GAS DISRUPTION STUDY
REPORT ON THE POTENTIAL IMPACTS ON THE NZ GAS MARKET

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WorleyParsons New Zealand (WorleyParsons) is the leader in the design, engineering, maintenance and provision of project delivery services for onshore, offshore, brownfield, greenfield, subsea and downstream hydrocarbons operations in New Zealand. For the purpose of this study it brought together and led a consortium of specialist energy analysts and engineers from within New Zealand, including;

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An integrated, Engineering, Project Management and Field Services Company specializing in the provision of Integrity Management Solutions to the Oil, Gas & Pipeline Industries.

Aretê Consulting Ltd

A specialist consultancy providing technical and strategic advice to the oil and gas sector including offering regular extensive reporting on the New Zealand Gas Market.

Hale and Twomey Ltd

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EXECUTIVE SUMMARY

This study, commissioned by the Ministry of Business, Innovation & Employment (MBIE), examines the likely consequences of a major gas disruption event within the New Zealand gas market and the risk management approaches applicable to reducing the economic losses that might arise. A major gas disruption event is defined for the purposed of this study as an event in which the direct losses exceed $100 million. The study builds upon, and extends, an earlier 2009 analysis by the Centre for Advanced Engineering (CAENZ) on the impacts on New Zealand's electricity generation system of a long term gas supply disruption.

The CAENZ study developed a series of scenarios based on credible loss events in order that the impacts on the industrial and electricity markets could be assessed, and response strategies considered. In this study we have taken a broader perspective and have relooked at the likely range of loss events that might conceivably have a sufficiently significant impact on the gas supply situation to warrant further interventions.

To this end we have examined in some detail:

- The natural gas supply chain, critical vulnerabilities, and the likelihood of occurrence for the different loss categories so defined,
- Changes that have occurred in gas supply / demand balances and the regulatory environment since the publication of the 2009 CAENZ report,
- Matters impacting security of supply as covered by the governance and regulatory framework for the industry including technical standards, gas quality and economic regulation and, finally
- The adequacy of existing practices and arrangements to mitigate the risks identified above.

From this analysis one arrives at essentially two gas disruption scenarios which have the potential to manifest themselves in a variety of ways:

- A Critical Contingency Management (CCM) event with significantly reduced allocations and curtailment of gas supply of up to 4-6 weeks.
- A significant (but not necessarily catastrophic) curtailment of gas supply for an extended period that goes well beyond any CCM-type event.

The question that thus arises is the likely impacts and scale of disruption in respect of both scenario-types and their impact on the NZ economy. It is not axiomatic, for example, that a longer duration curtailment event will lead to more severe economic loss and in this study we re-examined the interdependencies and commercial arrangements that would characterise each of the scenarios to fully establish the range of possible outcomes and consequences.

Natural gas continues to be an attractive energy choice for consumers and in the 2012 year gas supply accounted for 21 percent of NZ primary energy supply. Continued petroleum exploration activity has seen a strengthening of the gas reserves position to the current supply horizon of around 11 years at 2012 demand level. The industry demand side is very concentrated with 80% of the total gas demand consumed by approximately 31 sites comprising petrochemicals, electricity generation and a number of large industrial users in the export sector. A reliable and resilient supply chain is thus essential to New Zealand's economic wellbeing.

Descriptions of the supply chain and the market arrangements that cover trading of natural gas suggest that whilst the physical and commercial structures within the industry have not changed significantly since the CAENZ report there are a number of emerging trends that suggest a greater diversity and associated resilience in the gas market that help mitigate the economic impacts of gas supply interruptions:

- Gas supply is currently derived from some 15 producing fields with significant new capacity commissioned in the last five years, including Kupe, Mangahewa and Kowhai.
- The commissioning of New Zealand's first underground gas storage facility by Contact Energy at the depleted Ahuroa field has added another dimension to supply/demand management.
- Emergence of secondary trading platforms in energy to manage under and oversupply in bilateral gas agreements.
- Industry support for creating alternative capacity products and secondary trading in gas transmission.

There has also been significant, positive change in the regulatory environment which contributes to improved resilience. The gas industry's primary legislation is the Gas Act 1992, which was amended in 2004 to set up the co-regulatory model and the co-regulator, the Gas Industry Company (GIC). The policy frameworks within these recognise security as one amongst a number of imperatives to be managed.

The GIC operates under a unique co-regulatory model which allows the industry to develop its own arrangements which the GIC facilitates whilst providing a regulatory backstop for the Minister to intervene where the co-regulatory model is unable to do so. Importantly its role includes making recommendations on critical contingency management (CCM). The CCM Regulations have been invoked on three occasions, the most significant of which was a 5½ day outage in October 2011 caused by a failure in the Maui gas pipeline. Responses to the Maui outage showed that the CCM Regulations generally worked well, although a number of areas were identified in which improvements could be made; and recommendations in respect of these were reported back to the Minister of Energy and Resources in July 2013.

Two case studies were examined to help inform development of loss scenarios: the first covered the Maui pipeline outage of October 2011 and the second the 2008 Western Australian gas explosion Varanus Island. Both events provided useful lessons that could be transferred to the NZ scenarios. Whilst both caused significant disruptions to business and services neither proved to be catastrophic. Closer examination of the circumstances at the time and referral to the findings from subsequent reviews undertaken by the responsible agencies within both jurisdictions provided useful analogues for this study in informing what might be considered a worst case scenario going forward.

We consider an extended supply disruption at Pohokura as representative of the probable highest impact event created from a loss of gas processing facility or gas field interruption. The other selected scenario was a four week outage affecting the entire upper North Island from a complete gas transmission failure event, effectively an extension of the Maui pipeline outage but with the Vector 200mm line also affected and requiring repair in a more logistically challenging terrain.

For this study we considered the consequences of each loss scenario in terms of the economic impact on industries whose normal gas supply was disrupted. This is demonstrated in the Table following, which describes the extended North Island outage scenario. However, as we were not asked to undertake specific economic analysis, we adopted the estimates provided by New Zealand Institute for Economic Research (NZIER) for the review of the CCM regulations[1] to provide preliminary estimates of the contribution of gas consumption to value-added for those industries that use gas. This provides an

[1] "Value-added Associated with Gas Demand" NZIER report to Gas Industry Co., 11 October 2011

estimate of the value at stake if a firm ceases production but, as indicated by NZIER, the numbers provide only a guide; they do not take account of the willingness for firms to pay for uninterrupted supply or the extent to which firms can substitute other forms of energy.

Industry	**$/GJ**	**Quantity** (TJ)	**Per day** GJ	**Value lost ($ mln)**
Vector North				
Generation	5.53	17596	48,208	7,464,561
Dairy	97.61	1100	3,014	8,236,679
Steel	10.01	2000	5,479	1,535,781
Refining	39.9	2500	6,849	7,652,055
Horticulture	92.25	20	55	141,534
Urban Centres	300	1377	3,773	10,336
Greater Auckland	300	11942	32,718	274,829,589
Total		36535		299,870,535
Vector Central				
Peroxide	12.42	350	958.90411	333,468
Dairy (Te Rapa)	97.61	4600	12602.74	34,444,296
Urban centres	300	2485	6808.2192	57,189,041
Total		7435		91,966,805
BOP				-
Kinleith	34.25	2450	6712.3288	6,437,123
Whakatane	34.25	564	1545.2055	1,481,852
Kawerau	34.25	600	1643.8356	1,576,438
Dairy	97.61	1952	5347.9452	14,616,362
Urban centres	300	2629	7202.7397	60,503,014
Total		8195		84,614,789
Huntly	5.53	21300	58356.164	9,035,868
Total(incl Huntly)		29495		93,650,658
Total Impact				485,487,998

Scenario outcome for a four week outage across the entire upper North Island

As can be seen from the above analysis, amongst the industrials dairying is by far the most impacted. When combined with the other scenario considered in the study, and ignoring any multiplier effect, the results suggest the overall economic effects of the range of foreseeable major disruptive events are essentially bounded within the range of approximately $400 - $650 million, depending on the value attributed to activities not including generation/large industrials.

Beyond such direct impacts a number of general conclusions can be drawn from the study:

1) The loss of supply from a Pohokura type event is likely to be met by some increase in production from other fields[2] and reduced output of methanol production.

2) The expected frequency of a Pohokura type event of this magnitude is expected to be a 1 in 5000 year event.

3) The economic impact on other industries is likely to be through increased input costs rather than loss in output.

4) The CCM protocols that cover a pipeline event are robust and curtailment bands align with the principle of allocative efficiency.

5) The effects are likely to be short term and wash through quite quickly without permanent long term effects.

6) The scenarios can be managed through current market arrangements rather than Government intervention.

7) Under a worst case credible scenario the short term impact is expected to amount to less than 1% of GDP.

8) The commercial and residential mass market continues to be supplied through these events.

In addition to the above analysis the electricity sector effects were also evaluated for a prolonged gas curtailment event. There have been a number of significant changes in generation plant availability since the earlier CAENZ work including; new geothermal and gas capacity, the decommissioning of two of the four Huntly coal-fired units, the commissioning of Pole 3 which has expanded the capacity of the HVDC link, and establishment of gas storage at Ahuroa. As a result we conclude that under average hydrology conditions a major disruption to gas supplies is likely to be able to be handled without disrupting supply or seriously reducing system security.

We note, however, that energy loss due to a supply disruption is dependent on the time of year and hydro system inflow. The 500MW of coal capacity at Huntly plays a vital role in the event of gas supply disruption and thus retention of strategic coal storage may well have merit. In the event of a total outage in the upper North Island gas may not be available for start-up of these units and it is suggested that reinstatement of diesel fuel start up should also be investigated to improve security of these units. Whilst this study indicates that the electricity system appears relatively secure, this question deserves more detailed study, especially as to whether the remaining idle coal units have a contingency value; currently not included in any decision to decommission them.

Whilst it has not been possible in this study to evaluate the social impost of a major disruption or curtailment event, based on experience from Western Australia and the range of projected losses developed in this study, at the national economy level losses of the magnitudes considered are likely to only have a transient effect and are well within the bounds of normal business interruption scenarios. Another factor, not considered in this study, is that even for the most pessimistic scenario of a major loss at Pohokura it is conceivable that other producing gas fields may well be able to increase production to help meet potential long-term shortfalls.

[2] This assumption could be tested once NZP&M receives new information by 31 March 2014 on indicative maximum deliverability profile using the installed infrastructure.

In other words, a market based approach to reallocation of supply together with the CCM regulations should be feasible without further government intervention via emergency powers. Gas supply security is more a matter of getting the incentives in place for owners and operators of facilities to take actions that are aligned with the national good rather than a reliance on regulatory compliance as framed by predetermined risk outcomes. The drivers on market participants throughout the supply chain to manage disruption risk and minimize the time for any disruption event appear well aligned.

We suggest that a gradual evolution towards a more liquid secondary gas market will help mitigate the economic impacts of gas supply interruptions by enabling limited supply to be allocated to parties who value it the most during a period of gas supply curtailment. This may require additional policy interventions to speed progress in this area.

It is possible that a gas supply disruption may be triggered by an external natural hazard event or emergency situation of sufficient magnitude to lead to activation of a national civil defence response. In such a circumstance civil defence powers would appear to override existing contingency management arrangements under the CCM Regulations. Our analysis suggests that further clarity is required of coordination requirements in such an event, and the different roles and responsibilities that arise where there might be need to override existing commercial arrangements.

In summary, therefore, the study concludes that the New Zealand gas supply system has a high degree of resilience and that existing industry operating standards and market structures pose no undue threat to security of supply. This is not to say that continued scrutiny of the industry regulatory environment is not warranted, but experience over the last forty plus years shows that in-built redundancy within critical supply chain elements and the industry's own contingency management processes mean that in almost all situations unplanned interruptions of various durations, as occur from time to time, are usually rectified quickly and pass unnoticed by most other industry participants and consumers.

Threats to the supply chain are well known with the main hazards in respect of pipeline routing and facilities operation subject to statutory oversight/certification, regular monitoring, maintenance and/or mitigation works. Under AS 2885, pipeline operators are required to adhere rigorously to the risk assessment and safety management frameworks prescribed within the industry's Pipeline Integrity Management processes[3]. The creation of a new stand alone agency, WorkSafe NZ, that will administer pipeline safety requirements, may well add further dimensions to safety management practice, but it is yet too early to predict how this might unfold.

This study has provided a high level assessment of supply security risks. Further quantification of economic impacts may well be desirable but in the interim we suggest the following points be considered as items for consultation:

1) Creating a standardised economic treatment of asymmetric risk (low probability high consequence events) to ensure the economics are more robust and comparative industry studies utilise a common methodology.

2) Further analysis on how price/quality regulation might influence the approach to risk and the concomitant security standards that might apply, and the cost implications of adopting different security standards.

[3] Appendix 1

3) Additional stochastic modelling, similar to that undertaken in the original CAENZ study, to assess the impacts of gas supply disruption across the range of possible hydrological conditions and to better establish price volatility in the electricity market over an extended curtailment event due to fewer available schedulable generation sources, including the further loss of Huntly coal units.

4) Further analysis of the vulnerabilities and social cost elements arising from a severe loss event, especially within the major urban low pressure distribution networks.

5) Further assessment of geotechnical risks on the Vector transmission system.

6) Understanding the need/use for a supply disruption recovery committee or similar to meet unforeseen coordination requirements and secondary impacts, especially in the event of a national civil emergency being declared.

Finally, we comment that despite relative optimism on the robustness of the current gas market arrangements there are some opportunities for further mitigation of supply interruption impacts. These include:

1) Wider stakeholder engagement and a deeper level of transparency to ensure the market and the public are adequately informed of the risks to supply so that gas users are better incentivised to take mitigation action as required. Such risks include possible wider community impacts from local business interruptions and social impacts like loss of employment as a consequence of a gas supply disruption event.

2) Continued development of mechanisms for energy trading as well as progress towards more flexible transmission products will contribute to increased resilience and reduced vulnerability.

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APPENDICES

1. INTRODUCTION

A 2009 report by the New Zealand Centre for Advanced Engineering (CAENZ)[4] for Transpower, provides a high level analysis of the impact of gas supply disruptions on the gas and electricity markets. This current report was commissioned by the Ministry of Business, Innovation & Employment (MBIE) to refresh and extend the 2009 CAENZ analysis, as necessary, to inform a deeper understanding of the economic significance of supply risks, and to identify economic opportunities to mitigate those risks, if any.

The report builds on the earlier work undertaken by CAENZ, updated to reflect current gas supply and consumption arrangements, but considers in addition the influence of current gas market systems, process and rules on contingency response options, and the likely outcomes that will emerge under current governance arrangements.

To keep the report at a high level and in keeping with MBIE's broader question about scenarios with major economic impacts we have only considered gas supply interruption scenarios with immediate cost impacts greater than $100 million (direct costs). Further economic analysis is beyond the scope of this work but the scenario analysis is expected to identify the broader economic questions to investigate.

Differently from the CAENZ analysis we have chosen not to explore in depth key scenarios but have instead adapted the lessons learned from recent events that have resulted in a significant curtailment of gas supply, and used these lessons to form the different scenarios examined. The construct we have adopted is to explore what characterises the critical risks that emerge from these events and the interventions or risk management strategies likely to lead to reduced risk exposures, and thus loss.

An important additional benchmark is provided by the Maui gas transmission pipeline failure in October 2011. As a result of that failure the Ministry of Economic Development (now MBIE) undertook a review on behalf of the Minister of Energy and Resources into the cause of the outage, the adequacy of the governance arrangements that were in place at the time of the event, and the preparedness of business for the outage. That report and the consequent actions arising from its recommendations offered useful insights that informed this work. Estimates provided in the MBIE review suggest the gross cost of the outage was of the order of $200 million, dominated by costs incurred by the dairy industry.

The question that thus arises for this study was whether this event was likely to be typical of other possible events, and, if not, what might be the scale of other postulated disruption scenarios; and their impact on the NZ economy. It is not axiomatic that other events will be significantly worse or that longer duration curtailment events will lead to more severe economic loss. In this study, therefore, we re-examined the interdependencies and commercial arrangements that characterise the NZ gas supply system to fully establish the range of possible outcomes and consequences.

Ultimately, in the event of an extend period of curtailment, the dominant factor shifts from the initial contingency period where focus is very much on ensuring transmission system survival and reinstatement, to instead, providing the mechanisms for gas users themselves to adjust to the new balance between supply and demand that ensues. This raises important issues in respect of how one might go about managing that transition over time and the governance arrangements that lead to the most effective outcome. These issues are explored in the final section of this report.

We acknowledge the contributions received from the Ministry of Business, Innovation and Employment, Transpower Ltd, the pipeline owners and operators, and major gas users in bringing this study together.

[4] CAENZ "Long-Term Gas Supply Disruption-Impacts on New Zealand's Electricity Generation System". A Technical Report- September 2009.

2. APPROACH

This expert study is intended to examine appropriate risk management approaches applicable to the management of a major gas disruption event within the NZ gas market and to inform a deeper understanding of the economic significance of supply risks, as well as identify economic opportunities to mitigate any such risks deemed of sufficient magnitude for action.

In order to answer these questions it is first necessary to consider the likely range of loss events that might conceivably have a sufficiently significant impact on the gas supply situation to warrant further mitigation action or market interventions. To this end we have examined in some detail:

- The natural gas supply chain, critical vulnerabilities, and the frequency of occurrence for the different loss categories so defined,
- Changes that have occurred in gas supply / demand balances and the regulatory environment since the publication of the 2009 CAENZ report,
- The consequences arising and likely responses to a number of different loss scenarios supported by case study analysis of analogue events, including the 2011 Maui pipeline outage and the 2008 Varanus Island, Western Australia, gas plant explosion,
- Matters impacting security of supply as covered by the governance and regulatory framework for the industry including technical standards, gas quality and economic regulation and, finally
- The adequacy of existing practices and arrangements to mitigate the risks identified above.

The loss scenarios themselves are intended to reflect the inherent vulnerabilities present within the New Zealand Gas Supply system. Importantly, such vulnerabilities are not solely related to the gas transport (transmission and distribution) system but also include any dependencies that might arise in respect of the gas supply facilities and their connection to the transport system as well as the various inter-connections between different supply chain elements. No probabilities are assigned to the scenarios occurring, although where data could be accessed, frequency is provided to give a sense of potential likelihood.

Instead, the different scenario outcomes derived from the above analysis have been characterised and described in the report in terms of the likely range of consequences and risk implications that might reasonably be foreseen. We believe this approach is preferable to seeking to derive a precise loss estimate for the different situations as the events being described are infrequent and highly variable. The imposed uncertainties that thus derive can only be adequately treated using stochastic modelling techniques, which fall well beyond the budget scope of this study. Thus, scenario outcomes are described in this report in terms of expected outcomes:

- Loss effects
- Market effects
- Risk mitigation approaches

In addition the study brief required comment on whether any market or regulatory failures might affect the adequacy of risk management at a national level. This issue was simply considered on the basis of whether the perceived risk to public good from a major disruptive event was capable of being adequately managed by private good risk management, or whether alternative approaches might be considered.

Using this framework, an overview of safety and reliability performance within the industry is provided in the body of the report so as to inform non-industry stakeholder’s of the requirements prevailing for risk management within the industry. More detailed descriptions of pipeline integrity management approaches (AS 2885) as well as a discussion on technology improvements and their influence on risk management practice are offered in the appendices to the report.

The concepts of learning, evolution, and continual improvement described in these sections are inherently encapsulated in the integrity management process. This cycle continues throughout the lifetime of the built asset and when combined with current regulatory and governance oversight of the industry provides a suitable platform for any desired further analysis of potential mitigation options and/or consultation with interested parties on options to improve security of gas supply.

3. NATURAL GAS SUPPLY CHAIN

The Natural Gas Supply Chain comprises a physically connected network of producer fields, production stations, gas transmission (pipelines, compressors), and gas distribution. The large gas users, such as gas-fired power stations, petrochemical plants and major industrial sites are supplied directly from the transmission system, whilst the majority of users (smaller industrial, commercial and domestic) are supplied through local low pressure networks. This physical supply chain is overlain with the various commercial and regulatory arrangements governing product ownership, distribution and use of systems.

It is important to recognise the industry is complex and multi-faceted and that the successful operation and transfer of natural gas is reliant not only on the integrity of the physical infrastructure but as well the commercial and regulatory arrangements that govern the relationships between the various parties involved. This is well described in the Gas Industry Company publication “The New Zealand Gas Story” published in February 2013[5].

The back bone of the supply chain is the gas transmission pipeline system which transports gas at high pressure from production stations to delivery points supplying end-users and to the lower pressure local area gas distribution networks. There are two open access pipeline systems and as a matter of record, these are shown in Figure 1:

- the 308km Maui pipeline (mostly 750mm diameter), extending from Oaonui, in south west Taranaki, to Huntly, owned by Maui Development Limited (MDL) and
- the 2,220km Vector pipeline system (mostly from 100mm to 200mm diameter), generally radiating from the Maui pipeline and delivering gas throughout the North Island.

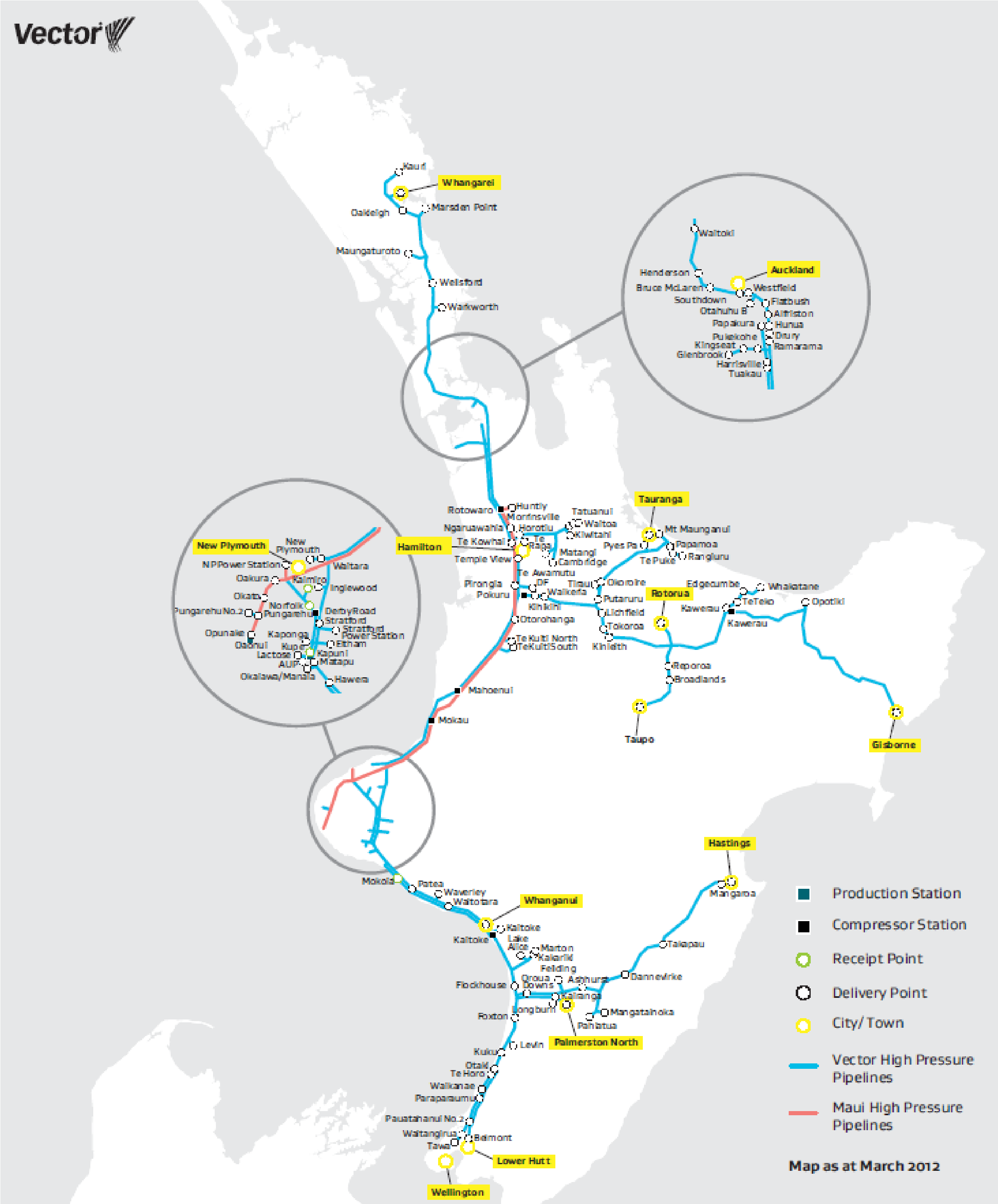
In addition to the open access pipelines, there are smaller pipelines owned by gas producers, and in some cases end-users, that do not offer open access. The principal ones include:

- Vector owned Low Temperature Separator (LTS) pipeline connecting Kapuni Gas Treatment Plant to the Faull Road Mixing Station (400 mm nominal bore, 50 km)
- NZEC owned Waihapa production station to New Plymouth Power Station (200 mm nominal bore, 45 km)
- Todd owned McKee to Faull Rd Mixing Station
- Turangi to Methanex bypass line
- Faull Rd Mixing Station pipelines to Methanex facilities at Motunui and Waitara Valley
- Nova Gas owned distribution networks (Wellington, Hastings, Hunua, Hawera)

In terms of a possible gas supply disruption the Vector and NZEC lines offer some potential backup to the open access system but on a limited geographical scale.

[5] “The NZ Gas Story - the State and Performance of the NZ Gas Industry”, Gas Industry Company, February 2013.

Figure 1:- New Zealand Natural Gas Transmission Pipelines



3.1 Overview of NZ Gas Supply and Demand

Gas supply for the 2012 calendar year accounted for 21% of New Zealand's 844 PJ of primary energy supply[6].

Supply and demand data are provided in Tables 1 and 2. For comparison purposes data for the 2007 year is also provided as an indication of the changes occurring within the industry and to provide comparison against the data reported in the CAENZ technical report[7] and as context for further discussion in this report.

Other developments in supply over this period include Solid Energy's pilot coal seam gas facility near Huntly, since decommissioned for lack of commercialisation opportunities, and the Contact Energy investment in the Ahuroa gas storage facility.

Key demand pattern changes included the restart of previously idle capacity at Methanex matched almost by an equal reduction in gas baseload generation at Contact's TCC and Otahuhu B plants in favour of smaller peaking plants to complement new wind generation and increased geothermal baseload plant owned by MRP (Nga Awa Purua). Fuel switching also occurred in the industrial sector with the Norske Skog timber processing site switching from natural gas to geothermal energy.

Table 1: - New Zealand Gas Demand (PJ)

Demand	2007	2012	Changes over Period
Electricity Generation	75.4	53.6	Addition of Stratford Peakers (2 x 100 MW) January 2011 and McKee Peak Plant (2x50MW) October 2012
Co-Generation	22.6	19.3	Southdown output reduced commensurate with increased geothermal generation
Petrochemicals	15.4	31.7	Methanol production output tripled. Restarted Motunui-2 methanol plant October 2008, shutdown Waitara Valley. In July 2012 restarted additional Motunui-1 facility
Industrial	35.2	46.4	Includes increase in consumer energy for methanol and ammonia urea petrochemical manufacture
Commercial	6.6	7.9	Approximately 2,700 connections per annum added
Residential	5.7	6.3	
	160.9	**165.2**	**Overall demand approximately unchanged**

6 Energy in New Zealand 2013.

7 CAENZ "Long-Term Gas Supply Disruption-Impacts on New Zealand's Electricity Generation System". A Technical Report-September 2009.

Table 2: - New Zealand Gas Supply (PJ)

Supply	2007	2012	Supply diversity increased with Kupe and smaller field developments onshore Taranaki to include new production stations at Kupe and Cheal to offset production declines in mature fields
Pohokura	69.6	73.5	
Maui	51.9	34.9	Field decline
Kupe	0	22.0	On-stream December 2009
Kapuni	21.4	13.3	Field decline
Mangahewa/ McKee	10.3	12.9	Field development at Mangahewa in 2012 to supply increased demand at Methanex
Turangi/ Kowhai	4.9	10.0	Kowhai development 2009 and field development at Turangi
Other	6.1	3.0	Smaller onshore gas fields declined with new production at Cheal, Sidewinder, Copper Moki in 2012

A more detailed breakdown of the major gas fired plants generating for supply to the grid are listed in Table 3. While Huntly has (nowadays) an additional three units[8], each of 250 MW capacity, which have operated on gas for much of their life, these have largely operated on coal for a number of years and are assumed to burn coal for the purposes of this study. Some gas is required to start these coal fired units.

Table 3: - Major gas fired power stations

Plant	Installed Capacity (MW)	Heat Rate (GJ/MWh)	Maximum Gas Consumption (TJ/day)
Otahuhu B	380	7.35	67.0
Southdown	190	10.00	45.6
Huntly U5	385	7.30	67.5
Huntly U6	50	10.53	12.6
McKee Peaker	100	10.50	25.2
Taranaki CCGT	380	7.70	70.2
Stratford Peaker	200	10.60	50.9
Total	**1685**		**339**

Data from Ministry of Business, Innovation and Employment "EDGS" database

The reliability of gas supplies for electricity generation is significantly affected by the following factors:

1) Taranaki plants are Contact's Stratford generation, and the cogeneration plants at Whareroa and Kapuni. Plants north of Taranaki consist of Huntly Units 5 & 6, Southdown, Otahuhu B and the co-generation at Kinleith and Te Rapa. There are no credible scenarios that would result in loss of both Taranaki and Northern parts of the system.

2) The 100 MW of open cycle gas turbine plant located at the McKee production facility is not dependent on the pipeline system for fuel supply and so is less vulnerable to fuel supply

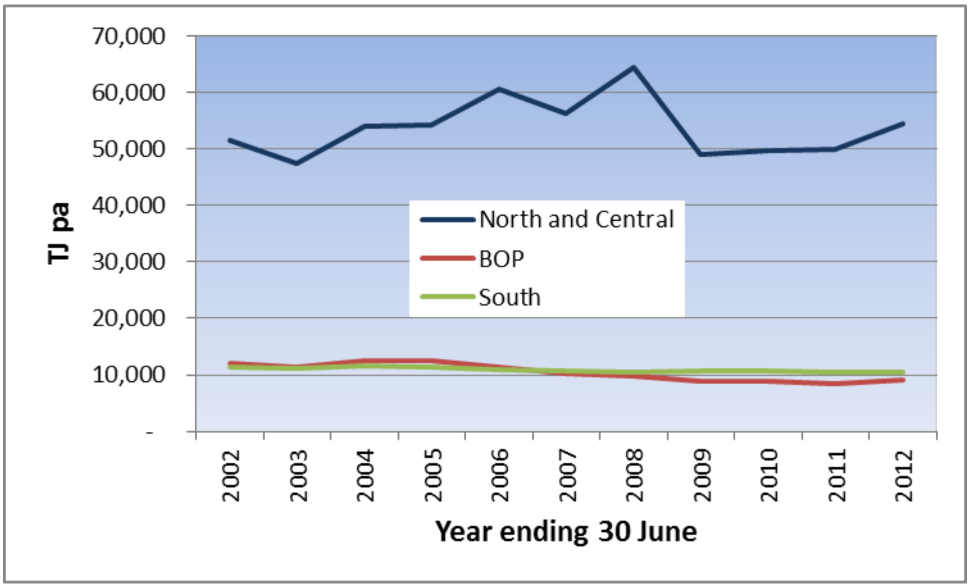
[8] Only two units expected to be operational by end of 2013 with the third to be put in storage. Stored unit can be brought back into the market but will take some months to recommission.

disruptions. Hence this facility is affected by production disruptions only, whereas other plants are at risk from both pipeline and production problems. The plant began operation in September 2012.

