FINAL REPORT

Public Version

Coordinated Marketing of Pohokura Gas - An Economic Analysis

Submitted to

Shell (Petroleum Mining) Limited
Preussag Energie GmbH
Todd (Petroleum Mining Company) Limited

Prepared by:

Charles River Associates (Asia Pacific) Ltd
Level 11, Mobil on the Park, 157 Lambton Quay
PO Box 1123, Wellington, New Zealand
Tel: + 64 4 473 5080 Fax: + 64 4 473 5090

20 December 2002

AUTHORS

The primary authors of this report were:

- Professor Lewis Evans, Senior Consultant;
- James Mellsop, Principal; and
- Matthew Burgess, Consulting Associate.

Other staff involved were:

- Patrick Hughes, Principal (Toronto);
- Patrick DeGraba, Senior Consultant (Washington, DC);
- Robert Levinson, Principal (Washington, DC); and
- Sharyn Jones, Consultant (Wellington).

TABLE OF CONTENTS

1. INTRODUCTION, DEFINITIONS AND SUMMARY 1

1.1. INTRODUCTION AND OVERVIEW OF CONCLUSIONS 1

1.2. DEFINITIONS: SEPARATE AND JOINT MARKETING..3

1.3. SUMMARY OF REPORT 6

2. KEY CHARACTERISTICS OF THE OIL AND GAS INDUSTRY..................10

2.1. INTRODUCTION...10

2.2. UNCERTAINTY AND RISK 10

2.2.1. Sources of Risk...10

2.2.2. Mitigation of Risk..13

2.3. COMMON POOL RESOURCE...15

2.4. LACK OF A SPOT MARKET IN NEW ZEALAND 17

3. GAS SUPPLY AND DEMAND IN NEW ZEALAND 18

3.1. GAS SUPPLY 18

3.2. GAS DEMAND...18

3.3. IMPLICATIONS FOR POHOKURA..20

4. MARKET DEFINITION 21

5. GAS MARKETING...23

5.1. INTRODUCTION AND SUMMARY 23

5.2. IMMATURITY OF THE NEW ZEALAND MARKET 24

5.3. COSTS AND BENEFITS OF SCENARIO 2 31

5.3.1. Intra-Joint Venture Competition and Production Externalities.................................31

5.3.2. Increased Transaction and Production Costs 34

5.3.3. Implications for Buyers of Gas...39

5.3.4. Implications for Gas Market Competition 39

5.3.5. Statutory Constraints 39

5.3.6. Summary of Costs and Benefits of Scenario 2 40

5.4. COSTS AND BENEFITS OF SCENARIO 1 40

5.4.1. Lack of Demand Side Information, Flexibility Constraints and Reduced Incentives to Explore 40

5.4.2. No Competition on Pricing..43

5.4.3. Balancing Arrangement 43
5.4.4. Statutory Constraints 43
5.4.5. Summary of Costs and Benefits of Scenario 1 43
5.5. COSTS AND BENEFITS OF JOINT MARKETING 44
5.5.1. Timely Development and Production 44
5.5.2. Promotion of Competition 44
5.5.3. Constraints on Market Power 44
5.5.4. Demand-Side Information 46
5.5.5. Summary of Costs and Benefits of Joint Marketing 46

6. COUNTERFACTUALS 48

7. IS THERE A SUBSTANTIAL LESSENING OF COMPETITION? 50

7.1. INTRODUCTION 50
7.2. AGAINST COUNTERFACTUAL 1 50
7.3. AGAINST COUNTERFACTUAL 2 50
7.4. AGAINST COUNTERFACTUAL 3 51

8. COUNTERVAILING BENEFITS 52

8.1. INTRODUCTION 52
8.2. PUBLIC BENEFITS 52
8.2.1. Timely Development of Pohokura 52
8.2.2. Other Public Benefits 68
8.3. CONCLUSION 69

APPENDIX A : ECONOMIC LITERATURE SURVEY 71

A.1 INTRODUCTION 71
A.2 RISK 72
A.2.1 Introduction 72
A.2.2 Ex Post Evaluation Bias 72
A.2.3 Risk Aversion 73
A.2.4 Mitigating Risk 75
A.2.5 Conclusion 76
A.3 ACQUIRING PROPERTY RIGHTS 76
A.3.1 Introduction 76
8.3.1. Sophistication and Heterogeneity of Firms 77
8.3.2. Risk and Risk Sharing 78

A.3.2 Bidding Joint Ventures Enhance Competition....79
A.3.3 Conclusion....79
A.4 RESOURCE ECONOMICS....79
A.4.1 Introduction....79
A.4.2 Differential Rents....80
A.4.3 Optimal Depletion Rates: The Price-Time Profile....80
A.5 PRODUCTION EXTERNALITIES: COMMON POOL PROBLEMS....82
A.5.1 Introduction....82
A.5.2 The Incentive Effect of Common Pool Problems: A Prisoner's Dilemma....83
8.3.3. Conclusion....84
A.6 EXPLORATION PROBLEMS: INFORMATIONAL EXTERNALITIES....85
A.6.1 Information as a Public Good....85
A.6.2 The Incentive Effect of Exploration Problems: A Prisoner's Dilemma....86
A.6.3 Empirical Importance....87
A.7 INCOMPLETE CONTRACTS AND HOLD-UP PROBLEMS....87
A.8 INSTITUTIONAL RESPONSES TO EXTERNALITIES....88
A.9 REFERENCE LIST....90

APPENDIX B : WELFARE ANALYSIS IN VERTICALLY RELATED MARKETS....93

APPENDIX C : ESTIMATING LOSSES....98

C.1 INTRODUCTION....98
C.2 ASSUMPTIONS AND PARAMETERS....98
C.3 SENSITIVITY ANALYSIS....100
C.4 BEYOND 2004....102
C.5 SCENARIO TESTING....102
C.6 METHANEX....104
C.7 WATER SHORTAGE....106

APPENDIX D : CURRENT TARANAKI PETROLEUM PERMITS....107

D.1 TARANAKI BASIN ONSHORE (387XX)....107
D.1.1 Petroleum Prospecting and Exploration Permits....107
D.2 TARANAKI BASIN OFFSHORE (384XX)....111
D.2.1 Petroleum Prospecting and Exploration Permits....111
D.2.2 Taranaki Basin Mining Licences and Permits....113

APPENDIX E : DERIVATION OF EFFECTIVE GAS PRICE CAP......................115

APPENDIX F : FUTURE GAS SUPPLIES IN NEW ZEALAND............................117

LIST OF TABLES

Table 1: Estimated Welfare Losses From Separate Marketing 9

Table 2: Geological Probability of Successful Well...12

Table 3: Geological Probability of Successful Well in Different Areas...............12

Table 4: Drilling Decision if NPV of Success Equals 90 13

Table 5: Drilling Decision if NPV of Success Equals 75 13

Table 6: Payoffs for Various *Ex Post* Outcomes under Risk Sharing 14

Table 7: Over-Extraction Incentives 32

Table 8: Expected Production Profile from Pohokura With Joint Marketing 52

Table 9: Expected Production Profile from Pohokura With Three Year Delay 53

Table 10: Prices Used for Base Modelling 59

Table 11: Welfare Losses in Base Case 63

Table 12: Welfare Losses if Methanex and Other Petrochemical Companies Consume 2006-9 64

Table 13: Scenario Testing Results..64

Table 14: Estimated Welfare Losses from Separate Marketing 70

Table 15: Hypothetical Infrastructure Investment 73

Table 16: Payoffs for Various *Ex Post* Outcomes Under Risk Sharing 76

Table 17: The Common Pool Prisoner’s Dilemma..83

Table 18: The Exploration Prisoner’s Dilemma 86

Table 19: Sensitivity Analysis 100

Table 20: Variables for Which the Result is Insensitive....................................102

Table 21: Expected Extraction Profiles for Maui and Pohokura 102

Table 22: Scenario Testing 103

Table 23: Expected Extraction Profiles from Currently Discovered Fields 117

LIST OF FIGURES

Figure 1: The Gas Marketing Continuum 5

Figure 2: NBR/Trace Hodgson Cartoon Depicting the Common Pool Problem...16

Figure 3: Conceptual Depiction of Welfare Changes 55

Figure 4: "Actual" Supply Curves 56

Figure 5: Estimated Pohokura Production Profile With Joint Marketing and Without Joint Marketing 58

Figure 6: Demand and Supply Curves for Base Case Modelling (2006) 62

Figure 7: New Zealand Daily Storage 66

Figure 8: Electricity Price at Haywards Node 67

Figure 9: Risk-Return Relationship And Defining The Optimum........................74

Figure 10: Price Profiles and Rates Of Depletion Outcomes Under Monopoly and Competition..81

Figure 11: Calculating Welfare Losses – Step 1 94

Figure 12: Calculating Welfare Losses – Step 2 94

Figure 13: Calculating Welfare Losses – Step 3 95

Figure 14: Calculating Welfare Losses – Step 4 96

Figure 15: Equivalence of Changes in Welfare in Three Markets........................97

Figure 16: Demand and Supply Curves for Base Case Modelling (2006) 100

Figure 17: Methanex in the Market (2006)...105

Figure 18: LRMC of Generating Electricity from Coal and Gas........................116

1. INTRODUCTION, DEFINITIONS AND SUMMARY

1.1. INTRODUCTION AND OVERVIEW OF CONCLUSIONS

The Pohokura condensate and gas field is located offshore from North Taranaki. The rights to it are owned by Shell (Petroleum Mining) Company Limited (18.333 percent), Shell Exploration New Zealand Limited (29.6673 percent),[1] Preussag Energie GmbH (35.8618 percent) and Todd (Petroleum Mining Company) Limited (16.1379 percent). We refer to these firms in this report as "the Pohokura joint venture parties".

The Pohokura joint venture parties wish to develop the Pohokura field and produce hydrocarbons from it. The field contains three primary product streams (gas, condensate and LPGs), and physically, no one product can be extracted without the others. Accordingly, prior to production, the joint venture parties need to have in place some sort of disposal mechanism for each product.[2]

We have been retained by the Pohokura joint venture parties to provide an economic analysis of "separate" versus "joint" marketing of gas from the field. Our conclusion is that joint marketing of Pohokura gas would be significantly more efficient than separate marketing.

For condensate and LPG, separate marketing is relatively simple. These products can be stored, and an international spot market exists for them. Accordingly, following joint production, processing and storage, the joint venture parties can each take their share of these products and separately market them.

However, the situation for natural gas is quite different. In New Zealand, there are no storage facilities for gas, and there is no spot market.

Because the discovery and production of hydrocarbons entails great uncertainty and a high level of sunk capital investment at all stages, the ability to efficiently market the gas materially affects decisions relating to both exploration and production. Furthermore, typical downstream gas users - such as electricity generators - own large specific assets that require contractual certainty if investment is to proceed. The efficient exploitation of a field is also affected by the well-known common property problem; if property rights are not defined, over-exploitation will take place.

1 Shell Exploration New Zealand Limited is a wholly owned subsidiary of Shell.

2 We assume that it would be illegal or otherwise inappropriate to simply dump any product.

The high level of uncertainty, very large sunk costs and common property characteristics combine to imply scope for post-contractual opportunism in gas marketing and production arrangements. This scope can be anticipated by all joint venture parties, and downstream users, and it produces inordinate coordination difficulties in specifying a credible arrangement for separate marketing. This coordination problem is exacerbated by the fact that New Zealand does not have a spot market for gas and is almost certainly not going to have one of the requisite depth in the foreseeable future. Particularly in this environment, we consider that separate marketing of gas is virtually infeasible. At a minimum, a regulatory prohibition on the coordination necessary for joint marketing would lead to, perhaps indefinite, delay in the Pohokura field's production. Furthermore, it will reduce competition because of the later availability and production of Pohokura gas and the signal it imparts for other exploration ventures that, if gas is found, marketing the gas will be a long, costly and problematic exercise.

In the thin New Zealand gas production market, a delay in production from Pohokura would result in significant welfare losses, similar in nature to those arising from a missing market.[3] We quantify these losses in this report.

Our argument does not make any use of the state or structure of the gas production market in New Zealand, excepting the absence of a deep spot market. It rests on the efficient balance of cooperation and competition without a spot market and concludes that transactions costs would be extremely large, even prohibitively high, if coordination of marketing is not allowed.

Without presaging what marketing contracts would evolve, joint marketing by a joint venture whose members have competing alternative interests in other related markets is likely to be pro-competitive as opposed to ownership of the field by a single entity.

Our conclusions are consistent with the more general economics literature on joint ventures, which recognises that horizontal agreements on price (and other dimensions) may be necessary in order to achieve important efficiencies. The United States courts recognise this. The following quote from the United States Supreme Court is particularly apt to the situation facing the Pohokura joint venture parties:[4]

> *[Joint ventures] are not unlawful, at least not as price fixing schemes, where the agreement on price is necessary to market the product at all (page 23).*

---

3 For discussions of the welfare consequences of missing markets, see Goolsbee, A. (2000) "In a World Without Borders: The Impact of Taxes on Internet Commerce", *Quarterly Journal of Economics*, 115(2), 561-576, and Hausman, J A (1997) "Valuing the Effect of Regulation on New Services in Telecommunications", *Brookings Papers on Economic Activity: Microeconomics*, 1-38.

4 *Broadcast Music, Inc v. CBS* 441 U.S. (1979).

In respect of this case, Evans and Schmalensee (1995) state that:[5]

> *In cases such as this, horizontal price agreements are necessary to correct a market failure arising from transaction costs between firms. Transaction costs can prevent profitable exchanges from taking place and can thereby reduce output or, in the extreme case, prevent a market from existing at all (page 887).*

Because joint ventures can have important efficiency benefits, the courts in the United States analyse them under a rule of reason approach, rather than a *per se* approach. Similarly, in New Zealand the Commerce Act provides an exception to the section 30 *per se* price fixing rule for joint marketing (section 31).

Our conclusion is implied by the peculiar nature of the industry and the state of the New Zealand gas market. It is also the position on joint marketing of gas in Australia, where the market characteristics are similar to those in New Zealand. The Australian Competition and Consumer Commission ("the ACCC") has authorised the joint marketing of gas in Australia in all cases in which applications have been made to it; the ACCC has found that separate marketing of gas is "infeasible", and that accordingly production would not commence in the absence of joint marketing.

This report sets out our analysis. It also considers the applicability of section 27 of the Commerce Act to the practice of joint marketing of Pohokura gas, and the public benefits of that practice.

1.2. Definitions: Separate and Joint Marketing

The terms "separate marketing" and "joint marketing" are frequently used in the oil and gas industry. Conceptually, the distinction between them is one of degree, entailing a variety of practices on a continuum measured by the degree of coordination.

From a practical perspective, it is possible to identify three specific points on that continuum as being particularly appropriate for the purposes of competition analysis. The continuum and these points are illustrated by Figure 1:

The three points are:

5 Evans, David S and Richard Schmalensee (1995) "Economic Aspects of Payment Card Systems and Antitrust Policy Toward Joint Ventures", *Antitrust Law Journal*, 63, 861-901.

- **"Joint marketing"**. This term typically describes the practice of the joint venture entering into a sales contract with a buyer (or buyers) on all relevant terms and conditions, including price, quantity, rate, specification and liability.[6] An agent or subcommittee of the joint venture parties may negotiate and enforce the contracts;

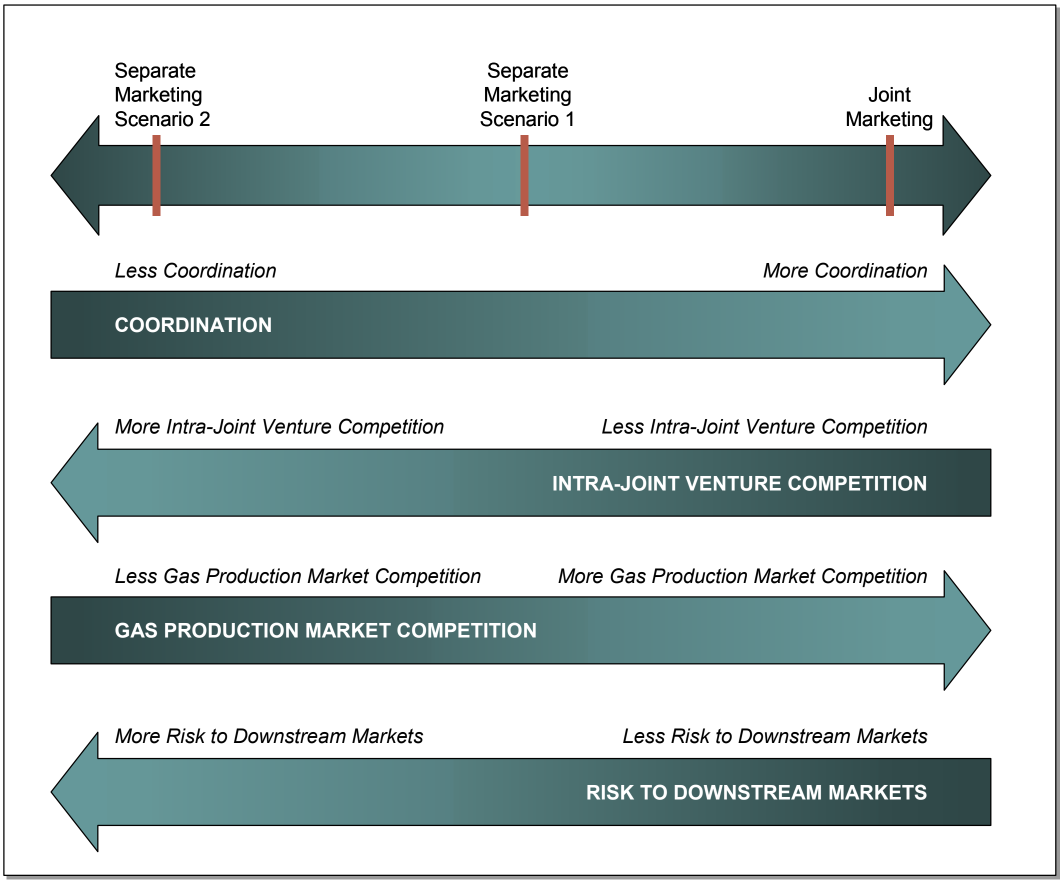
- **"Separate marketing scenario 1"**. We use this term (or more simply, "scenario 1") to refer to the situation where, pursuant to the existing joint venture agreement, the joint venture parties agree on various parameters for the development of the field, including an optimal depletion path (i.e., quantities and rates).[7] This path would probably represent the result of a mixture of reservoir engineering and financial analysis. The path might be framed in terms of maximum daily, average daily and annual quantities. Within these constraints, each joint venture party would be free to separately sell its share of gas to a buyer(s) on the basis of independently negotiated terms and conditions, the key one of which would be price; and

- **"Separate marketing scenario 2"**. We use this term (or more simply, "scenario 2") to refer to the situation where each joint venture party separately sells its share of gas to a buyer(s) on the basis of independently negotiated terms and conditions, including price, quantity, rate, specification and liability, and then returns to the others with its own depletion path and other terms as agreed with its buyer(s). The joint venture parties then agree on the appropriate development to support the sales contracts in place.

6 Legally, the joint venture is not a separate entity. Each joint venture party would have to sign the sales contract or contracts itself, or appoint an agent.

7 Other development parameters are discussed in section 5, and include system capacity and redundancy, and gas specification.

