FINAL REPORT

Coordinated Marketing of Pohokura Gas - Response to Draft Determination

Submitted to

Shell (Petroleum Mining) Limited
OMV New Zealand Limited
Todd (Petroleum Mining Company) Limited

Prepared by:

Lewis Evans
James Mellsop
Matthew Burgess

Charles River Associates (Asia Pacific) Ltd
Level 27, PWC Tower, Cnr Quay and Albert Sts
PO Box 2107, Auckland, New Zealand
Tel: + 64 9 368 9244 Fax: + 64 9 368 9255

17 June 2003

TABLE OF CONTENTS

1. INTRODUCTION

1.1. PURPOSE OF THIS REPORT

On 20 December 2002, the Pohokura joint venture parties filed an application with the Commerce Commission to jointly market gas from the Pohokura field. That application included a report by CRA analysing the efficiency of joint versus separate marketing.

On 16 May 2003, the Commission issued its draft determination on that application. In essence, the draft determination proposes that joint marketing of Pohokura gas be authorised, subject to certain conditions.

The Pohokura joint venture parties have asked us to review and respond to the economic issues raised by the Commission's draft determination, and the purpose of this report is to address these matters.

Accordingly, much of this report reacts to the Commission's views, and is structured in this way. However, before diving into the specific issues raised by the Commission, our report starts by:

- Describing perhaps more holistically our views on the efficiency of joint marketing of Pohokura gas (section 1.2); and
- Setting out as important context the key issues bearing on the investment decision to be taken by the Pohokura joint venture parties (section 2).

1.2. THE EFFICIENCY OF JOINT MARKETING FROM THE POHOKURA FIELD – KEY POINTS

In considering the efficiency of joint versus separate marketing, it is crucial to carefully consider the context:

- To extract the gas and liquids, the Pohokura joint venture parties would have to invest a further approximately $800 million, the vast majority of which would be sunk[1];
- The Pohokura joint venture parties face significant market risk and reserves risk, among others;
- The field is a common pool, implying perverse incentives and much risk;

[1] Unless otherwise stated, all monetary figures in this report are in New Zealand dollars.

- Essentially, under the joint venture agreement, the final investment decision and decisions to enter into joint venture sales contracts will require unanimity; and

- There is no gas spot market in New Zealand, and nor is there likely to be a liquid one in the foreseeable future.

Given the current fuel concerns for electricity generation in New Zealand, extraction of the Pohokura gas may well be valuable to the joint venture parties and to the economy. However, there is no reason to expect the Pohokura joint venture parties to invest in the necessary infrastructure to extract that gas (and the liquids) until they have in place contractual arrangements for the sale of gas and management of the massive risks they face. Enforced separate marketing would significantly increase commercial risks, and therefore the scope and complexity of the appropriate contracts.

It is against this background that the efficiency of joint versus separate marketing should be judged.

Our original report defined the terms "joint marketing" and "separate marketing". The Commission has identified scenario 1 separate marketing as the correct form of separate marketing to analyse. We re-emphasise here the fundamental features of joint and scenario 1 separate marketing.

- Separate marketing is not equivalent to "competitive marketing", because under scenario 1 separate marketing, *quantity is set jointly*. This is of course fundamentally distinct from what occurs in competitive markets, in which players set price and quantity independently.

- Joint marketing is not equivalent to "monopoly marketing". Joint marketing would involve three entities being forced to cooperate and agree. The different interests, incentives and views of these three parties can be expected to make coordination more difficult than it would be for a single firm running the venture. In addition, monopoly behaviour is limited, if not ruled out, by the fact that the rate of off take of the field is quite insensitive to the price of gas.

- Under joint marketing, gas sales contracts would be with the joint venture, whereas under separate marketing they would be with individual joint venture parties. Joint marketing places constraints on the decision-making of each joint venture party but relaxes the range of contracts that may be offered. The constraints arise because decisions by the joint venture are made by parties with different interests in the whole of their businesses and unanimity is required for the relevant decisions within the joint venture (including decisions on sales contracts). More contract flexibility in gas sale contracts arises because the contracts do not have to be tailored to particular joint venture shares and there is less uncertainty about the performance of all aspects of the field.

These fundamental features have important implications for the competition analysis of joint versus separate marketing. In particular, there can be no claim that separate marketing has competition benefits over joint marketing. In fact, joint marketing has competition benefits over separate marketing, and is more dynamically efficient than separate marketing, for the following reasons:

- Quantity would almost certainly be the same under both forms of marketing;
- It is therefore likely that the price of Pohokura gas would be the same under both forms of marketing (we analyse likely market pricing institutions);
- Regarding the ability of the Pohokura joint venture parties to price discriminate, there is no difference between joint and separate marketing. If price discrimination is possible (we are advised by the joint venture parties that they will not unreasonably restrict the resale of gas: this will have the effect of substantially ameliorating the prospects for discrimination), it is likely to be allocatively and dynamically efficient in this industry;
- Separate marketing could only lead to *less* flexibility and variation in respect of non-price terms compared to joint marketing, for the following reasons:
    - Scenario 1 envisages the joint venture parties agreeing on all of the key development and sales parameters prior to going to market;
    - The contracts would have to match each joint venture party's share of gas; and
    - There would be more risk attached to the performance of the contracts;
- Under separate marketing tranches offered may be in conjunction with gas from other fields with common ownership, whereas joint marketing introduces a separate entity;
- Under joint marketing, the different interests of the parties - particularly in downstream markets - imply that if one party wished to price gas low to itself it would have to, in effect, buy the gas at the joint venture contract price. There is a much greater likelihood of lower prices to joint venture parties with downstream interests under separate marketing than joint marketing. In this sense, gas from Pohokura is more likely to entail price discrimination under separate marketing than it would under joint marketing;

- Joint marketing is more likely than separate marketing to stimulate the development of a competitive gas market. Because separate marketing increases risk, constrains marketing contracts and decreases field value, it must also reduce exploration and production entry incentives. Put another way, if only single-owner fields can, in principle, jointly market entry may be severely reduced. Small and large companies rely on joint venture arrangements in exploration and production of oil and gas;

- To take this point further, separate marketing would entail long-term contracts (for the life of the field) between the joint venture parties in order to govern their relationship. These long-term contracts would constrain the ability of the parties to respond to market opportunities, e.g., to sell short-term contracts when capacity is under-utilised; and

- Joint marketing would result in earlier extraction of the gas.

Accordingly, there are zero detriments to joint marketing.

Regarding quantification of benefits of joint marketing, we consider that the Commission has considerably underestimated these in its draft determination.

- The Commission has assumed that separate marketing would only lead to a one-year delay in production. Given our understanding of the issues to be negotiated and the incentives operating on the parties, we consider a one-year delay to be implausible.

- Assuming the one-year delay, the Commission has attempted to predict the extra surplus from Pohokura at the end of field life in order to offset this against the earlier loss. At least under one production scenario, the Commission estimates a *net benefit from delayed production of gas*. We believe that this is not a natural outcome. It may be that there is a mismatch between model results and a qualitative assessment resulting from attempting to predict demand and supply conditions, and accordingly welfare, so far out into the future utilising trends. Rather, we believe that it is more appropriate to treat welfare past some near date, in our case 6 years in advance, as stationary, as we will describe.[2]

- The Commission has limited its analysis of liquids to condensate and has not attempted to estimate the losses arising from delayed LPG production. We carry out this extra analysis.

---

2 We note that the expected profile of the field is such that quantity would be the same under joint and separate marketing (with a three-year delay) between 2010 and 2012 (inclusive) anyway.

We shall show that correcting for these factors results in an expected benefit of joint marketing due to earlier production of $361.2m[3] (compared to the Commission's calculation of $22.9m to $57.0m).

In light of certain events that occurred subsequent to our original report, we also describe in Appendix A the welfare benefits of joint marketing under a range of alternative possible scenarios. We build into our base case the assumption that the effective gas price cap for most of the period of our analysis will be set by diesel rather than coal, because:

- It is unlikely that new coal-fired generation could be built within that period; but
- Existing gas-fired plants could convert to diesel within that period.[4]

The effect of this higher gas price cap is to increase the costs of delay.

In addition, we have included in the model a new gas extraction profile provided to us by the joint venture parties, which takes into account higher-than-anticipated Maui production following this year's energy shortage, but leaves production from other fields unchanged.

The combined effect of these changes is to produce an expected cost of a three-year delay of $413.8m.[5]

Retaining the diesel as the alternative fuel and the new production profile, we then model the impact on welfare of:

- A dry year – this yields benefits of joint marketing of between $414m and $595m; and
- A higher gas demand growth (4%, derived from a higher-than-expected electricity demand growth) – this results in benefits of joint marketing of between $418m and $476m.

---

3 It is comprised of $168.8m cost of delayed gas production, $124.1 delayed condensate production, and $68.3m delayed LPG production. It assumes an alternative fuel price of $8.00/GJ.

4 Insofar as certain thermal plants (for example, Huntly) can rapidly switch to coal this calculation provides an upper limit on the cost of delay in relation to the coal/diesel issue all else held constant.

5 Comprised of $221.4m cost of delayed gas production, $124.1 delayed condensate production, and $68.3m delayed LPG production. This value assumes an alternative fuel price of $11.70/GJ.

In addition, the dry year scenario is re-tested assuming a higher reserve price for Methanex (for reasons explained in Appendix A). This has the effect of increasing the cost of delayed production in dry years. In the case of the higher Methanex reserve price, set to the price of diesel, the losses from all products from a three-year delay between 2006 and 2009 are estimated to exceed $1 billion. We also test the effects of reducing demand elasticity from -0.2 to -0.1 in dry years (for reasons explained in Appendix A) and under a one-year delay in Pohokura development under separate marketing. The increase in costs of delay is modest under this reduced elasticity, but still significant.

The Commission proposes to authorise joint marketing from the Pohokura field, subject to certain conditions. In our view, these conditions are commercially and economically unworkable. Development of the Pohokura field is totally dependent on the writing of secure long-term contracts before development takes place. The proposed conditions impose so much risk on the sanctity of these contracts that neither buyers nor sellers are likely to enter into them in the first place, resulting in no development or inordinate delay (due to the necessity to negotiate intra-joint venture governance arrangements).

One of the themes of this report is that joint marketing places constraints on the decision-making of each joint venture party, including on any ability to exercise market power. In our view, it is likely that each of the Pohokura joint venture parties would have a strong preference “in a perfect world” to market gas separately, thereby avoiding the need to deal with the other parties. However, the practicalities of separate marketing from a common pool and development mean that it is privately and socially more efficient for the parties to market jointly.

2. THE POHOKURA INVESTMENT DECISION

2.1. Introduction

The Pohokura joint venture parties have already spent in the order of $200 million on the field (exploration, appraisal and development), but this is sunk and irrelevant to the future investment decision. To extract the gas and liquids from the field, they would have to invest in the order of another $800 million, most of which will be sunk.

The Pohokura field contains three primary product streams[6] (gas, condensate and LPGs), and physically, no one product can be extracted without the others. They are produced in fixed proportions, and it is important to understand that the liquids will contribute a very significant proportion to overall revenues from the Pohokura field. The condensate and LPG are tradable in international markets but the gas is not. The decision to extract from the field requires that all products be marketed. The annual off-take of the field is set by consideration of the field's joint products and is chosen in light of the potential costs and revenues of all elements, many of which are affected by the characteristics of the field. There is significant risk, particularly as to the quantity of reserves, performance of the field (e.g., deliverability), volume of demand and the market prices for the products. The joint nature of the product and the characteristics of the investment are such that the annual gas (and condensate and LPG and other liquids) off-take is not a variable that is easily or desirably varied in response to the returns from gas alone. Given this, the investment decision facing the Pohokura joint venture parties is really when to invest and open up the field. As we continue to argue, contracts of reasonable duration for the bulk of the gas are essential for investment in this field to meet normal commercial criteria. This will be affected by the institutional requirements implied by the application of competition law.

6 And potentially other products such as naphtha.

We note the context that New Zealand oil and gas exploration companies are very small on a world scale and that the New Zealand gas market is miniscule on a world scale. Because of the size of the gas market *per se,* participation by small firms is important for competition. This interest may be an important adjunct to larger international companies' exploration for liquids that are internationally tradable. Joint ventures in oil and gas exploration are common with very large companies and in the context of New Zealand markets are critically important if small local companies are to participate. To place this in perspective, the approximately $1 billion that will get Pohokura to market is roughly a third of the equity value of Lion Nathan and Cart Holt Harvey, and a tenth of Telecom New Zealand Limited. Todd's share of the further expenditure required (26 percent of $800 million) is a high percentage of its shareholders' funds. Furthermore, these relatively large sums do not include the costs (e.g., dry wells, seismic acquisition and processing) of search that preceded and, presumably, will follow Pohokura. Revenues from successful fields have to meet the costs of development of these fields and of failed explorations if exploration is to continue. Institutional restrictions that limit the marketing – particularly that of joint ventures - of gas from successful fields will adversely affect exploration and potentially exploration focus on gas for the New Zealand market as well as competition.

In this section we briefly consider some particular Pohokura investment issues

2.2. MARKET RISK

Condensate and LPGs can be traded on international spot markets, at commodity price risk.

Gas is not tradable internationally, and must be sold on the small and thin New Zealand market, where the decisions of single firms on the demand- or supply-side can create significant price and quantity risks. In this regard, we note with some surprise the Commission's view that (paragraph 299):

> *Unlike some circumstances where joint venture parties face high risks of not being able to market gas from a new project, the Commission notes that in the current New Zealand situation that risk appears to be very small.*

We think that caution is warranted when forecasting the demand and supply factors that determine the price and quantity of gas. While there does appear to be a healthy demand for gas today, this situation is fragile. For example, Methanex is constantly considering the possibility of closing its New Zealand operations, and the withdrawal of its gas demand would radically alter the market expectations of price and quantity.[7] As another example, electricity generators have the option to switch to alternative fuels, such as coal.[8] It should be appreciated that long term contracts can "lock in" alternative fuels to gas and reduce gas demand even if the price of gas ultimately is advantageous.

