a risk and systems based approach to licence compliance
- Contribution to AGL's advocacy on the Productivity Commission's review of the National Access Regime and the Parer Energy Market Review.

1994 to 1998 *Manager Northern Territory* – Pipelines

Responsible for:

- Profitable operation of AGL's NT pipeline business and development of AGL's interests in the NT.
- Performance of NT Gas as General Manager and Director of NT Gas Pty Limited.
- Management of AGL's relationship with the NT Government and general public profile.
- Leadership of staff of 38 including managing industrial relations agreement.

Achievements:

- Establishment of gas distribution business.
- Resolution of litigation relating to original construction of the NT Gas Pipeline.
- Construction and commissioning of NT Gas' first compressor station.
- Construction and commissioning of lateral to Mt Todd Goldmine.
- Contribution to completion of EBA with all AGL pipelines staff.

1993 to 1994 *Manager Central Tablelands*

Responsibilities:

- Profitable operation of gas business in Bathurst, Lithgow and Oberon and the surrounding areas.
- Growth of the gas network business.
- Leadership of approx 35 staff.

Achievements:

- Completion of Goldlining (mains rehabilitation) of Lithgow's distribution system.
- Commenced project to supply Wallerawang.

1989 to 1993 *Manager Gas Resources*

Responsibilities:

- Medium and long term gas supply planning and strategy.
- Administration of gas supply and transportation contracts.
- Commercial analysis and proposal development for new gas developments.
- Negotiation of new transportation agreements for new supply areas.
- Managing relationship with Pacific Power for future gas supply to major power developments.

Achievements:

- Completion of a joint long term study with Gas and Fuel Corp into gas supply in the south eastern corner of Australia.
- Joint study of a joint LNG facility with Pacific Power.
- Board approval for a number of new supply areas.
- Negotiation of transportation agreements to new towns.

1980 to 1988 Various technical positions

Appendix 2 – Additional information provided by First Gas

Document titles

AMP - Consolidated Model - GDB Capex - As Published.xlsx
AMP - Consolidated Model - GTB Capex - As Published.xlsx

Project Programme Update.pdf (Vector 2015 AMP - Table System growth projects excerpt p98.pdf)

Cambridge network failure flow.pdf

Cambridge network growth rate.pdf

Glasshouse Load Request.pdf

Email K Collins Whitecliffs Planned Expenditure Profile

Email L Treadway - Vector Distribution Modelling practices 7-3-17.pdf
Non AKL connections forecasting summary methodology.pptx

Non Auckland ICP Forecast for AMP 2016 v2.xlsx

Constant-price-revenue-growth-model.xlsx

Tauranga DC new dwellings consents.pdf

Copy of FGL New Connections Average Pricing Schedule incl Review 2016.xlsx

Vector projects mapped to FGL.xlsx

Wairakei & Te Tumu Long Term Development.pdf

FGL AMP Figures 2016 (22 Apr 2016).xlsx

Cambridge Options.pdf

Appdx E_AMP - Consolidated Model - GTB Capex - Commerce commission 3 Feb - Updated graphs.pdf

10yr - Activity Schedule - Pipeline.doc

403Line_HUN-HUN_PDP_A02676751-R004-0416_Final.pdf

Email L Treadway - RE: ARR - detailed look
Email and spreadsheet - L Treadway - First Gas Transmission expenditure forecast analysis (005).xlsx
Email L Treadway re OPEX Activities

Appendix 3 – Routine and corrective maintenance and inspection opex

First Gas - Transmission

RCMI Opex forecast analysis

($,000)

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Routine and corrective maintenance and inspection		$11,415	$15,743	$14,324	$13,487	$19,593	$17,391	$17,280	$17,252	$16,474	$16,741
2013/15 Average		$13,828									
2014/16 Average		$14,518									
Margin above 2013/15 average		-$2,412	$1,916	$496	-$341	$5,765	$3,564	$3,453	$3,424	$2,647	$2,914
Margin above 2014/16 average		-$3,103	$1,225	-$194	-$1,031	$5,075	$2,873	$2,762	$2,733	$1,956	$2,223
Step changes											
Confined space pit inspections	Sources: First Gas response to NZCC questions					$232					
Otahuhu Powers Station asset disp	Sources: First Gas response to NZCC questions					$310					
Recategorisation AAR to RCMI	Sources: First Gas response to NZCC questions					$930	$930	$930	$930	$930	$930
Geohazard management	Sources: First Gas response to NZCC questions					$319	$1,166	$1,159	$1,166	$1,170	$1,172
Asset Disposal	Sources: First Gas response to NZCC questions					$260	$260	$260			
RCMI - Henderson Comp Stn	Sources: First Gas response to NZCC questions					$124	$124	$124	$124	$124	$124
Waitotara River repairs Q1 FY17	Source: L Treadway					$90					
Oruakerataki Stream erosion remediation	Source: L Treadway					$100					
Kaukaha Road Un-named Stream erosion remediation	Source: L Treadway					$30					
Main Line Valve Lube lines repairs	Source: L Treadway					$267					
Corrosion remediation	Source: L Treadway					$206	$206	$206	$206	$206	$206
Station fence Repairs	Source: L Treadway					$234	$234	$234	$234	$234	$234
Station Specific MIJ remediations	Source: L Treadway					$200					
Supplementry station coating inspection	Source: L Treadway					$170					
Supplementry Coating repairs Deby Road CS	Source: L Treadway					$100					
Additional Pigging	Source: Email L Treadway 9/3/17					$209					
Defect excavation (FY15/16 average $355)Exp above 15/16 average, additonal exp due to change planning processes and additional excavations required by pipline integrity Plan. Source: Email L Treadway 9/3/17						$352	$76	$188	$61	-$109	$61
Total step changes						**$4,133**	**$2,996**	**$3,101**	**$2,721**	**$2,555**	**$2,727**
Margin above 2013/15 average less step changes						$1,632	$568	$352	$703	$92	$187
Margin above 2014/16 average less step changes						$941	-$123	-$339	$12	-$599	-$504
	Margin above 3 year average					**12%**	**4%**	**3%**	**5%**	**1%**	**1%**
	Margin above 2 year average					**6%**	**-1%**	**-2%**	**0%**	**-4%**	**-3%**

Appendix 4 – System growth capex in detail

First Gas
Distribution System Growth capex analysis
($)

Black text = IP
Blue text = MP

	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY17-22 Total		
Cambridge													
					1,100,000	2,400,000					3,500,000	*RNF6-010*	Cambridge - (i) 3.4km of 80mm IP from GS + 1DRS or (ii) 5.5km of 110mm MP7 from GS + 2 new DRS)
						215,000					215,000	RNF6-011	Cambridge - (i) 3.4km of 80mm IP from GS + 1DRS or (ii) 5.5km of 110mm MP7 from GS + 2 new DRS)
						240,000					240,000	RNF6-012	Cambridge - (i) gate station upgrade)
		363,000									363,000	RNF5-027	1.1km of 100mm reinforcement in Cambridge MP4 to from DR-80244-CA Queen St to bridge crossing in Queens. System p
		60,000									60,000	RNF5-028	Cambridge.MP4 Est. 450 metres of 50mm pipe. Linking the PE pipesThompson Street to improve the security of supply
	-	**423,000**	**-**	**-**	**1,100,000**	**2,855,000**	**-**	**-**	**-**	**-**	**4,378,000**		
Hamilton													
				770,000	770,000	770,000					2,310,000	*RNF6-017*	Hamilton IP reinforcement - From DRS139 inTe Rapa to DRS100 in Hamilton East - 7 km of 225mm PE IP10
	980,000										980,000	RNF6-013	Hamilton IP reinforcement - Te Kowhai gate station upgrade + IP uprating to 17 bar + DRS upgrade + New IP20/IP10 DRS
	400,000										400,000	RNF6-014	Hamilton IP reinforcement - Te Kowhai gate station upgrade + IP uprating to 17 bar + DRS upgrades + New IP20/IP10 DRS
		180,000									180,000	RNF6-015	Hamilton IP reinforcement - Te Kowhai gate station upgrade + IP uprating to 17 bar + DRS upgrade + New IP20/IP10 DRS
			180,000								180,000	RNF6-023	Hamilton West MP4 Reinforcement - Install new DRS in Te Kowhai Road IP20/MP4
					320,000						320,000	RNF5-026	Hamilton MP4 - Gordonton Road between Wairere Drive and Thomas Road - 2.1km of 80nb PE MP4
	200,000										200,000	RNF5-024	Hamilton MP4 - 400m of 100nb PE in Cambridge Rd from DR-80101-HM to Hillcrest Road, Hamilton
			100,000								100,000	RNF5-022	Hamilton Pukete MP4 Reinforcement - Te Rapa Road from DR-80139-HM to Mahana Road - 650m of 80nb PE MP4
			25,000								25,000	RNF5-023	Hamilton Pukete MP4 Reinforcement - Te Papa Road from Bryant Road to #558 Te Rapa Road - 180m of 50nb PE MP4
				20,000							20,000	RNF5-020	Hamiton West MP4 Reinforcement - Avalon Drive to Livingstone Avenue - 150m of 50nb PE MP4
				15,000							15,000	RNF5-021	Hamilton West MP4 Reinforcement - Roy Street to Livingstone Avenue - 100m of 50nb PE MP4
	50,000										50,000	RNF5-025	Hamilton MP4 - Boundary Road and Heaphy Terrace - 50m of 50nb PE MP4
	300,000										300,000	RNF5-032	Hamilton East LP: Construct 1,150 metres of 100mm PE pipe at a number of key sites in the Hamilton East LP pressure syst
		240,000									240,000	RNF6-016	Hamilton IP reinforcement - Te Kowhai gate station upgrade + IP uprating to 17 bar + DRS upgrade + New IP20/IP10 DRS
	1,930,000	**420,000**	**305,000**	**805,000**	**1,090,000**	**770,000**	**-**	**-**	**-**	**-**	**5,320,000**		
Gisborne													
				1,360,000							1,360,000	RNF6-022	Gisborne IP Reinforcement - Lytton Road between Aberdeen Road and Manuka Street, Te Hapara - 1.4km of 100mm IP20
			240,000								240,000	RNF6-021	Gisborne IP Reinforcement - Upgrade metering and regulators equipment of Gisborne gate station to allow an increase in t
	-	**-**	**240,000**	**1,360,000**	**-**	**-**	**-**	**-**	**-**	**-**	**1,600,000**		
Waitoa													
				801,000							801,000	RNF6-002	Waitoa IP20 reinforcements: Construct 800 metres of steel pipe and loop into the existing 50mm steel
		1,200,000									1,200,000	RNF5-013	Waitoa MP4 reinforcements Stage 1 (Incremental extension of 160mm MP7 PE if required - 5000m initial extension)
							1,200,000				-	RNF5-014	Waitoa MP4 reinforcements Stage 2 (Incremental extension of 160mm MP7 PE if required - 5000m initial extension)
		180,000	-								180,000	RNF5-015	Waitoa MP4 reinforcement (MP7/MP4 DRS at Ngarua)
							170,000				-	RNF5-016	Waitoa MP4 reinforcement (MP7/MP4 DRS at Ngarua) - Relocation south
	-	**1,380,000**	**-**	**801,000**	**-**	**-**	**1,370,000**	**-**	**-**	**-**	**2,181,000**		
Mt Manganui													
								800,000	800,000	890,000	-	*RNF6-004*	Mt Maunganui IP Reinforcement (Possible solutions: Option (2) Create IP20 loop - 2400m in Newton St and Hull Rd.
				180,000							180,000	RNF6-005	Mt Maunganui (Papamoa) - IP20 / MP7 DRS near Papamoa Gate Station
			561,000								561,000	RNF5-005	Mt Maunganui (Papamoa East) - 1700m of 225mm 7 bar PE (subject to growth) Tara Road
				330,000							330,000	RNF5-003	Mt Maunganui (Papamoa) - 1000m of 180mm 7 bar PE in Parton Road
		290,000									290,000	RNF5-004	Mt Maunganui (Papamoa) - 800m of 225mm 7 bar PE in Domain Road
					255,000						255,000	RNF5-006	Mt Maunganui (Papamoa) - MP7 / MP4 DRS at J/O Parton Rd and Papamoa Beach Rd
	-	**290,000**	**561,000**	**510,000**	**255,000**	**-**	**-**	**800,000**	**800,000**	**890,000**	**1,616,000**		
Paraparumu													
	300,000										300,000	RNF6-024	Paraparaumu IP reinforcement - Uprate current operating pressure from 1350kPa to 1800kPa (including gate station upgra
	360,000										360,000	RNF6-025	Paraparaumu IP reinforcement - Uprate current operating pressure from 1350kPa to 1800kPa (including gate station upgra
	-										-	RNF6-026	Paraparaumu IP reinforcement - Uprate current operating pressure from 1350kPa to 1800kPa - project cnacelled
			300,000	-							300,000	RNF5-010	Paraparaumu reinforcement - 1900m of 100 PE MP4 from the proposed MP7/MP4 DRS along Ratanui Road to Mazengarb
	660,000	**-**	**300,000**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**960,000**		
Waikanae													
		215,000									215,000	RNF6-001	Waikanae: Paraparaumu reinforcement feed from Waikanae GS - new IP20 to MP7 DRS
	460,000										460,000	RNF5-008	Waikanae: Paraparaumu reinforcement feed from Waikanae GS - 1700m of 125mm 7 bar PE
	53,000										53,000	RNF5-007	Waikanae: Paraparaumu reinforcement feed from Waikanae GS - 125mm 7 bar PE bridge crossing
		90,000									90,000	RNF5-031	Waikanae MP4: Construct approximately 600 metres of 50mm PE MP4 pipeline from Belvedere Avenue to David Street.
		180,000									180,000	RNF5-009	Waikanae: Paraparaumu reinforcement feed from Waikanae GS - MP7 / MP4 DRS
	513,000	**485,000**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**998,000**		
Tauranga													
	75,000										75,000	RNF6-009	Tauranga IP upgrade (Gate station upgrade + IP uprating to 17 bar + DRS upgrade)_scope of work limited to FIK installation
		375,000									375,000	RNF5-029	Tauranga MP4: Construct approximately 1,500 metres of 80mm PE pipeline between Bellevue and Bethlehem
	75,000										75,000	RNF5-030	Tauranga MP4 Extend approximately 500 metres of 50mm PE MP4 pipeline in Maru/Te Maire Street.
	150,000	**375,000**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**525,000**		
Horotiu													
				-							-	RNF6-019	Horotiu Development Plan - Up-rate the operating presure of Horotiu IP20 pressure system

Appendix B: Summary of ARR expenditure forecasts and allowances

Summary of ARR expenditure forecasts and allowances

Category	Forecast expenditure (FY 18 - FY22)	Average Expenditure across FY14/ FY15 (see note 1)	Expenditure breakdown	Note:
Pipelines	**66,087,629**	**10,059,615**		
Forecast Breakdown				
Whitecliffs			28,349,910	Increased expenditure above historical levels
Gilbert Stream			6,546,000	Increased expenditure above historical levels
Geohazard			17,700,000	Increased expenditure above historical levels
In-line inspections			8,233,719	Increased expenditure above historical levels
Off pipeline asset renewal			1,200,000	Increased expenditure above historical levels
Pipeline coating replacement			1,800,000	
Other			2,258,000	
Total			**66,087,629**	
Compressors	**18,766,000**	**13,678,238**		
Forecast Breakdown				
Turbine gas detection system replacement			1,200,000	Increased expenditure above historical levels
Hazardous area risk mitigation			1,040,000	Increased expenditure above historical levels
Gas cooler replacements			3,254,000	Increased expenditure above historical levels
Compressor and engine overhaul			5,791,000	
Control system replacement			6,816,000	
Other			665,000	
Total			**18,766,000**	
Other Stations	**22,002,776**	**12,404,220**		
Forecast Breakdown				
Pig trap upgrades programme			3,691,000	Increased expenditure above historical levels
Grove 80 regulator replacements programme			3,446,776	Increased expenditure above historical levels
Station fencing and security			1,100,000	Increased expenditure above historical levels
Actuator replacement programme			659,000	Increased expenditure above historical levels
Future regulator replacements			1,392,000	
Pressure safety valve replacements			1,080,000	
Valve replacements			2,821,000	
Electrical hazard and earthing and bonding			1,634,000	
In-station cathodic protection			755,000	
Station coating upgrade and replacement			515,000	
Pipe support replacement			764,000	
Gas detection replacement			156,000	
Other			3,989,000	
Total			**22,002,776**	
SCADA and Communications	**2,230,000**	**612,500**		
Forecast Breakdown				
Master system upgrade			1,190,000	Increased expenditure above historical levels
System component upgrades			640,000	
Fibre optic upgrades third party drive			400,000	
Total			**2,230,000**	
Main Line Valves	**4,115,000**	**2,438,680**		
Forecast Breakdown				
Remote actuation programme			1,815,000	Increased expenditure above historical levels
Actuation replacement programme			1,500,000	Increased expenditure above historical levels
Actuator refurbishment			500,000	Increased expenditure above historical levels
Other			300,000	
Total			**4,115,000**	
Heating Systems	**3,689,500**	**3,205,000**		
Forecast Breakdown				
Heater refurbishments			1,724,000	Increased expenditure above historical levels
Control system upgrades			515,000	Increased expenditure above historical levels
Heater replacement			600,000	
Other			850,000	
Total			**3,689,000**	
Metering Systems	**2,448,000**	**2,239,060**		
Forecast Breakdown				
Replacement programme			2,448,000	
Total			**2,448,000**	
Cathodic Protections	**1,368,000**	**973,720**		
Forecast Breakdown				
Rectifier, intelligent power supply replacement			600,000	Increased expenditure above historical levels
New rectifier installations			508,000	
Other			260,000	
Total			**1,368,000**	

Note 1:

- Previous disclosures did not provide disclosure information at asset category level. In order to get a figure to compare current forecast levels with asset category historical expenditure, the average expenditure for FY14 and FY15 was multiplied by 5.

Appendix C: Breakdown of ARR capex

Category	Explanation
Pipelines	• White Cliffs expenditure over the DPP period accounts for $28.5 million across the DPP period. • Gilbert Stream remediation is $6.5 million in FY18. Detailed information has been supplied regarding this project. • Re-categorisation of In-line-Inspection from opex to capex (in line with reasonable industry practice) has increased expenditure throughout the DPP period by $8.2 million. • Capex geohazard remediation expenditure is based on recent experience with Maui pipeline geohazard assessment surveys. It is assumed that 2 – 3 capital remediation projects will be completed per annum, at a cost of $17 million, over the DPP period (section 6.7.1 of the Transmission AMP describes geohazard risks). • Off-pipeline assets capital expenditure has not been included in previous forecast expenditures. An allowance of $1.2 million over the DPP period has been assumed (section 3.3.3 of the Transmission AMP describes off-pipeline assets).
Compressors	• Rotowaro compressor station turbine package fire and gas detection equipment is no longer supported by the vendor, and parts will soon no longer be available. An allowance of $1.2 million over the DPP period has been assumed (section 6.9 of the Transmission AMP describes fire and gas detection systems). • Gas detection systems in reciprocating compressor buildings are obsolete with parts no longer available. Forecast expenditure for hazardous area risk mitigation has not been included in previous forecasts and accounts for $1 million throughout the DPP period (section 6.9 of the Transmission AMP describes fire & gas detection systems). • Remaining life reviews undertaken by external consultants on compressor station gas coolers recommended that 4 units needed to be replaced, at an estimated cost of $3.4 million over the DPP period. This exceeds historical levels (section 6.9 of the Transmission AMP describes gas coolers and the life reviews underway).

Category	Explanation
Other stations	• First Gas was notified by the vendor that Grove 80 regulators were obsolete in FY13 and soft parts would no longer be made. All available soft parts were purchased to allow maintenance to continue until the end of 2019. A five-year replacement programme was initiated in FY14 to replace all Grove 80 regulators, due for completion in FY19. Stock level and stock shelf life require that this deadline be met. Beyond FY19 there may be insufficient stock to maintain regulators. This programme has been accelerated between FY18 and FY19, to achieve the deadline of FY19. Expenditure is forecast at $3.4 million across the DPP period (section 6.10.8 of the Transmission AMP describes regulators and reference to the Grove replacement programme). • A programme to upgrade all the pig traps to the minimum required standard has been planned. The expenditure across the DPP period is $3.6 million (section 6.10.6 of the Transmission AMP provides detail regarding the pig trap upgrade programme). • An allowance of $1.1 million across the DPP period has been allocated to replace and upgrade station security and fencing to the minimum standard. This exceeds historical levels (section 6.10.11 of the Transmission AMP describes station security upgrades). • An allowance of $2.8 million across the DPP period has been allocated to replace leaking station valves throughout the DPP. This exceeds historical levels (section 6.10.10 of the Transmission AMP describes “faulty” station valves).
SCADA and communications	• Due to the rapid advancement of computer technology, the SCADA system hardware platform has reached the upper limit of its useful life and is now obsolete and unsupported. $1.2 million dollars is forecast to be spent during the DPP regulatory period to upgrade the SCADA master system. This exceeds historical levels (section 6.10.5 of the Transmission AMP explains the need to replace the SCADA master system).
Main line valves	• Forecast expenditure on mainline valves is expected to increase by $1.8 million across the DPP period. This additional expenditure is to initiate a refurbishment programme to extend the service life of the existing mainline valves. This is in addition to the continued programme to install remote actuation equipment, which has been forecast in previous asset management plans (section 6.8 of the Transmission AMP explains main line valve programmes).
Heating systems	• Expenditure on heating systems is largely consistent with the FY14 – FY15 average with a slight increase attributed to the need to conduct refurbishment on some larger heaters throughout the DPP period (the unit cost for refurbishment is based on heater size) and upgrades for heater control systems (section 6.10.1 of the Transmission AMP explains heater upgrade programmes). ($3.7 million)
Cathodic protection	• Forecast expenditure is increasing through the DPP period. This is to accommodate installation of replacement transformer rectifier and intelligent power supply assemblies. A significant portion of the rectifiers are in excess of 40 years old and due for replacement during the next 5 years (section 6.7.3 of the Transmission AMP explains cathodic protection projects planned). ($1.37 million)

Appendix D: Breakdown of prior MDL expenditure reallocated by First Gas to RCMI

Category	DPP Forecast					Commentary
	FY 18	FY 19	FY 20	FY 21	FY 22	
Pipe support replacement	100,000	100,000	100,000	100,000	100,000	
MLV lube line and vent pipework replacement	50,000	50,000				
Huntly offtake PCV overhaul			110,000			
Easement land stabilisation	150,000	150,000	100,000	100,000		
Reactive replacement of obsolete equipment	200,000	200,000	200,000	200,000	200,000	
MDL AMP ARR Total	**500,000**	**500,000**	**510,000**	**400,000**	**300,000**	
Off Pipeline Asset Maintenance works						
Coal tar remnant removal	22,000	22,000	22,000	22,000	22,000	Removal of coal tar remnants dispersed throughout easements from construction
Access track maintenance	25,750	25,750	25,750	25,750	25,750	Access tracks
Major culvert maintenance	61,800	61,800	61,800	61,800	61,800	Large culverts
Minor culvert maintenance	15,450	15,450	15,450	15,450	15,450	Minor culverts
Easement drainage systems surface and sub surface	25,750	25,750	25,750	25,750	25,750	Surface and sub-surface drainage systems
Wooden structures	15,450	15,450	15,450	15,450	15,450	Timber structure
Timber retaining crib walls	15,450	15,450	15,450	15,450	15,450	Crib wall
Drainage catch pits	20,600	20,600	20,600	20,600	20,600	Surface and sub-surface drainage system
Rainfall monitoring systems	15,450	15,450	15,450	15,450	15,450	Rainfall monitoring system
Retired block fencing maintenance	15,000	15,000	15,000	15,000	15,000	Retired blocks of land, fencing repairs required to keep stock out
Total Off pipeline asset Maintenance	**232,700**	**232,700**	**232,700**	**232,700**	**232,700**	
Stations – Additional Identified Station works						
MLV recoating works	100,000	100,000	100,000	100,000	100,000	Allowance for 3 sites to be recoated/year
Corrosion remediation	30,000	30,000	30,000	30,000	30,000	Allowance to facilitate corrosion issues on Maui sites
Station fencing and security	20,000	20,000	20,000	50,000	50,000	Additional allocation FY 21/FY22 Mokau CS fencing repairs, high corrosion area
MLV lube line maintenance (NRM List)	41,670	41,670	91,670	91,670	91,670	$92,000 over 5 years, due to known issue, originally $50,000 forecast FY18/19
Total	191,670	191,670	241,670	271,670	271,670	
ARR TOTAL	924,370	924,370	984,370	904,370	804,370	

Appendix E: 10-year activity schedule

Line	Activity	KM	Risk	1	2	3	4	5	6	7	8	9	10
100	Kapuni GTP to Hawera DP	17.8	L						•				
	Hawera DP to Patea South MLV	27.7	I			•							
	Patea South MLV to Waverley OT	16.4	L							•			
	Waverley DP to Waitotara DP	7.3	I			•							
	Waitotara DP to Mosston Road MLV	33.5	H	•									
	Mosston Road MLV to Waikanae DP	123.4	L				•						
	Waikanae MLV to Waitangirua DP	34.4	H	•									
101	Okaiawa OT to Okaiawa DP	1.6	L									•	
102	Patea OT to Patea DP	1.5	L										
103	Waverley OT to Waverley DP	5.8	L								•		
104	Raumai SS to Marton DP	21.1	L						•				
105	Kaitoke OT to Kaitoke DP2	3.9	L				•						
106	Lake Alice OT to Lake Alice DP	1.3	L								•		
107	Himitangi OT to Palmerston Nth DP	27.2	L						•				
108	Longburn OT to Longburn DP	6.8	L							•			
109	Levin OT to Levin DP	6.8	L							•			
110	Waitangirua DP to Belmont DP	2.8	H	•									
111	Waitangirua DP to Tawa A DP	7.7	I	•									
112	Ammonia Urea Lateral	0.5	L							•			
113	Himitangi OT to Feilding OT	29.6	L					•					
114	Feilding OT to Feilding DP	8.7	L							•			
115	Kakariki Lateral (Offtake only)	0.01	L							•			
116	Kuku Lateral (Offtake only)	0.05	L							•			
117	Te Horo Lateral	0.15	L							•			
118	Paekakariki Lateral (Offtake only)	0.02	L							•			
119	Tawa B Lateral (Offtake only)	0.02	L							•			
120	Tawa B No2 (Offtake only)	0.03	L							•			
200	Kapuni GTP to Tariki MLV	30.4	L				•						
	Tariki MLV to McKee Mixing	21.6	I			•							
	McKee Mixing to Waiiti MLV	21.6	L						•				
	Waiiti MLV to Mohokatino SS	30.1	H	•									

Line	Activity	KM	Risk	1	2	3	4	5	6	7	8	9	10
	Mohokatino SS to Mahoenui CS	30.7	H	●									
	Mahoenui CS to Oparure MLV	49.5	H	●									
	Oparure MLV to Cannon Road MLV	28.7	I	●									
	Cannon Road MLV to Te Kowhai DP	40.1	L							●			
	Te Kowhai DP to Tuakau North MLV	60.1	H	●									
	Tuakau North MLV to Runciman RD PRS	77	I					●					
	Runciman Road PRS to Papakura DP	18.7	L				●						
201	Inglewood OT to Inglewood DP	4.1	L									●	
203	New Plymouth OT to New Plymouth DP	4.6	L									●	
204	Midhurst OT to Midhurst DP	2.8	L										
206	Eltham/Kaponga OT to Eltham DP	7.6	L									●	
207	Eltham/Kaponga OT to	5.3	L									●	
208	Te Kowhai Lateral	0.07	L										●
209	Pokuru Connection	0.2	L										●
300	Kapuni GTP to Frankley Road OT	46.6	L					●					
301	Stratford PS to Taranaki CC DP	0.2	L					●					
302	Stratford PS to Taranaki CC DP	0.2	L					●					
303	Pembroke Road SS to Stratford PS	8.6	L					●					
305	Toko Lateral (Decommissioned)	7.1	L										
306	Kapuni GTP to Kapuni DP	3.2	L									●	
307	Ammonia OT to Ammonia DP	0.16	L									●	
308	Kaimiro OT to Kaimiro DP	3.6	L									●	
309	Kapuni GTP Export to 300Line	0.24	L									●	
400	Oaonui PS to Tikorangi MLV	66.8	L										●
	Tikorangi MLV to Pukearuhe MLV	23.3	I			●							
	Pukearuhe MLV to Mokau CS	24.2	H	●									
	Mokau CS to Mahoenui SS	40	H	●									
	Mahoenui SS to Te Kuiti MLV	43.2	H	●									
	Te Kuiti MLV to Tihiroa SS	24.5	I			●							
	Tihiroa ML to Te Kowhia DP	43.2	L										●
	Te Kowhia DP to Huntly OT	25.4	H	●									
400	Rotowaro CS to Pukekawa MLV	35.4	H	●									
	Pukekawa MLV to Alfriston DP	34.8	I		●								

Line	Activity	KM	Risk	1	2	3	4	5	6	7	8	9	10
	Alfriston DP to Westfield DP	20.2	L					•					
401	Pungarehu DP1 to Pungarehu DP2	5.4	L									•	
402	Te Kowhai to Waitoa DP	50	L						•				
403	Huntly OT to Huntly PS	8.7	I			•							
404	Frankley Road OT to New Plymouth PS	9.1	L										•
405	Runciman RD PRS to Glenbrook DP	23	L						•				
406	Te Kuiti OT to Te Kuiti North DP	4.6	H	•									
407	Kuranui RD SS to Cambridge DP	22.7	L							•			
408	Tauwhare DP to Matangi DP	3.9	L								•		
409	Kiwitahi OT to Kiwitahi DP	1.4	L									•	
410	Te Rapa OT to Te Rapa DP	2.2	L								•		
412	Te Kuiti South OT to Te Kuiti South DP	8.3	H	•									
413	Oakura Lateral	0.02	L										•
414	Omata Tank Farm Lateral	0.04	L										•
416	Ngaruawahia Lateral	0.1	L										•
417	Ramarama Lateral	0.07	L										•
418	Papakura Lateral	0.04	L										•
419	Alfriston Lateral	0.1	L										•
420	Huntly Town Lateral	0.02	L										•
421	Te Awamutu OT to Te Awamutu DP	10.2	L						•				
422	Pironga OT to Pironga DP	0.4	L						•				
430	Westfield DP to Hillsborough MLV	9.8	L					•					
	Hillsborough MLV to Bruce Mclean OT	14.1	I		•								
	Bruce Mclean OT to Brown RD MLV	102.9	H	•									
	Brown RD MLV Salle RD MLV	14.6	I		•								
	Brown RD MLV Salle RD MLV	14.6	L				•						
	Salle RD MLV to Oakleigh DP	12.1	I		•								
	Oakleigh DP to Maungatapere MLV	16.9	H	•									
431	Waitoki Lateral	0.01	L					•					
432	Kaipara Flats OT to Warkworth DP	10	I		•								
433	Brown Road MLV to Maungaturoto DP	13.3	I		•								
434	Whangarei OT to Whangarei DP	9.1	H	•									
435	Maungatapere MLV to Kauri DP	21.5	I		•								