3) Stratford generation consists of the 380 MW Taranaki Combined Cycle and the Stratford Peaker open cycle plant of two units each of 100 MW capacity. This generation can be supplied from the Ahuroa gas storage facility which has a maximum capacity thought to be 15 PJ and is currently capable of delivering gas at the rate of 45 TJ/day. This rate of withdrawal from storage would be sufficient to run the 200 MW open cycle plant at full load.

Outside of electricity and methanol production gas demand has been reasonably stable over a long period. This is reflected in the Vector system demand statistics shown in Figure 7. It thus seems reasonable to assume that the 2012 data reflects the likely demand profile going forward unless there is significant new discovery or downstream investment.

Figure 2: - Vector System Demand[9]



The physical arrangements that are characteristic of New Zealand's gas supply chain include:

- Single supply point (Taranaki) for gas.
- Gas processing facilities are dedicated to associated fields (not interchangeable).
- Gas processing facilities, other than Kapuni, are single train operations.[10]
- 95% of gas demand is in Taranaki and north of Taranaki.
- 43.5% of demand is north of Taranaki, and 5.2% south.
- Over half of the demand is located near Taranaki gas fields.

[9] Fluctuations in Northern system largely determined by power generation at Otahuhu B and Southdown.
[10] Including Oaonui where gas processing redundancy has been removed in line with field output decline. The Kapuni production station has two trains, and the Kapuni Gas Treatment Plant has three trains, of which only two are currently utilised.

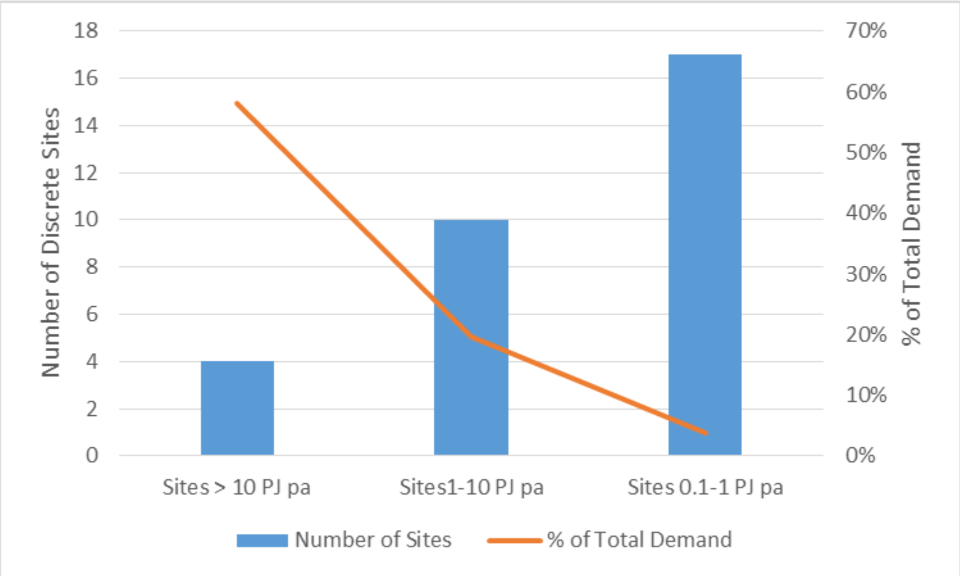
- Gas transmission is characterised by single trunk-lines and long laterals with only limited pipe looping that might offer some measure of redundancy.
- Key demand areas outside of Taranaki tend to be near the end of trunk-lines (Auckland, Waikato, Bay of Plenty, Wellington) and distant from the supply area. This increases the exposure risk to a transmission pipeline event.

Also, as previously noted, 80% of the total gas demand is concentrated in approximately 31 individual sites. This is aptly demonstrated in Figures 8 and 9.

To a degree the Maui pipeline rupture in October 2011 therefore represented close to a worst case scenario of a supply interruption event from transmission infrastructure failure. Fortunately the land subsidence that caused the rupture of the Maui Pipeline didn't affect the 200 mm Vector pipeline running right next to it. Limited supply therefore was able to be maintained to keep commercial and domestic users supply uninterrupted. Three additional factors would have made this event worse.[11][12]

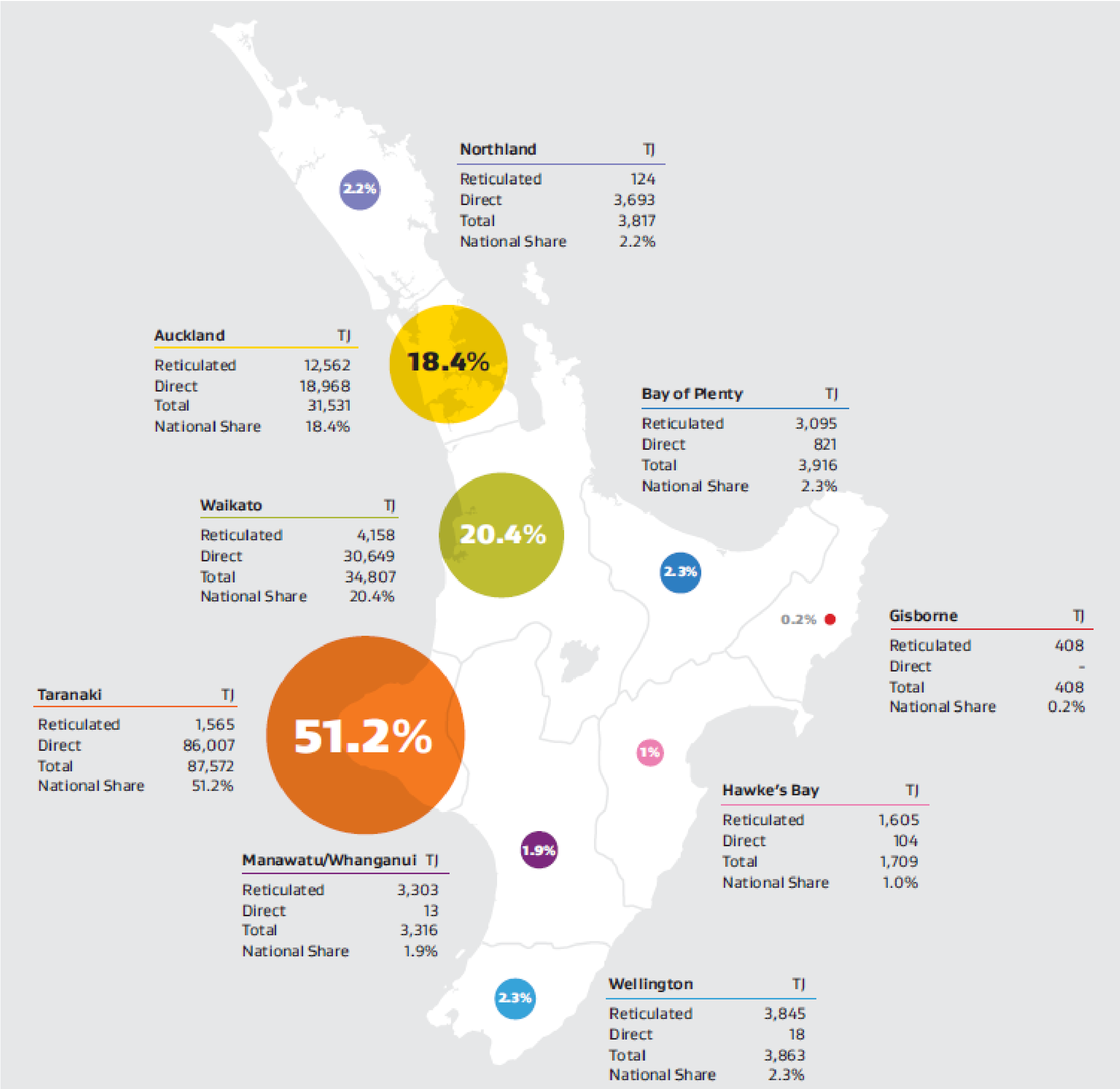
1) Concomitant failure of adjacent 200 mm Vector pipeline.
2) Event occurring in difficult to access terrain for repair.
3) Low hydrology combined with peak seasonal electricity demand.

Figure 3: - Share of total gas demand top 31 sites



[11] Only the failure of the 200 mm line might be classed as a dependent event given common failure mode (land slip). The other two are independent and hence probabilities are multiplied to reduce likelihood.
[12] From a regional perspective a failure of the Maui pipeline closer to Rotowaro may have reduced survival time for the Waikato, Auckland, and Northern regions, but it would also have left the Bay of Plenty region unaffected. These kind of permutations haven't been tested but are considered to be second order in relation to the three described factors.

Figure 4: - North Island Regional Gas Market (TJ)



Source: MBIE

In the New Zealand gas transmission system there are relatively long stretches of pipeline where pipelines are not looped to provide any redundancy for supply should a pipeline fail. For example any point past the Pokuru compressor station to Putaruru would affect all supply to the Bay of Plenty region including Taupo and Gisborne and would immediately impact processing industries including forestry, dairy processing, and enterprises such as Cedenco and Dominion Salt.

3.2 Market Arrangements

At the producer to wholesaler or producer to large customer level the New Zealand gas energy market arrangements are through non-standard bilateral contracts of various term durations, typically less than 5 years but longer in some cases, depending on confidence in available gas reserves or whether undeveloped reserves need to be underwritten with longer term supply agreements to develop them. Agreements are generally confidential between the parties creating a high level of opaqueness around terms including price. A liquid spot market hasn't yet developed although both Transpower and NZX are competing to introduce a spot market trading platform to balance the under and oversupply in bilateral arrangements.

At a retail level, at least for mass market residential customers, gas contract terms including price are standardised by retailer and available in the public domain.

Gas transmission arrangements are bilateral between shippers and the commercial operators of the transmission system and covered by the standard terms and conditions of the Maui Pipeline Operating Code (MPOC) and the Vector Transmission Code (VTC). Transmission pricing is also fully transparent for standard agreements and regulated under Part 4 of the Commerce Act. Vector also allows for Supplementary Agreements where VTC terms may be varied and agreed between the parties. There is limited disclosure on these arrangements.

Transmission capacity rights on the Maui pipeline are available through a common carriage regime which means that it is fully flexible with regards to quantities subject to a nominations regime and to maximum aggregate pipeline quantity limits, beyond which users are curtailed on an equal basis[13]. Vector operates a contract carriage model selling 12-month maximum capacity rights to shippers. Trading of these capacity rights is restricted by the terms of the VTC which requires Vector's approval before a trade is allowed although in 2011, in response to concerns about competition on the Vector's Northern Pipeline, Vector and a majority of shippers agreed the so-called Bridge Commitments[14] allowing for the transfer of capacity rights between shippers under certain conditions.

Capacity products are currently under review by the industry to create greater economic efficiencies in the gas transmission system.

The open access distribution (network) system operators (Vector, Powerco, GasNet) manage access to their networks through standard Use of System Agreements. Pricing of networks is standardised for most of the mass market (residential, small commercial) but all network operators also operate non-standard pricing for larger customers.

The market arrangements have not altered materially since the previous CAENZ report although there are emerging signals (gas trading platforms, GIC initiated Gas Transmission Investment Project) that market arrangements may start to mature towards more efficient arrangements common in deeper and more liquid markets. A gradual evolution towards these market arrangements will help mitigate the economic impacts of gas supply interruptions by enabling limited supply to be allocated to parties who value it the most.

[13] MPOC does have a product that gives users ability to have preferential rights in event of curtailment but in practice there has been no demand for this product.

[14] http://gasindustry.co.nz/sites/default/files/u254/20121231_bridgecommitments_quarterlyreport_184307.1_2.pdf

4. NEW ZEALAND GAS SYSTEM GOVERNANCE

Matters impacting security of the gas supply chain occur in different areas of the governance and regulatory framework including technical standards, gas quality and economic regulation. This section describes briefly where they arise, identifies any related new developments in the framework since the 2009 report and highlights potential areas of relevance to the scenarios. Where specific aspects impact directly on supply chain vulnerabilities these are picked up and discussed in the body of the report.

OVERVIEW

The gas industry's primary legislation is the Gas Act 1992, which was amended in 2004 to set up the co-regulatory model and the co-regulator, the Gas Industry Company (GIC). The Gas Act sets out the Government's policy objectives for the sector, which are supplemented by any policy statements the government may issue from time to time. The most recent Government Policy Statement dates from 2008. The Act and the GPS taken together provide an umbrella policy objective "for gas to be delivered in a safe, efficient, fair, reliable and environmentally sustainable manner". Other policy objectives include:

- The facilitation and promotion of the ongoing supply of gas meets New Zealand's energy needs, by providing access to essential infrastructure and competitive market arrangements.
- Barriers to competition in the gas industry are minimised.
- Incentives for investment in gas processing facilities, transmission and distribution, energy efficiency and demand-side management are maintained or enhanced.
- Delivered gas costs and prices are subject to sustained downward pressure.
- Risks relating to security of supply, including transport arrangements, are properly and efficiently managed by all parties.
- Consistency with the Government's gas safety regime is maintained.

Further objectives and outcomes the Government wants the GIC to have regard to in recommendations for rules or regulations, are established by the 2008 GPS, and include that:

- Energy and other resources used to deliver gas to consumers are used efficiently.
- The full costs of producing and transporting gas are signalled to consumers.
- The quality of gas services where those services include a trade-off between quality and price, as far as possible, reflect customers' preferences.
- The gas sector contributes to achieving the Government's climate change objectives as set out in the NZES, by minimising gas losses and promoting demand-side management and energy efficiency.

The GPS also notes the need for sound arrangements for the management of any critical gas contingencies.

Taken together the policy framework recognises security as one amongst a number of imperatives to be managed.

REGULATORY AGENCIES

MBIE

MBIE has primary responsibility for advising the government on gas policy matters and administering gas relevant legislation, including the safe supply and use. Importantly MBIE is the responsible agency for the Health and Safety in Employment Act 1999 (HSE Act) which aims to promote the prevention of harm to all persons at work. This legislation has scope to apply its general aims to specific activities. For example in the case of gas it is applied (amongst others) to gas pipelines (via the Health Safety and Employment (Pipelines) Regulations 1999) where the regulations set the standards in relation to design, construction, operation, maintenance, suspension, and abandonment of pipelines. The regulations require that a pipeline owner ensures that there is a current certificate of fitness in place for the pipeline. A more detailed listing is described in Table 5.

GAS INDUSTRY COMPANY

GIC is responsible as industry regulator for administering rules, regulations and arrangements in relation to wholesaling, processing, transmission, distribution, and the retailing of gas which includes recommendations on critical contingency management. The GIC operates under a unique co-regulatory model which allows the industry to develop its own arrangements which the GIC facilitates whilst providing a regulatory backstop for the Minister to intervene where the co-regulatory model is unable to do so. Additional policy objectives for the GIC are guided by the Government Policy Statement on Gas Governance

Section 43F contemplates that gas industry regulation-making powers can extend to:

- wholesale market (e.g. clearing and settlement)
- gas processing facilities (setting terms and conditions for access to, and use of)
- gas pipelines (setting reasonable terms for access, requiring expansions, upgrades or service quality improvements including how these will be paid for)

The GIC is also responsible for managing the Critical Contingency Regulations 2008, which set out the process for managing incidents that disrupt gas supply. These regulations have been the subject of a comprehensive review following the Maui pipeline disruption in October 2011. Revised regulations are currently in the drafting process with sign-off by the Governor General expected shortly.

COMMERCE COMMISSION

The Commerce Commission regulates the pricing and minimum service quality standards for gas pipeline businesses via a price-quality and information disclosure regime, introduced in 2008. The initial Default Price-Quality Path (DPP) came into effect in July 2013 and will run for 4 years. For information disclosure Gas Pipeline Businesses (GPB) are required to disclose a range of information regarding historical performance and asset management plans which include details of risk policies, assessment and mitigation (including areas of the network vulnerable to high impact/low probability events and description of the resilience of the network and asset management systems to such events).[15]

DPPs are set as generic price paths and are not intended to address more major levels of investment (over and above the allowance specified within the DPP). The framework provides a Customised Price-Quality Path (CPP) for this purpose, which envisages more detailed assessment and greater scrutiny of proposed expenditure than the default. Investments to address security issues may require GPBs to

[15] Gas Transmission Information Disclosure Determination 2012 (Clause 17).

apply for a CPP where the GPB requires a return on that investment, which raises some uncertainty as to date there have been no applications for a CPP (although we note the initial DPP has only recently come into force).

Under the Commission's Information Disclosure requirements, gas transmission businesses must disclose asset management plans which contain sufficient information to assess whether assets are being managed for the long term and should provide a sound basis for on-going assessment of asset-related risks, particularly high impact asset-related risks.[16] As an example, Vector has recently released its asset management plans for transmission and distribution.[17] The transmission asset management plan includes Vector's system security standard which defines a minimum level of system security and performance such as physical system capacity, and component redundancy levels (back up arrangements in case of pipeline system component failures).

MOU BETWEEN GIC AND COMMERCE COMMISSION

The Commerce Commission and GIC have overlapping areas of interest on matters such as quality of service, pricing outcomes and information disclosure. This is managed through a memorandum of understanding between the two where GIC is required to advise the Commission on any matters likely to be relevant to the Commission's Part 4 powers. In turn the Commission must take into account any gas governance arrangements developed by GIC.

An overlapping area is in investment in pipelines where GIC (via the Minister) can require investment (pipeline expansion, upgrade or improve service quality [Gas Act, Section 43F]) and the Commerce Commission considers that investment in setting or resetting price paths.

To date no applications for specific pipeline expenditure (via a CPP) have been submitted to the Commission; nor has GIC sought any investment to date. We note though that GIC's initiated Gas Transmission Investment Project, which is aimed at improving gas transmission arrangements, is considering whether an "investment test" for expansion is appropriate, which might overlap with the Commission's responsibilities.

TREASURY

Treasury has a role that touches on gas including as the responsible agency the National Infrastructure Unit (NIU) which provides a high-level cross-government coordination role across a range of infrastructure, including gas. The NIU's role is to take a national overview of infrastructure priorities – providing cross-government co-ordination, planning and expertise.

Treasury has also considered whether the current regulatory model is meeting best practice in supporting optimal investment, the allocation of pipeline capacity and the regulatory model (in particular whether New Zealand has too many industry specific regulators).

CIVIL DEFENCE AND EMERGENCY MANAGEMENT ACT 2002 (CDEMA)

The Ministry of Civil Defence & Emergency Management (MCDEM) administers the Act and its role is to provide strategic policy advice and structures to provide capability and management of emergencies, support to stakeholders, co-ordinate planning and to manage government response to major events. The relevant aims of CDEMA are to improve and promote the sustainable management of hazards and to encourage the co-ordination of emergency management.

[16] Commerce Commission, Gas Transmission Information Disclosure Determination 2012
[17] http://vector.co.nz/corporate/disclosures/gas/gas-asset-mgmt

The National Crisis Management Centre (NCMC) is activated in major emergencies and plays a central co-ordinating role. In case a gas critical contingency is longer than planned for or is part of a national emergency, the CDEMA may take precedence and the critical contingency may be managed through the NCMC (Regulation 14 under the Gas Governance (Critical Contingency Management) Regulations 2008). The NCMC may well act to reprioritise available gas depending on the situation and the predetermined curtailment bands may no longer apply.

How CDEM's role with others (e.g. GIC, CCO) would overlap in an emergency is not altogether clear. Whilst MCDEM recognises[18] that sector coordination will be required in large events, there does not appear to be any specific provision for a wider consultative/coordination role that would include end users in the event of a major crisis, similar perhaps to the National Emergency Sharing Organisation that exists in the liquid fuels industry or the Supply Disruption Committee that operated in Western Australia during the Varanus Island supply disruption.

CRITICAL CONTINGENCY

The Gas Governance (Critical Contingency Management) Regulations 2008 are intended to ensure the effective management of critical gas outages and other security of supply contingencies without compromising long-term security of supply. These regulations provide for, amongst other things, the development of critical contingency management plans and processes for managing a critical contingency.

During a critical contingency (depending on the severity of the event), the largest load is curtailed first. This includes generators and petrochemical plants. Next are large industrial and commercial users and so on until the final load to be curtailed is critical care providers (see Table 4: - Proposed curtailment bands). Domestic users are not covered under the regulations.

To cater for priority access to gas during a critical contingency, the bands provide for deferred curtailment status for Minimal Load Consumers (MLCs), Electricity System Security Providers (ESSPs), and Essential Services providers (now grouped in one band).[19]

Restoration of gas occurs in reverse order to curtailment (i.e. last curtailed, first restored). However, the Critical Contingency Operator (who manages the critical contingency) has discretion to change the order of restoration depending on the circumstances of the event. In the case that a partial amount of gas is available for a given band, the CCO has the discretion to curtail only a subset of the band or curtail the whole band's usage by a given amount. The exact decision will depend on the nature of the contingency. To date, it appears that this question has yet to be fully considered by the various likely-affected parties.

[18] Sector coordinating entities (SCE) are proposed incorporating the lifeline utilities to help facilitate solutions to issues, coordinate and provide sector information and contribute to NCMC planning activities.

[19] MLCs are allowed a small, predetermined amount of gas to ramp down their operations while the rest of their band would be curtailed immediately. ESSPs are also allowed a small amount of gas to start up generation units that can then switch completely to alternative fuel.

Table 4: - Proposed curtailment bands

Curtailment Band	Consumption	Description
0	N/A	Gas offtake for injection into storage
1	More than 15TJ per day	Consumers supplied directly from the transmission system and that have an alternative fuel capability
2	More than 15TJ per day	Consumers supplied directly from the transmission system and that do not have an alternative fuel capability
3	More than 10TJ per annum and up to 15TJ per day	Typically large industrial and commercial consumers
4	More than 250GJ per annum and up to 10TJ per annum	Medium-sized industrial and commercial consumers
5	More than 2TJ per annum	Essential service providers.
6	250J or less per annum	Small commercial consumers
7	N/A	Critical care providers

GAS QUALITY

Gas quality affects the reliability of gas supply and the long term integrity of the transport system. The GIC has acknowledged that arrangements for managing gas quality are complex and obscure[20]. There are on-going industry concerns about the responsibility and liability for gas quality in New Zealand. Despite the potential impact to the gas supply chain, no overarching industry arrangements or regulations are currently in place. GIC has no regulatory mandate in this work stream but has the responsibility to ensure that industry arrangements provide for gas quality in a manner that facilitates the safe, efficient, and reliable delivery of gas. To that end, GIC has been investigating industry arrangements for managing gas quality and the responsibility and liability for gas quality throughout the supply chain.[21]

GOVERNANCE FRAMEWORK

Table 5 and Table 6 identify the more significant legislation governing the gas system.

[20] http://gasindustry.co.nz/sites/default/files/u180/Advice_to_Minister_of_Gas_Quality__155013.pdf

[21] Recent amendments to the Gas (Safety and Measurement) Regulations 2010 have placed new obligations on retailers to protect consumers from gas quality events and these are prompting more focus on the wider industry arrangements for gas quality, around which GIC is maintaining an oversight role.

Table 5: - Governance Framework[22]

Arrangement	Purpose	Relevance to supply security	Substantial changes since 2009
Gas Act 1992	Repeals the previous legislation (Gas Act 1982), removes exclusive retail franchises and price controls, places a focus on open, competitive markets. Establishes co-regulatory regime [light-handed].	Section 43F (2) (a) (vi) empowers the Minister to make regulations for 'arrangements relating to outages and other security of supply contingencies' Section 43ZN outlines objectives of the industry body (GIC) in the recommendations it makes. The relevant objective is' risks relating to security of supply, including transport arrangements, are properly and efficiently managed by all parties' Section 54A prescribes requirements for a Safety Management System. Outlines that regulations made must provide for requirements relating to the systematic identification of existing and new hazards and management of those hazards.	No significant changes (minor and consequential amendments made) to the Legislation.
Government Policy Statement on Gas Governance (GPS)-2008	Sets out policy objectives additional to those in the Gas Act 1992.	Section 11(e) of the GPS reiterates the Gas Act's objectives for risks relating to the security of supply to be properly and efficiently managed by all parties (from Section 43ZN(b)(v) of the Gas Act). Section 13 asks for 'sound arrangements for the management of critical gas contingencies'.	No changes since 2008. Other regulatory and policy workstreams have been progressing the objectives of the GPS (such as Critical Contingency regulations and the Gas Transmission Investment Programme.
Health and Safety in Employment Act 1992	Promotes the prevention of harm in or near workplaces. Basis for specific regulations in 1999 relating to gas pipelines and petroleum exploration/extraction regulations being updated in 2013.	The HSE (Pipelines) regulations 1999 reference the standards to which pipelines must meet in relation to design, construction, operation, maintenance, suspension, and abandonment. The regulations require all pipelines to operate with a 'Certificate of Fitness'. Other regulations under the H&SE Act include: 1. The HSE (Petroleum Exploration and Extraction) Regulations 2013 are aimed at strengthening the management of hazards on or near onshore and offshore petroleum installations, reduce the likelihood of an uncontrolled release of oil and gas, and provide for information collection on incidents. 2. Health and Safety in Employment (Pressure Equipment, Cranes, and Passenger Ropeways) Regulations 1999 - Require Inspection Body to issue Certificate of Design Verification and Inspection to independently verify safety in equipment design and asset condition.	Major institutional changes have occurred and underway. The Health and Safety at Work Bill is intended to replace the Act by the end of 2014. The High Hazards unit was established in 2011 and WorkSafe NZ to be established at the end of 2013.

[22] Adapted from original table from http://gasindustry.co.nz/sites/default/files/publications/gas_story_183740.4.pdf, update from GIC via email on 23 September 2013

Arrangement	Purpose	Relevance to supply security	Substantial changes since 2009
Gas (Information Disclosure) Regulations[3] 1997	Introduced pursuant to the Gas Act 1992 to create information transparency as part of the light-handed regime.	Requires disclosure of asset management plans and reliability information.	Superseded from 1 October 2012 by new information disclosure requirements under Part 4 of the Commerce Act 1986. New disclosures to be made public by 2014.
Commerce Act 1986 Amendment (as amended in 2008)	Part 4 amendments include the economic regulation of gas distribution and transmission.	The Default Price-Quality Path sets a regulated revenue cap and incentives for gas transmission and distribution businesses. The Revenue Cap could effectively as a reference point in making investment decisions that impact the supply chain. The specific target of response time to emergencies sets a threshold for gas transmission and distribution businesses and provides for penalties if that threshold is not met. Future DPPs will include additional reliability measures based on data from information disclosures and consultation with stakeholders. Disclosure of asset management plans must include details of risk policies, assessment and mitigation of those risks and details of emergency response and contingency plans.	Major milestone in 2013 was the final decision on the initial Default Price-Quality Path for gas pipeline and distribution businesses which took effect on 1 July 2013.
Gas (Safety and Measurement) Regulations 2010	Prescribe rules and requirements for gas safety and measurement	Minor	Amended in 2011 provide clarity on the technical and policy intent of the regulations and reduce compliance costs.
Maui Pipeline Operating Code (MPOC) 2005	Open access on the Maui pipeline.	Contractual arrangements governing access to the pipeline, including Inter Connection Agreements (ICA) for welded parties governing minimum gas quality standards.	Various technical amendments to the Code. Potential for significant change in contractual arrangements depending on the implementation of the Gas Transmission Investment Programme (facilitated by GIC).
Vector Transmission Code (VTC) 2007	Code-based regime replaces bilateral contract approach to Vector transmission system.	Contractual arrangements governing access to the pipeline including Interconnection Agreements (ICA) for welded parties governing minimum gas quality standards.	Various technical amendments to the Code. Potential for significant change in contractual arrangements depending on the implementation of the Gas Transmission Investment Programme (facilitated by GIC).

Arrangement	Purpose	Relevance to supply security	Substantial changes since 2009
Submarine Pipelines and Cables Protection Act 1996	Protection of undersea pipelines and cables by banning all anchoring and most types of fishing to prevent damage.	Kupe, Pohokura and Maui pipelines are all covered under the Protection Orders under the Act.	

Table 6: - GIC administered rules, regulations and voluntary arrangements

Arrangement	Purpose	Relevance to supply security	Substantial changes since 2009
Gas (Switching Arrangements) Rules 2008	Facilitate customer switching between retailers.		Minor amendments in 2010.
Gas (Downstream Reconciliation) Rules 2008	Prescribe a process for volumes of gas consumed to be attributed to retailers responsible for them.		Minor amendments in 2009.
Gas Governance (Critical Contingency Management) Regulations 2008	Process for industry participants to plan for, respond to and manage a serious incident affecting gas supply.	The CCM Regulations set out the process for managing a gas critical contingency. The CCM regulations prescribe the process to curtail gas users through grouping users in 'bands' which are progressively curtailed. The bands range from storage to critical care providers (which are curtailed last). Domestic users are not covered under the regulations.	In the process of being amended. Amendments include reclassifying curtailment bands (priority of gas supply) and mandating communications requirements.
Gas (Processing Facilities Information Disclosure) Rules 2008	Require information to be provided by owners of gas processing facilities.	To provide a process to settle the issue of whether it is necessary to recommend rules or regulations setting reasonable terms and conditions for access to, and use of, gas processing facilities.[23]	Rules expire on 27 June 2014.
Gas Governance (Compliance) Regulations 2008	Determine and settle alleged breaches of the rules and regulations.		Minor consequential amendment.
Retail Gas Contracts Oversight Scheme 2010	Ensure retailers' supply contracts with small consumers are in the long-term best interests of those consumers.		To be reviewed in 2013/2014.
Gas Distribution Contracts Oversight Scheme	Establishes principles for contract arrangements between gas distributors and retailers which contribute to ensuring terms for retailers using distribution networks are fair and reasonable.		Introduced in 2012.

[23] http://gasindustry.co.nz/work-programme/gas-processing-facilities-information-disclosure?tab=287

5. SUPPLY CHAIN VULNERABILITIES - PIPELINES

Gas pipelines, like other infrastructure facilities, are subject to unplanned interruptions of various durations from time to time. Often these are rectified quickly and pass unnoticed by the other industry participants and consumers.

Over the 30 to 40 years of operation in New Zealand there have been few significant outages of the supply chain. Of these five are notable.[24]

- The rupture of the Kapuni North pipeline at Pukearuhe on the North Taranaki coast in 1977, due to a slow moving landslip.
- The rupture of the Kapuni North pipeline near Inglewood, Taranaki, circa 1985, due to being struck by a mechanical digger.
- The rupture of the Kapuni South pipeline at Himatangi in the lower North Island in 2002, due to being struck by a bulldozer.
- The forced shutdown of the pipeline supplying Hawke's Bay in 2004, when a section of pipe became detached from a bridge over the Pohangina River at Ashurst that was swept away during severe flooding.
- The rupture of the Maui pipeline at Pukearuhe in 2011, due to a slow moving landslip.