Furthermore, the joint venture parties must have regard to market risk over the life of the field (i.e., approximately 15 years), not just in the short term. The terms of long-term contracts will be set based on the price and quantity expectations of buyers and sellers over the length of the contract. Furthermore, unless the joint venture parties contract the entire field prior to development, it is likely that they will sell (and buyers will demand) contracts with a variety of durations. In essence, only joint marketing allows wide variation in contract length and the authorisation should extend to the life of the field to provide this flexibility.

The Commission appears to acknowledge these risks (see paragraph 153 of the draft determination), but seems to place little weight on them.

As we discuss several times in this report, a key implication of this risk is that the Pohokura joint venture parties will not develop the field until commercially prudent contracts are in place, including intra-joint venture contracts in the case of enforced separate marketing.

7 See, for example, the 23 May 2003 copy of EnergyReview.Net, which quotes Methanex Asia-Pacific vice-president Bruce Aitken as stating that, "He hoped Methanex would be able to get enough contractual gas in New Zealand to keep at least one of three methanol trains operating to perhaps 2006". The article also states that, "it was unlikely the Taranaki plants would be returned to full production in the future", and quotes president and chief executive officer, Pierre Choquette as saying, "the expanded facilities at Trinidad and Chile were expected to produce a total of 5.7 million tonnes of methanol a year once expansions in both countries had been completed by early 2004 and early 2005 respectively. This output would be equivalent to total Methanex world production in 2002".

8 In this context we note the recently announced 8-year coal supply contract between Solid Energy and Genesis. Genesis owns the Huntly Power Station, which can run on coal and gas. The new coal contract is for significant volumes (equivalent to about 40 PJs of gas per year from 2006/07) and might be expected to reduce Genesis' demand for gas from Pohokura. (Genesis is also the majority owner of the rights to the Kupe field.) The press release issued by the two companies also states that, "[Solid Energy] is also investigating how it can expand its output from its underground mines to meet growing demand from a range of industrial customers in New Zealand". Presumably these customers see coal as a substitute for gas.

2.3. INVESTMENT TIMING

At paragraph 299, the Commission argues, "there is a strong economic incentive for the parties to develop the Pohokura field even if they are required to market the gas separately". This belief appears to be based on a comparison of the estimated value of the Pohokura reserves and the estimated capital and operating expenses required to extract those reserves (paragraphs 257 to 258).

The Commission's conclusion may or may not turn out to be correct. However, the framework for drawing this conclusion is inappropriate, because it fails to incorporate the state of the market and appropriate commercial decision making that reflects risk management and the availability of delay options. As we have indicated, the gas market in the immediate future has downside risk as well as upside potential and beyond the short term uncertainty is such that it is difficult to plausibly specify scenarios. Again as we have argued and shall develop further, the uncertainty and the magnitude of the sunk investment required to open Pohokura requires, for acceptable economic and commercial risk management, long term contracts in place before investment that opens the field. Without such contracts, individual members of the joint venture are vulnerable to very substantial risks that depend upon the future state of the market. Once such contracts are in place, there would be urgency for development and gas off take. Before they are in place, there will be commercial decisions to be taken about the timing of these contracts. The contract timing will be affected by institutional arrangements, e.g., the permissibility of joint marketing (and any regulatory conditions on it), and by commercial assessments of the options to delay.[9]

Extraction of hydrocarbons is irreversible, but its timing is flexible. Combined with the uncertainty surrounding future liquids and gas prices and reserves, this means that the value of a field, both to its owner and to a hypothetical social planner, is very sensitive to the timing of extraction. Delaying extraction always has some value – for example, if the gas, condensate or LPG prices rise, the finite gas resource is sold at a higher price; if the price falls, extraction can be further delayed until the price rises again. Extraction should only occur when the value of extraction exceeds the value of waiting. In particular, the value of a field will not be maximized if hydrocarbons are extracted as soon as price exceeds the marginal extraction cost.[10] The same is true of welfare. Extracting hydrocarbons as soon as the flow of total surplus is positive is not welfare maximizing, so that even a hypothetical social planner would prefer to wait until the flow of total surplus exceeds some strictly positive threshold.

9 Real options theory, popularised by Professors Avinash Dixit and Robert Pindyck (*Investment Under Uncertainty*, Princeton University Press, 1994), provides a firm basis for the analysis of the optimal timing of extraction.

10 More precisely, the decision to accept gas sale contracts – and thence invest and extract pursuant to these contracts – should be taken at a time when the price of these contracts is such that the NPV of the field exceeds a positive threshold that includes the value of waiting: it should not be taken as soon as NPV is positive.

The delay option has implications for the timing of the development of the field but not the issue of form of marketing. First, we note that the delay option is extinguished when contracts for the gas are entered into: from that point in time the flexibility of delay has been eliminated and the joint venture has every incentive to start gas extraction pursuant to the contracts. Secondly, admitting the delay option – which can only be present before the contracts are in place and hence before the requisite investment - has no discernable implications for timing under joint marketing or scenario 1 separate marketing. Under both forms of marketing the Pohokura joint venture parties would jointly determine the timing and quantity of gas extracted. The factors leading to the delay in agreeing on a regime for separate marketing are not ameliorated by admitting extraction-delay options and as we have argued they mean that extraction cannot begin for quite some time, relative to the case of joint marketing. Therefore, the only effect of separate marketing is to delay the earliest date at which the option to extract begins. Under joint marketing the Pohokura field would have this option significantly earlier. Enforced separate marketing would in our view destroy this option for three or more years.[11]

2.4. Mitigation of Risks Through Contractual Mechanisms Prior to Development

Because of the large risks and sunk costs involved, it would be normal business practice for the joint venture parties to have comprehensive and enforceable contracts in place before they spend any significant money on development; anything else would be wildly imprudent. (For those joint venture parties relying on bank funding to develop Pohokura, we would expect that their bankers would require this as a pre-condition to providing the loan.) These contracts would include those for the sale of gas, and those between the joint venture parties themselves to govern their marketing arrangements. It is absolutely crucial to understand that these contracts would have to be in place prior to any investment being made – this cannot be overemphasised.

11 We note that delay options help explain why it would take so long to negotiate a separate marketing agreement and obtain the contracts necessary to provide the surety for investment: given increased opportunism available to joint venture parties under separate marketing wouldn't each party have a valuable option to delay relating to the decision to sign any agreement?

2.4.1. Long-Term Gas Sales Contracts

Investment in development of a gas field is an example of a *specific asset*. A specific asset is one that is most valuable in one specific setting or relationship.[12] The owner of such an asset is subject to the risk of being *held-up* by another party. For example, after the owner of a gas field has sunk its development investment, a purchaser of gas could refuse to pay the initially agreed price and, depending on the market circumstances, exploit the owner's sunk costs. The risk of such behaviour may result in the field owner refusing to make the investment at the outset.[13]

In the absence of a spot market, the solution to this problem is either a long-term contract or vertical integration.[14]

A second reason for having long-term contracts in place before taking the decision to invest for extraction is to manage commodity price risk. Sunk investments put in place long lived liabilities that any commercial entity must manage according to its appetite – resources and preference – for risk. The presence of spot markets just reveals this risk; it does not ameliorate it. It is normal prudent commercial practice to have a significant proportion of the financial obligations – whether resulting from loan or equity – implied by the sunk investment covered by long-term contracts relating to the revenue produced by the investment. Thus commodity price risk is a solid commercial and economic rationale for having long term contracts in place before the decision to invest is taken. To not have long term contracts at the time of investment would render vulnerability that would be analogous to, in some commodity markets, waiting until the price starts to rise before seeking hedge contracts.

Long-term contracts are a necessary condition for development.

12 The *specificity* of an asset is measured as the percentage of investment value that is lost when the asset is used outside the specific setting or relationship. See pages 134 to 139 of Paul Milgrom and John Roberts (1992) *Economics, Organization and Management*, Prentice Hall.

13 Hold-up by a joint venture party of the other joint venture parties is also a risk of separate marketing, because of the unanimity decision-making requirement.

14 While a spot market may, of itself, enable investment, it will generally be a complement to long-term contracts.

2.4.2. Marketing Governance Arrangements

As we demonstrated in our original report, enforced separate marketing would increase the risks to the Pohokura joint ventures parties. It is important to note that, whenever there is a common pool (particularly when the size of that pool is uncertain), the incentive to take the other parties' equity shares always exists, and is affected by the type of marketing.[15] Our original report noted that a joint marketing form of governance structure would be the most incentive-compatible and therefore welfare-maximising. A scenario 1 governance structure would likely be better at aligning incentives than a scenario 2 structure (but as we discuss throughout this report, would have no competition advantages over joint marketing). The degree of alignment would depend upon a number of factors, including balancing, penalties and remedies. However, because contracts are always incomplete, even a scenario 1 structure is likely to have "gaps" that could be exploited opportunistically. This results in extra risks for each joint venture party and each has the option to delay finalisation because unanimity is required in final investment decision-making.

Arrangements to support separate marketing in New Zealand would need to protect each party's share of the common pool, requiring an elaborate means of measuring the value taken by each individual party and a means to retrospectively rebalance a party's share of value. These arrangements would have to be in place prior to a decision to proceed with development.

---

15 Note that once the extraction capital is in place, the gross revenue relating to shares of the field gained by opportunism is pure profit because costs are essentially fixed by that time.

3. COMPETITION EFFECTS

3.1. INTRODUCTION AND SUMMARY

In this section, we address the Commission's claim that scenario 1 separate marketing would be more competitive than joint marketing. In our view, this is incorrect, and the error derives from a mistaken belief that "separate marketing" is equivalent to "competitive marketing". This is not the case, because under scenario 1 separate marketing, *quantity is set jointly*. This is of course fundamentally distinct from what occurs in competitive markets, in which players set price and quantity independently.

Professor Hazledine makes a similar error. For example, he refers to "three independent sellers" (paragraph 4.4.3 of his report). Under scenario 1, the sellers cannot be described as "independent", as they would coordinate on everything except price. Professor Hazledine also refers to oligopoly models that predict a price increase when the number of competing sellers drops. However, all of these models assume that a firm will gain market share by cutting its price, which is not the case with a gas field under scenario 1.

In fact, joint marketing has competition benefits over separate marketing, and is more dynamically efficient than separate marketing, for the following reasons:

- It is difficult to rationalise what difference in output over that of joint marketing would be chosen by the joint venture parties under scenario 1 – we see no compelling argument for quantity to be different;[16]

- It is therefore likely that the price of Pohokura gas would be the same under either form of marketing (we analyse pricing institutions);

- Regarding the ability of the Pohokura joint venture parties to price discriminate, there is no difference between joint and separate marketing. If price discrimination is possible (we are advised by the joint venture parties that they will not unreasonably restrict the resale of gas: this will have the effect of substantially ameliorating the prospects for discrimination), it is likely to be allocatively and dynamically efficient in this industry;

- Separate marketing could only lead to *less* flexibility and variance in respect of non-price terms than joint marketing, for the following reasons:

16 As we have already explained, annual off-take of gas will reflect the fact that it is a joint product and that various factors affect the cost and performance of a field, and that as a consequence the level of off-take is very likely insensitive to prospective variations in the price of gas. There are arguments to the effect that rate of off-take may be lower under separate, relative to joint, marketing because of the limitations implied for separate contracts. However, we do not rely on these arguments.

  - Scenario 1 envisages the joint venture parties agreeing on all of the key development and sales parameters prior to going to market;
  - The contracts would have to match each joint venture party's share of gas; and
  - There would be more risk attached to the performance of the contracts;

- Under separate marketing tranches offered may be in conjunction with gas from other fields with common ownership, whereas joint marketing introduces a separate entity;
- Under joint marketing, the different interests of the parties - particularly in downstream markets - imply that if one party wished to price gas low to itself it would have to, in effect, buy the gas at the joint venture contract price. There is a much greater likelihood of lower prices to joint venture parties with downstream interests under separate marketing than joint marketing; and
- Joint marketing is more likely than separate marketing to stimulate the development of a competitive gas market. Because separate marketing increases risk and decreases field value, it must also reduce entry incentives.

Prior to discussing these issues in more detail, we first consider the matter of the alleged market power of the Pohokura joint venture parties.

3.2. Do the Pohokura Joint Ventures Parties Have Market Power?

3.2.1. What is the Relevance of this Question?

The Commission concludes that the Pohokura joint venture parties have significant market power, and this finding appears to be very influential throughout the draft determination. For example, in response to the claim that separate marketing will reduce incentives to invest in exploration, the Commission states that, among other things (paragraph 498):

> - *the Commission's analysis of the implications of joint marketing is on a case by case basis. The decision in this instance could not be taken as an indication of what the Commission might conclude under different circumstances in the future;*
> - *the Commission's particular concerns in this case are the high level of market concentration, the existing market power of the Pohokura JV parties and the limited supply alternatives in the near future …*

In our view, it is not relevant to this authorisation application whether or not the Pohokura joint venture has market power. Rather, the relevant question is whether or not joint marketing would substantially lessen competition compared to separate marketing. In other words, the test involves comparing two different methods of marketing, not determining whether the beginning state is sub optimal.[17]

3.2.2. Market Power Analysis

For the purposes of discussion, we will assume for the moment that whether or not the Pohokura joint venture parties do have market power is relevant.

Suppose that the rights to the Pohokura field were owned by a single firm? Would that single firm have market power in the gas production market? As we have explained, the rate of gas output will be very insensitive to the price of gas, and so market power will be accordingly very limited indeed.

Because of the relative size of the Pohokura field, if the single owner raised its price above the "competitive level", then it *may* be difficult for existing alternative fields to increase production sufficiently to undermine that price increase – this is an empirical question. Also, if we assume that the Kupe field is higher cost, then the Pohokura owner could raise its price above its marginal cost (including the destroyed option value and scarcity rents) and still price lower than Kupe.[18]

In this sense, it is plausible that a single owner of the Pohokura field would earn "rents". However, it is absolutely critical to recognise that these rents are "Ricardian rents" and "rents to innovation" (often referred to in the oil and gas industry as "exploration rents"), as opposed to "functionless monopoly rents", as referred to in the *AMPS-A* case (discussed further below).

Sanderson and Winter (2002) provide definitions of Ricardian rents and profits or "pure rents" (and also of scarcity rents):[19]

17 We also note that a case-by-case analysis of joint marketing by the Commerce Commission poses uncertainty for prospective explorers about their marketing options.