Line	Activity	KM	Risk	1	2	3	4	5	6	7	8	9	10
437	Salle RD MLV to Marsden Point DP	6.9	L					●					
438	Bruce McLaren Lateral	0.07	L					●					
440	Waimauku lateral	0.009	L					●					
441	Smales Road – Waiouru Road Loop	3.6	L					●					
442	Waiouru MLV to Otahuhu B DP	2.5	L									●	
443	Otara Lateral	2.4	L									●	
444	Te Rapa Co-Gen	0.5	L									●	
500	Poruru OT to Parawera RD MLV	20.9	L									●	
	Parawera RD MLV to Arapuni MLV East	20.7	I		●								
	Arapuni MLV East to Kawerau DP	141	L						●				
501	Kawerau DP to Kinleith DP1	0.4	L				●						
502	Kawerau DP to Whakatane OT	18.8	L				●						
503	Rotorua/Taupo OT to Rotorua DP	18.0	I			●							
504	Rotorua/Taupo OT to Reporoa DP	18.2	L				●						
505	Gisborne OT to Ruatoki North MLV	28	I			●							
	Ruatoki North MLV to Opotiki MLV	38.5	H	●									
	Opotiki MLV to Trafford Hill MLV	50	L								●		
	Trafford Hill MLV to Oliver RD MLV	11.6	I			●							
	Trafford Hill MLV to Oliver RD MLV	11.6	H		●								
	Oliver RD MLV to Wahuka MLV	24	H		●								
	Wahuka MLV to Kaitaratahi SS	19.9	I				●						
	Kaitaratahi SS to Gisborne DP	7.3	I							●			
	Kaitaratahi SS to Gisborne DP	10	L				●						
506	Opotiki MLV to Opotiki DP	4.4	L			●							
507	Whakatane OT to Whakatane DP	13.7	L							●			
508	Reporoa DP to Taupo DP	38.9	L				●						
509	Lichfield Lateral	0.5	L										●
510	Broadlands Lateral	0.02	L										●
601	Otaki SS to Waikanae MLV	16.9	L					●					
602	Mosston Road MLV to Kaitoke CS	9.7	L							●			
603	Patea MLV to Waitotara MLV	25	L						●				
604	Waitotara MLV to Mosston Road MLV	26.2	H	●									
605	Waikanae MLV to Belmont DP	38.5	I			●							

Line	Activity	KM	Risk	1	2	3	4	5	6	7	8	9	10
606	Hawera DP to Patea MLV	13.2	I			•							
	Hawera DP to Patea MLV	13.2	L										
607	Whirkino - Foxton River Loop	1.8	L										
700	Feilding OT to Ashhurst DP	14.5	L					•					
	Ashhurst DP to Foley RD OT	13.2	H	•									
	Foley RD OT to Tataramoa MLV	31.1	I		•								
	Tataramoa MLV to Takapua DP	8.5	I		•								
	Tataramoa MLV to Hastings DP	85.6	L					•					
702	Foley RD OT to Mangatainoka OT	16.4	L						•				
	Mangatainoka OT to Pahiatua DP	4.8	I					•					
703	Mangatainoka OT to Mangatainoka DP	0.4	I					•					
705	Ashhurst Lateral	0.02	L	•									
800	Lichfield MS to Okoroire DP	17.5	L					•					
	Okoroire DP to Pyes Pa MLV	42.8	I		•								
	Pyes Pa MLV to Te Puke DP	28.5	L			•							
802	Tirau Lateral	2.0	L			•							
803	Pyes Pa MLV to Tauranga	7.9	L			•							
804	Mt Maunganui OT to Mt Maunganui DP	4.9	L			•							
805	Te Puke DP to Rangiuru DP	8.3	L			•							
806	Mt Maunganui Loop	3.73	L			•							
807	Pyes Pa Lateral	0.04	L			•							

Risk Level	Kilometres (km)
High	706
Intermediate	613.2
Low	1350.13
Total	**2669.33**

Appendix F: Maui pipeline (403 line) Assessment of geohazard features

Appendix G: Example of First Gas Board report on geohazard risks

APPENDIX 2 – GEOHAZARD TABLE

First Gas has the objective of completing a full Geohazard assessment of the transmission network in the next ten years. The Maui pipeline has been assessed for Geohazards via a process that took three years over 370 kilometres of pipeline.

The process to complete the assessment involves an initial desktop review and helicopter flight overview. From this system risk is assessed based upon observations, known local conditions and specific features into High, Medium and Low risks.

All high-risk sections have now been walked and features identified into a Geohazard features document unique to that section of pipeline. The control measures (e.g. add cover, add strain gauges, carry out aerial assessments etc.) have been included in the document and added to the Maintenance Plans.

The Medium risks are now being actioned and are likely to take three years to complete, and these will be followed by the low or no risk areas.

From current pipeline walks and observations, new risks or changes to conditions are reviewed, further risk assessed and if required are escalated to the appropriate category. New high risk sections are line walked immediately and added to the Geohazard document if appropriate.

Below are all the current high risk Geohazards.

During the month, two high risk hazards were successfully reduced to Low (Pukearuhe Strain Site and Wall Road).

Location	Identifier	Hazard	Precursor	Notable points to highlight	Actions	Assessed Risk [1]	Change in Rating
Gilbert Stream	400Line	Loss of pipeline integrity due to erosion of the cliff face.	Cliff face affected by coastal wave action, tidal currents and weathering.	Assessment of the erosion mechanism is due to slabbing of the 50m vertical cliff face. Coastal monitoring indicates that minor erosion is ongoing and that the clifftop is within 10m from the pipeline.	Relocation project released to detailed design and materials ordering Routine monitoring ongoing.	High	No change

[1] Based on Geohazard Risk Ranking Tool

Location	Identifier	Hazard	Precursor	Notable points to highlight	Actions	Assessed Risk [1]	Change in Rating
White Cliffs	400Line	Loss of pipeline integrity due to the erosion of cliff face.	Cliff face affected by coastal wave action, tidal currents and weathering.	Coastal monitoring indicates that erosion is ongoing and that the clifftop is within 25m from the pipeline. There are areas of interest outside the monitoring cross section (southern end) areas of additional interest noted.	Coastal erosion assessment review being completed by GNS over Jan17 McKenzie's cove access approved for mapping – Confined Space rules apply activity planned for Q1 to Q2 2017 Routine monitoring ongoing.	High	No Change
Turakina River Crossing	100Line	Pipeline exposed on bank side of river.	River bank erosion	Pipeline needs to be protected and not realigned. Bank needs to be reinstated	Project initiated and scope of works completed and handed to project delivery for execution in FY17	High	No Change
Pukearuhe Strain Site	400Line	Pipeline intersects a large active land feature; ongoing land movement has the potential for pipeline deformation from land induced stress.	Relic landslide with movement triggered by rainfall, elevated groundwater levels.	The pipeline crosses through an active land feature with visible land surface features, ILI results identified pipeline strain of which is associated with the identified surface features. Project plan resulted in the excavation and destressing of the section of pipeline.	Project remediation completed. **This will be removed next month**	Low	Changed from High to Low

Location	Identifier	Hazard	Precursor	Notable points to highlight	Actions	Assessed Risk [1]	Change in Rating
Waikokowai Rd	403Line	Pipeline crosses through the head of an active lobe associated with a larger relic landslide - potential for pipeline deformation from the land movement induced strain.	Heavy rainfall recently.	Recent events and continued monitoring confirms that this feature is active.	Pipeline integrity review completed and commencement of slope remediation options. Pipeline Integrity review completed in Jan17. Project scoped to remediate and passed to project delivery team. Routine monitoring ongoing.	High	No Change
Troopers Rd	400Line	Pipeline ascends through an area of active landslide slope; ongoing land movement has the potential for pipeline deformation from land movement induced stress.	Heavy rainfall recently.	The pipeline crosses through an active land feature, recorded ground movement is in the order of 120mm (since monitoring commenced). There is suspected pipeline deflection of some 0.87m over an approx. distance of 50m. Monitoring has identified three (3) upslope standpipes indicate some sub-surface deflection, recent monitoring identified that the lower slope standpipe has new deflection.	Pipeline integrity review completed. Within the Project plan this activity to be aligned with Mangatea Road 200Line Feature in Q1 2017. Drainage to be installed and overburden removed during early 2017. Routine monitoring ongoing.	High	No Change

Location	Identifier	Hazard	Precursor	Notable points to highlight	Actions	Assessed Risk [1]	Change in Rating
Wall Road (South)	400Line	Pipeline descends through a portion of an active landslide slope associated with a large relic landslide, ongoing land movement has the potential for pipeline deformation from land movement induced stress.	Heavy rainfall recently.	The pipeline crosses through an active land feature with visible land surface features, ILI results identified pipeline strain of which is associated with the identified surface features. Project plan resulted in the excavation and destressing of the section of pipeline.	Project remediation completed. Routine monitoring ongoing.	Low	Changed from High to Low
Mangatea Rd Te Kuiti	200 pipeline	Pipeline ascends through an active landslide; ongoing land movement has the potential for pipeline deformation from land movement induced stress.	Heavy rainfall recently.	Recent project investigation excavations completed this included reformation of open surface water contour drainage.	Within the project plan to be completed in Q1 2017, also to be aligned with Troopers Road 400Line Feature as described above. See table 4 for costs Routine monitoring ongoing.	High	No Change
Awakau Road	400Line	Pipeline traverses near the crest of a ridge.	Historical ridge regression.	Pipeline within 0.7m from the crest of the steep sided ridge.	Pipeline integrity review required. Routine monitoring ongoing.	High	No Change
Mokau Land Movement	200 / 400 Line	Slope Stability.	Heavy rainfall recently.	Pipelines ascend a steep slope from State Highway 3, historical failure and remediation has been conducted. Recent heavy rainfall and failure of the shear slope associated with State Highway.	Ongoing monitoring monthly Relocation. Pipeline integrity review required.	High	No Change

Location	Identifier	Hazard	Precursor	Notable points to highlight	Actions	Assessed Risk [1]	Change in Rating
Awakau Road	400Line	Slope Stability.	Heavy rainfall recently.	Pipelines traverse and area identified historically.	Pipeline Integrity review and Field Assessment required. Field Assessments completed during Dec16, Geotech report scheduled for Feb1.	High	No Change
Bexley Station	400 Line	Slope Stability.	Heavy rainfall recently.	Pipelines traverse and area identified historically.	Pipeline Integrity review and Field Assessment required. Field Assessments completed during Dec16, Geotech report scheduled for Feb1.	High	No Change
Mathers Road, Te Kuiti	400 Line	Landslide			Geotech report and investigation completed	High	No Change

Appendix H: Calculation of geohazard remediation costs

Cost breakdown of historical excavation opex costs associated with geohazard remediation

Summary order	Description	Start year	Description of Location	Actual $ in year completed	Escalation to FY16 $
2052231, 2052233	Pukearuhe Rd Defect repair from 31/10	2011	Line Oaonui to Rotowaro	367,798	402,114
2073583	(H) Threat 23A Awakau south (Maui)	2012	Line Oaonui to Rotowaro	158,046	169,737
2020002	Pipelines* - Backfilling Tomo's	2009	Line Otorohanga to Papakura	147,656	167,296
2052301, 2052302	PM02 Pukearuhe Rd 200 Line Excavation	2011	Line KGTP to Otorohanga	178,216	194,843
2133459	Pukearuhe 2011 leak loc strain relief	2013	Line Oaonui to Rotowaro	126,451	133,403
2113392	Otorohanga-Huntly land instability risks	2013	Line Oaonui to Rotowaro	66,271	69,915
				Average cost	**189,551**

Capex remediation costs have not been included in the historical analysis.

Assumptions

- The geohazard assessment process is a 10 year rolling plan.
- Between FY18 – FY22, during the DPP reset period, 75 pipeline sections are due to be assessed.
- Average kilometre to be assessed each year is 450km as per the attached "Activity Schedule" in **Appendix E**
- From these assessments an average of 3 geohazard features will require remediation per year.
- These 3 sites will also require temporary monitoring.
- A further 4 sites will require long term monitoring per annum.
- Average remediation expenditure of $190,000 per site based on historical expenditure (above).
- First Gas have estimated that setting up temporary monitoring and long-term monitoring will be $40,000 per site per annum.

Per annum cost calculation

Activity	No.	Unit cost	Total
Excavation and design	3 sites per year	190,000	570,000
Temporary monitoring	3 sites per year	40,000	120,000
Long-term monitoring	4 sites per year	40,000	160,000
Geohazard expenditure			**850,000**

Appendix I: Covec report on growth forecasts

Electricity & gas network connections forecasts

9 April 2014
for Vector

Aaron Schiff & Tim Denne

Contents

Summary

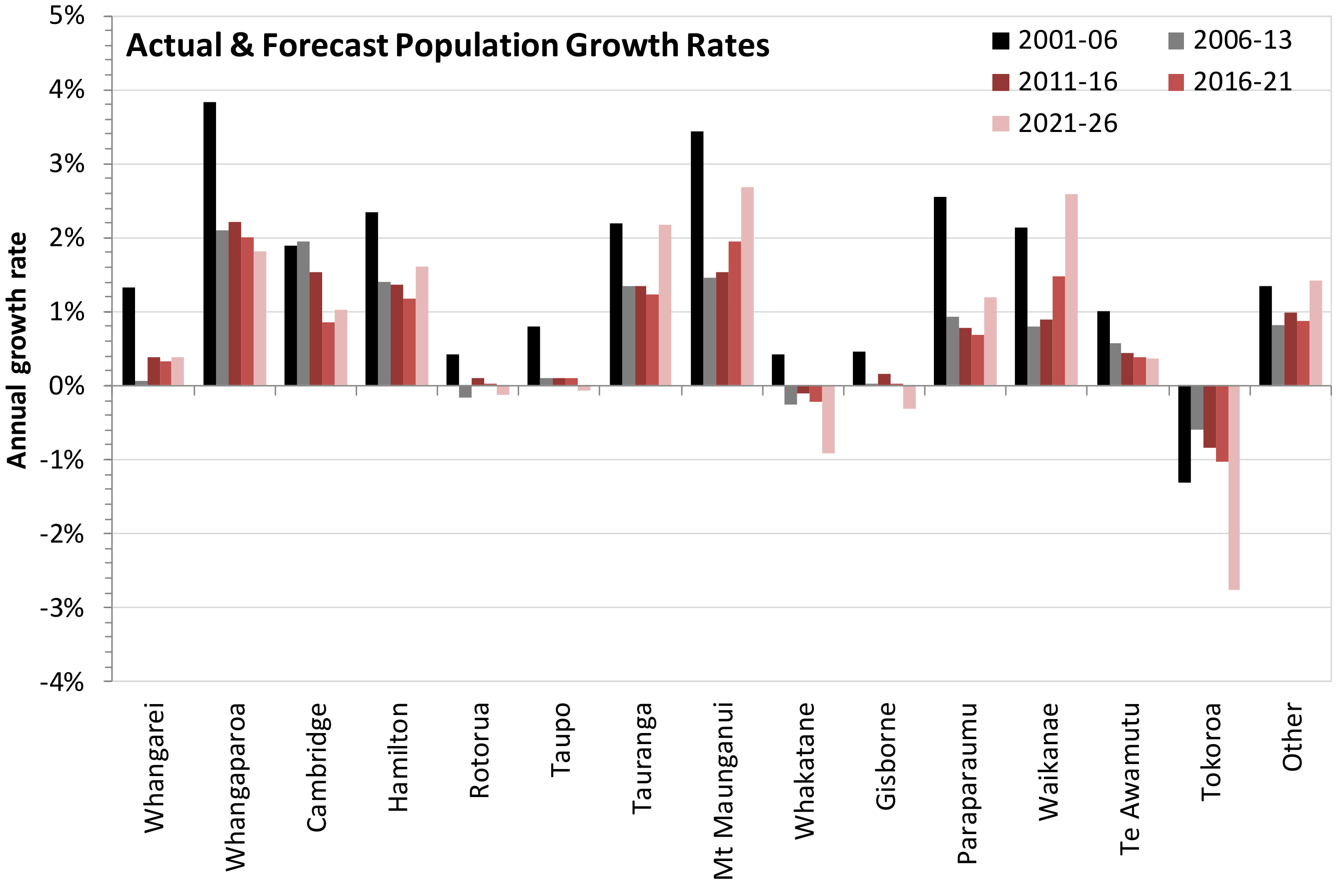
Key caveats & limitations

- Official Stats NZ population projections have not yet been updated to reflect 2013 Census results
  - Most recent Stats NZ forecasts released October 2012; we have adjusted these to reflect 2013 Census
- Gas forecasts assume Vector maintains its current business model
  - The number of connections could be higher or lower if Vector's pricing and/or promotion of gas is changed
- Limited information is available about gas connections where an existing dwelling was converted to gas
  - For example, the dwelling type breakdown for gas connections is uncertain
- Non-Auckland forecasts based on population projections

Key assumptions: Non-Auckland gas

- Residential connections forecasts for key regions are based on Stats NZ population growth projections, updated to reflect 2013 Census results
- Due to lack of other data, assuming population as a proxy for a region's overall prosperity
- Many key regions are forecast to have declining population growth in the short to medium term

Key assumptions: Non-Auckland gas



Declining population growth rates in the short to medium term are forecast in most areas

Source: Covec analysis of Statistics New Zealand data

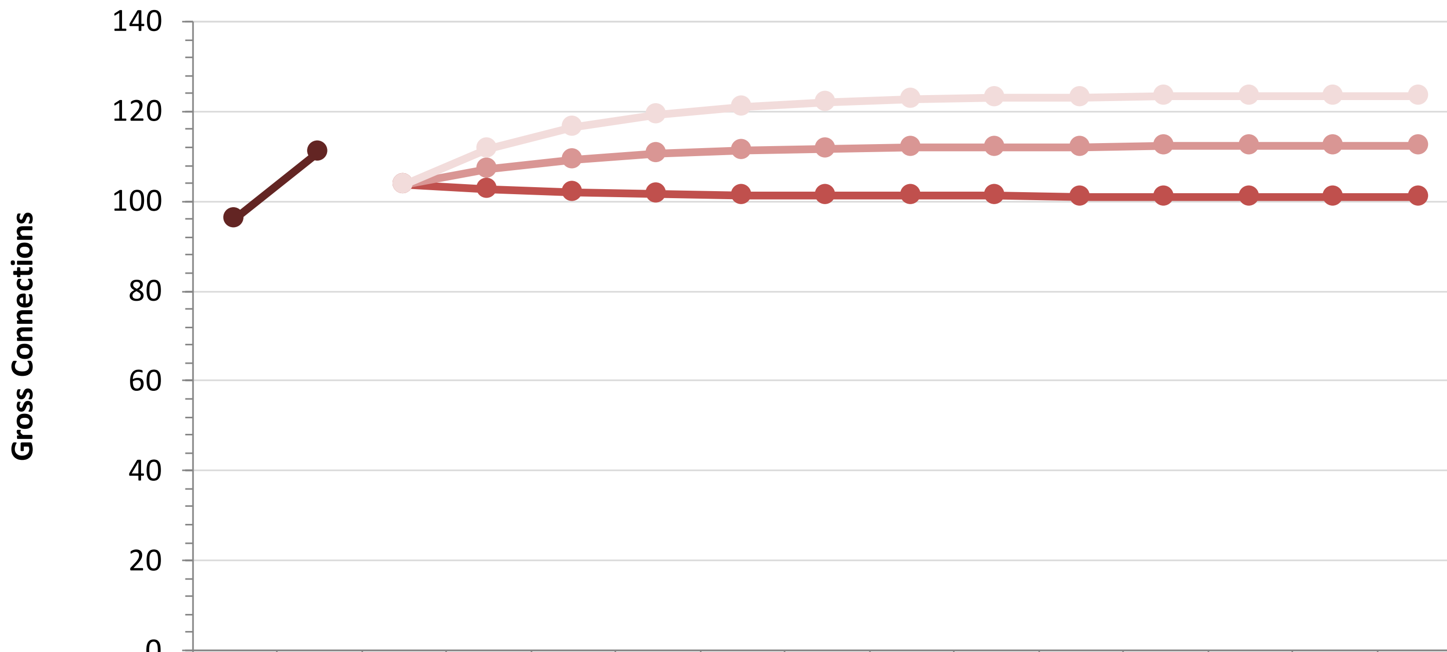
Key forecasts: Non-Auckland gas (residential medium scenario)

Area	Actuals		Forecast												
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Whangarei	5	7	9	8	7	7	6	6	6	5	5	5	5	5	5
Whangaparoa	118	213	257	259	260	261	261	261	264	266	268	270	271	278	285
Cambridge	65	63	58	53	47	42	37	31	32	34	35	36	38	38	38
Hamilton	439	477	486	468	451	434	417	400	435	471	508	547	587	597	606
Rotorua	31	41	54	48	43	38	33	28	23	18	14	10	6	4	3
Taupo	32	24	28	26	23	22	20	18	16	14	11	10	8	7	6
Tauranga	87	107	107	104	101	98	95	92	106	120	135	151	168	171	175
Mt Maunganui	50	67	68	72	76	80	84	89	98	107	117	127	138	142	145
Whakatane	0	2	1	1	1	1	1	0	0	0	0	0	0	0	0
Gisborne	16	14	18	16	14	12	10	9	7	4	2	0	0	0	0
Paraparaumu	46	45	42	41	40	39	38	37	44	51	57	65	72	73	74
Waikanae	13	12	15	17	19	21	23	25	30	34	39	44	50	51	52
Te Awamutu	21	14	16	15	14	13	12	11	11	10	10	10	9	9	9
Tokoroa	1	12	7	7	7	7	7	7	7	7	7	7	7	7	7
Other	42	38	177	169	161	153	146	137	147	158	170	182	196	196	197
Total	**966**	**1,136**	**1,343**	**1,304**	**1,264**	**1,228**	**1,190**	**1,151**	**1,226**	**1,299**	**1,378**	**1,464**	**1,555**	**1,578**	**1,602**

Source: Covec analysis of Statistics New Zealand & Vector data

Key forecasts: Non-Auckland gas (non-residential medium scenario)

Based on building consent forecasts with a 12 month delay



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	96	111													
Low			104	103	102	102	101	101	101	101	101	101	101	101	101
Medium			104	107	109	110	111	112	112	112	112	112	112	112	112
High			104	112	116	119	121	122	123	123	123	123	123	123	123

Source: Covec analysis of Statistics New Zealand & Vector data

Year Ended June

Methodology: Non-residential gas

- Exploit relationships with economic drivers where possible

- New medium & large commercial connections appear to have a relationship to GDP growth (with approx 18 months lag)
  - Forecast on the basis of GDP forecasts

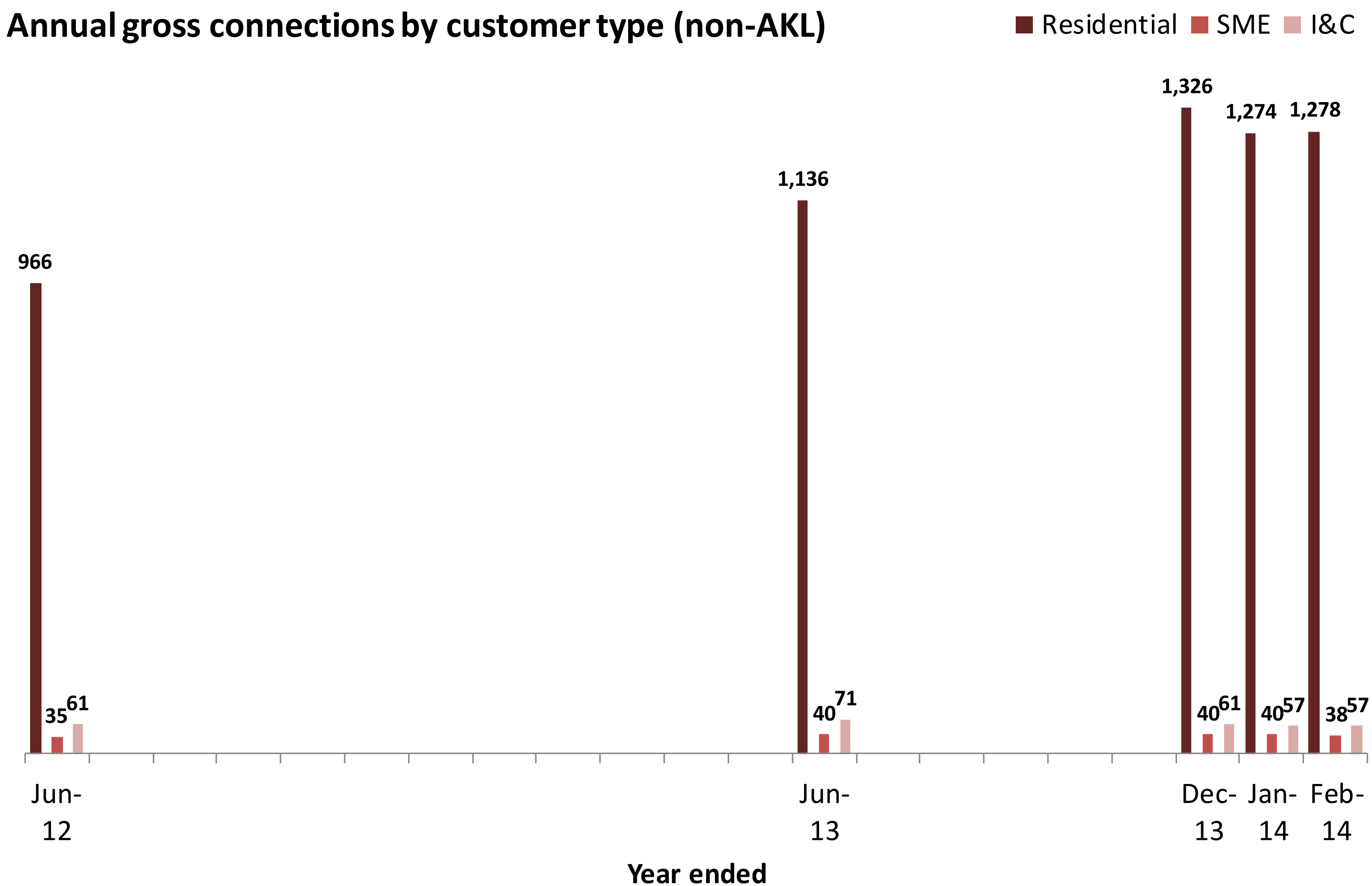
- Number of new industrial connections is small and not clearly related to GDP
  - Forecast on the basis of recent trends

Non-Auckland gas gross connections forecasts

Overview

- Forecasts of gross new connections to Vector's North Island gas networks excluding the Auckland region
  - 10 years ahead from YE June 2015
- Segmented by customer type: Residential, SME, I&C
- Segmented by region:
  - Whangarei
  - Whangaparoa
  - Cambridge
  - Hamilton
  - Rotorua
  - Taupo
  - Tauranga
  - Mount Maunganui
  - Whakatane
  - Gisborne
  - Paraparaumu
  - Waikanae
  - Te Awamutu
  - Tokoroa
  - Other

Recent trends in new connections



Source: Covec analysis of Vector data

Actual connections by area

Analysis area	Residential			SME			I&C		
	Total current	New YE June 2012	New YE June 2013	Total current	New YE June 2012	New YE June 2013	Total current	New YE June 2012	New YE June 2013
Whangarei	1,031	5	7	101	0	0	87	2	2
Whangaparoa	2,828	118	213	30	1	5	41	0	3
Cambridge	1,891	65	63	50	2	0	38	1	2
Hamilton	26,865	439	477	727	12	17	512	24	24
Rotorua	3,584	31	41	179	2	2	220	3	5
Taupo	1,927	32	24	102	6	2	112	2	0
Tauranga	4,275	87	107	170	3	5	206	2	11
Mt Maunganui	4,130	50	67	80	1	1	139	4	4
Whakatane	357	0	2	40	2	0	52	4	1
Gisborne	3,053	16	14	176	0	1	108	4	1
Paraparaumu	3,218	46	45	95	0	2	75	2	3
Waikanae	1,436	13	12	30	0	2	19	0	1
Te Awamutu	1,280	21	14	36	0	0	27	2	1
Tokoroa	899	1	12	63	1	0	59	5	3
Other	3,735	145	154	234	5	3	268	6	10
Total	**60,509**	**1,069**	**1,252**	**2,113**	**35**	**40**	**1,963**	**61**	**71**

