Review of the Draft Decision on the Revised Initial Default Price-Quality Paths for Gas Pipeline Services

Report to Vector Limited

December 2012

Acronyms and Abbreviations

Capex	Capital Expenditure
CPI	Consumer Price Index
CPP	Customised Price-Quality Path
CSV	Composite Scale Value
DPP	Default Price-Quality Path
EDBs	Electricity Distribution Businesses
FFO	Funds From Operations
GDBs	Gas Distribution Businesses
GJ	Gigajoule
GPBs	Gas Pipeline Businesses
GTBs	Gas Transmission Businesses
ICPs	Installation Control Points
LCI	Labour Cost Index
NPV	Net Present Value
Opex	Operating Expenditure
PPI	Producer Price Index
RAB	Regulatory Asset Base
RCF	Residual Cash Flow
WACC	Weighted Average Cost of Capital

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Executive Summary

The Commerce Commission (the Commission) has published a Revised Initial Reset of the 2013-2017 Default Price Path (DPP) for gas pipeline businesses ("the revised initial reset"). Vector has engaged Castalia to evaluate the revised initial reset decision, and to comment on possible improvements to the way that future costs and revenues are modelled.

We identify several improvements that should be made to the way that the Commission evaluates the current and projected profitability of suppliers. These improvements can be made before a final decision on this gas price reset is released (expected 28 February 2013), and would provide greater confidence that the DPP reset represents a reliable estimate of future supplier costs and revenues.

Our recommendations are divided into three main areas:

- Operating expenditure projections
- Revenue projections (based on forecasts of demand for gas distribution businesses)
- Capital expenditure projections.

There are also important linkages between these projections. The Commission needs to ensure that the forecasting approaches adopted are internally consistent, and that the investments that need to be made are financeable by suppliers.

Operating expenditure forecasts are subject to a high level of uncertainty

The revised initial reset adopts the same components for opex projections that were included in the recent price reset for electricity distribution businesses. The Commission uses 2011 as a base year for projecting opex, and incorporates changes over time to reflect changes in input prices, changes in scale, and changes in partial productivity (assumed to be zero).

A major difference between the gas and electricity price resets is that the Commission has less information on the performance and costs of gas networks than is available for electricity. The Commission acknowledges that its projections are based on lower quality data inputs than were available for the electricity DPP reset decision. The Commission has been unable to conduct robust econometric analysis of cost drivers, and is therefore less confident about assumed relationships between scale and opex. The decision also fails to give a strong level of confidence that the base year is representative of an average annual cost.

Suppliers will be understandably concerned about the impacts of this uncertainty. If the opex allowance does not permit suppliers to recover their efficient operating costs then suppliers will earn lower returns than forecast by the Commission.

Using recent New Zealand and Australian data provides a more reliable estimate of the relationship between scale and opex for GDBs

The Commission has used evidence from the United Kingdom to estimate the relationship between scale and opex for GDBs. We have two concerns about the use of the Ofgem study of British gas distribution businesses to represent the relationship between scale and opex for New Zealand gas distributors:

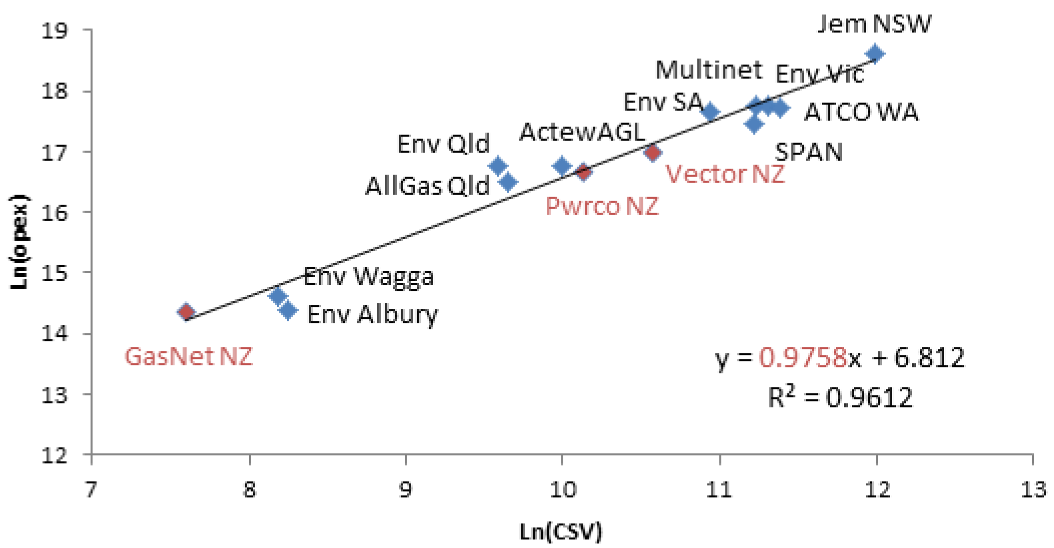
- Gas networks in the United Kingdom have very different scale characteristics to regulated suppliers in New Zealand. Gas distributors in the United

Kingdom have larger customer bases, a higher level of customer uptake, and serve a broader range of communities (New Zealand gas networks are concentrated in highly urbanised areas)

- The data used comes from 2006-2007, and is no longer used by the regulator in the United Kingdom for this purpose.

The relationship derived by Ofgem is simple to replicate. The analysis is based on drawing a trend line between supplier opex and a composite scale variable (CSV) that is weighted 50 percent towards changes in kilometres of pipeline and 50 percent towards customer numbers. We have replicated the Ofgem analysis using data from 2010 for New Zealand and Australian gas distributors. Our analysis shows that New Zealand gas distributors are more similar to the Australian gas distributors than the networks in the United Kingdom. New Zealand and Australia both have relatively low population densities, making gas networks cost effective in population centres only. In contrast, the gas networks in the United Kingdom cover medium density towns as well as major cities. Replicating the Ofgem analysis for New Zealand and Australia gas companies suggests that there is a stronger relationship between scale and opex in New Zealand and Australia than in the UK (as shown in Figure ES.1).

Figure ES.1: Aust/NZ Analysis of Relationship between Opex and Scale



Source: Data from "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators", Economic Insights, March 2012

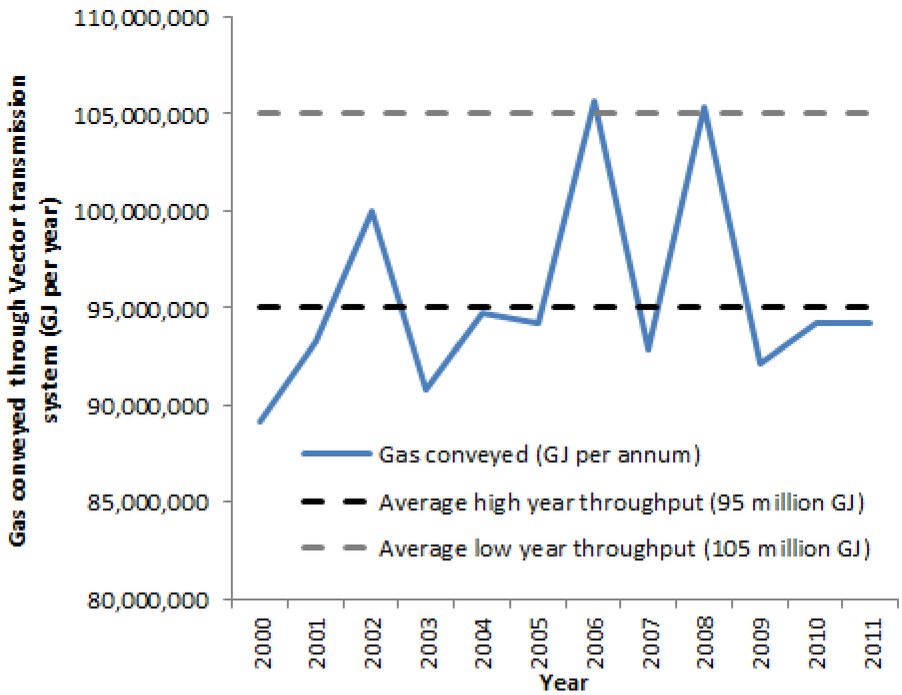
This analysis suggests that returns to scale are relatively constant in New Zealand and Australia (0.9758), whereas there are increasing returns to scale in the United Kingdom (0.7191). This reflects the fact that British gas distribution companies can connect new customers for less than the cost of connecting existing customers (the UK distribution network already covers most of the United Kingdom). In contrast, New Zealand and Australia have only developed gas networks in highly populated areas, so there are fewer scale benefits that come from extending the network that will lower the average cost of operating the network.

The base year used for transmission opex should be adjusted to reflect the likelihood that gas throughput will be higher in some years

The Commission states that a relationship is likely to exist between gas transmission opex and gas throughput (also known as gas conveyed). In the revised initial reset the Commission has set this relationship to zero, but has asked for submissions on how best to estimate this relationship.

In examining historical levels of gas throughput, we note that gas conveyed on the Vector transmission network appears to be concentrated around two levels: a more common low year average of around 95 million GJ per year, and an infrequent high level of around 105 million GJ per year (see Figure ES.2). We do not know the precise reason for this variation, but it is reasonable to expect that climate plays a significant role: colder weather will increase direct gas demand for heating, while also increasing demand for gas fired electricity generation. We find support for this relationship.

Figure ES.2: Historical Gas Conveyed through Vector Transmission Pipeline



Source: Information disclosures

The trends mean that transmission opex projections that use a base year of 2011 will not reflect any relationship between throughput and opex. Forward looking opex projections will therefore need to be adjusted to compensate suppliers for expected throughput, including the probability of a particularly cold or dry year creating large demand for gas.

Gas revenue forecasts have a very high degree of uncertainty, which creates risks for suppliers

The Commission uses Concept Consulting's Gas Supply and Demand Scenarios to project future demand for gas, which are used to forecast the revenue that gas distributors would earn at current prices. These scenarios have a very wide range, which creates material risks for suppliers.

If actual gas demand is lower than forecast, gas distributors will struggle to recover their costs, and will be reluctant to invest in their networks. This is detrimental for consumers, who will suffer less reliable gas supply in the future. In contrast, if actual demand is higher than forecast, gas distributors will earn more than the Commission's estimate of industry-wide WACC. This means consumers will be paying higher gas prices than were needed to incentive companies to invest in their networks. These consequences are asymmetric, suggesting than an allowance or explicit recognition of these risks is appropriate.

The Concept study focuses on drivers of supply, and does not forecast demand

The methodology used in the Concept study is focused on supply developments (exploration and production), and analyses how possible supply developments will influence future prices for natural gas. From our review of the Concept study and other available information (such as the current price of oil futures), we see little prospect of prices falling significantly over the regulatory period.