Figure 1: The Gas Marketing Continuum



All three forms of marketing involve coordination in respect of development and production. However, the level of coordination in respect of marketing differs:

- Joint marketing involves coordination on both quantity and price;
- Scenario 1 involves coordination on quantity, but not price[8]; and
- Scenario 2 does not involve coordination on either quantity or price.

We show later in this report that these descriptions are simplistic generalisations. For example, scenario 1 must involve some coordination on price in practice.

8 Because scenario 1 involves coordination on quantity, it could be argued that it does not really represent "separate marketing". However, this appears to be how the Australian Industry Commission (now called the Productivity Commission) uses the term. See Industry Commission (1995) *Study into the Australian Gas Industry and Markets*. In their decisions on authorisation applications for joint marketing of gas, it is not clear how the Australian Competition and Consumer Commission and the Australian Competition Tribunal interpret the term "separate marketing".

Other possible scenarios exist beyond these three points on the marketing continuum. For example, at one extreme, beyond the concept of joint marketing, the joint venture parties could merge to create a single firm. As another example, at the other extreme beyond scenario 2, the joint venture parties could undertake separate development of the field (including independent wells).

As the degree of coordination between the joint venture parties lessens (i.e., moving towards the left of Figure 1), the prospect for *intra*-joint venture competition increases,[9] driven in significant part by the common pool externality problem (which we describe below). However, movement in this direction also significantly raises the production and transaction costs of marketing and production. Two important implications of these increased costs are:

- Reduced field value. This lowers the incentive for firms to enter the gas production industry, and accordingly reduces competition in the market; and
- Delay in development and production. This raises price and quantity risks for downstream markets, particularly those for electricity.

This report develops these conclusions, which are illustrated in Figure 1. In our view, the most efficient point on this "marketing continuum" in New Zealand is joint marketing.

1.3. Summary of Report

In our view:

1. The production of oil and gas is characterised by:
    - Very large capital and sunk costs;
    - Significant uncertainty in discovery, costs, prices and reserves over the life of fields;
    - Externalities – in particular, the "common pool" problem that results in incentives to "over-extract" and a consequent loss in field value; and
    - Downstream demand utilising large specific capital assets.
2. Horizontal (and vertical) coordination are generally efficient institutional reactions to these characteristics.
3. The relevant market for competition analysis is the (continuously functioning) gas production market.

---

9 At least it does in theory; section 5.3.1 discusses how the incentive for intra-joint venture competition will be mitigated in practice.

4. Maui is now expected to be run down gradually and depleted by 2010.[10] At the same time, demand for gas is expected to rise, especially for electricity generation purposes. Accordingly, speed of development of Pohokura is critical in order to avoid significant gas and electricity supply reductions and price increases.

5. The gas production market in New Zealand is immature, has few participants, and is likely to remain in this position for the foreseeable future.

6. Against a similar background, the ACCC has found that separate marketing of gas is "infeasible".

7. At the very least, compared with joint marketing, separate marketing would entail significant:

   - Extra transaction costs;
   - Extra production costs;
   - Delay in, or non, development of the field;
   - Destruction of value of the field; and
   - Reduction in exploration incentives.

8. It is plausible that separate marketing would result in "no development", as found by the ACCC. Nevertheless, to be conservative and to reflect the strategic importance of Pohokura, we assume that the field could be developed even if separate marketing is mandated, albeit with a significant delay. Accordingly, there are three counterfactuals for the competition analysis:

   - Scenario 1, with development of the field delayed by x years;
   - Scenario 2, with development of the field delayed by y years;

     where $y > x$; and

   - No development.

9. Even if we take an optimistic view, for example, that $y > x = 3$, the welfare losses from separate marketing would be very large.

10 There is likely to be less gas than previously expected. The announced change in 2001 is indicative of the inherent uncertainty of reserves of even well established fields. A re-determination of reserves is currently underway.

10. While separate marketing *may* increase *intra*-joint venture competition (depending upon the scenario), it would ultimately result in a less competitive gas production market. In other words, joint marketing is actually pro-competitive and dynamically efficient.

11. Compared to any of the counterfactuals, joint marketing would not result in any detriment.

12. Should the Commission decide that the proposed arrangement would result in a substantial lessening of competition, the public benefits of the arrangement are so significant that they would outweigh any conceivable detriments. The key public benefit is the timely development of the Pohokura field. Separate marketing would entail a significant delay in development, a key consequence of which would be a significant decrease in gas and electricity supply and an increase in gas and electricity prices. Table 1 contains our estimates of the welfare losses from separate marketing (and therefore the welfare gains or public benefits from joint marketing). These estimates are conservative in that:

    - They only quantify some of the detriments of separate marketing; and
    - We have limited our calculations to a delay of three years. It is possible that the delay could be longer, and even infinite.

13. In some ways, the impact of a delay in Pohokura coming on-stream would engender a medium-run response as indicated by the short-run response of the electricity system to the low hydro inflows in the winter of 2001. In combination with a cold winter that increased demand for electricity, these low inflows caused the wholesale market price for electricity to increase four to five times its normal level for the winter period[11].

14. The welfare losses that would result from the combination of a delay in production from Pohokura and a dry year may be even greater than those set out in Table 1.[12, 13]

---

11 We would expect the longer-run demand and supply responses to a delay in production from Pohokura to be quantitatively and qualitatively different to those arising from what may be perceived to have been an unusually dry year.

12 In fact, electricity blackouts may even be a possibility.

13 The Maui field has historically been able to deliver large swings in production to meet demand and supply (e.g., hydro) variations. However, as the field depletes, we understand that this flexibility will decrease significantly.

Table 1: Estimated Welfare Losses From Separate Marketing

Year	Estimated Default Loss [14]	Present value of loss if Methanex and Other Petrochemicals Operate at Full Production to 2009[15]
2004	51.0M	51.0M
2005	79.2M	102.0M
2006	27.7M	102.0M
2007	72.5M	187.0M
2008	36.5M	136.0M
2009	34.9M	136.0M
Present Value	**204.1M**	**451.1M**

14 Discounted to 2002 at a rate of 10 percent.

15 Assumes Methanex and other petrochemical firms continue consuming gas until 2009. Discounted to 2002 at a rate of 10 percent.

2. KEY CHARACTERISTICS OF THE OIL AND GAS INDUSTRY

2.1. INTRODUCTION

A survey of the economic literature on the oil and gas industry is attached as Appendix A. This section of our report summarises the key conclusions of that survey. It also notes the lack of a gas spot market in New Zealand.

In addition to the fact that exploration and production of oil and gas each require substantial sunk investment,[16] two key characteristics of the industry are substantial risk and common pool resources.

2.2. UNCERTAINTY AND RISK

2.2.1. Sources of Risk

Risk is inherent in the process of exploration and production. It is most obvious in the uncertainty and large capital cost that attends exploration, but other substantial risks are intrinsic to this industry. For example, production is very costly and risky. Production risk arises from learning about the field as production proceeds. At the onset of production, and right up to depletion, the extent of a field's reserves and extraction costs may be quite uncertain. In New Zealand, this is illustrated by the experience with:

- Maui, in respect of which reserves were downgraded in November 2001 after more than 20 years of production; and
- The Waihapa Ngaere fields, in respect of which we are advised by the Pohokura joint venture parties that reserves have turned out to be lower than expected, resulting in significant spare production capacity.

Similarly, Wiggins and Libecap (1985) point out occurrences of large revisions of reserves estimates in the United States even after more than half of initial reserves had been extracted.[17]

The Pohokura joint venture parties are currently dealing with a very wide range of uncertainty about the recoverable reserves of the Pohokura field, reflecting the early stage of field appraisal.

---

16 The expected development costs for the Pohokura field exceed NZ$1 billion.

17 Wiggins, Steven N. and Gary D. Libecap (1985) "Oil Field Unitisation: Contractual Failure in the Presence of Imperfect Information," *American Economic Review* 75, 368.

These sources of uncertainty are in addition to those relating to future demand and supply conditions, and therefore price uncertainty.[18]

The significance of risk in the oil and gas industry is a key theme of this report, and at this point we elaborate on exploration and appraisal risks to indicate the extent of intrinsic uncertainty. We do so without relegating the other sources of uncertainty to lesser importance.

In section 5 of this report, we show that mandated separate marketing of gas would reduce the value of reservoirs, through a mixture of potentially reduced recoverable reserves, increased costs and deferred income. The simple elaboration below illustrates that this reduced value will in turn result in less exploration for oil and gas in New Zealand.

Geologically, the existence of an oil or gas reservoir is conditional on the presence of four physical components:

- Mature source rock;
- Reservoir rock (e.g. sandstone);
- A cap rock or seal; and
- A structural closure (for example, a closed anticline).

Furthermore, the relative timing of the formation of each of these components is important.

In respect of a prospect, geologists can assign certain probabilities to the presence of each of these four physical components and the timing component. By multiplying together these probabilities, a geologist can estimate the *geological* (as opposed to commercial) probability of success of an exploration well. Table 2 provides a hypothetical example.

18 In a 1994 Australian Petroleum Exploration Association (APEA) seminar, additional risks specific to the natural gas industry were identified. These include political risk (in particular tax and royalty legislation), exchange rate risk, risk of catastrophe and *force majeure*, operational risks (for example, extraction rates below expectation), and environmental risk (Adam Wheatley, "Financing Oil & Gas Projects", APEA seminar, 19 October 1994).

Table 2: Geological Probability of Successful Well

Component	Probability of Presence
Mature source rock	0.9
Reservoir rock	0.4
Cap rock	0.8
Structural closure	0.75
Relative timing[19]	0.9
Geological probability of successful well	**0.19**

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

We understand that a probability of 0.19 is fairly typical for an exploration well in a basin such as Taranaki. The probability of a well being successful will depend on the area being drilled in. Table 3 sets out some typical ranges of probabilities.

Table 3: Geological Probability of Successful Well in Different Areas

Type of well	Typical Probability of Geological Success
Infill development well	0.8 to 0.99
Outfield development well	0.5 to 0.8
Appraisal well	0.2 to 0.7
Mature basin exploration well	0.3 to 0.6
Proven basin exploration well[20]	0.10 to 0.25
Frontier basin exploration well	0.05 to 0.1

With this background, consider the following stylistic example to illustrate the economics of drilling an exploration well.[21]

19 This includes the significant factor of the charge (or migration) mechanism.

20 We understand that the Taranaki basin is generally considered to be a "proven" basin, although parts of onshore Taranaki may be approaching "mature" status.

21 We are advised by the Pohokura joint venture parties that the figures used in this example are reasonable approximations for certain Taranaki prospects.

Assume that:

- The cost of drilling the well is $20m;
- The commercial probability of the well being successful is 0.2; and
- If the well is successful, the net present value of the oil and gas in the reservoir is $90m, after deducting all costs (including drilling costs).

Table 4 analyses the firm's decision.

Table 4: Drilling Decision if NPV of Success Equals 90

Outcome	Probability	NPV ($m)	Probability Multiplied by NPV ($m)
Success	0.2	90	18
Dry hole	0.8	-20	-16
Expected payoff			**2**

In this case, the firm might drill the well.

Compare this decision to that which the firm would make if for some reason the net present value of the reservoir were $75m instead of $90m, as illustrated by Table 5.

Table 5: Drilling Decision if NPV of Success Equals 75

Outcome	Probability	NPV ($m)	Probability Multiplied by NPV ($m)
Success	0.2	75	15
Dry hole	0.8	-20	-16
Expected payoff			**-1**

In this case the firm would not drill the well.

2.2.2. Mitigation of Risk

As discussed in Appendix A, cooperative arrangements, both horizontal and vertical, are necessary for risk sharing in this industry. The need for large sunk capital investments together with risk are important factors in the extent to which oil and gas exploration and production firms choose to enter joint ventures, and they mean that the availability of other tools for mitigating uncertainty is important for field development and production.

The role of risk spreading can be illustrated by the following example. Consider the case of two firms considering exploration and development expenditures on two distinct tracts. Assume that, for each firm, there is a 50 percent probability that no oil will be found and a 50 percent probability that a resource with a net present value of $10 million will be found. The expected value of this "lottery" is $5 million. Given the high degree of risk associated with this investment, the *ex ante* value of this opportunity is equal to $5 million minus δ, where δ is the (positive) risk premium. If, however, the two firms become equal partners in the two projects, their payoff becomes:

Table 6: Payoffs for Various *Ex Post* Outcomes under Risk Sharing

Ex Post Outcome	Probability	Payoff
Neither project is successful	0.25	$0
One project is successful and one is not	0.50	$5 million
Both projects are successful	0.25	$10 million

This payoff profile has the same expected value as the case where each firm undertakes an independent investment. The variance to each firm, however, is lower. As a result, the risk premium necessary for a firm to make (*ex ante*) zero economic profits is lower.[22]

Additional uncertainty about aspects of the regulatory regime, possible contracting arrangements and the range of contracts available to participants may have a major effect on whether exploration or production options are taken up, or delayed perhaps indefinitely. Furthermore, the mitigation of business risk by the pre-production investment in or *ex ante* design of contracts that impart as much certainty as possible about processes for handling events and information as they unfold *ex post* and any potential opportunistic behaviour by members of a joint venture is very important. Contracts that need to reduce significant expected future enforcement costs and that are different from standard arrangements are likely to take much more time to negotiate, and thereby delay production. We come back to these issues in section 5, but note at this point that arrangements to support separate marketing would need to protect each party's share of the common pool (as discussed next in section 2.3), 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.

22 Sharing risk in joint ventures enables capital constrained firms to participate in exploration and development.

Finally, note that an assurance that joint marketing is permitted enables firms with a wide variety of resources to participate in exploration and production. Firms with a low resource base may not themselves have the resources to cover the investment required under separate marketing, even if such marketing were feasible, and this would dissuade entry by these firms.

2.3. Common Pool Resource

Common property characteristics arise when more than one company has access to an oil or gas resource pool. For joint ventures the same problem can arise depending upon the autonomy granted the parties under the joint venture agreement. Such common pool problems are a special case of the classic "common property" problem. In these situations, no one party has the right or ability to exclude another firm from using its portion of the resource pool, and (inefficient) over extraction will occur.[23] The solution to this problem requires co-ordinated action by the resource owners.

Common pool problems have been discussed in detail in the context of the oil and gas industry, e.g., Libecap and Smith (1999).[24] Doane and Spulber (1994) note that:[25]

> *Without clearly defined property rights, owners have an incentive to engage in a costly competition to extract the gas in the reservoir (page 512).*

Pierce (1987) notes that there are at least two sources of inefficiencies arising from the common pool problem in this industry:[26]

- The incentive to engage in excessive well drilling results in wasteful drilling costs; and
- The production of oil (to which we would add more generally hydrocarbons) requires energy from another source. If the hydrocarbons are produced too rapidly from a reservoir, the reservoir's source of energy may be dissipated long before all of the potentially recoverable reserves have been produced.

---

23 This problem is sometimes referred to as the "tragedy of the commons".

24 Libecap, Gary D. and James L Smith (1999), "The Self-Enforcing Provisions of Oil and Gas Unit Operation Agreements: Theory and Evidence," 12 *Journal of Law, Economics and Organization* 526.

25 Doane, Michael J and Daniel F Spulber (1994) "Open Access and the Evolution of the U.S. Spot Market for Natural Gas", *Journal of Law and Economics*, XXXVII, 477-517.

26 Pierce, Richard J (1987) "State Regulation of Natural Gas in a Federally Deregulated Market: The Tragedy of the Commons Revisited", *Cornell Law Review*, 73, 15-53.

In the context of a National Business Review article regarding the Maui redetermination, the following cartoon (Figure 2) depicts the common pool problem:[27, 28]

Figure 2: NBR/Trace Hodgson Cartoon Depicting the Common Pool Problem

The uncertainty relating to the state of an oil or gas field can exacerbate the common pool problem, especially in the absence of a deep spot market for oil or gas. Increased uncertainty increases the discount rate of firms, making them more "impatient", and therefore reducing their ability to coordinate. Uncertainty may induce individualistic behaviour that is the core of common pool resource efficiency problems. This issue is discussed further in section 5 of this report.

27 Reprinted with kind permission, the National Business Review and Trace Hodgson. This cartoon appeared on page 51 of the NBR, 31 May 2002.

28 Note that this cartoon depicts a competition between the buyers of gas from a common pool, rather than the sellers. Nevertheless, the principle is the same.

In short, in the absence of coordination that may include the assignment of property rights, the common pool of oil and/or gas will very likely be depleted inefficiently.

2.4. Lack of a Spot Market in New Zealand

The gas production market in New Zealand operates as a "contract" or "project" market, where gas is typically produced to meet specific, and often long-term, contractual obligations. ACIL[29] identified the following issues as inhibiting the development of a spot market:

- Restrictions on reselling gas;
- Access to the Maui pipeline;
- Protocols and standards for the management of gas flows across the transmission system; and
- Information requirements.

However, even if these issues were dealt with, New Zealand's small and sparse population make it unlikely that a "thick" spot market would develop in the foreseeable future.[30] As discussed in section 5.2 of this report, compared to countries like the United States and others with liquid spot markets, New Zealand has a relatively small number of gas buyers, a relatively small number of producing fields, a long and stringy pipeline grid, no gas storage and no formal gas brokers.

The implications of the lack of a spot market are discussed further below. They include the lack of an independent market-determined price for gas.

---

29 ACIL Consulting, *Review of the New Zealand Gas Sector – A Report to the Ministry of Economic Development*, October 2001.

30 Low population density results in high transport costs.

3. GAS SUPPLY AND DEMAND IN NEW ZEALAND

3.1. Gas Supply

Appendix F to this report contains a table setting out the Pohokura joint venture parties' expectations of extraction profiles from currently discovered fields, including the revised expectations for Maui.[31,32] These expectations assume that joint marketing will be permitted, and accordingly that production from Pohokura will commence in 2004.

There is evidence that exploration activity in New Zealand is increasing. In the 2001 calendar year, double the number of exploration and mining permits were issued than in 2000. Furthermore, the three major purchasers of Maui gas (Contact Energy, NGC and Methanex) all note in recent annual reports the increased rate of exploration for gas in New Zealand.[33] This increased activity is probably a significant reflection of the expected reduction in supply of gas as Maui runs down, and the expected increase in demand for electricity and consequent derived demand for gas.

It is also relevant to note that gas discoveries have averaged over 150 PJ per annum[34] since 1955 and that in its modeling, MED assumes new gas discoveries averaging around 80 PJ per annum until 2020.[35] Although substantial new gas discoveries are likely to be made during the next decades, the amounts, production cost, and timing of discovery and production remain extremely uncertain.

3.2. Gas Demand

Demand for energy is increasing in New Zealand. The Ministry of Economic Development estimates total energy consumption will increase at 1.1 percent per annum between 1998 and 2020.[36]

---

31 These expectations are based on the joint venture parties' analysis of public data.

32 [ ]

33 See Contact Energy's Annual Report 2002 (page 11), NGC's Annual Report 2001 (page 11) and Methanex's Annual Report 2000 (page 22).

34 This figure is the sum of total gas reserves discovered in New Zealand since modern exploration began in 1955, divided by the number of years since that time. The figures are 7,156 PJ estimated total reserves discovered over 47 years of exploration. These values are available from the Ministry of Economic Development website (www.med.govt.nz). We recognise the historical nature of these values and that the average disguises substantial variation.