Statistics on pipeline and facility failures are difficult to ascertain and, in general, reliance has to be given to industry standard data reported by the various international pipeline authorities or industry bodies. A summary of relevant data is provided in the section that follows. Of particular interest is the Australian Pipeline Industry Association data, which NZ began contributing to in 2008.

Within New Zealand there have been a number of qualitative risk assessments undertaken to assess the nature of landslide and related hazards that have potential to impact on the existing pipeline infrastructure.

These include:

- GNS Science report to Vector Ltd., of landslide and other erosion hazards along the Kapuni and Maui pipelines, July 2009, and
- MDL presentation to stakeholders in June 2013.

In essence the risk management approach adopted by these reports has been to understand and identify potential failure mechanisms, intervene when required and reduce risk to ALARP (As Low As Reasonably Practicable).

5.1 Safety & Reliability Performance

5.1.1 Australian Pipeline Industry Association

The Australian Pipeline Industry Association (APIA) has established a Pipeline Incident Database to enable statistics of pipeline incidents to be gathered. The APIA defines a pipeline incident as:

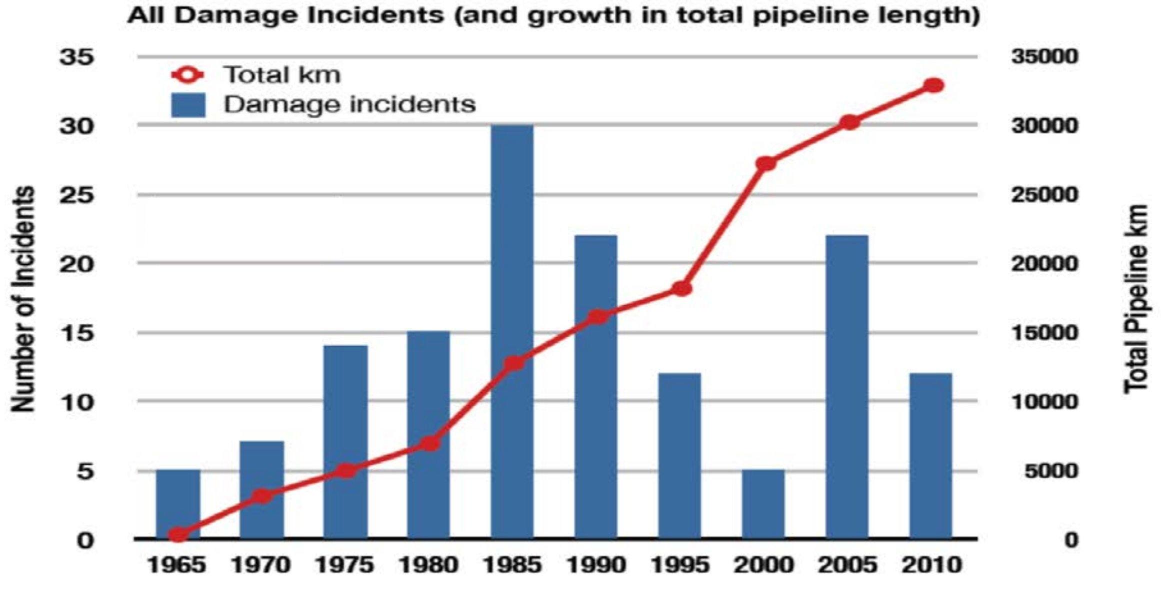
a) Any damage to the coating or pipe caused by mechanical equipment.

[24] "The NZ Gas Story - the State and Performance of the NZ Gas Industry", Gas Industry Company, February 2013

b) Any defect which causes the Maximum Allowable Operating Pressure (MAOP) to be de-rated, where gas leaks (not including minor leaks at flanges), where mechanical reinforcement is required to repair the defect OR where a section of pipe is cut out and replaced.

Figure 5 below shows the total number of pipeline incidents in 5-yearly periods and the total length of pipelines.

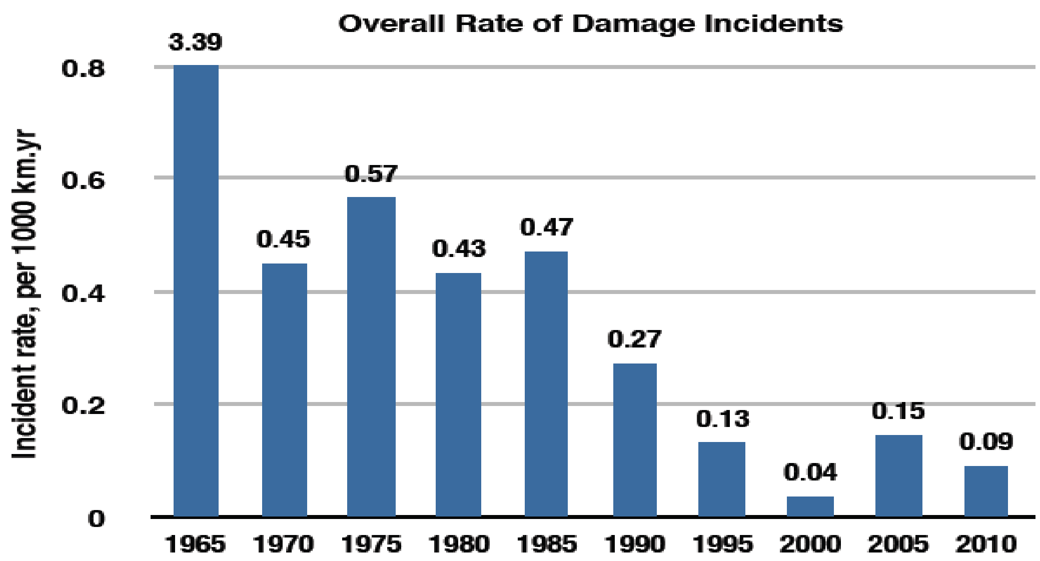
Figure 5: - All Damage Incidents



The number of incidents in the database grew significantly in 2004. The main reason for this was a concerted effort to obtain retrospective data from several pipeline operators.

The frequency rate for pipeline incidents expressed as incidents per 1000km per year is shown in Figure 6. This data is for Australian pipelines only, it excludes NZ data which was only included from 2008.

Figure 6: - Overall Rate of Damage Incidents

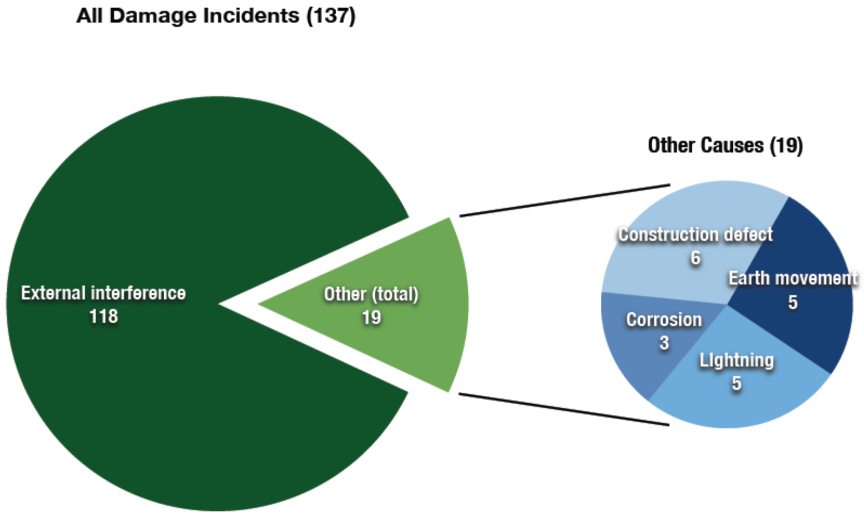


The APIA 5-year average incident frequency to 2010 (which represents the average incident frequency over the precious 5 years) was equal to 0.09 incidents per year per 1,000km.

There were 7 loss-of-containment incidents from 2001 to 2010 out of a total of 34 incidents, which is barely enough to derive a useful average. Nevertheless for the purpose of comparison the Australian loss-of-containment incident rate can be taken as very approximately 0.025 per 1000 km/year.

The primary causes of pipeline incidents were as shown below:

Figure 7: - Causes of All Damage Incidents



The APIA database does not provide information on the consequences of the incident however it is noted that there have been no recorded fatalities as a result of a pipeline incident recorded in the APIA database.[25]

5.1.2 European Gas Pipeline Incident Data

The European Gas Pipeline Incident Data Group (EGIG) is comprised of fifteen major gas transmission operators in Europe and is the owner of an extensive database of pipeline incident data collected since 1970.

The database now collects incident data on more than 135,000km of pipelines every year.

The criteria for an incident to be recorded in the EGIG database is one that leads to an unintentional gas release (i.e. loss of containment) The 8th EGIG Report (Doc. No. EGIG 11.R.0402) issued in December 2011 provides the following failure frequencies:

- The overall incident frequency over the period 1970 to 2010 was equal to 0.35 incidents per year per 1,000km.
- The 5-year moving average failure frequency in 2010 (which represents the average incident frequency over the past 5 years) was equal 0.16 per year per 1,000km.

The five year moving average and overall failure frequency has reduced consistently over the years, although it has tended to stabilise.

[25] Experience with the Australian Pipeline Incident Database, Tuft/Bonar

The reducing failure frequency over the years has been due to improved construction techniques and technological developments such as in-line inspection, condition monitoring and improved procedures for external interference prevention and detection.

The primary causes of pipeline incidents recorded under EGIG are:

Table 7: - Pipeline Incidents Recorded under EGIG

Cause	Distribution
External Interference	48.4%
Construction Defect / Material Failure	16.7%
Corrosion	16.1%
Ground Movement	7.4%
Hot Tap made by error	4.8%
Other / Unknown	6.6%

EGIG gives only statistical information about failure frequencies and causes of incidents. Some of the registered incidents are known to have resulted in injuries and fatalities. As an example, 24 people were killed in July 2004 in Ghislenghien, Belgium when a large diameter high pressure gas pipeline ruptured resulting in a large explosion.

5.1.3 United States Department of Transportation - Pipeline & Hazardous Materials Safety Administration

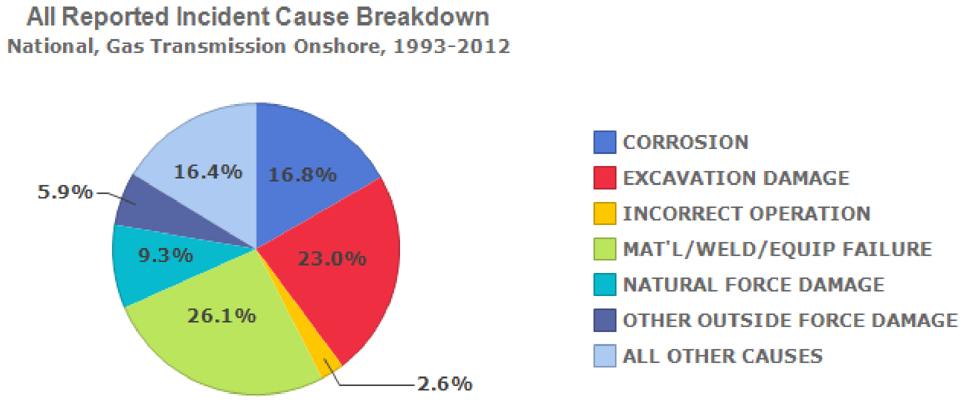
The US DoT collects annual statistics on pipeline failures from reportable incidents. DoT Regulations defines an *Incident* as an event that involves a release of gas from a pipeline and that results in one or more of the following consequences:

- A death, or personal injury necessitating in-patient hospitalization;
- Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost;
- Unintentional estimated gas loss of three million cubic feet or more.

For Gas Transmission Onshore Pipelines the 5-year average incident frequency to 2010 (which represents the average incident frequency over the past 5 years) was equal to 0.177 incidents per year per 1,000km.[26] The primary causes of pipeline incidents are provided in Figure 8, over.

[26] http://www.phmsa.dot.gov/pipeline

Figure 8: - USDOT Incident Cause Breakdown



Source: PHMSA Significant Incidents Files, Aug 30, 2013

The DoT also provides the following consequential analysis of pipeline incidents:

Table 8: - USDOT Summary Statistics

National Gas Transmission Onshore: Consequences Summary Statistics: 2008-2012

Year	Public Fatalities	Industry Fatalities	Public Injuries	Industry Injuries	Total Property Damage Notes 1,2	Public/Private Property Damage Notes 1,3	Emergency Response & Remediation Notes 1,4	Damage to Industry Property Notes 1,5	Value of Product Lost Note 1
2008	0	0	2	3	$113,571,540	$6,917,848	N/A	$102,638,824	$4,014,867
2009	0	0	7	4	$43,532,346	$2,402,195	N/A	$36,325,441	$4,804,710
2010	8	2	51	10	$404,121,628	$384,029,623	$1,668,247	$10,905,131	$7,518,626
2011	0	0	0	1	$89,222,538	$10,823,659	$2,875,222	$63,691,262	$11,832,393
2012	0	0	4	3	$42,442,518	$2,268,161	$913,409	$34,706,347	$4,554,601
Totals	8	2	64	21	$692,890,571	$406,441,487	$5,456,878	$248,267,006	$32,725,199

Table extracted from: http://primis.phmsa.dot.gov/comm/reports/safety/CPI.html | Report generated on: 09/11/13

Notes

1. The costs for incidents prior to 2012 are presented in 2012 dollars. Cost of Gas lost is indexed via the Energy Information Administration, Natural Gas City Gate Prices. All other costs are adjusted via the Bureau of Economic Analysis, Government Printing Office inflation values.

2. For years 2002 and later, property damage is estimated as the sum of all public and private costs reported in the 30-day incident report. For years prior to 2002, accident report forms did not include a breakdown of public and private costs so property damage for these years is the reported total property damage field in the report.

3. The public cost of an incident is defined as public and private (non operator) costs for the incident.

4. Prior to 2010, Emergency Response & Remediation costs were not required to be reported for Gas Transmission & Gathering or Gas Distribution incidents.

5. The industry cost of an incident is defined as all costs to the operator and its contractors.

5.1.4 Pipeline Incident Frequency Data Discussion

The average incident frequency rates between the Australian, European, and American databases over a five-year period to 2010 are shown in Table 9, over.

Table 9: - Comparison of Advance Incident Frequency Rates

Pipeline Incident Data Set	Incident Frequency Rate /1000 km/year
Australian Pipeline Industry Association (APIA) (Oil & Gas Pipelines)	0.09
European Gas Pipeline Incident Data (EGIG) (Gas Transmission Onshore Pipelines)	0.16
US Department of Transportation (US DoT) (Gas Transmission Onshore Pipelines)	0.177

It is important to note that each data set is based on a different definition of an incident so a direct comparison is not possible.

- The APIA definition is the most comprehensive and includes incidents that do not result in a loss of containment.
- EGIG does not explicitly define the type of incidents collected but the report clearly implies that the scope includes all loss of containment events, of any size, but not lesser damage.
- The US DoT incident definition is the most relaxed as it includes only events which result in fatality or hospitalisation, or more than $50,000 in costs (measured in 1984 US dollars), or significant loss of containment.
- It is apparent that Australian pipelines have a much better safety record than Europe and North America. The Australian incident rates are lower and there have been no recorded fatalities associated with pipeline damage.

There is no correlation between pipeline incident data and downstream economic impact. The economic impact is a feature of the specific pipeline and the nature, scale and duration of the resulting loss of containment and/or interruption to supply.

5.2 Regulatory Requirements Related to Pipeline Safety

5.2.1 HSE Pipeline Regulations

In November 1999, the *HSE (Pipelines) Regulations 1999* were enacted replacing the previous *Petroleum Pipelines Regulations 1984.* The revised regulations require that a pipeline owner ensures that there is a current Certificate of Fitness (COF) in place for any pipeline. Additionally, the *OSH Guidelines for Certificate of Fitness for High-Pressure Gas and Liquids Transmission Pipelines (Feb 2002)* provides guidance from the former Department of Labour (DOL) on steps to be undertaken in obtaining and maintaining a Certificate of Fitness for a pipeline from an independent and approved inspection body.

The COF provides evidence and independent audit & assurance to the Regulator of compliance with the appropriate codes and standards – independent assurance that the pipeline is designed, constructed, operated and maintained in accordance with the relevant codes and standards on an on-going basis. The COF certifies that the pipeline complies with the standard or code to which it was designed, constructed, operated and maintained.

The regulations and the OSH guide refer to a number of standards and codes that can be used as the basis for obtaining a COF, including:

- ANSI/ASME B31 series
- NZS 5223
- AS 2885 series

- Other higher standard or code

The OSH guide provides further guidance regarding certification based on “best practice” in accordance with AS 2885.

Pipelines in New Zealand have been built and operated in accordance with a range of standards over time. Typically, the ASME B31 series would have been used for the original pipelines; then NZS 5223 Code of Practice for High Pressure Gas and Petroleum Liquids Pipelines (this NZ code being developed from and aligned with the British Standards and codes that were current at the time). More recent pipelines will have been built to AS 2885. In general terms, the design code (and associated edition) used at the time of construction will have represented current best practice at the time.

AS 2885 has been developed and updated locally (jointly contributed to by Australian and New Zealand pipeline owners and industry participants). It has become the prevalent code for the design, construction and operation of gas and liquid pipelines in Australia and New Zealand. Its basis has been drawn from the applicable North American and European standards, and has aimed to provide a single comprehensive and complete management system for the design, construction and operation of transmission pipelines while incorporating local factors specific to Australia and New Zealand. It has been accepted and widely adopted by pipeline owners, operators, inspection bodies and regulators in Australia and New Zealand. On-going updates are made with appropriate review of international standards and trends. Part 3 provides detailed guidelines and requirements for the development and implementation of a pipeline management system (PMS) including the integrity management plan.

Most pipelines have been certified or re-certified to AS 2885 – we are not aware of any pipelines that are managed to an alternative code. Part 3 of the code provides comprehensive mandatory requirements and guidance for the establishment and administration of the Integrity Management System. The code effectively describes and mandates a specialised form of a quality management system (including quality assurance and continual improvement processes) for managing the pipeline. Adherence to the code must be certified by an independent inspection body – the certificate of fitness issued by the independent inspector must be current for the pipeline to continue to operate.

5.2.2 Commerce Commission Regulations

The Default Price-Quality and Information Disclosure regime referred to in Section 4 requires a wide range of information regarding the performance and asset management plans for the pipelines to be published in the public domain. It includes a wide range of planning, quality, performance and financial information as well as detailed asset management plans and a range of historical performance statistics (including interruptions).

It can be anticipated that the publication of the information required under the regulations will have a positive impact on the management of the pipelines in terms of adherence to requirements of the operating code (AS 2885); and delivery of planned activities (investment, maintenance, etc.) published in the asset management plans. The published information may also serve as a public reference point for other pipeline owners and assist in adherence to the code requirements.

The Commerce Commission regulations do not have a direct impact on the asset management, design, construction, operations and management practices used in the management of the pipelines and the threats/risks to which they are exposed. The AS 2885 standard provides the primary framework and detailed requirements in this respect.

The possibility of DPP regime having a negative impact on the level of investment in projects or assets that are designed to mitigate threats or increase the security of supply is discussed in section 9.2.1.

5.2.3 Potential for Increased Regulatory Oversight

Recent major loss incidents (both International & National) signal the likelihood of increased regulatory oversight of the industry. Two examples are outlined below.

1) Nearly half a million miles of high-volume pipeline transport natural gas, oil, and other hazardous liquids across the United States. The National Transportation Safety Board (NTSB) is an independent federal agency charged with determining the probable cause of transportation accidents (including pipeline accidents). In August 2011, the NTSB issued preliminary findings and recommendations from its investigation of the San Bruno Pipeline accident. The board concluded that “the multiple and recurring deficiencies in PG&E[27] operational practices indicate a systemic problem” with respect to its pipeline safety program. The board further concluded that the pipeline safety regulator within the state of California, failed to detect the inadequacies in PG&E’s integrity management program and that the Pipeline and Hazardous Materials Safety Administration (PHMSA) integrity management inspection protocols need improvement. The NTSB’s final accident report “concludes that PHMSA’s enforcement program and its monitoring of state oversight programs have been weak and have resulted in the lack of effective Federal oversight and state oversight.” The NTSB’s “Most Wanted List” for 2013 called for enhanced pipeline safety through improved oversight of the pipeline industry. [28]

2) These findings echo similar findings from the Royal Commission of Inquiry into the Pike River Incident. *“Although the commission is aware that structural change is not a panacea for righting performance ills, it considers that the major improvements required cannot be accomplished rapidly without organisational change. The sad reality is that DOL’s performance in relation to health and safety in the mining industry has been so poor, at both the strategic and operational levels, that the department lost industry and worker confidence.”* [29] There are 16 primary recommendations in the report - Recommendation 1: To improve New Zealand’s poor record in health and safety, a new Crown agent focusing solely on health and safety should be established.

There are further examples of incidents that have occurred internationally that have been linked to insufficient oversight from the Safety Regulator to ensure compliance and adherence to the relevant integrity management codes. The future expectation, therefore, is that there will be increased resources and focus brought to the areas of safety inspections, compliance and enforcement from the Safety Regulator, as evidenced by the recent formation of WorkSafe NZ. How this might unfold is beyond the scope of this report.

5.3 Pipeline Integrity Management

An Integrity Management approach is internationally recognised and accepted industry best practice for the operation and management of transmission pipelines. It provides a framework for the effective management of risks associated with transmission pipelines and the protection of people, property and the environment.

In essence, pipeline integrity management is an asset management approach that requires pipeline owners to:

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[27] Pacific Gas and Electric Company.
[28] Parfomak, 2013, Paul W. Parfomak, (January 9, 2013), *Keeping America’s Pipelines Safe and Secure: Key Issues for Congress.*
[29] Panckhurst et al, 2012, Graham Panckhurst, Stewart Bell, David Henry, (30/10/2012). *Royal Commission on the Pike River Coal Mine Tragedy.*

- Assess, evaluate, repair and validate through comprehensive analysis the integrity of pipeline segments.
- Prevent a leak or failure that could affect populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways.
- Develop and follow a program that provides for continually assessing the integrity of all pipeline segments that could affect these high consequence areas.
- Provide for periodically evaluating the pipeline segments through comprehensive information analysis, remediating potential problems found through the assessment and evaluation.
- Ensure additional protection to the segments and the high consequence areas through preventive and mitigative measures.

Refer to Appendix 1 and 2 for more information on typical requirements for pipeline integrity management and current changes underway intended to strengthen integrity management practice. Some of the key risk mitigation controls that are typically utilised include:

GENERAL PIPELINE SAFETY SYSTEMS

Safety Management System - Credible threats are identified that are relevant to the pipeline, product and operating environment. The threats are assessed in terms of likelihood and consequence. Appropriate mitigations are then developed, documented and applied to ensure the risks are mitigated to an acceptable (ALARP – as low as reasonably practicable) level.

Emergency Response processes – These are pre-planned and pre-rehearsed responses to emergency situations and scenarios. They ensure that adequate resources include competent personnel are available to deal with emergency situations should one arise.

SCADA System – The Supervisory Control and Data Acquisition system is a centralised computerised system which provides real-time continuous monitoring of safety equipment, pressures, temperatures, flows, etc. to the pipeline operator and triggers alarms when pre-set thresholds are passed.

EMPLOYEE SAFETY SYSTEMS

Job Hazard Analysis System – A JHA must be undertaken prior to work being performed on a pipeline or its facilities with the objective of providing a safe system of work, and shall be used to identify, assess and control safety and environmental hazards.

Permit to Work System - coordinates site works to ensure that activities are suitably managed and do not conflict. It is a requirement that any pipeline licensee shall have a range of permit classes covering at least the following:

- Cold work
- Hot work
- Entry to confined spaces
- Excavation alongside live pipelines

CORROSION PROTECTION SYSTEMS

Pipeline Coating Systems – Coatings normally are intended to form a continuous film of an electrically insulating material over the metallic surface to be protected. The function of such a coating is to isolate the metal from direct contact with the surrounding electrolyte (preventing the electrolyte from contacting the metal) and to interpose such a high electrical resistance that the electrochemical reactions cannot readily occur.[30]

Direct current voltage gradient (DCVG) testing is routinely performed on the pipeline to assess the condition of buried pipeline coating systems and detect potential failure points.

Cathodic Protection System – An impressed current cathodic protection (ICCP) system for a pipeline would typically consist of a DC power source arranged in such a way that impresses a negative voltage on the pipeline, relative to its surroundings, thereby preventing the normal chemical reactions associated with corrosion from occurring.

LOSS OF CONTAINMENT

Leak Detection – This is typically achieved through the use of fixed (e.g. at stations) and portable gas detectors being used as part of the regular pipeline patrolling and inspection routines along with visual indications such as dead foliage.

Isolation Valves – Pipeline isolation valves are located at regular intervals along the length of the pipeline and at stations to enable sections of pipelines or stations to be isolated for routine or exceptional maintenance activities or in the event of an emergency situation. The effective positioning of isolation valves minimises the inventory of gas vented in an emergency. In New Zealand, valves are typically manually operated although an increasing number of valves are becoming automated and/or remotely controlled. Conversely, international practice has been to provide automation and/or remote control for main-line valves. This is primarily due to the remote location of valves in large systems and the associated response times required for manual operation.

OVER PRESSURE PROTECTION

All pipelines operating to AS 2885 must have two independent pressure control devices (e.g. relief valve plus set point on compressor). Slam-shut isolation valves also serve to protect the pipeline from over pressure. Most over pressure protection systems are designed to maintain the system pressure below the MAOP of the pipeline, without necessarily interrupting supply to customers.

EXTERNAL (THIRD PARTY) INTERFERENCE

Before You Dig – This is a national system whereby contractors can access a free online service to determine the presence of underground assets in and around any proposed dig site; helping to protect people, communities and valuable assets during these works. When a contractor uses the online service, the system automatically contacts each registered asset owner on their behalf. Asset owners then respond directly to the contractor with any specific plans or instructions.

Easement Access Permitting System – A system used to log third party activity in the pipeline easement, assess threats prior to any work being undertaken (and remedy as necessary) and authorise as appropriate.

Other Key Systems - These include the installation of warning signs along the pipeline, routine pipeline patrols that aim to detect unauthorised activity being undertaken within the pipeline easement corridor,

[30] Peabody 2001, A.W., 2001. Peabody's Control of Pipeline Corrosion, 2nd Ed

public awareness campaigns and material and regular stakeholder liaison with landowners and contractors.

ENVIRONMENTAL IMPACT

Environmental Management System - The Australian Pipeline Industry Association's Code of Environmental Practice—Onshore Pipelines[31] provides guidance regarding an environmental management system. This includes the effective management of the pipeline corridor, noise emissions, heritage sites, water & waste management, spill prevention and response.

5.4 Deployment of the Critical Contingency Regulations

Irrespective of the above regulatory oversight and management practice unintended events will occur. In the rare situation where these evoke a critical contingency event there is a need to shed load from the gas system as quickly as possible so as to better match offtakes with any remaining gas injections and achieve balance while the underlying physical problem is fixed. To this end the CCM Regulations were issued in 2008.

As outlined in Section 4, the key mechanism used to manage critical gas outages and other security of supply contingencies is directing industrial and commercial gas consumers to either stop or in some instances reduce their use of gas. The regulations do not apply to domestic consumers.

The CCM Regulations have been invoked on three occasions, the most significant of which was a 5½ day outage in October 2011 caused by a failure in the Maui gas pipeline (Maui outage).

That outage reduced gas deliveries north and east of Taranaki by some 90% and was a major test of the procedures that had been put in place. Responses to the Maui outage showed that the CCM Regulations generally worked well, although a number of areas were identified in which improvements could be made; most notably in the area of deferred curtailment (customers who are given priority access to gas). These improvements have been picked up and recommendations reported back to the Minister of Energy and Resources in July 2013.

Currently critical contingencies are managed by providing for a Critical Contingency Operator (CCO) who determines the onset of a critical contingency and calls for load curtailment as required to balance the system.

The CCM Regulations also require each TSO to create a Critical Contingency Management Plan so as to ensure that it is well-prepared to carry out its duties under the regulations. The Gas Industry Company has recommended amendments to the curtailment bands to reduce any disincentive for end-users to invest in dual-fuel resilience as well as recommendations requiring retailers to inform customers of the CCM regulations and conditions for deferred curtailment. In essence this latter provision is aimed at improving compliance from non-industry participants who are intended to be covered under the revised regime.

An important consideration embedded in the regulations is processes for deferring curtailment in certain cases so as to minimise social costs associated with critical contingencies.

CCM regulations only indirectly deal with pipeline pressure maintenance on local distribution networks. In the event of a Critical Contingency Event distributors (Powerco, Vector, GasNet, and Nova) are part of the broader stakeholder group who are kept informed by the CCO; however network management is a matter for each distributor to deal with individually outside of the CCM regulations. In practical terms each

[31] http://www.apia.net.au/issues/guidelines-and-publications/

distributor is aware of the need to maintain survival times on its network and will have internal policies and procedures to manage an emergency event that mirror the philosophies of the CCM curtailment bands:

- Large industrial and commercial Time of Use metered sites are curtailed first.
- Larger commercial sites curtailed. (E.g. hospitality industry – hotels, restaurants etc.)
- Residential curtailed last.

Since the October 2011 Maui outage, which highlighted the lack of preparedness of a number of downstream businesses to deal with a gas supply interruption event, a number of industries have reviewed their business continuity plans. In particular Fonterra has carried out an internal review on substitute fuels for its processing sites and determined which sites warrant further investment in dual fuel capabilities.

6. SUPPLY CHAIN VULNERABILITIES – FACILITIES

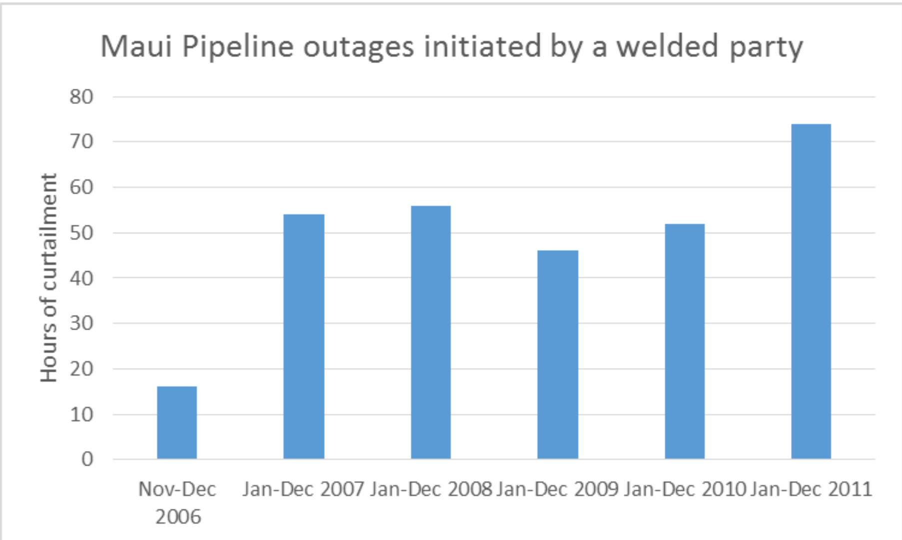
Gas field facilities are also subject to unplanned interruptions of various durations from time to time. As with pipelines these are usually rectified quickly and pass unnoticed by most other industry participants and consumers.