18 Scarcity rent reflects an opportunity cost: scarcity rent is the cost of using up a unit of gas today rather than in the future or rather than an alternative fuel.

19 Sanderson, Margaret and Ralph A Winter (2002) "'Profits' Versus 'Rents' in Antitrust Analysis: An Application to the Canadian Waste Services Merger", *Antitrust Law Journal*, 70(2).

Ricardian Rents

> *In any market a number of buyers and sellers meet to trade a product. At the market equilibrium price, demand and supply are equal … On the supply side, the marginal firm is the firm that breaks even, i.e., the firm whose marginal cost is just covered by the equilibrium price. All other firms, again called inframarginal firms, would have been willing to supply their good to the market for less than the equilibrium price. Ricardian rent refers to the income derived in a market by owners of inframarginal factors of production above the minimum amount necessary to elicit their supply in a market.*

So, if the marginal costs of extraction from Kupe exceed those for Pohokura, the owners of Pohokura would receive Ricardian rents. Ricardian rents are actually a component of opportunity cost, and do not imply market power.

Pure Rents

> *Pure rents or profits refer to the excess of revenue over costs that is due to barriers to entry into a market. A firm earns economic profits or pure rents when it acquires and maintains a monopoly position in a market not through particular acumen in meeting the demands of consumers but through anticompetitive, exclusionary practices or through allocation of monopoly rights by a government.*

We note that there are no material entry barriers to the gas production industry that could protect rents. While there are significant sunk costs, these by themselves do not constitute an entry barrier. Rather, the behaviour of the incumbent is critical.[20] The Commission has not claimed that gas producers have an incentive to limit price.

Rents to Innovation and Exploration

A theme of our original report was that risk in the oil and gas industry is severe. Section 2.2.1 of that report discussed exploration risks, and set out our understanding that:

- The geological probability of a successful well in a basin such as Taranaki is about 0.2; and

- The commercial probability of a successful well is even lower, as a certain proportion of reservoirs will be uneconomically small.

This level of risk is illustrated by advice from Todd that in 48 years it has drilled 51 exploration wells to discover three commercial discoveries (and this excludes numerous failed appraisal wells in the three commercial discoveries). This means that 6 percent of exploration wells have been commercial successes.

---

20 See Gilbert R J (1989) "Mobility Barriers and the Value of Incumbency", in Schmalensee R and R D Willig (eds) *Handbook of Industrial Organization*, Volume 1, Elsevier Science Publishers B.V., 475-535.

Quite clearly dynamic efficiency requires that oil and gas firms be permitted to earn sufficient revenues from successful discoveries to cover the costs of failed wells and related exploration costs. Without continual discovery and innovation the industry will decline in a comparatively short space of time.[21]

We have already commented on the importance of small exploration companies to the vibrancy of the New Zealand exploration industry. An exploration company's survival requires very careful risk management, for example, the use of farm-in arrangements. Enforced separate marketing would create a significant disincentive to enter farm-in arrangements. It is our understanding that all firms involved in exploration in New Zealand are small on a world scale, apart from Shell.

We note that at paragraph 136 of the draft determination, the Commission states that, "The current level of exploration is described by Crown Minerals as high, with 14 wells drilled in 2002 …". The Pohokura joint venture parties advise us that there were only actually 7 exploration wells drilled in 2002. The main reason for the discrepancy is that several of the 14 wells drilled were actually appraisal rather than exploration wells.

Misalignment of Incentives

Section 5.5.3 of our original report discussed the competitive constraints on the Pohokura joint venture parties. The constraint that we emphasise here arises from the fact that there is not a single owner of the Pohokura field, and joint marketing of the gas would not be equivalent to "one entity" versus three (see paragraph 372 of the draft determination) doing the marketing. Rather, joint marketing would involve three entities being forced to cooperate and agree on the specific enterprise only. In general, it can be expected that the interests and incentives of the parties to an oil and gas joint venture will vary to a certain extent, because of their business interests outside of the joint venture: they will each be seeking and managing new projects outside the joint venture that may in the present or in the future compete with those of their Pohokura joint venture partners. Furthermore, joint venture parties are likely to have disparate views about factors such as future gas demand and supply conditions, and therefore gas prices.

These different interests, incentives and views make coordination more difficult than it would be for a single firm running the venture. In particular, the exercise of any market power would be more complicated and accordingly constrained. To put this another way, a single firm is more likely to be able to exercise market power than a joint venture with the same market share.

21 In the *Kapuni* case, the High Court recognised the importance of incentivising exploration. See section 5.1.1 of this report.

3.3. Effect on Prices from Joint Marketing

3.3.1. Price and Quantity

Several submissions made by parties in respect of the Pohokura joint venture parties' authorisation application, including Professor Hazledine's, assert that separate marketing would result in lower gas prices than joint marketing. The Commission appears to agree with this.

As we noted in our original report, joint marketing would lead to an *increase* in competition and production in the gas production market compared to separate marketing, as it would result in greater exploration and development incentives (in other words, more entry). We return to this issue below.

The focus of many of the submissions, including Professor Hazledine's, has been on the implications for the price of Pohokura gas specifically of joint marketing versus scenario 1 separate marketing.

We re-emphasise that under both joint marketing and scenario 1 separate marketing, the joint venture parties would jointly determine the quantity of gas to be sold and it would be the same under both forms of marketing (we return to this point below).[22] In standard economic models (such as monopoly and Cournot oligopoly), setting supply is equivalent to setting price - once one is set, "the market" determines the other.

However, such models assume that buyers are price takers. As Professor Hazledine states (paragraph 6.6):

> *… in a small-numbers bargaining situation, output does not uniquely determine price (i.e., the latter cannot be simply read-off the demand curve). Even if the total quantity being traded is fixed, the final price will vary according to the relative bargaining strengths and negotiating skills of the buyers and sellers.*

In the context of a negotiation, we would agree with this analysis, although we note that of itself it does not imply that the *expected* price under scenario 1 would be any lower than under joint marketing - rather, the comment suggests that process should be considered and implicitly suggests some *variation* in possible price outcomes.

---

22 Furthermore, as noted in our original report, joint development of the optimal depletion profile must be based on, among other things, reservoir engineering analysis and price forecast analysis; indeed, economic efficiency requires this. In other words, the joint venture parties would have to agree on a future price path (or at least the range) that was acceptable to design the off take capability of the field. Finally, a balancing arrangement will almost certainly involve agreement on an internal transfer price.

However, we understand that the Pohokura joint venture parties intend to *tender or auction* the first tranche of Pohokura gas, rather than sell it by *negotiation*.[23] For the following reasons, we consider this to be a rational strategy:

- Each joint venture party would probably expect a higher price by seeking competing bids, rather than trying to negotiate, particularly in a market with "excess demand" (as appears to be the case for the gas production market at the moment). Bulow and Klemperer[24] show that, under many circumstances, a seller will earn more in expectation by running an auction with n+1 bidders than negotiating with n bidders. No amount of bargaining power is as valuable to the seller as attracting one extra bona fide bidder;

- Auctions reveal information about value; and

- Auctions are likely to be a quicker method of sale than negotiation.

In a market where there is likely to be bidding competition, an auction will effectively turn gas buyers into price takers, reveal demand for gas and yield tranche prices that accord with the principles of auctions.[25] This is of course why the Pohokura joint venture parties may use an auction mechanism to sell the gas, rather than a negotiation mechanism.

On this basis, if the Pohokura joint venture parties did have market power (and we show elsewhere that this is not the case), then they would be just as able to exercise it by setting quantity under scenario 1 as they would be by setting quantity under joint marketing. We would expect the winning bid or bids to be very similar, whether the gas is auctioned jointly or separately, and for the bids to be constrained by the demand for Pohokura gas and alternatives.

The quantity of gas being auctioned under joint marketing and scenario 1 will be the same, but the scenario 1 division would impose extra costs on buyers, and may therefore result in lower bids. To be more particular, under joint marketing the allocation of the production profile would be determined purely by the bids of buyers. However, under scenario 1, there would be an extra layer of constraint (i.e., the division between the three joint venture parties) limiting the flexibility of that allocation and the consequent scope of contracts. This may in turn increase the costs to buyers (for example, by requiring an aggregation of quantities from two sellers), which may need to be compensated by lower prices.

---

23 We use the term "auction" as it is used in the economics literature. The characteristic feature of an auction is that there is an explicit comparison made among bids (Milgrom, P R (1987) "Auction Theory", in Truman F Bewley (ed), *Advances in Economic Theory: Fifth World Congress*, Econometric Society Monographs No. 12, Cambridge University Press, 1-32). Auctions are one of a wide variety of market pricing institutions, other examples of which are posted prices (such as in a retail store) and negotiations.

24 Bulow, J and P Klemperer (1996) "Auctions Versus Negotiations", *American Economic Review*, 86, 180-194.

25 For example, the expected price in an English auction is the second highest valuation.

Hold-up by a joint venture party of the other joint venture parties is a risk of separate marketing, because of the unanimous decision-making requirement and the increased uncertainty implied by opportunism of any joint venture party.

It is difficult to envisage how buyers would be better off under scenario 1 than under joint marketing. The scope of contracts would be limited and any reduced price would only be as a result of increased costs. The reduced prices would not result from extra competition, but rather from an imposed constraint on flexibility.

The foregoing discussion assumes that quantity under joint marketing and under scenario 1 would be equal, or at least similar. Is this a reasonable assumption?

The Cournot (quantity-setting) oligopoly model predicts that, as the number of firms increases, total output or quantity will also increase, but for Pohokura, because of the joint investment in gas/liquids, output will be the same under joint and separate marketing. More generally, the Cournot model assumes *independent* behaviour where each producer controls its supply. Scenario 1, on the other hand, envisages explicit *coordination* between the firms, and accordingly we cannot expect the Cournot outcome. It is difficult to rationalise what difference in output over that of joint marketing would be chosen by the joint venture parties under scenario 1.[26] The joint nature of the product (i.e., gas, condensate and LPGs) and the characteristics of the investment are such that the annual gas (and condensate and LPG) off-take is not a variable that is easily or desirably varied in response the returns from gas alone. The output would be affected by the, arbitrary, requirement that tranches for each joint venture party be both commercially attractive and match their share of the gas, and by the increased production costs. In addition, it would likely be affected by the gas-holding positions of the joint venture parties in relation to other fields.

To elaborate this point further, we note that both the design of the tranches and the rate of off-take of the field would under separate marketing depend upon the wider market structure, in particular, the gas-holdings of the joint venture parties outside Pohokura. Indeed, comparison of prices under joint marketing and scenario 1 should also place weight on this factor even if the off-take was the same: because under separate marketing tranches offered may be in conjunction with gas from other fields with common ownership, whereas joint marketing introduces a separate entity.

26 Interestingly, enforced separate marketing would artificially increase risk and consequently distort marketing decisions. For example, enforced separate marketing would raise reserves risk for each Pohokura joint venture party and would lengthen the time it would take to negotiate an acceptable separate marketing arrangement. A long-term supply contract with an electricity generator may give the best price but may have associated higher risk. To mitigate this risk and optimise expected return, a party may accept a lower price in exchange for very high early off-take from the field, effectively "dumping" the gas to a potentially short-term demander, e.g., Methanex, reducing reserves risk.

As another possibility, in an attempt to mitigate reserves risk and improve security of supply, separate marketing may incentivise the parties to jointly agree to extract less gas each year and to extend the contract terms. However, because this would delay the extraction of value, it may not be profit maximising.

3.3.2. The NZIER Analysis

In an attempt to estimate the competition effects of joint versus separate marketing, the NZIER (advising NGC) has used a depletion model and a Cournot model. At this stage, we have not had the opportunity to carefully test the NZIER's application of these models. However, we believe that this is unnecessary, because neither model is actually applicable to the problem at hand, an issue that the NZIER itself flags when it states (page 1):

> *At this stage, these models are not exactly tailored to the Pohokura marketing scenarios. In particular, we have not captured the relationship between joint* development *and separate* marketing.

In our view, these models are simply not applicable (and accordingly their results are not informative), for the following reasons.

Depletion Model

The NZIER states that (page 1):

> *Our results indicate (given the assumptions described below) that competitive marketing (assumed analogous to separate marketing) produces an economic surplus around $1.5 billion more than with monopoly marketing (assumed analogous to joint marketing).*

This quote illustrates the fundamental inapplicability of the depletion model to the analysis of joint versus separate marketing from the Pohokura field.

- Competitive marketing is *not* analogous to separate marketing, or at least not scenario 1. Under scenario 1, quantity - and arguably price via the transfer price - is set jointly, which it would not be under "competitive" marketing.

- Monopoly marketing is *not* analogous to joint marketing. Firstly, the rate of off-take is unlikely to be very responsive to the price of gas. Secondly, as noted earlier in this report, joint marketing would involve three entities being forced to cooperate and agree. The different interests, incentives and views of these three parties can be expected to make coordination more difficult than it would be for a single firm running the venture. In particular, the exercise of any market power would be more complicated and accordingly constrained.

Cournot Model

As noted above, the Cournot (quantity-setting) oligopoly model predicts that, as the number of firms increase, total output or quantity will also increase. However, the Cournot model assumes *independent* behaviour where each producer controls its supply. Scenario 1, on the other hand, envisages explicit *coordination* between the firms, and accordingly we would not expect the Cournot outcome.

3.3.3. Price Discrimination

The Commission claims that price discrimination is likely to be possible under joint marketing, but not under separate marketing, and furthermore that price discrimination in respect of the Pohokura field is unlikely to be efficiency enhancing. We believe that these claims are incorrect.

The Conditions for Price Discrimination

The Commission's claim that price discrimination is likely to be possible under joint marketing, but not under separate marketing, appears to be based on assumptions that:

- "Substantial market power" is required to enable the practice of price discrimination; and
- Such power would exist under joint marketing but not under separate marketing.