Source: Covec analysis of Vector data

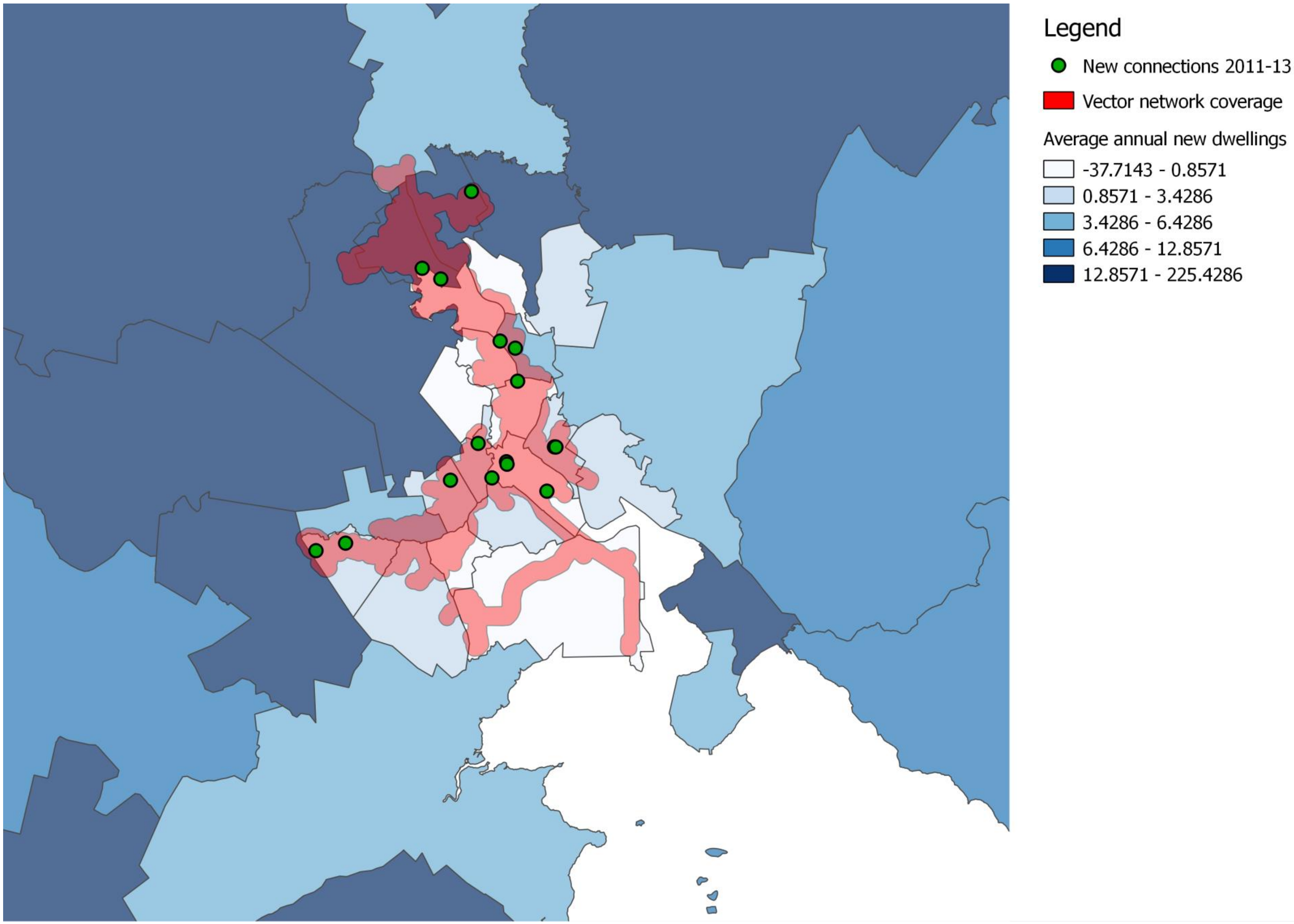
Available data: Residential

- New connections to Vector's gas network in the two years to June 2013 by geographic location
- 2013 Census population and dwelling counts by Census Area Unit
- Stats NZ population projections by Census Area Unit from 2006 to 2026
  - Published in October 2012
  - Do not reflect 2013 Census results – we have adjusted forecasts accordingly to produce reasonable gas connections forecasts

Methodology: Residential

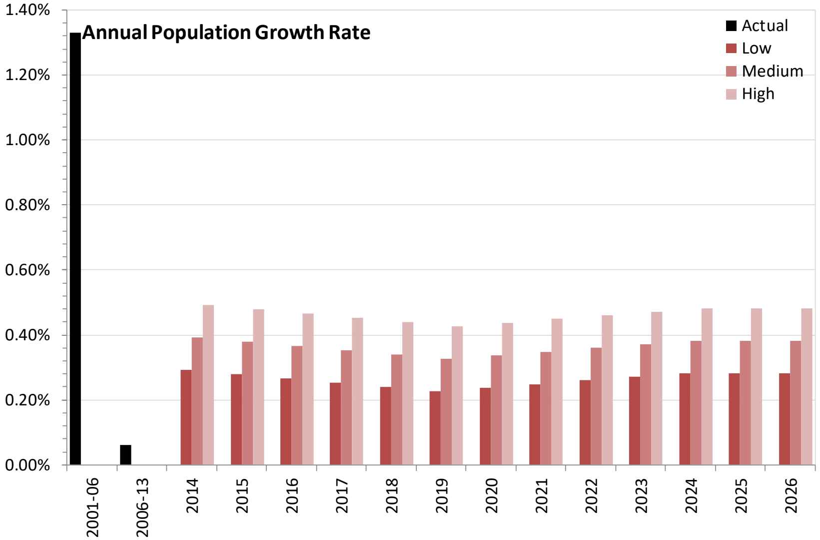
- Analysis area defined as all CAUs overlapping Vector gas network coverage
  - Allows for expansion of gas network into edge CAUs over time
  - Total population & dwellings for relevant CAUs calculated from 2013 Census data
  - Stats NZ CAU population forecasts modified to reflect 2013 Census results
  - Household size trend calculated from Census data and extrapolated
- New dwellings forecast for each area generated from population and household size forecasts
- Gas connection propensity calculated from 2012 & 2013 connections data for each region
  - Includes conversions as well as new connections
  - Assumes that conversions are in proportion to population growth in a region (using population growth as a proxy for regional economic factors)
- Gas connection propensities applied to new dwellings forecast to generate gross connections forecasts by area
- Forecasts modified slightly to account for recent connections trends

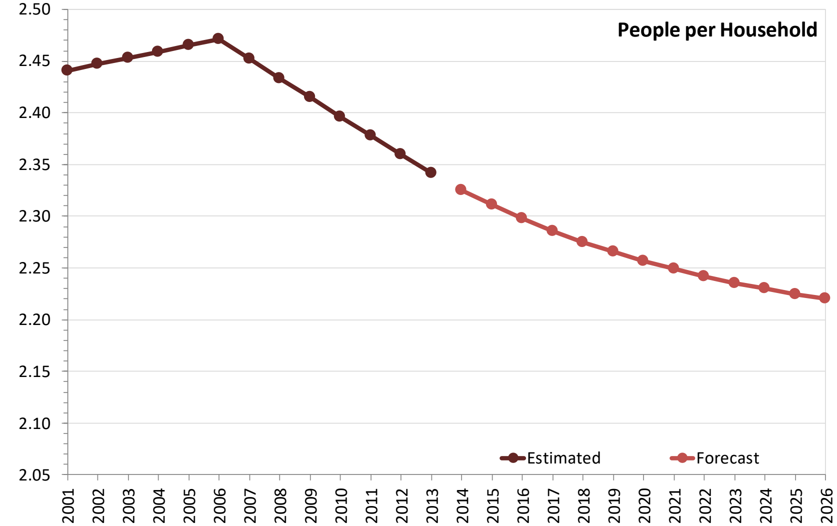
Whangarei

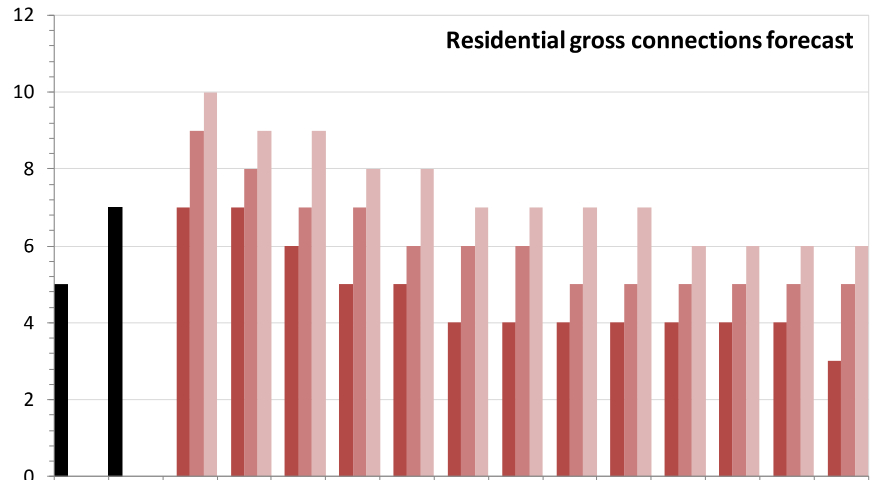

Legend
New connections 2011-13
Vector network coverage
Average annual new dwellings
-37.7143 - 0.8571
0.8571 - 3.4286
3.4286 - 6.4286
6.4286 - 12.8571
12.8571 - 225.4286

Source: Covec analysis of Statistics New Zealand & Vector data

Whangarei: Residential



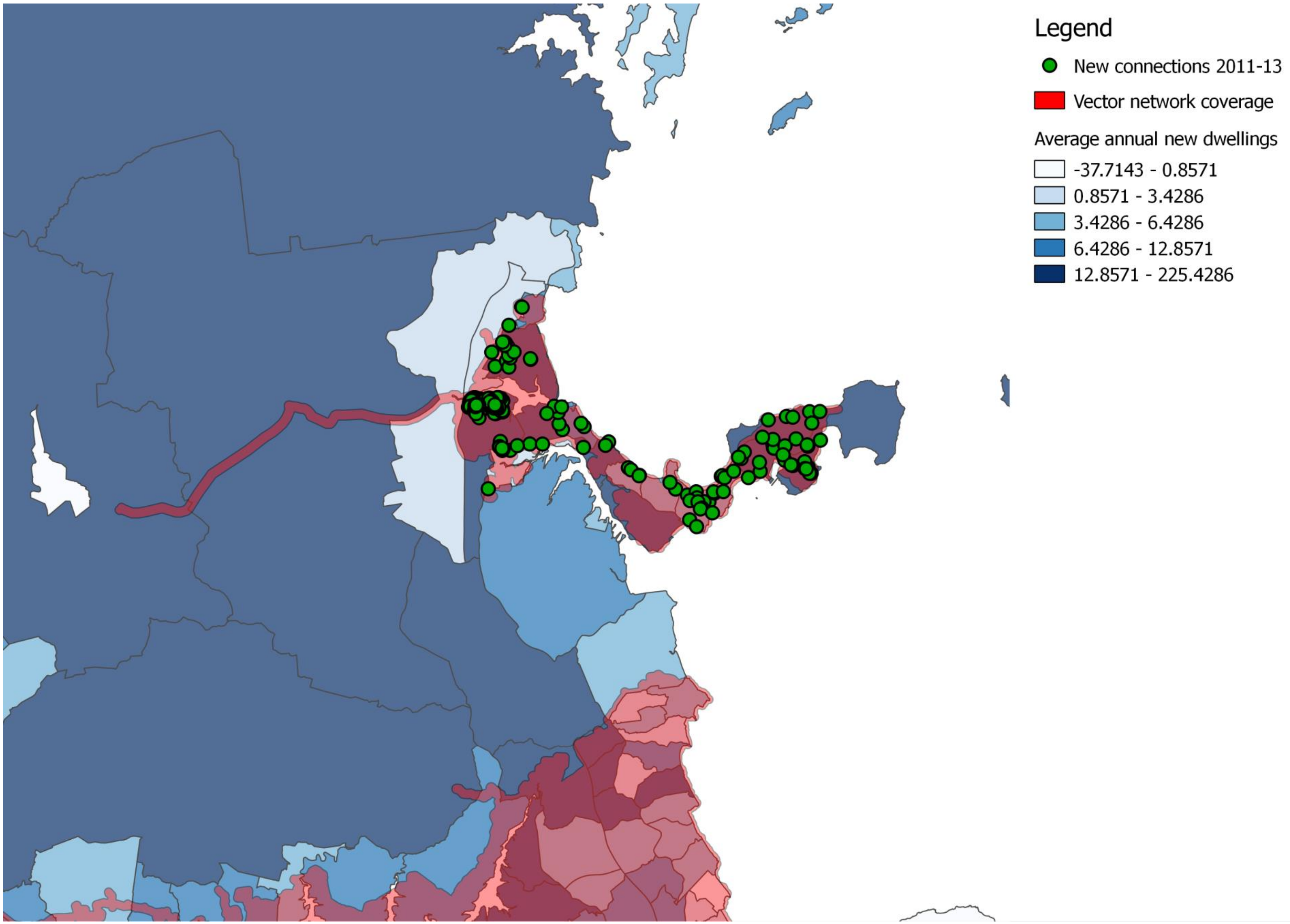




	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	5	7													
Low			7	7	6	5	5	4	4	4	4	4	4	4	3
Medium			9	8	7	7	6	6	6	5	5	5	5	5	5
High			10	9	9	8	8	7	7	7	7	6	6	6	6

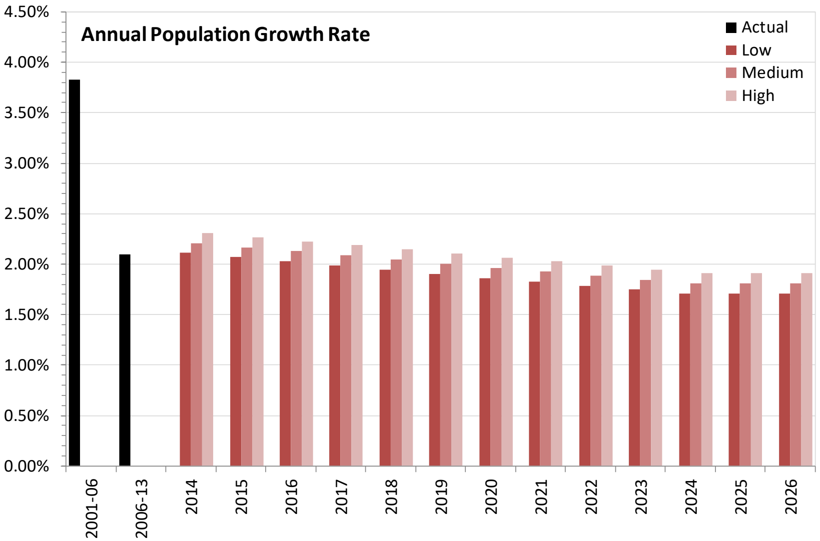
Source: Covec analysis of Statistics New Zealand & Vector data

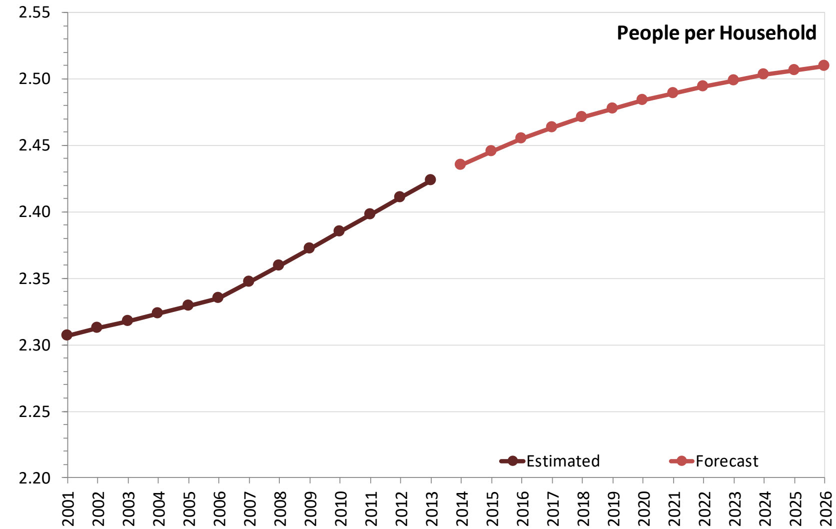
Whangaparoa



Source: Covec analysis of Statistics New Zealand & Vector data

Whangaparoa: Residential

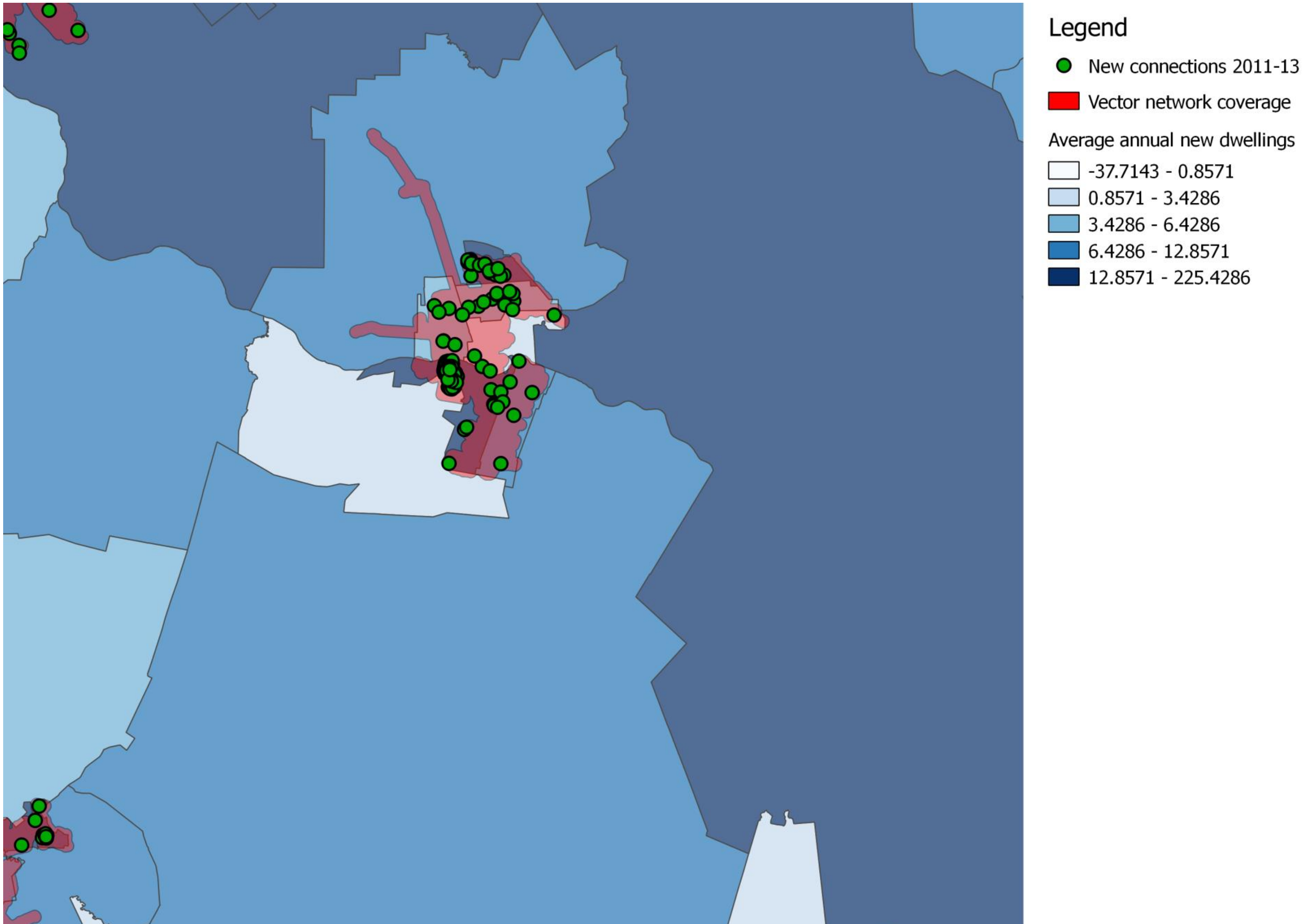




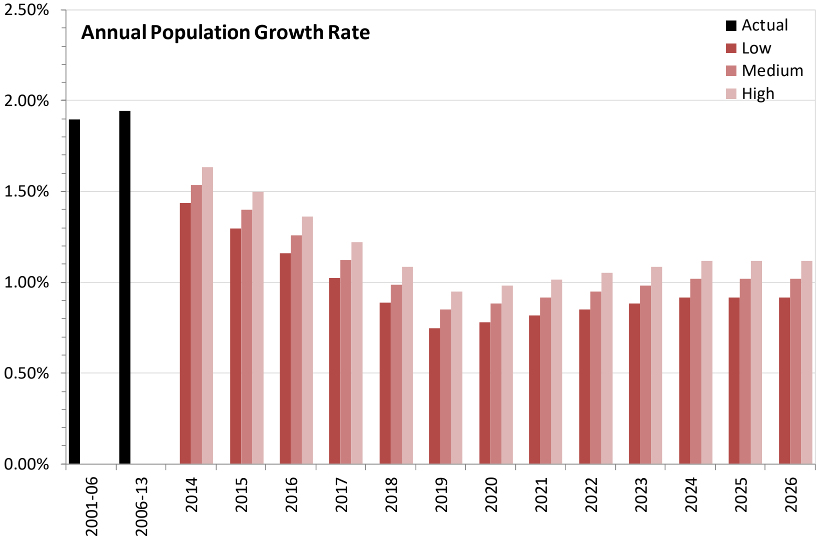
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	118	213													
Low			242	244	245	245	245	244	246	248	250	251	251	258	265
Medium			257	259	260	261	261	261	264	266	268	270	271	278	285
High			271	273	275	277	277	278	281	284	287	289	291	298	306

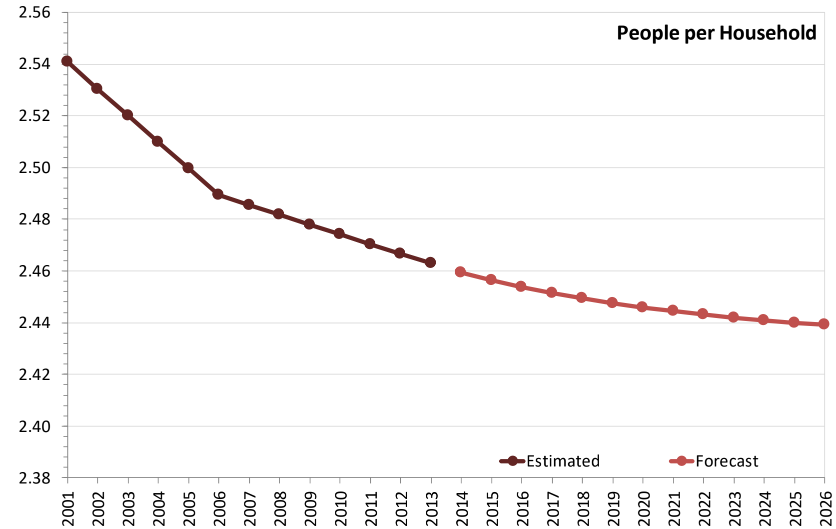
Source: Covec analysis of Statistics New Zealand & Vector data

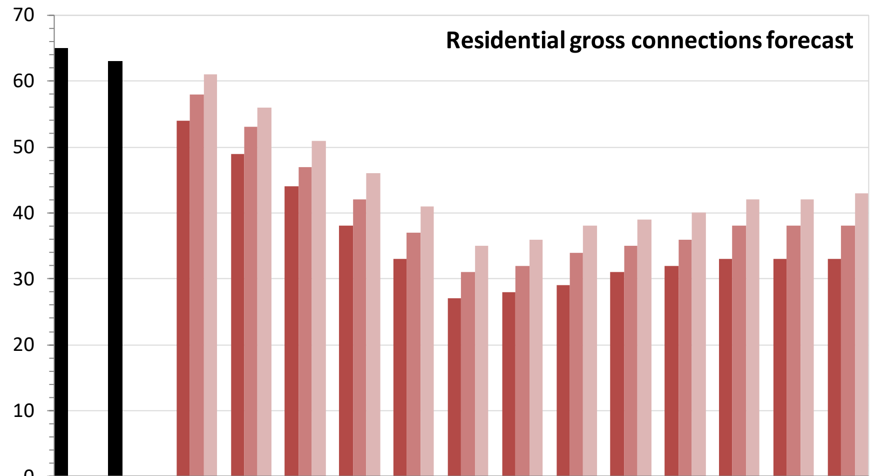
Cambridge



Cambridge: Residential



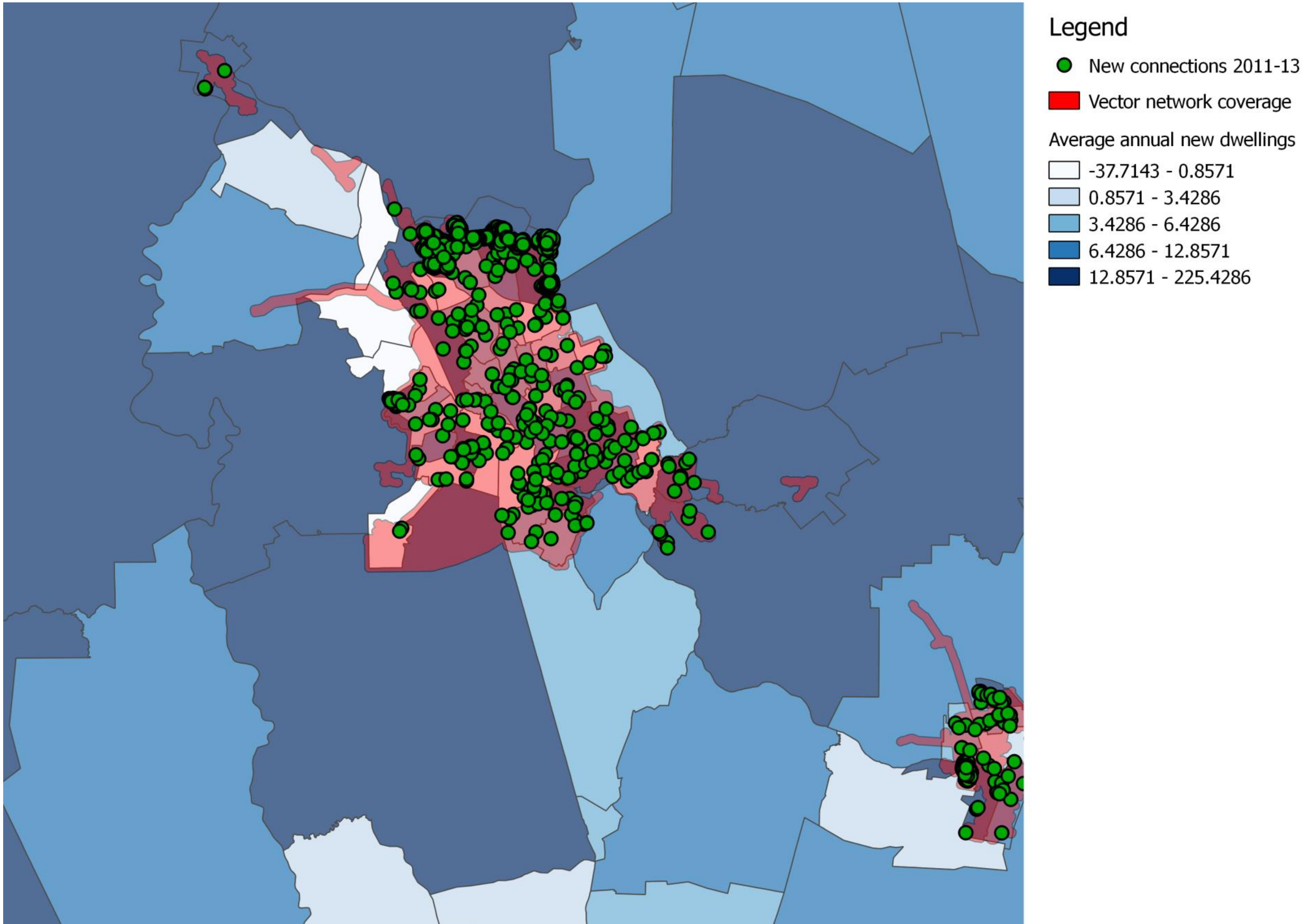




	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	65	63													
Low			54	49	44	38	33	27	28	29	31	32	33	33	33
Medium			58	53	47	42	37	31	32	34	35	36	38	38	38
High			61	56	51	46	41	35	36	38	39	40	42	42	43

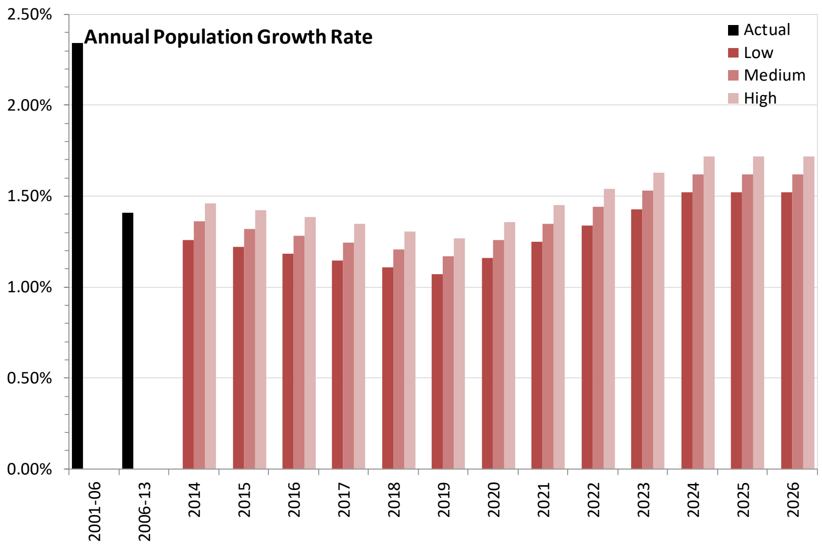
Source: Covec analysis of Statistics New Zealand & Vector data