The Gas (Information Disclosure) Regulations 1997 did not require the disclosure of information relating to outages, planned or unplanned for facilities. The Pohokura production station has been the subject of two relatively brief outages in 2011 and 2012 that triggered the industry's critical contingency management processes.[32]

Prior to Maui pipeline open access there have been a few incidents related to the Maui A platform which required contingency measures to be taken under a voluntary National Gas Outage Contingency Plan (NGOCP) designed to deal with a Maui contingency event. Generally curtailment related to these events had minimal impact as outages were able to be scheduled to give the industry time to respond in a measured way.

Indirect statistics on facility reliability can be inferred from the Maui Pipeline Information disclosure which gives a breakdown of hours of curtailment initiated by a welded party[33]. These are generally inferred to be from suppliers unable to supply according to their nominations for various reasons including unscheduled outages (Figure 9). Typically the aggregate curtailment related to facilities has averaged about 56 hrs per annum in the last five years. During 2012 there were 11 curtailments that led to reductions in scheduled gas transmissions. All of those were caused by third parties. On this basis unplanned facility outages average about five hours per year. Impact of these curtailments are usually managed at only one or two welded points and generally do not require a critical contingency management process to be initiated.

Figure 9: - Facility Supply Interruption



Source: Maui Pipeline

International statistics on failures are difficult to ascertain. There are a number of purported international databases including;

[32] "The NZ Gas Story - the State and Performance of the NZ Gas Industry", Gas Industry Company, February 2013.
[33] Welded Party" means any person who owns a Gas pipeline infrastructure or plant which is physically connected at a Welded Point to the Maui Pipeline, and who is the person named as a welded party in a valid and subsisting ICA. ref http://mauipipeline.co.nz/maui-pipeline/.

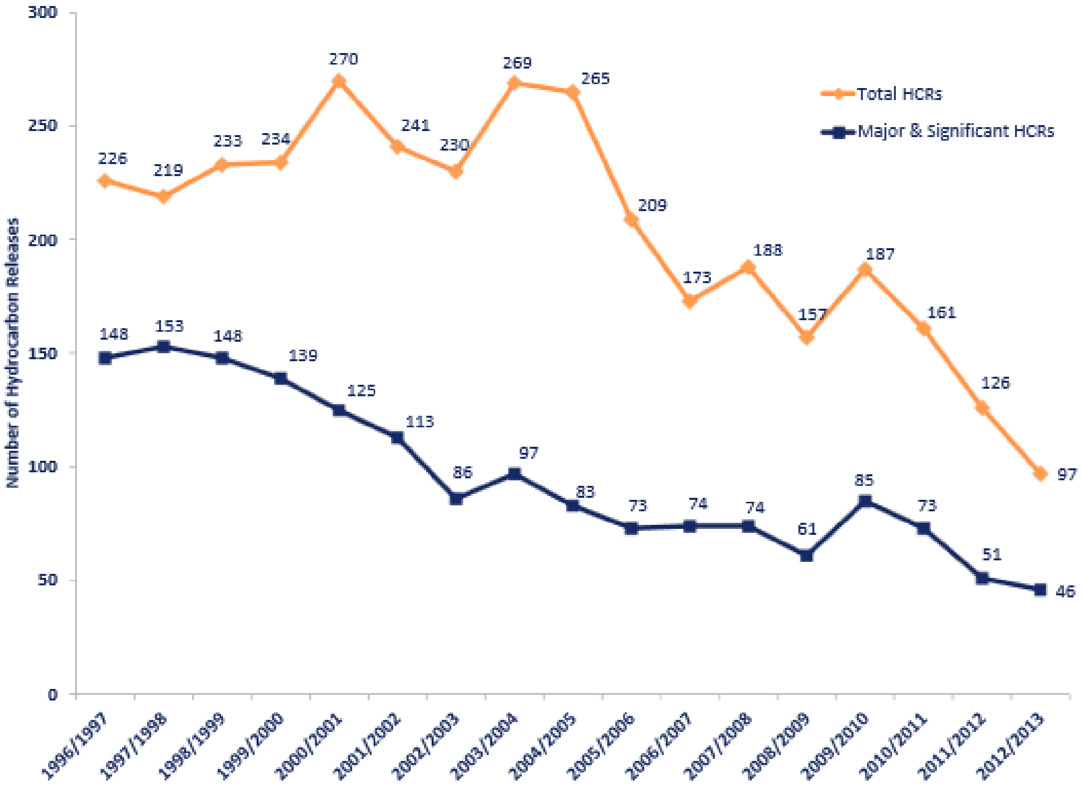
- Reportable Injuries, deaths and Dangerous Occurrences Regulations Database (RIDDOR) (operated by the UK Health & Safety Executive),
- European Union Major Accident Reporting System (MARS) (operated by the European Commission Joint Research Centre),
- Major Hazard Incident Data Service (MHIDAS) (operated by AEA Technology on behalf of the UK Health & Safety Executive),
- UK onshore chemical and major hazard industries voluntary reporting of loss of containment incidents (HSE 2004, HSE 2005, HSE 2006, HSE 2007, HSL 2003),
- Oil and Gas UK (Offshore) Health and Safety Report 2013, and
- DNV's Worldwide Offshore Accident Databank – (WOAD).

The databases are primarily HSE incident, rather than reliability focused so have limited application in determining frequency rates for plant outages.

The European data encompasses a broad spectrum of the chemical industry. Reporting is voluntary and focus is on identifying causes and lessons learnt of HSE incidents (including loss of containment). The Oil and Gas UK Health and Safety Report 2013 notes statistics related to Hydrocarbon Releases in the offshore oil and gas industry (Figure 10). Major Incidents are those incidents with the "*potential to quickly impact out with the local area e.g. affect the Temporary Refuge (TR), escape routes, escalate to other areas of the installation, causing serious injury or fatalities. A major leak, if ignited, would be likely to cause a "major accident", i.e. it would be of a size capable of causing multiple casualties or rapid escalation affecting TR, escape routes, etc*."

Significant Incidents are those with the "*potential to cause serious injury or fatality to personnel within the local area and to escalate within that local area e.g. by causing structural damage, secondary leaks or damage to safety systems. A significant leak, if ignited, might have the potential to cause an event severe enough to be viewed as a "major accident" or be of a size leading to significant escalation within the immediate area or module*."

Figure 10: - Number of Hydrocarbon Releases occurring offshore



Source: Health and Safety Executive

There are about 500 installations on the UK Continental Shelf.[34] Despite 46 major and significant hydrocarbon releases in 2012/13 only one incident led to a major disruption of a facility.

In the broader chemical sector[35] 41 out of 73 incidents (56%) in 2004/05 occurred during normal operation with only 7 (10%) occurring during start-up, and another 7 during maintenance events.

On a global basis the International Association of Oil and Gas Producers analysed Major Accidents in the onshore and offshore oil and gas production and process industries worldwide 1970-2007.[36] A Major Accident was one that resulted in at least one of the following:

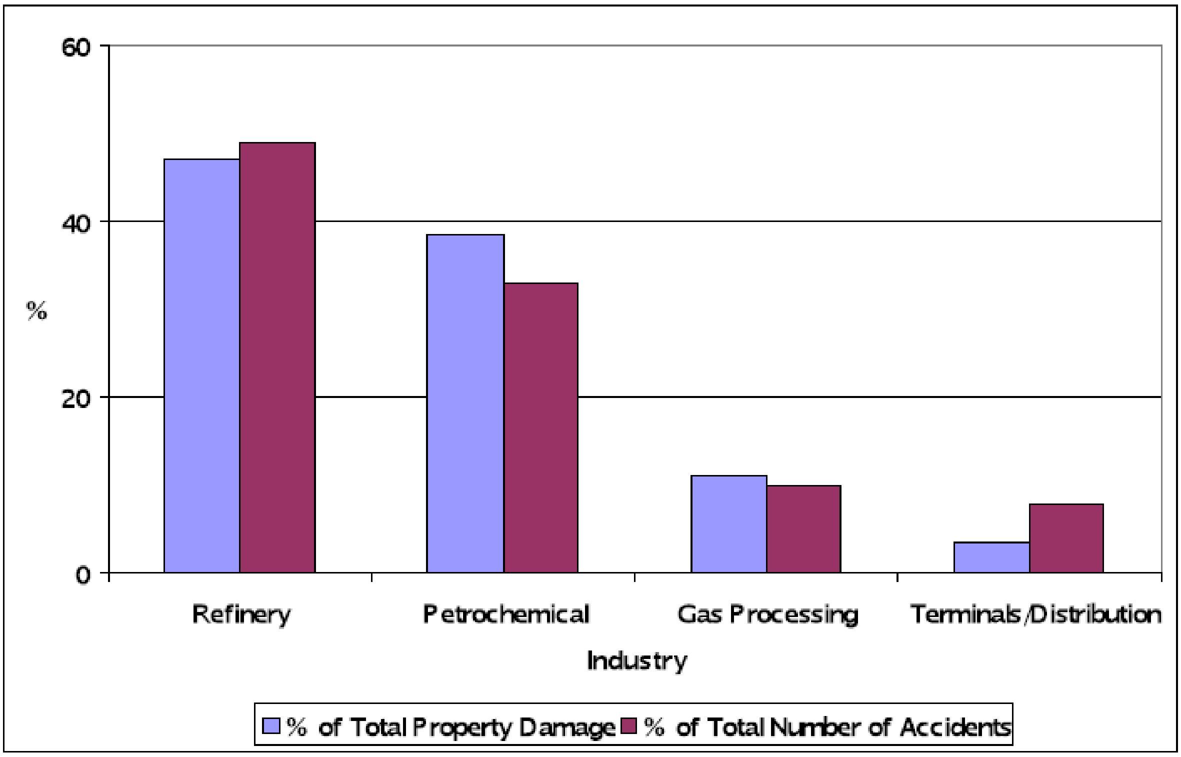
- Multiple Fatalities.
- For Onshore Units approximately US$100 million of property damage.
- For Offshore Units total loss (including constructive total loss from an insurance point of view) or Severe Damage to one or more modules of the unit.
- 1000 barrel oil spill.

Of the 55 major accidents for onshore events resulting in multiple deaths approximately 16 were related to oil and gas facilities.

For the top 100 Major Onshore Incidents between 1972 and 2001, only 10 incidents related to gas processing with a total loss of US$1.1 billion (2002 dollars).

34 www.decomnorthsea.com
35 Health and Safety Executive – “Findings from Voluntary Reporting of Loss of Containment Incidents 2004/05”
36 OGP Risk Assessment Data Directory – Report No.434-17 March 2010- Major Accidents

Figure 11: - Breakdown of Top 100 Major Onshore Incidents by Type of Unit 1972-2001



Source: OGP

The limited public statistical information on which we have been able to draw does suggest that major unplanned outages disrupting gas supply are relatively uncommon (one every three years somewhere in the world, or a frequency rate of approximately one in 5,000 years)[37] and possibly becoming even rarer as Health and Safety standards and regulations continue to tighten and industries adopt best practices learned from major incidents.

6.1 Facility Asset Integrity Management

As with pipelines, facility owners invest in various asset management systems both to meet statutory requirements around equipment safety, but also to avoid economic loss:

- Safety and Integrity in design through various codes and regulations.
- Health and Safety in Employment (Pressure Equipment, Cranes, and Passenger Ropeways) Regulations 1999 covers pressure vessel inspection and operating certificates.
- Health and Safety in Employment (Petroleum Exploration and Extraction) Regulations 2013 extending safety case requirements to onshore facilities. Safety cases require quantitative risk assessments (QRA) that help identify process safety vulnerabilities as well as occupational HSE issues.
- Risk Based Inspection (RBI), critical equipment maintenance, and other asset management systems to back Reliability, Availability, and Maintainability (RAM) philosophies in design.

Some other key risk mitigation controls include:

[37] According to a 2011 survey by Oil and Gas Journal there are about 1,906 gas processing plants globally which gives an approximate frequency rate of 0.00017 major incidents per plant per year.

GENERAL FACILITY SAFETY SYSTEMS

Safety Management System - Credible threats are identified that are relevant to the facility, product and operating environment. The threats are assessed in terms of likelihood and consequence. Appropriate mitigations are then developed, documented and applied to ensure the risks are mitigated to an acceptable (ALARP – as low as reasonably practicable) level.

Emergency Response processes – These are pre-planned and pre-rehearsed responses to emergency situations and scenarios. They ensure that adequate resources included competent personnel are available to deal with emergency situations should one arise.

Safety Shutdown System (SSD) – A separate system from Distributed Control System (DCS) control providing real-time continuous monitoring of safety equipment, pressures, temperatures, flows, hard wired and programmed to take executive control to shutdown the facility in a controlled and safe fashion if certain trigger points are reached.

EMPLOYEE SAFETY SYSTEMS

Job Hazard Analysis System – A JHA must be undertaken prior to work being performed on a pipeline or its facilities with the objective of providing a safe system of work, and shall be used to identify, assess and control safety and environmental hazards.

Permit to Work System - coordinates site works to ensure that activities are suitably managed and do not conflict. It is a requirement that any pipeline licensee shall have a range of permit classes covering at least the following:

- Cold work
- Hot work
- Entry to confined spaces
- Excavation alongside live pipelines

LOSS OF CONTAINMENT

Leak Detection – This is typically achieved through the use of fixed (e.g. at stations) and portable gas detectors.

Isolation Valves –Isolations valves are located at various parts of the process including plant battery limits to enable sections of pipelines or stations to be isolated for routine or exceptional maintenance activities or in the event of an emergency situation. The effective positioning of isolation valves minimises the inventory of gas vented in an emergency. Valves can be both manually operated or automated depending on criticality.

OVER PRESSURE PROTECTION

All pressure vessels, equipment, and lines with potential for overpressure are protected by safety relief valves (independently tested and certified during overhauls) that allow equipment to be safely vented to flare systems.

7. CASE STUDIES

7.1 Maui Pipeline Outage October 2011 – Electricity Sector Effects

In order to inform the discussion on scenarios it is useful to review the Maui Pipeline Outage of October 2011. This has been subject to detailed investigation by MBIE and highlighted a number of issues which are subject to ongoing work and risk management planning by the pipeline owner, the pipeline operator and the Gas Industry Company. Of importance for this report, however, is to look more closely at the effects on gas users; particularly electricity generation and the major industry users in terms of their response and capacity to adapt to a prolonged gas curtailment event.

7.1.1 Electricity Generation

The disruption of gas supplies to power stations occurred in the early hours of 25th October 2011. This was the Tuesday following the Labour Day holiday, which would have resulted in electricity demand being lower than would otherwise have been the case for Tuesday. With a major gas fired plant out for maintenance, and a large amount of idle coal-fired capacity available, the power system was able to cope with the disruption much more easily than might otherwise have been the case.

Power stations are categorized as Band 1 users. Curtailment of these consumers was imposed at 2:35 am on 25th. At this time the following large thermal plants were in service, at the loads specified:

Stratford combined cycle	161 MW
Huntly Coal unit 3	94 MW
Huntly combined cycle, unit 5	251 MW
Kinleith	39 MW
Te Rapa cogeneration	29 MW
Southdown	44 MW

Otahuhu B combined cycle was shut down for maintenance, while the open cycle gas turbines at Stratford and Huntly were all shutdown. The McKee Peaker plant had not been commissioned at this time.

Figure 12 (over) shows that in the previous week, only two of the four Huntly coal units had been in service, backing off at night.

Figure 13 and Table 10 show how in the early hours of the 26th, when the curtailment instruction was issued, the coal fired unit that was in service and a second unit that was shutdown (but hot) were able to quickly ramp up to their full load capacity of close to 500 MW. By 4:30 am, all the gas fired plants above were shutdown, except for the Stratford CCGT and Kinleith.

Figure 12: - Gas and coal generation total, showing how the coal fired plant was easily able to fill the gap left by the gas supply disruption

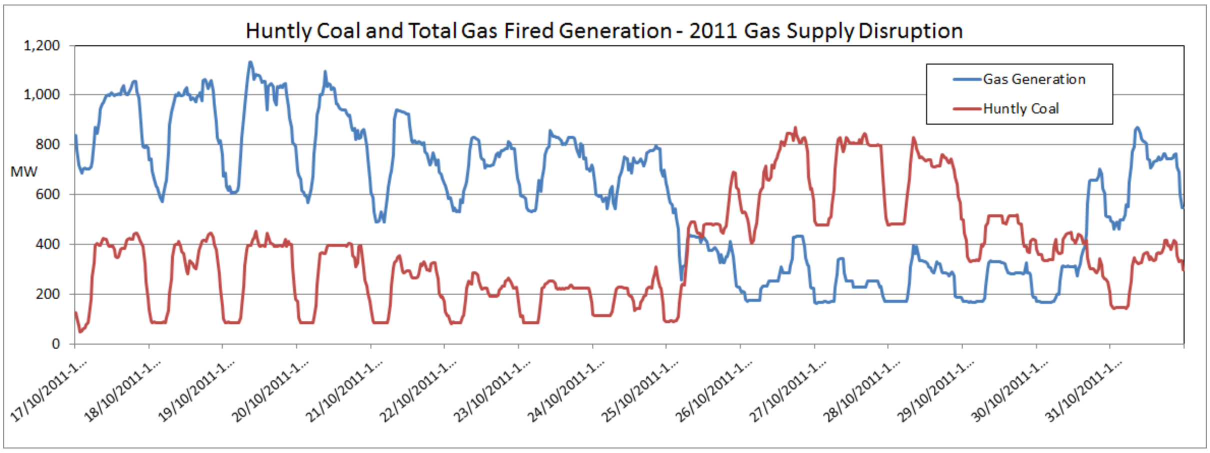
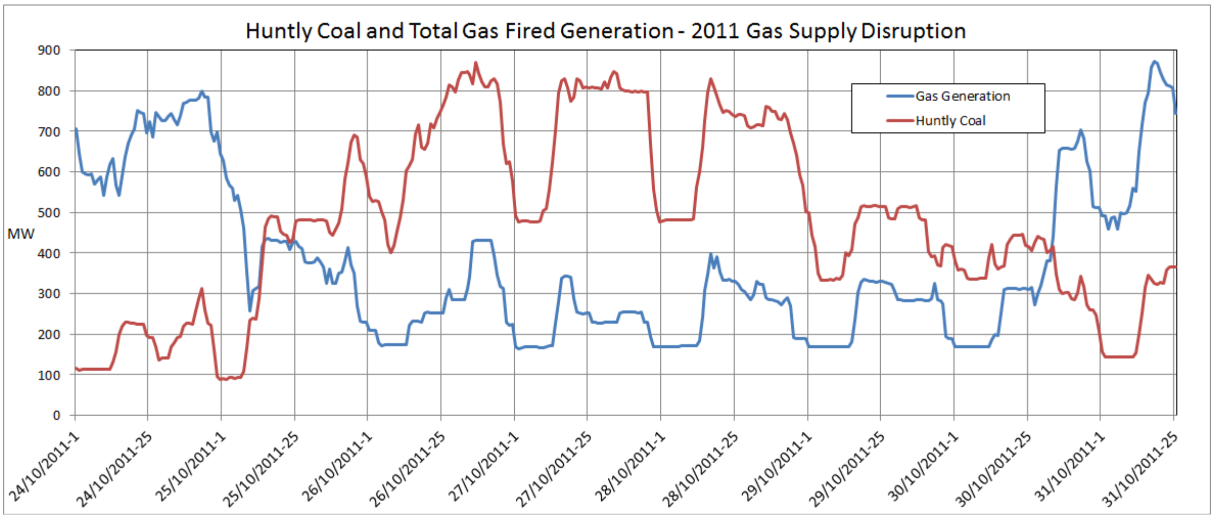


Figure 13: - Gas and coal generation total, showing the rapid changeover to coal fired generation at Huntly, and the start-ups of the 3rd and 4th units



Huntly unit 4 started soon after the curtailment instruction as it was hot following a shutdown at 11:30 pm just prior to the curtailment notice being issued. Huntly's remaining coal fired units 1 and 2 were cold resulting in long start up times. Huntly units started at the following times:

- Unit 4 25th, 4 am
- Unit 1 25th, 5 pm
- Unit 3 26th, 8 am

Total output from the 1000 MW Huntly coal station eventually exceeded 800 MW later in the week (Figure 13). This spare capacity enabled the loss of gas supplies to be handled easily - it was not even necessary for the full capacity of the four coal fired units to be used. In the early hours of the 27th, North Island demand was sufficiently low for power to be sent southwards over the HVDC link, as seen in Figure 14.

Figure 15 highlights the switch from gas to coal, and the variability of the contribution from wind generation.

Supply to Band 1 gas users was restored on Sunday 30th October at 3:30 am.

Table 10: - Generation Response to Gas Shutdown

Date	Trading Period	Huntly U1 (MW)	Huntly U2 (MW)	Huntly U3 (MW)	Huntly U4 (MW)	Gas - North of Taranaki (MW)
25/10/2011	5	0.0	0.0	90.8	0.0	363.0
25/10/2011	6	0.0	0.0	93.7	0.0	363.0
25/10/2011	7	0.0	0.0	94.2	0.0	334.0
25/10/2011	8	0.0	0.0	109.3	0.0	269.4
25/10/2011	9	0.0	0.0	118.8	47.7	140.3
25/10/2011	10	0.0	0.0	121.3	112.6	38.8
25/10/2011	11	0.0	0.0	119.6	121.1	38.9
25/10/2011	12	0.0	0.0	117.5	119.4	39.1
25/10/2011	13	0.0	0.0	170.5	117.0	39.2
25/10/2011	14	0.0	0.0	207.3	167.9	38.4
25/10/2011	15	0.0	0.0	229.9	234.4	39.2
25/10/2011	16	0.0	0.0	239.3	246.3	39.2
25/10/2011	**17**	**0.0**	**0.0**	**243.9**	**247.2**	**39.2**
25/10/2011	18	0.0	0.0	245.9	243.3	38.9
25/10/2011	34	0.0	0.0	239.3	242.4	29.6
25/10/2011	35	6.2	0.0	236.6	236.4	29.1
26/10/2011	16	230.4	0.0	233.3	228.9	0.0
26/10/2011	17	233.0	7.5	237.4	238.1	0.0
26/10/2011	24	209.2	114.3	211.9	211.3	0.0

Figure 14: - HVDC transfer showing reverse transfer during low load period due to operation of four Huntly units.

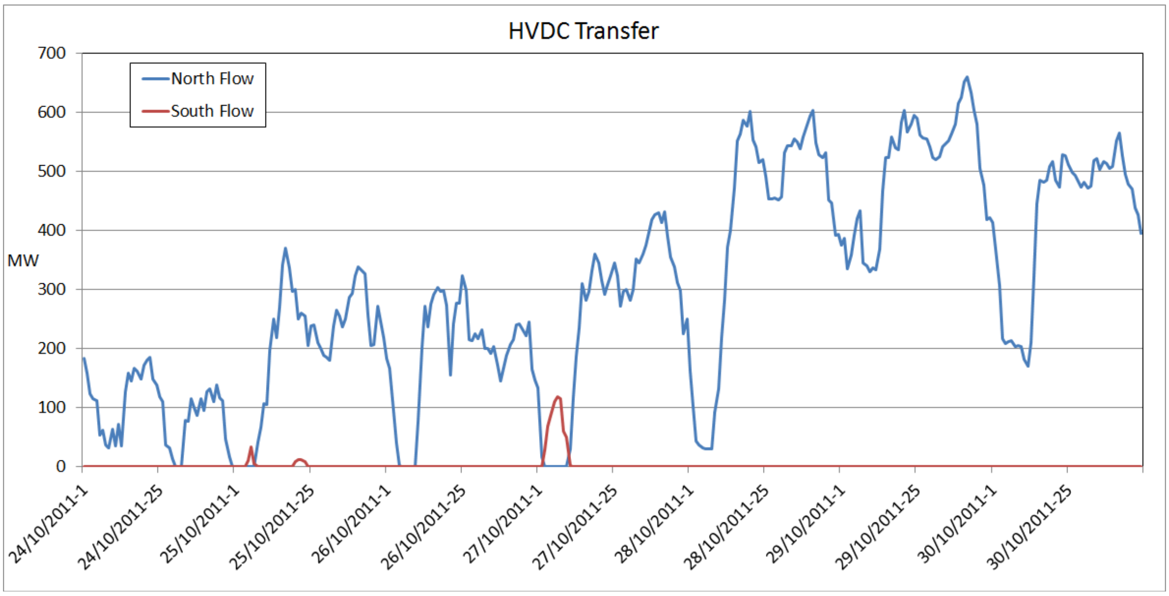
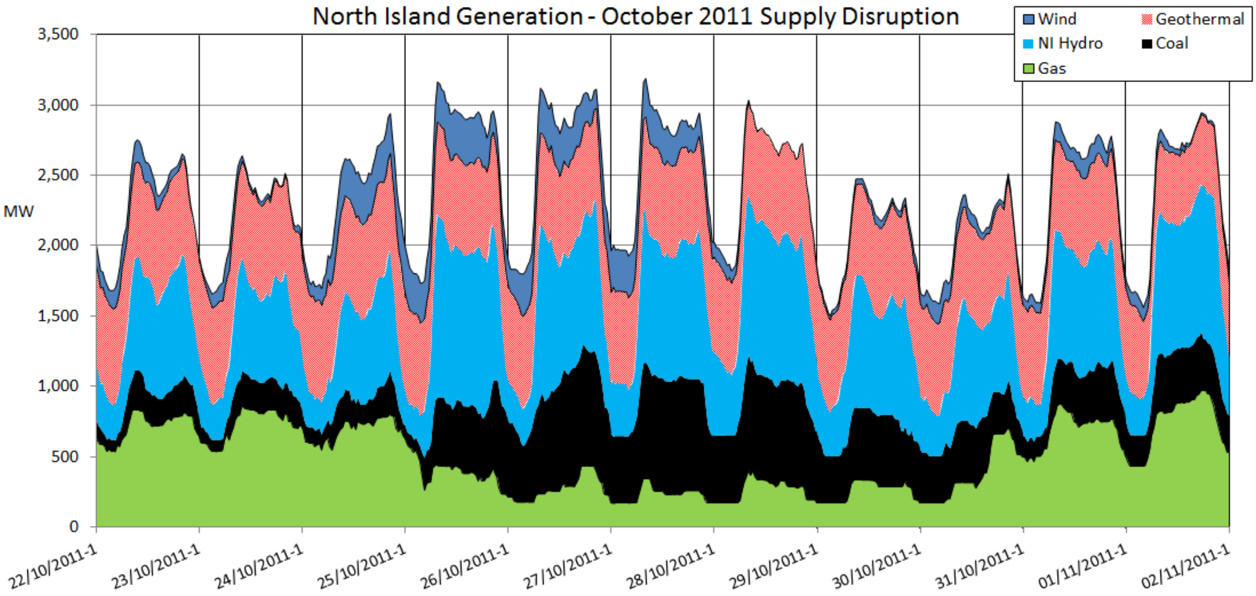


Figure 15: - North Island generation by fuel type during October 2011 gas disruption.



7.1.2 System Operator Simulation of the Electricity Impacts

The 2011 gas supply disruption occurred at a time when the power system was easily able to cope with the loss of gas supplies due to the low initial consumption, the availability of alternative coal fired capacity, and the relatively low load condition. Average daily load for the country for the week of the outage, Tuesday to Friday, was 103.2 GWh, with a peak load of 3470 MW between 8:00 and 8:30 am on Friday 28th October.

The System Operator, Transpower, has carried out a study which effectively simulates their responses and that of the electricity market to a similar disruption of gas supplies during a higher load period, beginning on a Tuesday in June. Generation offers etc. used in this study are typical offers, considered to be realistic under the circumstances, rather than the actual offers for any particular period. For this study North Island load peaked at 4213 MW, which is 743 MW above the peak reached during the October 2011 gas disruptions. The System Operator's report is included as Appendix 4.

The study considered the loss of 986 MW of capacity across the first evening peak, which is a more severe scenario than those considered in the scenarios considered in this report as it analysed the loss of generation both within Taranaki and north of Taranaki. The System Operator assumed that the Stratford CCGT plant could be supplied from the Ahuroa gas storage, although this is now known to have a more limited maximum withdrawal rate, sufficient only for approximately 200 MW of generation at the Stratford plants.

Replacement capacity for the simulation of the first peak period was obtained as in Table 11.

Table 11: - Replacement Generation for System Operator Study

Source	Capacity (MW)
Wairakei Geothermal	16
Tongariro Hydro	112
Whirinaki diesel	156
Matahina Hydro	20
HVDC increase	415
Load reductions	200
Total	**919**

Note: Load reductions shown above are due to loss of gas supplies interrupting industrial processes.

The simulation assumed that two Huntly coal fired units were in service, a third was cold and so could not contribute to the evening peak on the first day of the disruption and that the fourth unit was in long term storage and so unavailable at any time. HVDC northward transfer was at 885 MW, despite the installed capacity of the link being 1200 MW for the purposes of the study. The lower transfer was scheduled due to reserve requirements in the North Island.

We note that since this study was carried out in 2012, a second coal fired unit at Huntly has been decommissioned. The System Operator study assumed only two coal fired units, which is essentially equivalent to the current situation. (See section 7.1.4 for details of other changes to installed generation capacity - an overall capacity increase of 44 MW is given there).

The System Operator study shows that under the conditions studied, a major disruption to gas supplies could be handled without disrupting supply, or seriously reducing system security.

7.1.3 Energy Requirement Constraints

The above discussions have considered only generation capacity issues, which determine whether peak loads can be met. A further issue is the ability of the power system to provide the energy required over a period of time. Factors influencing this include:

- Time of year – load levels are higher in winter
- Hydro storage – volumes in the large storage lakes
- Hydro inflow conditions – the amount of rainfall varying with time of year and from year to year
- Huntly coal stockpile levels
- Ahuroa gas storage volume

At 30th June 2013, 877,000 tonnes of coal were in storage at Huntly. This is sufficient to run two units at full output for approximately 24 weeks. Ahuroa gas storage held 9.9 PJ at 30th June 2013, which is approximately that required to run the 200 MWs Stratford Peaker plant for 7 months.

The energy lost due to a supply disruption is dependent on the time of year and hydro system inflow conditions – gas generation is typically operating at higher levels during winter, and more gas generation will be lost if the hydro system is experiencing a dry year. A detailed stochastic model taking into account the full range of inflow scenarios would be required to analyse these factors.

The following analysis considers requirements for alternative energy sources for a gas supply outage beginning on 1 June 2012. Actual half hourly data has been analysed, but with the modification that only two coal fired units are available at Huntly. Additional output from Huntly above this level has been added to the additional energy that must be found, along with that lost from an outage of gas fired generation located north of Taranaki. The observed generation from Huntly Units 5 & 6, Te Rapa, Southdown, Otahuhu B and Kinleith is analysed as being replaced by extra generation from other plants. These other plants are loaded in the order given - Huntly coal fired units (two units only), Stratford (CCGT and peaking plant), McKee gas turbine, and finally hydro plant. The hydro plant category included those in both the North and South Islands. Both the McKee and Stratford peaking gas turbines have been limited to 50% output to approximate the operating mode expected from peaking type plant.

Results are shown in Table 12. This table shows the total additional energy required from 1 June to the specified date, to replace the generation recorded from the gas fired plant assumed to be no longer available. Huntly coal energy requirement is negative for the first two months because of the adjustment to represent two units only being available, whereas all four coal fired units were operational at that time.