35 Ministry of Economic Development (2000) *Energy Outlook to 2020*, 9 .

36 Ministry of Economic Development (2000) *Energy Outlook To 2020*.

A major and growing form of energy consumed in New Zealand is electricity. According to EECA, electricity is likely to continue expanding its share of energy provision into the future.[37] The Ministry of Economic Development forecasts growth in electricity consumption of 1.8 percent per annum from 113 PJ in 1998 to 167 PJ in 2020.[38,39] While there is considerable uncertainty about these forecast growth rates, we accept as a working hypothesis that these forecasts are reasonable.

New Zealand faces the significant problem of finding and developing primary energy sources to meet future electricity demand. Currently, hydropower stations generate most electricity in New Zealand (63.8 percent for the year ended 31 March 2001, according to the Ministry[40]). As the experiences of the 2001 winter show, this system is vulnerable to weather extremes and consequent electricity fuel supply variation.

Hydrological shortages were met to a significant degree by increased Maui gas output in 2001. The Maui field has historically been able to deliver large swings in production to meet demand variations. However, as the field depletes, we understand that this flexibility will decrease significantly.

In the future, the share of hydrological power in electricity generation is expected to decline as electricity demand increases and few, if any, new hydrological stations are built.[41] Reasons for the relative decline in hydrological generation include the distance of these stations from load, and resource consent difficulties. The most prominent possibility for new hydro development is Meridian's 570 MW proposal for the Waitaki River. According to Meridian's 2001 annual report, this project could take six years to build, and the 2002 annual report noted that Meridian expected to apply for resources consents later in 2002.

The two primary energy sources that are anticipated to supply most of the required growth of electricity generation in New Zealand are natural gas and coal.

---

37 EECA (2001) *National Energy Efficiency and Conservation Strategy*, 3.

38 Ministry of Economic Development (2000) *Energy Outlook To 2020*, 28.

39 Assuming that the extra 54 PJ of electricity were generated from gas, and assuming an efficiency ratio of 55 percent, this would equate to an increase of 98 PJ of gas.

40 Ministry of Economic Development (2001) *New Zealand Energy Data File*, 100.

41 Some efficiencies in hydroelectric generation remain to be unlocked, effectively increasing capacity, but these gains are not expected to be significant.

In the absence of specific (New Zealand) government action, EECA considers that gas-fired stations will meet the majority of additional electricity demand over the next 10-15 years.[42] This is consistent with the view of the Ministry, which forecasts in the *Energy Outlook to 2020* that gas-fired electricity generation will increase in absolute terms over the next twenty years.

The *Energy Outlook to 2020* also suggests that any shortfall in capacity of electricity generation by gas will be made up by coal. That is, if gas supplies are limited, coal will take its place as the primary source of energy for generation.

Gas is preferred over coal for electricity generation for two reasons. First, there are studies anticipating that over the next twenty years gas will generate electricity that is approximately 30% cheaper per unit than coal. For example, in an analysis for the Ministry of Economic Development, East Harbour Management Services calculated that unit electricity generation costs would range from 4.0 to 7.6 c/kWh for gas based technologies and from 6.7 to 10.1 c/kWh for coal based technologies, depending on assumptions about capital costs and fuel costs.[43] Secondly, generation by natural gas is cleaner than coal, and imposes considerably less externalities. Coal contains almost twice the carbon than that of natural gas. Furthermore, natural gas can be burned considerably more efficiently than coal.[44,45]

The forecast environmental impact of coal over gas is significant. The Ministry forecasts that if gas discoveries over the next two decades decline from an expected 80 PJ per annum to 40 PJ per annum, then New Zealand carbon dioxide emissions resulting from electricity generation will increase by 9.5% as carbon-rich coal is substituted for natural gas in electricity generation.[46] This may have serious implications for New Zealand under the Kyoto Protocol.

3.3. IMPLICATIONS FOR POHOKURA

In the context of increasing demand for gas and the imminent depletion of Maui, the timely development of the Pohokura field becomes critical for New Zealand. In our view, separate marketing would lead to delay in the development of Pohokura, and significant subsequent welfare losses. These conclusions, among others, are developed in the remainder of this report.

42 EECA (2000) *Draft National Energy Efficiency and Conservation Strategy*, 27.

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

44 Ministry of Economic Development (2000) *Energy Outlook To 2020*, 48.

45 We also understand that it is significantly quicker to build a gas turbine than it is to build a coal station.

46 Ministry of Economic Development (2000) *Energy Outlook to 2020*, 48.

4. MARKET DEFINITION

For the purposes of this report, we accept the product, geographic and functional dimensions of the Commission's market definition findings in *Decisions 408* and *411*. However, we believe that new facts do justify the Commission now altering the time dimension of its gas production market definition analysis.

In *Practice Note 4*,[47] the Commission states:

> *Generally, the Commission will view markets as functioning continuously over time. However, where a market is characterised by, for example, infrequent transactions, the Commission may seek to define a separate time dimension as part of its market definition process. Time considerations are also important where there are long term contracts and where there are depletable resources.*

In *Decisions 408* and *411*, the Commission defined the relevant gas markets as:

- The current gas production market; and
- The post-2009 gas production market.

The rationale for this distinction was the anticipated depletion date of 2009 for Maui.

Since the Commission's decisions, the estimate of the economically recoverable reserves from the Maui field has been downgraded (in November 2001), and a redetermination of those reserves is currently in progress. Furthermore, on the assumption that joint marketing will be permitted, there is now more certainty about the future development of Pohokura.

In our view, the gas production market should be considered as continuously functioning for the foreseeable future. In other words, there should be no inter-temporal split. Our reasons are as follows:

- As illustrated by Appendix F, the Pohokura joint venture parties expect the run-down of Maui to be fairly smooth;
- Subject to joint marketing by the Pohokura joint venture parties being permitted, Pohokura gas is expected to be on-stream by 2004, to a significant degree offsetting the run-down of Maui. Furthermore, the Pohokura joint venture parties expect production from Kupe and Kauhauroa to commence around 2008 and 2010 respectively;

47 *Practice Note: 4: The Commission's Approach to Adjudicating on Business Acquisitions Under the Changed Threshold in Section 47 – A Test of Substantially Lessening Competition* (available on the Commission's website: www.comcom.govt.nz).

- Of the four major Maui contracts, three of them expire in 2009 (the Crown's contract with the Maui Mining Companies, and the Crown's contracts with Contact Energy and NGC). The fourth contract (between the Crown and Methanex) expires in 2007, but delivery is only committed to 2005. However, the exhaustion of Maui appears to be well anticipated by the three major purchasers of gas from that field. All three purchasers have already indicated (for example, in their annual reports) that they are currently assessing the situation and are seeking contracts for supply from alternative sources;

- The preceding bullet point illustrates what economics would predict, i.e. that firms on the demand and supply side of the market will anticipate future depletion of fields, and incorporate it in their decisions now; and

- It is possible that Methanex will close its New Zealand plants in the next few years. However, Methanex has stated that this depends upon the outcome of its negotiations for replacement gas; it states that it is actively seeking a replacement long-term contract at the moment.

In our view, uncertainty about Methanex's future, and uncertainty about reserves in existing fields, makes it too speculative to specify an inter-temporal split, and prospective changes in the gas market affect decisions continuously.

5. GAS MARKETING

5.1. INTRODUCTION AND SUMMARY

The purpose of this section is to consider the costs and benefits of the three types of gas marketing that were identified as specific points on the marketing continuum in section 1.2.

The section starts with a review of the gas market in New Zealand. The absence of a thick spot market significantly increases the costs of separate marketing. We also show in this section that, even if there were a spot market, separate marketing would continue to be very costly, because of coordination difficulties.

It is relevant to note that there is no example of separate gas marketing in New Zealand.[48]

We then consider the three types of marketing. Our conclusions are that:

Intra-Joint Venture Competition

It is quite plausible that scenario 2 may not actually be feasible. However, if it were, it could result in intra-joint venture competition on sales terms including price, quantity and rates of extraction.

Scenario 1 is more likely to be feasible. However, it would offer no competition advantages over joint marketing; neither would it result in intra-joint venture competition.

Any ability of joint marketers to exercise market power would be significantly constrained by the:

- Misalignment of incentives (and other asymmetries) faced by each firm in the joint venture due to other business activities;
- Greater exploration incentives and therefore competition; and
- The expectation that new discoveries will be made.

48 It is sometimes claimed that Kapuni gas is separately marketed. However, we are advised by Shell and Todd that this is not the case. Rather, the gas is sold jointly.

Gas Production Market Competition

Both forms of separate marketing would reduce the value of gas fields, and accordingly would reduce incentives to enter the gas exploration and production industry. Therefore, separate marketing would ultimately reduce competition in the gas production market. In other words, joint marketing is actually pro-competitive.

Transaction Costs

Compared to joint marketing, the transaction costs of:

- Scenario 1 would be significant enough to delay development of the Pohokura field by x years; and
- Scenario 2 would be significant enough to delay development of the Pohokura field by $y > x$ years, or possibly indefinitely.

Even if we take a very conservative view, for example, that $y > x = 3$, the welfare losses from separate marketing would be very large.

Production Costs

Both forms of separate marketing would result in higher production costs than joint marketing.

Legal Constraints

Because of over-extraction incentives, delays in development and reduction in exploration incentives, both forms of separate marketing would entail a risk of the Ministry of Economic Development refusing to grant a mining permit. The risk would be higher under scenario 2.

5.2. IMMATURITY OF THE NEW ZEALAND MARKET

The ACCC has found that separate marketing of gas in the various relevant Australian markets is infeasible. While we understand that separate marketing of gas occurs in the USA, the UK and Canada, the gas production markets in those countries are very thick and sophisticated. The ACCC has identified a list of market features that are present in overseas gas markets where separate marketing is the norm:[49]

49 ACCC (1998), *Submission to the Gas Reform Implementation Group on Upstream Issues*.

- A large number of customers creating a diverse gas demand profile (for example, in 2000, there were 59,478,980 residential consumers, 5,090,586 commercial consumers and 235,064 industrial consumers in the USA[50]);

- A number of competitive suppliers (for example, there are approximately 8000 in the USA[51]);

- A range of transportation options creating a pipeline grid (for example, in the USA, more than 165 firms operate about 278,000 miles of transmission lines, and more than 1,300 local distribution firms operate in excess of another 700,000 miles of pipeline distribution infrastructure[52]);

- Storage close to demand centres (for example, there are 5 liquefied natural gas storage sites in the UK, as well as salt cavities and depleted gas fields);

- Brokers/aggregators providing supply and/or demand aggregation services as well as bundled supply packages;

- Gas-related financial markets; and

- Significant short term and spot markets.

None of these features currently exist in New Zealand, nor are they likely to in the foreseeable future.

Number of Customers

The demand side of the New Zealand gas production market is very thin. The key players include Contact Energy, Genesis, Methanex, NGC, Nova (which is related to Todd Energy, one of the Pohokura joint venture parties), Ballance and potentially certain other industrials and co-generators.

Number of Suppliers

The supply side of the New Zealand gas production market is discussed above in section 3. Current producers are Shell, Todd, NZOG, Swift, Indo Pacific and Greymouth Petroleum.

---

50 Source: Energy Information Administration (2000) *Natural Gas Annual*, Overview - Table 1.

51 Source: Natural Gas Supply Association (www.ngsa.org). Also, according to the Natural Gas Annual (see the preceding footnote), there were 306,239 gas and gas condensate wells producing gas in the USA in 2000.

52 Source: Energy Information Administration (2001) *U.S. Natural Gas Markets: Recent Trends and Prospects for the Future*, 16.

Transportation Options

Even if there were a significant number of producers and consumers in the gas production market, the development of liquid trading would depend on the ability to transport gas between those players. As we now describe, the gas networks in New Zealand are very long and thin, and significantly less extensive than the electricity networks.

There are two main gas transmission networks in New Zealand:

- The Maui pipeline, which runs from the Oaonui processing plant to Huntly. The Maui pipeline is owned by Maui Development Ltd (MDL), which in turn is owned by Shell, Todd and OMV. This pipeline currently transmits only gas to be sold under the Maui contract; and

- The NGC transmission pipelines. These comprise over 2,300 km of transmission pipelines, which essentially cover many of the cities and towns of the North Island.

There are other small transmission pipelines that connect specific fields to industrial and petrochemical loads, and various distribution networks.

The distribution networks are operated by NGC, Vector, Powerco and Wanganui Gas. Nova has a small number of bypass lines which provide a service mainly to industrial customers. We understand that the four main distribution companies all offer common carriage to retailers.

ACIL has identified the following concerns in respect of gas transmission in New Zealand:

- Lack of access to the Maui pipeline. The Maui pipeline is currently used only to transport gas under the Maui gas contracts. The existing rights may continue until 2009, depending on the outcome of the pending redetermination. However, we understand that the Pohokura joint venture parties are expecting this access issue to be resolved prior to the Pohokura gas coming on-stream;

- Gas specification. The Maui gas contract has a different gas specification to that of the NGC transmission system;

- NGC's access pricing and contractual terms have a standard contract term of 12 months. In its submission to the Ministry of Economic Development on the ACIL report, Shell noted that this disadvantages parties with gas to offer over shorter periods, and small suppliers with customers having variable loads. Effectively Shell argued that there can be no spot or on demand market for transmission services because of these transmission annual contracts[53]; and

- Gas balancing. In this context, gas balancing refers to the procedure by which customers match gas receipts to gas deliveries over a given period. Balancing is undertaken periodically, with penalties generally given for excessive imbalance. Currently NGCT (the transmission business of NGC) is responsible for maintaining the overall gas balance in the system, including the Maui pipeline. The current system is very simple and provides a high level of flexibility to the users that rely on the Maui gas field. However, both ACIL and the Ministry have concerns about its efficacy in the future. For example, the Ministry states that, "Overseas experience suggests that current arrangements may not suffice in the medium term with growth in demand (e.g., for gas-fired electricity) and in the number of injection points".[54]

Gas Storage

Gas storage can serve a number of useful purposes, including:

- Meeting demand variability;

- Assisting operation by dealing with operational incidents, such as compressor trips;

- Reducing pipeline investment; and

- Complementing a balancing arrangement (see section 5.3.2).

Natural gas can technically be stored in depleted reservoirs. However, for the following reasons, appropriate reservoirs do not exist in New Zealand, and are not likely to during the foreseeable future:

- There are no depleted reservoirs at the moment; and

53 We understand that NGC states that there is no impediment to a secondary market for transmission access rights. However, we are advised by the Pohokura joint venture parties that one has not developed in practice because of practical difficulties implementing the market.

54 Ministry of Economic Development, *Review of New Zealand's Gas Sector 2001-2002.*

- While Maui may be *technically* viable as a storage facility following its depletion, we understand that it would not be *economically* viable. In particular, the costs of operating the offshore platform and creating the required pressure for re-injection would make using Maui as a storage facility prohibitively expensive.[55]

Brokers

We understand that there are no firms in New Zealand performing a formal gas broking or aggregating role, although Contact Energy and NGC have performed an aggregation role by purchasing gas from a number of fields and using the gas for their own consumption or for resale to retailers and end-users.

Gas-Related Financial Markets

In order to manage spot market price risk, a financial gas market developed in the US in the late 1980s, offering futures and options contracts.[56] ACIL notes that the US "turn over in futures trading is in the hundreds of billions of dollars" (page 76). If a spot market develops in New Zealand (see the discussion below), it is possible that a complementary financial market could develop as well.

Short-Term and Spot Markets

There is no gas spot market in New Zealand, and nor is there likely to be a liquid one in the foreseeable future (for the reasons given in this section 5.2).

The implications of a lack of a liquid spot market for the marketing of gas from the Pohokura field are developed in this report. In summary, a liquid gas spot market would:

- Significantly reduce the transaction costs of negotiating and enforcing a balancing arrangement, because of an independently fixed price and the ability to transact overs and unders (see section 5.3.2); and

- Reduce the risk of hold-up, and accordingly the extent of reliance on long-term contracts (although these would remain very important).

Nevertheless, even if there were a spot market, separate marketing would continue to be very costly, because of coordination difficulties.

There is a wholesale gas spot market in Victoria, which has operated since 15 March 1999. Key features of that market include:

---

55 Furthermore, Maui is not close to significant variable load.

56 Andrej Juris (1998) "Development of Competitive Natural Gas Markets in the United States", *Public Policy for the Private Sector*, Note No. 141.

- A design that was developed to enable within-day gas scheduling and balancing of the pipeline system to be market driven.[57]

- There are four injection sources of gas. We understand that the vast majority of gas (around 98 percent) is injected from the offshore gas basins in Bass Strait, which are jointly owned and operated by Esso and BHPP. The other three production sources are an interconnection with the New South Wales system; the Otway Basin field and underground storage facility in the southwest of Victoria; and a LNG storage facility at Dandenong;

- There are three retail purchasers;

- Gas flows on substantial sections of the transmission pipeline can be bi-directional;

- The system, including the price determination model, is operated by VENCorp, an entity owned by the Victorian government;

- The majority of gas is traded under contracts between producers and retailers; and

- The spot market is settled as a net market, i.e. the participants pay for the excess of actual withdrawals over actual injections, or receive payment for the excess of actual injections over actual withdrawals.

We are not aware of any economic studies examining the efficiency of the Victorian gas spot market. However, we note that the market is very thin in terms of number of players and quantities, particularly when compared to the US and UK markets. It is relevant to note the following comment of the ACCC, made in its authorisation of the Victorian spot market rules:[58]

> *"However, with limited supply side competition at market commencement the Commission has some reservations that spot sales will be fully competitive. This is because it is initially expected that spot sales will relate to a relatively small amount of gas needed by participants to ensure that they are in physical balance. However, as the industry develops parties may become more willing to buy and sell gas on the day at the spot price" (page 23).*

---

57 See section 4.1 of "Vencorp's Guide to the Gas Market", available at www.vencorp.com.au.

58 ACCC Determination "VENCORP authorisation applications for Market and System Operations Rules", 19 August 1998.

A recent review of the Victorian market noted that the matter of limited upstream competition "… is not an issue that is caused by nor is it solvable solely by implementation of, or changes to, spot market or pipeline access arrangements".[59]

As noted in section 2.4 of this report, ACIL identified the following issues as inhibiting the development of a gas spot market in New Zealand:

- Restrictions on reselling of gas;
- Access to the Maui pipeline;
- Protocols and standards for the management of gas flows across the transmission system; and
- Information requirements.

If these types of issues were addressed, then it may be possible to engineer a gas spot market in New Zealand. However, New Zealand's small and sparse population makes it unlikely that a liquid spot market would develop in the foreseeable future. Even an illiquid one would probably take several months or years to develop.

Together, these factors raise a lot of uncertainty for the Pohokura joint venture parties now about the prospects and efficacy of a New Zealand gas spot market. Accordingly, we do not believe that the possibility of a gas spot market developing at some unknown point in the future will:

- Significantly reduce the transaction costs of negotiating and enforcing a balancing arrangement; or
- Reduce the risk of hold-up, and accordingly the extent of reliance on long-term contracts (these are still likely to be important even in the presence of a spot market).

To be more specific, even if a spot market were in prospect:

- If there is uncertainty about the general efficiency of the price discovery of a gas spot market, the joint venture parties would not be happy to base value transfer decisions on it; and

59 "Review of Victorian Gas Market Arrangements", Vencorp, 15 March 2001, page ii. That same review also noted the ongoing importance of long-term arrangements in the Victorian gas market, and stated that (page i): "The principal determinant of retail gas prices in Victoria is therefore the primary Gascor-BHPP/ESSO contract."