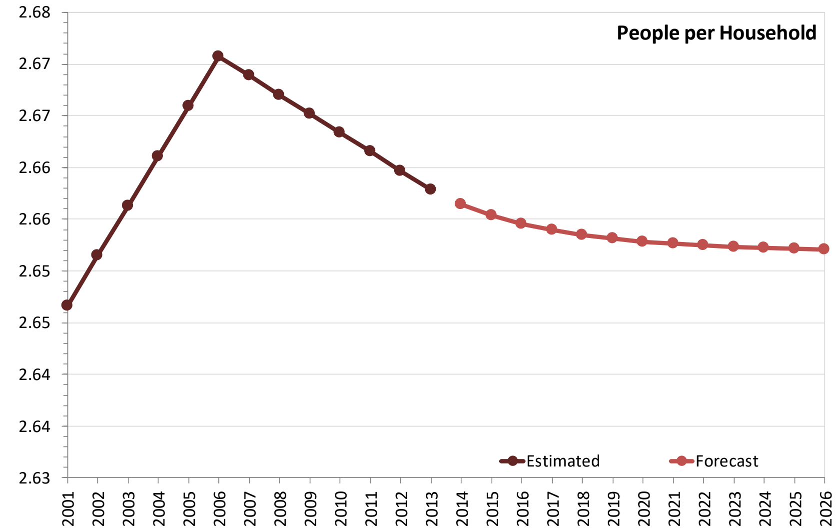
Hamilton

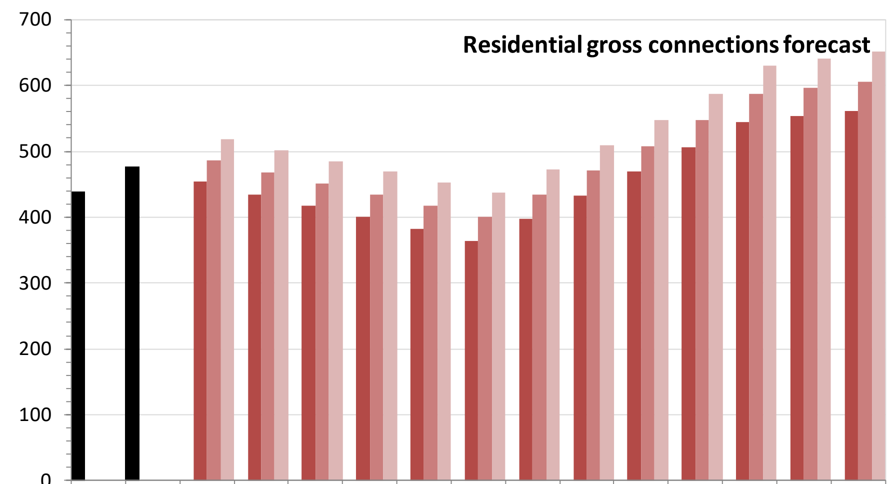


Source: Covec analysis of Statistics New Zealand & Vector data

Hamilton: Residential

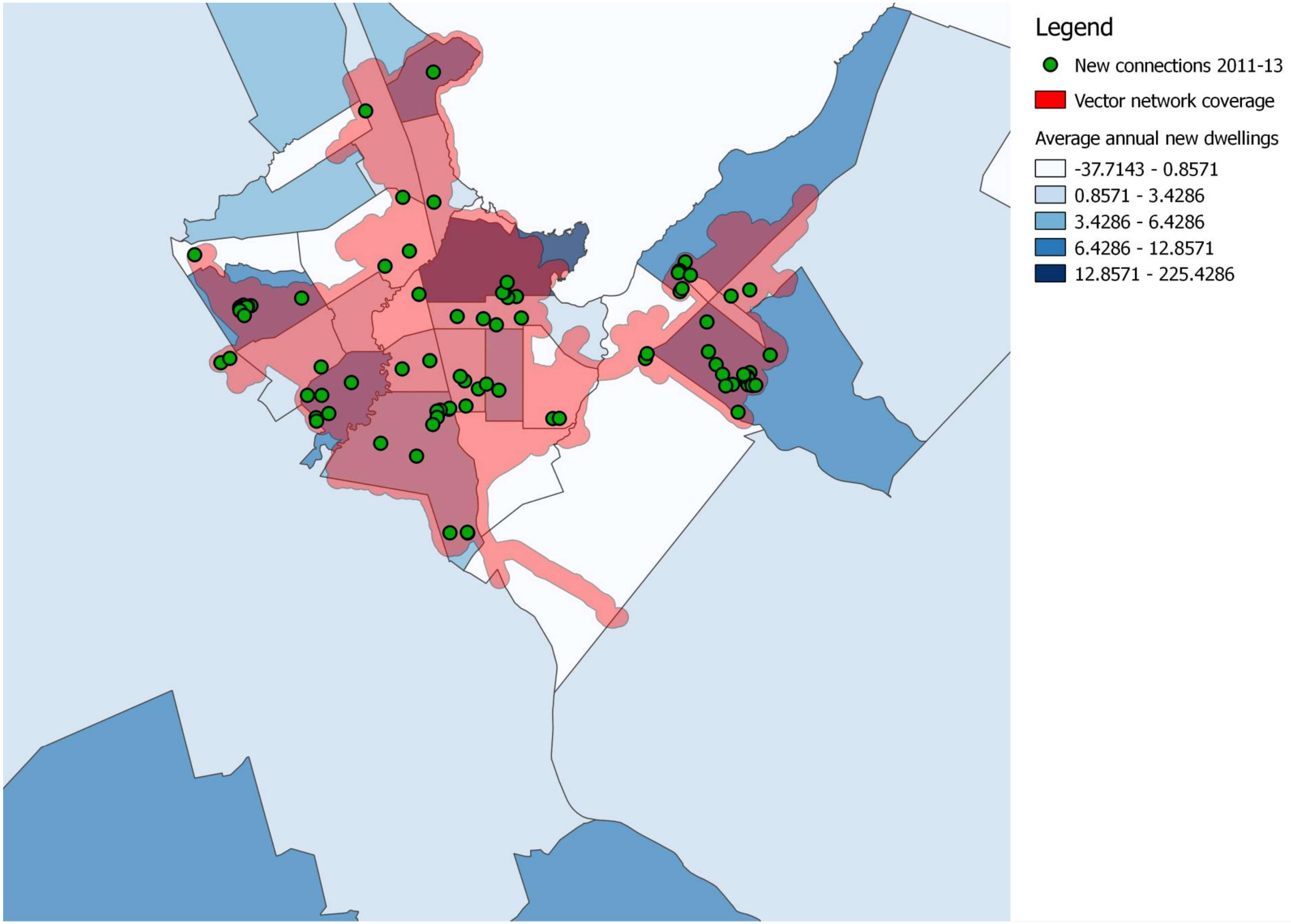




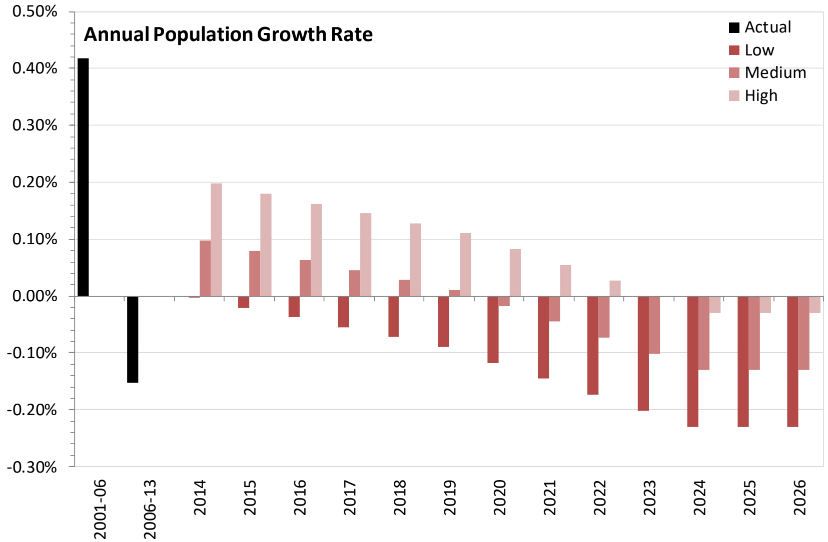


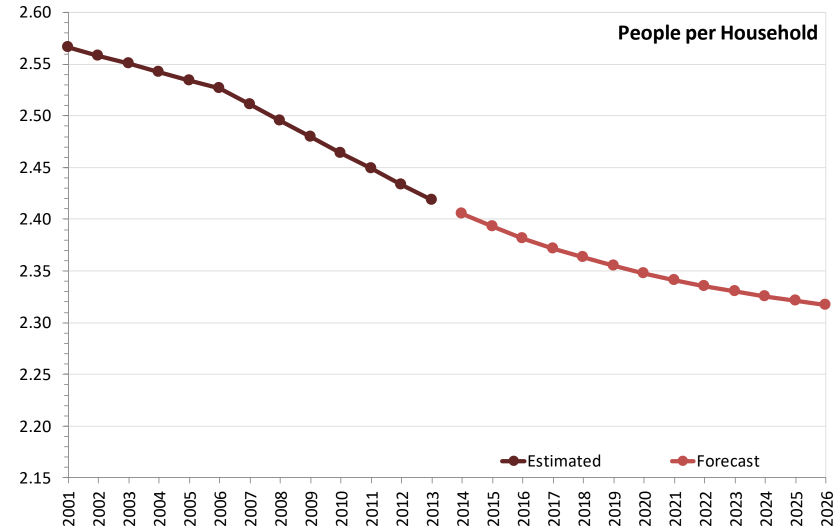
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	439	477													
Low			454	435	417	400	382	364	398	432	469	506	545	553	561
Medium			486	468	451	434	417	400	435	471	508	547	587	597	606
High			518	502	485	469	453	437	472	509	548	588	630	641	652

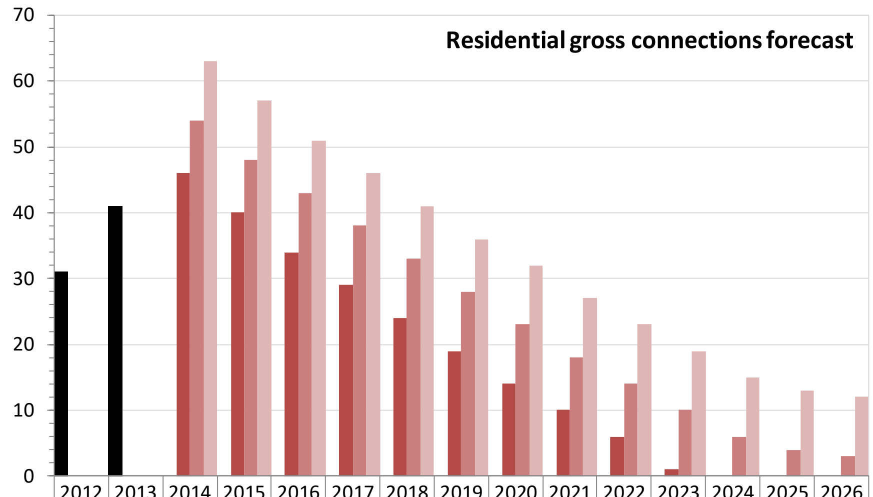
Rotorua


Legend
New connections 2011-13
Vector network coverage
Average annual new dwellings
-37.7143 - 0.8571
0.8571 - 3.4286
3.4286 - 6.4286
6.4286 - 12.8571
12.8571 - 225.4286

Rotorua: Residential

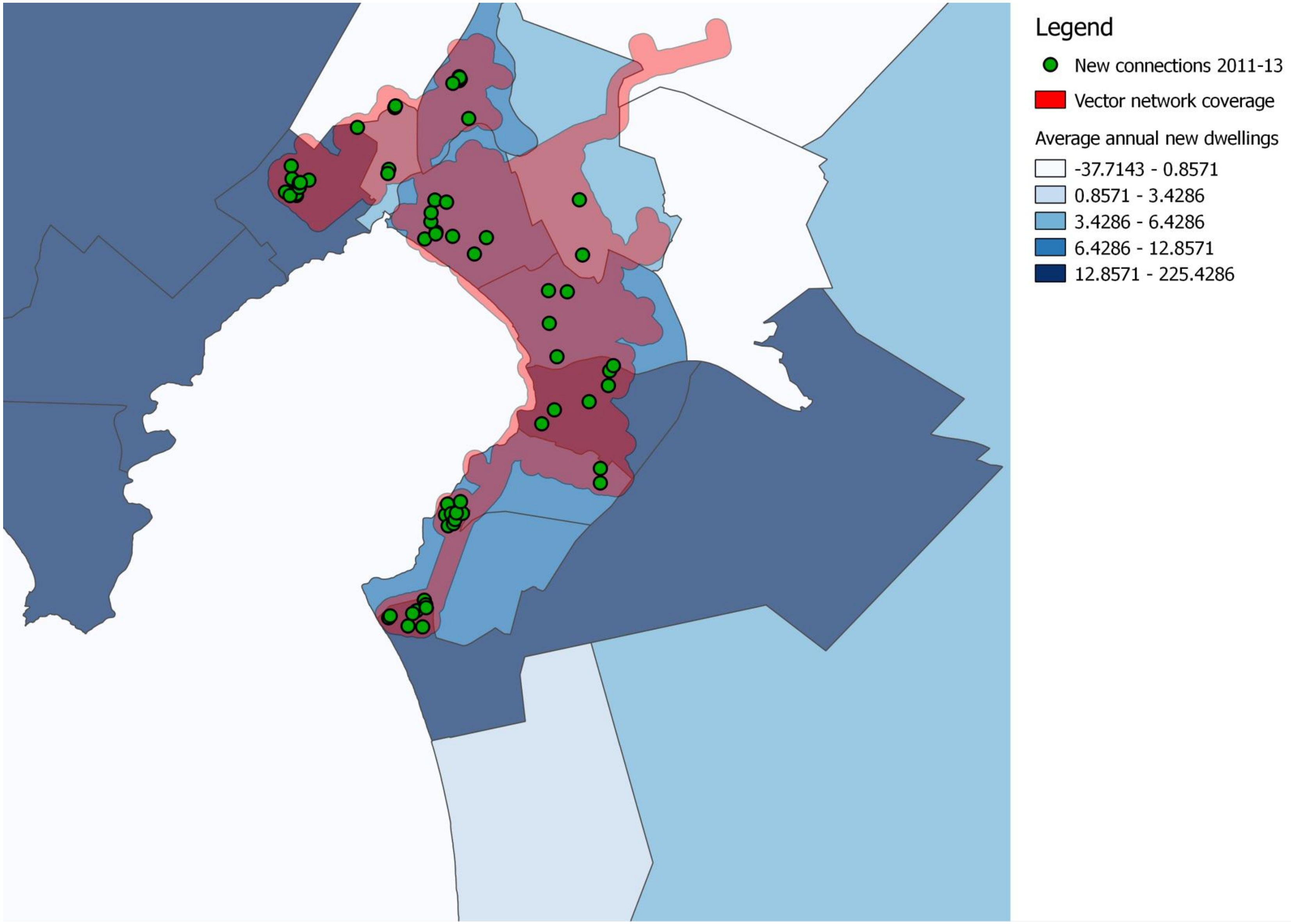




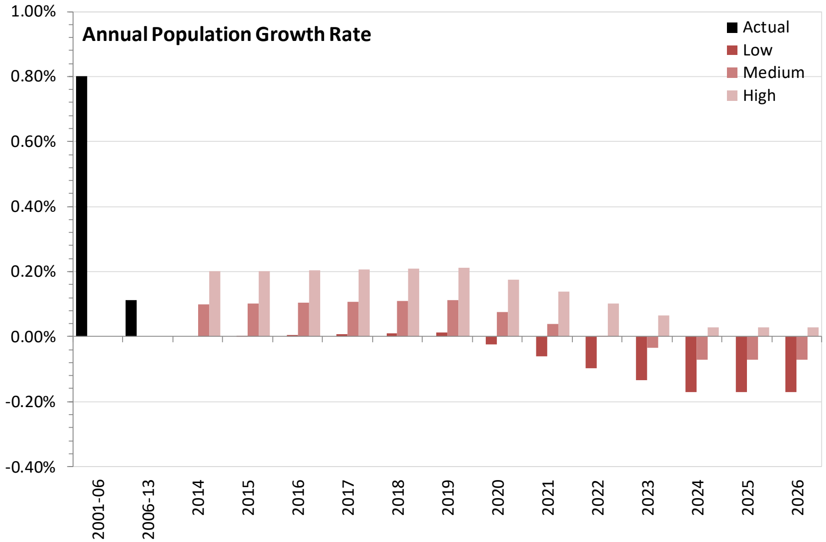


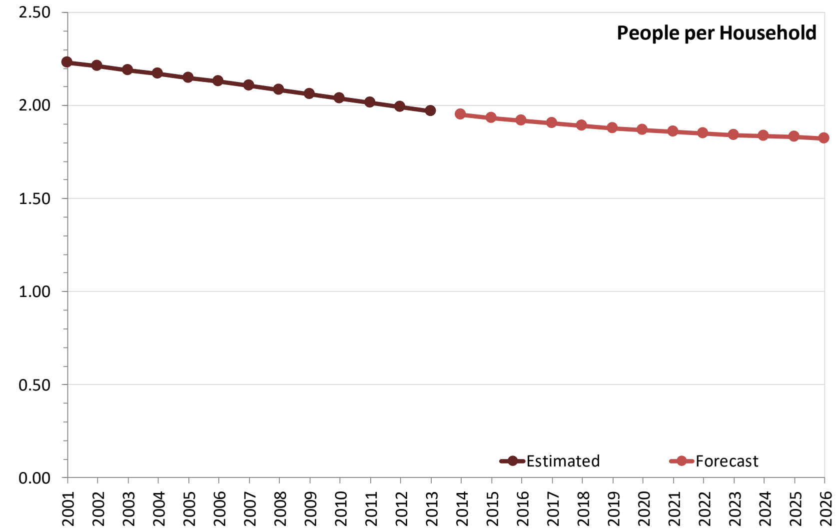
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	31	41													
Low			46	40	34	29	24	19	14	10	6	1	0	0	0
Medium			54	48	43	38	33	28	23	18	14	10	6	4	3
High			63	57	51	46	41	36	32	27	23	19	15	13	12

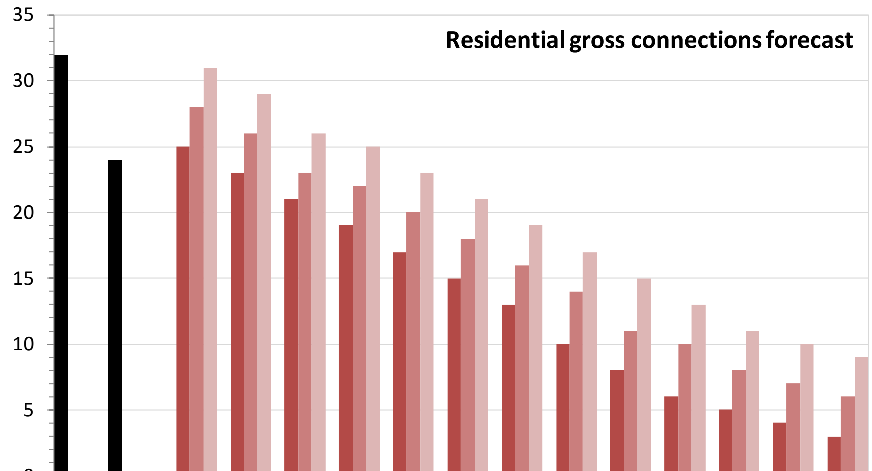
Taupo


Legend
New connections 2011-13
Vector network coverage
Average annual new dwellings
-37.7143 - 0.8571
0.8571 - 3.4286
3.4286 - 6.4286
6.4286 - 12.8571
12.8571 - 225.4286

Taupo: Residential

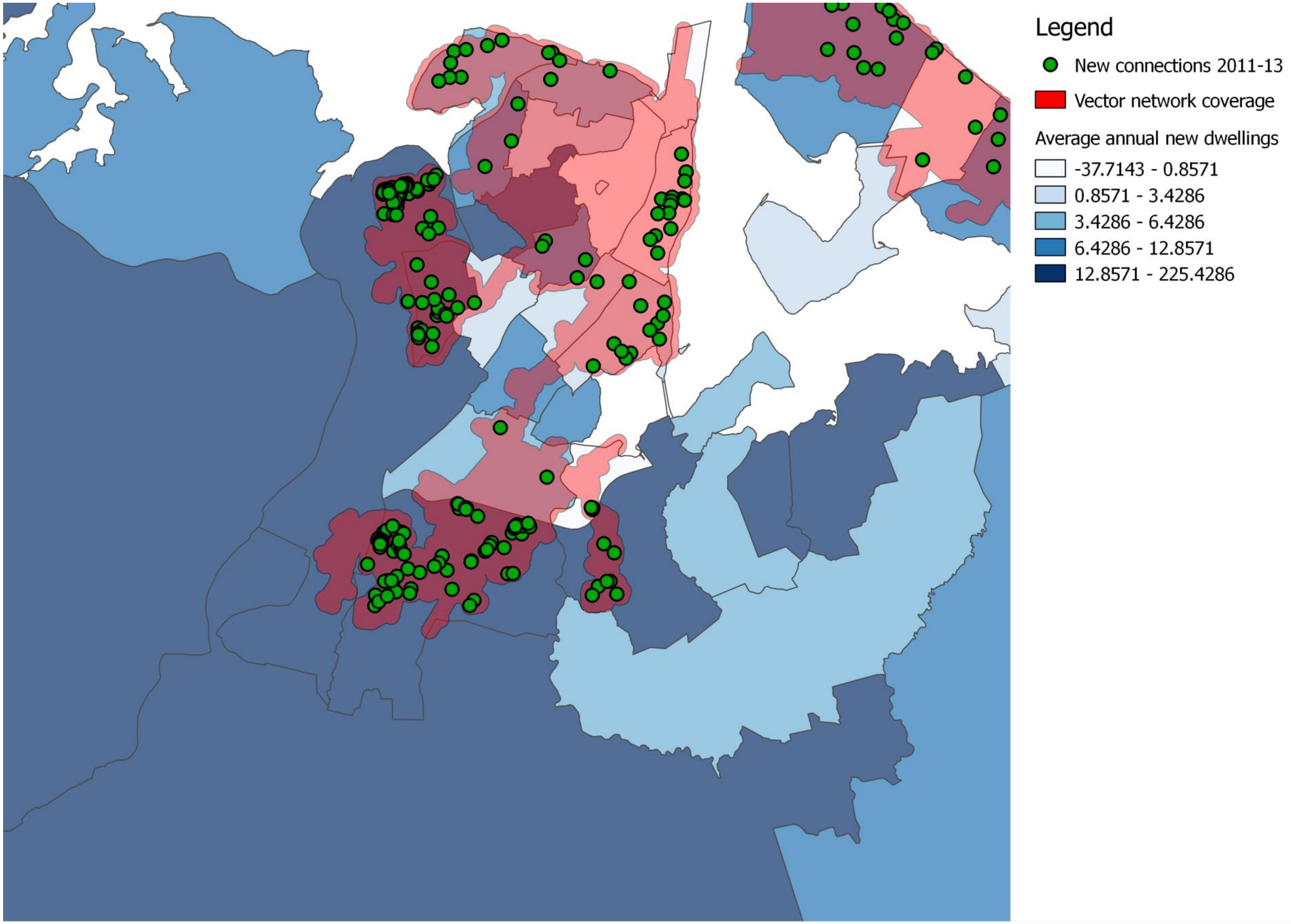




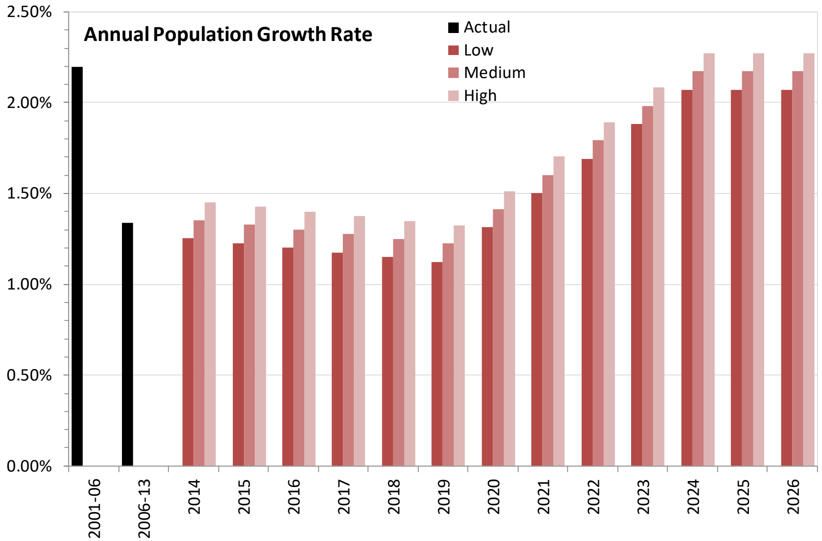


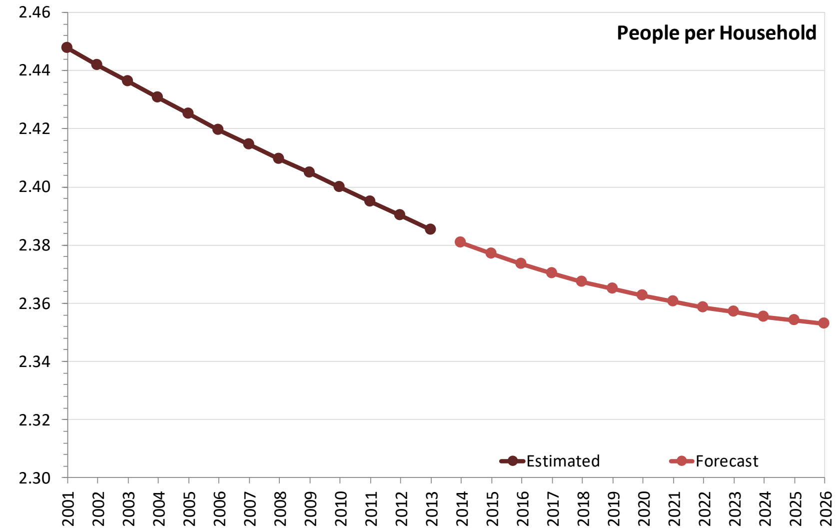
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	32	24													
Low			25	23	21	19	17	15	13	10	8	6	5	4	3
Medium			28	26	23	22	20	18	16	14	11	10	8	7	6
High			31	29	26	25	23	21	19	17	15	13	11	10	9

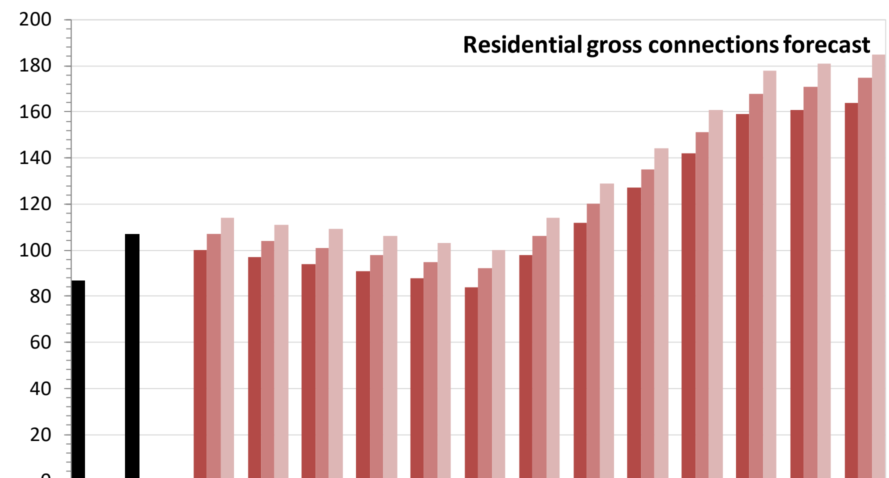
Tauranga


Legend
New connections 2011-13
Vector network coverage
Average annual new dwellings
-37.7143 - 0.8571
0.8571 - 3.4286
3.4286 - 6.4286
6.4286 - 12.8571
12.8571 - 225.4286

Tauranga: Residential



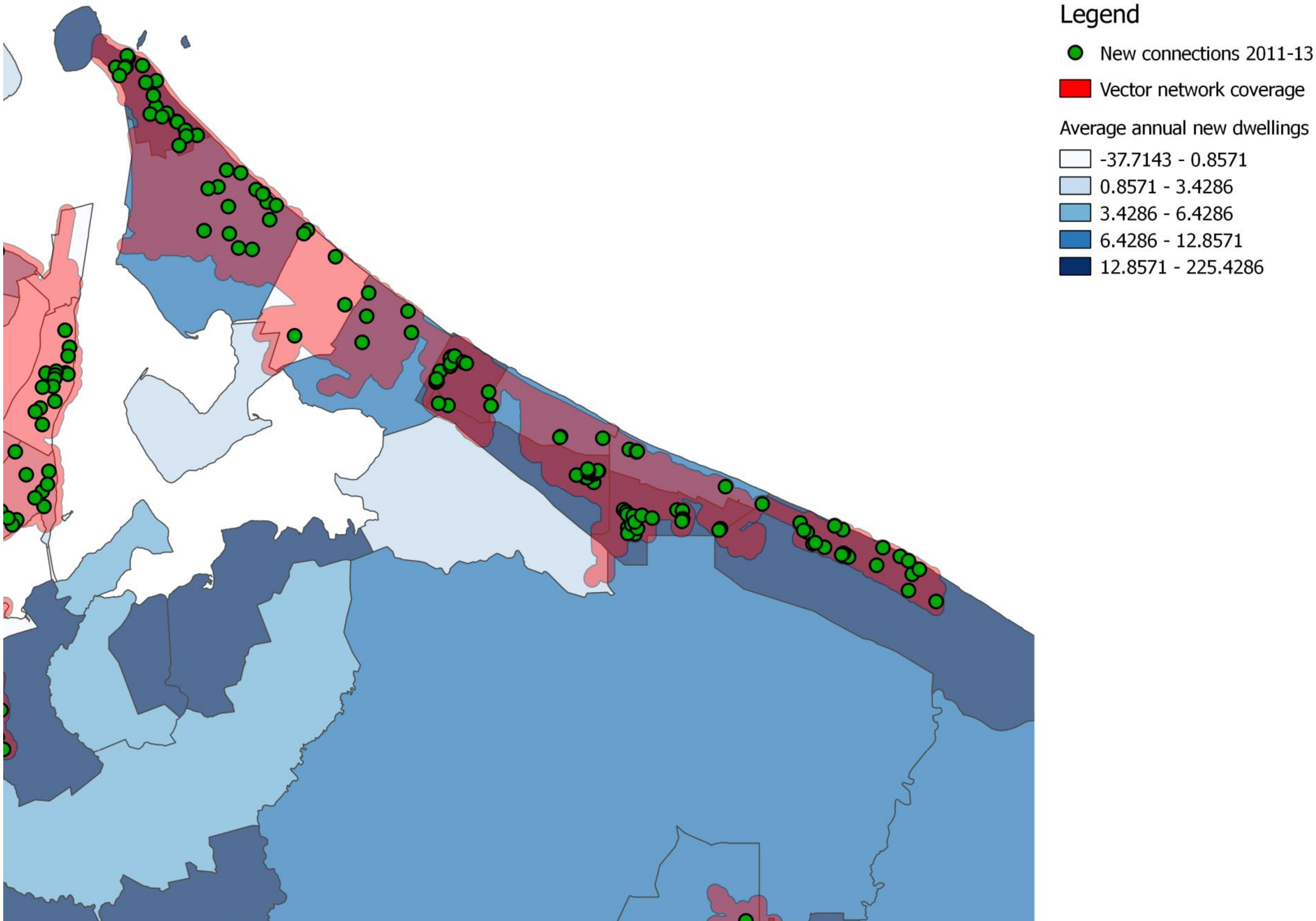




	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	87	107													
Low			100	97	94	91	88	84	98	112	127	142	159	161	164
Medium			107	104	101	98	95	92	106	120	135	151	168	171	175
High			114	111	109	106	103	100	114	129	144	161	178	181	185

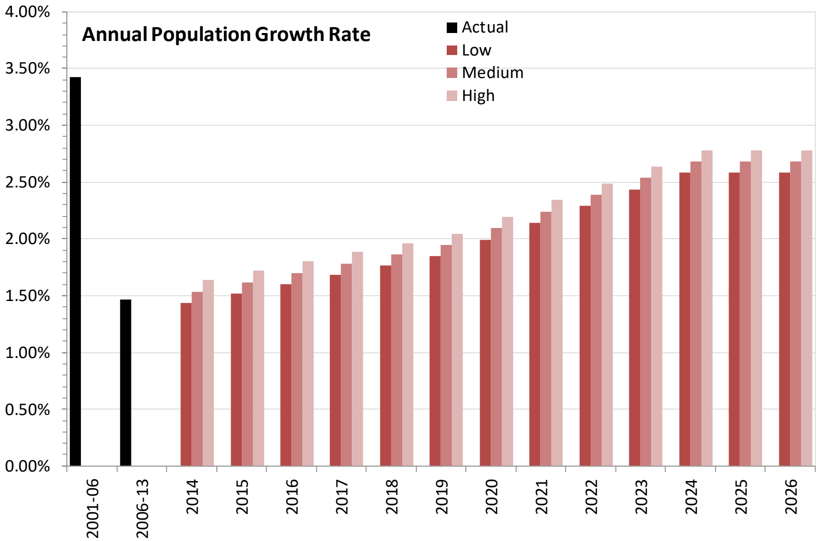
Source: Covec analysis of Statistics New Zealand & Vector data