The Stratford plants are required to generate an extra 105.6 GWh in June, 193.4 GWh total for the period June and July, up to 351.5 GWh for a four month disruption.

The Huntly coal stockpile contained sufficient coal for 2000 GWh generation on 1 June 2013, so the extra 300 GWh required would be feasible. Constraints on gas supplies to Stratford and McKee are unknown, but the 50% derating applied to the gas turbines results in their generation being less than the maximum feasible. For hydro generation, the feasibility of generating an extra 1062 GWh depends on storage conditions. On 1 June 2012, total hydro storage was approximately 2000 GWh, which is 349 GWh above the 1% risk curve. A total of 615 GWh of contingent storage is available from Lakes Pukaki and Hawea. This storage is not included in the risk calculations carried out by the System Operator for the contingency case, as it a last resort source available only under special circumstances. This gives a total of 964 GWh of hydro storage available, in addition to that at the 1% risk of deficit level. Hence it is likely that the 1066 GWh of additional hydro generation required for a three month disruption could have been achieved.

With some load reductions due to industrial processes being suspended due to lack of gas supplies, and some demand side response to high prices, there was probably enough energy in storage for a four month disruption for this specific situation.

Table 12: - Additional Energy Requirements for 2012 Gas Disruption, Cumulative Totals (GWh)

	Huntly Coal	Stratford Gas	McKee Gas	Hydros
1/07/12	-87.0	105.8	35.6	538.5
1/08/12	-69.6	196.8	67.1	855.5
1/09/12	41.9	249.8	93.9	1066.3
1/10/12	303.4	364.6	111.0	1131.0

Note: Huntly generation adjusted for 2 units, actual 4 units.

It should be further noted that the above discussion applies only to the hydrological conditions existing in 2012. A further important qualification is that the hydro risk curves were calculated based on the system configuration applying at that time – the curves are affected by the decommissioning of Huntly units and the commissioning of new wind and geothermal plant and the expanded HVDC. No consideration has been given to whether dispatch of generation to meet these modified schedules is feasible (e.g. ramp rates, minimum loads) nor have spinning reserve requirements been considered.

The 500 MW of coal capacity at Huntly clearly plays a vital role in the event of gas supply disruption. Huntly boilers require gas supplies to begin the steam raising process. Initially, this is likely to be available from line pack, but this might not be the case for a more prolonged outage. If a unit needs to shut down, due to maintenance requirements for example, it may not be possible to re-start. Gas from the Vector pipeline cannot be used for this purpose. Re-instatement of the diesel fuel start up is likely to be worth investigation to improve security of operation of these units.

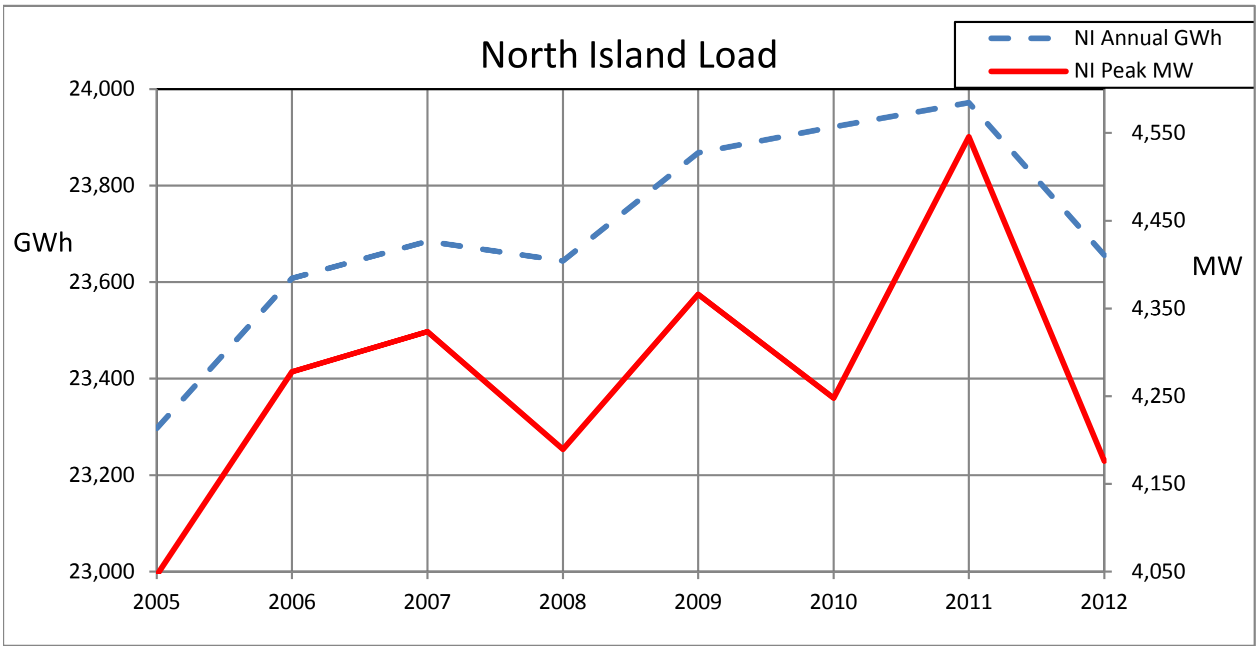
7.1.4 Future Electricity System Trends

The System Operator's study indicates that there is sufficient installed capacity in the power system to meet major gas supply disruption. This section describes changes that might affect that conclusion.

Figure 21 shows North Island loads since 2005. 2012 load is similar to that for 2006 in energy terms, but the peak load is lower. The lower peak may be due to weather conditions – an especially cold spell results in a higher peak. There is no clear trend in loads. The global economy is likely to be an important effect, as is the Christchurch earthquake, but the various energy efficiency programs may also be affecting loads. Hence no clear conclusion can be drawn regarding load changes influencing the ability of the power system to deal with gas supply disruptions.

The System Operator study included the effect of one coal fired unit at Huntly being put into long term storage, and the expanded capacity of the HVDC link, with the commissioning of Pole 3 and associated equipment taking capacity to 1200 MW northward transfer.

Figure 16: - North Island load trends.



Regarding the capacity of generation plant available, the following changes have occurred, or are expected, since the System Operator study:

- 100 MW open cycle gas turbine has been installed at the McKee gas production station
- Ngatamariki geothermal, 80 MW has been commissioned
- Genesis has announced the decommissioning of a second Huntly coal fired unit
- Te Mihi geothermal, is due to be commissioned in 2014, giving a net gain in output of 114 MW
- Mill Creek wind farm, 60 MW, is expected to be in full operation in July 2014

This gives a net gain of 44 MW of capacity, plus the Mill Creek wind farm.

HVDC link capacity has been brought up to 1000 MW for northward transfer with the commissioning of the replacement equipment as Pole 3. A further increase in capacity to 1200 MW was completed in December 2013. Capacity would increase again to 1400 MW if additional under-sea cable capacity was installed.

Provision is made during a supply disruption for gas supplies to power stations to enable them to be started to provide voltage support to the system. Once up to speed and synchronized, the gas is no longer needed. It is understood that this voltage support role has been carried out by the Southdown plant in the past. With the increasing use of Static VAR Systems[38] (SVS), less use is being made of generation plant by the System Operator for this purpose.

Demand side participation in the electricity market offers a means of reducing the economic impact of electricity supply limitations, however the limitations are caused. This is because demand side participation allows lower value users to reduce load first, both to manage peak period constraints, and in case of longer term energy constraints. Participation of the demand side has been somewhat limited in the past, but current developments indicate that this situation is changing. For example, Transpower is currently running a trial period of contracts for load reductions at times when transmission lines are forecast to be overloaded. It seems likely that further dispatchable demand and peak management initiatives will occur through market mechanisms, reducing the economic impact of gas supply disruptions affecting electricity generation.

7.1.5 Management of the Power System

Emergency power system management is the responsibility of the System Operator, Transpower, under the Electricity Act, 2010. Their web site contains documents detailing how these responsibilities would be carried out, including an Emergency Management Policy which refers explicitly to a Gas Critical Contingency.

Two aspects of power system management associated with a gas supply disruption will be considered here – management of peaks and the handling of longer term supply shortfalls.

The System Operator study given in Appendix 4 to this report demonstrated how a disruption over a peak demand period could be managed effectively, without outages. The following observations are made of their study:

- Spinning reserve requirements can be compromised when this is necessary to avoid load shedding. Spinning reserve is unloaded generation capacity which is connected to the system and which will increase its output automatically in the event of some other generation source tripping off. Spinning reserve required to meet normal standards can be around 300 MW, representing significant additional generation capacity which is available in the event of a grid emergency. However, compromising this standard reduces the reliability of supply.
- Generator’s offers can be forced to be dispatched, even if not cleared by the market, should the System Operator require this to maintain system security. These plants are “constrained on” and are not paid at the market clearing price. This is because their offer price would be higher than the market clearing price, but the constrained on plants are not defined as setting the clearing price.
- The System Operator does not have the power to require generators to offer all available plant.

[38] *A Static VAR system provides the reactive power necessary for power system voltage control. This function can also be carried out by generation units. The Static VAR system involves the use of power electronic devices and associated controls, avoiding the costs that are incurred if it is necessary to run a generator specifically to provide reactive power.*

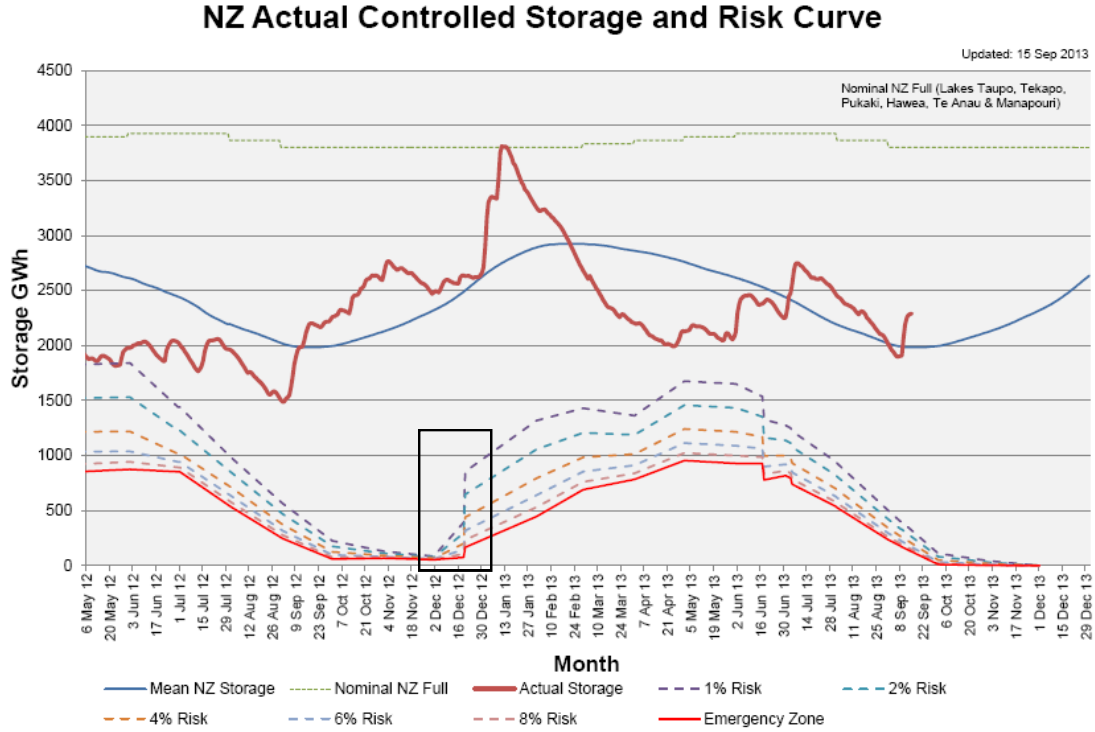
- Demand side response will occur through market mechanisms as spot prices increase. The System Operator assumed that this response occurred in their study.

Longer term disruptions to gas supplies may result in energy shortfalls, rather than a shortage of installed capacity to meet peaks. The additional demands for energy from hydro stations will result in hydro lakes being drawn down more quickly, triggering various actions at different levels of risk to supply.

Figure 17 shows a recent set of hydro risk curves, published by the System Operator in accordance with their "Security of Supply Information Policy". The dashed lines show the hydro storage levels at which the estimated risk of deficit occurring is at various levels of probability. One of the purposes of these curves is to inform the market, influencing the management of hydro storage. Additional information is to be published when storage drops below the 1% probability curve. The System Operator is required to commence an official conservation campaign when in either the South Island or New Zealand as a whole, the risk of shortage is 10% or more (or to begin the campaign on a date agreed with the Electricity Authority). The System Operator is also responsible for initiating rolling outages, as a last resort.

In the event that some plant became unavailable due to gas disruptions for an extended period, the risk curves would be recalculated. The curves would move upwards, as hydro storage drawdown would be higher during the period of disruption. An example of this upwards movement is shown in December 2012, caused by a change in HVDC link availability due to Pole 3 testing.

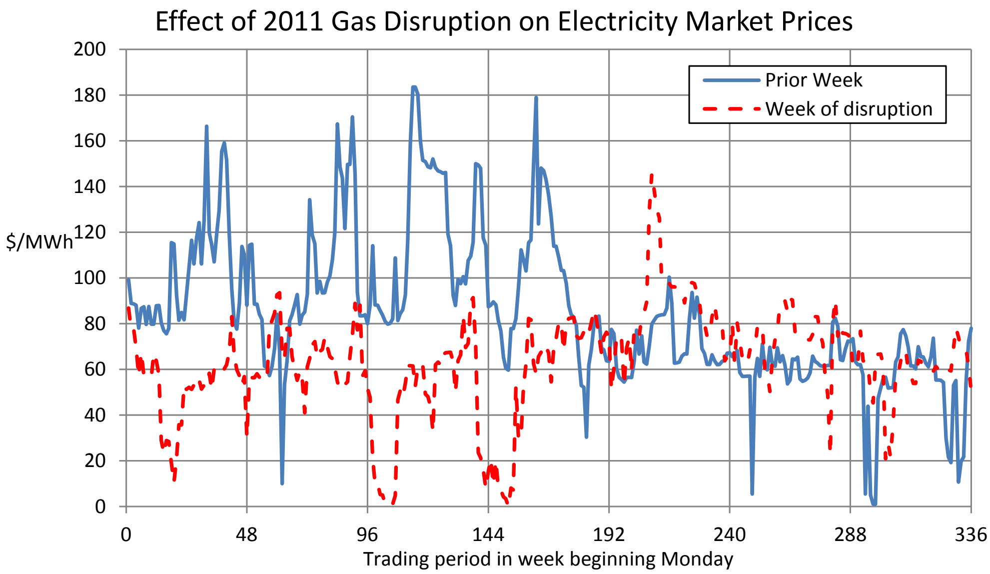
Figure 17: - Hydro risk curves issued by the System Operator, 15th September, 2013



7.1.6 Electricity Market Price Effects

The detailed study of electricity market price effects is beyond the scope of report but some observations are made. Figure 18 shows half hourly prices in the electricity market for the week of the October 2011 gas supply disruption, and those for the previous week. Lower prices occur in the week of the disruption, falling to $1/MWh for four trading periods on Wednesday 26th October, and to zero for one period on the next day. These low prices are due to the Huntly units being forced to remain committed at their minimum load during the early hours of the morning.

Figure 18: - Electricity market prices in week of gas disruption, October 2011, and those in prior week for comparison.



Prices during a more severe event are difficult to predict as generation companies might raise prices to maximise profits and cause price responsive loads to curtail. Companies with hydro resources may raise prices significantly in an attempt to conserve storage. Not only will they wish to manage their resources during the gas disruption period, but also after gas supplies have been restored they will wish to have water in storage to avoid being a significant net buyer on the spot market. This would expose the generation company to market risk in order to meet their retail loads and hedge contracts. Price impacts of a prolonged disruption might last long after gas supplies are restored due to the low levels of stocks of water, coal and gas storage.

A further factor complicating future market prices is the increasing proportion of supply from non-schedulable sources – wind, solar and geothermal. These sources generate whenever possible, but cannot be used to follow load, or to provide additional output in the event of shortfalls elsewhere in the system. It was shown in the report "An analysis of the Effect of Renewable Energy Targets in the Electricity Sector on the New Zealand Gas Industry" (CAENZ, February 2008) that high levels of penetration of these sources may lead to increased price volatility. This increased volatility is likely to be amplified in the event of gas supply disruptions as there will be fewer alternative (schedulable) sources of generation that can replace the lost gas fired generation.

7.2 Case Study - 2008 Western Australia Gas Crisis

A case study describing a high impact, low likelihood event translated into a New Zealand facility supply disruption scenario is the loss event that occurred on 3 June 2008 in Western Australia on Varanus Island. That event was initiated by the rupture of a corroded pipeline which created a subsequent explosion at the Apache operated processing facility on Varanus Island. The Apache facility supplied 35% of the state's gas. The plant was fully shutdown for six weeks while the detailed engineering investigation and repairs were carried out. Plant output was gradually ramped up from late August to 85% of full output by December 2008.

7.2.1 Macroeconomic Impacts

The macroeconomic impacts of the outage were not precisely known as the incident occurred during the global financial crisis so it was difficult to separate out the effects. Economic loss estimates varied between A$2.4 billion in lost turnover and A$120 million impact on the WA gross state product in the period 2008-2012 with the effects of the event appearing to "wash out" of the economy within the two years. Gross State Product (GSP) growth was estimated to have reduced from 7.5% to 7.0% in 2007-08 with forecast growth in subsequent budget years being unchanged.

A Chamber of Commerce and Industry survey of WA industry[39] reported that nearly 17% of respondents indicated that their business had been directly affected by the outage while a further 33% had been indirectly affected. Of those businesses impacted their production declined by an average of 31%.

Loss of employment wasn't considered significant mainly because WA was already experiencing skill shortages and companies were reluctant to lay off workers that they might not get back. Anecdotally it appears that some firms did take the opportunity to move forward scheduled outrages and consequently forced workers to take their annual leave provisions at a time not necessarily mutually convenient for them.

WA Treasury modelling suggested that the worst affected were the energy intensive processing industries.

WA is described as heavily reliant on continuous supply of gas for electricity generation, industrial processing, manufacturing and residential use.[40] In WA industrial usage is about 58% of supply (NZ-59% if cogeneration and petrochemicals are included with industrial). Electricity generation is about 29% of supply in WA and about 60% of generation capacity is fuelled by gas.

7.2.2 Critical Contingency Management

The incident led to an immediate political response by the State to manage the incident impacts and also subsequently to a Senate Committee inquiry investigating the state government's response and economic impacts.[41]

Gas Supply Coordination Committee

The state government acted immediately to set up a Gas Supply Coordination Committee and a Gas Supply Disruption Recovery Committee. The Gas Supply Coordination Committee adopted a five-point plan that involved accessing gas from the North West Shelf and other suppliers, accessing energy from other sources to free up gas (displacing gas from power stations with distillate fuel), public energy conservation campaign, load shifting, and ensuring diesel was available to replace natural gas. The committee established guiding principles in relation to allocation priorities based on the need to protect the health and safety and property of the community, minimise broad community disruption and minimise economic impact. The priority schedule wasn't designed to override contractual arrangements.

The State Government also set up an email based secondary gas trading Gas Bulletin Board (GBB) facilitated by the Independent Market Operator (IMO) which operated through the first period of the outage until supplies were starting to be restored. Successful trades were matched at between $15.50-$18.50/ GJ which was at about 50% of the diesel substitute price. Various commercial impediments hampered the total success of this arrangement including ability to access commercially acceptable transport arrangements for traded gas, contractual limitations to on-sell gas, and competition concerns which prevented gas aggregation on behalf of a number of customers. Nevertheless in spite of these

[39] http://www.aph.gov.au/Senate/committee/economics_ctte/wa_gas_08/submissions/sub16.pdf
[40] APPEA – "Economics and Industry Standing Committee Inquiry into Domestic Gas Price" – June 2010.
[41] The Senate Standing Committee on Economics Matters relating to the gas explosion at Varanus Island, Western Australia – December 2008.

shortcomings the GBB was hailed as a success in its ability to provide transparency to gas trades and from the cooperation received from various parties.

Supply Disruption Recovery Committee

The Supply Disruption Recovery Committee coordinated the response to the economic and social impact of the event such as the shutdown and closure of some businesses; concerns about the potential for job losses and flow-on effects for businesses and the community; the effect on essential services, including food supplies and hospitals; and the effect on future economic growth and the mining industry. The aim was to support industry, businesses, services and communities affected by the supply disruption to return as quickly as possible to normal function. The committee itself comprised representatives from state government including; Treasury, Health, Agriculture and Food, Industry and Resources, as well as industry bodies. The committee also included job search support through Centrelink to assist workers whose employment was affected by the incident. As a mechanism for creating transparency and two way dialogue the effectiveness of this committee was questioned by a number of consumer groups.

The State Government made an early decision not to invoke its powers under the Emergency Management Act 2005 (WA) but rather allow market mechanisms to allocate remaining supplies. The fact that there was no collapse or depressurisation of the gas system also meant that emergency management measures weren't required to be imposed centrally and the privatised gas market based on contractual obligations gave little capacity for government intervention.

7.2.3 Other Impacts

Household gas supplies were largely unaffected. The supply disruption was also partially mitigated by fuel source switching (diesel for power generation) and returning coal fired power generation units to service. The switch to diesel created a separate risk of shortfall in diesel for transport fuel use, which was managed by the government authorising the release of emergency fuel reserves stored at the Garden Island naval facility. Diesel switching meant that consumers faced higher input costs.

There were some allegations that the incident was used by some suppliers to terminate existing contracts under Force Majeure provisions and then to renegotiate new agreements for two to three year periods at a substantially higher price.

The incident also generated a broader discussion on the need for an energy security policy by the state noting the state's dependence on two single pipelines bringing 95% of the state's supplies from the North West, South. This may be less of an issue in New Zealand where the electricity sector in particular is well diversified in its fuel sources and generation facilities. The dependency on Taranaki as the only producing gas province is still a reality, although even there supply diversity has increased since 2007.

The Insurance Council of Australia reported a relatively modest impact on the insurance industry. It appears that most companies did not take out business interruption insurance and also high deductibles and claims being limited to total gas supply loss rather than just reduced supplies reduced scope for claims.

The Senate Committee Inquiry concluded with six key recommendations.

1) To formalise the emergency response measures developed during the crisis.

2) For the WA State Government to conduct an internal analysis of its legislative framework during an energy crisis, particularly its capacity to invoke emergency powers in the public interest.

3) For the WA State Government to conduct a review on gas security.

4) To increase transparency and completion in energy markets:

   a) Establish a permanent gas bulletin board.

   b) Encourage energy diversification through encouragement of alternative energy industry in WA.

   c) WA State Government to examine whether a market based approach to energy supply is providing sufficient information, openness and competition to WA consumers.

5) For the WA State Government to commence discussions with energy suppliers on the need to balance a market approach with community and industry needs during a period of gas shortage. This was to address the “price gouging” and unfair contracts claims made.

6) The Department of Human Services should investigate the concerns about contractors who were severely affected by the outage who were unable to receive social welfare support from Centrelink.

7.2.4 Parallels with New Zealand Scenario

The WA case (a 1 in a 5,000 year type event) is considered a useful benchmark for this study because of notable parallels with a “worst case” scenario of a Pohokura outage (see Section 8.1.2):

1) Incident affected 35% of WA’s supply; a loss at Pohokura, our dominant producer is about 38%.

2) The demand mix in WA of 58% industrial, 29% electricity is similar to North Island demand connected to gas infrastructure at 59% industrial[42], and 32% electricity.

3) 80-90% of the Varanus Island gas was used by industrial customers. Pohokura’s gas contracts and customers are undisclosed but as discussed key customers are assumed to be Methanex, Genesis, Vector, and Nova Energy (assuming Contact falls out of the mix in 2014). Genesis and Nova are assumed to be supplying the higher value commercial and residential markets in the Vector BOP and North/ Central North Systems. This still puts an estimated 70% - 80% of Pohokura’s output into the industrial/ generation sector.

4) Demand management is likely to play out via commercial arrangements rather than government emergency powers.

5) New Zealand also does not have a deep and liquid spot gas trading market to facilitate secondary trading although one is emerging through the EMS platform. The current design is similar to the Gas Bulletin Board set up in WA during the contingency event.

6) New Zealand has similar issues on Gas Sale Agreement contractual constraints that limit the ability to on-sell gas through provisions in bilateral contracts when off-take arrangements have stronger call options. Where the option characteristic in the contract more closely resembles a put option the customer generally has a right for on-sale to offset their volume risk.

7) New Zealand also has similar constraints around gas transmission rights and the ability to transport gas to different parts of the network. This is probably not as important in this particular scenario as we are dealing with a reduction in total supply and generally it is not a problem moving less gas through contractually entitled maximum capacity rights.

[42] New Zealand “Industrial” in this context includes cogeneration and petrochemical demand. Cogeneration is associated with industrial site use and petrochemicals are a subset of overall industrial production.

8) The functions of the Gas Supply Coordination Committee have been codified in the CCM regulations 2008. These regulations has already established, tested, and accepted protocols for communication to the wider market. Further improvements to the regulations have already been identified through the Maui pipeline incident of November 2008.

9) The curtailment bands in the Critical Contingency Management Regulations in New Zealand arrive at a similar outcome for priority and economic impact, albeit via a different logic to manage transmission survival times and linepack.[43]

7.2.5 Differences

There are some features that make the New Zealand case different.

1) There may be more limitations around immediate fuel switching in New Zealand.

   a) The decommissioning program for Genesis' coal units at Huntly is leading to lower redundancy in thermal generation equipment. Currently Unit 3 has been retired with another unit to be retired in 2014. This represents a reduction of 500 MW of generation backup. Whilst this study indicates that the electricity system appears relatively secure, this question deserves more detailed study, especially as to whether the remaining idle coal units have a contingency value, currently not included in any decision to decommission them.

   b) Heating plant at various Fonterra and other Dairy processing sites are not all configured to switch to distillate fuels. Fonterra and others are evaluating their options on dual fuel firing, but it is unlikely that all their plants will have dual fuel capability. An extended outage beyond about a week is likely to lead to lost dairy production as milking frequency is reduced and herds dried off early.

   c) It is questionable whether a sudden demand in diesel supply can be met by current stockpiles and production capacity at the refinery.

2) There is a lower reliance in New Zealand on thermal generation than in WA. Gas generation in New Zealand is only 20% of total generation compared to 60% in WA. Under favourable hydro and seasonal conditions this dependency reduces to as low as 10% (although it can be as high as 50% under least favourable conditions). Nevertheless even with a full field outage at Pohokura both Genesis and Contact are still guaranteed gas supplies through Kupe and Ahuroa storage and Todd Energy would still supply its peaker plant at McKee. The flow on effects in the electricity market pricing and energy input pricing is therefore expected to be more muted depending on hydrology and season.

3) There are differences in legislative frameworks to address competition effects, civil emergencies, employment impacts, and ability to access social welfare services.

7.2.6 Other Lessons

Supplier Gaming

The Senate Inquiry raised a concern that certain suppliers used the emergency to their commercial advantage by activating Force Majeure provisions to terminate negotiated long term agreements and create a squeeze to force buyers into less favourable long term agreements. It wasn't clear whether this

[43] NZIER – "Value added associated with gas demand-Estimates of value added by industry for informing decisions on critical contingency management" - NZIER report to Gas Industry Co. 11 October 2012.

was for gas supplies or for electricity supplies. The evidence provided to the Inquiry was anecdotal rather than positive proof as some of the retailers declined to appear before the inquiry and aggrieved parties were prevented under confidentiality provisions in their agreements from providing more concrete evidence. The case for the legality of such behaviour was not addressed through the inquiry.

As a scenario it is important to note that such practices do create long term residual economic impacts affecting competitiveness of downstream customers. In New Zealand these matters might be addressed through the Commerce Act 1986, possibly through Part 2 (Restrictive Trade Practices) although a Commission Advisor wasn't able to give a clear answer to this question. It seems therefore that this is a matter of commercial contract law and the best means of mitigating this risk is for parties to recognise and deal with this scenario through contract.

Supply Disruption Recovery Committee

There are currently no centrally coordinated mechanisms for dealing with wider economic and social impacts created out of long term supply disruptions. The effectiveness of the committee in the WA incident seems to have been in question with some stakeholders although local governments considered it worthwhile despite its limited impact on local decision making. Local Government appreciated mainly the opportunity for dialogue and information sharing rather than driving any emergency management activities.

CCM regulations do not address secondary impacts of a critical supply disruption event, particularly how this might affect communities or other sectors such as tourism hospitality and accommodation.

The value of considering secondary impacts and how these would be responded to may be a matter for further follow-up. This would be to determine whether there should be a separate emergency committee to deal with mitigating flow on effects from a supply disruption event.

8. LOSS SCENARIOS

The following examines a number of scenarios to illustrate what constitutes a major gas disruption. We consider:

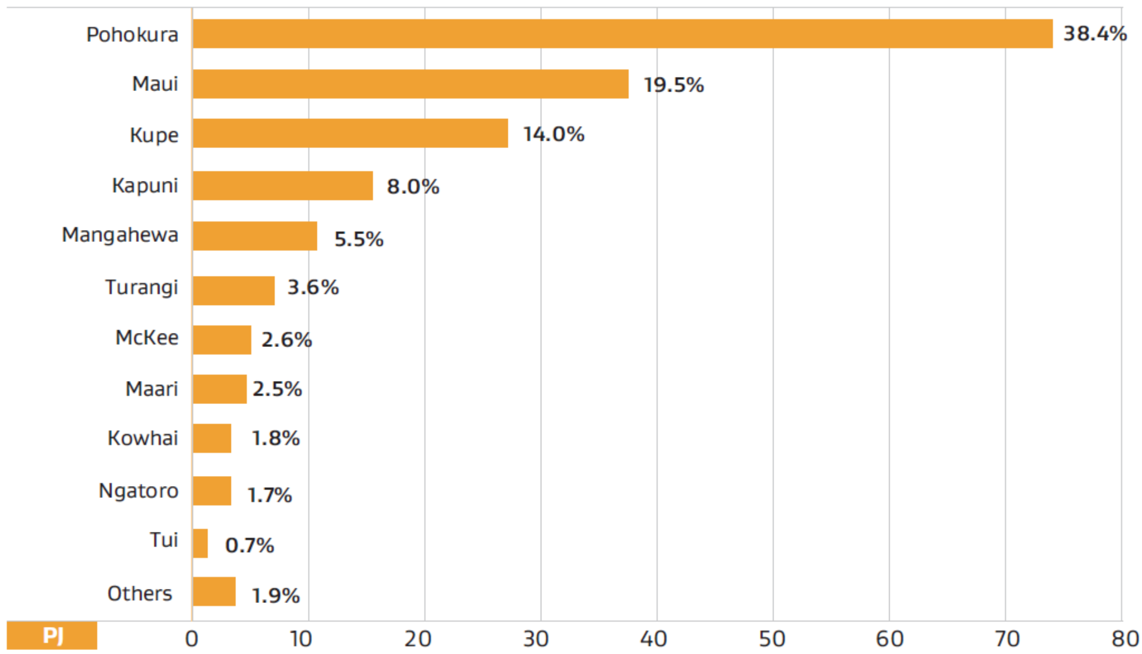
- failure modes,
- consequences,
- interdependencies, and
- perceived criticality – short term focus.