Focusing only on supply dynamics ignores factors that will affect demand for gas, such as:

- The price of substitutes like electricity. Even if natural gas prices fall, a larger fall in electricity prices would cause demand for gas to decrease
- Consumer attitudes towards gas as an energy source. If consumers are less inclined to install gas appliances in their homes (particularly in new property developments), then gas demand may fall irrespective of price.

The evidence on both of these demand drivers moderates our expectations of future gas demand.

- The price of wholesale electricity contracts is falling. After a period of increasing prices, wholesale electricity prices are currently subject to considerable downward pressure due to weak demand growth and low cost new build options. This is reflected in the lowest hedge contract electricity prices in the past 25 years.
- Consumer interest in new gas connections appears modest in areas where gas distribution networks are present. Historical evidence shows that demand for natural gas can be affected by changing consumer tastes and habits.

The Commission's approach to projecting capex is not sustainable

The Commission has adopted supplier's capex forecasts up to a cap of 20 percent above historical levels. The Commission notes that this does not drive significant differences between the revenues projected in the decision and the costs forecast by suppliers. However, most of the revenues required as a result of capex are earned outside of a single regulatory period, which means that getting capex estimates right remains important.

We are concerned that the Commission has failed to develop an approach to projecting capex that resolves the fundamental tension between:

- The fact that suppliers are the only party able to accurately forecast capex needs for their networks
- The fact that "RPI-X" style regulation creates an incentive to overstate capex to increase returns (if not deliberately, then at least when discretion is exercised in estimating costs).

The electricity DPP relied on asset management plans prepared by suppliers before they knew that their plans would be used for this purpose. The gas DPP caps allowances at

20 percent above historical levels, but adopting this approach again would turn the cap into a target.

A sliding scale should be adopted to encourage accurate, disciplined capex forecasts

Regulators in the United Kingdom have introduced a sliding scale for capex allowances. This mechanism allows suppliers to choose between lower capex forecasts with higher incentives, and higher forecasts but they keep less if they underspend.

A sliding scale would address the adverse incentives that currently exist in the revised decision.

- **The sliding scale is designed to be incentive compatible.** Suppliers that need larger capital expenditure allowances would be better off by forecasting higher expenditures and retaining a lower percentage of any underspend. In contrast, companies that have lower expenditure needs can take advantage of higher-powered incentives by forecasting lower capex, and keeping a higher percentage of any underspend
- **Each supplier has an ongoing incentive to limit expenditure.** Regardless of the allowance, suppliers have incentives to control their actual capital expenditure through an ability to increase the 'reward' under the sliding scale
- **The sliding scale mechanism is a low cost approach.** The sliding scale does not require audit or verification of supplier information. As shown by the experience of Ofwat, a sliding scale can be calibrated against historical capex expenditures, while recognising that future capex needs may be different
- **A sliding scale increases certainty in the regulatory regime.** The approach could be applied to future price resets, providing greater certainty and predictability for gas businesses. Adjustments to the mechanism could be made over time to improve how the sliding scale operates, but the experience in the United Kingdom demonstrates that the approach is fundamentally sound.

It is relatively simple to develop a sliding scale suitable for gas suppliers in New Zealand. The baseline in the sliding scale would need to be set to reflect the expected level of capital expenditure to maintain the current capital stock of the supplier plus a margin for growth. Suppliers would then be able to select from a menu of options higher or lower than the baseline by giving up more or less incentives.

This sliding scale would not address the issue of suppliers that need a step change in capex. We agree with the Commission that a CPP is likely to be the only way to accommodate those changes.

Summary of recommended changes to revised initial reset

This report identifies a number of actions the Commission should take to improve the accuracy, and consistency of the decision to reset prices. In summary, we recommend that the Commission:

- Conducts its own analysis to estimate the relationship between changes in scale and changes in opex using data on New Zealand and Australian gas distributors
- Adjusts its estimates of base year opex for gas transmission businesses to reflect the probability that gas throughput is high (which will drive increases in the cost of compressor fuel)

- Prepares a gas demand forecast (which could draw on the Concept scenario analysis) that represents the Commission's view on the most likely level of demand over the regulatory period. This forecast should take explicit account of the impact of consumers switching away from gas as electricity prices fall, and the latest information on consumer tastes and preferences for gas
- Incorporates a sliding scale for capex that allows suppliers to choose between a menu of options for the capital allowance over the regulatory period
- Routinely calculates financeability ratios in its determinations to demonstrate that price path decisions are in fact financeable, and adds pro forma profit and loss, balance sheet and cash flow statements to the DPP financial model.

1 Introduction

The Commerce Commission (the Commission) has published a Revised Initial Reset of the 2013-2017 Default Price Path (DPP) for gas pipeline businesses ("the revised initial reset decision"). Vector has engaged Castalia to evaluate the revised initial reset decision, and to comment on possible improvements to the way that future costs and revenues are modelled. The views expressed in this report are Castalia's, and do not necessarily reflect the views of Vector.

This report focuses in particular on the approaches used by the Commission to evaluate the current and projected profitability of gas transmission and distribution businesses ("suppliers"). This report is structured as follows:

- Section 2 reviews the approach to forecasting operating expenditure, and suggests ways to improve the accuracy of the projections made by the Commission by better accounting for changes in the scale of distribution businesses and setting a more reflective starting opex level for transmission businesses
- Section 3 reviews the approach to forecasting capital expenditure, and shows how adopting a sliding scale would encourage suppliers to provide good information on forecast expenditure needs while at the same time providing stronger incentives to keep these costs down
- Section 4 reviews the approach to forecasting real revenue growth, and suggests ways to improve the confidence in the forecasts by incorporating a fuller understanding of the drivers of demand in addition to the price of wholesale natural gas
- Section 5 comments on whether the decision might create financial hardship for suppliers, given the significant price reductions required, and assesses whether an allowance for this risk would be appropriate.

2 Operating Expenditure Projections

Opex forecasts represent the largest single difference between supplier's estimates of cost over the regulatory period and the Commission's allowed revenues. In our view, the reset does not appropriately reflect how changes in the scale of gas distribution companies will influence future opex. The Commission uses a British study from 2006-2007. We have put together a New Zealand and Australian dataset from 2010 that gives a more appropriate relationship between scale and opex.

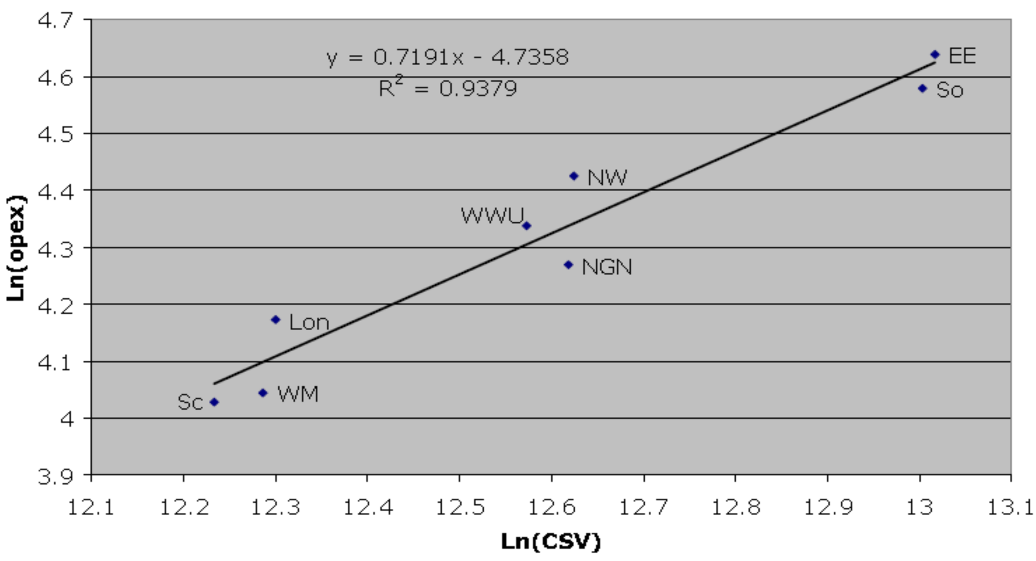
The reset decision also uses a base year for gas transmission opex that may not accurately capture average opex levels. The Commission accepts that opex is affected by the amount of gas conveyed by transmission pipelines, primarily because more compressor fuel will add to cost. However, the Commission uses a base year of 2011 to project opex over the regulatory period—which has lower levels of gas conveyed than an average year.

We have estimated a more appropriate relationship between scale and operating expenditure for New Zealand gas distribution companies

The Commission assumed that the relationship that Ofgem found between scale (a weighted variable of kilometres of mains lines and number of customer connections) and operating costs was applicable for New Zealand gas distribution companies. The rationale for using the Ofgem study is that there is insufficient data in New Zealand to undertake a credible econometric analysis.

However, the coefficient of 0.7 from the United Kingdom is based on 8 data points – the opex and composite scale variable (CSV) for 8 gas distributors in 2006-2007. This analysis is shown in Figure 2.1.

Figure 2.1: Ofgem Analysis of Relationship between Opex and Scale

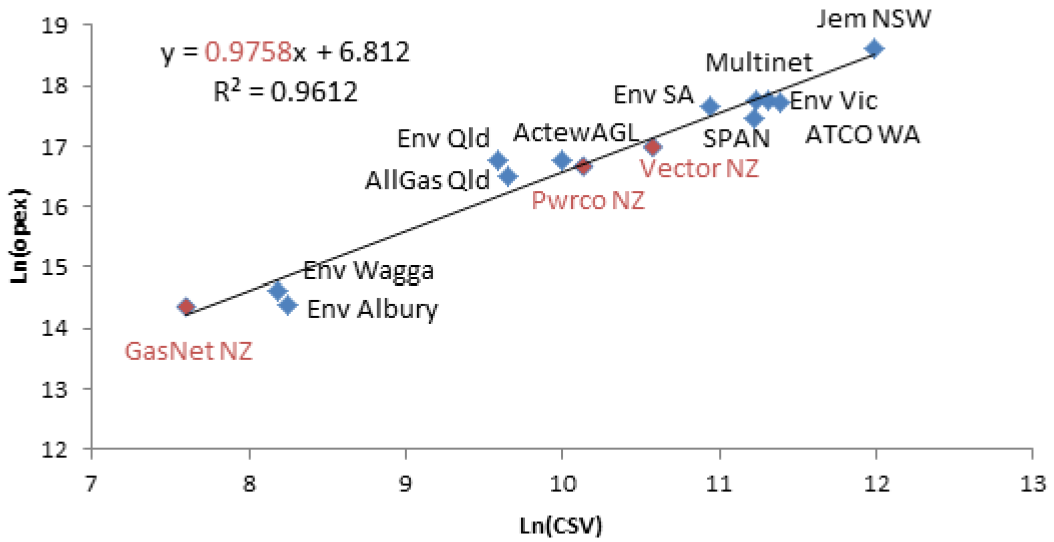


Source: Ofgem, *Gas Distribution Price Control Review, Final Proposals Document – Supplementary Appendices,* December 2007, at page 42

This analysis can be easily replicated using 2010 data on the opex and scale of New Zealand and Australian gas distributors. As shown in Figure 2.2, this provides an estimated relationship between the CSV and opex of 0.9612. In other words a 10 percent increase in the composite scale variable for New Zealand and Australian suppliers corresponds to a 9.8 percent increase in opex.