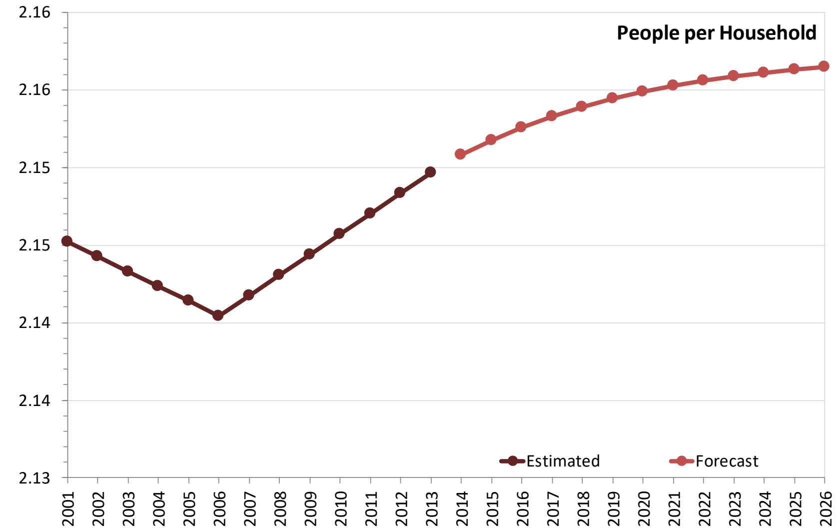
Mt Maunganui

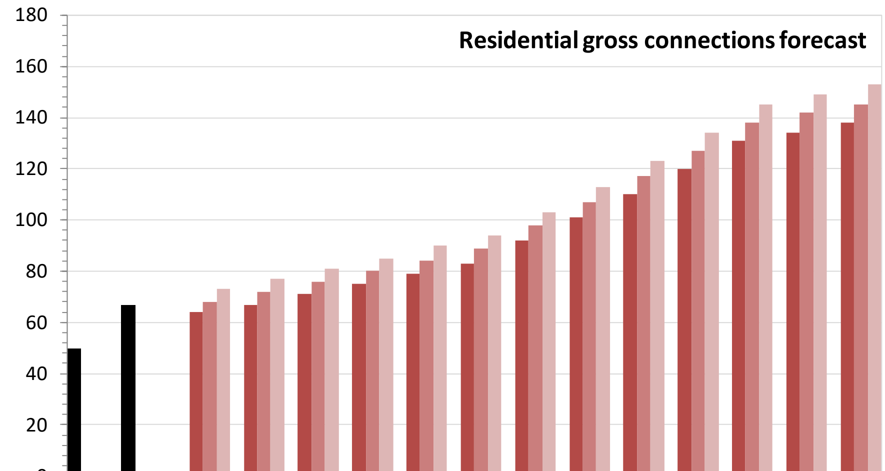


Source: Covec analysis of Statistics New Zealand & Vector data

Mt Maunganui: Residential



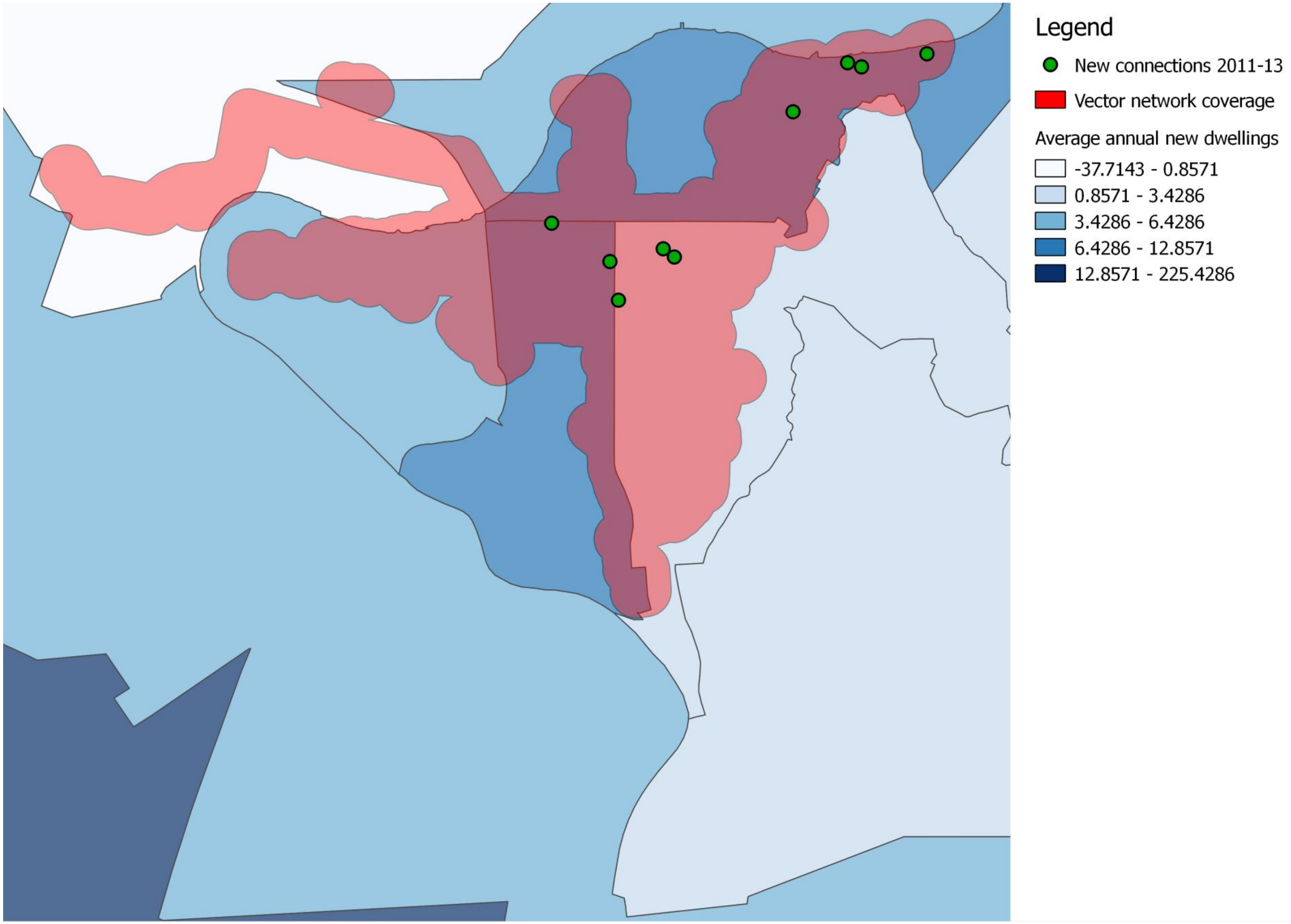




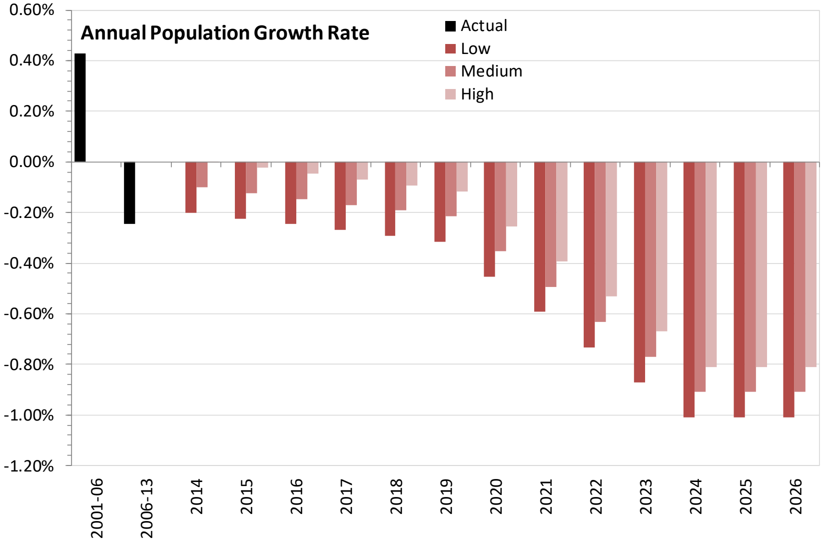
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	50	67													
Low			64	67	71	75	79	83	92	101	110	120	131	134	138
Medium			68	72	76	80	84	89	98	107	117	127	138	142	145
High			73	77	81	85	90	94	103	113	123	134	145	149	153

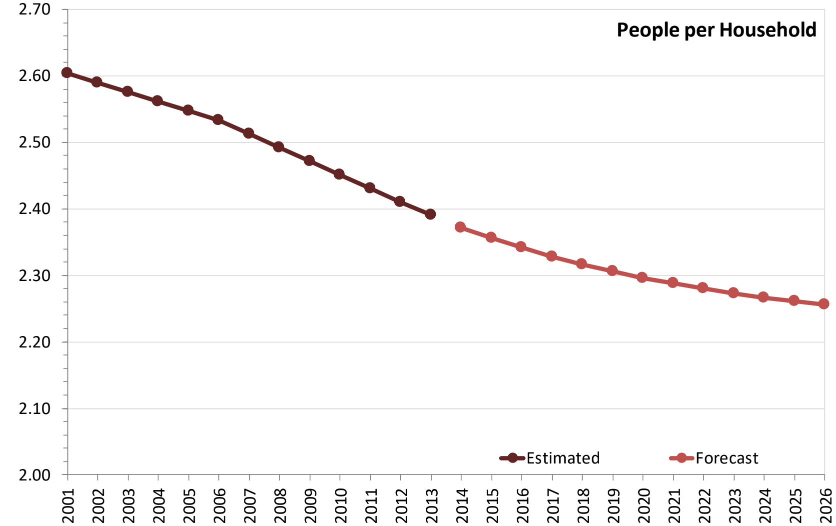
Source: Covec analysis of Statistics New Zealand & Vector data

Whakatane



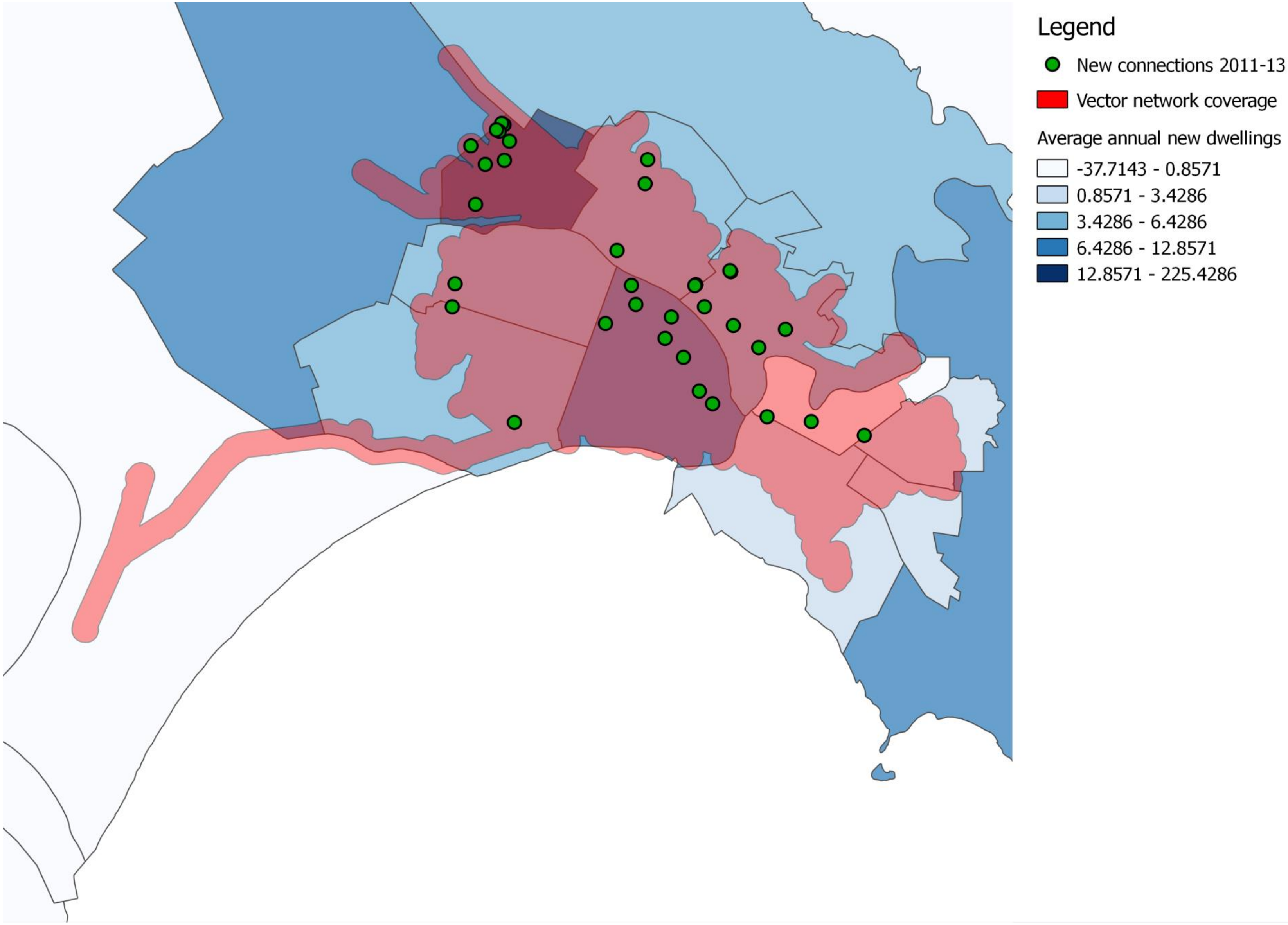
Whakatane: Residential





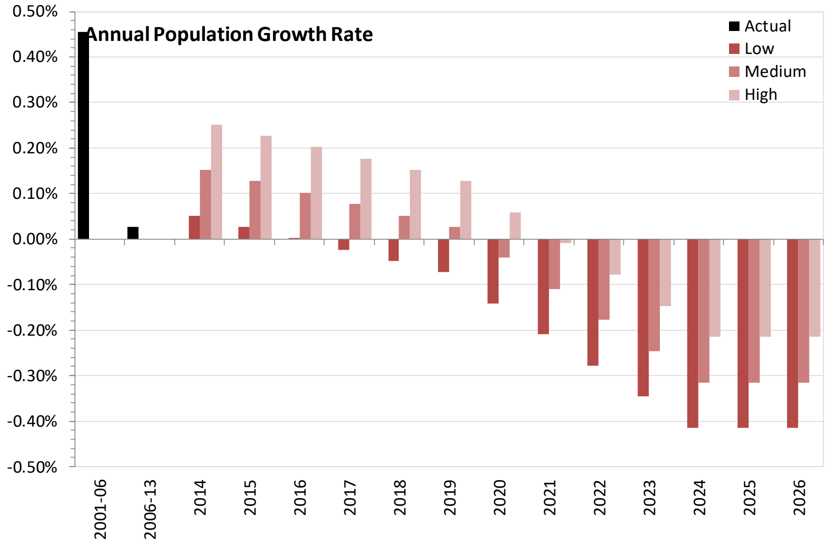
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	0	2													
Low			1	0	0	0	0	0	0	0	0	0	0	0	0
Medium			1	1	1	1	1	0	0	0	0	0	0	0	0
High			2	2	2	1	1	1	1	0	0	0	0	0	0

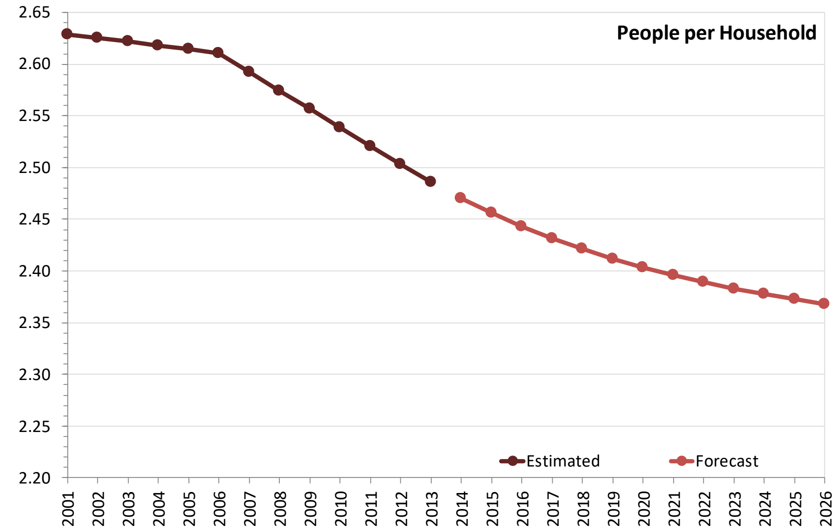
Gisborne

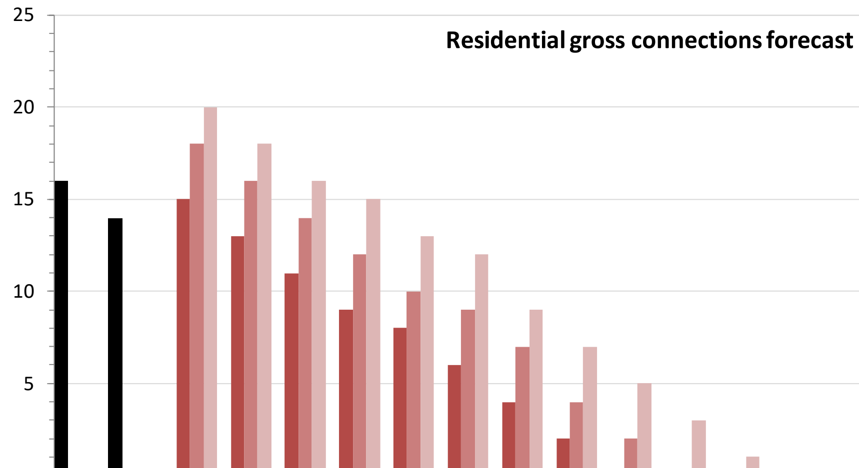

Legend
New connections 2011-13
Vector network coverage
Average annual new dwellings
-37.7143 - 0.8571
0.8571 - 3.4286
3.4286 - 6.4286
6.4286 - 12.8571
12.8571 - 225.4286

Source: Covec analysis of Statistics New Zealand & Vector data

Gisborne: Residential



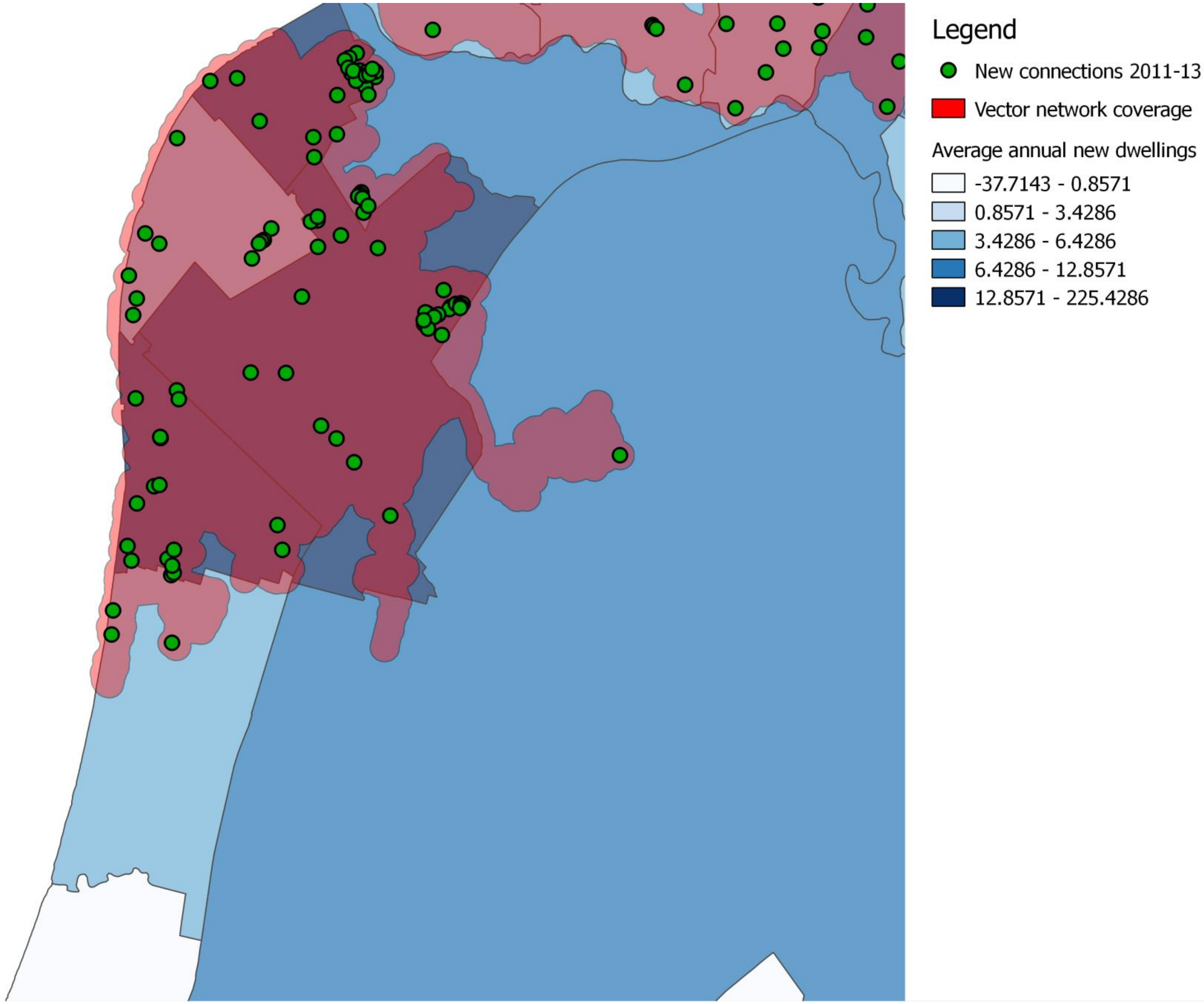




	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	16	14													
Low			15	13	11	9	8	6	4	2	0	0	0	0	0
Medium			18	16	14	12	10	9	7	4	2	0	0	0	0
High			20	18	16	15	13	12	9	7	5	3	1	0	0

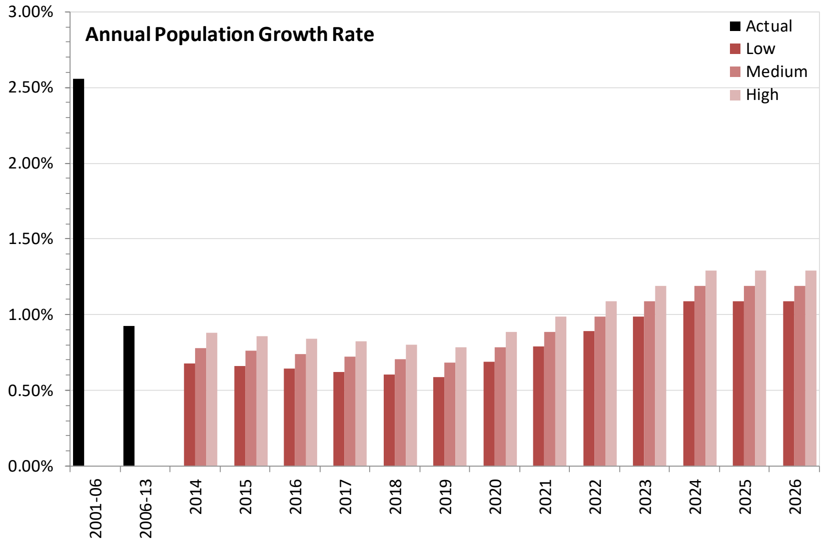
Source: Covec analysis of Statistics New Zealand & Vector data

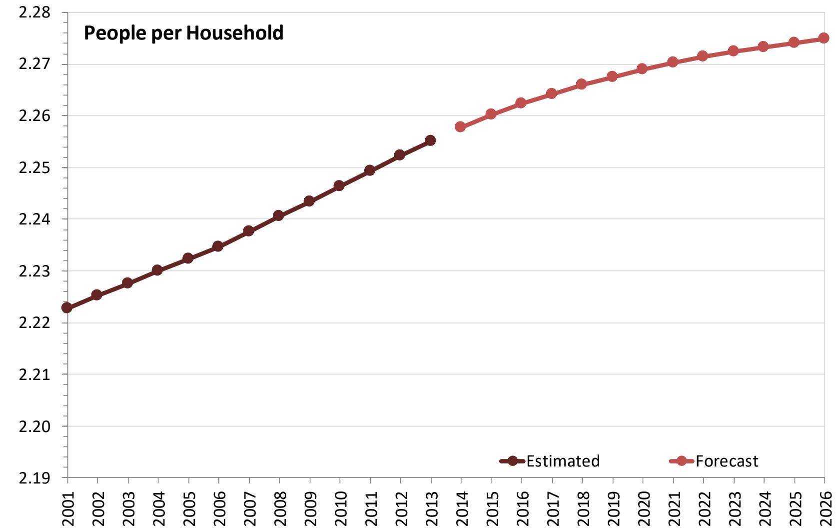
Paraparaumu

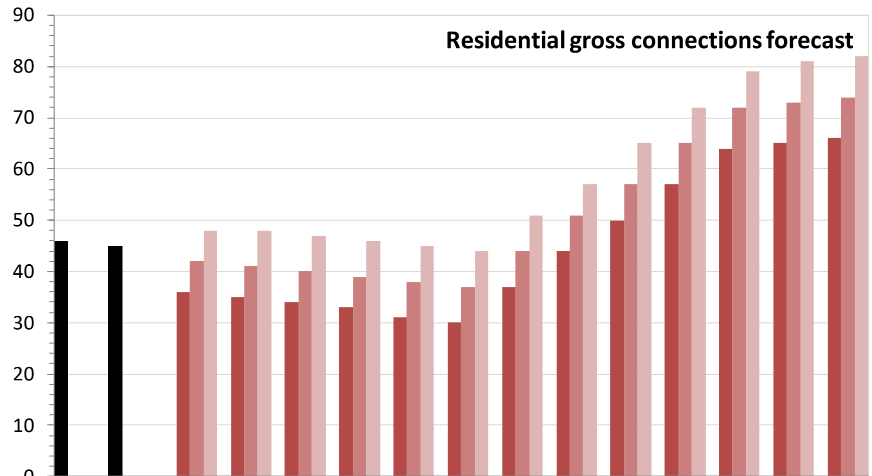


Source: Covec analysis of Statistics New Zealand & Vector data

Paraparaumu: Residential



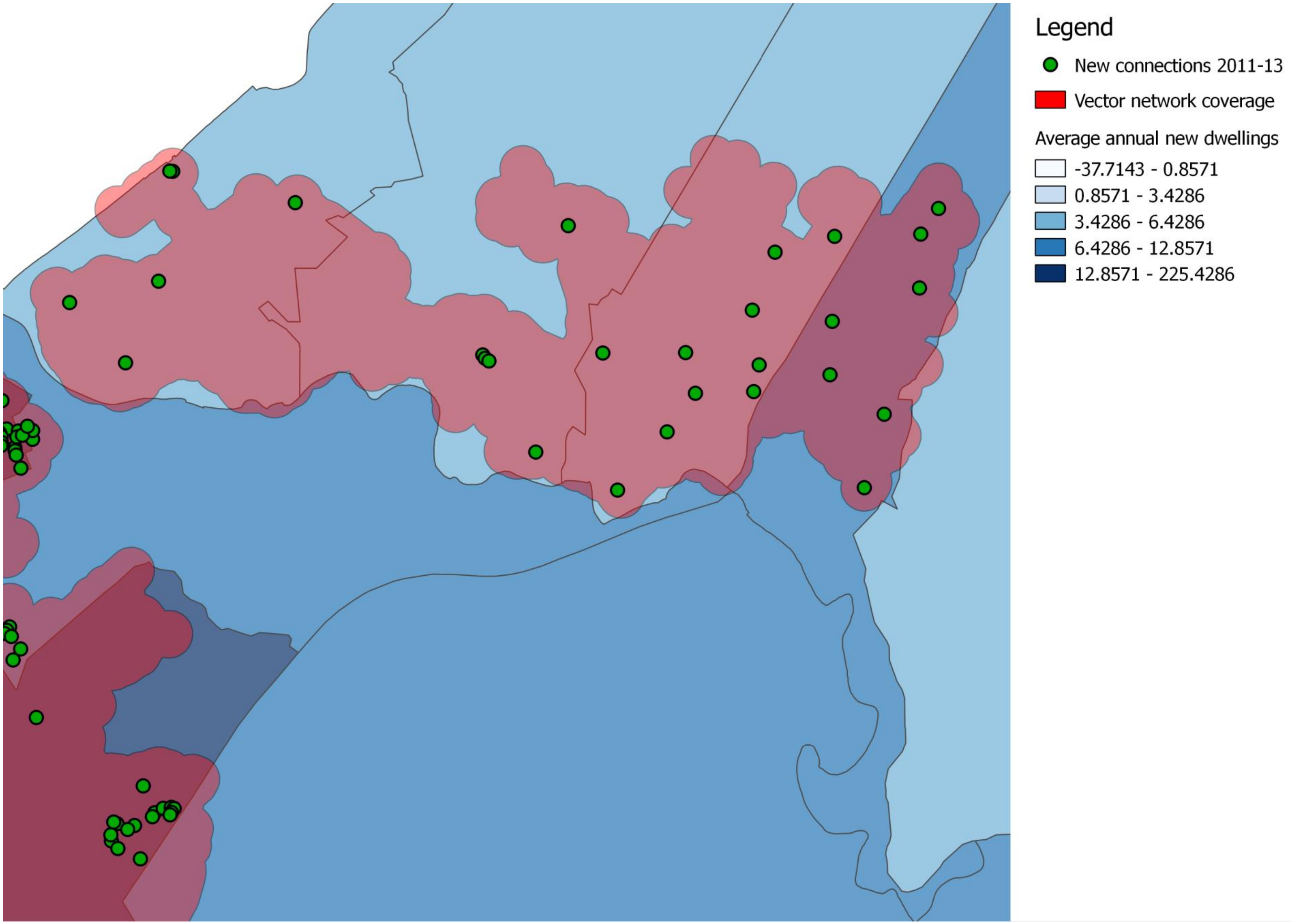




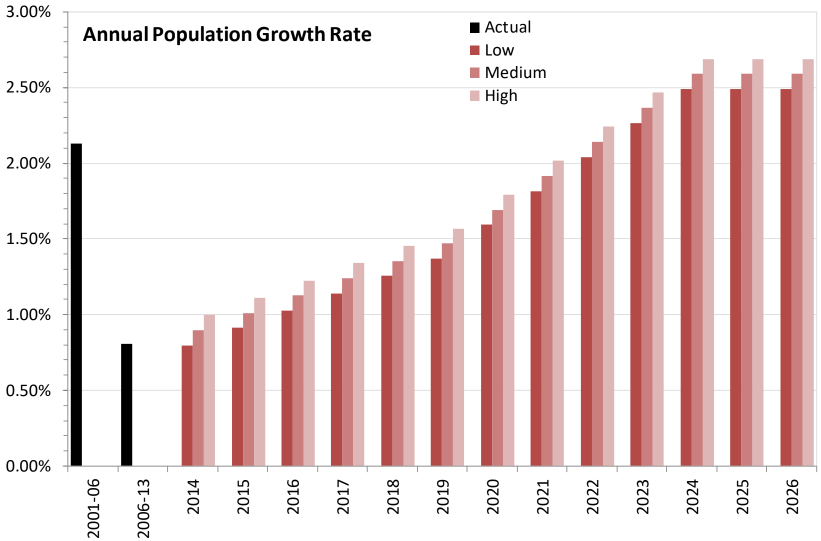
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	46	45													
Low			36	35	34	33	31	30	37	44	50	57	64	65	66
Medium			42	41	40	39	38	37	44	51	57	65	72	73	74
High			48	48	47	46	45	44	51	57	65	72	79	81	82