- If there is uncertainty about the quantities of gas available on a spot market, and concomitantly the volatility of price, the joint venture parties would be reluctant to design a balancing arrangement on the basis of their ability to make-up deficits from it, nor would they be happy to risk huge sunk investments on it.

5.3. Costs and Benefits of Scenario 2

5.3.1. Intra-Joint Venture Competition and Production Externalities

Under scenario 2, each joint venture party would independently negotiate contractual sales terms with buyers, including price, quantity, specification and liability. The joint venture parties would then convene to agree on the appropriate development to support the sales contracts in place. The process would have to be iterative and involve the final purchasers.

The transactions would be materially affected by uncertainty about the total economically recoverable reserves from a field. At best, the joint venture parties would be able to estimate a probability distribution for the amount of recoverable gas. Until final depletion, the quantity of gas in a field is very uncertain.

This uncertainty about future quantities (and prices) creates an incentive on each joint venture party to:

- Extract gas earlier than might otherwise be the case; and
- Avoid being an "under-lifter" at any point in time.

For example, consider a discovery by three joint venture parties with equal shares, and assume that the expected quantity of recoverable gas is 1000 PJ. Accordingly, each party expects to recover 333 PJ. However, there is a certain probability that the field will contain less than 1000 PJ. Given this risk, each party will want to avoid being in a position of "under-lift" at any point in time, in case the field is depleted "prematurely". In effect, this uncertainty sets up a "race" between the joint venture parties to extract first, manifested under scenario 2 by each joint venture party attempting to sell a greater quantity of gas than the others.

As discussed in respect of the common pool problem in section 2.3 of this report, these incentives would lead to more expenditure than is optimal, and could lead to over-extraction and fewer resources being ultimately captured. These incentives can be illustrated by the prisoners' dilemma game. Each joint venture party has an incentive to extract competitively, even though this action reduces the total value of the pool. The pay-offs in the following representation of the game (Table 7) are stylistic illustrations of the value of each of two joint venture parties' interests in a field.

Table 7: Over-Extraction Incentives

	Player 2: Cooperative strategy	Player 2: Non-cooperative strategy
Player 1: Cooperative strategy	10, 10	2, 15
Player 1: Non-cooperative strategy	15, 2	5, 5

Non-cooperation is a dominant strategy. That is, even if the parties could achieve a tenuous agreement to cooperate, each would have an incentive to deviate from that agreement. Both players are worse off under the equilibrium outcome (the bottom, right-hand cell), as their competition to extract first will lead to sub-optimal depletion of the field, and consequent loss of value. The economy is also worse off.[60]

To the extent that part of the value of the field would be destroyed, *ex ante* the incentive to explore for gas would be reduced. Under scenario 2, the incentive to over-extract would manifest itself in each joint venture party competing to sell a greater quantity of gas than the others, i.e., the incentive would promote intra-joint venture competition. However, other incentives may mitigate this to an extent. These other incentives depend on whether costs are allocated *ex ante* or not.

If the joint venture parties agree on development and production cost allocation prior to separate selling, then they would continue to have an incentive to compete between themselves, on various dimensions.

60 The joint venture parties might repeat this one-shot game. However, because the horizon is finite, and because the uncertainty about remaining reserves is likely to result in high discount rates, the folk theorem does not apply and the cooperative outcome will not obtain. (Note that cooperation cannot be sustained in a prisoner's dilemma game even for long but finite games (Tirole, J (1988) *The Theory of Industrial Organization*, The MIT Press). Where the game horizon is finite but occurs at an indefinite point in time, as it is in the case of extraction from a gas reserve whose exact size is unknown, there is some possibility for cooperation to be the optimal outcome. However, Tirole notes that when the future is discounted but only exists with probability *x*, and *x* decreases sharply at some point in time (as we consider is the case with gas extraction), then "one would suspect that…collusion [cooperation] would be hard to sustain in such an environment" (page 253)). Furthermore, information, cost and use asymmetries between the firms will make it harder to reach an efficient solution than in the standard case. Therefore, cooperation is most unlikely to be an equilibrium outcome even if the game were repeated.

However, it would seem unlikely that the joint venture parties would agree on cost allocation *ex ante*. To illustrate, consider the "swing" term in a gas sales contract. "Swing" is the difference between, for example, the average daily quantity of gas and the maximum daily quantity. Swing is valuable to electricity generators in New Zealand, because electricity demand is variable, and gas cannot be stored in New Zealand.[61] Accordingly, we might expect joint venture parties under scenario 2 to compete on swing. Of course, the greater the swing, the greater the capacity of the facilities required to provide it, and the greater the capital cost to be allocated among the joint venture parties.

Suppose that, according to an *ex ante* cost allocation agreement, joint venture party A is to pay for 40 percent of all development and production costs.[62] Suppose further that:

- The incremental cost to the joint venture of a unit of swing is $100; and
- The incremental benefit to buyer X of a unit of swing is $80.

The incremental cost to joint venture party A of a unit of swing is $40. Joint venture party A would accordingly have an incentive to sell a unit of swing to buyer X at a price between $40 and $80. However, one or both of joint venture parties B and C would not receive any value for their expenditure.

Accordingly, it is more realistic to expect the joint venture parties to allocate costs after they have entered into their separate sales agreements.[63] What then would the incentives be for intra-joint venture competition?

In a world of perfect information, the *ex post* allocation of costs should not alter the incentives to compete. If joint venture party A sells one more unit of swing than the other parties, it would simply pay the incremental cost of providing that swing. However, in practice identifying the true incremental cost would be very complicated; allocation of common costs is notoriously difficult. Joint venture party A might consider the incremental cost to be $100, while the other parties might consider it to be $120. The uncertainty about the true incremental cost and availability of swing is likely to "chill" the incentives on all joint venture parties to be an "outlier" on any particular dimension, such as swing.

---

61 The right to purchase gas in excess of the daily quantity can be thought of as a real option.

62 Because we are considering scenario 2, quantity parameters are not specified.

63 Or to specify quantity parameters, but this would be scenario 1.

5.3.2. Increased Transaction and Production Costs

After having independently negotiated gas sales contracts with buyers, the joint venture parties would have to return to the joint venture table under scenario 2 to agree on the field development and consequent cost allocation.

Field development entails decision-making on a number of important parameters, including:

- Number of wells;
- Number of platforms;
- System capacity (including wells, pipelines and processing plant);
- System redundancy, to allow maintenance while maintaining production;
- System reliability; and
- Average throughput, for design of by-product (e.g., LPG) storage and export facilities.

Each of these parameters will depend on a number of variables and trade-offs. For example, while improved reliability will be valuable to buyers, it comes at a cost and the willingness to pay (or demand) for reliability will vary between buyers.

Having independently negotiated gas sales contracts, each joint venture party would have different information about these variables, and different views as to the trade-offs. Furthermore, each joint venture party would have different requirements for, and constraints on, the development, reflecting the terms of its own gas sales contract(s).

For these reasons, scenario 2 would lead to significantly increased transaction and production costs, compared with joint marketing.

Increased Transaction Costs

Because each joint venture party would have different information, value and expectational judgments, and contractual constraints, in respect of each development parameter, the scope for disagreement is very large. When combined with the intrinsic reserves uncertainty, prospective sunk and very large investment,[64] and anticipation of opportunistic behaviour under separate selling, negotiations would be long and contentious, and result in a very incomplete contract (if any).[65] In short, the nature of scenario 2 is intra-joint venture opportunism; therefore, for those cooperative elements that are essential, there would have to be very extensive investment in information and contract design for a feasible arrangement to emerge.[66]

Litigation between the joint venture parties would be a very real prospect, both before and after development decisions are made.

To illustrate, consider the swing term in a gas sales contract again. We would expect the allocation of the capital costs to provide swing to be very complicated. Even if by coincidence the gas sales contracts of all joint venture parties provide for the same daily quantity, it is likely that the swing will differ. Furthermore, the timing of swing demand is also likely to vary across types of customers, suggesting benefits from coordinated contracts.[67]

The difficulties imposed by differing reliability and other contractual constraints would add cumulatively to these complications.

---

64 Estimated to exceed $NZ1 billion for Pohokura.

65 An "incomplete contract" is one that does not describe what action is to be taken and payments made in every possible contingency. Contracts are seldom complete because of limited foresight, imprecise language, the costs of calculating solutions and the costs of writing down a plan – collectively, the "bounded rationality" of people.

66 As noted in the Appendix A literature survey, Hendricks and Porter (1996) point out that information asymmetries make it difficult for firms to use unitisation agreements in the United States. Also, information heterogeneities may inhibit the willingness of firms to enter joint ventures.

67 The higher the degree of flexibility in offtake, the more valuable the gas is likely to be to buyers. The ability to use as much of the installed field capacity as possible to provide this flexibility to buyers is thus valuable and influences the price a joint venture party might expect to receive. Even if the joint venture is able to agree on a development plan and the capacity of the facilities, under separate marketing each party has an incentive to pay a lower share of the high upfront facilities costs but nevertheless *ex post* disproportionately use a greater share of the installed capacity. Any arrangement to separately sell would have to deal with the risk that capacity paid for would not be available for subsequent use. Unless all parties can be guaranteed use of capacity they have paid for, it is likely that the parties will have great difficulty agreeing to invest the large capital sums required for development of the project.

It is important to note that the price in each joint venture party's sales contract would reflect all of the terms and conditions of that contract. Accordingly, the constraints imposed by each sales contract on the development decisions are real; any compromise by a joint venture party in its development negotiations with the other joint venture parties would have value implications. As part of the development negotiations, joint venture parties would almost certainly have to renegotiate their sales contracts, including price, with buyers.

Furthermore, because negotiations over the development parameters would involve revelation of the terms and conditions of each gas sales contract, it would seem almost inevitable that the prices in the gas sales contracts would also be revealed. This might lead to price convergence in the context of renegotiations with buyers.

Because of these transaction costs, significant delay in development is inevitable under scenario 2. The delay is likely to be measured in years, and may possibly be indefinite.

In this regard, the work of Libecap and Wiggins (1985)[68] is relevant. They study the impact of information asymmetries on negotiation time for joint agreements in the US oil and gas industry. Each party to the proposed agreement on a given gas or oilfield may have multiple wells drilled into the field. From these wells information about the field is gathered, which is private to that party. Since under a joint arrangement the share of net revenues from the whole field attributable to each party is determined by the value of the wells each party owns, each party has an incentive to overstate the value of their wells. This reduces the ability of each party to credibly share information on the value of their wells. In these circumstances, negotiation of joint venture operating agreements takes on average seven years, versus six months when there are no such information asymmetries.

Balancing Arrangements

Information, value and expectational asymmetries are likely to be significant in respect of many of the development parameters on which the joint venture parties would need to agree. Included in this list is the negotiation of a "balancing arrangement". Under scenario 2, it is very unlikely that each joint venture party would negotiate a sales contract with identical:

- Annual, monthly and daily quantities;
- Swing; and
- Term.

68 Libecap, G D and S N Wiggins (1985) "Oil Field Unitization: Contractual Failure in the Presence of Imperfect Information", *American Economic Review*, 75(3), 368-385.

Rather, it is very likely that there would be a divergence between entitlements and sales at any one point in time.[69]

In order to deplete the field in equity proportions overall, a balancing arrangement is required. (Conceptually, gas storage would also provide a solution. However, as noted above, gas storage is not practical or commercially justifiable in New Zealand, and is unlikely to be for the foreseeable future).[70]

Imbalances could be rectified with cash payments. However, this would require a price for gas that reflects its value at the time imbalances are rectified. If there was a spot market, a price related to the spot price could be used for balancing. However, in the absence of such an objective price, the joint venture parties would have to agree on an internal transfer price, which could be expected to form the floor price for external sales, and which would amount to price setting for the field.

The alternative is in-kind balancing. An "over-lifting" joint venture party could repay an "under-lifting" joint venture party:

- With equivalent gas from another field; or
- By effectively transferring entitlement to unproduced gas in the reservoir.

However, both methods are difficult in the New Zealand context.

Regarding the first method, unless the over-lifting joint venture party has its own alternative source of uncommitted gas,[71] the lack of a short-term contract or spot market would make it difficult for it to obtain the replacement gas, and difficult to value the gas. Furthermore, the under-lifting joint venture party would take on supply risk.

---

69 Factors driving these almost inevitable differences will include differing consumer preferences, and differing beliefs amongst the joint venture parties about discount rates and future prices.

70 Interestingly, oil and gas producing states in the United States have responded to the balancing problem by regulation. Pierce (1987) notes that: "All producing states have recognised the concept of correlative rights in response to the potential for one owner to "steal" gas from other owners through uncompensated drainage. The doctrine of correlative rights provides a legal framework in which each owner of oil and gas in a reservoir can produce its fair share of the total oil and gas in the reservoir, measured with reference to its proportionate ownership of the reservoir" (page 19) (Pierce, Richard J (1987) "State Regulation of Natural Gas in a Federally Deregulated Market: The Tragedy of the Commons Revisited", *Cornell Law Review*, 73, 15-53).

One of the forms of regulation used (for example, in Oklahoma) requires the operator of a field to provide each other owner (joint venture party) the option to elect to have the operator market each owner's share of the gas on terms at least as favourable as those the operator obtains for its own share. "Electing owners become, in effect, co-owners for gas marketing purposes" (Pierce 1987, 26).

We note that this form of regulation effectively authorises joint marketing of gas.

71 Of sufficient volume and deliverability.

While Shell and Todd have interests in other New Zealand gas fields, we understand that their only current sources of uncommitted gas are smaller fields such as Kapuni, McKee and Mangahewa (the latter two being Todd only). However, given the rising demand for gas, and the depletion of Maui, it would seem unlikely that the Pohokura joint venture parties would enter into a balancing arrangement that was based on such gas remaining uncommitted. It is unlikely that the highest value use for such gas would be as a balancing vehicle for Pohokura gas.

Furthermore, Preussag does not have any alternative source of gas. This asymmetry is likely to make this type of balancing arrangement infeasible.

Regarding the second method of in-kind balancing, the arrangement would also be used to attempt to mitigate the common pool incentive problems; in other words, the arrangement would be designed to mitigate the over-extraction incentives outlined in section 5.3.1. However, the uncertainty and asymmetric information (and judgments) among the parties about relevant variables is likely to make negotiations long and contentious, and to result in a very incomplete contract.

For example, recall that the over-extraction incentive arises from the uncertainty about the quantity of economically recoverable reserves. To achieve incentive compatibility, i.e., to align the incentives of all joint venture parties to cooperate rather than compete in pool depletion, a risk compensation mechanism would need to be designed. This would be complicated because the risk premium would depend on the state of knowledge about geology, the state of depletion of the field, the length of time until extraction, etc. Each of these variables would "vary" depending on the timing of the imbalance, and each joint venture party would have different views on their values.

Because a balancing arrangement is unlikely to be as complete and incentive compatible as a joint marketing arrangement, the costs of enforcement (for example, legal fees, management opportunity cost and production delays) will almost certainly be higher.

Increased Production Costs

Scenario 2 would involve higher production costs than joint marketing, for several reasons.

Firstly, the fact that each joint venture party would return to the joint venture table armed with different contractual obligations and constraints is likely to result in sub optimal capital expenditure decisions.

Secondly, the unmitigated common pool incentives would lead to more capital being expended than is optimal.

Thirdly, both scenarios 1 and 2 would entail multiple sales negotiations.

Finally, under both scenarios, there would be the extra costs of administering several sales contracts, including the resolution of disputes.

5.3.3. Implications for Buyers of Gas

Consider also the *ex ante* implications of these delays and uncertainties for prospective buyers of gas. For example, electricity generators may require the certainty of long-term gas contracts in order to undertake investment in gas-fired generation plants. While gas field joint venture parties may be able to enter into long-term sales contracts under scenario 2, buyers would anticipate the subsequent development difficulties and inherent uncertainty about the physical performance of the field, and these factors would markedly reduce any certainty about gas supply.

Consequently, the price that generators would be prepared to pay for gas would be lower, and in turn the value of the gas field to the joint venture parties would be lower. Therefore, *ex ante* the incentive to explore for gas would be reduced.

The increased uncertainty would almost certainly result in the delay of investment in gas-fired power stations.

5.3.4. Implications for Gas Market Competition

At several points in this section 5.3 we have noted that the over-extraction incentives, transaction costs and production costs inherent in scenario 2 would result in reduced field value. *Ex ante*, this would reduce the incentives on firms to enter the New Zealand oil and gas exploration industry. Accordingly, separate marketing would ultimately lead to *less* competition in the gas production market than would joint marketing.

5.3.5. Statutory Constraints

Prior to issuing a mining permit, the Ministry of Economic Development evaluates the proposed development plans of the field right holders pursuant to its powers and obligations under the Crown Minerals Act 1991. The Minister of Energy is required to consider a number of factors, including efficient extraction and the encouragement of continued investment in petroleum exploration and mining.

Furthermore, once a mining permit is granted, production is monitored.

We would expect the Minister to be concerned about the effects of scenario 2. Of particular concern would be the over-extraction incentives, delays in development and reduction in exploration incentives.

5.3.6. Summary of Costs and Benefits of Scenario 2

In summary, compared to joint marketing, scenario 2 would result in:

- Intra-joint venture competition;[72]
- Over-extraction incentives and loss of field value;
- Reduction in exploration incentives;
- Reduction in competition in the gas production market;
- Significantly increased transaction costs;
- Significantly increased production costs; and
- Significantly delayed development and production.

Furthermore, scenario 2 would entail a risk of the Ministry of Economic Development refusing to grant a mining permit.

5.4. Costs and Benefits of Scenario 1

5.4.1. Lack of Demand Side Information, Flexibility Constraints and Reduced Incentives to Explore

It is important to note that scenario 1 effectively involves the joint venture parties making decisions on development parameters (including quantities and rates) *prior* to sales contracts being entered into. This approach could mitigate the over-extraction incentives to an extent. However, a disadvantage of it is that those parameters would be established using a smaller set of demand-side information than could be obtained under, for example, joint marketing. The consequences are that:

- The parameters are less likely to be set at the welfare maximising point; and
- Negotiations over those parameters would be longer and more contentious, particularly given that there would be an asymmetry between each joint venture party's imperfect set of demand-side information.

72 At least it does in theory; section 5.3.1 discusses how the incentive for intra-joint venture competition will be mitigated in practice.

Furthermore, the *ex ante* determined parameters would act as constraints limiting the flexibility of each joint venture party in negotiations with buyers. In particular, there would be little flexibility to compete on available quantities or rates of flow. The implications of this for competition on price are discussed below. Other implications include potential extension and complication of negotiations with buyers.

One aspect is that the annual quantity of each joint venture party by itself might not be sufficient to fulfil the requirements of a buyer. For example, expected buyers of Pohokura gas include electricity generators. We understand that an efficient gas-fired generation plant producing 370 MW would consume approximately 20 PJ of gas per annum. The current expectation of the Pohokura joint venture parties is that they may jointly sell at an annual rate of 30 PJ in the initial stage of the development and at an annual rate of 70 PJ from about 2007 (on the assumption that joint marketing is permitted) Based on current joint venture percentage interests, the 70 PJ figure would give Shell approximately 33.6PJ, Preussag 25 PJ and Todd 11 PJ, and of course the allocations would be even lower at 30 PJ.