Ideally the consequences of each loss scenario would include a measure of the economic impact on industries whose normal gas supply is disrupted. However we have not been asked to undertake specific economic analysis. To provide preliminary analysis we have adopted the estimates provided by NZIER for the review of the CCM regulations to provide estimates of the contribution of gas consumption to value-added for those industries that use gas. This provides a measure of the value at stake if a firm ceases production, but as indicated by NZIER, the numbers provide a guide; they do not take account of the willingness for firms to pay for uninterrupted supply or the extent to which firms can substitute to other forms of energy. Hence these numbers should not be interpreted as a full assessment of economic value.

8.1 Gas Supply Disruption from Loss of Producing Field

The scenario is an extended supply disruption event at a major gas field. Figure 19 provides an overview of which gas fields and production stations dominate.

Figure 19: - Total Natural Gas Production by Field for 2012



Source: MBIE – Energy In New Zealand 2013

The three dominant fields and respective production stations are Pohokura, Maui, and Kupe. Maui and Kupe also produce LPG whereas only Todd produces LPG, through its McKee straddle plant, from

Pohokura gas. Loss of LPG is not considered material to this study as New Zealand continues to be able to import LPG.

All three gas fields have their own dedicated facilities and are unable to process gas from each other or any other fields. In terms of disruption scenarios it therefore does not matter whether the event is a field event or a facilities event.

Pohokura gas customers are not disclosed publicly but the upstream focus of the selling parties indicate that tranches are likely to be sold to gas wholesalers including Genesis, Vector, Contact, as well as directly to Methanex. Todd is also likely to be taking its share for both Nova and possibly Methanex. Contact's dependence on Pohokura gas however is expected to reduce substantially if not entirely from 2014.

Maui gas customers are principally assumed to be Contact and Vector through Right of First Refusal (ROFR) agreements extending out to 2014. Whereas Contact's entitlement underpins mainly its generation plant, Vector targets mainly the industrial market for its customers.

Genesis is contracted to buy all of the gas produced by the Kupe Joint Venture which underpins fuel supply to Unit 5 at Huntly (e3p).

Disruption at any gas field is felt initially through the existing contract arrangements in place. These are almost exclusively bilateral and long term. Generally these will have some provisions for alternative supply on a "best endeavours" basis.

Consumers are not always diversified in their supply arrangements which may tie them critically to a particular field and production station. Ballance Agri-Nutrients Ltd for example has an exclusive arrangement with Greymouth Petroleum through Turangi and Kowhai for its 7PJ of annual demand. Greymouth has approximately 28 other customers assumed to be smaller industrial plants. A supply disruption at Turangi would trigger FM provisions and force these customers to seek gas from other suppliers. Although disruptive to individual customers the relatively small volume of gas involved (less than 10 PJ pa) is likely to be met by remaining fields. Only Ballance might find it difficult to gather sufficient gas to run its facility. The economic consequence would fall mainly on its cooperative shareholders who would receive less rebate for the locally produced urea fertiliser when it is forced to import the product from overseas.

For these reasons we consider the scenario of an extended supply disruption at Pohokura to be the highest impact event for a producing gas field outage due to:

1) The dominance of the gas field in terms of total supply.

2) Diversity of its customers through further wholesale and retail arrangements.

A guide for likely consequence can be found by considering the analogous Western Australian event in June 2008 with the gas explosion at Varanus Island.

We also compare a Pohokura outage event with a Kupe outage primarily to evaluate the impact of a gas field supply to a single customer (Genesis).

Scenario 1: - Loss of Kupe

1) INFRASTRUCTURE			
Event (Failure Mode)	**Consequences**	**Interdependencies**	**Perceived criticality**
Gas Field - A loss of containment event at the Kupe Wellhead platform causes a fire and explosion which destroys the wellhead platform with a total loss of supply to the onshore Kupe gas plant.	Extent of Loss: • 55 TJ/day (~14% of demand). • Duration – 12 months. Critical contingency invoked – duration uncertain. Impact on electricity generation due to Kupe gas primarily contracted to Genesis (HU-5).	Critical Contingency invoked: a) Users consuming more than 15TJ/day directed to curtail (to Bands 1and 2). b) CCO curtails Genesis (HU-5) – CCO has discretion to curtail subset of demand within band. c) CCO terminates CC when satisfied that supply of gas is sufficient to meet or exceed the reasonably expected consumption (all demand except for directly contracted Kupe). 1) Alternative supply arrangements for Kupe occur as market conditions allow.	1) Short term (12 month) impact on generation. 2) Uncertain impact on gas availability longer term: • CCM necessary to handle immediate event but quickly terminated. • Bilateral nature of market assumes affected parties find options for more gas supply or fuel substitution for electricity generation - possible implications for electricity prices (where higher gas prices paid to secure availability).

8.1.1 Kupe Scenario Outcomes

Based on the foregoing discussion we would anticipate a sudden and prolonged supply disruption to play out as follows in the gas market:

Immediate-Within 24 Hours

1) Selling parties for Kupe declare a FM event and initiate curtailment procedures through contractual provisions.

2) Critical Contingency Operator declares a Critical Contingency event on the transmission system and initiates its own procedures to manage and stabilise transmission system pressure and line-pack.

3) Genesis shuts down e3p and switches to its Huntly coal units.

After 24 Hours

4) Huntly coal units likely to be on-line as Genesis conserves gas to meet its industrial, commercial, and residential markets.

5) Genesis looks to bring a coal unit out of storage (current estimate 9 months to reinstate).

6) Genesis goes to market for uncontracted gas and looks to rebalance its electricity retail portfolio to minimise electricity spot price risk (not renewing hedge contracts, invoking FM provisions).

7) Main impact is felt through the electricity market in line with discussion in section 7.1.6 “Electricity Market Price Effects” and likely to be felt first by consumers on spot price contracts and to flow onto consumers hedge contracts as they expire.

Note: much will depend on the time of the year the event would occur. Spare deliverability from remaining fields is considerably better in low demand periods (November to March) – particularly Maui when need for dairy processing is highest, which could possibly assist in dairy processing continuing. However this is also a period when some fields take scheduled maintenance outages – e.g. Kapuni.

This scenario raises a broader issue as to the value of the Huntly coal units as they are being progressively retired and decommissioned. Currently it is assumed that Genesis is not being rewarded in the market for keeping these units available and its generation mix means that any losses in gas generation is partly offset by higher spot prices for its hydro generation. The impact is therefore felt by consumers more than generators.

Scenario 2: – Loss of Pohokura Production Station[44]

Event (Failure Mode)	Consequences	Interdependencies	Perceived Criticality
Production Station - on 24 June 2014 a series of explosions followed by fires occurs at the Pohokura Production Station. Production ceases.	1) Extent of loss 190 TJ/day (-~43% of demand). 2) Estimated time to resumption of production - 60% within 2 months (100% within 3 months).	Critical Contingency invoked: • Bands 1- 4 curtailed (all demand down to medium sized industrial and commercial consumers). • First 24 hours: o Selling parties declare force majeure. o Pohokura partners look to supply from other equity fields. o Wholesalers initiate full/partial curtailment; look to substitute with alternative supply (potential to reduce curtailment impact). • Beyond: o Market participants adjust supply/demand arrangements: ▪ Methanex reduces throughput. ▪ Major consumers reduce production; economic impacts adjusted by rescheduling where possible (maintenance). • Secondary market trading re-establishes limited supply to those affected. • Critical contingency operator terminates CC satisfied that supply of gas is sufficient to meet or exceed the reasonably expected consumption.	• Post CCM (or once system stabilised) a constrained amount of gas available i.e. the pool of users is greater than the availability – what mechanism is available to determine how gas is assigned? *Note: Australian security studies suggest establishing a short term trading market as an alternative to voluntary or involuntary curtailment.* • Much depends on the timing of event: o Spare deliverability from remaining fields is considerably better in low demand periods (November to March) – particularly Maui and Kupe when need for dairy processing is highest, which could possibly assist in dairy processing continuing. o However this is also a period when some fields take scheduled maintenance outages – e.g. Kupe, Kapuni. o Residential and commercial sectors are not expected to be affected by the outage.

[44] *Note: we considered a similar scenario to Kupe (Wellhead Platform destruction) however the impact is somewhat mitigated by the ability of Pohokura to continue partial supply via two onshore wells. Although the disruption period could be 12-24 months (estimate from industry source) to re-establish a function wellheads platform facility, the onshore wells could continue to deliver an uninterrupted 20%-30% from the field.*

8.1.2 Pohokura Scenario Outcomes

Based on the foregoing discussion we would anticipate a sudden and prolonged supply disruption to play out as follows in the gas market:

Immediate-Within 24 Hours (CCM dominated response)

1) Critical Contingency Operator (CCO) declares a Critical Contingency event on the transmission system and initiates its own procedures to manage and stabilise transmission system pressure and line-pack primarily affecting large users initially.

2) Selling parties for Pohokura gas declare a FM event and initiate curtailment procedures through contractual provisions.

3) Pohokura JV parties look to supply gas from other fields with possible spare deliverability – principally Maui and Mangahewa/ McKee. Likely available deliverability and quantities will assist large consumers (Methanex, generators) to safely curtail demand.

4) Depending on time of year Genesis may also be in a position to uplift more gas from Kupe.

5) Gas wholesale parties (Vector, Genesis, and Contact) would deal with larger ToU metered customers to initiate full or partial curtailments. Wholesalers tend to have several sources of gas supply and agreements with their customers are assumed to not be directly linked to a particular gas source. The impact on wholesalers and their customers is therefore partial, rather than full loss of supply. Rationing procedures will be peculiar to each wholesaler.

After 24 Hours (Contractual dominated response)

6) Pohokura Operator has made an initial assessment of expected duration of outage.

7) Huntly coal units likely to be on-line as Genesis conserves gas to meet its industrial, commercial, and residential markets.

8) CCO assessment on line pack stability enables restoration of curtailment bands leaving opportunity within those bands for trading of available gas.

9) Methanex shuts down one methanol train at Motunui.

10) Fonterra makes an assessment on which Dairy North Island Processing Plants to shutdown (NB Whareroa site expected to continue as supply is through Todd-Fonterra JV from Kapuni gas field.) Contact is assumed to have insufficient gas to run Te Rapa (4.2 PJ pa) and Todd may not be able to supply Edgecumbe (1.2 PJ pa). Total gas loss to Fonterra dairy process could amount to as much as 6PJ pa equivalent.

11) Secondary market spot trading and/or short term supply contracts are negotiated between wholesalers and suppliers.

12) Some industrial sites may choose to move forward scheduled downtime.

13) Mass market (monthly metered sites) is unaffected.

Note: much will depend on the time of the year the event would occur. Spare deliverability from remaining fields is considerably better in low demand periods (November to March) – particularly Maui and Kupe when need for dairy processing is highest, which could possibly assist in dairy processing continuing. However this is also a period when some fields take scheduled maintenance outages – e.g. Kupe, Kapuni.

8.1.3 Possible Worst Case Scenario

A feasible worst case scenario is a complete gas outage for at least six months affecting one methanol train at Motunui (35 PJ pa)[45] and three months for half of North Island dairy processing (6 PJ pa), Refining NZ (2.5 PJ pa), gas generation (CCGT 25 PJ pa). Dairy processing is unlikely to be interrupted provided suitable gas trading is enabled, either through an open trading platform, or bilaterally through gas retailers. The value added component of gas to dairy production was calculated to be $97.61/ GJ according to NZIER. Dairy processing would either switch to diesel where sites are configured for dual fuel capability, or negotiate gas at diesel price equivalent (about $29/ GJ) which is assumed to be equivalent to Methanex's point of indifference.[46]

With respect to other large users potentially affected including NZ Steel, Refining New Zealand, and Carter Holt Harvey pulp and paper the impact is assumed to be felt largely through a temporary price increase in gas.[47]

The direct cost impacts are assumed to be the difference between diesel price equivalent and current gas price – or approximately $20/ GJ.

Based on NZIER figures[48] for industry value added and value added per GJ a 3 month outage could equate to a loss of about $400 million. No account is taken of the cost implication in respects of the Pohokura asset owners.

Table 13: - Scenario 2 Lost Estimates

Industry	$/ GJ	Gas Quantity (TJ)	Value lost ($ million)
Methanol	12.42	17,500	217
Dairy	20.00	2,000	40
NZ Steel	20.00	500	10
Pulp and Paper	20.00	800	16
Electricity Generation	5.53	6,250	69
Petroleum manufacture	20.00	625	12

The losses suffered by the Pohokura Joint Venture parties are excluded in this broad based analysis, as are forgone royalty revenues by the Crown from loss of production. Principally this is because the revenues from sale of product and crown royalties are not foregone so much a delayed since the resource is still sitting in the Pohokura reservoir. Repair costs associated with the facilities also are assumed to be insured.

[45] It is not known how much gas Methanex might have contracted from Pohokura but worst case it might be most of one methanol train at Motunui.

[46] NZIER calculated a value add of $12.42/ GJ for methanol but conversation with Methanex suggested that their cost neutral position would be higher to account for other supply chain costs and risks as they look to supply their customers from other sources.

[47] Reduction in methanol output is also expected to affect revenues at Port Taranaki but this is relatively minor (less than $10 million) compared to higher gas input costs.

[48] NZIER – ibid. NB the value added component may not be the neutral value for companies since other supply chain factors including purchase price of substitute and risk variables will impact the risk equivalence price. Thus $12.42/ GJ for methanol is likely to be less than Methanex' opportunity cost as it seeks alternative methanol supply arrangements to meet its customer obligations. We have assumed based on a conversation with Methanex that the opportunity cost is closer to $25/ GJ.

8.2 Gas Supply Disruption from Loss of Pipelines

The following section examines loss of key infrastructure. As previously described in October 2011 the Maui pipeline suffered a loss of containment event for approximately 5 - 6 days. As a result critical contingency was called and all consumers north of the event, with the exception of residential consumers, were directed to curtail their use of gas. This was the first significant outage of the pipeline since construction in 1977. The failure was assessed to be due to overload caused by landslide movement at the Pukaruhe site. Landslide movement was known to be a risk.

The outage caused significant disruption to businesses and services in the top half of the North Island that rely on gas for their normal operation. A review by MBIE estimated that the gross economic cost of this disruption was $200 million, with costs heavily concentrated on the dairy and large industrial sector.

The Maui pipeline was constructed in 1977. At places it shares the pipeline corridor with the smaller Vector 8“ line that was built earlier. This was the case at Pukearuhe. The route north of Taranaki travels through difficult terrain which exposes the pipelines to significant geotechnical risk, as well as potential access constraints (terrain/weather) in the event a repair is needed. Hence any response to a similar event may be impacted by a range of factors that will have an influence of time to restitution of supply.

If anything despite being a major event the time taken to repair the 2011 outage (taking into account the terrain, location of the pipe and adjacent Vector pipeline, relatively benign weather conditions etc.) suggests that compared to what might be a worst case scenario (where a perfect storm of conditions coincides to exacerbate the impact and frustrate repairs) the Maui outage could be considered to have been fixed relatively quickly. Also supply was able to be maintained because of the availability of the smaller Vector line, which enabled supply to continue to the residential sector and avoid major safety issues associated with the need to restart domestic appliances in a safe manner.

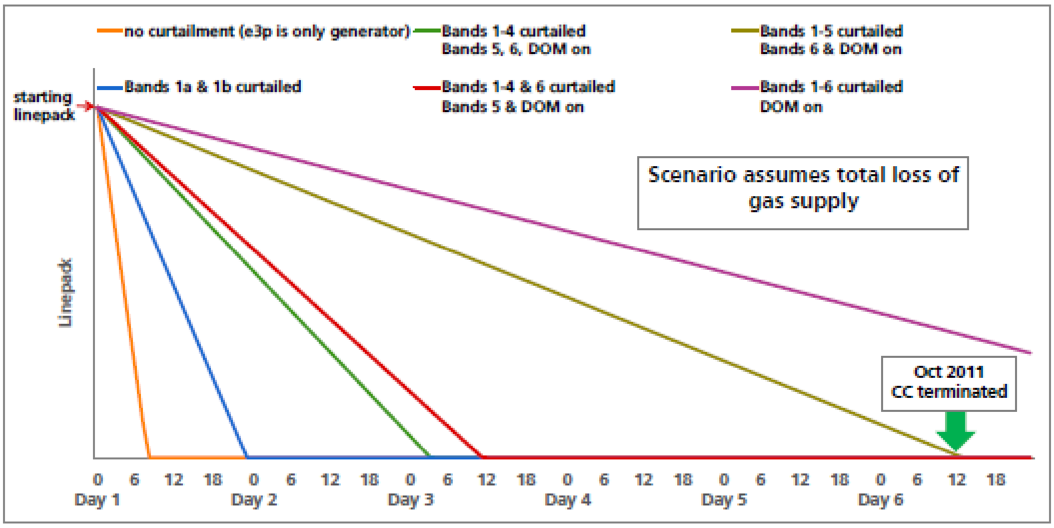
The following scenario is intended illustrate a “worst case” where a number of factors conspire to create a significant outage.

Scenario 3 – Loss of Maui and Vector pipeline

Event (Failure Mode)	Consequences	Interdependencies	Perceived criticality
Transmission - following a sustained period of heavy rain a huge landslip over 50m in length some 7km north of Mahoenui severely damages the MDL pipeline and severs the Vector pipeline. Both pipelines are isolated and all gas transmission north is curtailed. Repairs begin with immediate effect but heavy rains and the location of the slip make access to the pipelines difficult.	Extent of loss – all demand north of the outage (Vector North, Central and BOP). Extent dependent on timing - could be (202 TJ/day): Generation – 121 (includes Southdown, Otahuhu, area cogen, Huntly). Major Industry (Steel, Dairy, Refining, Pulp and Paper, Peroxide – 30). Small Industrial / Large Commercial – 33. Small Commercial / Residential – 18. Repair approach – priority focus on Vector line to maintain residential/critical care. Curtailment for bands 1 – 4 continues until the Maui pipeline available. Repair involves temporary fix to get gas flowing. Time to affect repairs assumed: • Vector (4 days). • MDL (4 weeks).	Critical Contingency invoked -availability of gas for essential services and critical care depends on line-pack conditions at the time and seasonal domestic demand: • All demand down to Band 4 curtailed. • Uncertainty around linepack for demand below requires publicity campaign to encourage demand restraint – safety). CDEM activated. Repair time priority/duration requires close cooperation between and dependent on response by two commercial owners – raises: • Preparedness. • Alignment with resupply imperative. Electricity supply – Vector pipeline not configured to provide supply to Huntly – risk of gas being unavailable for restart on coal. Consumer Business Continuity Plans invoked.	Outage **Extreme/Prolonged.** CCO focus is to maintain system integrity. CCM remains activated until full supply restored. Civil Defence Emergency Management activated (during 2011 outage CDEM activated monitoring and information distribution role only – CCM regulations gives precedence to CDEM where gas shortage severe). Government sets up monitoring/ coordination activity similar to NESO for petroleum liquids - raises questions of overall responsibility. Gas users north of outage initiate Business Continuity Plans, drawing on alternate fuels (diesel, LPG, coal) – Impact of draw on liquid fuels system unclear.

The safety risk to residential customers requires a restoration approach to maintain or restore gas supply as quickly as possible. In the Statement of Proposal supporting amendments to the Gas Governance (Critical Contingency Management) Regulations 2008 GIC estimated the following following times to failure. These estimates are dependent both upon linepack at the time, the rate at which curtailment is affected and minimum operating pressures required to maintain gas flow. Hence in a total disruption there would still be uncertainty around the risks to residential customers. A temporary fix of the Vector pipeline is considered to be critical to maintaining minimum supply.

Figure 20: - Time to Failure under Different Curtailment Scenarios



8.2.1 Scenario Impact

The outage has an effect across the entire upper North Island (Waikato, Bay of Plenty, Auckland and Northland). This scenario affects the same sectors impacted by the 2011 Maui outage but for longer.

For the review of the Maui pipeline outage in October 2011 MBIE estimated a gross economic cost using a methodology that takes into account the number for gas consumers, duration of the outage, and average daily cost and vulnerability of firms to disruption. MBIE calculated a gross cost of $200 million over the 5 day duration of the outage ($40 million per day). The report noted that the cost was heavily concentrated in the dairy and large industrial sector.

A simple extrapolation of 4 weeks would suggest a cost $1,012 million (based on 28 days at approximately $40 million per day). This is less than 1% of GDP but still significant (we note the Varanus island outage estimates vary but one put the cost at around 1.0% of WA's GSP.[49][50]

We have examined the NZIER analysis commissioned by GIC for its review of the CCM Regulations, which provides estimates of value added in $/GJ across industries in the North Island which use gas. The objective of the analysis was to provide a guide to the relative magnitudes of potential value at risk due to demand curtailment (and by definition which would guide the order in which demand was curtailed).

We have applied these estimates to the gas demand in the areas affected by the scenario (Table 14) and applied an average rate to activities over and above generation/large industrial etc.

[49] $2.4 billion relative to $200 billion Gross State Product.
50 https://www.slp.wa.gov.au/salesinfo/varanusinquiry.pdf

Taking an average for the bulk of activity outside electricity/major industrials is necessary because there are industries which have a high $/GJ value but which would not cease operation in an actual gas shortage (e.g. insurance services). The methodology suggests a 4 week outage could equate to a loss (ignoring any multiplier effects) of $485-650 million, with the range dependent on the value attributed to activities not including generation/large industrial etc. For the low end of the range we have assigned $300 ($400 for the high end) for the value added per GJ.

Table 14: - Scenario 3 Lost Estimates

Industry	**$/GJ**	**Quantity**	**Per day**	**Value lost ($ mln)**
		(TJ)	GJ	
Vector North				
Generation	5.53	17596	48,208	7,464,561
Dairy	97.61	1100	3,014	8,236,679
Steel	10.01	2000	5,479	1,535,781
Refining	39.9	2500	6,849	7,652,055
Horticulture	92.25	20	55	141,534
Urban Centres	300	1377	3,773	10,336
Greater Auckland	300	11942	32,718	274,829,589
Total		36535		299,870,535
Vector Central				
Peroxide	12.42	350	958.90411	333,468
Dairy (Te Rapa)	97.61	4600	12602.74	34,444,296
Urban centres	300	2485	6808.2192	57,189,041
Total		7435		91,966,805
BOP				-
Kinleith	34.25	2450	6712.3288	6,437,123
Whakatane	34.25	564	1545.2055	1,481,852
Kawerau	34.25	600	1643.8356	1,576,438
Dairy	97.61	1952	5347.9452	14,616,362
Urban centres	300	2629	7202.7397	60,503,014
Total		8195		84,614,789
Huntly	5.53	21300	58356.164	9,035,868
Total(incl Huntly)		29495		93,650,658
Total Impact				485,487,998

This approach indicates a lower value than the MBIE estimate although it could be higher because:

- It ignores any multiplier effects (the gas outage which affected the Wellington CBD had multiple affects, with unsubstantiated reports of businesses failing).[51]
- Timing - October is the height of the dairy season but June may have little impact for the dairy sector) whereas NZIER's numbers are by definition an averaging on value.
- The actual extent of the outage (reinstatement of the Vector line would lead to early re-establishment of some gas supply).

Another influence would be the priority focus and early re-establishment of the Vector line, which is assumed to be more easily capable of a temporary fix. However we note that this would not assist generation at Huntly as currently it is not connected.

Non Infrastructure

We have considered events related to non-infrastructure such as gas quality issues, pandemics and cyber threats but these are not considered to be realistic scenarios that would have major impacts on supply availability.

[51] http://www.nzherald.co.nz/nz/news/article.cfm?c_id=1&objectid=10399200

9. RISK MANAGEMENT CONSIDERATIONS

9.1 Understanding the Risk Horizons

What the scenario analysis tells us is that, assuming current gas supply arrangements and continuation of current use patterns, then the overall economic effects of a major disruptive event are essentially bounded within the range of approximately $400 - $650 million. Essentially we have two gas disruption scenarios:

1) A CCM event with significantly reduced allocations and curtailment of gas supply of up to 4-6 weeks.

2) A significant (but not necessarily catastrophic) curtailment of gas supply for an extended period that goes well beyond any CCM-type event.

In both situations we find that the consequences that arise from any loss event are likely to be manageable, and well within the bounds of normal business interruption scenarios. For example the System Operator's study of the electricity generation following an outage clearly shows that there is sufficient installed capacity in the power system to meet major gas supply disruption under both scenarios. Depending on hydrological conditions it is also probable that the ability to supply energy over a long duration event will be relatively secure.

Basically there are two influences that characterise the risk equation. The first is the diversity that exists within the NZ gas supply chain which creates an inherent resilience within the system to disruption to gas supply, and the second is the emergence of a secondary gas market allowing gas users flexibility in their response options beyond conventional business continuity provisions.

The Varanus Island case study aptly describes these influences. This incident reinforces that those most severely impacted upon were the energy intensive processing industries. In the NZ context this is essentially limited to Methanex and Fonterra; other industries have alternative sources of energy available to them which acts to limit the effect of curtailment of supply. Other than Methanex, economic impact is mainly felt through temporary higher input prices rather than lost output. Once supply is restored the effects are likely to wash through quite quickly so no permanent or long term loss is suffered. Moreover, it is conceivable that even for the most pessimistic scenario of a major loss event at Pohokura, other producing fields will be able increase field production to some extent to meet any long-term shortfall.

The Varanus case study also underscores the benefits that a liquid spot gas trading market provides. During the Varanus event secondary trading emerged and the WA government did not need to proceed with the emergency response measures it had available to it. Over time, demand management played out via commercial arrangements and the ability to on-sell gas though bilateral contracts. NZ has an emerging secondary gas market and thus the response mechanisms already available to it.

The reason for having some optimism as to the implications arising from an extended curtailment event is that the impacts and disruptions are largely isolated to just a few customers (Methanex, Contact, Genesis, MRP) rather than the broader range of consumers and industries that would be affected by a transmission event. Discussion with Methanex and Fonterra indicates that these firms are fully cognisant of the risks they face from disruption to their gas supply and, in turn, are well placed to respond to minimise any adverse impacts on their businesses, provided there is sufficient transparency to provide for informed decision making.

Petrochemical plants can be turned down, gas entitlements can be on-sold to higher value uses, fuels can be switched, and industrial production can be adjusted. The question thus arises as to what constitutes a major disruption event?

Whilst one might be able to assign likelihood to particular events there is no credible scenario that leaves NZ without sufficient natural gas to meet essential service provider requirements (except for short term failure modes) or losses beyond an estimated $650 million maximum probable loss. Characteristically one might assign a low likelihood of such an event occurring.

This leaves open the question as to whether risk to public good can being adequately managed by private good risk management.

With some caveats, which are discussed in the following section, it would appear that adopting a market based approach together with the improvements proposed to the current CCM regulations should be sufficient without further government intervention via extended emergency powers. Gas supply security is more a matter of getting the incentives in place for owners and operators of facilities to take actions that are aligned with the national good rather than a reliance merely on regulatory compliance as framed by predetermined risk outcomes.

The organisational reputation of gas market participants, strong commercial drivers to ensure business continuity and existing contractual obligations in respect of gas supply will in all likelihood lead to a market outcome that minimises risk.

9.2 Adequacy of Current Market and Regulatory Interventions

We have been asked to comment whether any market or regulatory failures may affect the adequacy of risk management. Our review indicates no stand out areas but a number of matters are worth highlighting.

9.2.1 Capex Treatment

One question concerns the influence of the price quality regime on risk management when investment is required to mitigate a threat to, or improve, security of supply. These kinds of projects can be difficult to justify. The question is whether the price quality regime might alter how an asset owner views its risk profile in the approach to such investments which, in turn, may affect adequacy of risk management.

In its recently released 2013-2023 Asset Management Plan Vector[52] commented that the Default Price Path (DPP) should be capable of dealing with expenditure, which while “lumpy” is inherently part of the gas transmission business. The inference is that Vector considers the DPP should be capable of considering lumpy capex (including that related to security). Equally Vector does not consider a Customised Price Path (CPP) as a satisfactory mechanism and has commented that elements of the CPP process could result in undue delay to an investment.[53]

As discussed in Sections 4 and 5.2.2 a DPP applies a standardised capex allowance. For requirements outside that, the Commission has determined that a regulated business should seek a CPP, to enable the Commission to examine the proposed expenditure and develop the appropriate price path.

[52] http://vector.co.nz/sites/vector.co.nz/files/Gas%20Transmission%20Asset%20Management%20Plan%202013-2023.pdf at Section 1, page 6 of 18
[53] Ibid, Section 9,page 14 of 15

The requirements of a CPP are more onerous[54] and once submitted, an application cannot be withdrawn. Hence a regulated entity would need to weigh up carefully whether to proceed with a CPP. This appears to be the reason for Vector's comment around delay.

It is known that Maui Development Ltd is considering realigning the Maui pipeline in the next year or so to avoid coastal erosion in the Whitecliffs area. This could be by way of a CPP but at this stage MDL's preferred approach is unclear. Vector has noted that it too may have to relocate its pipeline as it is in the same area that affects Maui. But it has suggested an alternative of isolating and abandoning the affected section because of its lower forecast expenditure.[55] How this might impact the security profile of the pipeline is not indicated.

The Commission is currently consulting on incentives for GPB's to control expenditure during a regulatory period.[56] The assumption is that a supplier is rewarded with higher profits if expenditure is controlled. The same reasoning is applied to investments that lower operating cost and boost profits. The suggestion is that a GPB would be incentivised to invest early in a regulatory period so as to maximise the time available for the benefits to accrue before the next reset. A security investment however may simply mean increased cost impacting returns. In this case the GPB might be incentivised to delay capex for as long as practicable, at least until the end of the period so that it can more quickly be taken into the regulated asset base at the next reset.

The comments from Vector and the Commission's ongoing programme affirm that the regulated pricing framework will influence the way in which GPBs approach expenditure but it's not clear whether this would alter or change the risk profile adopted by a GPB. In fact Vector notes that any decision will be supported by robust risk management decision-making to reduce the risk to an acceptable level (the ALARP standard), which is consistent with its existing practice and regulatory requirements.

We need also to consider (as noted in Section 5.2.1) the certification requirements on a pipeline owner arising out of the HSE (Pipelines) Regulations 1999 and adherence to the standards and codes that form the basis for obtaining a valid Certificate of Fitness. Ultimately it is a valid Certificate of Fitness which determines the ability of the GPB to operate.

Although the regulatory environment has changed since 2009 (the first regulatory period is now operating) we do not consider that there is risk of regulatory failure by virtue of the pricing framework being in force. There are incentives operating that could potentially alter a GPB's decision making framework but there is nothing to suggest that this would alter a GPB's risk management approach, nor detract from adherence to the standards, codes and operating practices by which GPBs are certified to operate.

9.2.2 Market Failure

The discussion in Section 3.2 suggests no immediately major or obvious questions of alignment that would suggest serious risk of market failure. Directionally, market participants have strong incentives to

[54] In a Customised Price-Quality Path (CPP) a supplier can have all of their information considered through an audit, verification and evaluation processes which the Commerce Commission then uses to determine whether proposed investments not considered in a DPP are required and sets a customised price-quality path with those investments included. Regulated suppliers consider CPP's as an expensive and risky option as it requires greater audit and verification of components and a chance that a CPP could place a lower price-quality path than a DPP (and a CPP application cannot be withdrawn once it is submitted). The Commerce Commission considers the risks mitigated through the transparency of the input methodologies (all the rules are known 'up-front'), recourse to a merits appeal to the High Court, and provisions in the CPP application for 'contingent' and 'unforeseen' projects – giving some flexibility to suppliers to make investment decisions.