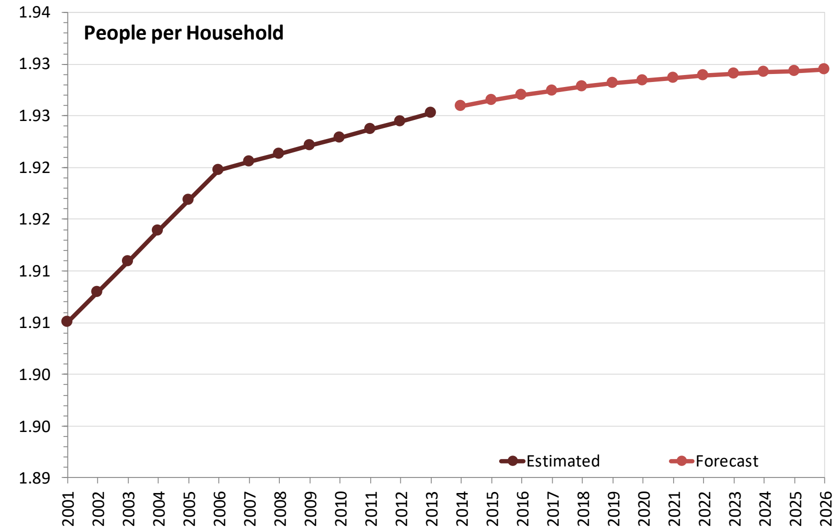
Source: Covec analysis of Statistics New Zealand & Vector data

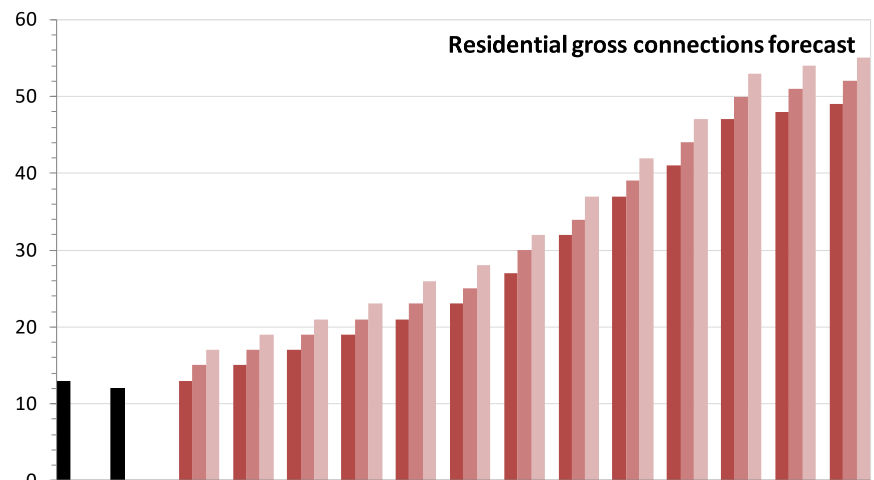
Waikanae



Waikanae: Residential

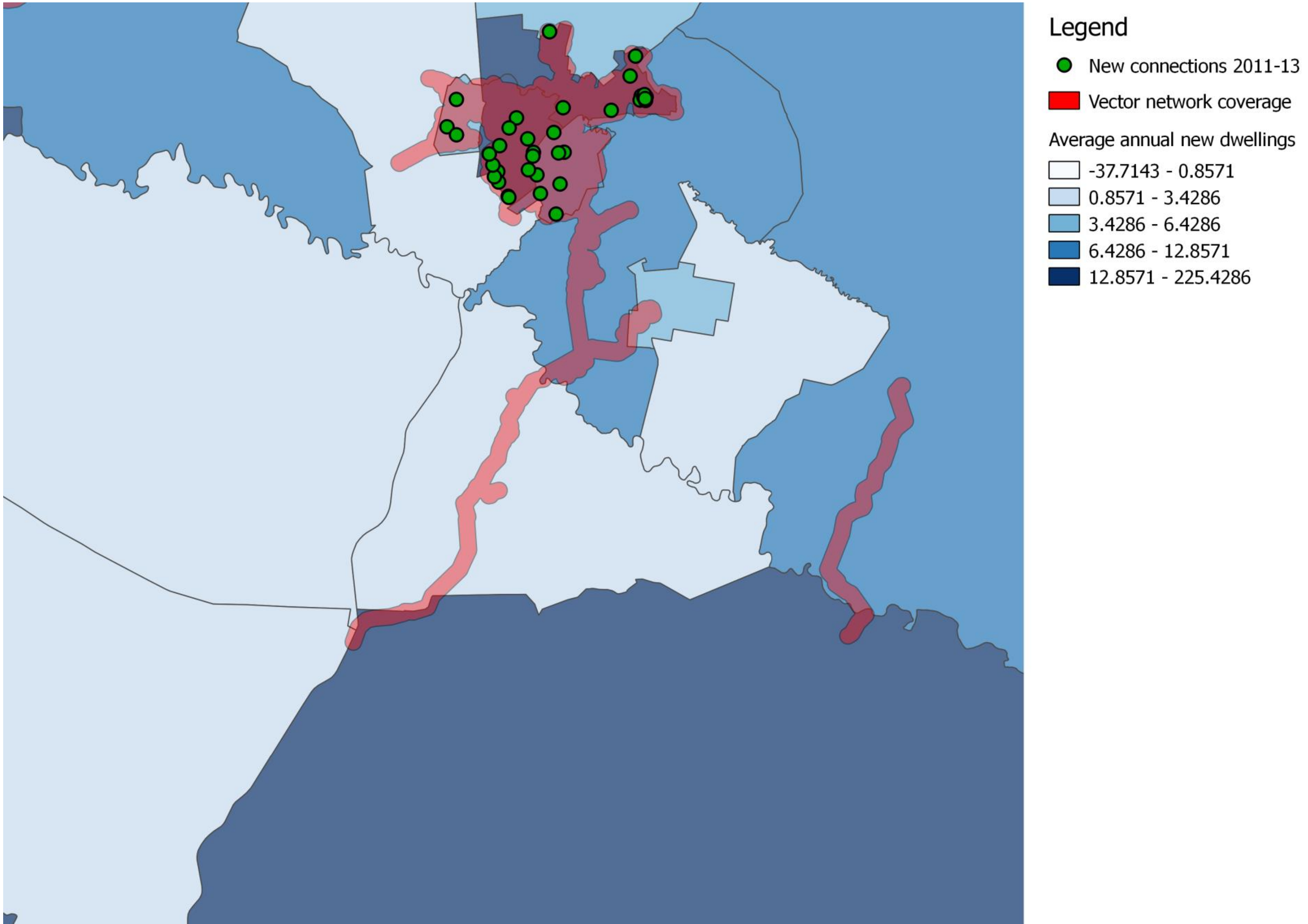






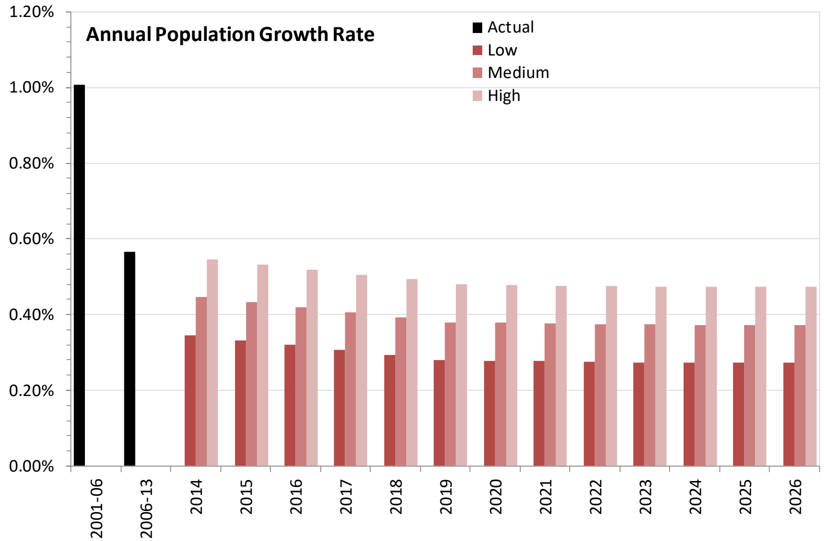
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	13	12													
Low			13	15	17	19	21	23	27	32	37	41	47	48	49
Medium			15	17	19	21	23	25	30	34	39	44	50	51	52
High			17	19	21	23	26	28	32	37	42	47	53	54	55

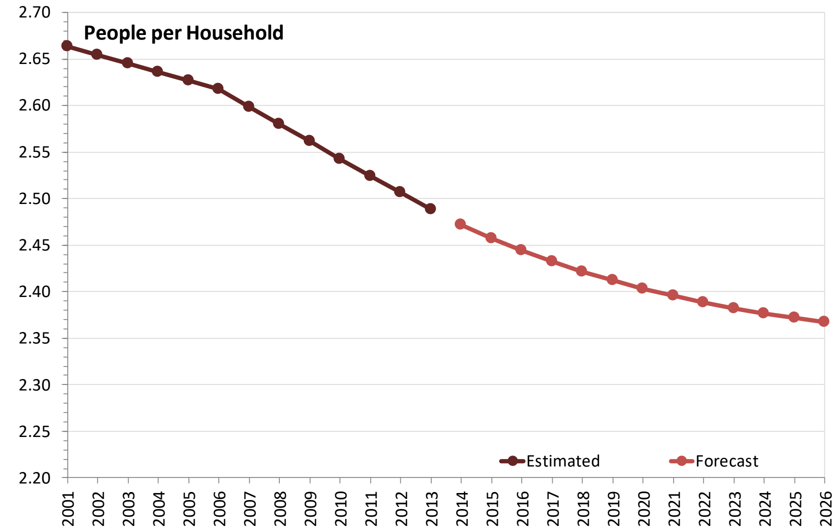
Te Awamutu

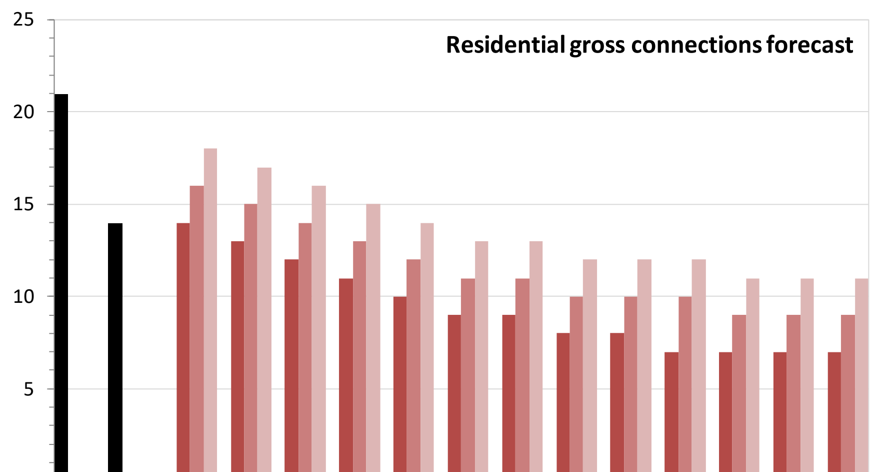

Legend
New connections 2011-13
Vector network coverage
Average annual new dwellings
-37.7143 - 0.8571
0.8571 - 3.4286
3.4286 - 6.4286
6.4286 - 12.8571
12.8571 - 225.4286

Source: Covec analysis of Statistics New Zealand & Vector data

Te Awamutu: Residential



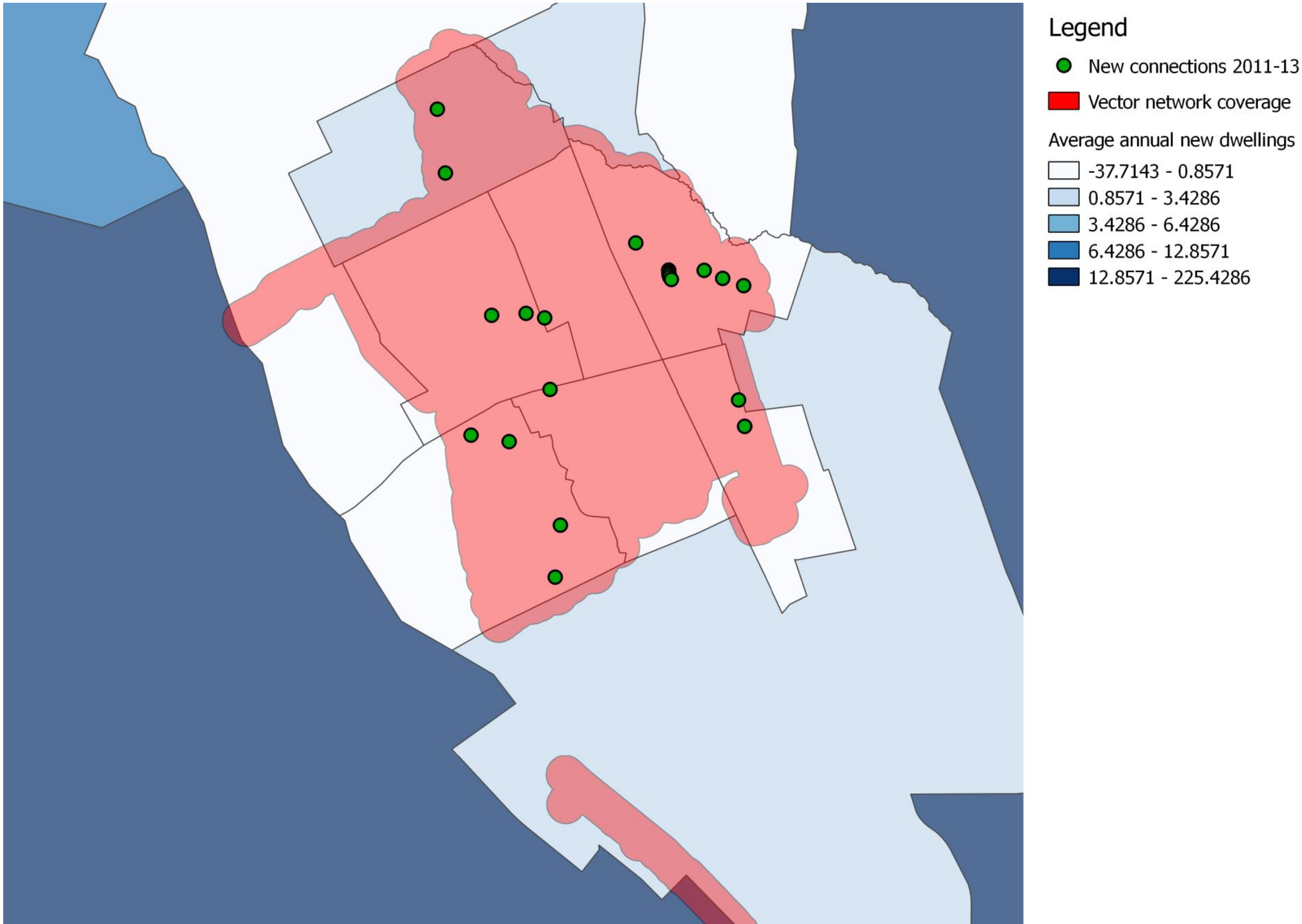




	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	21	14													
Low			14	13	12	11	10	9	9	8	8	7	7	7	7
Medium			16	15	14	13	12	11	11	10	10	10	9	9	9
High			18	17	16	15	14	13	13	12	12	12	11	11	11

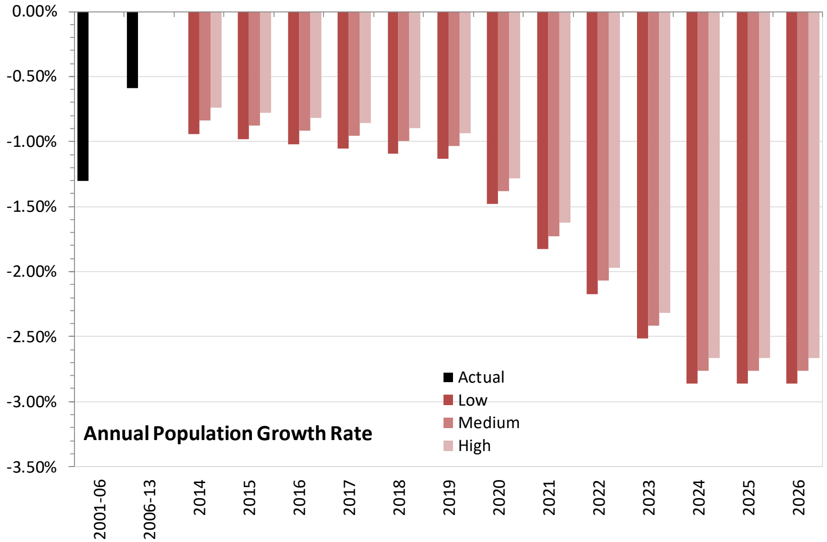
Source: Covec analysis of Statistics New Zealand & Vector data

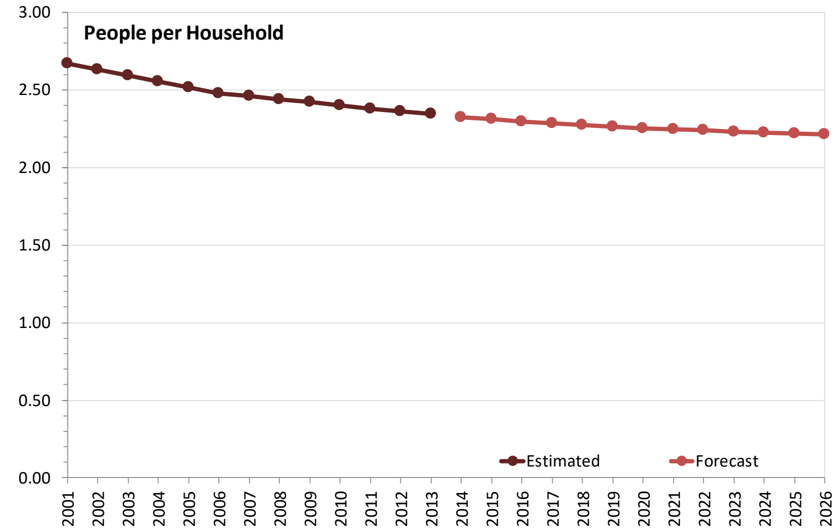
Tokoroa



Source: Covec analysis of Statistics New Zealand & Vector data

Tokoroa: Residential

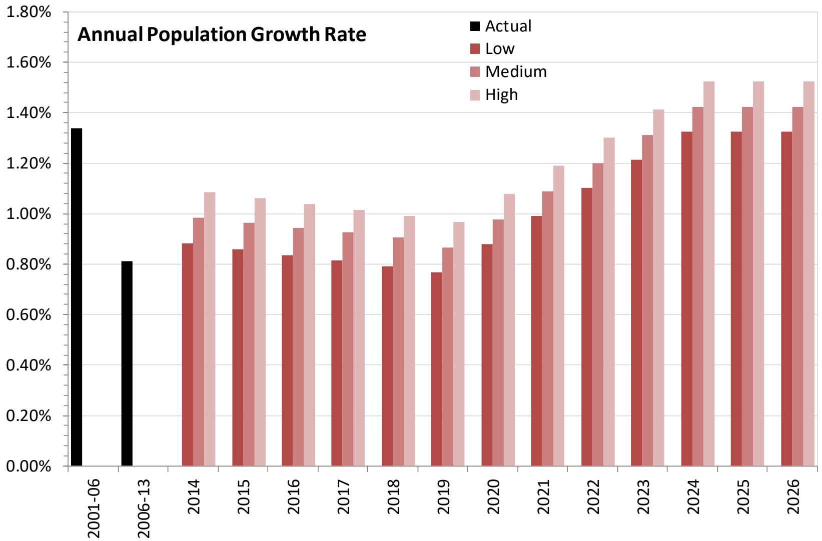


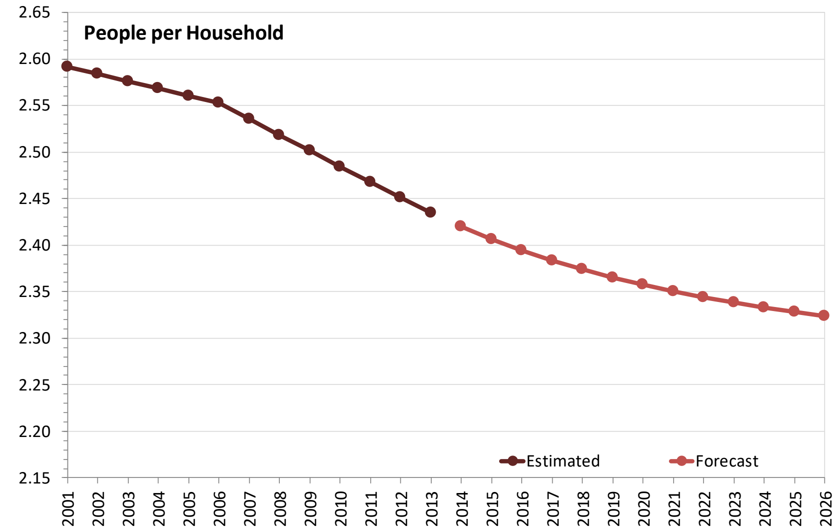


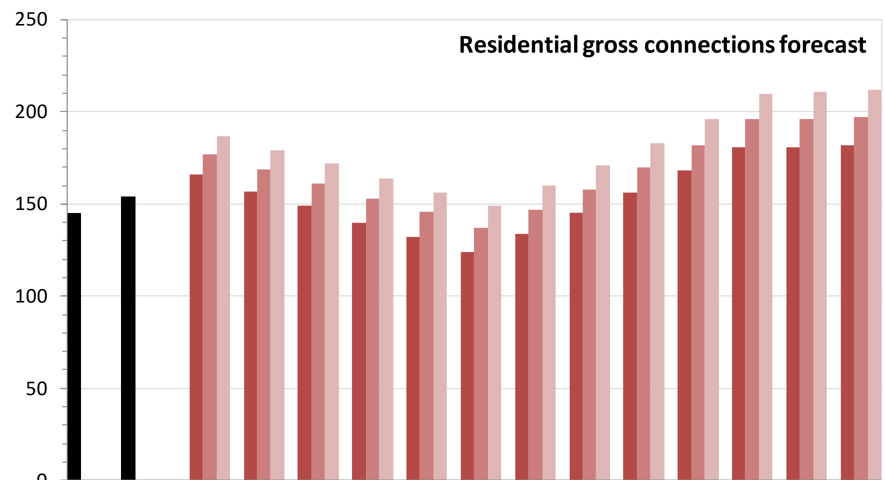
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	1	12													
Low			4	4	4	4	3	3	3	3	3	3	3	3	3
Medium			7	7	7	7	7	7	7	7	7	7	7	7	7
High			11	11	10	10	10	10	10	10	10	10	10	10	10

Source: Covec analysis of Statistics New Zealand & Vector data

All other areas: Residential

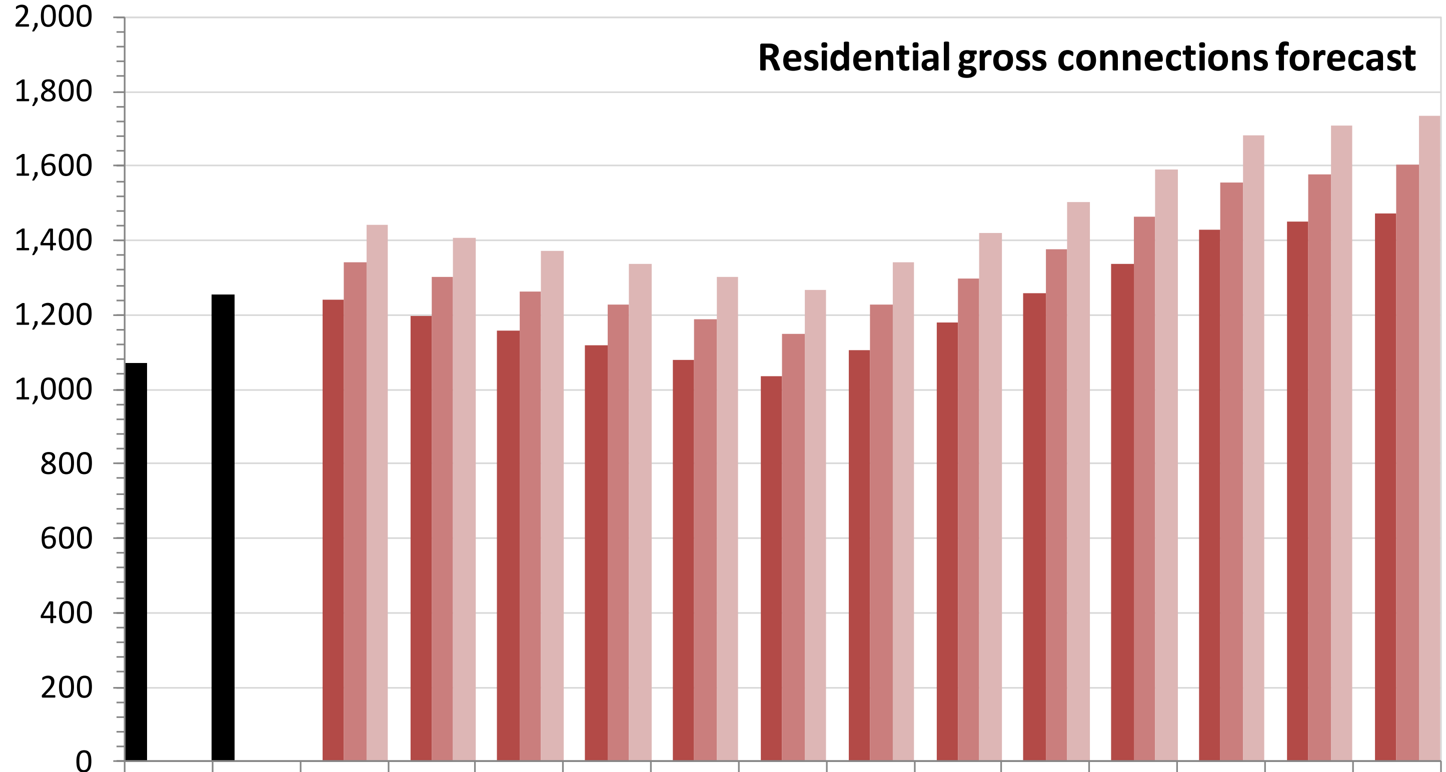






	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	145	154													
Low			166	157	149	140	132	124	134	145	156	168	181	181	182
Medium			177	169	161	153	146	137	147	158	170	182	196	196	197
High			187	179	172	164	156	149	160	171	183	196	210	211	212

Residential total



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Actual	1,069	1,252													
Low			1,241	1,199	1,159	1,118	1,078	1,035	1,107	1,180	1,259	1,338	1,430	1,451	1,474
Medium			1,343	1,304	1,264	1,228	1,190	1,151	1,226	1,299	1,378	1,464	1,555	1,578	1,602
High			1,444	1,408	1,371	1,336	1,301	1,265	1,340	1,418	1,503	1,590	1,682	1,707	1,736

Residential summary: Low

Area	Actuals		Forecast												
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Whangarei	5	7	7	7	6	5	5	4	4	4	4	4	4	4	3
Whangaparoa	118	213	242	244	245	245	245	244	246	248	250	251	251	258	265
Cambridge	65	63	54	49	44	38	33	27	28	29	31	32	33	33	33
Hamilton	439	477	454	435	417	400	382	364	398	432	469	506	545	553	561
Rotorua	31	41	46	40	34	29	24	19	14	10	6	1	0	0	0
Taupo	32	24	25	23	21	19	17	15	13	10	8	6	5	4	3
Tauranga	87	107	100	97	94	91	88	84	98	112	127	142	159	161	164
Mt Maunganui	50	67	64	67	71	75	79	83	92	101	110	120	131	134	138
Whakatane	0	2	1	0	0	0	0	0	0	0	0	0	0	0	0
Gisborne	16	14	15	13	11	9	8	6	4	2	0	0	0	0	0
Paraparaumu	46	45	36	35	34	33	31	30	37	44	50	57	64	65	66
Waikanae	13	12	13	15	17	19	21	23	27	32	37	41	47	48	49
Te Awamutu	21	14	14	13	12	11	10	9	9	8	8	7	7	7	7
Tokoroa	1	12	4	4	4	4	3	3	3	3	3	3	3	3	3
Other	42	38	166	157	149	140	132	124	134	145	156	168	181	181	182
Total	**966**	**1,136**	**1,241**	**1,199**	**1,159**	**1,118**	**1,078**	**1,035**	**1,107**	**1,180**	**1,259**	**1,338**	**1,430**	**1,451**	**1,474**