The Commission states that price discrimination "can usually occur only where the seller has a substantial degree of market power" (paragraph 385). However, casual and empirical observation demonstrates that this cannot be right, and this is supported by recent economic theory.[27] Firms in many (workably) competitive markets can and do price discriminate, e.g., books, fresh fish, banking, movie theatres, hotels and airlines. Baumol and Swanson (2003)[28] show that (page 662):

> *…scale economies in general, and repeated sunk costs in particular, force firms in the affected industries, if they operate in competitive markets, to adopt prices that are discriminatory and exceed marginal cost…*

Similarly, Varian (1996)[29] states:

> *The evidence shows that differential pricing is ubiquitous in industries that exhibit large fixed or shared costs. This is true for industries that are highly concentrated and industries that are highly competitive … If there are large fixed costs, and low marginal costs, differential pricing may be required for a producer to be economically viable.*

---

27 For discussions, see Levine, Michael E (2000) "Price Discrimination Without Market Power", Harvard law School Discussion Paper No. 276, and Asplund, Marcus, Rickard Ericsson and Niklas Strand, "Price Discrimination in Oligopoly: Evidence from Swedish Newspapers", SSE/EFI Working Paper Series in Economics and Finance No 468. More generally, see the "Symposium on Competitive Price Discrimination" in the *Antitrust Law Journal*, Volume 70, 2003.

28 Baumol, W J and D G Swanson (2003) "The New Economy and Ubiquitous *Competitive* Price Discrimination: Identifying Defensible Criteria of Market Power", *Antitrust Law Journal*, 70, 661-685.

29 Varian, H (1996) http://www.firstmonday.dk/issues/issue2/different/.

A key condition for price discrimination is that buyers cannot resell the product. We are advised by the joint venture parties that they will not unreasonably restrict the resale of gas. This will have the effect of substantially ameliorating the prospects for discrimination.

Regarding the Commission's assumption that substantial market power would exist under joint marketing but not under separate marketing, we have addressed that issue earlier in this report. We reiterate that scenario 1 separate marketing has no competition benefits over joint marketing.

Efficiency of Price Discrimination

The Commission acknowledges that price discrimination can be efficiency enhancing, but asserts that this is unlikely to be the case for Pohokura gas "as it would be unlikely to cause supply to be augmented, or customers to be supplied who would not otherwise be" (paragraph 439).

It is not clear to us how the Commission reaches this conclusion without explicit consideration of cost and demand curves, particularly elasticities. In the absence of such data, it would be at least as plausible to argue that price discrimination in this industry would be an efficient outcome, because of the massive fixed costs involved. Under these circumstances, discriminatory pricing tends to yield the efficient quantity sold and facilitate dynamic efficiency by permitting the recovery of costs of dry wells and inducing entry to exploration.

At paragraph 440, the Commission states that:

> *[Price discrimination] could have an undesirable impact on downstream markets where competition is limited if the higher prices were passed on. The electricity market might be detrimentally affected, for example.*

While this comment is slightly cryptic, we assume that the claim is that price discrimination could lead to a cost asymmetry among producers (e.g., electricity generators) in a downstream market. Assuming for the moment that none of the Pohokura joint venture parties have downstream interests, it is hard to see why those parties would discriminate between downstream competitors; it is likely that, for example, competing thermal electricity generators would have a fairly similar willingness to pay for gas.

We come back to the issue of the sale of gas to downstream subsidiaries of the Pohokura joint venture parties later in this report. Our conclusion is that any attempts to "leverage market power" (as claimed by the Commission) are more likely to succeed under *separate* marketing than under *joint* marketing.

We note that if price discrimination in the gas production market does not result in a different quantity to that implied by uniform pricing (i.e., no allocative efficiency change), then there would also be no efficiency change in vertically related markets. See the analysis in our original report of the measurement of welfare changes in vertically related markets.

3.4. EFFECT ON TERMS AVAILABLE TO GAS PURCHASERS

The Commission argues that the choice of terms and conditions offered to potential gas acquirers is likely to be greater under separate marketing (paragraph 393).

For the reasons discussed in section 5.4.1 of our original report, it appears to us that scenario 1 could only lead to *less* flexibility and variation in respect of non-price terms, for the following reasons:

- Scenario 1 envisages the joint venture parties agreeing on all of the key development and sales parameters prior to going to market;
- The contracts would have to match each joint venture party's share of gas. Note that this may severely limit the range of contracts that could be offered. For example, if as seems likely the most verifiable contracts under separate marketing have the same annual flow rates so that each party's share of reserves remain approximately the same over time, contracts under separate marketing may be quite restrictive and perhaps will drive higher levels of vertical integration; and.
- There would be more risk attached to the performance of the contracts.

The Pohokura joint venture parties have analysed how each of the key development, production and sales parameters would be determined under joint marketing versus scenario 1 separate marketing, in order to identify whether or not separate marketing would lead to greater choice over terms and conditions. The results are set out in the joint venture parties' submission to the Commission, and demonstrate that for the majority of key parameters, either:

- The terms and conditions would be determined in the same way under both forms of marketing, i.e., jointly; or
- There would actually be less contractual flexibility and variation, as the terms and conditions would be set jointly by the joint venture parties before "going out to market", and therefore there would be less ability to respond to demand-side preferences.

3.5. EFFECT ON THE DEVELOPMENT OF COMPETITIVE MARKETS IN THE FUTURE

The Commission argues that separate marketing would facilitate a more competitive gas production market, because the separate sellers would result in a greater depth to the market.

We emphasise again that separate marketing is not the same as competitive marketing, and comparing separate marketing to joint marketing is not the same as comparing three sellers to one. This is a theme of this report.

We also wish to re-emphasise that because separate marketing increases risk and decreases field value, it *must* also reduce entry incentives. Accordingly, it is actually separate marketing that would retard the development of a more competitive gas production market. As we noted in our original report, joint marketing is pro-competitive and dynamically efficient.

The increased risk and decreased field value consequent upon separate marketing is particularly significant for the relatively small New Zealand exploration firms on whom the vibrancy of the market will depend. As we noted earlier in this report, the small New Zealand market and non-tradability of gas must affect the interest of large multinational firms to explore here.

We note that where secure long-term contracts that permit resale are taken up under joint marketing there is every prospect that the development of future competitive markets for gas will be enhanced.

4. PUBLIC BENEFITS AND DETRIMENTS

4.1. INTRODUCTION AND SUMMARY

As we have emphasised continuously in this report, joint marketing is actually pro-competitive and dynamically efficient compared to separate marketing. Accordingly, there are zero detriments to joint marketing.

We also consider that the Commission has considerably underestimated the benefits of joint marketing, particularly in its quantification.

- The Commission has assumed that separate marketing would only lead to a one-year delay in production. Given our understanding of the issues to be negotiated and the incentives operating on the parties, we consider a one-year delay to be implausible. We understand that this issue is being addressed in a separate submission to the Commission.

- Assuming the one-year delay, the Commission has attempted to predict the extra surplus from Pohokura at the end of field life in order to offset this against the earlier loss. At least under one production scenario, the Commission estimates a net benefit from delayed production of gas. We believe that this is not a natural outcome. It may be that there is a mismatch between model results and a qualitative assessment resulting from attempting to predict demand and supply conditions, and accordingly welfare, so far out into the future utilising trends. Rather, we believe that it is more appropriate to treat welfare past some near date, in our case 6 years in advance as stationary, as we will describe.

- The Commission has limited its analysis of liquids to condensate and has not attempted to estimate the losses arising from delayed LPG production.

We demonstrate that when these factors are corrected the expected benefit of joint marketing due to earlier production of $361.2m[30] (compared to the Commission's calculation of $22.9m to $57.0m).

In light of certain events that occurred subsequent to our original report, we also describe in Appendix A the welfare benefits of joint marketing under a range of alternative possible scenarios. We build into our base case the assumption that the effective gas price cap for most of the period of our analysis will be set by diesel rather than coal, because:

- It is unlikely that new coal-fired generation could be built within that period; but

30 It is comprised of $168.8m cost of delayed gas production, $124.1 delayed condensate production, and $68.3m delayed LPG production. It assumes an alternative fuel price of $8.00/GJ.

- Existing gas-fired plants could convert to diesel within that period.[31]

The effect of this higher gas price cap is to increase the cost of delay.

In addition, we have included in the model a new gas extraction profile provided to us by the joint venture parties, which takes into account higher-than-anticipated Maui production following this year's energy shortage, but leaves production from other fields unchanged.

The combined effect of these changes is to change the expected cost of a three-year delay to $413.8m.[32]

Still assuming these higher prices and new production profile, we then model the impact on welfare of:

- A dry year – this yields benefits of joint marketing of between $414m and $595m depending on the year assumed to be dry; and

- A higher gas demand growth – this produces benefits of joint marketing of between $418m and $476m.

In addition, the dry year scenario is re-examined assuming a higher reserve price for Methanex. This has the effect of increasing the cost of delayed production in dry years. In the case of a higher Methanex reserve price, set to the price of diesel, combined losses from the three outputs of a three-year delay between 2006 and 2009 are estimated to exceed $1 billion. We also test the effects of reducing demand elasticity from -0.2 to -0.1 in dry years and under a one-year delay in Pohokura development under separate marketing. The increase in costs of delay is modest under this reduced elasticity, but still significant.

This section of our report develops these arguments. We start by clarifying the appropriate framework for quantifying the benefits of joint marketing, and by responding to certain criticisms of our model.

4.2. Framework for Calculating Benefit of Joint Marketing

Our approach to the calculation of the welfare benefit of joint marketing was to estimate the net present value of welfare of the Pohokura field at date *t* as against *t+3* for separate marketing. If the gas supply starts at date *t* this is:

$$NPVW(t,t) = \sum_{i=t}^{t+17} S(t,i)/(1+r)^{i-t}$$

---

31 Insofar as certain thermal plants (for example, Huntly) can rapidly switch to coal, this calculation provides an upper limit on the cost of delay in relation to the coal/diesel issue all else held constant.

32 Comprised of $221.4m cost of delayed gas production, $124.1 delayed condensate production, and $68.3m delayed LPG production. This value assumes an alternative fuel price of $11.70/GJ.

where *S(t,i)* is the total of producers' and consumers' surplus expected to be generated by Pohokura in year *i* and the field is expected to last for 18 years. The stream of benefits, *S(t,i),* into the future may incorporate the effects of options to delay the start-up of the field. [33] It can be period-specific and incorporate forecast changes in market structure that relate to specific periods[34] or it can be stationary where it is assumed that uncertainty is at such a level that the estimated benefits just reflect the profile of the field over its life and not when the field starts. That is, under stationarity it is assumed that the state of knowledge is such that there is no reason (because of the structure of the market, potential discoveries, subsidies of renewables, etc) to treat the expected surplus of a field to be different if the start of a field is later, except predictably as costs change over the life or profile of the field: in particular there is no long term trend. In this stationary case welfare depends upon the *S(i), i = 1, ... ,18* and not upon the reference date *t*, and the formula becomes:

$$NPVW(t,t) = \sum_{i=t}^{t+17} S(i)/(1+r)^{i-t}$$

because under stationarity $S(t,i) = S(i)$ as it does not depend on the starting year.

We distinguish between gas and liquids. Liquids produced by Pohokura are internationally traded in established competitive markets and consequently the expected stream of benefits of liquids might be expected to be the same no matter what year the field started operation. Thus benefits relating to Pohokura's liquids might reasonably be viewed as stationary.[35]

If it is anticipated that extraction is delayed by three years, the net present value at date *t* is in general:

$$NPVW(t,t+3) = \sum_{i=t+3}^{t+20} S(t,i)/(1+r)^{i-t} .$$

In the stationary case where it is assumed that there is nothing special about starting in the first (indeed, any) year the formula reduces to:

$$NPVW(t,t+3) = \tfrac{1}{(1+r)^3} \sum_{i=t}^{t+17} S(i)/(1+r)^{i-t} = \tfrac{1}{(1+r)^3} NPV(t,t)$$

The benefit of joint marketing is then the difference in the net present value of the welfare relating to the two starting dates as in:

$$Joint\ Marketing\ \ Benefit = NPVW(t,t) - NPVW(t,t+3)$$

33 In which case there would be an expected start-up date as of date *t* and the final closing of the field would reflect this.

34 For example, as it would in differentiating between the presence and absence of Maui as of a particular date.

35 This use of the term stationary does not imply that the prices of commodities are stationary in the strict statistical sense of this term.

in general, which we approximated by the net present value of the extra welfare generated by the gas over the period 2004-2009 relative to that of the counterfactual 2007-2009. Beyond 2009 we presumed a stationary situation in which there were no positive or negative net benefits to the earlier start date in any year until the field's closure.[36] We have neglected subtracting the net benefit of the final three years of the field under separate marketing because these are heavily discounted as they relate to periods so far into the future.

For the case where there is nothing special about the starting year of the field the formula is simply:

$$Joint\ \ Marketing\ \ Benefit = \left[1 - \tfrac{1}{(1+r)^3}\right] NPVW\,(t,t)$$

which we consider is particularly appropriate for the internationally traded liquids component of the field as it be taken as stationary.[37] Note that there will be a benefit from joint marketing in the case of stationarity whenever the present value of expected net benefits is positive. The factor $\left[1 - \tfrac{1}{(1+r)^3}\right]$ is 25% in the case of the 10% discount rate, which means that the benefit of joint marketing is 25% of the net present value.

The other, general, formula requires specifying the year-specific added consumer and producer surplus arising from Pohokura with and without the 3-year delay. Based on our view of the state of risk in this market we do not forecast beyond 2009 on a year-specific basis and assume a stationary process after that date for the figures we report below: such is the unforcastability of demand and alternative supply changes past this date. We note that various scenarios are possible, even those where demand and the prices of alternative supplies of fuels grow at such rates that delays in bringing Pohokura to market would have a positive net benefit, but this is not our view.

We now turn to the specific issues of the draft authorisation.

---

36 In fact we are informed that for much of the life of the field the marginal cost of extraction is constant in which case in a stationary environment annual welfare will be the same once the field is in full production (from 2009) to at least 2012. Late in the life of the field marginal cost rises, which has the effect of reducing the annual welfare produced by the field.

37 Note that most of the infrastructure costs are common to gas and liquids and the net present value calculation should reflect that.