Using information on 14 gas distributors from New Zealand and Australia also improves the confidence we have in the scale relationship derived from this analysis (Ofgem's analysis only used 8 companies). Differences in scale explain 96 percent of the variation in opex among New Zealand and Australian gas distributors, while Ofgem's analysis explains 94 percent of the variation in opex.

Figure 2.2: Aust/NZ Analysis of Relationship between Opex and Scale



Source: Data from "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs Using Partial Productivity Indicators", Economic Insights, March 2012 http://www.aer.gov.au/sites/default/files/Attachment%205.6%20Economic%20Insights%20-%20Partial%20Indicator%20Report.pdf

We see important differences between gas distribution networks in the United Kingdom and New Zealand/Australia that warrant changing the approach to projecting opex to rely on data from New Zealand and Australia. In particular:

- The UK gas market has potential to be much larger (larger population, more densely populated) but has exploited much more of this potential (78 percent of population have access to gas, with population density in areas with gas only 1.5 times that of population density in other parts of the country)
- In comparison, New Zealand and Australian gas markets do not have potential to be very large (as they have small and sparsely distributed populations). They have started with the low hanging fruit, creating networks concentrated only in a few densely populated locations (population density in cities with gas is 40-50 times that of population density in the rest of the country).

This means that in New Zealand and Australia, connecting the next customer/km is likely to cost a similar amount to extending to the last customer/km. Whereas in Britain, population density means that although a lot of the population are already connected to gas, the network is so extensive and the unconnected population lies sufficiently close to the existing network that connecting a new customer/km costs only 70 percent of connecting the last customer/km.

Table 2.1 summarises some important characteristics of gas distribution networks.

Table 2.1: Comparing Features of UK versus NZ and Australian Gas Distribution Markets

	NZ	Australia	UK
Number of gas distribution businesses	3	12	8
Average ICPs per gas distribution business	87,000	383,000	2,675,000
Percentage of households with a gas connection	6%	19%	78%
Population density in cities with gas as a ratio of population density in the rest of the country*	37.9	50.7	1.5

Notes: *Only for parts of the country with gas networks: excluded the South Island of New Zealand and two states of Australia (Northern Territory and Western Australia)

Sources: http://www.oft.gov.uk/shared_oft/market-studies/off-grid/OFT1380annexes.pdf

http://www.citypopulation.de/UK-England.html

http://unstats.un.org/unsd/demographic/products/dyb/dyb2009-2010.htm

http://data.worldbank.org/indicator/EN.POP.DNST

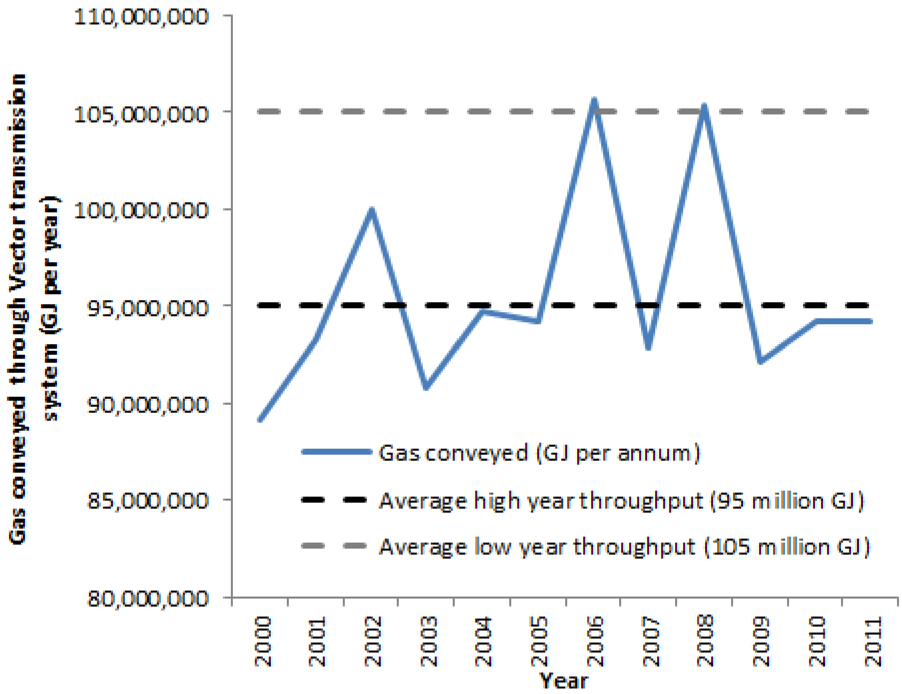
We estimate that adopting a scale factor of 0.9758, will increase the industry distribution opex allowance by around $2.7 million.

The starting price for gas transmission company opex does not adequately account for average gas throughput

For transmission, the Commission has invited submissions on how opex changes with energy throughput (see paragraph C15.2). The Commission considers that higher throughput will increase opex because more money needs to be spent on compressor fuel. We understand that compressor makes up roughly 10-15 percent of total transmission operating costs.

Information disclosures on gas conveyed suggest that in recent years throughput on Vector's transmission network has varied considerably—falling into two groups of around 95 million GJ per year and 105 million GJ per year.

Figure 2.3: Historical Gas Conveyed through Vector Transmission Pipeline



Source: Information disclosures

The Commission has assumed that the most recent year of gas conveyed is typical, and therefore provides an appropriate starting point for the next regulatory period. However, this year actually corresponds to a low point in the level of gas conveyed, not an average of gas conveyed. As a result, the Commission's starting operating expenditure is likely to be too low because the Commission has used a single atypical starting year for gas conveyed.

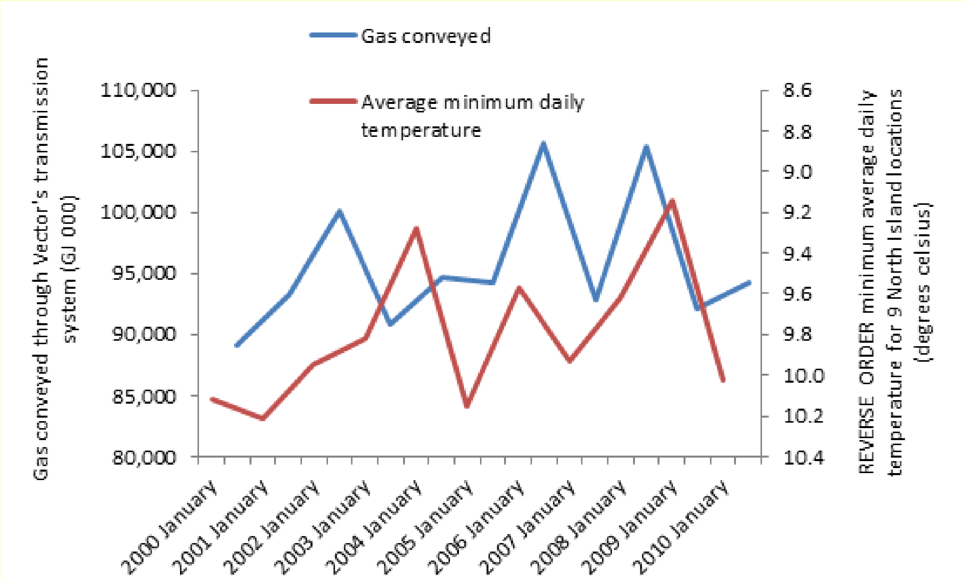
Box 2.1: Estimating a Typical Annual Gas Throughput According to Average Temperatures

- Gas throughput is affected by a number of factors including the demand for gas from electricity producers, the demand for gas for domestic heating and the demand for goods produced using gas (milk powder, steel etc).
- Gas throughput is closely correlated with the demand for heating–in particularly cold years, gas demand increases (both households who use gas directly for heating, and electricity producers who use gas peaking when electricity demand is high during cold periods).
- Figure 2.4 shows that there is a close correlation between average minimum daily temperate in the North Island and the amount of gas throughput. In particular, we found that gas conveyed = 150000 – 560 * average minimum daily temperature.
- By using opex in 2011 as a base year, the commission is explicitly assuming that throughput in 2011 is typical. However the graph below shows that gas conveyed in 2011 was at a low point. This may be because the average daily minimum temperature 2011 was higher than normal (so less gas needed to meet demand for heating): the average daily minimum temperature in the North Island in 2011 was 10.2 degrees, while the average over the past 10 years

was 9.7 degrees Celsius.

- Assuming that the relationships between temperature and gas conveyed and the between gas conveyed and opex are both linear, using a base year with temperatures 5 percent higher than the average year results in using opex that is 5 percent lower than average. A more typical base year for Vector's transmission company would result in base year opex of $33.6 million ($1.6 million higher than the current base year).

Figure 2.4: Relationship between Gas Conveyed and Average Annual Minimum Daily Temperature in the North Island



Source: NIWA data from nine New Zealand North Island weather stations (three from Auckland, two from Hamilton, one from Napier, one from New Plymouth and two from Wellington).

3 Capital Expenditure Projections

Setting capital expenditure allowances is inherently difficult under the DPP. The Commission has indicated that supplier information will not be audited or verified under the DPP (to reduce regulatory costs), but only suppliers have a good information about capital expenditure needs on their networks. Suppliers know the current condition of their assets, the service quality that those assets are expected to provide over the regulatory period, and what needs to be spent to achieve those outcomes.

The Commission resolves this challenge in the revised initial gas DPP by setting capital expenditure allowances equal to supplier forecasts, with allowances capped at 20 percent above a historical baseline (the average capex for each supplier from 2008 to 2011).[1] The fundamental problem with this approach is that it is not sustainable—the Commission cannot apply the same approach again because doing so would reward suppliers for forecasting a 20 percent increase in capex even when it is not needed.

The Commission can create a durable solution to this problem by incorporating a simple incentive scheme into starting price adjustments that rewards companies for accurate capex forecasting (with corresponding penalties for poor forecasting). This approach would replicate effective measures that have been in place in the United Kingdom (known as sliding scales), which give suppliers incentives to reveal their true capex needs. The approach is entirely consistent with the DPP (it does not require audit or verification), provides more certainty for suppliers (capex allowances could be set using a consistent methodology at each review), and benefits consumers by providing incentives to suppliers to think harder about the capital needs on their network.