More generally, enforced separate marketing could result in "sub-economic" packages for smaller players, and for all players in smaller fields.[73] *Ex ante*, this would reduce exploration incentives, leading ultimately to less competition and to welfare losses. It would also probably result in a longer timeframe for arranging the sale of gas.

It is worth reflecting at this point on the significant number of exploration and mining permits in New Zealand in respect of which players have relatively small percentage interests. We attach as Appendix D the list of current Taranaki permits and permit holders to illustrate this.[74]

A buyer could aggregate the quantities of two or more of the joint venture parties. For example, assume that the total annual quantity parameter from a field is 45 PJ, divided equally between three joint venture parties. Also assume that a generator requires 20 PJ per year. The generator could negotiate with both Company A and Company B, purchasing, for example, 15 PJ from Company A and 5 PJ from Company B. However, two negotiations would add significantly to the transactions and production costs. Furthermore, Company B would be left with 10 PJ of gas per year.

73 We note that there are several gas contracts in place in New Zealand for relatively small annual quantities. However, the circumstances of these fields can be distinguished from Pohokura. For example, the gas from McKee is associated with oil. We understand that the purchaser of McKee gas (Methanex) has agreed to take whatever gas is extracted, with no control over the profile. As another example, the gas from TAWN was purchased by ECNZ to augment its Maui base; the TAWN gas was not a necessary condition to ECNZ developing a power station.

74 Source: Ministry of Economic Development website (www.med.govt.nz).

Importantly, the fact that separate marketing may result in some joint venture parties being left with sub-economic packages may create some inefficient dynamics. In particular, while the three hypothetical joint venture parties would share costs and quantities equally, it may turn out that they do not earn equal revenues. This could make agreement on future expenditures difficult.

As well as the annual quantity of each joint venture party by itself potentially being insufficient to fulfil the requirements of a buyer, a contract for that quantity is also unlikely to be significant enough to justify development of the field on its own. Each sales contract would have to be conditional on the other joint venture parties writing contracts that in aggregate justify development. This lack of coordination is likely to delay development, particularly given that any sub-economic packages may take longer to sell. Furthermore, from the perspective of a buyer, a condition in the contract would raise uncertainty, and lower the contract's expected value. Once again, *ex ante* exploration incentives would be reduced.

In this regard, the Upstream Issues Working Group (UIWG) stated in its report to the Australian and New Zealand Minerals and Energy Council and the Council of Australian Governments[75] that (page 29):

> *Where joint venture production is seen as the most efficient way of undertaking gas developments, the UIWG considers that prohibiting joint marketing could raise the costs and/or increase the risks of entering gas production, where separate marketing is not viable. This could act as a significant barrier to entry, and could have a perverse effect on supplier competition by potentially discouraging new parties from entering the industry and by inhibiting the development of reserves.*

And on page 30:

> *The UIWG considers that there is merit in arguments presented in a number of submissions that mandating separate marketing under current circumstances could potentially result in an* ***increase*** *in gas prices. The view was expressed in a large number of submissions that, given the current immaturity of parts of the Australian gas market, the requirement to market separately would represent a major obstacle to both small players and new entrants into the gas industry. This could restrict supplier participation in the market and the development of reserves, ultimately inhibiting competition.*

75 December 1998. The UIWG consisted of representatives from the Commonwealth, State and Territory Governments, the Australian Gas Association (AGA), the Australian Petroleum Production and Exploration Association (APPEA), the Australian Pipeline Industry Association (APIA), the Business Council of Australia (BCA), and was independently chaired. The ACCC and the National Competition Council (NCC) attended as "interested observers".

5.4.2. No Competition on Pricing

Scenario 1 envisages the joint venture parties separately marketing their gas once they have jointly agreed on certain key parameters, such as quantity and rate (i.e., the optimal depletion profile). For two reasons, scenario 1 would not result in price competition:

- Joint development of the optimal depletion profile must be based on a variety of factors, including 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 the least a range) that was acceptable to design the off take capability of the field; and

- Joint agreement on quantities and rates would mean that the share of each joint venture party is fixed. Accordingly, a price cut from the market-clearing price for the total quantity could only result in lower revenue. In other words, there would be no gain to a joint venture party in trying to undercut the other joint venture parties, as it could not gain any of their market shares, at least with respect to that field. This is in contrast to the situation in most other markets, where a firm could expect to gain market share from its competitors by cutting price.

5.4.3. Balancing Arrangement

Scenario 1 would also require the joint venture parties to agree on a balancing arrangement. While not having to deal with the same scale or scope of complexity as a scenario 2 balancing arrangement (because of the mitigated over-extraction incentives), the transaction costs of negotiation could nevertheless be expected to be significant.

5.4.4. Statutory Constraints

While over-extraction incentives would be less of an issue under scenario 1, the Ministry of Economic Development might still be concerned about the potential for this form of marketing to delay field development and to reduce exploration incentives.

5.4.5. Summary of Costs and Benefits of Scenario 1

In summary, compared to joint marketing, scenario 1 would result in:

- No extra intra-joint venture competition;

- Loss of field value;

- Reduction in exploration incentives;

- Reduction in competition in the gas production market;

- Significantly increased transaction costs;
- Significantly increased production costs; and
- Significantly delayed development and production.

Furthermore, scenario 1 would entail a risk of the Ministry of Economic Development refusing to grant a mining permit.

5.5. Costs and Benefits of Joint Marketing

5.5.1. Timely Development and Production

An important benefit of joint marketing is the avoidance of many of the transaction costs (and production costs) of either form of separate marketing. Important factors are that:

- Information, value judgments and contractual constraints would be much more symmetric;
- Balancing arrangements would be unnecessary; and
- Over-extraction incentives would be mitigated.

Accordingly, joint marketing would result in quicker and more efficient field development and production.

5.5.2. Promotion of Competition

For the reasons outlined in sections 5.3 and 5.4, joint marketing would also result in greater field value than either form of separate marketing. This in turn would encourage greater entry into the gas production market, and accordingly more competition.

5.5.3. Constraints on Market Power

Under joint marketing, the joint venture parties would not compete with each other on either price or quantity within the joint venture. However, the developers of the Pohokura field are likely to face considerable constraints on their ability to exercise any market power. These constraints include:

- The misalignment of incentives (and other asymmetries) faced by each firm in the joint venture due to other business activities;
- Greater exploration incentives and therefore competition;
- The market expectation that new discoveries will be made; and

- Expansion of production from existing fields.

Misalignment of Incentives

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. For example, while they may be cooperating in respect of exploration on and production from a particular tract, they may compete in other areas, and may have different vertical interests. As an illustration, consider Genesis, which as an electricity generator is a likely gas purchaser. Genesis has a 70 percent interest in the Kupe gas field.

In respect of the Pohokura joint venture parties, Todd Energy has interests in gas-fired cogeneration plants and a retailer of gas, Nova. Therefore, Todd is both a buyer and a seller of gas. While the incentives on Todd Energy are likely to be complicated, it is likely that they will be different to those of its 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 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. 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. Indeed, the bundling of joint venture parties' interests in a joint venture can mitigate the market power they might otherwise exhibit given their other interests in that market.

Future Gas Discoveries and Exploration Incentives

The potential for gas discoveries was outlined in section 3.1 of this report. Importantly, we suspect that one of the assumptions on which many firms are basing their exploration decisions is that they will be permitted to jointly market any gas they find. As noted above, mandatory separate marketing would reduce exploration incentives.

The effect of new discoveries will be to lower the Pohokura joint venture's market share. The threat of future entry into the market by as-yet unidentified gas fields and operators acts (presently) to undermine any market power of the Pohokura joint venture parties. It can be expected that negotiations for Pohokura gas will be carried out by parties fully aware of the likely future competition Pohokura will face (including the Kupe field, in respect of which one of the owners (NZOG) has publicly stated that a price of $3.50 to $4.50 would be sufficient to justify development[76]).

Expansion of Production from Existing Fields

The Pohokura joint venture parties advise us that existing fields typically have scope for further incremental recovery. Technology to enhance recovery has become an increasingly specialised area in recent years. The degree to which recovery can be increased varies from field to field and in most cases is an issue of economics. As the gas price rises, additional options can become economic. The incremental supply from enhanced scope for recovery from existing gas fields is therefore an ongoing competitive constraint on any new field such as Pohokura.

5.5.4. Demand-Side Information

As noted above, many of the field development parameters require the joint venture parties to form judgments about important variables and trade-offs, for example, the marginal costs and benefits of increased swing. Joint marketing would enable the joint venture parties to elicit demand-side information together. This should lead to:

- More efficient decision-making from the social perspective; and
- Less asymmetry of information, thereby reducing the transaction costs of development.

5.5.5. Summary of Costs and Benefits of Joint Marketing

In summary, compared to either form of separate marketing, joint marketing would result in:

- No intra-joint venture competition (although any ability to exercise market power would be constrained);
- Greater field value;
- Greater exploration incentives;
- Greater competition in the gas production market;

76 Submission in response to ACIL report, 31 January 2002, page 3.

- Significantly lower transaction costs;
- Significantly lower production costs; and
- Significantly quicker development of the field.

In other words, joint marketing is actually *pro-competitive and dynamically economically efficient*.

6. COUNTERFACTUALS

As noted previously in this report, the ACCC and the Australian Competition Tribunal have found that separate marketing in Australia is not feasible, and that therefore the appropriate counterfactual for competition analysis is "no development".

It is unclear what the ACCC and the Competition Tribunal had in mind by the term "separate marketing".

In our view, it is quite plausible that a requirement on the Pohokura joint venture parties to separately market in the sense of scenario 2 would lead to no development. Section 5.3 of this report discusses the very significant difficulties that scenario 2 would entail. Accordingly, "no development" is one counterfactual.

Nevertheless, it is possible that the field may be eventually developed even if scenario 2 separate marketing were mandated. However, it is our view that, compared with joint marketing, separate marketing would entail significant:

- Extra production costs;
- Extra transaction costs;
- Delay in the development of the field;
- Destruction of value of the field; and
- Reduction in exploration incentives.

While these factors would be worse under scenario 2 than under scenario 1, scenario 1 would also have no competition advantages over joint marketing (in fact, both forms of separate marketing would have competition *disadvantages* compared to joint marketing).

Three counterfactuals follow from our analysis:

1. Scenario 1, with development of the field delayed by x years;
2. Scenario 2, with development of the field delayed by y years;

   where $y > x$; and
3. No development.

It is very difficult to predict the values of x and y. In fact, it is plausible that $y \rightarrow \infty$, i.e., that scenario 2 approaches an indefinite delay scenario.

Even if we take a conservative view, for example, that $y > x = 3$, we show in section 8 that the welfare losses from separate marketing would be very large. If joint marketing is permitted, the Pohokura joint venture parties expect to commence production by 2004. A 3-year delay would push this start date out to a time when production from Maui is very low.

7. IS THERE A SUBSTANTIAL LESSENING OF COMPETITION?

7.1. Introduction

Section 27(1) of the Commerce Act provides that:

> *"No person shall enter into a contract or arrangement, or arrive at an understanding, containing a provision that has the purpose, or has or is likely to have the effect, of substantially lessening competition in a market."*

The costs and benefits of each of the three types of gas marketing identified as specific points on the marketing continuum in section 1.2 were analysed in section 5. The purpose of this section is to summarise the conclusions of that analysis in the context of section 27.

7.2. Against Counterfactual 1

Joint marketing would not lead to any lessening of intra-joint venture competition compared to scenario 1. In fact, joint marketing would lead to an *increase* in competition (and production) in the gas production market compared to scenario 1, as it would result in greater exploration and development incentives.[77]

Compared to scenario 1, joint marketing would also result in:

- Earlier development and production;
- More efficient development decision making;
- Significantly lower transaction costs; and
- Significantly lower production costs.

7.3. Against Counterfactual 2

Joint marketing would result in less intra-joint venture competition than scenario 2.[78] However, joint marketing would lead to an *increase* in competition (and production) in the gas production market compared to scenario 2, as it would result in greater exploration and development incentives.[79]

---

77 For firms of all sizes.

78 At least it does in theory; section 5.3.1 discusses how the incentive for intra-joint venture competition under scenario 2 will be mitigated in practice.

79 For firms of all sizes.

Compared to scenario 2, joint marketing would also result in:

- More efficient development decision making;
- More efficient extraction;
- Earlier development and production;
- Significantly lower transaction costs; and
- Significantly lower production costs.

7.4. AGAINST COUNTERFACTUAL 3

Joint marketing would result in an increase in competition in the gas production market against a counterfactual of no development, as it would lead to one extra producing field in the market. No development would cause explorers to question whether an exploration success could be turned into a development or alternatively whether the economic cost of the extended delay caused by separate marketing still justifies the investment in high-risk exploration. Joint marketing therefore retains better incentives for entry.

8. COUNTERVAILING BENEFITS

8.1. INTRODUCTION

We consider that there is no detriment arising from the practice of joint marketing. Rather, we believe that this arrangement would increase competition compared to all of the possible counterfactuals, and would increase dynamic economic efficiency.

Furthermore, we have outlined in this report other efficiency advantages of joint marketing over separate marketing. The purpose of this section is to quantify some of the efficiencies. We recognise that the Commission will seek quantification of countervailing benefits if, despite the analysis of this report, it does consider that the proposed arrangement would substantially lessen competition in the gas production market.

8.2. PUBLIC BENEFITS

8.2.1. Timely Development of Pohokura

Introduction

If joint marketing is permitted, the Pohokura joint venture parties expect to be producing from Pohokura by 2004. However, if they are forced to market separately, section 5 of this report demonstrated that development would be significantly delayed (potentially indefinitely), because of increased transaction costs.

In our view, joint marketing is necessary for timely development of the field. Absent joint marketing, delay in development and production would be *at least* of the order of three years beyond that which would otherwise occur. Accordingly (and conservatively), we quantify welfare effects for a three-year delay.

If joint marketing is permitted, the Pohokura joint venture parties expect to develop and produce from the field by 2004, with the profile in Table 8.

Table 8: Expected Production Profile from Pohokura With Joint Marketing

Year	Production
2004	[ ] PJ
2005	[ ] PJ
2006	[ ] PJ
2007 onwards	[ ] PJ

This production profile reflects an initial onshore development, followed by an offshore development (which is responsible for the higher production from 2007).

A three-year delay would result in the production profile in Table 9.

Table 9: Expected Production Profile from Pohokura With Three Year Delay

Year	Production
2007	[ ] PJ
2008	[ ] PJ
2009	[ ] PJ
2010 onwards	[ ] PJ

Qualitatively, it is clear that such a delay would result in significant welfare losses for New Zealand. It is likely that separate marketing would result in Pohokura not coming on stream until after the substantial depletion of Maui, leaving a significant gap in supply at a time when demand for gas is rising. Possibly the greatest impact would be on electricity generation. A significant rise in electricity prices could have severe impacts on the international competitiveness of New Zealand businesses. There would also of course be a negative impact on domestic electricity (and gas) consumers.

The impact would be particularly significant in the event of another "dry year" such as occurred in 2001, or if electricity demand continues to grow (as is expected).

Quantitatively, the cost of this delay is measured by the discounted value of the sum of the (net) lost consumer and producer surplus in the affected markets.

The primary market to be analysed is the gas production market. However, a restriction in supply in that market would affect related markets (i.e., those for substitutes and complements) as well.

This raises the issue about how many markets we should be attempting to quantify welfare effects in. Quantification of welfare effects in all related markets would be resource-intensive, requiring an appropriately modified general equilibrium model that would not be cost effective compared to the partial equilibrium approach we adopt.[80]

80 The term of our analysis allows for some adjustment in the gas production market. Given a policy prohibiting joint marketing, all participants in gas, electricity, other fuels, and related markets would make responding adjustments, especially if they perceived it to be a permanent policy.

Accordingly, to illustrate the magnitude of the welfare impact of a delay in development of Pohokura, we limit our analysis to the effects on the key set of vertically related markets that are the:

- Gas production market, the electricity generation market, and the electricity retailing market;[81] and

- Gas production market and the petrochemicals production market.

In choosing to concentrate on these markets, we note that currently the single biggest user of gas in New Zealand is the electricity generation sector (about 44 percent).[82] The next largest user of natural gas in New Zealand is the petrochemicals sector (about 42 percent), which is dominated (about 92 percent) by Methanex.[83] The impact on the petrochemicals sector of a delay in production from Pohokura is potentially significant (i.e., reduced production, or shut-down).

Methanex, other petrochemical companies and electricity generation consume approximately 85 percent of New Zealand natural gas. Other uses of gas, for example reticulation, are excluded from the analysis.

Quantifying Losses

In Appendix B we show that performing welfare analysis in the gas production market can approximate welfare losses in vertically related markets for electricity generation and retailing, and methanol production. In other words, by analysing welfare losses in the gas production market alone, we can calculate total welfare effects in all four markets.[84]

Just et. al (1982) summarise this convenient result succinctly in the following equation:[85]

$$\Delta C_n^* + \Delta P_n^* = \sum_{j=1}^{N} \Delta R_j$$

---

81 We recognise that by ignoring the impact on the markets for substitutes, our analysis will overstate the magnitude of the welfare losses. However, we consider that substitutes for natural gas in the generation of electricity, at least in a reasonably short time frame, are quite limited (the only real possibility being coal for Huntly). Hence, any overstatement is likely to be small. Furthermore, by ignoring consumption of gas by end-users (for example, residential and industrial users), our analysis will understate the welfare losses.