4.3. CRITIQUES OF CRA'S QUANTIFICATION APPROACH

4.3.1. Model Based on Perfect Competition

The Commission claims that our quantification model is based on the concept of perfect competition, and that this is not an accurate representation of the market. We agree that the gas production industry is more correctly described as an oligopoly (and indeed the demand side of the market is an oligopsony). However, we believe that our approach is reasonable and robust. We consider that modelling the multi-market welfare effects using an oligopoly-oligopsony model would be intractable and very dependent upon prospective behavioural assumptions. We consider that our assumption of demand and supply curves - that in fact may not be well-defined under oligopoly-oligopsony - does yield credible measures of welfare to a good approximation.

4.3.2. The Equilibrium Demand Curve

The Commission states that (paragraph 465):

> *…in applying the model, the focus is upon determining "observable" or "actual demand". However, the welfare model used is based upon "equilibrium demand", which is a theoretical construct that is not directly observable. For example, the equilibrium demand curve will have a steeper slope than the actual demand curve …*

This is incorrect. The equilibrium demand curve is the net result of demand and supply feedback from all upstream and downstream markets. Given the vertical relationships of the markets for gas, electricity generation and consumption, it is the *equilibrium* demand curve that is being estimated, while it is standalone demand for natural gas that cannot be directly observed.

However, this is a moot point. It does not actually matter which demand curve is or is not observable, since we do not claim to have observed any demand curve in setting the demand parameters. Instead, given the paucity of relevant empirical information on the matter, we have been forced to assume relevant parameters and then sensitivity test them to gain comfort that the effects of error in our estimate are in fact not serious.

4.3.3. Adjustment to Welfare Losses for Extension of Life of Field

In his submission, Professor Tim Hazledine states that (paragraph 4.4.2):

> *Second, this year-by-year welfare analysis is not appropriate to a resource in finite total supply. A Peta-Joule of Pohokura gas not produced this year is not thereby lost forever, it can be extracted at some future date. This is not allowed for in the CRA welfare analysis.*

The Commission has made a similar critique of the CRA model.

It is correct to note that, if separate marketing does delay production from Pohokura, then there would be certain years in the future in which a greater surplus would be enjoyed than would otherwise be the case. In particular, if joint marketing is permitted, then it is expected that the Pohokura field would be depleted by 2021. If production is delayed by three years, then the field may not be depleted until 2024. Extra surplus may be enjoyed in the years 2022, 2023 and 2024.

However, estimates of future welfare losses or gains need to be discounted to obtain their present values. The further out in time that the estimate of welfare loss or gain is, the smaller its value in present value terms. For example, a $50 million loss or gain in 3 years time would have a present value of $37.6 million, while the equivalent loss (or gain) in 14 years time would be $13 million, using a 10% discount rate, as per our original report.

Furthermore, the further out in time that a welfare gain or loss occurs, the more uncertainty there will be about the estimate of the future value of that gain or loss. To develop estimates of future values in the years 2004 to 2009, CRA had to derive demand and supply curves, using a mixture of hard data, theory and assumptions. The further into the future that derivations of these curves are estimated, the less accurate they will be – the further one looks out, the less hard data there will be, and the less credible particular year-specific scenarios will be.

In sum, the CRA report does not estimate welfare effects towards the end of the life of the Pohokura field for the reasons:

- The uncertainty is such that the economic environment can be taken as stationary beyond 2009;
- The informative value of these estimates would be very low; and
- The present value of them is almost certainly dwarfed by the present value of losses in earlier years.

4.4. Assessment of Detriments

4.4.1. Allocative Efficiency

The Commission claims that joint marketing would result in allocative efficiency losses due to:

- Price discrimination; and
- Longer-term retardation of a competitive gas market.

We have already addressed both of these claims earlier in this report. In neither case did we find that separate marketing would lead to *improvements* in allocative efficiency.

4.4.2. Dynamic Efficiency

The Commission claims that there will be dynamic efficiency losses moving forwards from a retardation of a competitive gas market. As previously discussed in this report and in our original report, we disagree with this view, and consider that joint marketing is pro-competitive and dynamically efficient.

In paragraph 435, the Commission asserts that the market power of Shell and Todd will deter entry into the gas production market. On the contrary, if there is market power and accordingly rents available, then entry will actually be encouraged, not deterred. Entry may not occur if there are barriers, but this does not appear to be the case. Also, the Commission has not claimed any theory of strategic entry deterrence by the incumbents, and there is not any obvious theory. In our view, the only deterrent to entry into the gas production industry would be the prospect of enforced separate marketing, or joint marketing subject to onerous conditions.

The Commission also claims that (paragraph 435):

> *... joint marketing beyond the short-term may enhance the potential for Shell and Todd in particular to leverage their market power into down-stream markets ...*

This claim is wrong. Firstly, it appears to rely on the assumption that joint marketing would result in greater market power than separate marketing, which we have demonstrated to be untrue. Secondly, under joint marketing the gas contracts would be with the joint venture: indeed, this is the very essence of joint marketing and it implies that the prices for all the tranches would be set with the unanimous agreement of all parties. The different interests of the parties - particularly in downstream markets - imply that if one party wished to price gas low to itself it would have to, in effect, buy the gas at the joint venture contract price. There is a much greater likelihood of lower prices to joint venture parties with downstream interests under separate marketing than joint marketing.

The Geographe/Thylacine and Yolla fields in Australia provide interesting examples of one joint venture party (Origin) selling to its subsidiary under separate marketing.

We note also that the existence of long term contracts with re-sale options to non-joint venture parties is likely to strengthen competition in downstream markets.

4.4.3. Surplus Transfers

The Commerce Commission in its analysis of price discrimination introduces the issue of foreign versus domestic ownership of firms. It suggests that transfers between consumers and producers net out for the New Zealand public in the case of New Zealand owned firms but for foreign-owned firms a transfer to them of profit might be considered a detriment. We note that the same issue might be posed in any analysis of efficiency and in particular in the cost-benefit analysis of delay implied by separate marketing, although the Commission does not do so.

The Commission quotes from its own *Guidelines*[38] its definition of "public" in "public benefit" as being:

> *The 'public' is the public of New Zealand; benefits to foreigners are only counted to the extent that they also involve benefits to New Zealanders.*

The Commission relies for its authority on the relevant High Court finding in the *AMPS-A* case, which the Commission reports as stating:[39]

> *We reject any view that profits earned by overseas investment in this country are necessarily to be regarded as a drain on New Zealand. New Zealand seeks to be a member of a liberal multilateral trading and investment community. Consistent with this stance, we observe that improvements in international efficiency create gains from trade and investment which, from a long-run perspective, benefit the New Zealand public.*
>
> *On the other hand, if there are circumstances in which the exercise of market power gives rise to functionless monopoly rents, supra-normal profits that arise either from cost savings or innovation, and which accrue to overseas shareholders, we think it right to regard these as exploitation of the New Zealand community and to be counted as a detriment to the public.*

The Commission misreports this authority in a fundamental way. It should read:

> *… supra-normal profits that arise neither from cost savings nor innovation …*

The Commission's interpretation as to what elements of public benefits and costs should be discriminated against on the basis of ownership therefore is quite unclear. Although the Commission's misquotation of the *AMPS-A* case suggests a very wide class of circumstances in which discrimination may be contemplated, the Court was much more circumspect. Examples listed in the Commission's *Guidelines* provide a mixed view: some take the wider approach, but the *Guidelines* conclude that certain indirect benefits provided by foreign investment should not be discriminated against. It is relevant to note by example the broad implications of any interpretation: because competition law constrains commercial arrangements, discriminating in competition law between foreign and domestic firms is to discriminate on the same grounds in the application of contract law.

38 Commerce Commission (1997) *Guidelines to the Analysis of Public Benefits and Detriments*, Revised.

39 *Telecom Corporation of New Zealand Limited v Commerce Commission* (1991) 4 TCLR 473.

We consider that the wider interpretation that the High Court has not proposed is static in that if time and dynamic considerations are not considered, then profits simply represent a transfer among firms and consumers and thereby people. However, it is well accepted that generally profits are far from functionless as they induce competition, innovation, investment and improved consumer welfare in the future. Baumol (2002, 40)[40] divides profits into Ricardian rent (profit due to scarcity), Schumpeterian rent (profit that reflects the outcome of successful innovation) and monopoly rent (profit due simply to the exclusion of rivals for reasons other than scarcity and innovation and that persists over time).

It is our position that the functionless monopoly rents are Baumol's monopoly profits. These rents are unlikely to affect behaviour that enhances the dynamic efficiency of the economy. The monopoly profits of Baumol will generally not arise in market situations, wherever alternatives, entry and innovation are possible: in these circumstances profits will influence the behaviour of firms and thereby dynamic efficiency. We note that it is for the reason of dynamic efficiency that contract law does not to our knowledge discriminate between firms on the basis of ownership, or take the static view of efficiency in contract cases.

As described elsewhere in this report, we consider that joint marketing has the effect of enhancing competition in the New Zealand gas market. Also, and again as described elsewhere, there is open entry and exit into gas exploration and production, and alternative fuels, about all of which there is considerable uncertainty. On this basis any profits will not be of the monopoly or functionless rent variety and there should be no discrimination between firms on the basis of their foreign or domestic ownership.

At paragraph 447 the Commission concludes that the transfers that would occur would be between entities that have roughly the same percentage of foreign ownership and thus can be treated as if between members of the New Zealand public and ignored. This is a static analysis that ignores effects of such ownership on the quantification of other aspects of the efficiency calculation and on downstream domestic markets affected by gas, e.g., electricity. We reaffirm that we consider there is no reason to consider discrimination against foreign firms in this case.

4.5. Assessment of Benefits

4.5.1. Commission's Adoption of CRA Model

Despite making various criticisms of our quantification model, we note that the Commission does use that model, implying that the Commission considers it to be appropriate.

---

40 Baumol W J (2002) *The free Market Innovation Machine: Analysing the Growth Miracle of Capitalism*, Princeton University Press.

We have obtained from the Commission the full set of data and assumptions it used for its modelling, and we have attempted to replicate the Commission's results. The supply data from the Commission was that published in the draft determination; no commercially sensitive data was used in this analysis.

The Commission's estimates were successfully replicated to a reasonable approximation, with deviations from the Commission's results being small enough to suggest that these deviations were caused by rounding of the commercially sensitive data.

The successful replication of the Commission's results suggests that the Commission has correctly used the CRA model (CRA is not privy to details of the Commission's work because of confidentiality concerns). However, having verified the plausibility of results, questions about the reasonableness of the Commission's assumptions remain.

4.5.2. The Commission's Assumptions

The Commission uses a number of alternative assumptions and inputs for its modelling to those originally used by us. While we have reservations about some of these, we restrict our comments here to what we consider to be the two key alternatives, described in Table 1.

Table 1: Key Commission and CRA assumptions compared

Assumption	Commission Assumptions	CRA Assumptions
Period of Analysis	2006-2020	2004-2009
Counterfactual Delay	1 year	3 years

We discuss the period of analysis below.

Given our understanding of the issues to be negotiated and the incentives operating on the parties, we consider a one-year delay to be implausible. We understand that this issue is being addressed in a separate submission to the Commission.

The Commission estimates total welfare under two industry extraction profiles:

- **MED "new fields"** assumed profile;[41] and

41 This profile is described on page 116 of the draft determination.

- **MED 175PJs assumption**. This is the same profile as that in "new fields" up to 2009, after which total gas production increases to a constant 175PJs per annum, with the additional gas assumed to be developed from yet-to-be discovered gas fields.

Note that under each of these scenarios Pohokura output is the same, but output from competing fields is changed. The costs of delay are different under each scenario because surplus is a function of both Pohokura and industry output.

4.5.3. Commission Results

Under these assumptions, the Commission estimates the following welfare losses from a one-year delay in the development of Pohokura.

Table 2: Commission Losses From a One-Year Delay in Development of Pohokura

	Gas Plus Condensate	Condensate Only	Gas Only[42]
New Fields Assumption	\$22.9m[43]	\$45.4m	-\$22.5m
175 PJs Assumption	\$57.0m	\$45.4m	\$11.6m

Under the gas profile labelled New Fields, the Commission estimates a negative welfare loss for gas, i.e., a benefit to delay. Under the higher production scenario, a delay of Pohokura produces a loss.

4.5.4. Interpretation

The Commission estimates a benefit from delaying production of gas under one of its two production scenarios. Benefits arise from delay because the value of additional gas available in later years (brought about by a delayed start to production) raises total surplus by enough to overcome the welfare lost from foregone consumption at the start of the field's life. Note that in order to produce a negative loss, the benefits of delay, which only start to arrive in years 8 of 14, must be so large as to overcome the substantial effect of discounting. The effect of discounting is disproportionately large on benefits of delay, which arrive well after the costs of delay.[44]

---

42 The cost of delayed gas production is calculated as the cost of delayed gas and condensate less the cost of delayed condensate production.

43 The figure in the draft determination is incorrectly rounded. The precise estimate under the Commission's assumptions is \$22,881,405.

44 The value of a benefit received fifteen years from now at 10% cost of capital has 80% of its value eliminated by discounting.

The interpretation of a negative loss of a one-year delay is that society would be better off leaving the gas in the ground and delaying the development of Pohokura. In other words, the result derived from the Commission's set of assumptions suggests that having additional gas available from 2013 onwards will be so valuable as to justify foregoing consumption now. This is a perverse outcome given the dry year risk and the Government's clear concern regarding an early start to Pohokura production (see the section 26 statement).

While such a scenario may be possible, it is not in our view a natural one to choose. It may be that there is a mismatch between model results and a qualitative assessment resulting from an attempt to predict demand and supply conditions, and accordingly welfare, so far out into the future utilising trends. Rather, we believe that it is more appropriate to treat welfare post-2009 as stationary, as described above.

4.5.5. Liquids

Introduction

In the draft determination, the Commission estimates the cost of delaying the introduction of condensate extracted from Pohokura by one year.[45] This cost is in addition to the cost of the delayed introduction of gas from the field. The Commission's estimates are set out in Table 2.

The Commission tested the losses from two gas extraction profiles, and to each estimate of gas losses added a constant for the cost of delayed condensate production.[46]

We have obtained an expected profile of condensate and LPG production from the joint venture and have estimated, using a similar methodology to that employed by the Commission, the cost of a delay in the production of both condensate and LPG from Pohokura.[47]

Methodology

As discussed in section 4.2, the key assumption of this analysis is *stationarity*, meaning that the starting date for production will not systematically change the annual welfare produced by the field one way or another. Once production has started, stationarity means the starting date has no effect on the extraction profile, revenues received and costs incurred.