The Commission needs to rely on suppliers' forecasts, but is concerned about incentives to overstate true capex needs

The Commission uses suppliers' forecasts of capital expenditure in the revised initial gas DPP, and has used supplier estimates of capex in the revised draft electricity DPP. However, simply relying on supplier forecasts creates an incentive to overestimate "true" capex needs—even if suppliers do not deliberately overstate capex forecasts, it is reasonable to expect suppliers to exercise any discretion or judgement in favour of higher forecasts.

This incentive was identified by the Commission when preparing the input methodology for starting price adjustments (no longer required). In the consultation paper on the additional IMs, the Commission stated that "for capex, suppliers could have an incentive to inflate their forecasts". The Commission thought this incentive could be addressed by relying on extrapolations of historical data, but acknowledged that historical levels of capex are not necessarily a good predictor of future levels of capex (due to asset age and replacement needs).[2]

The forecasting approach is not sustainable

The inherent tension in setting prices under an incentive-based regulatory regime has not been satisfactorily resolved by the Commission in either price reset:

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[1] Based on data supplied in the information requests under section 53ZD [Commerce Commission, *Notice to Supply Information to the Commerce Commission under section 53ZD of the Commerce Act 1986*, 22 June 2012.]

[2] http://www.comcom.govt.nz/assets/Pan-Industry/Input-Methodologies/Additional-IM-electricity-and-gas-DPP/Additional-IMs-for-DPP-Process-and-Issues-Paper-9-December-2011.pdf at paragraphs 163-164

- In the electricity price reset, the Commission used Asset Management Plans (AMPs) that had been prepared by suppliers before the Commission announced that AMPs would be used for price setting purposes. Suppliers now know that AMPs may be used to reset their prices, changing the dynamics when AMPs are prepared
- In the gas price reset, the Commission has capped capex allowances at 20 percent above historical levels. In future resets, suppliers will have a legitimate expectation that if capex forecasts are less than 20 percent above historical expenditure levels, then the allowance will be based on their forecast.

The Commission's approach to projecting capital expenditure is therefore not sustainable. If the proposed approach was used again, suppliers will have an incentive to submit forecasts to just below the 20 percent cap, whether or not this level of expenditure is actually needed. If suppliers' true forecasts are above the 20 percent cap, under the proposed approach they will be unable to fund the investments required to operate a safe and reliable network (unless they apply for CPPs). This could create an incentive to reduce the quality of supply, or to defer capital expenditure in ways that are not optimal, but fit better with the regulatory calendar.

It seems inevitable that the Commission will change the approach to projecting capex in the next price reset to address these incentives. In our view, a more durable solution needs to be evaluated to actually resolve the fundamental information asymmetry in forecasting capex—rather than continually kicking the can to the next reset.

Information quality incentives can improve capital expenditure forecasts

Regulators overseas have found elegant, simple ways to solve this problem. In the United Kingdom, Ofgem (the energy regulator) has introduced a "sliding scale" system that provides financial incentives for suppliers to accurately disclose their capex needs. This system was developed to respond to concerns that electricity distribution companies were deliberately increasing capital expenditure forecasts due to pressure to lower other costs (particularly opex). In fact, suppliers forecast that their capex needs from 2005-2010 would be nearly 50 percent higher on average than in the previous five years.[3] Ofgem realised that arbitrarily lowering these forecasts would not be in customers' interests because it was almost impossible to determine which capex increases were truly justified.

The sliding scale approach resolves this information asymmetry by allowing suppliers to choose between:

- Lower expenditure forecasts with higher-powered incentives, allowing companies to retain a larger proportion of any under-spending, and
- Higher expenditure forecasts with lower-powered incentives, meaning that companies are allowed to spend more but retain a smaller proportion of any benefits of under-spending against forecasts.

The real elegance of this system is that it maintains the incentives throughout the regulatory period to beat capex forecasts (this is known as having an incentive compatible system). The sliding scale mechanism has been developed further by Ofgem (and renamed as the Information Quality Incentive, IQI). The IQI combines all expenditure (capital and operating) into one 'pot', with 15 percent treated as 'fast money'

[3] Ofgem, "Electricity Distribution Price Control Review Final Proposals," (2004) at page 84

(like opex), and 85 percent is treated as 'slow money' (like capex). Under this approach both types of expenditure are subject to the same efficiency incentive, which eliminates any benefits from trading-off opex with capex to increase overall revenue allowances.

The sliding scale has now been adopted by the United Kingdom Water Regulator, Ofwat, to set capital expenditure allowances.[4] The approach applied by Ofwat is essentially the same as applied by Ofgem, although Ofwat uses the average historical level of capital expenditure to set a baseline for the scale, whereas Ofgem uses independent engineering assessments to establish a baseline level of capex.

An incentive compatible sliding scale would ideally suit the DPP

We consider that a sliding scale approach would be a significant improvement to the approaches adopted by the Commission in the electricity and gas DPP resets. A sliding scale would address the adverse incentives that currently exist in the revised decision.

- **The mechanism is designed to be incentive compatible.** Suppliers that need larger capital expenditure allowances would be better off by forecasting higher expenditures and retaining a lower percentage of any underspend. In contrast, companies that have lower expenditure needs can take advantage of higher-powered incentives by forecasting lower capex, and keeping a higher percentage of any underspend
- **Each supplier has an ongoing incentive to limit expenditure.** Regardless of the allowance, suppliers have incentives to control their actual capital expenditure through an ability to increase the 'reward' under the sliding scale
- **The sliding scale mechanism is a low cost approach.** The sliding scale does not require audit or verification of supplier information. As shown by the experience of Ofwat, a sliding scale can be calibrated against historical capex expenditures, while recognising that future capex needs may be different
- **A sliding scale increases certainty in the regulatory regime.** The approach could be applied to future price resets, providing greater certainty and predictability for gas businesses. Adjustments to the mechanism could be made over time to improve how the sliding scale operates, but the experience in the United Kingdom demonstrates that the approach is fundamentally sound.

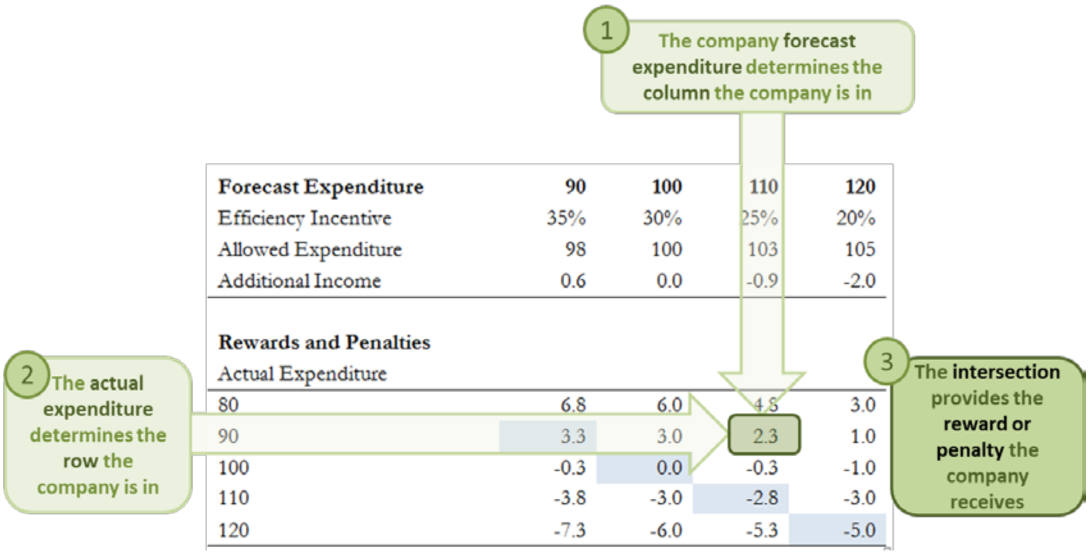
Sliding scale mechanisms are simple to implement and understand. Figure 3.1 illustrates how to use the sliding scale to determine the efficiency incentives and corresponding rewards and penalties. Using the sliding scale matrix requires three simple steps:

- **Step 1—Determine column**: The forecast expenditure row provides the ratios of the suppliers' expected expenditure plans to the baseline expenditure. This ratio determines the column of the matrix that each company falls in. In essence, each column represents a regulatory contract that each supplier can select based on its confidence about future capital expenditure needs.
- **Step 2—Determine row:** The actual expenditure column provides ratios of the actual expenditure to the baseline expenditure. Each supplier will end up in one of the rows at the end of the regulatory period, depending on actual capex.

[4] Ofwat, "Future water and sewerage charges 2010-15: final determinations", 2009

- **Step 3—Find reward/penalty**: The intersection of the column and row determines the reward (or penalty) for the supplier. The rewards and penalties are calculated using the allowed and actual expenditures, the efficiency rate, and an additional income according to the formula: *Total reward = (allowed expenditure – actual expenditure) x efficiency rate + additional income.*

Figure 3.1: Illustration of a Sliding Scale



Forecast Expenditure	90	100	110	120
Efficiency Incentive	35%	30%	25%	20%
Allowed Expenditure	98	100	103	105
Additional Income	0.6	0.0	-0.9	-2.0
Rewards and Penalties				
Actual Expenditure				
80	6.8	6.0	4.8	3.0
90	3.3	3.0	2.3	1.0
100	-0.3	0.0	-0.3	-1.0
110	-3.8	-3.0	-2.8	-3.0
120	-7.3	-6.0	-5.3	-5.0

Note: All figures in the matrix, except the 'efficiency incentive' line, are percentages of the baseline expenditure. The matrix can be extended beyond the range illustrated here using the same functions to determine appropriate rewards and penalties.

The rewards and penalties are simple to incorporate into the overall regulatory approach. The rewards and penalties are added to the total allowed revenues in the following regulatory period. The actual expenditure *ex-post* (rather than the allowed expenditure) is used to for determining the regulatory asset base (RAB) in the following price reset.

Applying a sliding scale to New Zealand gas networks

To demonstrate that the sliding scale can be easily adopted for the current gas price reset, we have created an incentive compatible sliding scale tailored to the decision. This requires four key variables to be set:

- **The baseline.** There are a number of different approaches to setting the baseline level of capex in the sliding scale. A summary of possible ways to set the baseline are described in Appendix A. We think that the rate of depreciation of the RAB plus an appropriate growth factor is likely to be the best way to set the baseline. Depreciation provides an accurate indication of costs of replacing or repairing existing assets, and a growth factor would reflect any additional capex required to expand the network.
- **The breakeven point.** The breakeven point is the location in the scale where companies receive zero rewards/penalties. In our scale, this point is set to when forecast and actual expenditure ratios are 100 (i.e. the supplier chose an allowance equal to its historical average and spent this amount).
- **The incentive strength.** The regulator can choose the strength of incentives applied in the scale. UK regulators have used incentives ranging from 18-40 percent. Our scale uses a range from between 18 and 38 percent.