82 Source: Ministry of Economic Development (2001) *New Zealand Energy Data File*, 82.

83 Methanex consumes about 90PJ of gas per annum, with other petrochemicals plants consuming 8PJ per annum.

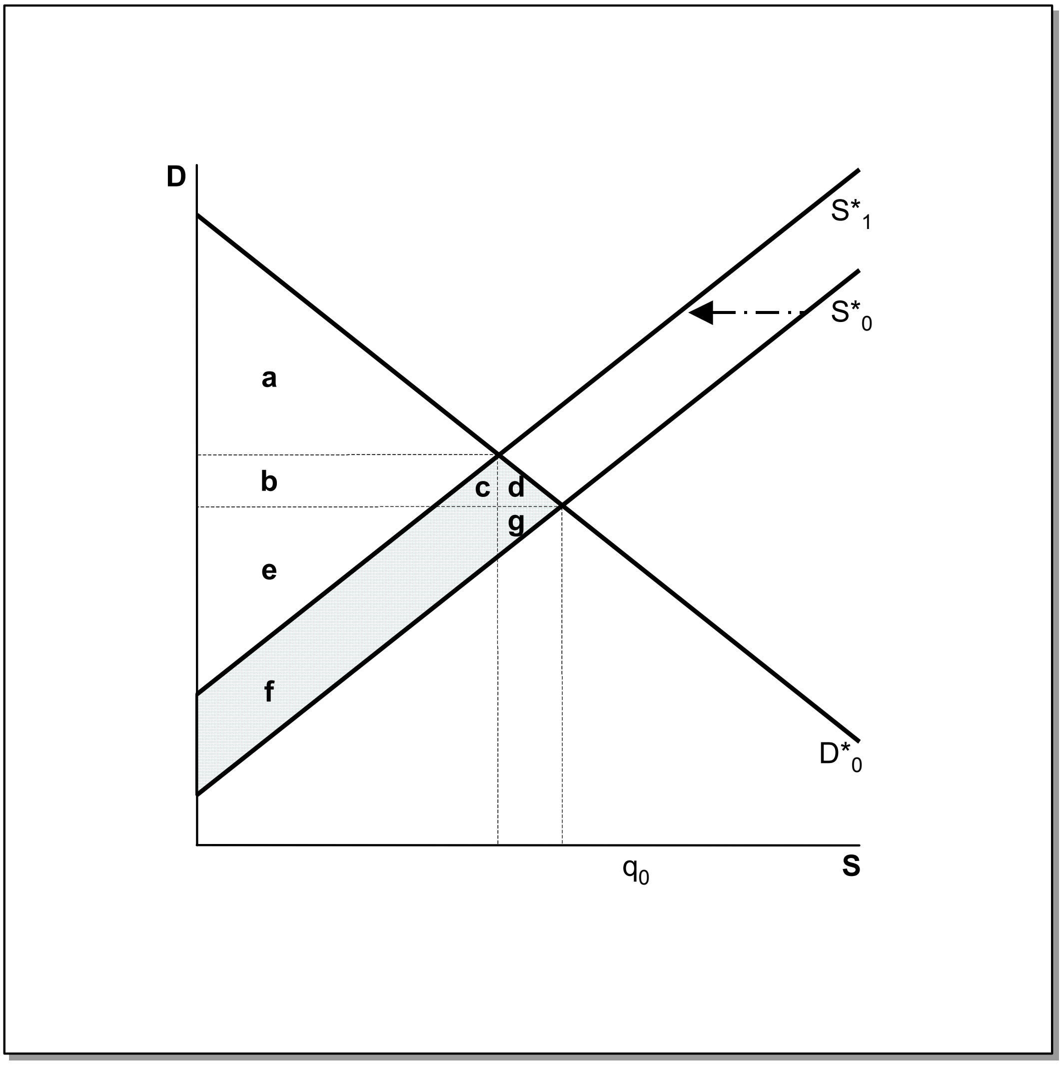
84 The concept of an equilibrium demand curve is central to this analysis; this is described in Appendix B.

85 Just, R, D Hueth and A Schmitz (1982) *Applied Welfare Economics and Public Policy*, Prentice-Hall, 187.

where ΔC_n^* denotes change in consumer surplus in the affected market, ΔP_n^* denotes change in producer surplus in the affected market, and ΔR_j is the change in total surplus in market j. This equation says that in a vertically-related set of N markets, the sum of changes in producer and consumer surplus in the affected market equals the total change in surplus in all markets where all relevant prices are allowed to vary.[86]

Accordingly, we can focus on measuring the welfare changes in the gas production market, as illustrated by Figure 3.

Figure 3: Conceptual Depiction of Welfare Changes



86 By "affected market", we mean the market for which there has been a change in supply or demand conditions; in the present case, that is the gas production market.

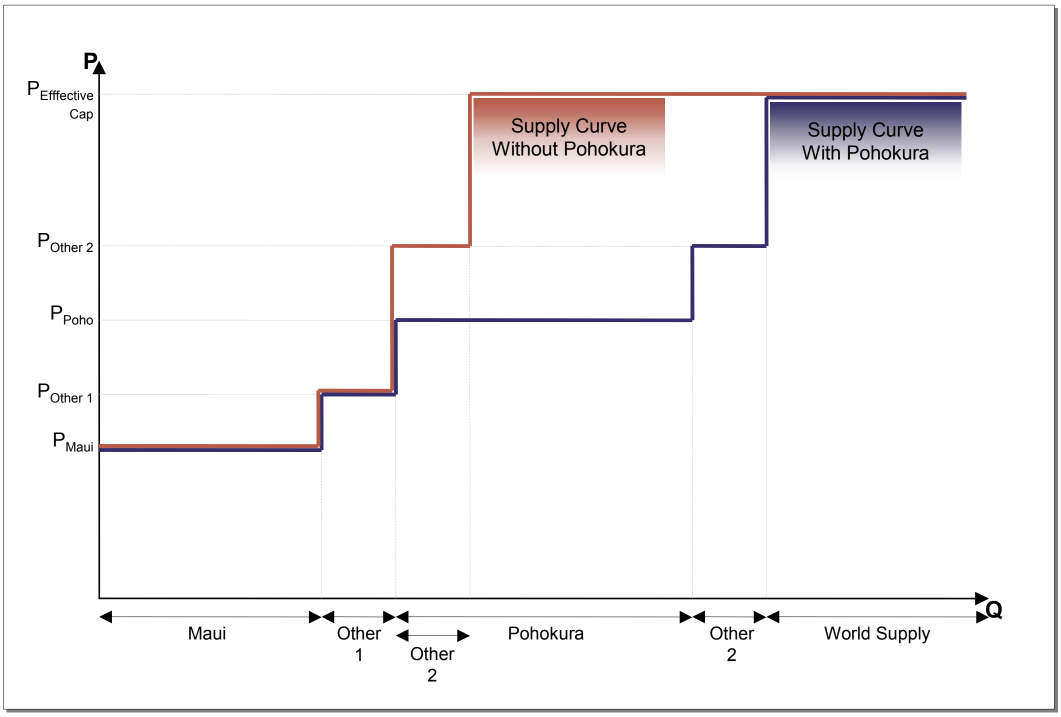
Following a constriction of natural gas supply the reduction in consumer and producer surplus is represented by the shaded area in Figure 3. Consumers lose areas c+d (plus b, which goes to producers), while producers lose areas f+g (but gain b). (Area b is a transfer from consumers to producers).

The loss to society comes in two parts. Firstly, alternative and more expensive sources of production must be developed after the supply constriction; the increased cost of producing gas from these alternative fields is a loss in welfare.[87] This loss corresponds to areas f+c in Figure 3. Secondly, there is a reduction in the total amount of gas produced so there is a loss corresponding to the traditional dead weight loss that occurs when there is a reduction in output. This corresponds to areas d+g in Figure 3.

Derivation of Supply

Figure 3 shows a stylised view of supply and demand in the market for gas production, but in reality these curves are less smooth. We describe here the practical derivation of these curves for calculating our estimate of public welfare effects from delay.

Figure 4: "Actual" Supply Curves



87 We assume that gas fields with lower production costs are developed first. Following a delay in production from Pohokura, fields which are "harder" or, equivalently, more costly to produce from must then be developed to satiate demand. The cost of production from existing fields will be unchanged in either scenario.

A view of an "actual" supply curve is shown in Figure 4. This is a step function, one step for each developed gas field at some time *t*. These fields are ordered such that lowest cost fields are situated at the left, while higher cost fields are represented moving rightwards. The effect of this is to produce an upwards-sloping step function. The reason for this ordering is that consumers in the market for gas will seek out lowest cost sources first: from a starting point of zero supply, we assume the lowest cost source of natural gas will be developed first, followed by the next lowest-cost field, and so on. The horizontal length of each step indicates the available supply from each field in time period *t*. The highest step situated at the extreme right of the diagram is the price at which a generator would be indifferent between purchasing natural gas and coal. This price is an effective cap on the gas price; we set out its derivation in Appendix E. Any local fields for which natural gas has a (long run) supply cost exceeding this mark would not be developed, since it would be cheaper to use coal.

Although our analysis is to be carried out over a relatively short time frame of six years, adjustments will take place if the development of Pohokura is delayed. Thus we allow demand and supply to adjust and the appropriate costs to be considered in this analysis are long run marginal costs. This means that fixed costs are included that would not otherwise be considered in a short run view of costs. The reason for the inclusion of fixed costs is that suppliers of natural gas will be unwilling to sell gas at a price that does not contribute to both fixed costs and short run variable costs. This is particularly true in the absence of spot markets and when gas is sold under long-term contracts. The relevant price floor, below which suppliers will not be willing to provide gas, is therefore considered to be long run marginal cost, and it is this cost on which decisions are likely to be based.

We consider that the price at which the fields are sold is an indicator of long run marginal cost, and assume these fields would not be willingly developed in the absence of a price that recovers fixed costs.

The practical determination of the position of the actual supply curve requires two pieces of information for each step in the curve:

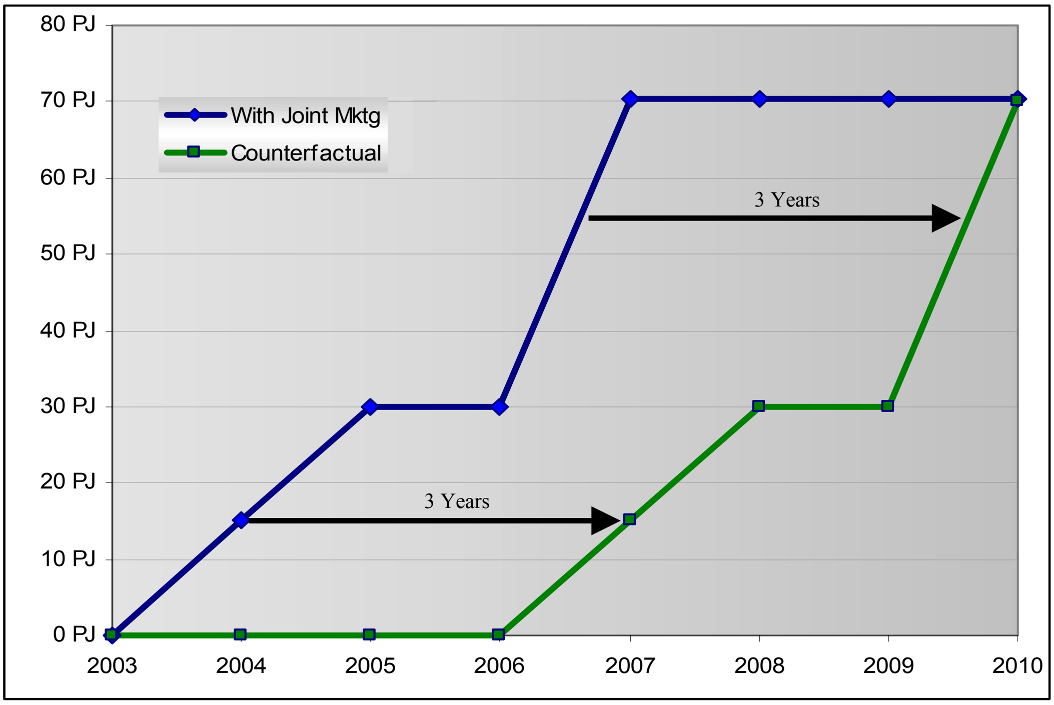
- The available quantity from each field in time period *t*; and
- The price at which these fields are supplied.

In our base case modelling, we have used the:

- Quantities set out in Appendix F (multiplied by 0.85 to eliminate the share of supply being used for other than generation and petrochemicals production purposes), and as illustrated in Figure 5; and

- Prices as set out in Table 10[88].

Figure 5: Estimated Pohokura Production Profile With Joint Marketing and Without Joint Marketing



88 The prices we use are based on publicly available information. We have not received any non-public information about prices from any of the Pohokura joint venture parties

Table 10: Prices Used for Base Modelling

Source	Price (NZ$ per GJ)
Maui	[ ] [89]
Other (1)	[ ] [90]
Pohokura	[ ] [91]
Cap set by coal	[ ] [92]

Our model also includes Kupe and Kauhauroa.[93] While Kauhauroa is not expected to commence production within the relevant timeframe, we have assumed that Kupe will come on-line in 2008, producing 10PJ that year at $[ ] per GJ. The effect of Kupe is to provide a substitute gas source for Pohokura, reducing the costs of a delay in the development of Pohokura.

We vary the Pohokura quantity and price in our sensitivity analysis.

The final key assumption we make on the supply side is that only the output from Pohokura changes under the counterfactual (to zero). We assume that the output from other fields would not change. This seems a reasonable assumption given that the only field that has had the ability to deliver significant swing in the past (Maui) is close to being depleted.

89 We understand that the price received by the Maui joint venture parties under their contract with the Crown is approximately $[ ] (including the energy resources levy), although a significant proportion of this gas is on-sold at higher prices.

90 If the prices for gas from Kapuni, Mangahewa, McKee, TAWN, Kaimiro, Ngatoro and Rimu are somewhere between the Maui price and the likely Pohokura price (which seems a reasonable assumption), then their exact level does not matter for our analysis. For the sake of simplicity, we have assumed that they are half way between the prices for Maui and Pohokura.

91 In its 2 November 2001 report in respect of the proposed Edison Mission takeover offer for Contact Energy, Grant Samuel stated that generators in New Zealand pay in the range of $2 to $3.80 per GJ for gas. Grant Samuel also noted that "it is expected that as Maui moves towards the end of its economic life prices negotiated for gas from undeveloped fields such as Pohokura will rise" (page 24). In its 31 January 2001 submission to the Ministry of Economic Development in respect of the ACIL report, NZOG stated that it "believes that electricity generators will need to pay $3.50 to $4.50/GJ to acquire gas from significant new gas field developments, such as Kupe or Pohokura" (page 3).

92 See Appendix E for a derivation.

93 The sensitivity of welfare losses to the price and quantity of natural gas available from these fields each period is tested in the sensitivity analysis.

Derivation of Demand

Like supply, demand for gas in the market for gas production is likely to be a step function. This is because there are few purchasers of gas, and because for at least one purchaser (Methanex), demand is likely to instantly fall to zero above a given price.

We understand that Methanex is currently paying about $2.00 per GJ.[94] We are aware of a public statement referring to a price that Methanex is willing to pay for gas of $4.00, although we discount this to some extent.[95] We are also aware of speculation that even if Methanex cannot continue to purchase "cheap" gas in New Zealand, it might continue to run its plants at low capacity (for example, 50 percent) as a back-up to its new Australian plant.

For these reasons, we assume in our baseline scenario in 2004 that Methanex and other petrochemical firms takes its full contracted gas amounts. In 2005, Methanex and other petrochemical firms consume just 49PJ, following redetermination of reserves in Maui and the reserves Methanex is entitled to. In addition to the 49PJ, Methanex and other petrochemical firms will consume any gas it can purchase for less than $[ ]/GJ. After 2005, Methanex and other petrochemical firms is assumed to operate plants at capacity if natural gas is available at less than $[ ] per GJ, and at 50% of capacity at a price between $[ ] per GJ and $[ ] per GJ. Above a price of $[ ] per GJ, we assume that the plant is shut down. We also test for the welfare impacts of alternative behaviour by Methanex and other petrochemical firms.

Unlike supply, actual demand is not observable at prices that deviate from current prices. Demand can be thought of as a descending list of consumer reservation prices. It is clearly difficult to estimate what the willingness to pay for gas by electricity generators (and others) will be in the future. We understand that generators have mentioned figures such as $[ ] per gigajoule, although we are unable to verify this. Furthermore, in the current environment where both buyers and sellers are preparing for crucial market transactions, we would not expect any public statements about willingness to pay to be precise revelations. Nevertheless, given that:

- [ ];
- demand for gas by generators is expected to grow; and
- the supply of Maui gas is reducing,

---

94 Source: ACIL *Review of the New Zealand Gas Sector – A Report to the Ministry of Economic Development*, October 2001, page A5-7.

95 Made orally by Bruce Aitken, Managing Director of Methanex, at the 2002 New Zealand Petroleum Conference. We did not hear this comment directly, and so we are not sure of the context in which it was made. Accordingly, we have conservatively discounted it.

$[ ] appears to be a reasonable (and arguably conservative) estimate.

Generators currently consume approximately 103 PJ of gas per year. We understand that both Genesis and Contact Energy are proposing to build new gas-fired plants. While there is some uncertainty over timing,[96] it seems reasonable to assume for the purposes of our modelling that both plants will come on stream in 2005. Each of these plants is likely to consume about 20 PJ per year. However, this new capacity may replace some existing capacity. It is difficult to predict what the net demand for gas by generators will be. For our base case modelling, we pragmatically assume that 101 PJ of gas will be demanded by generators in 2004, 123 PJ of gas will be demanded by generators in 2005 as new plants come online,[97] with market demand for natural gas growing at an assumed rate of two percent per annum (meaning, for example, that 126 PJ would be demanded by generators in 2006 at a price of $[ ]/GJ). (Two percent growth is arguably a conservative estimate. We test alternative assumptions in our sensitivity analysis; the results indicate that a higher growth estimate would result in greater welfare losses arising from enforced separate marketing).

We assume a linear demand curve. We also assume in the baseline scenario that demand for gas is inelastic (-0.5). The response of electricity prices to the water shortage in 2001 indicates that (particularly short-run) demand for electricity is inelastic. As the demand for gas is significantly derived from the demand for electricity, we believe an assumption of inelasticity for gas demand is reasonable. However, we do alter this assumption in our sensitivity analysis.

Our base modelling is also conservative in that it assumes that hydro storage in the relevant years will be at average levels. If there is another "dry" year like 2001, the welfare effects would be significantly greater.

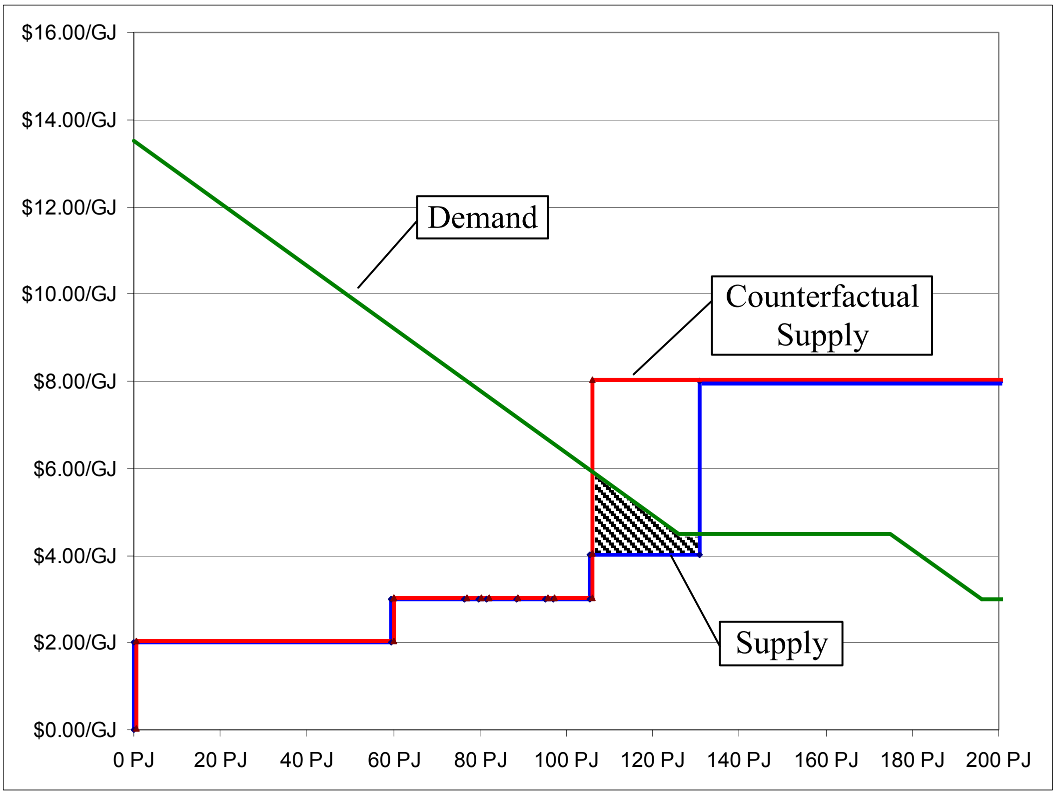
Figure 6 illustrates the demand and supply curves that we use for our base case modelling. The welfare loss is indicated by the shaded area.