---

45 The Commission did not produce an estimate of the cost of delayed LPG production.

46 The gas profile and details of the cashflow analysis are contained in the Appendix.

47 We are informed by the joint venture parties that in addition to LPG and condensate, other valuable products are also expected to be extracted from Pohokura (e.g., naphtha). If this is the case, then the cost of delay will be increased further. However, in this analysis we ignore this other production.

As noted in section 4.2, the formula for calculating the benefits of joint marketing under the stationarity assumption is:

$$Joint\ Marketing\ Benefit = \left[1 - \frac{1}{(1+r)^n}\right] NPVW(t,t)$$

where we are ignoring the real option for delay.[48] The equation above is the basis of this analysis. The analysis follows each of these steps:

1. Estimate the NPV of the non-delayed liquids;[49]

2. Discount the value of the field for each of *n* periods of delay; and

3. The cost of delay for *n* periods is the difference in field value with and without delay

We estimate the cost of delay of between 1 and 5 years.

Assumptions on Liquids Values

The variable assumptions made in this analysis are shown in Table 3. The quantity profiles used are commercially sensitive to the Pohokura joint venture parties, but can be made available to the Commission on a confidential basis.

48 In these calculations we are ignoring the real option for delay which, when the ability to finalise sale contracts is in place, we assume for this analysis will be unaffected by the impediments and associated delays in ability to write these contracts.

49 For this analysis we have not attempted to estimate demand curves. Rather, we use the difference between price and marginal cost as a proxy for welfare.

Table 3: Pohokura Liquids Assumptions

Assumption	CRA Value	Commission Value[50]
Discount Rate	10%	10%
Variable Costs as Percentage of Revenue	20%[51]	17%[52]
Fixed Costs	$0[53]	$0
Condensate Price ($US/bbl)	US$26.00[54]	US$17.175
LPG Price ($US/tonne)	US$241.50[55]	-
$US:$NZ Exchange	0.5803[56]	0.5803[57]

The results under each set of assumptions are shown in Table 4. Given the overall similarity of the respective profiles, the discrepancy between Commission and CRA estimates of loss largely result from differences in revenue and cost assumptions.

50 The Commission analysis is carried out for condensate only.

51 Assumed value.

52 The Commission assumes that only 5/6 of field gas is extractable. This translates, in effect, to a variable costs equivalent to 1-5/6 = 1/6 or 17%.

53 Assumed value. We received no information on incremental fixed costs from the joint venture parties. Accordingly, our results will tend to overstate welfare. On the other hand, our analysis excludes option values, which means that our results will tend to understate welfare.

54 Price for Tapis condensate; supplied by Todd Energy.

55 Unweighted average price of propane and butane in June 2003.
Source: http://www.alpga.asn.au/infonet/pricing.asp

56 Source: www.rbnz.govt.nz, 3 June 2003.

57 The Commission's figures quoted to us were in New Zealand dollars. This price was converted back to $US at the rate of 0.5803.

Table 4: Condensate Present Value under CRA and Commission Assumptions

Total Field Value	CRA Assumptions	Commission Assumptions
Present Value	$687,531,944	$499,222,960
Cost of 1 Year Delay	$62,502,904	$45,383,905

CRA Condensate and LPG Results

The present value of the liquids contained in Pohokura under CRA assumptions are shown in Table 5.

Table 5: Present Value of Pohokura Liquids

Total Field Value	Condensate	LPG
Present Value with No Delay	$687,531,944	$263,794,926

Using the equation described above, the cost of delay for various values of n is set out in Table 6.

Table 6: Estimated Cost of Delayed Introduction of Pohokura Liquids

Total Field Value	Condensate	LPG
Present Value with No Delay	$0	$0
1 year delay	$62,502,904	$23,981,357
2 year delay	$119,323,726	$45,782,591
3 year delay	$170,979,018	$65,601,894
4 year delay	$217,938,375	$83,619,442
5 year delay	$260,628,700	$99,999,032

4.5.6. Total Benefits From Earlier Production

As discussed above, we consider that the Commission has considerably underestimated the benefits arising from the earlier production implied by joint marketing for three reasons:

- The Commission has assumed that separate marketing would only lead to a one-year delay in production, which we consider to be implausible. In our view, a three-year delay is a more appropriate assumption to make for modelling purposes;

- Assuming the one-year delay, the Commission has attempted to predict the extra surplus from Pohokura at the end of field life in order to offset this against the earlier loss. We believe that it is more appropriate to treat welfare past 2009 as stationary and that we can ignore the benefits of the run-off of the field in its final three years under separate marketing (for the reasons more fully described in section 4.3.3); and

- The Commission has limited its analysis of liquids to condensate and has not attempted to estimate the losses arising from delayed LPG production.

We have re-estimated the benefits of early production of gas, condensate and LPG using all available Commission assumptions (including those for condensate) with the following changes:

- Three year delay i.e. instead of production commencing in 2006, it commences 2009;

- Gas stationary economic environment post-2009; and

- Additional LPG analysis.

We estimate the following benefits of early production of these products.

Table 7: Results under Adjusted Commission Assumptions[58]

	PV Cost of Delay – Commission Estimate	PV Cost of Delay – CRA Estimate
Gas	-\$22.5m to \$11.6m	\$168.8m[59]
Condensate	\$45.3m	\$124.1m[60]
LPG	-	\$68.3m[61]
Total	**\$22.9m – \$57.0m**	**\$361.2m**

The increased cost of delayed gas production stems from both the longer delay and the assumed lack of systematic benefits post 2009 (i.e. production is stationary and we ignore the final three years). The increased condensate benefits are entirely due to the increased delay in production (since we assume identical price and supply).

4.6. Exploration Incentives

The Commission dismisses the argument that a decision to enforce separate marketing would result in less exploration and investment in the future, essentially because it claims that Pohokura is a special case, because of the existing market power. We have also noted that the same issues will arise in most joint venture cases, and that case-by-case differentiation in the treatment of joint venture contracts will itself affect interest in New Zealand exploration

We have already noted that the existing level of market power is irrelevant – what matters is whether or not the arrangement would substantially lessen competition.

We have also already noted that because separate marketing increases risk and decreases field value, it *must* also reduce entry incentives. To put this in another way, any form of regulatory compulsion must reduce producer surplus, and therefore incentives for entry.

---

58 Both Commission and CRA present values calculated using a 10 percent discount rate.

59 Since the CRA assumptions limit analysis to 2009, and the Commission's alternative gas production profiles are different only from 2010 onwards, the cost of delay is the same under both scenarios for the CRA estimate.

60 This estimated cost of a three-year delay differs from that in Table 6 because the Table 7 estimate uses the Commission's assumptions about the condensate production profile, variable costs and price.

61 This estimated cost of a three-year delay differs from that in Table 6 because the Table 7 estimate uses the Commission's condensate variable cost assumption. In Table 7, the Commission's assumption that variable costs comprise 16.6 percent of gross revenues is used. In Table 6, the assumed value for variable costs, made by CRA, is 20 percent of gross revenues.

The increased risk and decreased field value consequent upon separate marketing is particularly significant for participation in the industry by relatively small firms on whom the vibrancy of the New Zealand market will depend. As we noted earlier in this report, the small New Zealand market and non-tradability of gas must affect the interest of large multinational firms in gas exploration here.

5. PROPOSED CONDITIONS

The Commission proposes to authorise joint marketing from the Pohokura field, subject to four conditions. We comment on those conditions below.

5.1. AUTHORISATION FOR A FINITE PERIOD

The Commission proposes to limit the time period for the authorisation to five years from the date of first production. This proposal raises two issues that we consider next. We conclude that a five-year term does not solve any of the issues relating to the effect of separate marketing.

First we note that the limited authorisation carries the presumption that, depending upon the market circumstance, the Commission or the courts may well undo a gas contract after this date. This affects contracting today, because there can be no surety that a contract written today for a period longer than the authorisation period would stand a challenge utilising competition law. Indeed, because the Commission has specified a short authorisation termination date there is a presumption that a challenge from any party would stand a good chance of a receptive hearing.

5.1.1. Length of Contract

The first issue relates to the recovery of sunk costs.

In our view, long-term gas contracts are generally efficient in New Zealand, given the:

- Lack of a gas spot market; and
- Amount of sunk capital required for both supply-side and demand-side development.

As we have explained, investment in development of a gas field is an example of a *specific asset*. A specific asset is one that is most valuable in one specific setting or relationship. The owner of such an asset is subject to the risk of being *held-up* by another party. For example, after the owner of a gas field has sunk its development investment, a purchaser of gas could refuse to pay the initially agreed price and, depending on the market circumstances, exploit the owner's sunk costs. The risk of such behaviour may result in the field owner refusing to make the investment at the outset.

In the absence of a spot market, the solution to this problem is either a long-term contract or vertical integration, prior to expenditure. While a spot market may, of itself, enable investment, it will generally be a complement to long-term contracts.

It is important to note that it may not only be the field owner who is subject to the risk of *ex post* opportunism or hold-up; the purchaser of gas could equally be held-up by the field owner. For example, a gas-fired electricity generation plant is a specific asset. Accordingly, the demand side of the gas production market may also require a long-term contract if investment is to proceed in a dynamically efficient way.

Furthermore, a purchaser of gas would have an interest in the management of the gas field, for security of supply reasons, even if there were no opportunism by the supplier. For example, a purchaser would be concerned about risks relating to the common pool problem and over-extraction incentives leading to early depletion.

Finally we note that even in the absence of hold up, long-term contracts serve a vital function. Commodity prices are noted for their variability: indeed such is their unpredictability that the risk must be hedged when large irreversible investments are contemplated. Thus even in the presence of a spot market there is a place for long-term contracts to provide the revenue surety that enables investment in substantial sunk assets. Without the hedge provided by such a contract a company will not have matched its long-term liabilities commitment to a long-term commitment to a stable revenue stream and will be very vulnerable to runs of low prices. It is not commercially reasonable to invest without such surety: even for very large companies when the amount of investment is large.

To justify investment, the gas sales contract (or contracts) needs to be long enough to provide the investors (on both sides of the market) with an expectation that they will recover their capital and operating expenditure, and earn a risk-adjusted return on that capital. The "optimal" length for a contract depends on many factors, including:

- Characteristics of demand;
- Any institutional factor affecting the credibility of the contract: as we argue, examples include the conditions proposed by the Commission, e.g., the 5-year authorisation and restricting the authorisation to existing joint venture parties;
- The other terms of the contract, for example, whether there is a take-or-pay or equivalent clause;
- The durability and irreversibility of the demand- and supply-side assets required to perform the contractual obligations;
- The specificity of those assets; and
- The risks facing each party.

It is not possible to accurately identify a particular length of contract as being "optimal", in the sense of achieving the "perfect" balance between dynamic efficiency incentives and competition concerns. However, the following factors suggest that the 5-year timeframe for Pohokura gas proposed by the Commission is quite insufficient:

- We understand that modelling by one of the Pohokura joint venture parties indicates that a 15-year contract would be the preference for a developer of a gas-fired generation plant; the modelling indicates that 10 years would not be long enough;

- We have been advised by the project finance arm of a major Australasian bank that if there is any uncertainty in relation to the quantity of gas available to a generator at commercial prices over the debt term (as the bank believes there is in New Zealand), then banks will generally require a gas contract that is longer than the debt term (i.e., a "tail") when lending to the generator. For example, a 15-year fully amortising project financing of a gas generator might require a 20-year gas feedstock contract;[62]

- In *Re: AGL Cooper Basin Natural Gas Supply Arrangements*,[63] the Australian Competition Tribunal found that it was not possible to conclude whether an initial term of 30 years was excessive;

- In *Mereenie Producers – Gasco Sales Agreement*,[64] the ACCC authorised a 10-year contract. However, it is important to note that the authorised contract built upon two previous gas sales contracts (with terms of 25 and 15 years). While the new contract required additional investment, it appears that some of the initial investment costs had already been recovered under the first two contracts; the rationale for this illustrates our argument; and

62 We are advised that the exact requirements of project finance lenders in relation to the tenure of gas feedstock contracts will depend on many things, such as gas availability, forecast gas price fluctuations, sensitivity to gas prices, the shareholder(s), the off-taker, the industry, the asset, the country, the gearing level, the amortisation profile, and the coverage ratios. If there was a high level of certainty about gas being available, and it was more an issue of price rather than volume, banks could look to lend on the basis of there being no "tail". We are advised that there are actually examples of deals being done where the tenure of the gas contract is shorter than the tenure of the project financing - these deals will have specific characteristics that enable acceptance of a shorter tenure gas contract, such as short tenure debt, high levels of cash sharing, low gearing/high coverage ratios, unlimited gas availability, and forecast gas price variances being in a limited band. Another way to shorten the required tail is to have a significant portion or all the debt maturing prior to full repayment.

63 (1997) ATPR ¶41-593.

64 7 April 1999.

- In the *Kapuni* case,[65] the High Court determined that the initial term of the Kapuni gas sales contract ended in 1996, after commencing in 1967. While the Court found the contract to breach section 27 of the Commerce Act, it made the following statements:

  In the US, [long-term] contracts are often, as seen above, approved by the FTC based on efficiency arguments and by applying the "rule of reason". In Australia and New Zealand they can be authorised. We would expect any such authorisation to be for a fixed period, long enough to allow recovery of the capital investment, a return on that investment, and to maintain an acceptable level of exploration … Had we been asked in 1986, to authorise the agreement, with the benefit of hindsight, on a mixture of competition and public benefit grounds, we might then have been persuaded to let the contract run on to 1991 or even 1996. We should state for the record that, as at present informed, we should not be minded, if we were asked, to authorise it beyond 1996, but we emphasise that no such application is before us. (Page 532)

5.1.2. Feasibility of Separate Marketing from Pohokura in the Future

The Commission's proposal also raises the issue as to whether it would be easier to separately market gas from Pohokura at a point in the future when development costs have been recovered (or at least significantly recovered).