- **The upper and lower bounds.** The upper and lower bounds of the matrix define how far allowances can vary from the baseline (historical average). We have used the same bounds as applied by Ofwat (85 percent and 125 percent of the baseline). This only captures the forecasts made by the three gas distribution networks—the capex forecasts made by the two transmission companies are treated as though their forecasts are equal to the upper bound (for illustrative purposes). Above the upper bound, incentives to underspend become progressively lower (which is a feature of an incentive compatible matrix).[5]

Figure 3.2 illustrates how the sliding scale would apply to Vector's gas distribution business assuming that the baseline is calculated by depreciation, and using Vector's current forecasts (ratio of 85 percent). This graph shows the rewards/penalties that Vector distribution would receive if the company spends its allowance, underspends the allowance by 10 percent, or overspends the allowance by 10 percent.

Comparing the rewards/penalties under each scenario, it is clear that Vector is incentivised to underspend its capex forecast for distribution. Vector would be able to increase its allowed revenues for the following regulatory period by around $100,000 if it spends exactly its allowance or $561,000 if it underspends by just 10 percent.

Figure 3.2: Rewards or Penalties for Vector's Gas Distribution Business with a Baseline Expenditure Using Depreciation

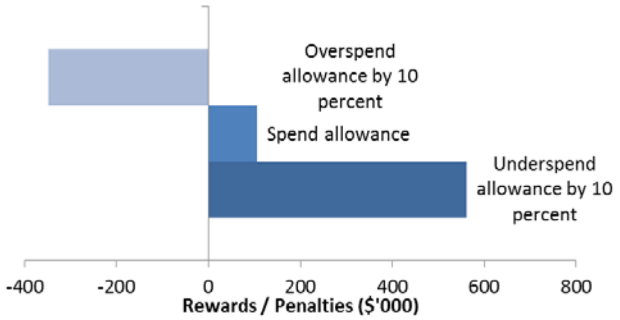
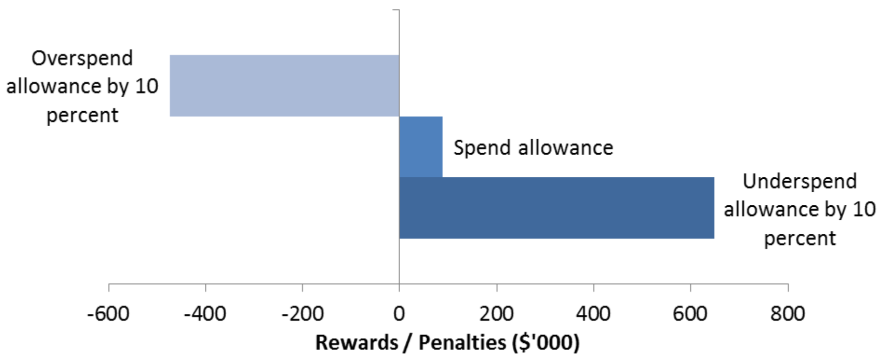


Figure 3.3 illustrates how the sliding scale would apply to Vector's gas transmission business. Using Vector's capital expenditure forecast and depreciation for 2011, Vector has a forecast to baseline ratio of 92. We illustrate the rewards or penalties that Vector would receive under the sliding scale using this ratio. If Vector overspends its allowance by 10 percent it will be penalised by a reduced allowance in the next regulatory period by $473,000, but could achieve a reward of $648,000 if it underspent by 10 percent.

[5] "It is not mathematically possible to maintain the pure 'incentive compatibility' of the CIS matrix, while also retaining sufficiently strong efficiency incentives beyond the upper limit" The Ofwat approach therefore prioritises efficiency incentives over incentive compatibility beyond the upper limit. Ofwat, "Future water and sewerage charges 2010-15: final determinations", 2009

Figure 3.3: Possible Rewards or Penalties for Vector's Gas Transmission Business



4 Revenue Forecasts

To forecast constant price revenue for Vector's industrial, commercial, and residential gas customers, the Commission needs to model future demand for gas distribution services. This is a difficult task and will inevitably involve considerable uncertainty. The Commission relies on Concept Consulting's draft report entitled "Gas Supply and Demand Scenarios: 2012:2027". However, Concept's work is not a demand forecast—instead the study focuses on supply developments and the resulting price of wholesale natural gas. There are other important drivers of demand that need to be considered for Concept's work to be used to forecast demand—particularly the price of substitutes (like electricity) and possible changes in consumer tastes and preferences for gas.

Accounting for all relevant demand drivers tends to support the use of the high price scenario in the Concept study (rather than the low or moderate price scenario). Even if the moderate supply scenario remained the most likely of the three analysed by Concept, we believe that it would be appropriate for the Commission to incorporate an explicit allowance for uncertainty due to the asymmetric consequences of actual demand being higher or lower than expected. The financial consequences of overestimating future demand are explored further in Section 5.

The Concept Study does not provide a demand forecast

The Commission's constant price revenue forecast is based on the three scenarios shown in Table 4.1. The descriptions highlight the dominant role that supply has in determining future gas prices—in all three scenarios, price is driven by future gas exploration success. However, price of any good or service is only one factor that influences demand.

Table 4.1: Concept Gas Price Scenarios

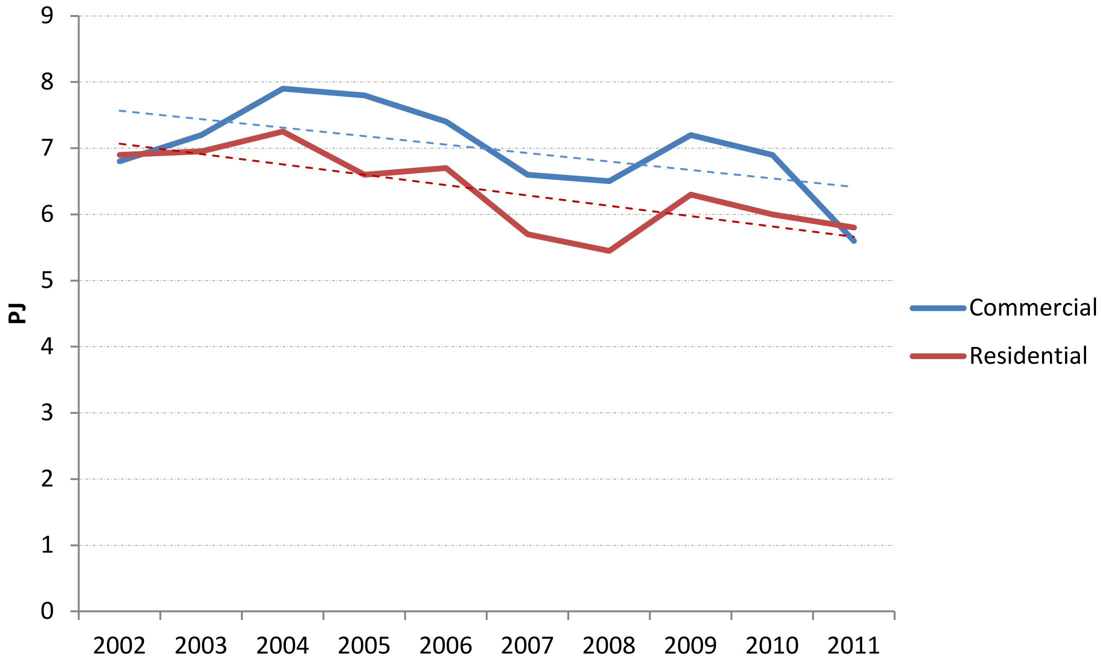
Scenario	Gas Price (2012 $)	Description
Plentiful supply (low price)	$4.50/GJ	Greater exploration success leads to a lengthening of reserves to production ratios (more Taranaki success or unconventional gas finds)
Moderate supply (medium price)	$7/GJ	Continuing adequate gas supply through an unchanged rate of exploration success
Tight supply (high price)	$12/GJ	Reduced reserve/production ratio, or alternatively, significant exploration success leading to export production (with NZ supply at world prices)

Source: Concept (2012) Gas Supply and Demand Scenarios 2012-2027, page 29

The resulting gas prices shown in Table 4.1 are based on assumed discoveries and production, and are outputs of an assumed supply model—rather than the results of a model that captures demand drivers of gas consumption. Even relying on the outlook for potential oil exploration (of which gas discoveries are generally understood to be a by-product), just because there is greater oil exploration activity, larger gas discoveries cannot automatically be assumed. Greater exploration activity does not increase the geological likelihood of successful drilling.

We note that in contrast to the expectation of growth in gas volumes, the Energy Data File published by the Ministry of Business Innovation and Employment shows a progressive fall in both commercial and residential gas demand since 2009 (Figure 4.1). We do not show industrial consumers since many obtain gas directly from the transmission network (and are therefore not relevant to this analysis).

Figure 4.1: Historic Commercial and Residential Gas Consumption



Source: Concept (2012), MBIE Energy Data File (2012)

There is little support for the plentiful supply scenario

The moderate supply scenario is effectively a steady state that does not assume a higher or lower frequency of new discoveries, but still acknowledges recent discoveries and exploration activity. Concept states that the price levels assumed in this scenario are still lower than contract prices observed between 2006 and 2011. On average, even a conservative assessment of moderate supply requires upstream gas interests to discover enough new gas supply to keep reserve to production ratios constant.

The plentiful supply scenario is optimistic, and predicated on finding more gas to enter domestic supply. It assumes that contract prices move to a level similar to what applied following the Maui discovery. Lower prices could reflect buyers accepting a greater proportion of supply risk than in the other scenarios.

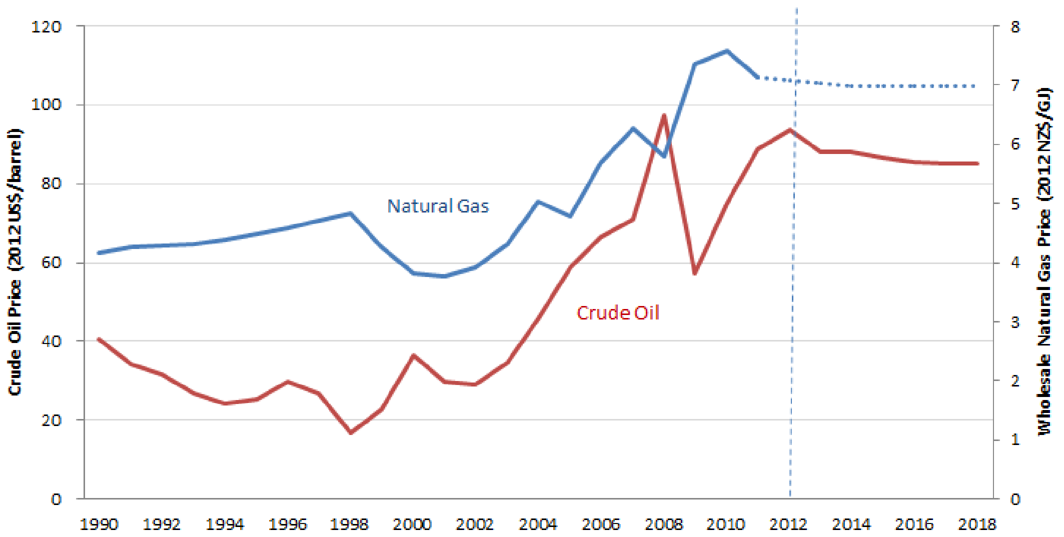
If new production is developed, as modelled by Concept, then reserve capacity for domestic consumption would need to be built in a large increment. This would eventually lead to a lower price for discoveries—but only up to a certain volume, beyond which new supply might justify a larger export facility causing domestic gas prices to rise toward the world price. Either way, the increase in capacity to process a higher rate of gas discoveries would take time due to the lead-in time for development and investment in plant.