---

96 For example, Contact Energy has stated that it has delayed its Otahuhu project pending resolution of various issues, which include the securing of gas (see Contact Energy's half year report to 31 March 2002).

97 Which is equivalent to assuming that only one of the new plants will add to existing demand.

Figure 6: Demand and Supply Curves for Base Case Modelling (2006)



Results of Quantification

Table 11 sets out our estimates of welfare loss under our base case scenario. Under this scenario, Methanex has reduced production to near zero in 2006, with slightly raised consumption in 2007 and 2008.[98]

98 These outcomes for Methanex's consumption follow from the assumptions regarding Methanex's behaviour described above and in Appendix C.

Table 11: Welfare Losses in Base Case

Year	Estimated Default Loss [99]
2004	51.0M
2005	79.2M
2006	27.7M
2007	72.5M
2008	36.5M
2009	34.9M
Present Value	**204.1M**

The increase in estimated loss is due to the reduction in Maui volumes towards depletion some time after 2009, and the increasing opportunity cost of delaying Pohokura, as expected production from Pohokura under joint marketing increases. In addition, the base scenario assumes an average growth in demand for natural gas by electricity generators of 2% per annum. Losses in 2008 are cushioned as the Kupe gas field is expected to commence production, providing an alternative source of gas and reducing the cost of Pohokura's delay.

Table 12 sets out our estimates of welfare loss if Methanex and other petrochemical companies continue consuming gas at current rates.

99 Discounted to 2002 at a rate of 10 percent.

Table 12: Welfare Losses if Methanex and Other Petrochemical Companies Consume 2006-9

Year	Estimated Loss if Methanex and Other Petrochemical Companies Operate at Full Production to 2009[100]
2004	51.0M
2005	102.0M
2006	102.0M
2007	187.0M
2008	136.0M
2009	136.0M
Present Value	**451.1M**

Appendix C provides a more comprehensive description of our model and assumptions, and summarises the results of our sensitivity analysis. For ease of reference, we set out in Table 13 a copy of the scenario testing results from Appendix C.

Table 13: Scenario Testing Results

Description	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	Total	NPV[101]	
Original Scenario	51.0m	79.2m	27.7m	72.5m	36.5m	34.9m	301.9m	204.1m	
Eliminates Methanex from market from 2006	51.0m	79.2m	26.8m	69.6m	36.4m	34.9m	298.0m	201.7m	
Methanex gets cheap gas first	51.0m	102.0m	102.0m	187.0m	136.0m	136.0m	714.0m	451.1m	**Max Loss**
Very Price Sensitive (ε=-2)[102]	23.1m	29.4m	16.5m	35.7m	21.9m	21.5m	148.0m	97.9m	**Min Loss**
Price Sensitive (ε=-1)	39.8m	46.0m	20.2m	47.9m	26.8m	26.0m	206.7m	139.5m	

100 Discounted to 2002 at a rate of 10 percent.

101 Discounted to 2002 at a rate of 10 per cent.

102 Default price elasticity of demand is –0.5.

Description	2004	2005	2006	2007	2008	2009	Total	NPV[101]	
Price Insensitive (ε=-0.25)	51.0m	101.9m	42.7m	110.7m	56.1m	52.8m	415.2m	275.4m	
Generator demand grows 7% pa from current levels (103 PJ)	51.0m	102.0m	93.1m	180.9m	134.0m	135.9m	697.0m	440.1m	
Initial Position of demand curve shifted down (Price -0.5)[103]	51.0m	59.1m	17.8m	50.3m	24.5m	23.5m	226.2m	155.8m	
Initial Position of demand curve shifted up (Price +0.5)[104]	51.0m	94.0m	41.1m	98.3m	52.3m	50.1m	386.8m	257.1m	
Zero electricity generator demand growth from 2006	51.0m	76.5m	22.2m	57.7m	24.5m	21.4m	253.3m	175.4m	
5% electricity generator demand growth from 2006	51.0m	82.9m	38.0m	99.0m	63.5m	69.1m	403.7m	263.3m	
10% producer demand growth from 2006	51.0m	88.3m	54.8m	140.7m	106.0m	119.2m	560.0m	354.3m	
Pohokura price reduced 50c/GJ	57.4m	92.0m	40.5m	95.9m	53.5m	51.9m	391.1m	260.5m	
Pohokura price increased 50c/GJ	44.6m	66.5m	15.0m	49.1m	19.5m	17.9m	212.6m	147.8m	
Gas price cap reduced 50c	44.6m	77.3m	27.7m	72.5m	36.5m	34.9m	293.5m	197.4m	
Gas price cap increased 50c	57.4m	79.2m	27.7m	72.5m	36.5m	34.9m	308.3m	209.4m	
Pohokura output reduced by 30%	42.0m	68.7m	25.5m	60.3m	22.4m	21.1m	239.9m	164.6m	
Pohokura output increased by 30%	78.0m	102.0m	34.5m	81.4m	43.4m	42.1m	381.3m	261.2m	

103 Reduction in demand is simulated by reducing the price at which a given quantity is demanded. This is equivalent to reducing the quantity demanded at a given price.

104 Demand is increased by raising the price at which a given quantity is demanded. See footnote 103.

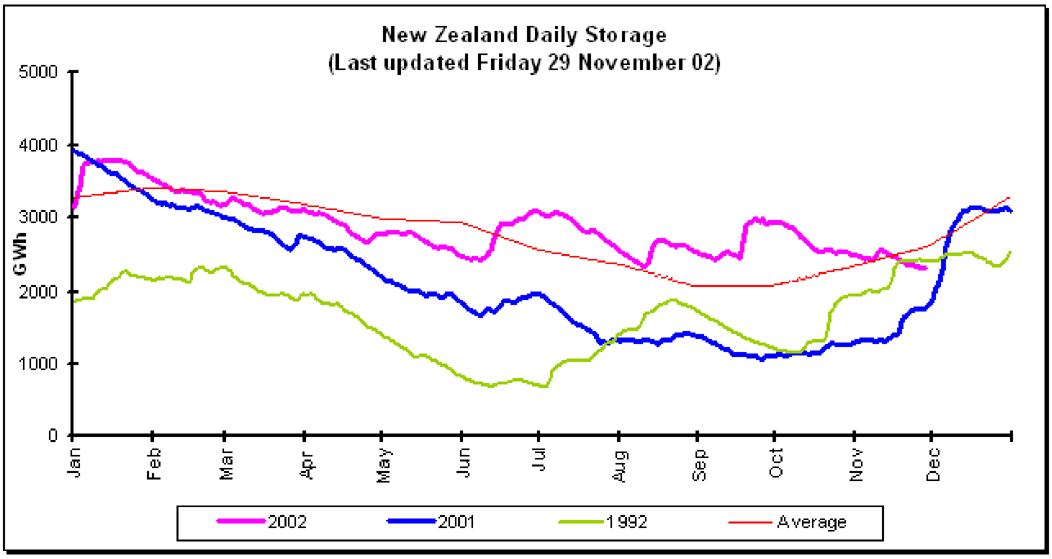
Description	2004	2005	2006	2007	2008	2009	Total	NPV[101]	
Smoothed run-down of Maui supplies (remaining supplies consumed evenly 2006-8)	51.0m	96.1m	27.0m	28.0m	17.0m	17.0m	236.0m	168.4m	

The 2001 Winter Power Crisis

As a complement to the welfare effects quantified above, it is useful to consider the impact of the lack of rainfall in South Island hydro lakes in 2001 on wholesale electricity prices. In some ways, the impact of a delay in Pohokura coming on-stream would engender a medium-run response as indicated by the short-run response of the electricity system to the low hydro inflows in the winter of 2001.[105]

In the winter of 2001, hydro lake inflows were significantly below average. Consequently hydro lake storage levels declined. This can be seen in Figure 7, which plots the lake storage levels in 1992, 2001 and available data for 2002 compared to the average daily storage levels.

Figure 7: New Zealand Daily Storage

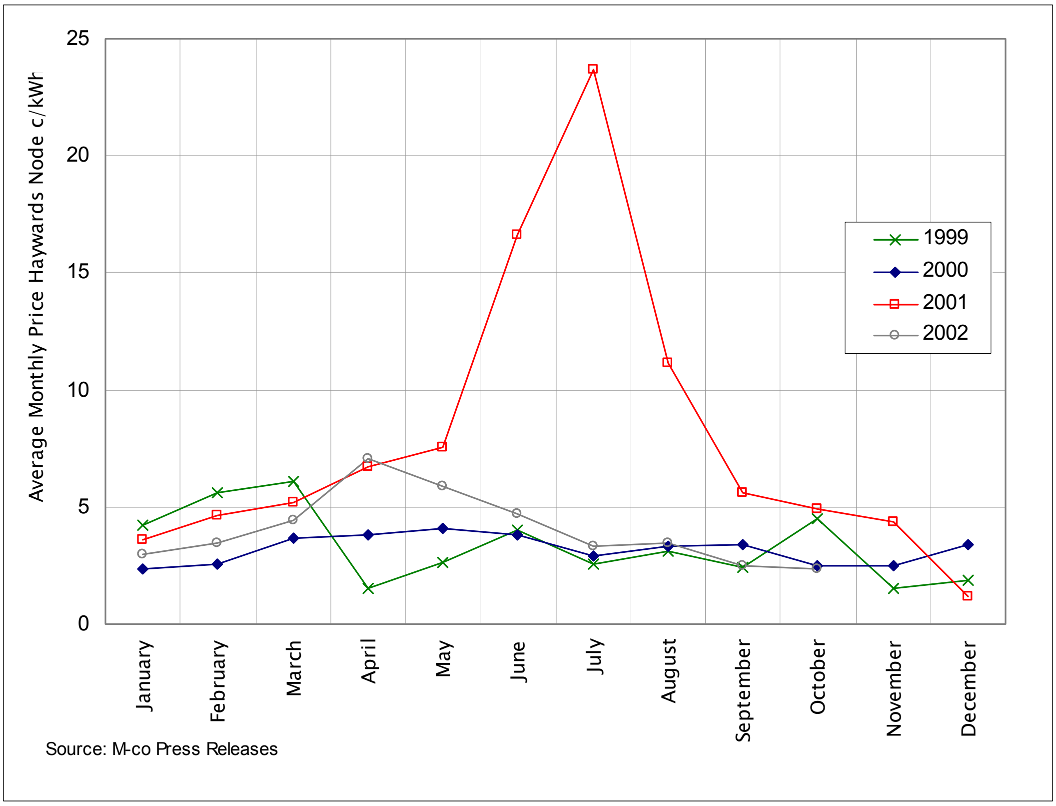


Source: www.comitfree.co.nz

105 We would expect the longer-run demand and supply responses to a delay in production from Pohokura to be quantitatively and qualitatively different to those arising from what may be perceived to have been an unusually dry year.

In reaction to the reduction in storage levels, hydro generators anticipated that there would be insufficient inflows over the winter period, in combination with a colder winter that increased electricity demand, and priced their electricity to reflect the option value of their water. While actual offer strategies are vastly complicated by the presence of hedges, the price data are in accord with the large South Island storage lakes being low implying that the option value of waiting to dispatch hydroelectric plant was very high, causing the wholesale market price for electricity to increase four to fives times its normal level for the winter period. Figure 8 plots the average monthly price from May 1999 to December 2001 at the Haywards[106] reference point. The graph clearly shows the effect the declining storage levels had on the wholesale electricity price. Note that the graph shows a monthly average; the effect is considerably greater on a daily basis. The highest price recorded in July 2001 was $920.33/MWh with 1209 half hour periods where the wholesale price was over $100/MWh.[107] Were Pohokura not to be available until after 2004, a year of low inflows would yield much higher welfare losses than those reported in our analysis.

Figure 8: Electricity Price at Haywards Node



---

106 The Benmore reference point was also studied and found to be similar in pattern to the Haywards reference point.

107 This price was observed at the Haywards reference node.

8.2.2. Other Public Benefits

Section 5 of this report identified other benefits of joint marketing over the counterfactuals. At this stage, we have not quantified them, either because they are likely to be smaller in magnitude than those quantified in section 8.2.1, or because they are harder to quantify. Nevertheless, we believe that these benefits are significant, and we re-emphasise them here.

Exploration Incentives

As discussed in section 5, separate marketing would result in, among other things:

- Extra transaction and production costs; and
- Loss of field value.

Accordingly, the rewards from exploring for gas would be reduced in expectation. This in turn would reduce the amount of exploration activity, and ultimately the supply of gas. Once again, the consequent losses in efficiency could be measured by the (net) loss in consumer and producer welfare from a shift in the supply curve.

Optimal Pool Depletion

As discussed in section 5, separate marketing would create an incentive to over-extract, resulting in a potentially material loss of field value. The magnitude of this problem would be significantly greater under scenario 2.

As noted in the Appendix A literature survey, Libecap and Wiggins (1985) cite an estimate in *Oil Weekly* that "early unitization [a form of cooperative resource exploitation] of solution gas fields would increase recovery from two to five times that of unconstrained production."[108] We doubt that the improvement in resource extraction consequent upon joint marketing versus separate marketing would be any where near this dramatic. Nevertheless, the losses arising from over-extraction under scenario 2 in particular could be significant.

Cost Savings

Joint marketing would result in lower production and transaction costs.

---

108 While the precise returns to coordination of extraction of oil and gas reserves are difficult to quantify, Libecap and Wiggins (1985) also note the following statistics. In 1980, the United States, which leads the world in competitive (non-cooperative) extraction, had 88 percent of the world's active oil and gas wells but only 14 percent of world production. In terms of oil production, the United States produced on average 16 barrels of oil per well per day. By contrast Canada produced 71 barrels per well per day, Venezuela produced 426, and Saudi Arabia produced 13,124.

Environmental Benefits

From an electricity generator's perspective, the next best alternative to gas for generation is probably coal (see section 3.2 of this report). As noted in section 3.2, the negative externalities from burning coal are significantly worse than those from burning gas.

8.3. CONCLUSION

Joint marketing of Pohokura gas would be significantly more efficient than separate marketing, and is necessary for timely investment in production.

Joint marketing is actually *pro-competitive*, and it would result in earlier production of Pohokura gas. In contrast, separate marketing would imply a significant delay in production, a key consequence of which would be a significant increase in gas and electricity prices. Table 14 contains our estimates of the welfare losses from separate marketing. These estimates are conservative, in that:

- They only quantify some of the detriments of separate marketing (as discussed in section 8.2.2); and

- We have limited our calculations to a delay of three years. It is possible that the delay could be longer, and even infinite.

Table 14: Estimated Welfare Losses from Separate Marketing

Year	Present value of loss if Methanex has exited[109]	Present value of loss if Methanex and Other Petrochemicals Operate at Full Production to 2009[110]
2004	51.0M	51.0M
2005	79.2M	102.0M
2006	27.7M	102.0M
2007	72.5M	187.0M
2008	36.5M	136.0M
2009	34.9M	136.0M
PV	**204.1M**	**451.1M**

In some ways, the impact of a delay in Pohokura coming on-stream would engender a medium-run response as indicated by the short-run response of the electricity system to the low hydrological inflows in the winter of 2001. In combination with a cold winter that increased demand for electricity, these low inflows caused the wholesale market price for electricity to increase four to five times its normal level for the winter period.

The welfare losses that would result from the combination of a delay in production from Pohokura and a dry year may be even greater than those set out in Table 14.

109 Discounted to 2002 at a rate of 10 percent.

110 Discounted to 2002 at a rate of 10 percent.

APPENDIX A: ECONOMIC LITERATURE SURVEY

A.1 INTRODUCTION

There are a number of comprehensive studies of the economics of the oil industry (e.g., Bain (1947), Chazeau and Kahn (1959) and Abdel-Aal and Schmalensee (1976)). These studies explain that the oil industry is a complex industry encompassing activities to find and produce crude oil and gas, transporting the oil to the refinery, refining, transporting gas and/or oil to market and retailing. Vertical integration is pervasive in the industry in most if not all jurisdictions, with some participation of unintegrated players ("independents") at various stages. This provides a difficult challenge for economic commentators. On its face, there may be some basis for concern about concentration and cooperation (especially in retail gasoline). At the same time, however, there are numerous industry specific reasons to expect that cooperation between firms may be unrelated to market power and rather may be necessary for efficiency reasons.

As is generally the case across industries, the petroleum industry poses a trade-off between productive efficiency and market power concerns. This standard paradigm can be seen in much of the earlier economic literature. In the mid-1970's, Allvine and Patterson (1972) argued for horizontal divestiture. The U.S. Federal Trade Commission held extensive hearings into such concerns in 1973-1975. Several economists took the opposite view, arguing that market power concerns were overstated (MacAvoy (1983)) and that the vertically integrated nature of the industry yielded substantial efficiencies (Teece (1976)). For the most part, the latter view has won the day as most economists and the U.S. antitrust agencies appreciate the likely efficiencies of existing industry structure.[111]

The more recent literature has considered the rationale for inter-firm cooperation in the industry much more deeply. It illustrates that the petroleum industry is characterized by an extraordinary degree of risk, as well as production and informational externalities that imply that the competitive equilibrium will be laden with inefficient results. Thus, while the standard market power vs. efficiency paradigm remains relevant, there are several key efficiency arguments that are fairly unique to the oil and gas industry.

111 In the 1980s, several economists studied the world market in detail and an econometric literature testing whether OPEC had market power also emerged (Schmalensee (1976) and Salant (1976)). The literature examines OPEC as a case study for cartel theory and considers the notion that, in the long-run, any market power that a cartel possesses is often undermined by entry on new margins due to the attractiveness of the price level supported by cartel activities. There is not a parallel literature on market power in natural gas. This probably reflects the fact that the dynamics of natural gas markets are more likely than crude oil markets to reflect local supply and demand considerations.

This survey considers these elements of the petroleum industry. Section A2 discusses the issues posed by the degree of risk inherent in the industry. Section A3 comments on the acquisition of property rights. Section A4 provides a discussion of the implications of the exhaustible resource literature. Section A5 analyses production externalities. Section A6 assesses informational externalities. Section A6 comments on hold-up problems. Section A7 discusses institutional responses to these economic incentives. Section A8 concludes.

A.2 RISK

A.2.1 Introduction

There is a substantial economics literature on risk, some of which is applied specifically to the oil and gas industry. Risk plays a pervasive role in the economic analysis of almost any industry. Without it, financial and capital markets would cease to exist as we know them because transactions would consist of an exchange of a single instrument each period. A fundamental distinction in this branch of microeconomic theory is that of risk versus uncertainty.[112] The standard way of modelling risk is the expected utility model that employs a von Neumann-Morgenstern utility function.

Risk is a critical determinant of investment decisions in the oil and gas industry. An oil and gas producer incurs a significant portion of costs prior to producing any output. Leland (1978) identifies three major sources of risk:

- The amount of reserves;
- Final output prices; and
- Extraction costs.

A.2.2 Ex Post Evaluation Bias

In any industry where risk is important, there can be a significant difference between *ex ante* and *ex post* rates of return. This difference can persist even when a large number of projects are observed because of self-selection – i.e. projects that have the poorest realized returns are often abandoned as soon as possible and thus any average will be taken over a truncated distribution that does not include the lowest return projects.