As set out in our original report, there are four factors that make separate marketing of gas from the Pohokura field extremely difficult, if not impossible.

1. The high level of uncertainty.
2. The very large sunk costs.
3. The common pool problem.
4. The lack of a liquid spot market.

The first three factors combine to imply scope for post-contractual opportunism, and produce inordinate coordination difficulties. This coordination problem is exacerbated by the unanimity rule of decision-making (for relevant decisions) and the lack of a liquid spot market.

65 *Shell v Kapuni Gas Contracts* (1997) 7 TCLR 463.

Once the point in time has been reached where development costs have been recovered (or at least significantly recovered), we would expect that the level of reserves uncertainty would also have been reduced (although the recent Maui experience illustrates how material this uncertainty can be even in a "mature" field).[66] Accordingly, we would expect separate marketing to be easier to coordinate at that point in time. Nevertheless:

- The level of uncertainty would still be material;
- The transactions costs would still be high;
- The common pool incentives would still exist; and
- We doubt that New Zealand will have a spot market of the requisite depth in the foreseeable future (for the reasons set out in section 5.2 of our original report).

Furthermore, the prospect of separate marketing at a future point against the market characteristics remaining then (i.e., uncertainty, common pool incentives and lack of a deep spot market) would require the joint venture parties to negotiate the required intra-joint venture governance arrangements (e.g., a balancing agreement) *prior* to development of the field. This would undermine, even eliminate, the earlier development advantages of joint marketing.

5.1.3. Conclusion on Proposal to Limit Authorisation Period

It is most unlikely that a five-year contract would be sufficient to underwrite the massive investment required to produce from the Pohokura field, or the investment required to build a gas-fired power plant. Any longer-term contract would be subject to the risk of attack under the Commerce Act once the five years is up. This must raise serious doubts about whether any seller or buyer (e.g., an electricity generator) would enter into such a contract, or whether a bank would lend on the basis of it. Accordingly, it is unlikely that granting authorisation subject to the five-year condition would "allow the development of the Pohokura field … to proceed as planned" (paragraph 510 of the draft determination). This would of course have significant negative implications for the value of the field, and exploration incentives more generally.

66 The level of uncertainty would reduce in the sense that the standard deviation would become a smaller number. However, compared to the now smaller mean, the level of uncertainty may actually rise as the field depletes. To put this in another way, the coefficient of variation (i.e., the standard deviation divided by the mean) may actually rise as the field depletes.

Even if the authorisation period was extended out to a period long enough to underwrite the investments, the prospect of separate marketing at that point against the market characteristics remaining then (i.e., uncertainty, common pool incentives and lack of a deep spot market) would require the joint venture parties to negotiate the required intra-joint venture governance arrangements (e.g., a balancing agreement) *prior* to development of the field. This would prospectively limit the length of contracts that could be offered and more generally undermine the characteristics of joint marketing that produce earlier development.

5.2. Requirement for Pohokura to be Developed by Certain Time

The Commission proposes to impose as a condition of the authorisation a requirement that production commence by February 2006.

We understand that the Pohokura operator's current timetable provides for a February 2006 commencement date. However, this date is subject to significant and numerous risks that are well beyond the control of the Pohokura joint venture parties. For example, an article in The Daily News of 28 May 2003 reported that an environmental activist has "succeeded in forcing a potentially prolonged court hearing over resource consents for the proposed $900 million project". A comprehensive list of such risks is set out in the joint venture parties' submission to the Commission.

Furthermore, it is not just the joint venture parties who face these risks; any requirement to force commencement by February 2006 would also impose risk on a buyer under a long-term contract, i.e., the buyer would face the risk that its contract would not be safe from attack under the Commerce Act. In these circumstances, it is unlikely that a buyer would enter into a contract, and accordingly development would not occur.

Once marketing contracts are in place the joint venture's options to delay have been extinguished and it has every incentive to develop the field rapidly in accordance with the contracts. To have a risky threshold which if not met rescinds the ability to jointly market (and thereby rescinds the contracts with reasonable probability), creates the same environment as separate marketing even before gas contracts are agreed and hence before the investment decision.

5.3. Assignment of Authorisation to Successors

The Commission proposes to restrict the authorisation to the existing Pohokura joint venture parties.

For reasons similar to those outlined above, this restriction would have significant efficiency costs. In particular, any assignment of a joint venture party's interest in Pohokura would put the field's long-term contracts at risk of a Commerce Act attack. This constraint on transferability would reduce the value of the contracts to the Pohokura joint venture parties and to the providers of (debt or equity) finance for the development of the field. The outcome would be to limit the availability of funds for the development of Pohokura in conjunction with enhancing the transaction cost issues analogously to those of separate marketing.

The Commission's rationale for this proposed condition is (paragraph 516):

> *...protect against the risk of common ownership between competing projects and the subsequent increased information flow between these projects.*

It is not clear to us why section 47 of the Commerce Act does not deal with this concern.

5.4. Ring-Fenced Marketing

The stated aim of the Commission's proposal to require ring fencing is, "to ensure that gas from the Pohokura field is marketed in competition from gas from other fields" (paragraph 518).

If this is the Commission's objective, then a ring-fencing requirement is unnecessary and inefficient. We first note that contracts for the sale of gas under joint marketing will be with the joint venture, and not individual parties. It is the effect of joint marketing to take gas that, were separate marketing feasible, if separately marketed would potentially be marketed with other fields, and ensure that it is marketed through another entity. Given the disparate interests and the tensions that we have explained exist within a joint venture there is no reason to expect co-ordination with other suppliers, and certainly the likelihood of coordination is vastly lower than it is under the counterfactual of separate marketing.

We emphasise again that joint marketing (by itself, i.e., without ring-fencing) is actually pro-competitive, for the following reasons:

- Under separate marketing, gas tranches offered may be in conjunction with gas from other fields with common ownership, whereas joint marketing introduces a separate entity (in which the players have conflicting interests and incentives). (Ironically, it would actually be easier to make a case for ring fencing under separate marketing than under joint marketing.); and
- Because separate marketing increases risk and decreases field value, it *must* also reduce entry incentives. Accordingly, it is actually separate marketing that would retard the development of a more competitive gas production market.

Finally we emphasise that gas contracts should be in place for a large proportion of Pohokura gas before any investment takes place. Such large investment will require the approval of the boards of the companies in all cases and they will not have the information to do this if the managers of the projects are ring-fenced into the joint venture. Once these long-term contracts are in place the major decisions have been taken and ring fencing the partners' Pohokura managers would only insert unnecessary principal agent problems in ongoing management of the fields and the companies.

APPENDIX A: FURTHER QUANTIFICATION

A.1 INTRODUCTION

Since our original report, several events have occurred that mean there is value in altering our original modelling. In particular:

- The results of the Maui re-determination have been announced;[67]
- Hydro lake in-flows have been low again in 2003, highlighting fuel concerns for electricity generation in New Zealand. Furthermore, the low lake levels have resulted in greater Maui off take than was originally expected, leaving less to be extracted in the future;
- Demand for electricity appears to have grown faster than expected; and
- The demand for gas at present is high in part because the price of methanol is high.

Beyond 2003, Maui declines rapidly, and each year it will be increasingly difficult for Maui to provide the shortfall of energy required in a dry year. This issue becomes even more accentuated from 2005/6, when even in a normal year supply will be at risk. Therefore a delay of Pohokura beyond 2006 will almost certainly place at risk the supply of gas to meet energy requirements. The severe impact of this on the economy has presumably prompted the Minister to issue his Section 26 statement.

67 In the JV gas profile, assumed production from Maui includes gas supplied from Ihi. The JV parties have indicated that Ihi has not been developed and will only be developed if the Crown will deal at a price that significantly exceeds the Maui price. The decision to include Ihi in the Maui production profile increases alternative sources of gas, which systematically lowers the welfare losses of separate marketing, and is therefore conservative.

Regarding the fuel concerns, in our original report we analysed coal as a substitute for gas. Recent events have raised the profile of diesel as another substitute, and so we consider it appropriate to analyse this. While diesel is more expensive than coal, diesel-fired generation can be brought on-line more quickly than coal-fired generation. The joint venture parties have received advice that it is likely to take between five and six years to develop a new coal-fired plant, including site identification and resource consent time.[68] In contrast, the parties have received advice that certain existing gas-fired plants (e.g., Otahuhu B) can run on diesel almost as efficiently as gas (although some new infrastructure may be required, e.g., storage facilities). Also, Contact Energy has announced that it is restoring dual-fuel capability to the New Plymouth Power Station, in order to deal with possible gas shortages. In light of these events, we have altered our model in the following ways.

Supply Side

In our original analysis, we assumed coal would be a substitute for gas in the period of analysis, and therefore capped the price of gas and gas substitutes at the price (after accounting for relative efficiency losses) of coal at NZ$8.00/GJ. However, if it takes more than five years for a coal-fired plant to be up and running, then the role of coal as a substitute for gas within the period of our welfare analysis (2006 to 2009) will be limited. Rather, the effective gas price cap that we used in our original analysis should be set by higher-cost diesel.

We assume the following alternative fuel price caps.

Table 8: Alternative Fuel Price Caps

Year	Price Cap
2006	$11.70/GJ
2007	$11.70/GJ
2008	$11.70/GJ
2009	$8.00/GJ

68 On page 4 of the Proceedings of IJPGC 98: International Joint Power Generation Conference and Exhibition 24-26 August 1998, Baltimore, MD, the average time construction of coal-fired generation is listed as 5.6 years. Decision-making, resource consents and the negotiation of long term contracts will all be additional to this time.

As noted above, the joint venture parties have received advice that certain gas-fired plants can also operate on diesel, with very little loss in efficiency. This is supported by the following statement by East Harbour Management in its 2002 report for the Ministry of Economic Development (pages 1 and 2):[69]

> *Natural gas firing gives a slightly higher output than distillate firing by about 2% for a given gas turbine. The efficiency is also slightly higher by about 4% when burning gas, i.e. multiply the efficiency given in the text for gas firing by 0.96 to obtain the efficiency when firing distillate.*

We are advised that distillate is chemically very similar to diesel.

The joint venture parties commissioned Ian Twomey of Hale & Twomey Limited to estimate the effective price of diesel per GJ, taking into account transport and extra infrastructure costs (but not electricity conversion efficiency). Depending on the location of the power station, this price varies between $11.45 and $12.03 per GJ[70]. Accordingly, in our model we replace the effective price cap set by coal at $8.00 per GJ with an effective price cap set by diesel at $11.70 per GJ. Modelling is done under two gas profiles, provided to CRA by the joint venture parties and by the Commission. These profiles are similar; the joint venture profile is most distinguishable from the Commission profile by the more aggressive depletion of Maui. Under both profiles, non-delayed production from Pohokura commences in 2006, and the gas production profile for Pohokura is the same under both profiles.

Demand Side

In our original analysis, we assumed that the demand curve shifted by 2 percent per year. Meridian has recently produced estimates of the sources of new supply for electricity.[71] These estimates imply increasing demand for gas in the order of 4% per annum.[72] We (separately) test the welfare impact of a delay in Pohokura when demand for gas is increasing at 4% per year.

---

69 East Harbour Management Services Ltd (2002) "Costs of Fossil Fuel Generating Plant", Report to the Ministry of Economic Development.

70 We understand that the New Plymouth power station is designed to run on bunker C fuel oil, which is cheaper (approximately $7-$8/GJ). Situations like these suggest that our original assumption that generators are willing to pay $4.50/GJ is conservative. Therefore, our estimated benefits from joint marketing are likely to be understated.

71 See http://www.projectaqua.co.nz/why+nz+needs+more+power/default.htm.

72 Demand for all electricity is expected by Meridian (and the MED, in the Energy Outlook) to increase at approximately 2% per annum into the near future. Since a disproportionately large share of the increase in total energy consumed is expected to come from gas, the calculated increase in gas demand outstrips that for total demand.

The Commission has assumed a one-year delay in its modelling, whereas we assumed a three-year delay in our original analysis. This alternative timeframe has implications for the elasticity of the demand curve. In particular, if market participants believe that a one-year delay is the likely outcome, then they are less likely to alter their behaviour than if they expect a three-year delay. Accordingly, the one-year delay demand curve would be more inelastic than the annual demand curve used under a three-year delay analysis.

Dry Year

As we noted in our original report, our analysis was conservative for several reasons, one of which was that we assumed a normal hydro year. We can estimate the welfare losses arising from the combination of a delay in production from Pohokura and a dry year by shifting the demand curve in our model. To be more particular:

- Concept Consulting Group have reviewed inflows for the last 15 years and found that in the driest of those years production of electricity from hydro sources was approximately 3,100 GWh lower than the mean. This is equivalent to 11.2 PJs of electricity, or:
    - 31 PJs of gas at Huntly; or
    - 22 PJs of gas through a combined cycle plant;
- We accordingly model a dry year by shifting the demand curve in our model to the right by 26.5 PJs (i.e. a simple average of 31 PJs and 22 PJs). This of course assumes that the hydro shortfall is picked up entirely by gas-fired generation where possible.

A.2 TESTING

In this section, the estimated welfare impact of delayed Pohokura development is calculated under the following scenarios:

- Delay of only one year;
- A "dry" year; and
- Increased demand for gas.

Each scenario is tested under two Maui gas profiles, provided by the Commission and by the joint venture parties.[73]

[73] The Commission profile used is that labelled by the Commission as the "New Fields" gas production profiles.

In testing each scenario, a baseline scenario is established. Testing of each scenario occurs by changing one or two variables from the baseline; all other variables are left unchanged. This baseline is summarised in Table 9.

Table 9: Baseline Assumptions for Gas Modelling Variables

Variables	Baseline Value
Demand Growth	0%
Demand Step	50 PJ
Year of Demand Step	2007
Demand Elasticity	-0.50
Initial Demand Price	$4.50/GJ
Initial Position of Demand	101.36 PJ
Methanex Reserve Price[74]	$4.50/GJ
Methanex Gas Consumption	98.0 PJ
JV Gas Profile Delay	3 years
Commission Gas Profile Assumed Delay	3 years
Alternative Fuel Price	NZ$11.70[75]
Dry Year	No Dry Year
Stationarity	Post-2009

Under these default settings, the estimated welfare losses are:

Table 10: Baseline Scenario Results – Gas Only

Gas Profile	PV of Cost of Three Year Delay
JV Gas Profile	$221.4m
Commission Gas Profile	$170.0m

The increased cost of delay under the JV profile occurs because of Maui's higher rate of depletion prior to 2006. These higher JV-profile losses are consistent features of all the scenarios tested.