We would therefore expect the market to be able to see a 'low price' scenario occurring several years ahead of time, since processing capacity can be a further constraint on upstream gas supply. Given the time between discovery and commercial gas production, building new capacity would need to already be occurring.

There is no indication of this higher level of development capital yet being deployed. Concept nevertheless considers, based on reported prices from company disclosures and available data (including, for instance, projected Queensland prices following export-scale gas discoveries) that the current New Zealand gas market conditions are likely to be somewhere between the medium and low price scenarios.

In our view, futures prices are the most reliable indicator of energy prices over coming years. However, there is currently no futures market for wholesale natural gas in New Zealand—even current contract prices are not released. Crude oil is traded in futures markets and the trends between New Zealand wholesale natural gas and international crude oil prices reveal some interesting correlations. Extrapolating this relationship into the future (in Figure 4.2) suggests that it is more realistic to expect wholesale gas prices to remain around $7/GJ (which is consistent with the moderate scenario used by the Commission).

Figure 4.2: Relationship between Natural Gas Prices and Crude Oil Prices (1990-2018)



Note: Futures prices need to be adjusted for inflation, so will be higher than shown.

Source: Ministry of Business Innovation and Employment (2012) Real Annual Average Fuel Prices

The correlation between natural gas prices in New Zealand and global oil prices can be explained by the fact that these energy resources are substitutes in consumption and also complements in production. As noted above, gas is also usually discovered as a by-product of oil exploration meaning greater exploration effort can encourage gas development due to a stronger oil price—if gas is indeed discovered.

The effect of prices for gas substitutes is not examined

Another factor limiting the demand for gas as an energy source for New Zealand industrial, commercial, and residential customers is the price of other fuel alternatives. Electricity prices in particular seem important, as the most obvious energy alternative for commercial and residential customers' space and water heating requirements.

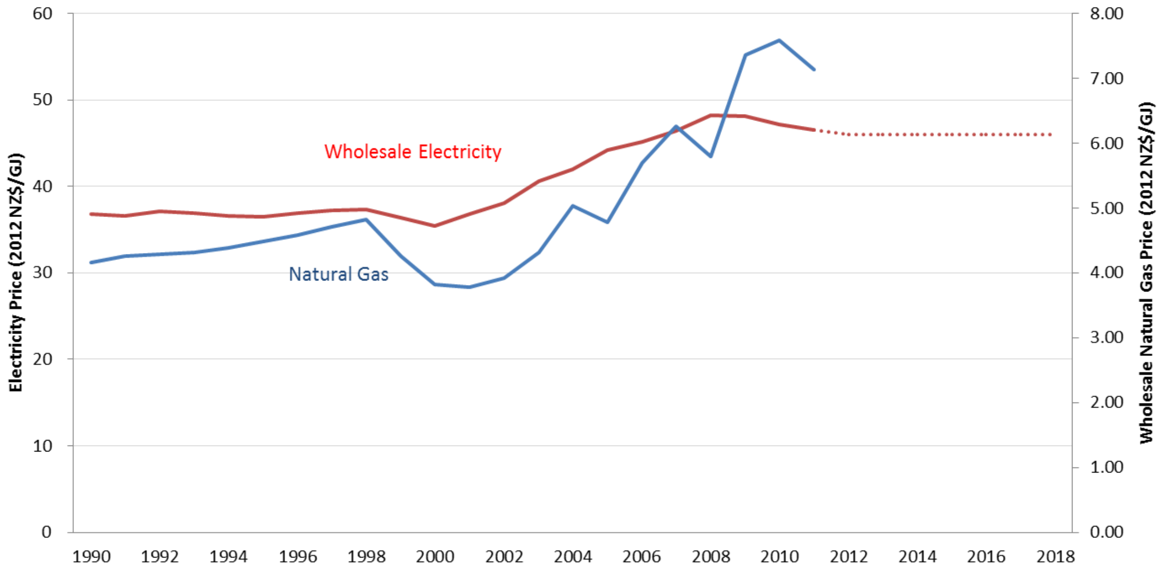
While the gas price scenarios are not linked to any specific demand drivers, the substitutability of gas with alternative energy sources is examined in Chapter Three of the draft Concept report in order to estimate the likely rate of gas demand growth. Concept notes that gas consumption does not exhibit any clear correlation with GDP or population growth, and concludes that, apart from high-temperature uses, there is likely to be significant substitutability with other fuels. Demand projections in the medium-price scenario are negative for space heating (-0.5 percent annually), and positive for water heating (2 percent growth)—with the difference due to switching capital costs, such as installing a gas connection and new equipment for gas water heating.

What this analysis does not consider is the movement in prices that gas faces in commercial and residential heating markets. Recent increases in natural gas prices have tracked increases in wholesale electricity prices—both of which are significantly driven by the run-down in Maui gas volumes. However, there are several factors pointing to relative prices diverging in coming years, with electricity becoming relatively more favourable:

- Long-run marginal costs of new electricity generation are relatively flat, with recent decreases in the cost of developing new geothermal. Several parties hold resource consents for new generation sites that are not needed
- Demand for electricity is expected to experience relatively modest growth, but the future operation of Tiwai Point aluminium smelter will have a significant impact. The commissioning of Pole 3 of the HVDC link (along with other transmission investments) may also enable the power generated at Manapouri to flow north and compete with gas in the North Island.

Figure 4.3 shows wholesale electricity prices from 1990. While increasing over the early 2000s, these have flattened and show a recent decline since 2008. This is consistent with the observation that hedge contract electricity prices are currently trading at their lowest level in the past 25 years. As substitutes, there is likely to be downward pressure on demand for gas as a result of the strengthened electricity competitiveness.

Figure 4.3: Natural Gas Prices and Wholesale Electricity Prices (1990-2018)



Source: Ministry of Business Innovation and Employment (2012) Real Annual Average Fuel Prices

Tastes and preferences also have an impact on demand

Gas faces competition from other fuel alternatives, and customers have a stronger ability to switch demand away from gas towards electricity than away from electricity towards gas. This is because gas connections have a greater on-site equipment investment requirement than contracts for electricity supply already installed at most sites.

The Commission has previously stated that "to reflect the discretionary uptake of gas, we considered developing an uptake factor to weight revenue projections".[6] However, this does not appear to have been implemented in the draft reset.

Previous studies have shown that customer perceptions and preferences towards gas can have material impacts on demand. A study conducted by Maani and Kask in 1991 estimates the impact of consumer preferences and attitudes towards gas connections when purchasing houses.[7] The study uses hedonic pricing to estimate consumer willingness to pay to avoid a gas pipeline in a residential area (using data from Mount Roskill in Auckland). The study illustrates that when gas was perceived to be dangerous (in 1983 when a gas pipeline was being constructed accompanied by a lot of media attention focusing on the dangers of gas), home buyers would pay a premium of up to 11 percent for a comparable house without a gas connection. This premium dropped to almost zero only a few years later when gas connections were considered to be a lower safety risk (reflected by little attention in the media).

Although this study was conducted twenty years ago, it illustrates that the demand for gas can change substantially when consumer perceptions of gas change. The Commission should be aware of the drivers of consumer taste and preferences, and try to understand how these drivers might influence demand over the regulatory period.

One way to measure the relative popularity of gas is to track how gas connections changes with changes in population. If gas is maintaining its share of the energy fuel market, we would expect to see proportionate growth of installation control points (ICPs) that roughly matches growth in household numbers. Figure 4.4 shows how population growth by region has translated into growth in gas ICPs from 2009-2012 (the period where statistics are available from the Gas Industry Company). Where the orange line is higher than the grey line, then uptake is increasing, i.e. in Hawkes Bay. In other areas, the grey line is higher than the orange line, which suggests that uptake is decreasing. This decrease appears small in some areas (such as Auckland), but significant in others (such as the Bay of Plenty).

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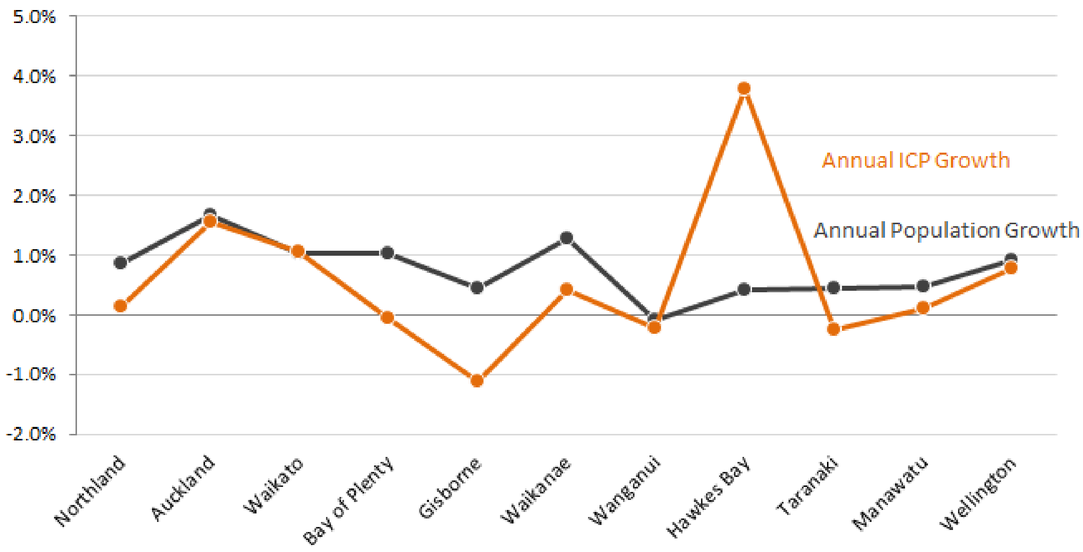
[6] http://www.comcom.govt.nz/assets/Pan-Industry/Input-Methodologies/Additional-IM-electricity-and-gas-DPP/Additional-IMs-for-DPP-Process-and-Issues-Paper-9-December-2011.pdf at paragraph 73

[7] S.A. Maani & S.B. Kask, "Risk and Information: a Hedonic Price Study in the New Zealand Housing Market", *Economic Record,* 67, 3, September 1991

Figure 4.4: Regional Population and Gas ICP Growth



Source: EDB Draft Price Reset and GIC Gas Registry

Vector's demand and revenue risks are asymmetric

Costs of capital are estimated on the assumption of normal distribution, but risks facing Vector's revenue are of a different category. Vector faces a range of risks for which the probability distribution of expected returns is skewed toward the downside, and which Vector has a limited ability to mitigate or diversify away from. These are downside demand risks that Vector has little control over, and while they relate most strongly to whether a customer chooses to be connected to gas (and therefore be reliant on gas), they also derive from likely volumes demanded.