[55] Ibid, Section 9, Page 14 of 15

[56] http://www.comcom.govt.nz/regulated-industries/input-methodologies-2/amendments-and-clarifications/

ensure that the gas supply chain operates without interruption, and that security risks are managed to the ALARP standard.

For upstream producers the driver is for continuous gas offtake to ensure access to hydrocarbon liquids. While natural gas production represents a significant share of production revenue (in the case of Pohokura some 40-50%), liquids revenue is also significant (a similar percentage for Pohokura). As noted in Section 3.1 95% of gas demand is in Taranaki and north of Taranaki, with 43.5% of demand north of Taranaki. Hence a significant share of gas volumes is placed through the MDL and Vector pipelines. With Methanex now operating at levels approaching full capacity additional production needs to ensure continued access to upper North Island demand.

The mid-stream position raises some questions. Vector is a private sector company with a significant degree of vertical and horizontal integration; it is likely to face competing claims on capex from different parts of its business and may see less incentive to invest in gas infrastructure (particularly given its revenue is capped under Part 4 of the Commerce Act) compared to other investments.

It is doubtful however that constraint on investment would act to undermine security thresholds. Like the upstream in reverse Vector is a significant retailer of gas and electricity and has a strong incentive to support its downstream gas marketing activities. Nevertheless capital constraints may be an influence, altering Vector’s approach. This may be a particular challenge if and when significant investment is required for capacity expansion.

There is a question whether these drivers would operate (and what other drivers would operate) if the pipeline infrastructure was owned as a standalone asset, where an owner had no upstream or downstream interest. Contracting arrangements would likely be similar to what pertains now where shippers contract with the owner for capacity. Revenues for a standalone owner would come from throughput and hence the incentive on the owner is to ensure the pipeline continues to operate to avoid any impact on its revenue. A non-integrated owner would have no upstream or downstream incentive but users of the pipeline would be expected to enter into shipping arrangements with the owner that reflect the risks they carry in the supply of natural gas. We would expect these to be reflected in the commercial arrangements for access. Hence it is difficult to imagine that the contracted standards would differ from that which holds currently. Furthermore operating standards are reinforced by the Certificate of Fitness requirements prescribed by regulation. This suggests that different ownership structures are unlikely to result in a different risk profile that currently operates.

9.2.3 Trading

The review of the Varanus Island outage (section 7.2) identified the need to provide an appropriate trading or exchange platform to assist market participants getting access to gas.

New trading platforms are emerging in New Zealand but these are in the very early stages of development with low levels of liquidity. Previous trading initiatives have struggled to gain traction.

In a Critical Contingency event the CCO has the option to cancel a curtailment where the CCO is satisfied that the supply/demand balance has been re-established. The expectation is that market participants would be able to identify gas availabilities and agree appropriate terms. This is certainly the case with the Pohokura scenario where sufficient gas is held by one player (Methanex) that would allow other market participants the opportunity to strike a deal with Methanex; however this may not be the case for an extended pipeline outage scenario, particularly where supply is gradually restored.

The lack of an effective trading platform with sufficient liquidity may prevent gas from being utilised by its highest value use. MBIE should take a keen interest in the developing trading proposals to assess how they might operate as part of any security event – continuing access to gas may reduce the impact of lost production even though leading to higher input costs.

9.2.4 Consistent Framework (and Transparency)

Our review indicates that aspects of governance and requirements for supply security arise in a number of areas including the HSE Act 1992, Part 4 of the Commerce Act, the CDEM Act, the Gas Act and the codes that providers of pipeline services operate for providing access. This is not to suggest that the framework is inconsistent or at odds with the overall objectives of the Gas Act and GPS but equally it is not clear how the range of regulatory instruments fits together. In some cases e.g. gas quality, the regulatory framework is inadequate but we have been unable to point to a scenario that would put gas quality as an event with significant consequence (low probability/high impact). We note also the likelihood for increased regulatory oversight of the industry which we highlight on page 28.

Our concern is that there is a risk of poor transparency, partly due to the extent and nature of regulation and the risks for transparency this creates. For some aspects we think transparency can and should be improved. An example for pipelines is risk treatment and the ALARP process which is discussed in Appendix 1. There is a requirement to demonstrate ALARP which, in turn, requires that reasons be given for not reducing risks further; but it is not clear how that should be communicated to consumers over and above the requirements set for achieving certification.[57] The lessons from the Maui outage have lifted the market's understanding of the risks in being a gas user but it's not clear how any reporting obligation is intended to be a continuing requirement. An example would be the likely timing and duration of the MDL realignment project (including for Vector), which may appear in asset management plans but with some uncertainty as to where else.

There may be a role for MBIE and/or GIC to be more proactive in bringing about more disclosure.

9.2.5 Coordination and Relationship with CDEM

It is possible that a large scale civil emergency arising from any of a variety of natural hazard events or other emergency situations may lead to activation of a CDEM response. CDEM has extensive powers including the ability to override existing arrangements (including the CCM Regulations)[58]. As noted in Section 4 of this report coordination of a civil emergency is to be provided through activation of the National Crisis Management Centre (NCMC). But apart from the assumption that CDEM has extensive powers it's not readily apparent how this might operate in practice should there be significant disruption to gas supply as a consequence of the emergency situation; particularly if there is a need to override existing commercial arrangements.

Further consultation beyond the current reliance on Sector Coordinating Entities will inevitably be needed to provide effective liaison between the various market participants, regulatory agencies, parties directly affected by any outage and other relevant stakeholders (other agencies). Some more detailed guideline when the NCMC is fully operational would appear justified.

We comment that the scenarios examined in this report indicate, however, that although the impacts of a major gas disruption on its own may well be significant, they are unlikely to require CDEM activation (or may require it for only a short time).[59] Nevertheless a level of coordination may still be required because of the significance of the event and competing interests, including whether, as contemplated by the

[57] We note that consideration is also required to be given to wider economic loss in assessing the consequences of any threat.
[58] Regulation 14, Gas Governance (Critical Contingency Management) Regulations 2008.
[59] The Maui outage in October 2011 did not require CDEM activation.

Pohokura scenario, some form of gas trading emerges as an efficient way to manage curtailment of supply.[60]

We would recommend some further review of how coordination of the gas sector might operate during a disruption emergency where a national emergency is declared.

[60] This was an observation from the Varanus Island supply disruption.

10. SUMMARY AND CONCLUSIONS

In summary we conclude that the New Zealand gas supply system has a high degree of reliability and that existing industry operating standards and market structures pose no undue threat to security of supply. In particular New Zealand appears to be in a stronger (more resilient) position than when this study was first done in 2009. There is more diversity in gas supply through Kupe, expansion of Mangahewa, and a greater number of smaller onshore gas fields such as Cheal and Sidewinder. Ahuroa storage commissioning has also added some additional buffer to supply disruption and fuel diversification away from gas in the electricity market (wind, geothermal) has reduced electricity generation baseload dependence of CCGTs.

The consequences arising from any loss event are likely to be manageable, reasonably predictable and well within the bounds of normal business interruption scenarios. Cost impacts are likely to be temporary rather than permanent and it's unlikely to have any permanent impact on economic output. Market arrangements have not altered materially since the previous CAENZ report although there are emerging signals that market arrangements may start to mature towards more efficient arrangements common in deeper and more liquid markets.

Gas supply security is more a matter of getting the incentives in place for owners and operators of facilities to take actions that are aligned with the national good rather than a reliance merely on regulatory compliance as framed by predetermined risk outcomes. A gradual evolution towards a more liquid secondary gas market will help mitigate the economic impacts of gas supply interruptions by enabling limited supply to be allocated to parties who value it the most during a period of gas supply curtailment.

This study has not identified any particular risk of regulatory failure, however, that is not to say that continued scrutiny of the industry regulatory environment is not warranted. There is, for example, a possibility that the regulated pricing framework may alter the incentives on pipeline owners for investment in projects designed to mitigate threats or increase the security of supply. Whilst possibly impacting on overall risk profiles, current risk management approaches remain fully consistent with the various standards, codes and operating practices by which GPB's are certified to operate.

Whilst this study has not specifically addressed risk control opportunities at the asset or system component level we comment that experience over the last forty plus years shows that in-built redundancy within critical supply chain elements and the industry's own contingency management processes mean that in almost all situations unplanned interruptions of various durations, as occur from time to time, are usually rectified quickly and pass unnoticed by most other industry participants and consumers. Threats are well known with the main hazards in respect of pipeline routing and facilities operation subject to regular monitoring, maintenance and/or mitigation works.

An important aspect of this study has been the focus given to pipeline integrity management practice as it applies in this country. Under AS 2885, pipeline operators are required to adhere rigorously to the risk assessment and safety management frameworks embodied in the processes and practices adopted[61]. This approach is internationally recognised and continues to be improved so as to strengthen industry practice. The creation of a new stand alone agency, WorkSafe NZ, that will administer pipeline safety requirements may well add further dimensions to safety management practice, but it is yet too early to predict how this might unfold.

Regards the other components of the study we present the following key findings:

[61] Appendix 1

ELECTRICITY GENERATION

1) The Electricity System Operator studies have shown that currently installed generation capacity was adequate to enable peak demand to be met in 2012 in the event of a gas supply disruption larger than any considered here.

2) The ability of the system to supply adequate energy over a longer period is dependent on gas, coal, and water in storage and the level of inflows to the hydro system. Ability to reliably schedule generation over a long duration outage has not been investigated.

3) Storage levels in June 2012 are likely to have been adequate for a four month gas disruption affecting all plant north of Taranaki, given some load reductions due to lack of gas for industrial processes and demand side price responses.

4) For longer term outages fuel stockpiles are important:

    a) As of 30th June 2013, 877,000 tonnes of coal were in storage at Huntly, which is approximately the amount required to run two units at full load for 24 weeks, without further deliveries of coal.

    b) Ahuroa gas storage was at 9.9 PJ at the same date, sufficient to run the 200 MW gas turbine peakers at full load for 7 months.

5) Resilience of the electricity system to gas supply disruptions is significantly increased by supplies being independent amongst the three groups of plant:

    a) North of Taranaki – Huntly, Southdown, Otahuhu, Te Rapa, Kinleith.

    b) Stratford combined cycle and Open Cycle plants.

    c) The 100 MW gas turbine plant at the McKee production facility does not rely on the gas pipeline network.

6) Huntly coal fired units require gas for their start up process. Retaining sufficient gas in the pipeline system for a number of starts is therefore an important safeguard for minimizing impacts on electricity supply. The option of restoring the ability to start Huntly units on an alternative fuel should be considered to enable these units to start if gas is not available. The unavailability of gas is a possibility during an extended gas disruption.

7) Stochastic modelling is needed to assess the impacts of gas supply disruption across the range of possible hydrological conditions[62]. Impacts from gas supply disruptions are highly dependent on:

    a) Time of year.

    b) Electricity system loads.

    c) Hydrological conditions, both in terms of water in storage reservoirs and current rainfall affecting generation from side flows which cannot be stored.

    d) Ability to reliably schedule generation over a long duration outage has not been investigated.

[62] Whilst such analysis may properly reside with Transpower as System Operator we note that the System Operator does not have the authority to require alternative investments; such as replacement start-up fuels.

RISK REDUCTION OPPORTUNITIES

Despite relative optimism on the robustness of the current gas market arrangements there are some opportunities for further mitigation of supply interruption impacts.

Electricity Market

The cost of gas supply interruption falls on the broader electricity market through higher spot prices, particularly as the ability to bring online Huntly coal units reduces as these are progressively taken off-line, put in storage, and eventually decommissioned. As from end of 2013 it is possible that only two coal units will be available, whereas in 2009, all four units were available. The higher cost of electricity is borne by the economy overall, rather than individual generators. The broader question is whether there is a public good component to the Huntly Coal units that needs to be included in any decision to retire these units, and how the cost of maintaining otherwise uneconomic units should be met.

Gas and Gas Transmission Trading

The industry is developing more transparent trading mechanisms for energy trading that allow gas contract surplus and deficits to be traded. A potential impediment to the full economic benefits delivered of such a system is the ability to transport the energy to various points on the transmission system where insufficient capacity rights are held by purchasing parties. This issue is being examined by the industry through the GIC but progress towards more flexible transmission products that reflect economic value is likely to be slow.

Relationship and Coordination between a Civil Emergency and CCM Event

In the event of a major civil emergency that results in the activation of the NCMC the CDEMA takes precedence over the CCM regulations. Examination of the various scenarios presented in this report suggest that further clarity was required where there might be need to override existing commercial arrangements, and that further review of roles and responsibilities was warranted.

Wider Stakeholder Management

The Varanus Island incident triggered a government response that not only managed demand but also considered wider affected stakeholders including the broader community. In particular there are no current arrangements that consider wider social impacts including loss of employment or impacts on other sectors, including tourism (particularly the hospitality sector) generated out of a supply interruption event. The previous events in New Zealand suggest that it is not likely to be a large problem; however it may still be worthwhile to consider whether broader social and economic impacts should be considered in a more proactive way.

Pipeline Vulnerabilities

From the Maui pipeline incident a geotechnical assessment was done on other parts of the Maui pipeline route that helped to identify other areas for assessment and monitoring. It is possibly useful to extend this to parts of the Vector System, particularly the BOP system and the South System which has the potential to disrupt large geographical areas.

RECOMMENDED FURTHER ANALYSIS

The study team recommends the following points be examined further as possible items for consultation:

1) Creating a standardised economic treatment of asymmetric risk (low probability high consequence events) to ensure the economics are more robust and comparative industry studies utilise a common methodology.

2) Further analysis on how price/quality regulation might influence the approach to risk and the concomitant security standards that might apply, and the cost implications of adopting different security standards.

3) Additional stochastic modelling, similar to that undertaken in the original CAENZ study, to assess the impacts of gas supply disruption across the range of possible hydrological conditions and to better establish price volatility in the electricity market over an extended curtailment event due to fewer available schedulable generation sources, including the further loss of Huntly coal units.

4) Further analysis of the vulnerabilities and social cost elements arising from a severe loss event, especially within the major urban low pressure distribution networks.

5) Further assessment of geotechnical risks on the Vector transmission system.

6) Understanding the need/use for a supply disruption recovery committee or similar to meet unforeseen coordination requirements and secondary impacts, especially in the event of a national civil emergency being declared.

11. GLOSSARY

ALARP	As low as reasonably practicable
ANSI	American National Standards Institute
APIA	Australian Pipeline Industry Association
AS 2885	Australian Standard 2885
ASME	American Security of Mechanical Engineers
CAENZ	Centre for Advanced Engineering
CBD	Central Business District
CCGT	Combined Cycle Gas Turbine
CCM	Critical Contingency Management (refer to Critical Contingency Regulations 2008)
CCO	Critical Contingency Operator
CDEMA	Civil Defence & Emergency Management Act
COF	Certificate of Fitness
CPP	Customised Price-Quality Path
DC	Direct Current
DCS	Distributed Control System
DCVG	Direct Current Voltage Gradient
DOL	Department of Labour
DPP	Default Price-Quality Path
EGIG	European Gas Pipeline Incident Data Group
EMAT	Electro-Magnetic Acoustic Transducer
ESSP	Electricity System Security Providers
FM	Force Majeure
GBB	Gas Bulletin Board
GDP	Gross Domestic Product
GIC	Gas Industry Company
GNS	Institute of Geological & Nuclear Science
GPB	Gas Pipeline Business
GPS	Government Policy Statement
GPS	Global Positioning System
GSP	Gross State Product
GWh	Gigawatt hour
HAZOP	Hazard & Operability Analysis

HSE Act	Health & Safety in Employment Act
HVDC	High Voltage Direct Current
ICA	Inter Connection Agreement
ICCP	Impressed Current Cathodic Protection
ILI	In-Line Inspection (or “pigging”)
IMO	Independent Market Operator
IMU	Inertial Measurement Unit
JHA	Job Hazard Analysis
km	Kilometre
LIDAR	Light Detection & Ranging techniques
LTS	Low Temperature Separator
MAOP	Maximum Allowable Operating Pressure
MARS	European Union Major Accident Reporting System (Operated by the European Commission Joint Research Centre)
MBIE	Ministry of Business, Innovation & Employment
MCDEM	Ministry of Civil Defence & Emergency Management
MDL	Maui Development Limited
MFL	Magnetic Flux Leakage
MHIDAS	Major Hazard Incident Data Service (Operated by AEA Technology on behalf of the UK Health & Safety Executive)
MLC	Minimal Load Consumers
MPOC	Maui Pipeline Operating Code
MRP	Mighty River Power Ltd
MW	Megawatt
NCMC	National Crisis Management Centre
NESO	National Emergency Sharing Organisation
NGOCP	National Gas Outage Contingency Plan
NIU	National Infrastructure Unit
NTSB	The National Transportation Safety Board
NZES	NZ Energy Strategy
NZIER	New Zealand Institute for Economic Research
NZS	New Zealand Standards
NZX	New Zealand Exchange
OSH	Occupational Safety & Health

OTDR	Optical Time Domain Reflectometry
pa	Per Annum
PG&E	Pacific Gas & Electric Company
PHMSA	Pipeline & Hazardous Materials Safety Administration
PIMP	Pipeline Integrity Management Plan
PJ	Petajoule
PMS	Pipeline Management System
QRA	Quantitative Risk Assessments
RAM	Reliability, Availability & Maintainability
RBI	Risk Based Inspection
RIDDOR	Dangerous Occurrences Regulations Database (Operated by the UK Health & Safety Executive
ROFR	Right of First Refusal
SCADA	Supervisory Control & Data Acquisition System
SCADA	Supervisory Control & Date Acquisition
SCC	Stress Corrosion Cracking
SMS	Safety Management Study
SSD	Safety Shutdown System
SVS	Static VAR Systems
TCC	Taranaki Combined Cycle plant
TJ	Terajoules
TPI	Third-Party Interference
TR	Temporary Refuge
TSO	Transmission System Operator
US DoT	United States Department of Transport
VTC	Vector Transmission Code
WA	Western Australia

Appendix 1.
Pipeline Integrity Management (AS 2885)

PIPELINE INTEGRITY MANAGEMENT

Pipeline Integrity Management processes are mandated by most jurisdictions. An Integrity Management approach is internationally recognised and accepted industry best practice for the operation and management of transmission pipelines. It provides a framework for the effective management of risks associated with transmission pipelines and the protection of people, property and the environment.

The Pipeline Management System (PMS) is the key quality management system used to document and present the Licensees approach to managing the pipeline. The Licensee must be regularly audited against the PMS by an independent recognised inspection body in order to obtain and maintain a current COF. The PMS must cover all necessary aspects of:

- ***management*** (including policy & commitment, management structure, responsibilities, accountabilities & authorities, training & competency, resourcing, change management and management review);
- ***planning*** (including normal, abnormal and emergency operation);
- ***implementation*** (including readiness & handover for operation, site safety and environmental management, pipeline integrity management, station operations and maintenance, emergency response and records management);
- ***measurement & evaluation***, (including data acquisition and analysis, accident/incident investigation and reporting, system audits, and corrective & preventative action); and
- ***consultation, communication and reporting*** (including stakeholder liaison and statutory reporting requirements).

The development, implementation and regular review of a Pipeline Integrity Management Plan (PIMP) is mandated (along with prescribed minimum review intervals) as part of the PMS. The integrity management process is similar in many respects to that required under other codes - requiring regular identification and collection of data, risk assessments (referred to as the Safety Management Study), integrity management review, response activities and condition monitoring. The code focuses on and provides detailed requirements for the management of pipeline structural integrity, anomaly assessment and defect repair, external interference threats, operating condition changes and remaining life review and station operation and maintenance.

Pipeline integrity management is an asset management approach that requires pipeline owners to:

- Assess, evaluate, repair and validate through comprehensive analysis the integrity of pipeline segments.
- Prevent a leak or failure that could affect populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways.
- Develop and follow a program that provides for continually assessing the integrity of all pipeline segments that could affect these high consequence areas.
- Provide for periodically evaluating the pipeline segments through comprehensive information analysis, remediating potential problems found through the assessment and evaluation.
- Ensure additional protection to the segments and the high consequence areas through preventive and mitigative measures.[63]

[63] *(Pioli & DiPalma, 2002)*

Risk Management under AS 2885

The essential outcomes of the safety management process prescribed under AS 2885 are:

- assurance that the threats to the pipeline and associated risks are identified and understood by those that are responsible for addressing them; and
- appropriate plans are made to manage these risks

> Pipeline safety management shall be undertaken rigorously, shall apply controls to identified threats and shall reduce residual risk to an acceptable level through a safety management study, and a risk assessment of threats that are not controlled.
>
> All threats to the integrity of the pipeline shall be identified and multiple independent controls shall be applied to each identified threat.
>
> This Standard recognizes the hierarchy of effectiveness of controls:
>
> (a) Elimination.
>
> (b) Physical controls.
>
> (c) Procedural controls.
>
> (d) Reduction.
>
> (e) Mitigation.
>
> Mandatory requirements are specified for control of external interference threats (which are known to be the most frequent events with the potential to create a failure).
>
> Mandatory requirements are specified in high consequence areas for—
>
> (i) elimination of rupture; and
>
> (ii) maximum energy release rate.
>
> Where land use changes from a low consequence area to a high consequence area, this Standard applies mandatory requirements for maintaining the risk at an acceptable level.

Source: AS 2885.1 – 2012

Under AS 2885, the Safety Management Study (SMS) and the Pipeline Integrity Management Plan (PIMP) serve as the primary documents for the management of pipeline risks. The SMS is a detailed risk assessment for pipelines that is developed in accordance with a systematic process detailed in the code. The PIMP provides a detailed plan for the implementation of the controls and treatments identified in the SMS. These two documents underpin the integrity management process and are subject to regular audit by a recognised independent inspection body.

SAFETY MANAGEMENT STUDY

The safety management study shall be undertaken by personnel with expertise in each component of the design, construction and operation of the pipeline, including, or with the support of, personnel closely familiar with the land uses and environments along the entire route.

The code prescribes the collation and consideration of an extensive range of information in compiling the SMS, including:

- Design basis, calculations, drawings
- Initial safety management study
- Corrosion mitigation strategy
- Safety management study of common threats to typical designs
- Pipeline alignment, location classifications and assessment of current and future land uses

- Documented investigations of external threats
- Construction, landowner and environmental constraints
- Pipeline management system including standard procedural controls – patrolling, access procedures, etc.
- Isolation plan, HAZOP, fracture control plan and consequence modelling
- Environmental studies
- Inspection and integrity management history and maintenance history
- Previous safety management studies

The safety management study is essentially a detailed risk assessment that is developed through a workshop process involving competent experienced engineers and field technicians who are familiar with the pipeline, its history and the above information. For each section of the pipeline, all threats that could adversely affect the pipeline are listed and assessed through a systematic process.

> Threat identification consists of the identification of all threats to the pipeline including the following types of threats:
>
> (a) Threats that are unique to a particular location, such as a threat of external interference from third parties, or due to topographical features at the location.
>
> (b) Threats that could exist along the whole length of the pipeline and which are not specific to a location. These threats may include internal corrosion from the fluid being transported, external corrosion or possible threats from maintenance activities.
>
> (c) Location-specific threats, which become apparent from a detailed metre-by-metre review of the route. However, non-location-specific threats require a separate identification process to be undertaken. In both cases, the details recorded for threat analysis need to be sufficient such that the appropriate design and controls can be implemented.
>
> The following list presents some of the most commonly identified threats:
>
> (i) External Interference.
>
> (ii) Corrosion.
>
> (iii) Natural events.
>
> (iv) Operations and maintenance.
>
> (v) Design defects.
>
> (vi) Material defects.
>
> (vii) Construction defects.
>
> (viii) Intentional damage.
>
> This list should not be considered exhaustive.
>
> The following sections describe in detail the nature and types of threats and provides examples of each category.

Source: AS 2885.1 – 2012

Appropriate treatments and additional controls must then be developed to reduce the risk to an intermediate level or below. All intermediate level risks must be assessed to confirm that the level of risk has been reduced to “as low as reasonably practical” (ALARP).

QUALITATIVE RISK ASSESSMENT

Consideration of wider economic loss is mandated through the qualitative risk assessment process which requires the risk assessment to be conducted in accordance with AS/NZS ISO 31000. The extract below shows the main consequences that must be assessed for each threat.

F2 CONSEQUENCE ANALYSIS

The severity of the consequences of each failure event shall be assessed. Consequences to be assessed shall include the potential for—

(a) human injury or fatality;

(b) interruption to continuity of supply with economic impact; and

(c) environmental damage.

NOTES:

1 Other factors, such as property damage and loss of reputation, may also be considered.

2 Gas pipelines and some liquid petroleum pipelines may be identified as 'essential infrastructure' where the consequence of a loss of supply is significant. This may be in terms of the potential for economic impact, and in some cases significant fatalities may result from the cascading consequence of loss of the energy supply.

Source: AS 2885.1 - 2012

The consequences are assessed in terms of their potential severity. The table below includes the range the severity classes assigned to the varying degrees of impact of a loss of supply.

TABLE F2
SEVERITY CLASSES

	Severity class				
	Catastrophic	Major	Severe	Minor	Trivial
Dimension	Measures of severity				
People	Multiple fatalities result	Few fatalities; several people with life-threatening injuries	Injury or illness requiring hospital treatment	Injuries requiring first aid treatment	Minimal impact on health and safety
Supply	Long-term interruption of supply	Prolonged interruption; long-term restriction of supply	Short-term interruption; prolonged restriction of supply	Short-term interruption; restriction of supply but shortfall met from other sources	No impact; no restriction of pipeline supply
Environment (see Note)	Effects widespread; viability of ecosystems or species affected; permanent major changes	Major off-site impact; long-term severe effects; rectification difficult	Localized (<1 ha) and short-term (<2 y) effects, easily rectified	Effect very localized (<0.1 ha) and very short-term (weeks), minimal rectification	No effect; minor on-site effects rectified rapidly with negligible residual effect

NOTE: Significant environmental consequences may occur in locations that are relatively small and isolated.

Source: AS 2885.1 - 2012

The frequency of occurrence for each failure event is then assigned for each location based on the table below.

TABLE F3

FREQUENCY CLASSES

Frequency class	Frequency description
Frequent	Expected to occur once per year or more
Occasional	May occur occasionally in the life of the pipeline
Unlikely	Unlikely to occur within the life of the pipeline, but possible
Remote	Not anticipated for this pipeline at this location
Hypothetical	Theoretically possible but has never occurred on a similar pipeline

Source: AS 2885.1 - 2012

The risk rank can then be determined based on the combination of severity class and frequency in accordance with the table below

TABLE F4

RISK MATRIX

	Catastrophic	Major	Severe	Minor	Trivial
Frequent	Extreme	Extreme	High	Intermediate	Low
Occasional	Extreme	High	Intermediate	Low	Low
Unlikely	High	High	Intermediate	Low	Negligible
Remote	High	Intermediate	Low	Negligible	Negligible
Hypothetical	Intermediate	Low	Negligible	Negligible	Negligible

Source: AS 2885.1 - 2012

RISK TREATMENT AND ALARP PROCESS

Once the risk ratings are established action must be taken (or treatments developed) to reduce the risk to acceptable levels. Development, documentation and approval of the actions/treatments developed form part of the safety management study. The table below prescribes the risk treatment requirements based on the assessed level of risk.

TABLE F5

RISK TREATMENT ACTIONS

Risk rank	Required action
Extreme	Modify the threat, the frequency or the consequences so that the risk rank is reduced to 'intermediate' or lower For an in-service pipeline the risk shall be reduced immediately
High	Modify the threat, the frequency or the consequences so that the risk rank is reduced to Intermediate or lower For an in-service pipeline the risk shall be reduced as soon as possible, typically within a timescale of not more than a few weeks
Intermediate	Repeat threat identification and risk evaluation processes to verify and, where possible, quantify the risk estimation; determine the accuracy and uncertainty of the estimation. Where the risk rank is confirmed to be 'intermediate', if possible modify the threat, the frequency or the consequence to reduce the risk rank to 'low' or 'negligible' Where the risk rank cannot be reduced to 'low' or 'negligible', action shall be taken to— (a) remove threats, reduce frequencies and/or reduce severity of consequences to the extent practicable; and (b) demonstrate ALARP For an in-service pipeline, the reduction to 'low' or 'negligible' or demonstration of ALARP shall be completed as soon as possible; typically within a timescale of not more than a few months
Low	Determine the management plan for the threat to prevent occurrence and to monitor changes that could affect the classification
Negligible	Review at the next review interval

Source: AS 2885.1 - 2012

The code mandates that action must be taken within prescribed timeframes to reduce the risk level for extreme and high risks to intermediate or below. Similarly, action must be taken over time to reduce intermediate risks to a lower level or ALARP must be demonstrated. A risk cannot be demonstrated as ALARP until consideration has been given to:

a) Means of further reducing the risk; and

b) the reasons why these further means have not been adopted.

ALARP is achieved when the cost of further risk reduction measures is grossly disproportionate to the benefit gained from the reduced risk that would result.

PIPELINE INTEGRITY MANAGEMENT PLAN

Pipeline integrity management shall be carried out by competent personnel so that the responsibilities for approvals can be adequately implemented and demonstrated as sufficient for independent review.

The diagram below shows the pipeline integrity management process, which incorporates the safety management study and an on-going process of monitoring and review.

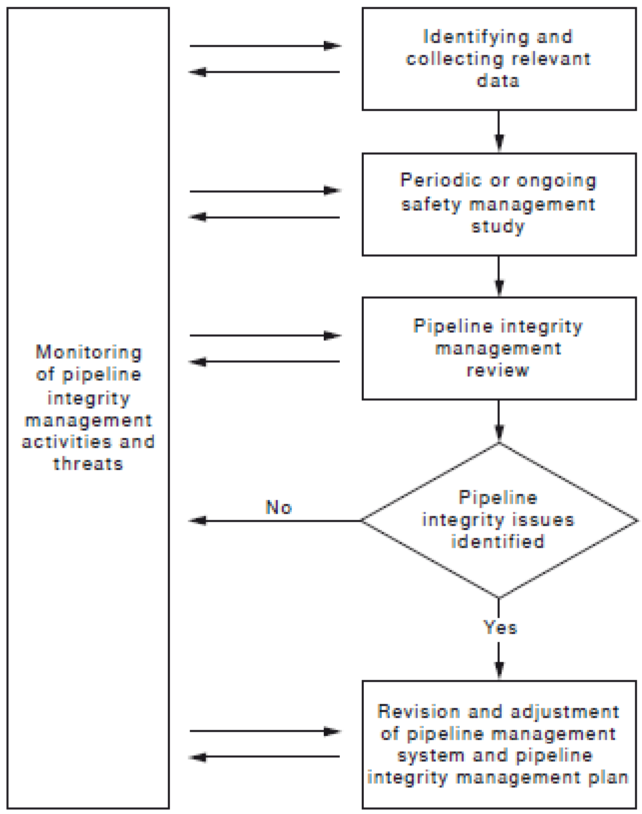


FIGURE 5.1 PIPELINE INTEGRITY MANAGEMENT PROCESS

Source: AS 2885.3 - 2012

Monitoring, inspection and mitigation of the identified integrity threats shall be appropriate for the threats and controls identified in the safety management study prepared in accordance with AS 2885.1. Pipeline integrity management procedures shall be developed for each monitoring, inspection or mitigation action, to ensure the controls identified during the safety management study remain effective.