The total estimated cost of delay, including the cost of delayed liquids production, is shown in Table 11.

74 Methanex is assumed to exit the market entirely above this price.

75 Except for 2009, when it is $8.

Table 11: Three-Year Delay Costs under Baseline Scenario – All Fuels

All Fuels Profile	PV of Cost of Three Year Delay
Gas	$170.0m to $221.4m
Condensate	$124.1m
LPG	$68.3m
Total	**$362.4m to $413.8m**

A.2.1 One Year Delay

In testing welfare losses under a single year delay, we intend to assess the reasonableness of the Commission's estimated welfare loss. We adopt the Commission's assumption of a relatively short delay (one year) in Pohokura's development under separate marketing. Apart from reducing the baseline three-year delay to one, we also reduce demand elasticity from -0.5 to -0.2.

The assumption of a smaller elasticity under a single year delay is made because shorter delays reduce the scale of efficient changes in consumption, and makes "sitting out" the delay more worthwhile. Longer delays, it is assumed, increases the flexibility of gas consumers to react to anticipated supply reductions.

Results

Table 12: One-Year Cost of Delay – Gas Only[76]

Gas Profile	PV of Cost of One Year Delay
JV Gas Profile	$36.6m
Commission Gas Profile	$52.0m

Including the cost of delayed liquids production, the total estimated cost of a one-year delay is shown in Table 13.

76 The values expressed in this table and Table 13 are the present value of total welfare losses over the period 2006-2009 stemming from a one-year delay.

Table 13: One-Year Cost of Delay – All Fuels

Gas Profile	PV of Cost of One Year Delay
Gas	$36.6m to $52.0m
Condensate	$45.4m
LPG	$25.0m
Total	**$107.0m to $122.4m**

This analysis suggests even a single year delay in the development of Pohokura is likely to cause substantial welfare losses, considerably larger than those estimated by the Commission. The main cause of this larger loss from that estimated by the Commission is:

1. The addition of LPG to the estimated loss; and

2. Less elastic demand for gas by generators.

The higher alternative fuel price does not change the cost of delay, since under a one-year delay the model predicts demand will not be sufficient to induce consumption of an alternative fuel, even with a delay.

A.2.2 Dry Years in 2006-2009

A delay in the development of Pohokura may coincide with a dry year i.e. low rainfall in the catchment areas of hydro generation. The effect of a dry year will be to raise the demand for substitutes of hydroelectric generation, including gas.[77]

The effect of a dry year is simulated in the welfare model by shifting the demand curve for gas by generators in the dry year outwards. The question of the magnitude of the shift has been addressed by Concept Consulting Group (see above).

[77] Even if a dry year does not coincide with a year of Pohokura delay, the possibility of the two combining raises risk management costs.

Since the occurrence of a dry year is not forecastable and its occurrence is generally only identified shortly before price increases and restrictions apply, it is likely that the demand response will be constrained. That is, demand will be relatively inelastic during the short dry period. For this reason we assume, for the dry year only, that the elasticity of demand reduces from -0.5 to -0.2.[78]

Results

The welfare effects of dry years are tested in each of the years between 2006 and 2009. The results of this testing are shown in Table 14. Where we estimate the total welfare loss with a dry year, a reduction in demand elasticity from -0.5 to -0.2 occurs in the dry year only.

Table 14: Total Cost of Delay for All Years with Varying Dry Years – JV Gas Profile – Gas Only

	Dry Year in 2006	Dry Year in 2007	Dry Year in 2008	Dry Year in 2009
PV of Cost of Three Year Delay with No Dry Year	$221.356m	$221.4m	$221.4m	$221.4m
PV of Cost of Three Year Delay with Dry Year– Reduced Elasticity in Dry Year	$221.364m[79]	$402.1m	$385.4m	$243.8m
PV of Cost of Three Year Delay with Dry Year– Unchanged Elasticity in Dry Year	$221.359m	$265.1m	$259.2m	$232.6m

Including the cost of delayed liquids production, the total estimated cost of delay is shown in Table 15.

78 CRA has surveyed 36 studies of short run elasticity of demand for electricity, in which there were a total of 117 elasticity estimates. The median estimate of short run elasticities from these studies is -0.25, and the mean is -0.33. The relatively short time period considered in this study – temporary interruptions caused by unforeseen dry years or 12 month delays – is the justification for our use of -0.2 and -0.1 elasticities in these circumstances.

79 In 2006, demand for gas is such that the extra demand implied by a dry year is nearly entirely met by gas given up by Methanex at its assumed reservation price.

Table 15: Combined Gas and Liquids Delay Costs with Dry Year and Reduced Elasticity – All Fuels

Gas Profile	PV of Cost of Three Year Delay with Dry Year
Gas	$221.4m to $402.1m
Condensate[80]	$124.1m
LPG	$68.3m
Total	**$413.8m to $594.5m**

If dry years were to occur in both 2007 and 2008, the estimated NPV welfare losses from delayed gas production is $566.2m.

Table 16: Single Year Losses With and Without Dry Year – JV Gas Profile – Gas Only[81]

	2006	2007	2008	2009
Without Dry Year	$21.2m	$135.2m	$156.3m	$28.3m
With Dry Year	$21.3m	$399.9m	$420.5m	$68.0m
% Change	+0%	+196%	+169%	+140%

A dry year in 2006 is expected to cause almost no additional costs over and above those caused by the delay of Pohokura gas. The reason is that Methanex is assumed to be capable of re-selling gas to higher-value consumers of gas, resulting in almost no efficiency loss. The above analysis assumes that, having purchased the gas at an equilibrium price of $4.00/GJ, Methanex will elect to re-sell the gas at its reservation price of $4.50/GJ and exit the market. However, this price may not sufficient to compensate Methanex for foregone revenues and options less avoided costs. In addition, Methanex will be aware of the gas shortage, and may elect to re-sell gas at the price of the next best alternative for generators, perhaps as high as the cost of the most widely available short run alternative fuel, diesel. We therefore re-test the effects of a dry year with Methanex electing to re-sell at $11.70.

80 We assume unchanged costs of delayed liquids production in a dry year.

81 Assumes reduced elasticity of demand from -0.5 to -0.2 for the JV gas profile.

Table 17: Total Cost of Delay for All Years with Varying Dry Years – JV Gas Profile – Gas Only – Methanex Reserve Price of $11.70

	Dry Year in 2006	Dry Year in 2007	Dry Year in 2008	Dry Year in 2009
PV of Cost of Three Year Delay with No Dry Year	$779.1m	$779.1m	$779.1m	$779.1m
PV of Cost of Three Year Delay with Dry Year– Reduced Elasticity in Dry Year	$865.5m	$789.9m	$784.5m	$ 779.1m

These figures should be compared with those in Table 14. Including the cost of delayed liquids production, the total estimated cost of delay is shown in Table 18.

Table 18: Combined Gas and Liquids Delay Costs with Dry Year and Reduced Elasticity – All Fuels – Methanex Reserve Price of $11.70

Gas Profile	PV of Cost of Three Year Delay with Dry Year
Gas	$779.1m to $865.5m
Condensate[82]	$124.1m
LPG	$68.3m
Total	**$971.5m to $1,057.9m**

These figures should be compared with those in Table 15.

Table 19: Single Year Losses With and Without Dry Year – JV Gas Profile – Gas Only – Methanex Reserve Price of $11.70[83]

	2006	2007	2008	2009
Without Dry Year	$212.2m	$442.4m	$449.5m	$68.0m
With Dry Year	$327.2m	$458.1m	$458.2m	$68.0m
% Change	+54%	+4%	+2%	-0%

These figures should be compared with those in Table 16.

82 We assume unchanged costs of delayed liquids production in a dry year.

83 Assumes reduced elasticity of demand from -0.5 to -0.2 for the JV gas profile.

A.2.3 Increased Demand Growth

There is some indication that the demand for gas will increase at a rate that exceeds the 2% annual growth assumed in the main analysis. Meridian has recently produced estimates of the sources of new supply for gas. These estimates imply increasing demand for gas in the order of 4%-6% per annum.[84] In this section we test the welfare impact of a delay in Pohokura when the demand for gas is growing at a rate of 4% per annum. These estimates are calculated assuming, as in the baseline scenario, a three-year delay in Pohokura development.

Results

The resulting total loss of welfare under each production profile is shown in Table 20.

Table 20: Three-Year Delay Costs with Demand Increasing at 4% pa – Gas Only

Gas Profile	Cost of Delay with Demand Growing at 4%
JV Gas Profile	\$283.7m
Commission Gas Profile	\$225.2m

The following total welfare reductions are estimated when the costs of delayed liquids production is added. We assume independent demand for liquids.

Table 21: Three-Year Delay Costs with Demand Increasing at 4% pa – All Fuels

Gas Profile	Cost of Delay with Demand Growing at 4%
Gas	\$225.2m to \$283.7m
Condensate[85]	\$124.1m
LPG	\$68.3m
Total	**\$417.6m to \$476.1m**

84 Demand for all energy is expected by Meridian (and the MED, in the Energy Outlook) to increase at approximately 2% per annum into the near future. Since a disproportionately large share of the increase in total energy consumed is expected to come from gas, the calculated increase in gas demand outstrips that for total demand.

85 We assume unchanged costs of delayed liquids production in a dry year.

A.2.4 Reduced Elasticity of Demand in Short Run

In the above one year delay and dry year scenarios, we assume a demand response of –0.2. This means that a 10% price increase will reduce the quantity demanded by 2%.

However, for periods as short as a year, the actual demand response may be more limited. We test the costs of a one year delay and dry years with a demand response of –0.1.

One Year Delay

Table 22: One-Year Cost of Delay – Gas Only – Demand Elasticity –0.1[86]

Gas Profile	PV of Cost of One Year Delay
JV Gas Profile	$51.3m
Commission Gas Profile	$82.3m

These figures should be compared with those in Table 12. Adding the cost of delayed liquids production, the total estimated cost of a one-year delay is shown in Table 23.

86 The values expressed in this table and Table 13 are the present value of total welfare losses over the period 2006-2009 stemming from a one-year delay.

Table 23: One-Year Cost of Delay – All Fuels – Demand Elasticity –0.1

Gas Profile	PV of Cost of One Year Delay
Gas	$51.3m to $82.3m
Condensate	$45.4m
LPG	$25.0m
Total	**$121.7m to $152.7m**

These figures should be compared with the figures in Table 13.

Dry Year

The welfare effects of dry years are tested in each of the years between 2006 and 2009. In the first tests of dry years, we assumed a reduction in elasticity of demand in those years to –0.2. Here, we test the effect of demand elasticity of –0.1. The results of this testing are shown in Table 24. Where we estimate the total welfare loss with a dry year, a reduction in demand elasticity from -0.5 to -0.1 occurs in the dry year only.

Table 24: Total Cost of Delay for All Years with Varying Dry Years – JV Gas Profile – Gas Only – Demand Elasticity –0.1[87]

	Dry Year in 2006	Dry Year in 2007	Dry Year in 2008	Dry Year in 2009
PV of Cost of Three Year Delay with No Dry Year	$221.356m	$221.4m	$221.4m	$221.4m
PV of Cost of Three Year Delay with Dry Year– Reduced Elasticity in Dry Year	$221.373m	$441.6m	$408.8m	$243.8m

These figures should be compared with the figures in Table 14. Including the cost of delayed liquids production, the total estimated cost of delay is shown in Table 25.

87 Methanex reserve price in this table is assumed to be $4.50.

Table 25: Combined Gas and Liquids Delay Costs with Dry Year and Reduced Elasticity – All Fuels – Demand Elasticity –0.1

Gas Profile	PV of Cost of Three Year Delay with Dry Year
Gas	$221.4m to $441.6m
Condensate[88]	$124.1m
LPG	$68.3m
Total	**$413.8m to $634.0m**

These figures should be compared with the figures in Table 15.

Table 26: Single Year Losses With and Without Dry Year – JV Gas Profile – Gas Only – Demand Elasticity –0.1

	2006	2007	2008	2009
Without Dry Year	$21.2m	$135.2m	$156.3m	$28.3m
With Dry Year	$21.3m	$457.7m	$458.1m	$68.0m
% Change	+0%	+238%	+193%	+140%

These figures should be compared with the figures in Table 16.

A.3 Summary

The losses estimated in the analysis contained in our first report were based on a set of very conservative assumptions. In this section, these conservative assumptions were updated to show that much more serious losses could occur in the event that one or more of the above scenarios eventuates over the period of 2006-9.

We built into our base case the assumption that the effective gas price cap for most of the period of our analysis will be set by diesel rather than coal, because:

- It is unlikely that new coal-fired generation could be built within that period; but
- Existing gas-fired plants could convert to diesel within that period.

88 We assume unchanged costs of delayed liquids production in a dry year.

The effect of this higher gas price cap was to increase the costs of delay.

We then modelled the impact on welfare of:

- A dry year – this produces benefits of joint marketing of between $414m and $595m; and
- A higher gas demand growth – this results in benefits of joint marketing of between $418m and $476m.

In addition, we tested the effect of a higher reserve price for Methanex, and further-reduced demand elasticity in the short run. These had the effect of increasing further the cost of one-year delays and delayed production in dry years. In the case of the higher Methanex reserve price, set to the price of diesel, combined losses from a three-year delay between 2006 and 2009 were estimated to exceed $1 billion. We also tested the effects of reducing the demand elasticity from -0.2 to -0.1 in dry years and under a one-year delay in Pohokura development under separate marketing. The increase in costs of delay are more modest under this reduced elasticity but significant.

The efficiency losses estimated here exceed half a billion dollars, which is a substantial portion – around a third – of the total value of the Pohokura field in its entirety (including liquids). Yet these estimates may be conservative. While we estimate the effect of the scenarios separately, in truth these scenarios may coincide: a dry year may coincide with higher-than-expected demand, producing even larger losses.