The ability to pass on any price increase is constrained by competition from alternative fuels—which Vector has no control over—so if Vector faces a demand reduction as a result of lower prices from substitutes, increases in price to maintain revenue would risk market share loss and make the demand reduction worse.

The demand characteristics of gas customers are highly relevant to these demand risks—which are also mainly beyond Vector's control.

- A large number of residential customers will demand gas in response to temporary climatic conditions. Given New Zealand's geography, housing infrastructure, and vulnerability to climatic conditions, heating requirements are both volatile and impossible for Vector to influence.
- Industrial and commercial users' demand is likely to be more closely related to broader economic activity and demand for their output. Industrial users are also larger customers that expect to grow and demand more energy over time. These connections therefore individually make up substantial portions of Vector's demanded capacity, the loss of which is greater than the likely gain from new customers.

While Vector can mitigate marginal demand risks, such as by using take or pay arrangements to limit volume demand risks from individual customers, they are not helpful in case of customers cancelling supply, or where customers face a higher risk of financial stress or company closure. While customers can switch to fuel alternatives immediately (for instance by removing gas facilities when upgrading equipment), it takes time and up-front costs to connect new customers and develop capacity in the gas network.

The effect of the downside risks eventuating should also be compared with the potential upside revenue scenario. An increase in demand for gas distributed through Vector's network would result in stronger company returns and improved outcomes for shareholders which, in a transparent environment with regulatory oversight, are unlikely to go unnoticed by consumers.

On the other hand, a reduction in demand (with no ability to adjust prices) risks under-recovery of network investments. If fixed costs receive no contribution due to a fall-off in revenue, but crucial capex is required to maintain network reliability and quality of service, the distributor faces potential bankruptcy.

Resolving these concerns about demand forecasting

While we acknowledge the lack of publicly available information on future gas demand, adopting any one of the scenarios in the Concept study is unlikely to be the best way to reliably assess future revenues for the DPP. We recommend that the Commission instead prepares its own gas demand forecast (drawing on the Concept scenario analysis) that represents the Commission's view on the most likely level of demand over the regulatory period. This forecast should take explicit account of the impact of consumers switching away from gas as electricity prices fall, and the latest information on consumer tastes and preferences for gas.

This approach does not need to be analytically complex, but should represent the Commission's "best guess" of likely demand over the regulatory period. On the basis of the demand drivers investigated above this might involve starting with the moderate supply scenario, and then adjusting this forecast downward to reflect weakening demand pressures over the next five years (in particular in terms of the price of wholesale electricity). For example, taking the mid-point between the moderate supply and tight scenarios would lead to forecast demand growth of -0.2 percent.

5 Tests for Financial Hardship

The Commission states that it is prepared to apply an alternative rate of change if the proposed reset would limit supplier's ability to finance its reasonable investment needs and invites suppliers to provide evidence that the proposed price and revenue reductions would do so. In this section we consider the tests for financial hardship that are used overseas and we look at how these practices could be applied in the current DPP draft reset.

Financeability of regulatory determinations

In theory, regulatory approaches like the DPP should not require additional allowances for financial hardship. If the regulator sets a revenue path that allows the regulated business to recover its efficient costs over the regulatory period, then this revenue path should provide sufficient incentives to investors and debt providers, and thus be financeable.

In reality, financial markets—both debt and equity—are not perfect and they do not have infinite liquidity as assumed by the Capital Asset Pricing Model (CAPM) used to establish the regulated entities' Weighted Average Cost of Capital (WACC). These imperfections, coupled with banking practices, mean that—particularly during periods of financial instability—it is entirely possible that an economically viable revenue path may not be bankable. In other words, the revenue path may meet the regulator's NPV=0 requirement, but provide insufficient liquidity during some periods to maintain a viable capital structure.

For this reason, many regulators such as IPART, AER and Ofgem use financeability checks such as evaluating key ratios and credit metrics implied by a regulated revenue path they set to ensure financeability. For example, Table 5.1 presents IPART's analysis of the key ratios and credit metrics for its recent revenue determination for Sydney Water. On the basis of this data, IPART concluded that its determination is financeable as the credit metrics are within the bounds for an investment grade credit rating and remain so over the regulatory period.

Table 5.1: Assessment of Sydney Water Financeability

	2011/12	2012/13	2013/14	2014/15	2015/16
Funds from operations interest cover	2.2	2.3	2.2	2.1	2.0
Funds from operations/total debt	7.5%	7.9%	7.3%	6.9%	6.8%
Debt gearing (regulatory value)	51%	52%	53%	53%	54%
EBIT interest cover	1.9	1.9	1.8	1.7	1.7
RCF to Capex	0.5	0.5	0.5	0.6	0.7

a Financial ratios presented are based on the assumption of a 70% dividend payout ratio and Sydney Water meeting our forecasts of efficient operating and capital costs.

Source: IPART analysis.

We recommend that the Commission routinely calculates similar ratios in its determination to demonstrate that price path decisions are in fact financeable. We also suggest that the Commission adds pro forma profit and loss, balance sheet and cash flow statements to the DPP financial model to improve transparency, and to allow the model to provide more information than the calculations behind the staring price adjustment.

When is financeability likely to be a problem?

We see two scenarios under which economically viable price paths may not be able to be financed in normal circumstances:

- Where a step change in capital expenditure is forecast such that the regulated business will require material new debt and possibly additional equity to finance the capital expenditure program. Given imperfect capital markets with scarcity of capital it is possible that even if the regulatory WACC is reasonable, finance cannot be raised. Of course, in these circumstances, the WACC is below the reasonable expectations of investors, they are unlikely to commit significant new capital; and
- Where there is turmoil in the financial markets such that liquidity is low or non-existent and essentially new capital—either debt or equity—cannot be raised at any price.

In both these scenarios, an appropriate level of WACC set by the regulator may help reduce the financeability problem but it is unlikely to eliminate the problem entirely. The salutation may require that customers contribute some of the required capital through an explicit financeability adjustment to the regulated revenue.

DPP financeability issues

While the Commission states that it is prepared to apply an alternative rate of change if the reset would limit supplier's ability to finance its reasonable investment needs, such a scenario is unlikely to arise in relation to a DPP. This is because in the DPP process the Commission has explicitly ignored any step change in capital expenditure by capping suppliers' forecasts at 20 percent above historical levels. Furthermore, because the DPP process is low cost and relies on information that is independent from the supplier, a supplier cannot supply evidence of financial hardship. This is because under the DPP process the Commission wants to reduce or eliminate audit, verification and approval requirements to keep regulatory costs low. This means that supplier forecasts have not been subject to independent audit, verification and approval—and cannot be tested this way under the DPP.

However, supplier forecast clearly represent the companies' views on the level of capital and operating expenditure needed to maintain, operate, refurbish and expand its gas distribution and transmission networks, and to meet applicable standards for safety, reliability and service levels.

The DPP process creates a new financeability risk

The Commission's forecasting methodology for capital and operating expenditure results in estimates that are significantly lower than supplier forecasts, and high constant price revenue estimates. In Sections 2, 3 and 4 of this report we present a number of concerns that the Commission's projections are highly uncertain and could be improved.

The combination of the large differences when compared with supplier forecasts and concerns with forecasting approaches combine to create a new financeability risk if the Commission's forecasts are wrong. If, for example, the capital that is actually needed to maintain reliability levels and service standards is closer to supplier estimates than the Commission's forecast, then it is unlikely that sufficient capital can be raised from either debt or equity investors to undertake the needed investment.

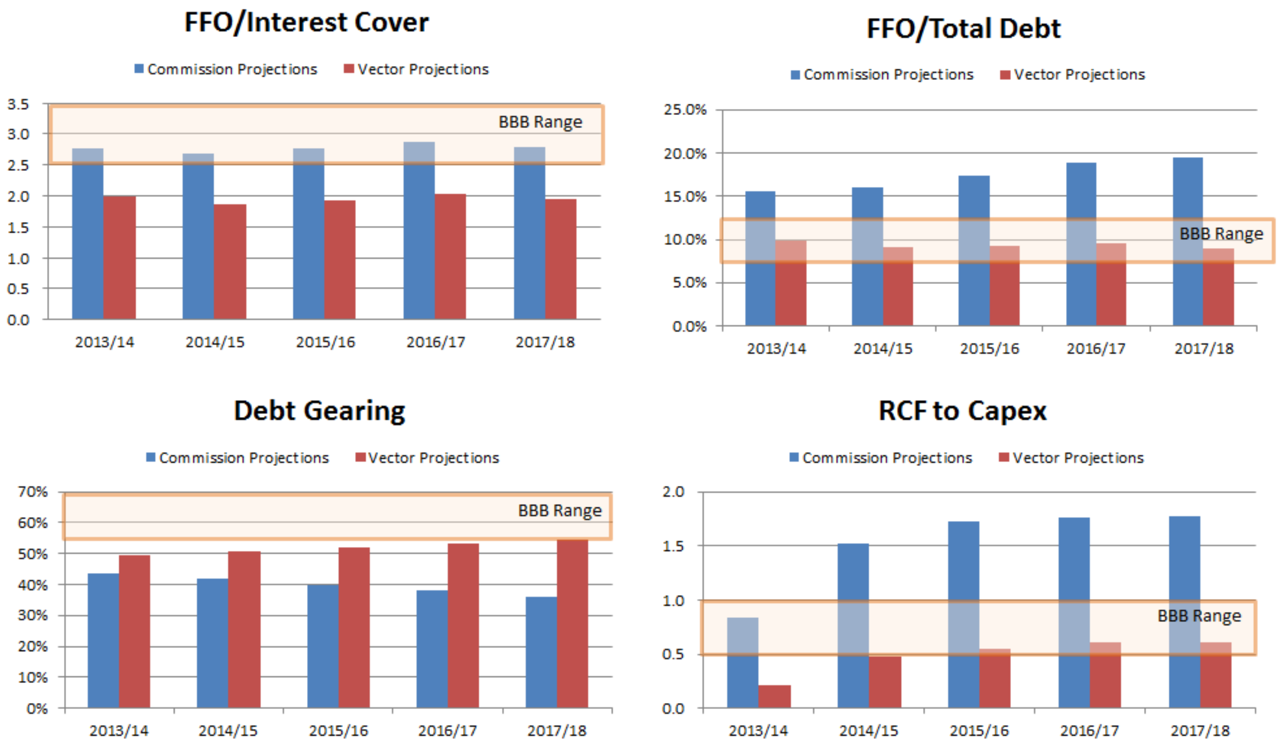
Figure 5.1 and Figure 5.2 present key financial ratios for Vector's transmission and distribution businesses using first the Commission's estimates of capital and operating expenditure, and then the supplier forecasts. The metrics shown are:

- Free funds from operation (FFO)/interest cover and FFO/total debt provide an indication of the ability of the company to repay its debtors from available cash
- Debt gearing is a measure of the ratio between debt holders (who have first call on the returns of the company) and equity holders (who only receive returns after debt obligations are satisfied
- Residual cash flow to capex measures a company's ability to acquire long-term assets using free cash flow.