A pipeline owner is required to develop, regularly review and maintain a Pipeline Integrity Management Plan (PIMP) for the on-going operation and maintenance of the pipeline.

The PIMP shall cover the following:

a) Pipeline structural integrity, including the technical aspects of maintaining pipelines

b) Anomaly assessment and defect repair

c) External interference threats to the pipeline

d) Operating condition changes and remaining life review

e) Stations operations and maintenance

The PIMP includes all of the routine surveillance and maintenance activities and other activities associated with the controls and treatments established through the SMS process to ensure the integrity of the pipeline is maintained throughout its lifetime.

Appendix 2. Technology Developments

TECHNOLOGY DEVELOPMENTS

As is the case in most industries, the availability of increasingly sophisticated and advanced technologies has enabled asset owners to significantly improve the quality of their asset condition and risk assessment data. The oil & gas industry has benefitted significantly from technology developments. This section seeks to provide a brief overview of the technologies that are currently utilised by pipeline owners to effectively monitor and assess the range of threats to which their assets are exposed.

IN-LINE INSPECTION (ILI)

ILI (or "pigging") is the commonly used industry term for the in-line inspection of pipelines and it forms a critical component of the accepted inspection, maintenance and on-going integrity management of pipelines. The use of 'Intelligent pigs' which utilise a range of sensors and computerised analysis techniques to gather detailed information regarding the condition of the pipeline is well established within the pipeline industry and an area of continuing development. The increasing sophistication of the sensors/tools and post inspection analysis continues to provide more and more tools and options for pipeline owners and operators to assess the condition of their pipelines. Magnetic flux leakage (MFL) tools have been commonly used in NZ for a number of years and more recently geospatial tools have also been used. Further details regarding the in-line inspection tools and technology currently available and in use in New Zealand, are provided below:

CALLIPER TOOL (GEOMETRY)

The prime objective of the calliper tool is to measure the geometric soundness of the pipeline. They are typically used to confirm non-obstructive passage for other intelligent inspection tools.

The tools possess a fully computerized measuring system designed to inspect the internal geometry of the pipeline and provide detailed information about the location and size of geometrical features, such as welds, valves, bends, fittings, obstructions, ovality, wrinkles and dents. The tool consists of the following:

- Geometry Sensor Device
- Odometer System
- Mechanical Dipper System
- Temperature Sensor
- Data Storage Device

The measurement principle is based on multi-channel eddy-current technology and performs touch-less distance measurements from the sensor surface to the inner pipe wall. This allows for thorough geometry inspections. Overlapping sensor measurements ensure full circumferential coverage. Typical probabilities of detection performance specifications for an 80% confidence level are:

- Ovality Change 2% of internal diameter
- Dent Depth 1.5% of outside diameter

The tools can identify deformation in a pipeline caused by land movement or third party damage. However, they will not identify where a pipeline is subject to strain induced by land movement unless that strain has resulted in some physical deformation. The survey data can be loaded into pipeline integrity management software to enable the pipeline operator to identify and prioritize maintenance and repair actions.

MAGNETIC FLUX LEAKAGE (MFL)

The prime objective of the Magnetic Flux Leakage (MFL) tool is to measure metal loss in the pipe wall although through analysis and interpretation of the data they can also detect a variety of pipeline anomalies such as dents, gouges, buckles, wrinkles and weld features. The tool consists of the following:

- Magnet Unit
- Sensor Unit
- Odometer Unit
- Computer Unit
- Central Tool Body

The basic element of the metal loss survey is high-resolution MFL technology. The pipe wall is magnetized axially to high saturation level using magnets. High magnetization levels are necessary to differentiate corrosion from other pipeline features such as hard spots, stress and strain variations. In a pipeline with no flaws, the magnetic flux travels undisturbed through the walls. In the presence of internal and external metal loss, the flux “leaks” out of the pipeline and is recorded by hall-effect sensors, of which there can be hundreds. The sensor system provides high resolution and sensitivity with 360-degree full circumferential coverage.

The service providers provide performance specifications for the tools ability to locate and size defects based on Probability of Detection levels. For example, the probability of detecting a general corrosion defect greater than 10% of the wall thickness is typically 90%.

The data captured by the survey is verified through the physical excavation and measurement of defects. A comprehensive report provided by the service provider contains details of all the identified pipeline features. The quality of the data is influenced by the quality of the inspection run so it is important to ensure the pipeline is clean and flow rates are managed to ensure optimal speed of the inspection tool.

The survey data can be loaded into pipeline integrity management software to enable the pipeline operator to identify and prioritize maintenance and repair actions. Through effective use of the data a corrosion rate for the pipeline can be quantified to enable optimum corrosion mitigation strategies to be implemented.

GEOSPATIAL MAPPING TOOL (IMU)

The prime objective of the Geospatial Mapping Tool is to determine three-dimensional geographical coordinates of the pipeline. The tool utilizes an inertial measurement unit (IMU) and records information about the pipeline's location, depicted by plan, elevation, and distance views. In conjunction with this, accurate GPS information is used to fix the pipe's location in 3 dimensions, typically called "XYZ".

Various factors are accurately measured, computed and reported: pipeline alignment, direction and the orientation of horizontal and vertical bends with respect to angle, radius, direction and location.

When an IMU tool is run in combination with a Caliper and MFL tool, features such as welds, fittings, dents, ovalities, wrinkles and metal loss can be recorded simultaneously. As a result, exact XYZ coordinates are assigned to these features.

The pig's translational and rotational movements are measured with the help of accelerometers and gyroscopes, which are the main components of this inertial system. After compensating for the earth's rotation, gravitation and other forces, it determines orientations and velocities in X, Y and Z directions. By correlating the inertial system results with the data from dippers and odometer information, the pig computes the exact orientation and position of the pipeline in three dimensions.

Known reference points are necessary to achieve sufficient accuracy of absolute measurements. An accurate above ground GPS survey of the pipeline is required prior to the inspection to position above-ground markers at known GPS reference points. The above ground marker is activated by an on-board transmitter system as the tool passes thus verifying its GPS position along the length of the pipeline.

The survey data can be loaded into pipeline integrity management software to provide geospatial pipeline data visually to the pipeline operator which supports:

- Accurate pipeline data alignment
- Integration of in-line inspection data with field and other survey data
- Overlaying of aerial imagery and interface with the Graphical Information System (GIS)
- Linkage to pipeline as-built information
- Assessment and prioritisation of pipeline defects and anomalies
- Pipeline repair and rehabilitation data capture

The data recorded by the IMU can be further evaluated to calculate pipeline movement and bending strain. This is achieved by detecting and measuring pipeline curvature and converting this to pipe strain and therefore stress on the basis that:

- Curvature is a numerical measure of the out-of-straightness of a pipeline (how "bent" it is).
- Curvature is calculated from the IMU gyro data (angle) and odometer distance.
- It is defined as the angle that the pipe turns through per unit length.
- Units are radians/m or % strain (equivalent bending strain).
- For a straight line curvature is zero.

Strain can also be calculated from pipe movement between successive IMU inspections, the advantages of using curvature as opposed to XYZ displacements are:

- Curvature is directly related to bending strain.
- Curvature can be determined from a single IMU run.
- Curvature is a direct measure of local shape verses deriving strain from displacements.
- Displacements are subject to gyro drift errors.
- Displacements are sensitive to GPS survey errors.

It is important to note that such an assessment has limitations as it does not take into account all the stresses in the pipe and has the following limitations:

- Axial strain cannot be detected unless it has resulted in pipeline deformation detected by a Caliper tool or pipeline movement.
- The calculations assume that initially the pipe is straight – although analysis of IMU data can differentiate between field bends and environmentally induced bends because field bends are constructed in one spool length while environmentally induced bends are likely to affect more than one spool length.
- Does not take into account other existing pipe stresses such as pressure and temperature.

Service providers provide typical Strain Detection Thresholds which equate to a detectable deflection of 30mm over a 12m length of pipe from first IMU run and 5mm over a 12m length of pipe for subsequent IMU runs.

ULTRASONIC TOOLS (AFD)

The prime objective of Ultrasonic Tools is to identify pipeline flaws such as stress corrosion cracking (SCC), manufacturing defects or fatigue cracks in the pipe wall and welds which cannot be identified by calliper or magnetic flux leakage tools. The tools utilize ultrasonic technology and have traditionally required a liquid medium to couple the ultrasonic energy into the pipe. This is difficult and expensive in gas pipelines due the operational challenges of introducing liquids to a gas pipeline.

Rosen has developed a tool based on the concept of an Electro-Magnetic Acoustic Transducer (EMAT) that allows the detection of both stress corrosion cracking and dis-bonded coating. The EMAT sensors are designed for gas pipelines which alleviates the need for a liquid medium. Coating dis-bondment is understood to be a precursor to SCC by increasing the susceptibility of the pipeline to corrosion.

SUPERVISORY CONTROL AND DATA ACQUISITION SYSTEMS (SCADA)

SCADA systems have been widely used to monitor and control pipelines for several decades. SCADA systems typically comprise an array of computers, transducers, meters, analysers, remote actuators and other intelligent electronic devices, algorithms and communication networks to provide a central operator with real-time monitoring of the pipeline temperatures, pressures, flows and line-pack, etc, as well as remote control of compressor stations, valves and other stations. The extent, complexity and functionality of the SCADA systems continue to develop in tandem with the development of computational systems generally.

LAND MOVEMENT MEASUREMENT AND MONITORING EQUIPMENT

Land movement measurement and monitoring equipment and techniques have been advanced through the development and availability of new technologies. One example, involves the use of Light Detection and Ranging (LIDAR) techniques – an optical remote sensing technology that can measure the distance (and other properties) of remote objects by illuminating them with laser light and analysing the backscattered light. The technique is used to produce very accurate topographical maps of an area that can be used to identify geological features (such as fault lines or landslide areas) very accurately as well as changes (such as active land movement threats) through the computerised analysis of successive LIDAR scans over time.

A combination of inclinometers, piezometers and vibrating-wire strain gauges has been used on pipelines in USA, to detect land movement in high risk areas. When the information returned from the monitoring equipment indicated land movement combined with increasing strain on the pipeline, action was taken to excavate a trench on the upslope side of the pipeline to relieve stress. Based on previous experience with landslide issues in the areas, it was considered that without the pre-emptive stress relief operations, the pipeline would have almost certainly ruptured. The lessons learned here, concluded that the best approach to monitoring includes identifying the hazard, evaluating the risks of the hazard, designing the monitoring programme as an element of mitigation, implementing trigger levels and contingency plans and reviewing the data regularly.[64]

Optical Time Domain Reflectometry (OTDR) equipment involves the uses of monitoring equipment connected to fibre optic cables that are installed along the length of the pipeline or in other areas of interest. The equipment monitors the fibre optic cable and can detect temperature changes (used to detect a leakage), stresses/ strains and vibrations (used to detect possible third party interference) along the length of the pipeline. OTDR can also be used to monitor changes and movements in the external surrounding geologic medium.[65]

Specialised in-line inspection tools can also be used to map the centreline of a pipeline – including the plan and profile of the pipeline. Flexural strains can be deduced from the curvatures determined from the pipeline coordinates. Changes in the pipeline geometry can be identified and evaluated in terms of strain affect.[66]

LIKELY FUTURE CHANGES

As with most industries, the availability and feasibility of new technologies continues to improve. Remote intrusion detection is one example of a new technology that is currently not utilised in New Zealand, but may be utilised in the future. Remote intrusion detection systems are specially designed to promote

[64] Douglas Pass Case Study (31/01/2012). http://www.slopeindicator.co/stories/douglaspass-pipeline
[65] Pipeline Routes – Ground Motion Monitoring using OTDR (2013). http://www.zostrich.com/Monitoring_PDF/pipeline_monitoring.pdf
[66] Honegger D.G., et al., May 2009. Guidelines for managing risks to pipelines through landslide and subsidence hazard areas.

physical security of buried pipelines and other in-ground infrastructure. An example of this type of system utilizes a fibre-optic cable buried along a pipeline to detect and locate ground vibrations associated with third-party interference activity.

Third-Party Interference (TPI), including unauthorized excavation in the pipeline easement, is the leading cause of pipeline accidents and losses. A single incident can have devastating effects, causing death, property destruction, service interruptions, and environmental damage, and often costing the pipeline operator millions of dollars in financial losses.

This type of monitoring solution is an efficient and cost effective way to mitigate such risks. Designed to sense vibration, earth movement, and other physical disturbances, these systems detect excavation activity long before the digging equipment can reach the sensing cable and the pipe itself. By providing an early warning and the precise location of an incident, this system can help responders prevent costly damage.

The system may also be integrated with security systems protecting pumping stations and other pipeline facilities. Typically, all alarm processing equipment can be installed at such facilities, with the fibre-optic sensors covering the distance between the stations.

Existing fibre-optic communication cables, buried together with pipelines, can often be retrofitted to enable pipeline monitoring.

CONTINUAL IMPROVEMENT

The concepts of learning, evolution and continual improvement are inherently encapsulated in the integrity management process. It is a cyclical process designed to identify and respond to new or changing threats or information about the integrity of the pipeline. Information is collated regarding the condition and risk profile of the pipeline. The risk assessment is completed, which drives further inspection and monitoring requirements, which in turn drives remedial action. The information retrieved from inspections and field activities is fed back into the risk assessment process to improve the accuracy of the assessment. This cycle continues throughout the lifetime of the pipeline.

Appendix 3.
List of Abbreviations for System Operator Simulation Study

CAN	(System Operator's) Customer Advice Notice
CCGT	Combined Cycle Gas Turbine
CCO	(Gas) Critical Contingency Operator
CE	Contingent event
DCN	HVDC north flow
ECE	Extended Contingent Event
FIR	Fast Instantaneous Reserves
HVDC	High Voltage Direct Current link between North and Couth Islands
IL	Interruptible Load
MRP	Mighty River Power
NCC	(System Operator's) National Co-ordination Centre
NIPS	North Island Power System (Load)
NRSL	Non Response Schedule Long (a rolling 48 trading periods) – uses the medium term load forecast plus nonconforming load (bids)
NRSS	Non Response Schedule Short (next 8 trading periods)
PRSS	Price Response Schedule Short (next 8 trading periods) – uses medium term forecast plus (nonconforming load (bids) - difference bids)
SC	(System Operator's) Security Co-ordinator
SIR	Sustained Instantaneous Reserve

Bus Name Abbreviations

BPE	Bunnythorpe
HAY	Haywards
WDV	Woodville

Power Station Abbreviations

ANI	Aniwhenua hydro
BGA	Ngawha geothermal
GLN	Glenbrook co-generation
HLY	Huntly units 1 to 6
KIN	Kinleith geothermal
KMI	Kaimai hydro
KPI	Kapuni co-generation
MAT	Matahina hydro

MHO	Mangahao hydro
MOK	Mokai geothermal
NAP	Nga Awa Purua geothermal
OKI	Ohaaki geotherma
PPI	Poihipi geothermal
PTA	Patea hydro
RKA	Rotokawa geothermal
SFD 21	Stratford open cycle unit 1
SFD 22	Stratford open cycle unit 2
SPL	Stratford Combined Cycle
SWN	Southdown cogeneration & combined cycle
TAA	Tauhara geothermal
TRC	Te Rapa co-generation
TRO	Tongariro - Tokaanu and Rangipo
WAA	Whareroa co-generation
WHE	Wheao / Flaxy hydro
WHI	Whirinaki OCGT diesel
WKA	Waikaremoana hydro system
WRK	Wairakei geothermal
WTO	Waikato hydro system

Appendix 4.
System Operator Gas Disruption Scenarios

October 2012

Gas Disruption Scenarios

The System Operator's National Co-ordination Centre (NCC) develops and practices plans for a variety of possible power system events. Included in the planning are power system events resulting from gas supply disruptions to the major gas-fired generation stations in the North Island and major industrial plants.

These stations are at Stratford, Huntly and Auckland and are operated by Contact Energy (Contact), Genesis Power (Genesis) and Mighty River Power (MRP). The major industrial plants include those operated by Fonterra, Carter Holt Harvey, and Methanex. These industrial plants are situated from Taranaki north, in regions served by the major gas pipeline network extending from Taranaki.

NCC has a clear procedure which is used to provide information to system co-ordination staff about national gas contingency arrangements. The procedure is also used to guide system co-ordinators managing the power system consequences of a gas contingency while a declared contingency exists.

The following is a description of a simulated gas contingency event, from the system operator's perspective. While it has strong similarity to an event which occurred in late 2011 it is not intended to reflect in detail that actual event. Rather, it is intended to generally describe power system management when a gas contingency arises.

The event is described in a time sequence of related events and NCC actions. Some knowledge of power system operations and the New Zealand market structure is assumed, as is some knowledge of the gas contingency notice and curtailment arrangements.

The scenario

A full gas supply disruption has occurred, commencing at 15:00 on a Tuesday in June. The event will last 3 days, ending on the following Thursday. The national gas Critical Contingency Operator (CCO) at Bell Block, near New Plymouth had become aware of gas supply problems earlier in the morning. The CCO had issued a Potential Critical Gas Contingency notice at 07:00.

Power system conditions

- The HVDC poles 2 and 3 (the link between the South and North Islands) are in service. North transfer across the HVDC is limited to 900 MW to avoid the HVDC becoming the North Island (NI) risk setter. This avoids having to reduce NI generation so as to provide adequate NI reserves
- NI load peaks of 4100MW in the morning and 4400 MW in the evening are expected.
- generation plant availability (based on notified, planned plant outages) shows 634 MW of NI generation is unavailable (probably being out for maintenance)
- Gas storage at Contact Energy's Ahuroa reservoir facility allows that company's CCGT at Stratford to generate during the gas contingency.
- Huntly unit 3 in long term storage
- Future, committed generation developments have not been included in this scenario

Managing the event: Day 1

07:00. When the Potential Critical Gas Contingency is declared at 07:00 the Security Coordinator (SC) issues a Customer Advice Notice (CAN) to the industry advising a Potential Critical Gas Contingency has been declared.

The SC discusses the situation with the CCO reminding the CCO of the system operator's need to be kept updated with developments. The SC is advised it is highly likely the Potential Critical Gas Contingency will escalate to a Critical Gas Contingency.

The SC then considers the likely consequences of a Critical Gas Contingency being declared. Relevant considerations are the available gas line pack and the timing of any required gas curtailments, especially the impact of such curtailments on the NI generators.

07:45. The SC rings Contact, MRP and Genesis to discuss the situation and to pass on the information gained from CCO:

- Contact is asked[1] to ensure WHI is readied for service should that plant be needed.
- Genesis is asked to arrange the two in-service gas fired HLY units (currently being dispatched) to be switched to coal, in order to preserve gas line pack in anticipation of a Critical Gas Contingency being declared. This might have the effect of delaying any curtailment. Also discussed is the possibility of a third HLY unit being returned to service (also using coal). However, the third unit is cold and has a 24 hour return to service time. Genesis agrees to initiate the return to service process. The 4th HLY unit is in long term storage with a significant return time. Genesis will take no steps to return that unit to service
- each of the generator companies agrees to review availability of generation unit status in light of the potential for a Critical Gas Contingency being declared.

The SC carries out studies for the evening peak period. Based on current actual load data, weather and forecast load data, the evening peak is expected to be similar to the previous evening (around 4400MW).

The SC observes the following NI schedule information for 18:00:

NIPS 4408

SFD – 566 (SPL 356, SFD 21 105, SFD 22 105)
HLY – 934 (HLY U5 390, HLY U1 250, HLY U2 248, HLY U6 46)
NI Wind – 154
TRC – 50
TAA – 25
OKI – 42
WRK – 158
PPI – 51
KIN – 34
GLN – 55
NGA – 22
MOK – 112
RKA – 33
NAP – 139
WAA – 21
MHO – 28
TRO – 203 (TKU 143 RPO 60)
WKA – 82
SWN – 173
WTO – 897
WHE – 16
KMI – 39
PTA – 27
MAT – 60
ANI – 23
KPI – 19
DCN – 465

NI Risk HLY U5 390

[1] The Electricity Industry Participation Code does not give the system operator power to require generator to take such actions and does not compel generators to follow such requests.

NI Reserve (FIR) cleared – 301
NI Reserve (SIR) cleared – 390

NI Reserve (FIR) offered – 387
NI Reserve (SIR) offered – 637

IL reserve offered – 269 FIR 311 SIR

Un-cleared energy offers:
WKA – 16
TRO – 112
WTO – 50 Hz regulating reserve
WHI – 156
MAT – 20

The SC's analysis of the potential consequence of a Critical Gas Contingency with curtailment bands of 1a and 1b being required (the most likely initial scenario) is as follows:

a) Total loss of gas fired generation.

HLY – 436MW (assumes U1 and 2 have been changed to coal)
SFD – 210MW (assumes SPL can run using storage gas/local supply)
SWN – 173MW
TRC – 50MW
KPI – 19MW
WAA – 21MW (a possibility of some alternative capacity but removed for this study)
NPA – 22MW
GLN – 55MW

b) Summary of analysis:

- total potential loss of 986 MW generation - across evening peak
- some replacement for 300 MW from un-cleared offers plus HVDC north (DCN) transfer of approximately an additional 420 MW
- 3rd HLY unit won't be in service by today's peak so discounted
- expected reduction in load (especially industrial and controlled) in response to likely high prices and disruption to some industrial processes that rely on supply of gas. Allowed for an estimated 200 MW load reductions.
- possible instantaneous reserve deficits in schedules with high DCN. NI risk setter close between a HLY unit and the HVDC but in any event there is little in the way of reserves available. Some IL could drop out with price-related load reductions.
- expect DCN to be around 880 MW's. The CE risk is possibly not being fully covered but there is no binding ECE risk. Load shedding over and above voluntary market-based responses is unlikely to be required
- potential AC constraints around BPE, HAY and WDV will need to be studied
- current system wind actuals are tracking close to forecast. Potential additional 100 MW's available this evening based on forecast.

Overall: the power system situation is not good but sustainable, pending AC constraint studies. A more accurate assessment will be undertaken once gas impacts (if any) are confirmed and subsequent generation offers and difference bids/non-conforming loads are updated.

10:00. The SC received an update from the CCO. No formal status change has occurred but the CCO advises the Potential Critical Gas Contingency is increasingly likely to be escalated to a Critical Gas Contingency.

SC discusses this advice with generators likely to be affected. Genesis advises it has fully switched to coal on 2 units and that the Unit 4 start is underway. There is a possible earlier return time (of U4) but it will definitely not be available for tonight's peak. Generators advise no offers will be updated until CGC declares a Critical Gas Contingency and curtailment requirements are confirmed.

SC carries out initial studies on high DCN over peak, with reduced NI thermal generation. This shows no binding AC constraints are likely to arise from 880 DCN transfer levels. The DCN transfer limit will be driven by availability of reserves with the only available options being to run with a larger reserves deficit or managing load pre-contingently. System Operations management is informed.

15:00. CCO advises the SC:

- a Critical Gas Contingency has been declared
- gas supply is severely compromised with 1a and 1b curtailment orders imminent
- the generators will be the next to be advised of Critical Gas Contingency and will at the same time be told the likely curtailment requirements.

The CCO instructs various bands 1a and 1b gas users (mostly gas fired generators) to cease consumption of gas as soon as practicable. Full cessation of gas consumption following this instruction is expected to take one hour.

SC advises System Operations management.

A CAN is issued to industry notifying of the declaration and the bands 1a and 1b curtailments.

The SC contacts all generators to request that revised offers are processed and submitted as soon as possible (though in accordance with the gate closure rules). Contact advises the Stratford peakers can remain on using gas storage.

A quick system status review indicates no issues likely at 16:00. A lower NIPS, plus Stratford peakers, allows more reserves and energy to cover generation unavailable due to the curtailments.

CCO declares Curtailments in bands 1a and 1b are required by 16:00. The CCO schedules a phone conference for 15:30 between CCO, SO and impacted generators.

15:30. Outcome from conference:

- CCO advises the event is related to extensive Maui pipe damage which is still being assessed. There is no return to service estimate as yet. CCO is unlikely to have more information until the evening, at the earliest. Gas generators need to be off by 16:00, apart from Stratford units. The pipeline damage is north of the Stratford station so it is unnecessary to use gas storage reserves
- generator offers have been revised for today and tomorrow, and are being processed in the NRSS and NRSL schedules. Any issues (energy or reserves shortfalls) arising from them will be notified as per normal procedures. Initial indications are the system should be secure through the evening peak without load shedding, subject to expected price-related demand response reductions and expected (forecast) wind generation
- HLY U4 is tentatively scheduled for 23:00 tonight. U4 has been offered from that time.
- conference parties agree to a 17:30 phone conference update, unless important information comes to light in the meantime.

NRSL schedule complete and studies show a 38 MW reserve deficit over the evening peak. NIPS and prices are high and there is 141 MW of wind.

16:00. Gas fired thermals dispatched off at 16:00. This generation is replaced mainly with the HVDC (750MW) and WTO. WHI is not yet required.

SC declares a GEN for insufficient reserves from 16:15 until 19:00. The GEN, is issued in writing to the market, and requests more energy and reserve offers and demand reductions.

SC expects demand responses will resolve the reserves deficit unless wind generation also reduces. There is little unoffered generation left on the supply side.

16:30. WHI is dispatched on (in merit order).

17:30. WHI is at full load and the HVDC is at 850MW. NIPS is around 4100MW. There is still some room on the HVDC and from WTO. The 18:00 PRSS shows 153 MW of price response bids. The load forecast profile reflects this (18:00 PRSS) change and the scheduled reserve deficit reduces to 21 MW.

A CCO-arranged phone conference is held. The CCO advises repair on the Maui pipe will take 3 days. HLY U4 is well on the way to being in service with synchronisation bought forward to 21:00. HLY station offers have been consequentially updated. Generators will defer any planned outages and testing until the gas supply problem is resolved. The next phone conference is planned for the next day at 09:00 unless a change in circumstances dictates an earlier time.

System Operator management is updated and a CAN is issued providing an update with the information above.

18:00. The evening peak (4213) is managed without load shedding:

- system reserve deficit is of an immaterial amount in the first 3 RTD solutions of the trading period.
- demand has responded to high prices
- DC marginal (reserve prices and availability mean if loads drop the DCN will reduce). DCN reaches 885MW. The system deficit is reflective of the already increased DCN. Any further DCN would increase the size of the reserves deficit. However, there is no danger of the ECE risk binding.

The 18:00 NRSL is studied for the next day. With HLY U4 in service and expected further demand side responses, the NRSL shows no issues. There is ample SI generation to accommodate increased DCN transfer levels. Meridian and TrustPower have been made aware of the gas contingency and the consequences. There are no planned SI or NI transmission outages (and associated constraint impacts) that might limit any generator's ability to maximise output.

The next day morning and evening peaks are studied, assuming no wind and slightly higher loads. This shows a potential slight deficit over the evening peak but it is difficult to study exact impacts due to the inability to remove offers in future schedules and thereby assess the subsequent effect on reserves. A view is reached that, in the worst case, there is sufficient energy to meet demand but potentially insufficient reserves to cover risk. The results don't justify issuing a WRN (to advise reserve deficits appearing in future schedules).

21:43. HLY U4 is returned to service though with a slow ramp up. The unit will be at full load by 04:00, assuming all goes to plan.

Managing the event: Day 2

04:56. HLY U4 is at full load.

The morning peak is covered (generation and reserves) without incident.

09:00. The morning COO phone conference with NCC and generators confirms the gas event is being managed well and sustainably from power system participant's perspective. SC notes the forecast for the evening peak is still tight with load predictions being somewhat unreliable.

The PRSL and PRSS schedules are being closely analysed as they are beginning to produce more accurate results. The CCO notes pipeline repair work commenced the previous evening and finished around 01:00. The work party was back on site by 08:00 and repair work is continuing this morning. At this stage, the work is on schedule for completion by end of tomorrow. The next phone conference is planned for 09:00 tomorrow unless a change in circumstances dictates an earlier time.

Wind is tracking close to offers at around 150 MW. PRSS/SL's show some price response bids and nonconforming loads with revised bids are tracking accurately. Demand seems to be responding to the situation with an approximate average 100 MW reduction on last week's actuals.

12:00. The12:00 NRSL contains a binding constraint impacting Bay of Plenty generation, including top of the Waikato river hydro and Taupo area geothermal plants. This is caused by a THI_WKM circuit outage resulting in potential overloading of the RPO_WRK and RPO_TNG circuits. The outage is from 07:00 until 17:30. Studies by the SC show a significant impact if the return is delayed to after the peak. The SC escalates to the Duty Operations Manager who in turn discusses the position with the Grid Performance Northern Regional Services Manager. Although the outage is planned to be back by 17:30 and there is a chance the Maui pipe line repairs might be completed before hand, the Grid owner cancels the outage.

15:00. Wind generation continues to reflect offers and at 15:00, based on the weather forecast and the day's actuals, scheduled generation amounts are now being considered reliable. A study of the NRSS and PRSS shows no impact would arise from a 30% reduction in wind and a 10% increase in load (above the previous evenings actual) for the forthcoming evening peak.

16:00. The 16:00 NRSL and PRSL schedules show no material issues occurring for the next day. The Stratford peakers are scheduled off over night and both HLY and SPL are scheduled at their respective minimums. Therefore, there is a chance some discretion may be required to keep thermals at their minimums (thereby avoiding the system security risk of thermal plant leaving the system and being unavailable due to start up considerations). The schedule analysis makes it clear the SC will need to use discretion to keep SPL connected should the NRSS and RTD schedules dispatch SPL below the plant minimum. System security reasons require the plant to remain available (if offered). WHI will be required over both morning and evening peaks (offers are in place to allow merit order running).

18:00. The evening peak load is slightly higher than the previous day. There is a small reserves deficit, due to WHI ramping (normally no GEN is issued for such situations). This is resolved once WHI reaches its set point. Otherwise, all system requirements are managed comfortably.

Managing the event: Day 3

06:00. SPL is scheduled below minimum but dispatched up (using discretion) for system security reasons. Wind is reduced to compensate for additional output at SPL.

08:00. A SFD peaker failed to start for two trading periods but was on for the morning peak. Only 2 units at WHI were required over the peak.

09:00. The CCO advises repair of the pipe is expected by 16:00 today. Confirmation will be made at 12:00 so generators can initiate thermal plant start-up procedures. A phone conference is called for 12:00.

A review of schedules shows no issues for today. Some transmission outages planned for the next day will potentially impact on generation. The Duty Operations Manager raises this with the Grid Performance Northern Regional Services Manager. It is agreed a decision will be made on whether such outages will go ahead after the 12:00 update (or even later if uncertainty still exists).

12:00. At 12:00 the CCO advises that repairs are almost complete. Pipeline transmission is likely commence around 15:00 with the line pack built sufficiently by 16:00 to end curtailments. The SC informs the Duty Operations Manager who notifies the SO System Operations Manager and the Grid Performance N.I. Regional Services Managers.

14:51. The CCO declares the Critical Gas Contingency to be over. SC advises System Operations management.