Source: Covec analysis of Statistics New Zealand & Vector data

Residential summary: High

Area	Actuals		Forecast												
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Whangarei	5	7	10	9	9	8	8	7	7	7	7	6	6	6	6
Whangaparoa	118	213	271	273	275	277	277	278	281	284	287	289	291	298	306
Cambridge	65	63	61	56	51	46	41	35	36	38	39	40	42	42	43
Hamilton	439	477	518	502	485	469	453	437	472	509	548	588	630	641	652
Rotorua	31	41	63	57	51	46	41	36	32	27	23	19	15	13	12
Taupo	32	24	31	29	26	25	23	21	19	17	15	13	11	10	9
Tauranga	87	107	114	111	109	106	103	100	114	129	144	161	178	181	185
Mt Maunganui	50	67	73	77	81	85	90	94	103	113	123	134	145	149	153
Whakatane	0	2	2	2	2	1	1	1	1	0	0	0	0	0	0
Gisborne	16	14	20	18	16	15	13	12	9	7	5	3	1	0	0
Paraparaumu	46	45	48	48	47	46	45	44	51	57	65	72	79	81	82
Waikanae	13	12	17	19	21	23	26	28	32	37	42	47	53	54	55
Te Awamutu	21	14	18	17	16	15	14	13	13	12	12	12	11	11	11
Tokoroa	1	12	11	11	10	10	10	10	10	10	10	10	10	10	10
Other	42	38	187	179	172	164	156	149	160	171	183	196	210	211	212
Total	**966**	**1,136**	**1,444**	**1,408**	**1,371**	**1,336**	**1,301**	**1,265**	**1,340**	**1,418**	**1,503**	**1,590**	**1,682**	**1,707**	**1,736**

Source: Covec analysis of Statistics New Zealand & Vector data

Residential: Greenfields proportions

Analysis area	2012	2013	Average
Whangarei	0%	14%	7%
Whangaparoa	75%	91%	83%
Cambridge	71%	83%	77%
Hamilton	77%	65%	71%
Rotorua	35%	41%	38%
Taupo	69%	83%	76%
Tauranga	78%	83%	81%
Mt Maunganui	56%	63%	59%
Whakatane	0%	0%	0%
Gisborne	19%	36%	27%
Paraparaumu	70%	76%	73%
Waikanae	23%	17%	20%
Te Awamutu	38%	64%	51%
Tokoroa	0%	0%	0%
Other	50%	66%	58%
All areas	**69%**	**71%**	**70%**

Source: Covec analysis of Vector data

Available data: SME and I&C

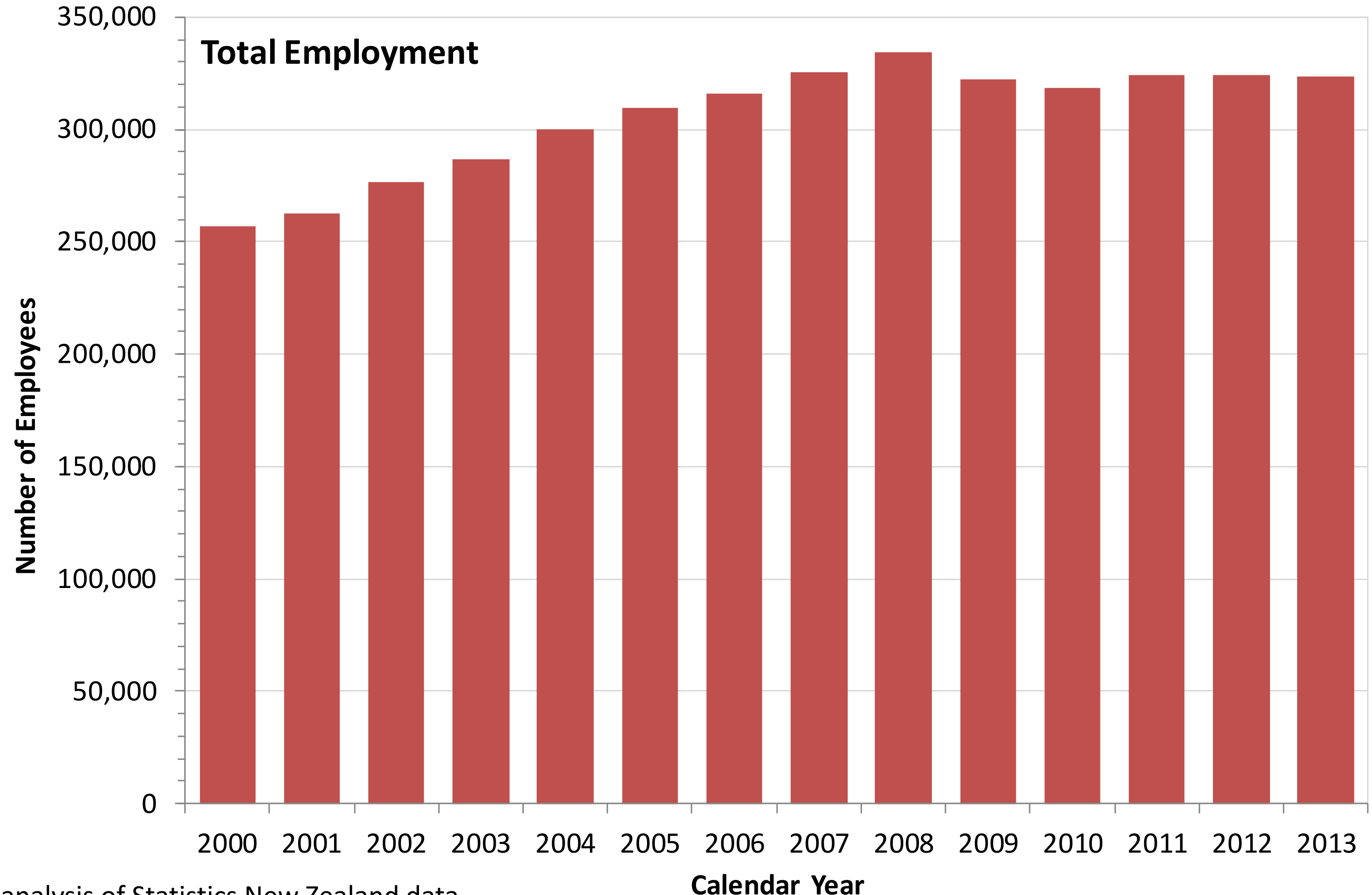
- New connections to Vector's gas network in the two years to June 2013 by geographic location
- Employment and number of business units by Census Area Unit to June 2013
- Non-residential building consents by Census Area Unit to December 2013

Methodology: SME and I&C

- Analyse Census Area Units overlapping with Vector's gas network coverage in each area
- Recent trends in employment, business units, and building consents in relevant CAUs used to determine overall trend in non-residential connections
- Total non-residential connections disaggregated into SME and I&C and by location based on distribution of connections in 2012 & 2013
  - Small number of connections in individual areas may limit the accuracy of the disaggregated forecasts

Employment: Total

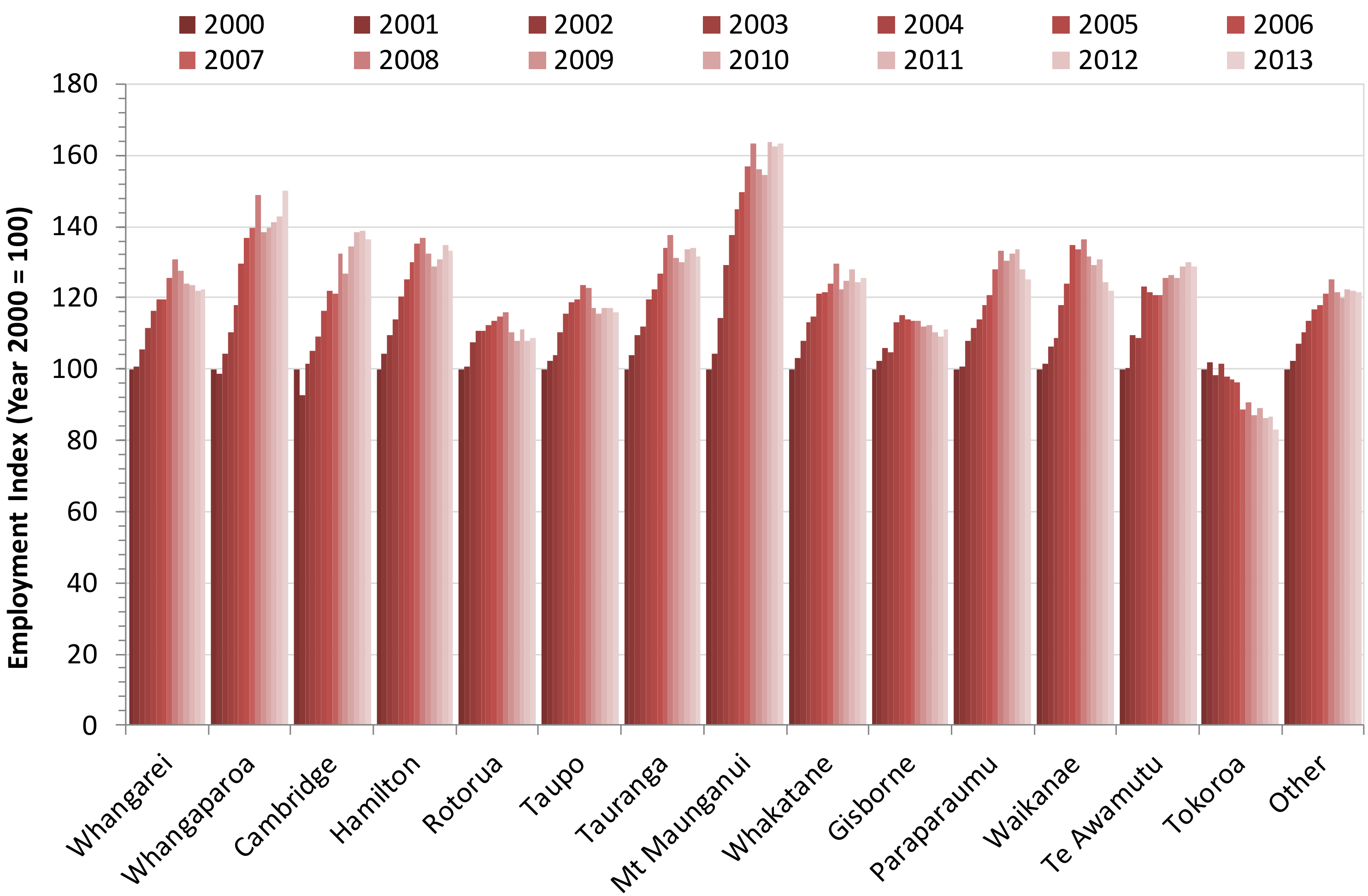
Total employment in areas covered by Vector's gas network has been static since 2009



Source: Covec analysis of Statistics New Zealand data

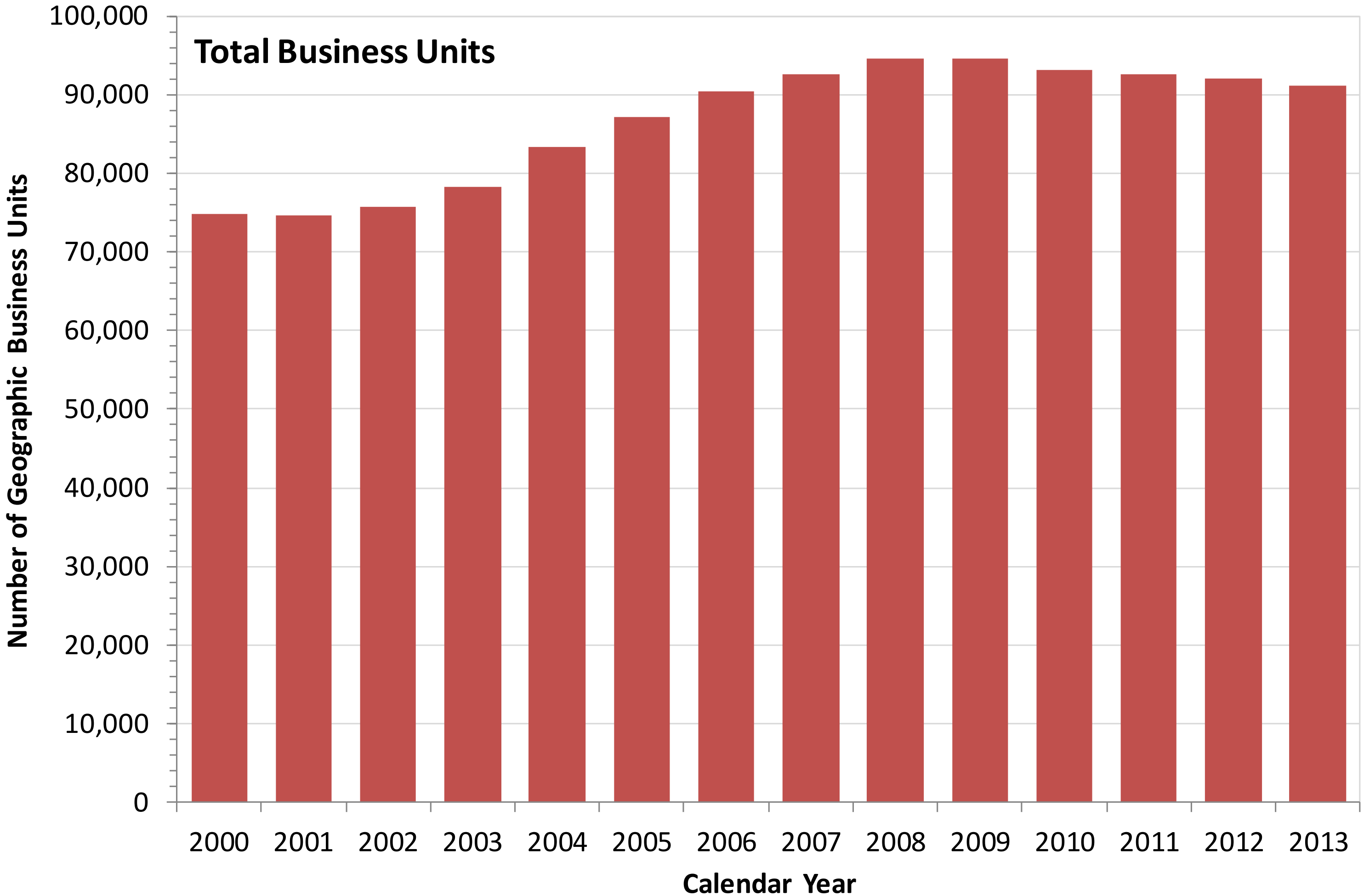
Employment: By Geographic Area

Consistent pattern of flat or declining employment in most areas since 2009



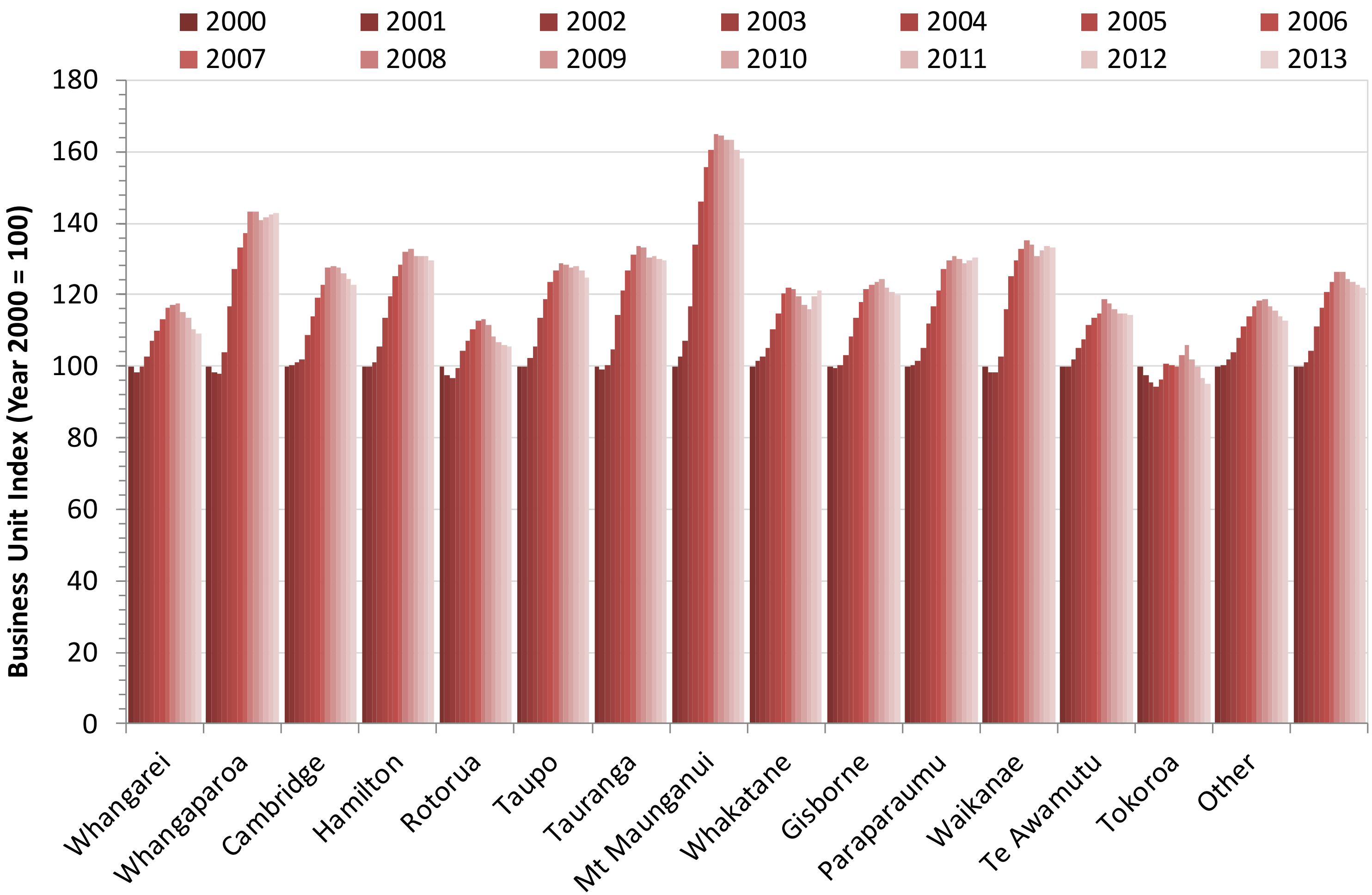
Business Units: Total

Number of business units in areas covered by Vector's gas network has been declining since 2009



Business Units: By Geographic Area

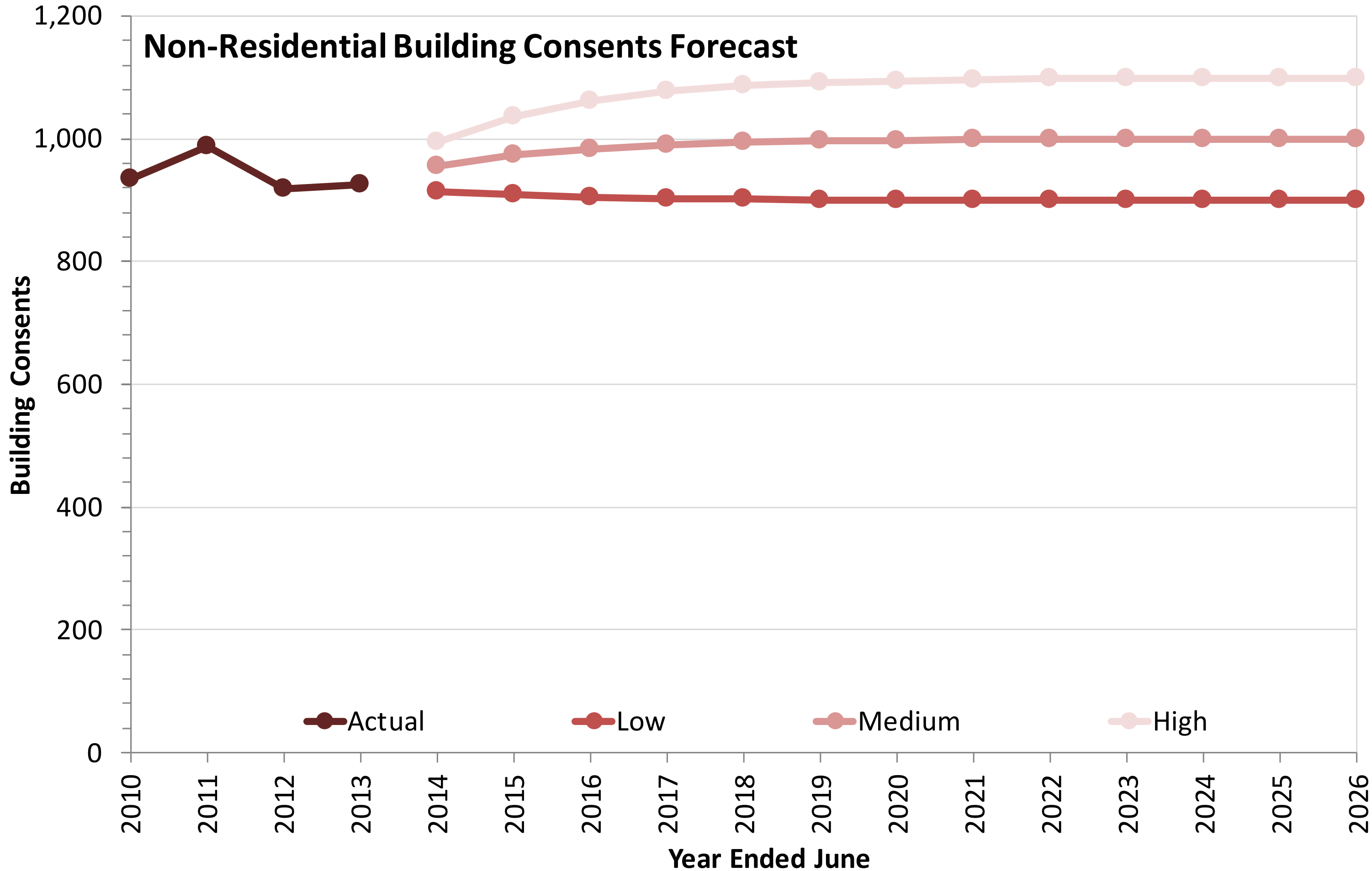
Similar consistency in flat or declining number of business units across regions



Source: Covec analysis of Statistics New Zealand data

Building Consents Forecast

Assume non-residential consents will gradually recover to 2011 levels in the medium scenario



SME Forecast Breakdown: Low

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Whangarei	0	0	0	0	0	0	0	0	0	0	0	0	0
Whangaparoa	3	3	3	3	3	3	3	3	3	3	3	3	3
Cambridge	1	1	1	1	1	1	1	1	1	1	1	1	1
Hamilton	15	14	14	14	14	14	14	14	14	14	14	14	14
Rotorua	2	2	2	2	2	2	2	2	2	2	2	2	2
Taupo	4	4	4	4	4	4	4	4	4	4	4	4	4
Tauranga	4	4	4	4	4	4	4	4	4	4	4	4	4
Mt Maunganui	1	1	1	1	1	1	1	1	1	1	1	1	1
Whakatane	1	1	1	1	1	1	1	1	1	1	1	1	1
Gisborne	1	0	0	0	0	0	0	0	0	0	0	0	0
Paraparaumu	1	1	1	1	1	1	1	1	1	1	1	1	1
Waikanae	1	1	1	1	1	1	1	1	1	1	1	1	1
Te Awamutu	0	0	0	0	0	0	0	0	0	0	0	0	0
Tokoroa	1	0	0	0	0	0	0	0	0	0	0	0	0
Other	4	4	4	4	4	4	4	4	4	4	4	4	4
Total	**38**	**37**	**37**	**37**	**37**	**37**	**37**	**37**	**37**	**37**	**37**	**37**	**37**

Source: Covec analysis of Statistics New Zealand & Vector data

SME Forecast Breakdown: Medium

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Whangarei	0	0	0	0	0	0	0	0	0	0	0	0	0
Whangaparoa	3	3	3	3	3	3	3	3	3	3	3	3	3
Cambridge	1	1	1	1	1	1	1	1	1	1	1	1	1
Hamilton	15	15	15	15	16	16	16	16	16	16	16	16	16
Rotorua	2	2	2	2	2	2	2	2	2	2	2	2	2
Taupo	4	4	4	4	4	4	4	4	4	4	4	4	4
Tauranga	4	4	4	4	4	4	4	4	4	4	4	4	4
Mt Maunganui	1	1	1	1	1	1	1	1	1	1	1	1	1
Whakatane	1	1	1	1	1	1	1	1	1	1	1	1	1
Gisborne	1	1	1	1	1	1	1	1	1	1	1	1	1
Paraparaumu	1	1	1	1	1	1	1	1	1	1	1	1	1
Waikanae	1	1	1	1	1	1	1	1	1	1	1	1	1
Te Awamutu	0	0	0	0	0	0	0	0	0	0	0	0	0
Tokoroa	1	1	1	1	1	1	1	1	1	1	1	1	1
Other	4	4	4	4	4	4	4	4	4	4	4	4	4
Total	**38**	**39**	**40**	**40**	**40**	**40**	**41**	**41**	**41**	**41**	**41**	**41**	**41**

Source: Covec analysis of Statistics New Zealand & Vector data

SME Forecast Breakdown: High

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Whangarei	0	0	0	0	0	0	0	0	0	0	0	0	0
Whangaparoa	3	3	3	3	4	4	4	4	4	4	4	4	4
Cambridge	1	1	1	1	1	1	1	1	1	1	1	1	1
Hamilton	15	16	16	17	17	17	17	17	17	17	17	17	17
Rotorua	2	2	2	2	2	2	2	2	2	2	2	2	2
Taupo	4	4	5	5	5	5	5	5	5	5	5	5	5
Tauranga	4	4	5	5	5	5	5	5	5	5	5	5	5
Mt Maunganui	1	1	1	1	1	1	1	1	1	1	1	1	1
Whakatane	1	1	1	1	1	1	1	1	1	1	1	1	1
Gisborne	1	1	1	1	1	1	1	1	1	1	1	1	1
Paraparaumu	1	1	1	1	1	1	1	1	1	1	1	1	1
Waikanae	1	1	1	1	1	1	1	1	1	1	1	1	1
Te Awamutu	0	0	0	0	0	0	0	0	0	0	0	0	0
Tokoroa	1	1	1	1	1	1	1	1	1	1	1	1	1
Other	4	4	5	5	5	5	5	5	5	5	5	5	5
Total	**38**	**40**	**42**	**43**	**44**	**44**	**44**	**45**	**45**	**45**	**45**	**45**	**45**

Source: Covec analysis of Statistics New Zealand & Vector data

I&C Forecast Breakdown: Low

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Whangarei	2	2	2	2	2	2	2	2	2	2	2	2	2
Whangaparoa	2	1	1	1	1	1	1	1	1	1	1	1	1
Cambridge	2	1	1	1	1	1	1	1	1	1	1	1	1
Hamilton	24	24	24	24	24	23	23	23	23	23	23	23	23
Rotorua	4	4	4	4	4	4	4	4	4	4	4	4	4
Taupo	1	1	1	1	1	1	1	1	1	1	1	1	1
Tauranga	7	6	6	6	6	6	6	6	6	6	6	6	6
Mt Maunganui	4	4	4	4	4	4	4	4	4	4	4	4	4
Whakatane	3	2	2	2	2	2	2	2	2	2	2	2	2
Gisborne	3	2	2	2	2	2	2	2	2	2	2	2	2
Paraparaumu	3	2	2	2	2	2	2	2	2	2	2	2	2
Waikanae	1	0	0	0	0	0	0	0	0	0	0	0	0
Te Awamutu	2	1	1	1	1	1	1	1	1	1	1	1	1
Tokoroa	4	4	4	4	4	4	4	4	4	4	4	4	4
Other	8	8	8	8	8	8	8	8	8	8	8	8	8
Total	**66**	**66**	**65**	**65**	**65**	**65**	**65**	**64**	**64**	**64**	**64**	**64**	**64**

Source: Covec analysis of Statistics New Zealand & Vector data

I&C Forecast Breakdown: Medium

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Whangarei	2	2	2	2	2	2	2	2	2	2	2	2	2
Whangaparoa	2	2	2	2	2	2	2	2	2	2	2	2	2
Cambridge	2	2	2	2	2	2	2	2	2	2	2	2	2
Hamilton	24	25	25	26	26	26	26	26	26	26	26	26	26
Rotorua	4	4	4	4	4	4	4	4	4	4	4	4	4
Taupo	1	1	1	1	1	1	1	1	1	1	1	1	1
Tauranga	7	7	7	7	7	7	7	7	7	7	7	7	7
Mt Maunganui	4	4	4	4	4	4	4	4	4	4	4	4	4
Whakatane	3	3	3	3	3	3	3	3	3	3	3	3	3
Gisborne	3	3	3	3	3	3	3	3	3	3	3	3	3
Paraparaumu	3	3	3	3	3	3	3	3	3	3	3	3	3
Waikanae	1	1	1	1	1	1	1	1	1	1	1	1	1
Te Awamutu	2	2	2	2	2	2	2	2	2	2	2	2	2
Tokoroa	4	4	4	4	4	4	4	4	4	4	4	4	4
Other	8	8	8	9	9	9	9	9	9	9	9	9	9
Total	**66**	**68**	**70**	**70**	**71**	**71**	**71**	**71**	**72**	**72**	**72**	**72**	**72**