We also show the expected range for each metric that corresponds to a BBB—that is investment grade—credit rating for regulated network companies in the United Kingdom. This data comes from various credit rating agencies' published methodologies and ratings updates as collated and reported by Ofgem.[8]

The results show that while Vector's credit metrics will remain stable and even improve slightly under the Commission's projections of capital expenditure, operating expenditure and revenue, if supplier estimates are correct then financial outcomes will be materially different. Vector's gearing would be expected to increase over the regulatory period and all credit metrics would suffer a marked deterioration. The key metric of FFO/interest cover would be outside the normal range for a BBB-rated entity over the regulatory period for both transmission and distribution and the trend is deteriorating (if Vector actually spends at the level of its forecasts, rather than at the regulatory allowances).

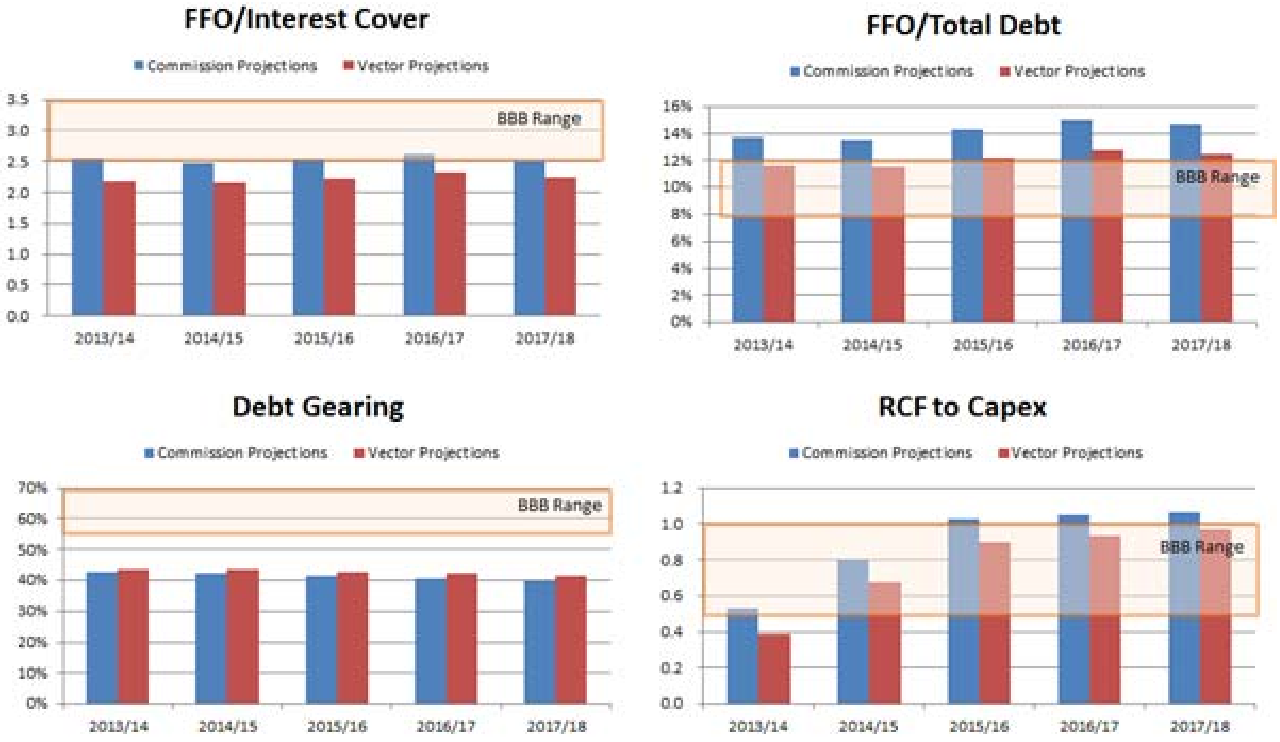
Figure 5.1: Forecasts of Vector Transmission's Key Financial Ratios



Source: Castalia from Commission financial model

8 *Consultation on strategy for the next electricity distribution price controls – RIIO-ED1 – Financial Issues*, Ofgem, September 2012

Figure 5.2: Forecasts of Vector Distribution's Key Financial Ratios



Source: Castalia from Commission financial model

While Vector has the option of applying for a CPP, we continue to see material uncertainty, risk and cost for both the Commission and Vector in this process.

- No business has yet been subject to the CPP process so for both the Commission and the business it will be a learning experience and there may well be flaws and unintended consequences of the current approach
- The Commission has not defined the "standard of proof" for the independent audit and verification of supplier specific forecasts. Neither party is fully aware of the resources needed to undertake this task; and
- The financial model underpinning the translation of the Input Methodologies into detailed calculations and formulas has not yet been developed.

For these reasons, we recommend that the Commission specifically considers financeability issues that will arise due to the higher risk of forecasting error under the DPP, and publish a set of indicative credit metrics to improve the transparency and understanding of its decisions.

Appendix A: Further Information on the Sliding Scale

In this appendix we detail the methodology used to construct the sliding scale. The methodology of the sliding scale has been constructed based on the model developed by Oxera for Ofwat, taking into consideration the approaches used elsewhere, particularly by Ofgem. A detailed version of the sliding scale is presented in Table A.1

Table A.1: Sliding Scale

Forecast Expenditure	**85**	**90**	**95**	**100**	**105**	**110**	**115**	**120**	**125**
Efficiency Incentive	38%	35%	33%	30%	28%	25%	23%	20%	18%
Allowed Expenditure	96.25	97.5	98.75	100	101.25	102.5	103.75	105	106.25
Additional Income	0.8	0.6	0.3	0.0	-0.4	-0.9	-1.4	-2.0	-2.7
Rewards and Penalties									
Actual Expenditure									
80	6.9	6.8	6.4	6.0	5.4	4.8	3.9	3.0	1.9
85	5.1	5.0	4.8	4.5	4.1	3.5	2.8	2.0	1.1
90	3.2	3.3	3.2	3.0	2.7	2.3	1.7	1.0	0.2
95	1.3	1.5	1.6	1.5	1.3	1.0	0.6	0.0	-0.7
100	-0.6	-0.3	-0.1	0.0	-0.1	-0.3	-0.6	-1.0	-1.6
105	-2.4	-2.0	-1.7	-1.5	-1.4	-1.5	-1.7	-2.0	-2.4
110	-4.3	-3.8	-3.3	-3.0	-2.8	-2.8	-2.8	-3.0	-3.3
115	-6.2	-5.5	-4.9	-4.5	-4.2	-4.0	-3.9	-4.0	-4.2
120	-8.1	-7.3	-6.6	-6.0	-5.6	-5.3	-5.1	-5.0	-5.1
125	-9.9	-9.0	-8.2	-7.5	-6.9	-6.5	-6.2	-6.0	-5.9

Source: Oxera, "Assessing approaches to expenditure and incentives", report prepared for Ofwat, October 2007

Determine the baseline

The forecast expenditure baseline provides the foundation for the sliding scale. The baseline is an independent evaluation of the expected capital expenditure requirements to provide a safe and reliable gas pipeline service. Methods for setting the baseline include

- **Independent engineering review**—Ofgem used this approach to set the baseline for the electricity distribution companies in the United Kingdom. This can be a costly approach to determining the baseline
- **Econometric models**—This can be a complicated approach increasing the regulatory burden, especially to achieve an industry consensus on the most appropriate methodology. It also requires sufficient data, which is unlikely to be available in the New Zealand industry
- **Average historical expenditure**—This approach averages the capital expenditure over previous years, and is currently used by the Commission to set a baseline in the draft decision
- **Companies own forecasts provided in first business plans**—This approach was used by the Commerce Commission for the electricity DPP reset, but is unsustainable for future price resets. This approach does not

eliminate the Commission's inherent mistrust that companies will inflate forecasts

- **Depreciation—**Depreciation in the base year provides a strong indication of the assets that require capital expenditure to maintain or replace in the next regulatory period. This is combined with a growth factor to allow for network and demand growth. We recommend this approach be used by the Commission.

Ratios to slide along the scale

- Each of the components within the sliding scale, except the efficiency rate, is a ratio (percentage) of the baseline expenditure. The first two ratios used to determine the location of any company within the scale are:
  - **Forecast Expenditure—**The ratio between the company forecast expenditure and the baseline determines which column that each company sits in within the sliding scale
  - **Actual Expenditure**—This is the ratio of what companies actually spent *ex-post* to the baseline expenditure

Calculating the rewards/penalties

- The remaining components of the sliding scale are used to calculate the rewards and penalties, according to the following formulae

Total reward = (allowed expenditure – actual expenditure) x efficiency rate + additional income

- The first two components are ratios against the baseline expenditure, that are used in combination with the efficiency incentive
  - **Allowed Expenditure**—The allowed expenditure ratio determines what percentage of the baseline companies are allowed to spend in the regulatory period. This ratio is also used by the regulator, with the actual expenditure, to calculate the reward or penalty in the scale
  - **Additional Income**—This is an adjustment factor that ensures that the sliding scale mechanism is incentive compatible. That is companies have an incentive to forecast accurately
  - **Efficiency Incentive**—The efficiency incentive determines the strength of the incentives—the proportion of the efficiency improvements that may be retained by shareholders, with the remaining returned to customers
- To understand how each of these components are constructed, we present the formula and corresponding parameters in Table A.2

Table A.2: Parameters for the Sliding Scale

Parameter	Purpose of Parameter	Proposed Parameter
Efficiency Incentive Rate		
		0.8
	Slope of the efficiency line determines the strength of incentives	-0.005
Allowed Expenditure: Baseline Ratio		
	Determines the shape of the incentives	75
		0.25
Additional Income: Baseline Ratio		
	Adjusts the profitability to determine where the breakeven point (zero reward) lies within the matrix	-5
	First and second order parameters (automatically determined) to achieve incentive compatibility	0.175
		-0.00125

Source: Based on parameters from Oxera, "Assessing approaches to expenditure and incentives", report prepared for Ofwat, October 2007

- The parameters may be altered to suit the industry that the sliding scale is used within. However, we found that the majority of the parameters have been consistent across industries in the United Kingdom.

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