Source: Covec analysis of Statistics New Zealand & Vector data

I&C Forecast Breakdown: High

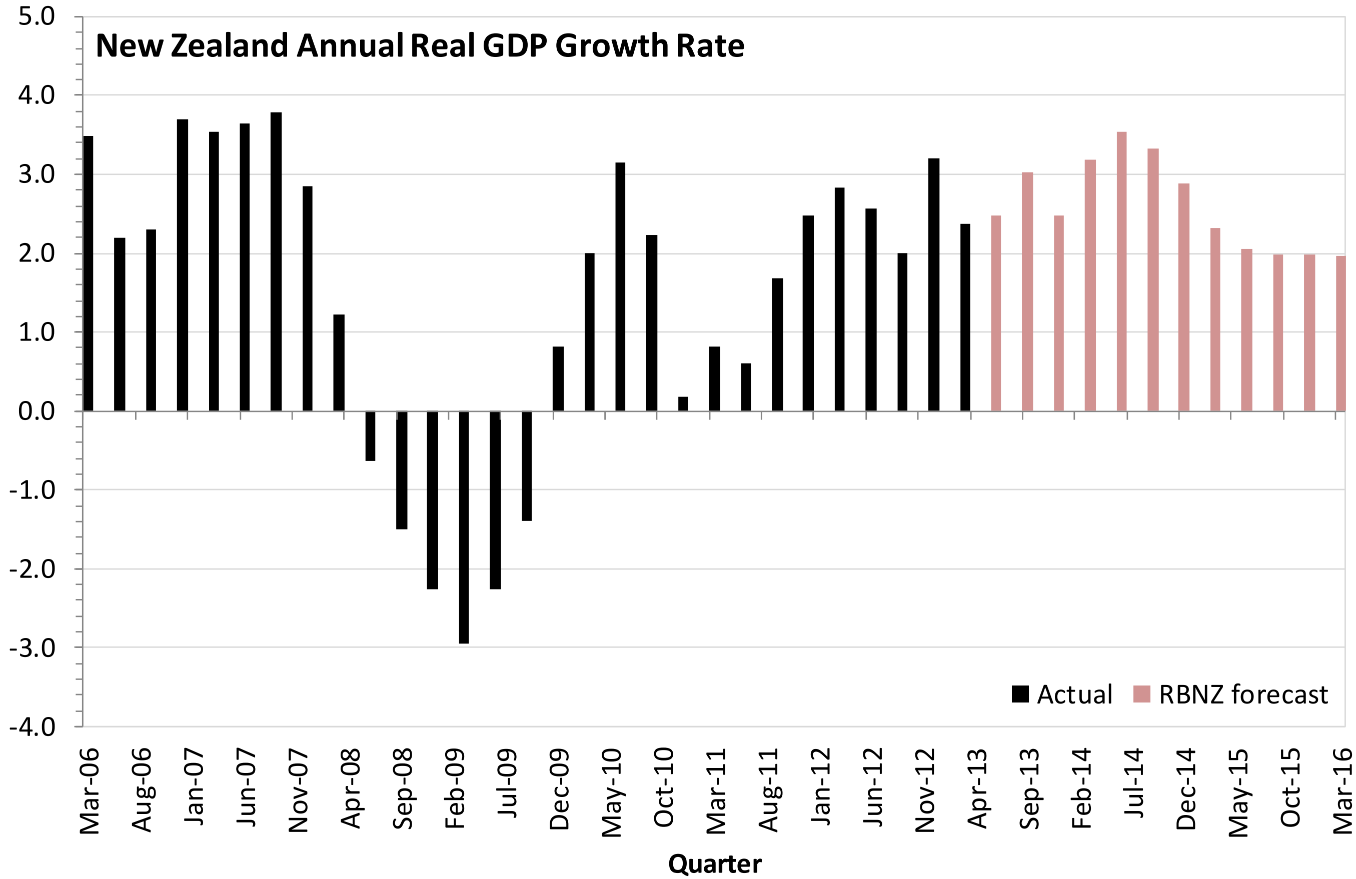
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Whangarei	2	2	2	2	2	2	2	2	2	2	2	2	2
Whangaparoa	2	2	2	2	2	2	2	2	2	2	2	2	2
Cambridge	2	2	2	2	2	2	2	2	2	2	2	2	2
Hamilton	24	26	27	28	28	28	28	29	29	29	29	29	29
Rotorua	4	4	5	5	5	5	5	5	5	5	5	5	5
Taupo	1	1	1	1	1	1	1	1	1	1	1	1	1
Tauranga	7	7	7	7	8	8	8	8	8	8	8	8	8
Mt Maunganui	4	4	5	5	5	5	5	5	5	5	5	5	5
Whakatane	3	3	3	3	3	3	3	3	3	3	3	3	3
Gisborne	3	3	3	3	3	3	3	3	3	3	3	3	3
Paraparaumu	3	3	3	3	3	3	3	3	3	3	3	3	3
Waikanae	1	1	1	1	1	1	1	1	1	1	1	1	1
Te Awamutu	2	2	2	2	2	2	2	2	2	2	2	2	2
Tokoroa	4	4	5	5	5	5	5	5	5	5	5	5	5
Other	8	9	9	9	9	9	9	10	10	10	10	10	10
Total	**66**	**71**	**74**	**76**	**77**	**78**	**78**	**78**	**79**	**79**	**79**	**79**	**79**

Source: Covec analysis of Statistics New Zealand & Vector data

Appendix: Context & further details

Context: National economy

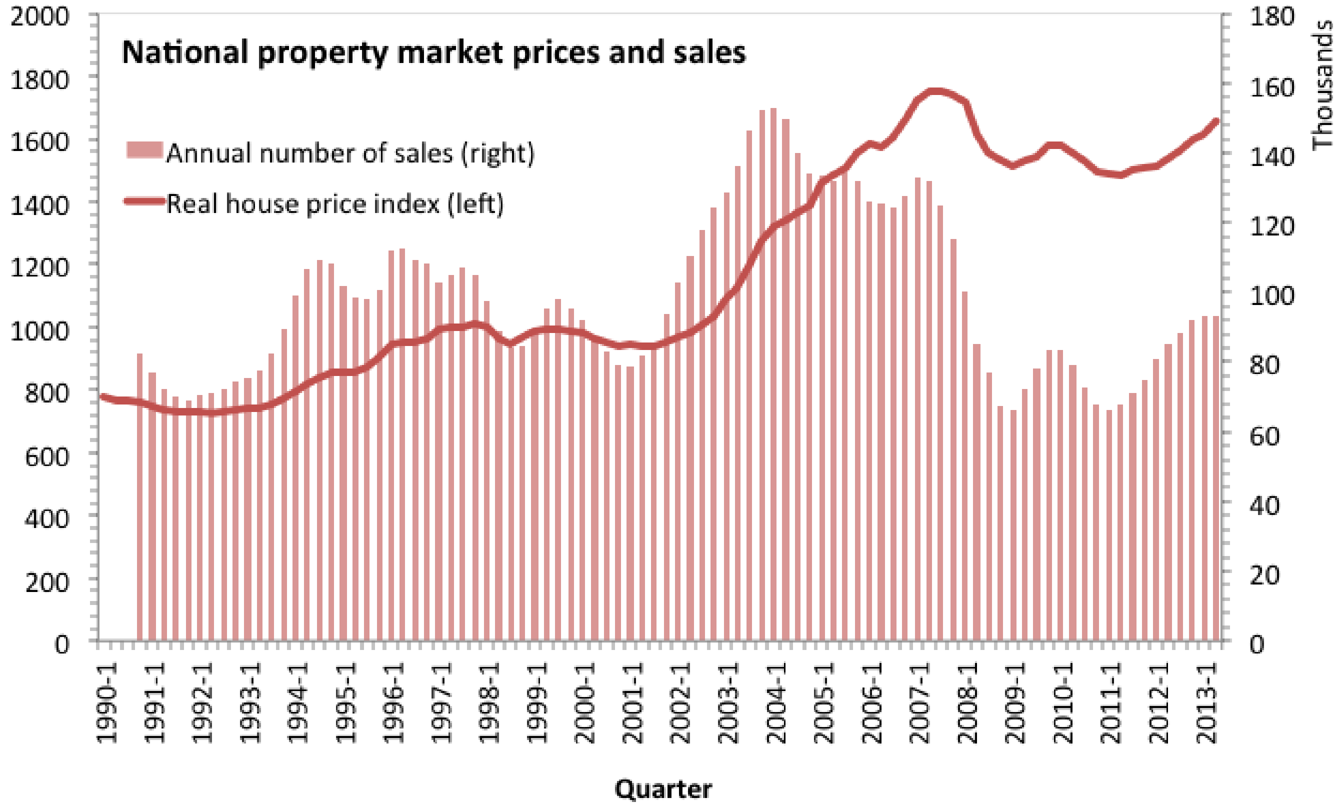
The economy has recovered from the GFC and real GDP growth rates of 2 – 3.5% are expected over the next three years



Source: Reserve Bank

Context: Property market

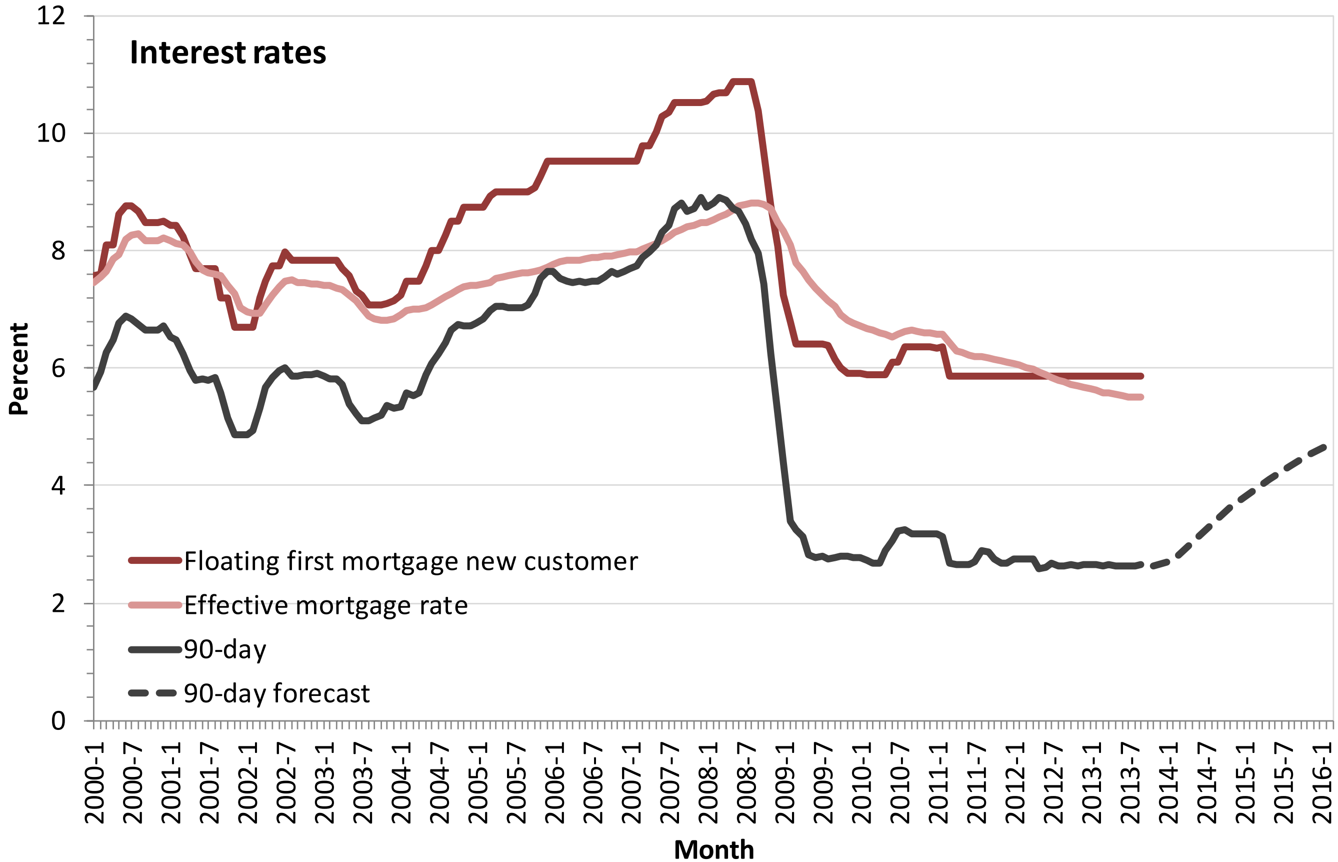
National house prices remain high, while the number of sales has not recovered to pre-GFC levels



Source: Reserve Bank

Context: Property market

Mortgage interest rates are low and expected to increase but remain relatively low in the medium term



Source: Reserve Bank

Appendix J: Revised customer connection capex forecasts

Level 1 - AMP Category	Level 2 - AMP Asset Type	Level 3a (internal) ID 1	Level 3b (internal) ID 2	FY17	FY18	FY19	DPP Forecast FY20	FY21	FY22	FY23	Additional Information Overall Description of Forecast	Costing or Units	Cost Basis
Consumer Connection (Total)				3,320,284	2,493,962	2,592,284	2,692,075	2,796,205	2,911,960	3,028,647			
Mains Extensions/Subdivisions				2,491,962	1,583,524	1,680,128	1,775,117	1,878,021	1,990,349	2,110,526			
Consumer connection	Medium Pressure	Mains Pipe	Subdivisions/Mains Extensions	2,491,962	1,583,524	1,680,128	1,775,117	1,878,021	1,990,349	2,110,526	Original forecast base used		Based on original forecast
Service Connections - Residential				859,992	866,179	872,366	878,553	884,740	890,927	893,766			
Consumer connection	Medium Pressure	Service Pipe Residential connections	>15M connection	394,610.44	397,449.36	400,288.28	403,127.21	405,966.13	408,805.06	411,643.98	Expected gross customer connections forecast 70%	3,154	Unit price per connection
		Service Pipe Residential connections	<15M Ccnnection	465,382.01	468,730.08	472,078.15	475,426.22	478,774.30	482,122.37	482,122.37		1,594	
Service Connections - Commercial				191,637	195,322	199,007	206,378	210,063	217,434	221,119			
Consumer connection	Medium Pressure	Service Pipe	Commercial connections	191,637	195,322	199,007	206,378	210,063	217,434	221,119	Expected gross customer connections forecast. Applying applied growth figures original forecast was flat	3685.32194	Unit price per connection
Customer Easements				42,000	42,504	43,014	43,530	44,053	44,581	45,116			
Consumer connection	Medium Pressure	Service Pipe	Easement costs	42,000	42,504	43,014	43,530	44,053	44,581	45,116	Expected gross customer connections forecast Anticipated spend $3k to $4k per month + T/W (fY17), then increase 1.2%		
Less: Capital Contributions Funding Consumer Connection				265,307	193,568	202,232	211,504	220,672	231,331	241,881			
Consumer Connections		Residential connections (7%)	7%	27,622.73	27,821.46	28,020.18	28,218.90	28,417.63	28,616.35	28,815.08			
		Subdivisions/Mains Extensions (8%)	8%	199,356.97	126,681.92	134,410.27	142,009.35	150,241.69	159,227.91	168,842.11			
		Commercial connections (20%	20%	38,327.35	39,064.41	39,801.48	41,275.61	42,012.67	43,486.80	44,223.86			

Connection rates

Level 1 - AMP Category	Level 2 - AMP Asset Type	Level 3a (internal) ID 1	Level 3b (internal) ID 2	FY17	FY18	FY19	DPP Forecast FY20	FY21	FY22	FY23	Assumptions
Consumer Connection (Total)				469	473	477	482	486	491	493	
Mains Extensions/Subdivisions Totoal Connections				0	0	0	0	0	0	0	
Consumer connection	Subdivisions/Mains Extensions										Used low Non-Auckland forecast. Fall back alternative 38.75
Service Connections - Residential				417	420	423	426	429	432	433	
Consumer connection	Residential connections	> 15M connection	30	125	126	127	128	129	130	131	<15M connections
		<15M connection	70	292	294	296	298	300	302	302	>15M connection
Service Connections - Commercial				52	53	54	56	57	59	60	Expected gross customer connections Forecast
Consumer connection	Medium Pressure	Service Pipe	Commercial connections	59	59	60	61	62	63	64	
			Industrial	-7	-6	-6	-5	-5	-4	-4	

Appendix K: Cambridge options, network growth rate and network failure flow

5.10.10.2 Gate Stations

The Cambridge network system is fed from one gate station. The gate station winter peak demand statistics are summarised in Table 5-2.

5.10.10.3 District Regulating Stations

The Cambridge network system consists of three DRSs.

5.10.10.4 Pressure Systems

Cambridge IP20

The Cambridge IP20 pressure system operates at a NOP of 1,900kPa. The maximum flow into the system in the base year was 1,867scmh, resulting in a MinOP of 1,154kPa (61% of the NOP). Total forecast planning demand during the planning period is estimated to be 2,026scmh, resulting in a MinOP of 1,032kPa (54% of the NOP).

However, recent analysis of the potential load growth in Cambridge suggests that the system pressure will fall below the MinOP criteria during the planning period. Recently, Vector accepted a gas supply to a 280 lot residential subdivision in St Kilda Road which will be developed in various stages over the next five years. In addition, a couple of enquiries with considerable load requirements from prospective customers were received and have been processed recently. Gas demand is estimated to increase significantly over the next couple of years; hence, capacity constraints on the Cambridge IP20 are expected.

In order to meet the growth requirements in Cambridge, the following reinforcement options have been investigated:

IP20 pipeline option:

- Elevate the Harrisville gate station outlet pressure 1,800kPa (under investigation);
- Construct approximately 3,400 metres of 80mm IP20 steel pipeline from the Cambridge gate station along Zig Zag Road into Swayne Road; and
- Install a DRS (IP20/MP4) at 79 Swayne Road.

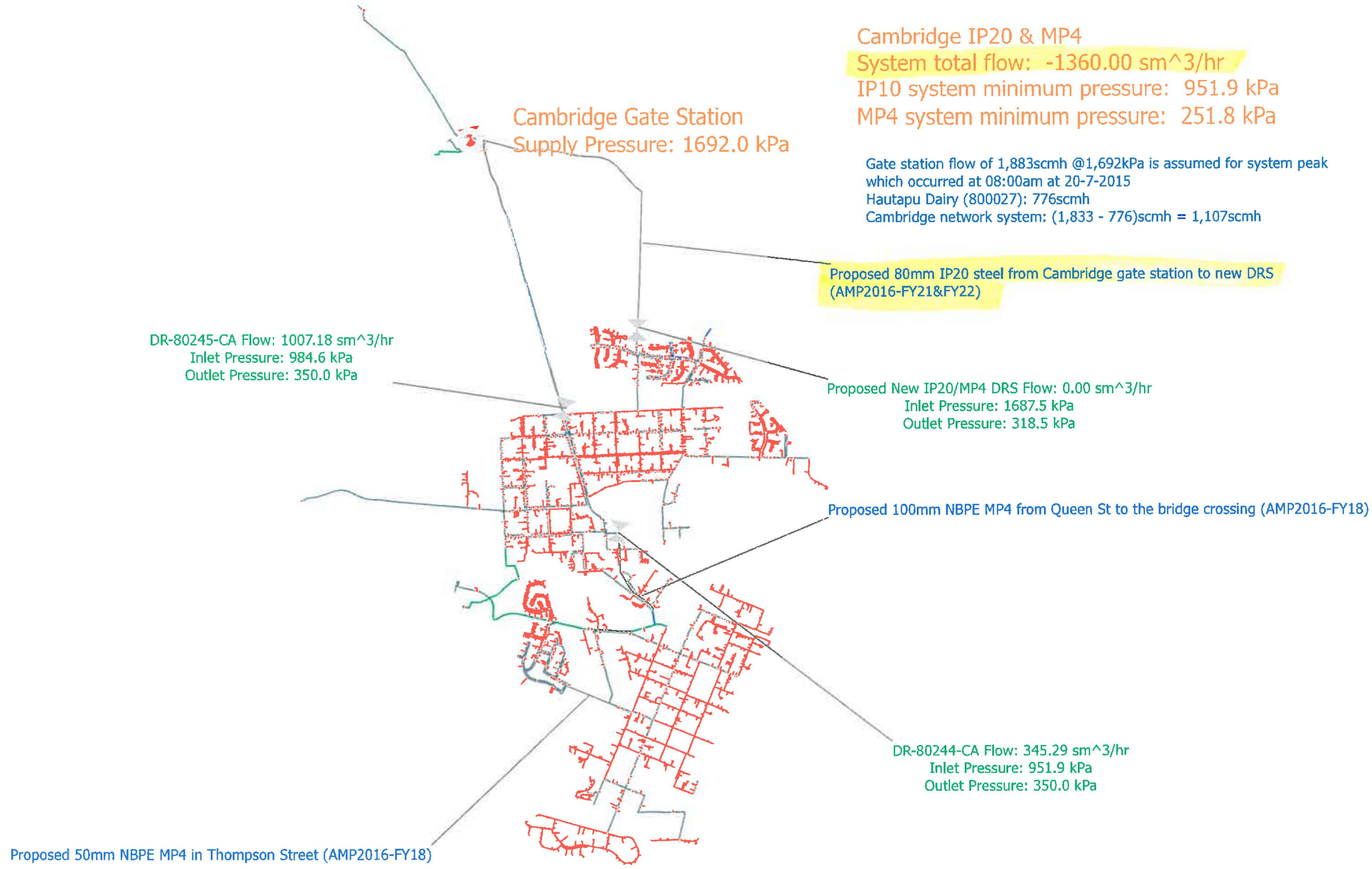
MP7 pipeline option:

- Construct approximately 4,050 metres of 110mm PE MP7 from the Cambridge gate station along Zig Zag Road and Watkins Road to the junction of St Kilda Road;
- Construct approximately 1,400 metres of 110mm PE MP7 in Swayne Road between Zig Zag Road and #79 Swayne Road; and
- Install two MP7/MP4 DRS at 79 Swayne Road and at the junction of Watkins Road and St Kilda Road.

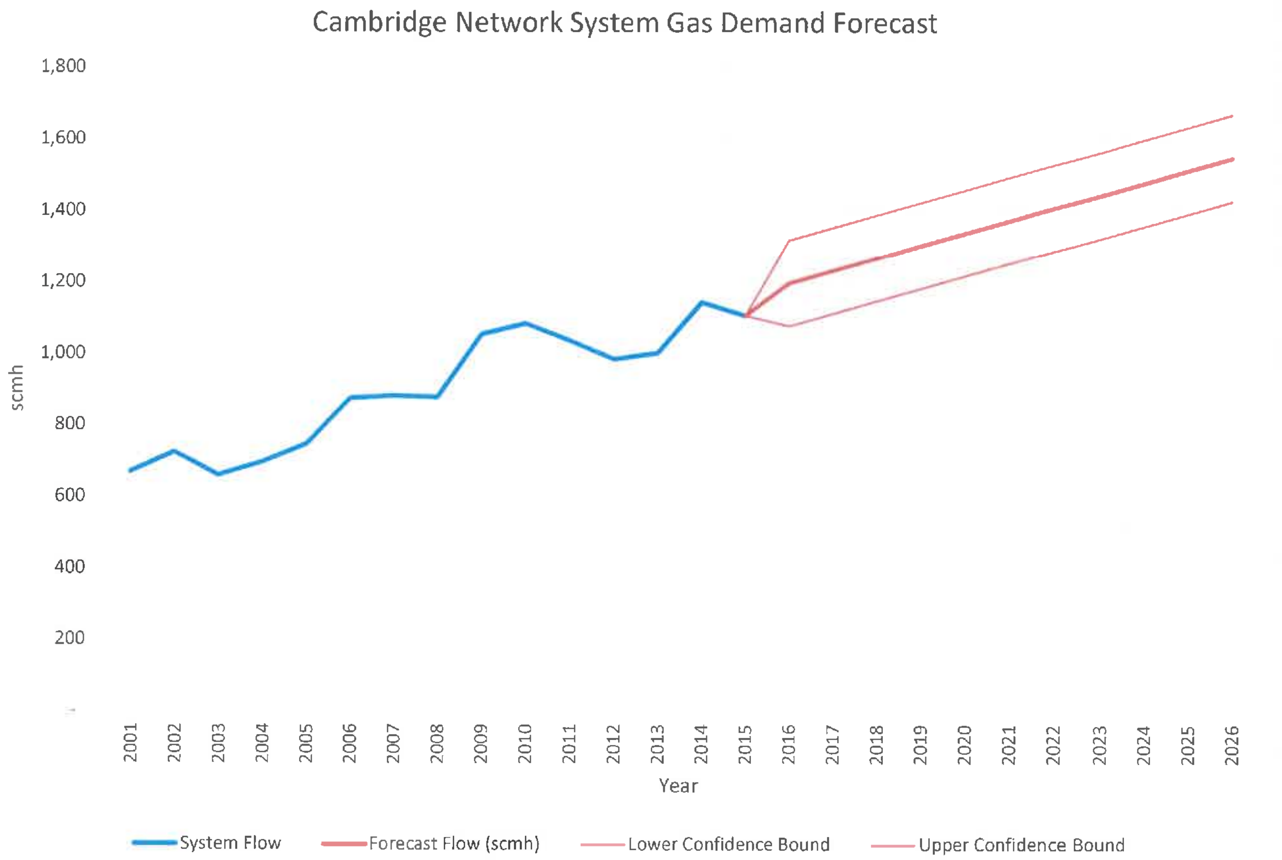
From the options considered, the IP20 pipeline reinforcements have been selected and included in the 10 year planning period.

Cambridge MP4

The Cambridge MP4 pressure system operates at a NOP of 400kPa. The maximum flow into the system in the base year was 1,052scmh, resulting in a MinOP of 308kPa (77% of the NOP). Total forecast planning demand during the planning period is estimated to be 1,142scmh, resulting in a MinOP of 301kPa (75% of the NOP). No constraints have been identified and the system pressure is not forecast to fall below the MinOP criteria during the planning period.


Cambridge IP20 & MP4
System total flow: -1360.00 sm^3/hr
IP10 system minimum pressure: 951.9 kPa
MP4 system minimum pressure: 251.8 kPa
Cambridge Gate Station
Supply Pressure: 1692.0 kPa
Gate station flow of 1,883scmh @1,692kPa is assumed for system peak which occurred at 08:00am at 20-7-2015
Hautapu Dairy (800027): 776scmh
Cambridge network system: (1,833 - 776)scmh = 1,107scmh
Proposed 80mm IP20 steel from Cambridge gate station to new DRS (AMP2016-FY21&FY22)
DR-80245-CA Flow: 1007.18 sm^3/hr
Inlet Pressure: 984.6 kPa
Outlet Pressure: 350.0 kPa
Proposed New IP20/MP4 DRS Flow: 0.00 sm^3/hr
Inlet Pressure: 1687.5 kPa
Outlet Pressure: 318.5 kPa
Proposed 100mm NBPE MP4 from Queen St to the bridge crossing (AMP2016-FY18)
DR-80244-CA Flow: 345.29 sm^3/hr
Inlet Pressure: 951.9 kPa
Outlet Pressure: 350.0 kPa
Proposed 50mm NBPE MP4 in Thompson Street (AMP2016-FY18)

Timeline	System Flow	Forecast Flow (scmh)	Lower Confidence Bound	Upper Confidence Bound
2001	669			
2002	724			
2003	659			
2004	696			
2005	746			
2006	875			
2007	881			
2008	878			
2009	1,054			
2010	1,084			
2011	1,037			
2012	985			
2013	1,002			
2014	1,144			
2015	1,107	1,107	1,107	1,107
2016		1,198	1,078	1,319
2017		1,234	1,113	1,354
2018		1,269	1,148	1,390
2019		1,304	1,183	1,425
2020		1,339	1,219	1,460
2021		1,375	1,254	1,495
2022		1,410	1,289	1,531
2023		1,445	1,324	1,566
2024		1,480	1,360	1,601
2025		1,516	1,395	1,636
2026		1,551	1,430	1,672



Appendix L: Vector projects mapped to First Gas

Vector projects mapped to First Gas Limited

	Vector 2015 AMP[1]					First Gas AMP				
Location	Reference	Project description	Capex estimate ($,000)	Schedule	Status at start of FY17	Reference	Project description	Capex estimate ($,000)	Proportion of Vector deferred from FY16	Schedule
Cambridge	Vector AMP 2015, section 5, page 98	Cambridge (i) 3.4km of 80mm IP from GS + 1DRS, or (ii) 5.5km of 110mm MP7 from GS + 2 new DRS)	$3,753	FY16 to FY18	Not commenced	Appendix F11	Construct approximately 3,400 metres of 80mm IP20 steel pipeline from the Cambridge gate station along Zig Zag Road into Swayne Road	$3,500	$1,251	FY21-22
Hamilton	Vector AMP 2015, section 5, page 98	Hamilton IP reinforcement - Te Kowhai gate station upgrade + IP uprating to 17 bar + DRS upgrade + New IP20/IP10 DRS	$1,797	FY16 to FY18	Not commenced	Appendix F6	Upgrading the existing IP pipeline from Te Kowhai gate station to Avalon Drive from 1,200kPa to 1,900kPa. Includes: • Uprating of pipeline • DRS130 and DRS145 upgrades • New IP20/IP10 DRS • Upgrades at Te Kowhai gate station	$1,800	$599	FY17-18
Hamilton	Vector AMP 2015, section 5, page 98	Hamilton MP4 - 400m of 100nb PE in Cambridge Rd from DR-80101-HM to Hillcrest Road, Hamilton	$72	FY16	Not commenced	Appendix F6	Construct approximately 400 metres of 100mm PE MP4 in Cambridge Road from the outlet of DR-80101-HM to Hillcrest Road and tie into the existing 80mm steel.	$200	$72	FY17
Mt Maunganui	Vector AMP 2015, section 5, page 99	"Mt Maunganui (Bakels) - 500 metres of 50 NB MP4 at the very end of the network supplying Bakels	$90	FY16	Not commenced	Appendix F27	Extend approximately 500 metres of 50mm PE MP4 pipeline in Maru/Te Maire Street.	$75	$90	FY17
Paraparaumu	Vector AMP 2015, section 5, page 100	Paraparaumu IP reinforcement - Uprate current operating pressure from 1350kPa to 1800kPa (including gate station upgrade) and DRS upgrade	$522	FY16	Not commenced	Appendix F39	Uprate the Paraparaumu IP20 pressure system from the current operating pressure of 1,350kPa to 1,800kPa (including the upgrade of the Paraparaumu gate station and DRS DR-80052-PR and DR-80081-PR upgrades).	$660	$522	FY17
Waitoa[2]	Vector AMP 2015, section 5, page 101	Waitoa MP4 reinforcements (Incremental extension of 160mm MP7 PE if required - 5000m initial extension)	$610	FY16 to FY17	Not commenced	Appendix F10	Extend approximately 5,000 metres of 160mm MP7 PE pipeline from the existing Waitoa MP7 pressure system to connect to a proposed MP7/MP4 DRS in Ngarua (stage 1).	$1,200	$305	FY18
Waitoa	Vector AMP 2015, section 5, page 101	Waitoa MP4 reinforcements (Incremental extension of 160mm MP7 PE if required - 5200m further extension)	$1264	FY16	Not commenced	Appendix F10	Extend approximately 5,200 metres of 160mm MP7 PE pipeline to the south of Waitoa and relocate a proposed new DRS to a new location to the end of the MP7 network (stage 2).	$1,200	$1,264	FY23

[1] All projects deferred from FY16 from previous Vector AMP that are required to be completed FY17 or future years. Pro-rated work deferred from FY16 (from Vector estimates) is approximately $4.1 million

[2] 2013 AMP originally planned for FY15-FY16, subsequently deferred.