112 A situation is said to involve **risk** if the randomness facing an economic agent can be expressed in terms of numerical probabilities. A situation is said to involve **uncertainty** if the agent cannot (or does not) assign actual probabilities to alternative possible occurrences (Knight (1921)).

To illustrate, consider the following example. Table 15 below shows a hypothetical infrastructure investment. Assume that the firm's WACC is 16 per cent. There are three possible outcomes of the investment: failure, moderate success, and best case. Each outcome is equally likely. There are two possible policy settings: unregulated or regulated.

Table 15: Hypothetical Infrastructure Investment

		Expected Return (per cent)	
Scenario	**Likelihood of each scenario**	**Unregulated**	**Regulated**
Failure	0.33	0	0
Moderate success	0.33	12	12
Best case	0.33	36	16
Expected return		16	9.33
Investors' cost of capital		16	16
Investment decision		**Invest**	**Do not invest**

Under the regulated scenario, assume that the provider will not be allowed to earn a return in excess of its WACC. The two right-hand columns show the returns the investor expects under each scenario. For the failure and moderate success scenarios, the returns are below the investor's cost of capital, so the regulator would not intervene. Under the best-case scenario, the unregulated profit would be 36 per cent. However, in the regulated scenario, this would be limited to 16 per cent, and project adoption would not occur.

The implication is that a significant *ex post* return may be necessary to assure a firm earns ex ante zero economic profits from an up front investment which is associated with substantial "specific risk."

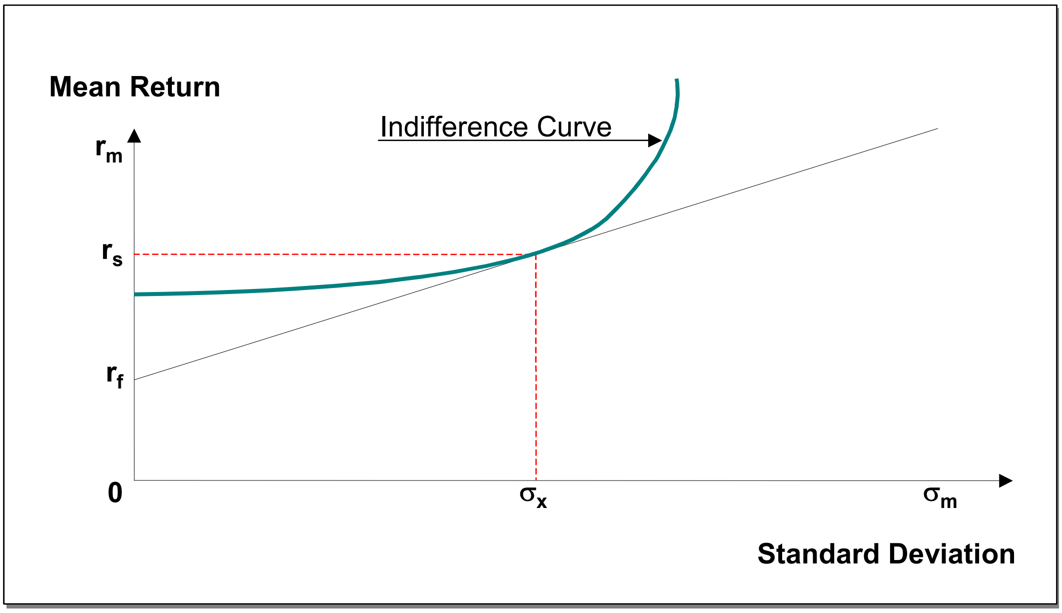
A.2.3 Risk Aversion

In a world of perfect contingent claims markets, there is no need for firms to display risk aversion - i.e. shareholders could engage in the necessary diversification to reduce risk. However, transactions costs and informational asymmetries give rise to incomplete contingent claims markets (e.g., bankruptcy costs induce investors and firms to view "specific risks" as important). Thus, Leland (1978) argues that risk sharing is important in the oil and gas industry (also see Hughart (1975)).

One implication of the importance of "specific risk" is that firms will rationally exhibit risk aversion in regard to investments in the oil and gas industry. That is, the willingness of any company to make irreversible investments with a risky payoff will depend on the mean expected return and its variance. There are three main sources of risk in the oil and gas industry. The first is change in the price of petroleum products over time. The second is firm specific risk that a particular asset (e.g., a property right to minerals contained in a particular tract, irreversible investments in potential production areas) generates product. The third is the magnitude of extraction costs.[113]

The most popular special case of the expected utility model is the Mean-Variance approach. Instead of postulating that a consumer's preferences depend on the entire probability distribution of his or her wealth, this approach assumes that preferences can be well described by considering just a few summary statistics – i.e., mean and variance.[114] The variance measures the "spread" of the distribution and therefore is a reasonable measure of the riskiness involved with an asset with a particular expected value. Then, define a risk-free asset, which is assumed to pay a fixed rate of return r_f with certainty. Then a risk averse agent's preferences can be represented as in Figure 9.

Figure 9: Risk-Return Relationship And Defining The Optimum



113 The risk associated with extraction costs and with the amount of recoverable resources are, of course, related since the amount of "recoverable" resources is defined with the costs of extraction in mind.

114 Suppose that a random variable w takes on the values w_s for s = 1, 2, 3, … , S with probability π_s. The mean is simply the average value: $\mu_s = \Sigma\pi_s w_s$, and the variance is the average value of (w - μ_s), i.e. $\sigma_w^2 = \Sigma\pi_s(w - \mu_s)^2$.

In Figure 9, (r_m,σ_m) represent a risky asset and (r_x,σ_x) represent a weighted average of the two assets. The indifference curves depict the agent's preferences where an increase in expected value of the portfolio is traded-off against increased risk. The essential lessons are that risky assets will have a "risk premium" associated with them and agents will seek to mitigate risk to the degree possible.

A.2.4 Mitigating Risk

Risk averse agents can use a number of instruments to mitigate the risk that they would otherwise face. A **forward** contract is an agreement where one party promises to buy an asset from another party at some specified time in the future and at some specified price. No money changes hands until the delivery date or maturity of the contract. The terms of the contract make it an obligation to buy the asset at the delivery date; there is no choice in the matter. A **futures** contract is very similar to a forward contract. Futures contracts are usually traded through an exchange, which standardizes the terms of the contracts. The profit or loss from a futures position is calculated every day and the change in this value is paid from one party to another. Thus, with futures contracts, there is a gradual payment of funds from initiation to maturity.[115]

Even if risk-mitigating strategies do not increase the expected payoff, they can be beneficial if they reduce the variance. Spreading risk through joint ownership of risky assets (e.g., oil and gas rights) can play an important role in mitigating risk. By pooling ownership of assets with similar risk characteristics, a firm can reduce the variance while preserving the mean of the distribution.

The role of risk spreading can be illustrated by the following example. Consider the case of two firms considering exploration and development expenditures on two distinct tracts. Assume that, for each firm, there is a 50 percent probability that no oil will be found and a 50 percent probability that a resource with a net present value of $10 million will be found. The expected value of this "lottery" is $5 million. Given the high degree of risk associated with this investment, the ex ante value of this opportunity is equal to $5 million minus δ, where δ is the (positive) risk premium. If, however, the two firms become equal partners in the two projects, their payoff becomes:

115 Options are similar. A call option is the right to buy a particular asset for an agreed amount at a specified time in the future. A put option is the right to sell a particular asset for an agreed upon amount at a specified time in the future. The Black-Scholes model revolutionized the economic theory of options. It is based on the principle that there should be no arbitrage opportunities available in the market. It derives a formula for option value that depends on only five directly observable variables.

Table 16: Payoffs for Various *Ex Post* Outcomes Under Risk Sharing

Ex Post Outcome	Probability	Payoff
Neither project is successful	0.25	$0
One project is successful and one is not	0.50	$5 million
Both projects are successful	0.25	$10 million

This payoff profile has the same expected value as the case where each firm undertakes an independent investment. The variance, however, is lower. As a result, the risk premium necessary for a firm to make (ex ante) zero economic profits is lower.

A.2.5 Conclusion

There is substantial risk in the oil and gas industry. There are two implications. First, an examination of *ex post* results will tend to overstate *ex ante* economic profits. Second, firms have a private incentive to engage in a number of practices to mitigate risk. Risk sharing through joint ventures is an important example. Such practices can be privately profitable even if there is no effect on market power in final output markets.

A.3 Acquiring Property Rights

A.3.1 Introduction

The acquisition of mineral rights is essentially the acquisition of a (highly) risky asset. In some cases, firms compete to purchase mineral rights from landowners in a relatively unstructured manner. More recently, formal auctions of oil leases have become important. With the opening of the U.S. Outer Continental Shelf (OCS)[116] to drilling by private firms in 1954, auction mechanisms have been used. A common institutional framework for the auction is a first-price sealed bid auction.

116 The OCS refers to mineral rights to offshore land more than three miles from the coast out to the 200 mile limit.

Three types of leases are auctioned. Wildcat leases are auctioned in areas where geology is not well known.[117] Drainage and development leases, in contrast, are auctioned in areas where oil has already been discovered.[118] Areas leased are typically about 5,000 acres. (See: Porter (1995) and Hughart (1975) for a detailed discussion of the historical experience). Not all countries use auction mechanisms to structure competition for these rights, but the lessons from the auction literature on efficient competition for risky assets have some application in other environments (e.g., the decision of when (and whether) to drill on a tract however the rights were acquired).

These auctions have been extensively studied in the literature. There are a number of insights that are relevant both to auctions specifically as well as to the economics of the industry more generally. These are:

- The sophistication and heterogeneity of firms;
- The degree of risk in the industry; and
- Bidding joint ventures enhance competition.

Each of these is discussed in more detail below.

8.3.1. Sophistication and Heterogeneity of Firms

The literature indicates that oil and gas producers are highly sophisticated firms that often have quite different expectations on the likelihood of striking oil on a given tract (i.e. private components of valuations are important). To put this somewhat differently, there are important "informational asymmetries" – a term used to describe a situation in which some participants have more (or better) information about the value of a good or service (here a property right) being sold than do others.

Hendricks, Pinskse and Porter (2001) study bidding for wildcat tracts off the coasts of Texas and Louisiana held during the period 1954 to 1970 inclusive, and find that the winner's curse is evident from the data and that bidders are aware of its presence and bid accordingly.[119] The authors also conclude that valuations probably have both common and private components and common components appear to be important.

---

117 Firms are often allowed to conduct seismic studies prior to bidding for these tracts but they are usually not allowed to drill exploratory wells.

118 Development leases occur in cases where a tract was previously leased, but was abandoned by the successful bidder (typically leases in the US run for 5 years, and if they are not developed, the lease expires and the rights revert back to the government.

119 The winner's curse arises from the fact that if there are sufficient bidders, the winning bidder will almost surely have overestimated the value of the resource. Firms recognising this are likely to adjust their bids downwards too much.

8.3.2. Risk and Risk Sharing

The evidence also supports the contention that the exploration decision is a costly and risky investment that can involve millions of dollars. A large number of leases (602 leases, over 25 percent of the total sample) were abandoned without engaging in any exploration. These were valuable assets (mean winning bid on these tracts was $2.86 million in 1972 U.S. dollars) thus firms would not walk away from this investment unless making additional investments in explorations were not also a highly risky proposition.[120] Of the 75 percent of tracts that firms chose to explore (1653 tracts), a little over 50 percent (897 instances) were unproductive. The authors report information from the American Petroleum Institute that estimates the average cost of these unproductive wells was $1.52 million U.S. dollars. An ex post evaluation of the efficiency with which firms employed the information that was available at the time – i.e. regressing determinants of drilling activity on drilling outcomes – provides some indication that firms were not processing information optimally.

It is important to note, however, that oil and gas leases typically involve both up-front "bonus" payments as well as royalty payments – i.e. a fraction of realized oil and gas revenue – which is paid to the ultimate owner of the property right (the government). Leland (1978) analyses the role for these arrangements to achieve a degree of risk sharing between the producer and the government. That is, a payment contingent on realized revenues, all other things equal, means that the oil producer faces less risk than it would otherwise.

Hendricks and Porter (1993) examine the timing of drilling and production investments on the U. S. Outer Continental Shelf. In particular, the authors examine exploratory drilling activity on wildcat OCS tracts in the Gulf of Mexico (as above) that were sold between 1954 and 1990. For each lease, the authors study the determinants of whether or not to begin exploratory drilling and the outcome of any drilling activity. In the sample studied, 2,255 leases were sold (in about 10 percent of the cases, a tract received bids, but the bid was rejected by the government).

The evidence illustrates that the risk associated with oil and gas production does not end with the acquisition of rights, but extends into the exploration phase. In the sample studied, only half the tracts that were explored yielded productive, commercially viable wells.[121]

---

120 The authors note that the price of crude over this period was approximately constant; therefore the risk must reflect exploration risk – i.e. whether the quantity of reserves and extraction costs ultimately found are sufficient to justify the additional exploration expenses.

121 The sample standard deviation of the logarithm of discounted revenues on productive tracts that the authors report is approximately 1.5 – i.e. a quite large degree of variance and thus risk.

A.3.2 Bidding Joint Ventures Enhance Competition

Bidding joint ventures can in theory both enhance competition (e.g., lower barriers to entry facing smaller firms, increase willingness to pay given risk sharing) and reduce it (e.g., reducing the number of potential bidders). Several papers argue that the competition enhancing effects are larger (see, for example, Krishna and Morgan (1997)).

A.3.3 Conclusion

The U.S. experience with OCS leases indicates that there is a high degree of risk associated both with acquiring rights and exploiting those rights through making investments in drilling and production. Study of exploration and drilling activity once firms acquire leases provide indications that information is not being processed optimally by firms.

A.4 RESOURCE ECONOMICS

A.4.1 Introduction

An exhaustible resource is a term that has come to be associated with a resource (such as oil and gas) that does not renew itself rapidly in its natural setting. This literature examines the rate at which a resource will be exploited under various assumptions about market structure. Hotelling (1931) establishes the now-famous "Hotelling Rule" which (in its simplest form) states that the price of an exhaustible resource must grow at the rate of interest both along an efficient extraction path and in a competitive equilibrium.[122] The intuition is that the present value of a unit extracted must be the same in all periods if there is to be no gain from shifting extraction among periods.[123] More recent treatments of the problem have focused on the general characteristics of demand required for a monopolist to deplete more slowly or more rapidly (Lewis (1976) and Dasgupta and Heal (1979)).

122 As noted, this is the simplest statement of the rule. More generally, the royalty (or price net of the cost of extracting the marginal unit of the resource) will grow at the rate of interest (r).

123 For the present value to be the same in all periods, the undiscounted value must be growing at precisely the rate of interest. Further, if demand is stable, output declines monotonically and ultimately declines to zero (at least asymptotically).

A.4.2 Differential Rents

A key result in this literature is that depletable resources with heterogeneous characteristics will earn "differential rents" (sometimes called "Ricardian" rents). The return earned by inframarginal units is sometimes mistakenly confused with monopoly rent. But this is incorrect. The increased return represents the scarcity value of the resource. The increased price paid for both marginal and inframarginal units serves an important economic purpose – it provides a market signal to bring more units into production to meet increased demand. Principles of resource economics underlie much of the literature on the economics of the oil and gas industry. It is most explicit in Adelman (1990).

A.4.3 Optimal Depletion Rates: The Price-Time Profile

A second key result relates to the timing of production and its relation to proven reserves. While empirical tests of Hotelling's Rule have been mixed (or even disappointing), the logic behind the model can be applied directly to a firm's decisions on how to manage its reserves. Specifically, a firm will look to a flow of production over time.

In addition, one can see an efficiency rationale for inter-firm cooperation with regard to reserve management. If there is indivisibility and randomness in discovery, location and accessibility of reserves, even if there is no affect on market power, there can be advantages to smoothing extraction over time. In particular, if there are a number of sites that could produce hydrocarbons in a field, a field is managed optimally when the projects with the highest present value are pursued. The number of projects a firm would optimally produce would depend, among other things, on the expected output prices. Under divided ownership, each firm will pursue the projects with the highest present value within its portion of the field. However, the best projects within a part of a field may not be among the best projects for the entire field.

A relatively simple, yet often overlooked implication relates to the hypothetical monopolist hypothesis generally used in merger analysis. Exercise of market power in a final output market, even if it were shown to exist, is related across time periods. The primary (and indeed sometimes the only) effect of market power is not to <u>raise</u> prices, but to change the profile of prices over time, increasing some prices and reducing others. For example, consider the case where there are only 10 units of a product available and two time periods, today and tomorrow. Say that under competition 5 units are sold today and 5 units are sold tomorrow. A monopolist with market power might choose to contract output today to earn a higher price as per the usual model, e.g. to 3. But there is an offsetting effect in tomorrow's market, output increases to 7, and thus price falls. The competitive and monopoly situations can be compared, but the overall welfare results depend on issues such as those that drive price discrimination results – ambiguous welfare effects. A monopoly can still have adverse effects, but the results are more complex.

Devarajan and Fisher (1981) summarize the literature as follows. A natural hypothesis is that a monopolist will restrict output and raise price, initially, as compared to a competitive industry. Price and output paths (over time) under monopoly and competition would then look like those depicted in Figure 10.

Figure 10: Price Profiles and Rates Of Depletion Outcomes Under Monopoly and Competition

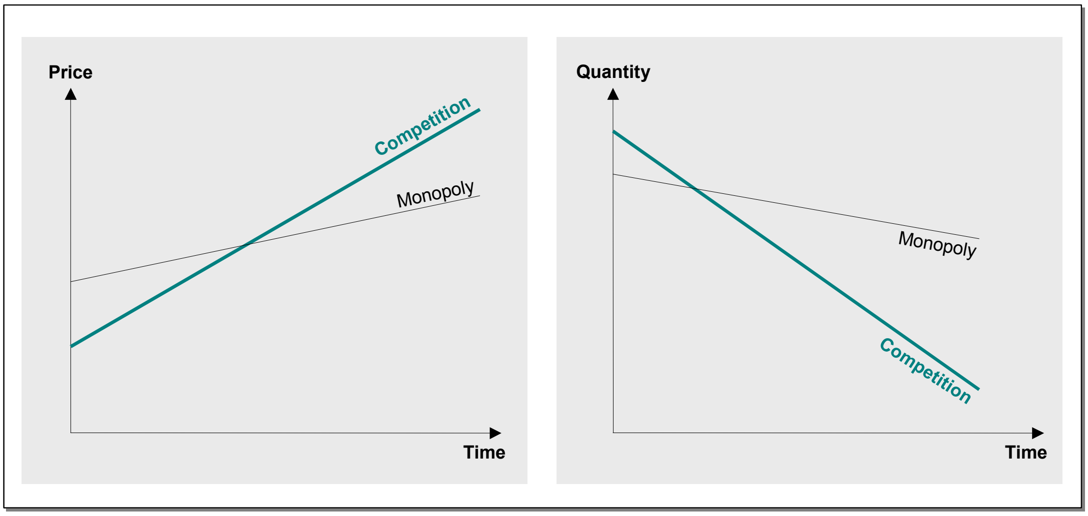


Figure 10 is drawn to show the monopoly price profile and the rate of depletion of the stock drawn flatter than under competition. This is intuitive, but not necessarily the case. Rather, the outcome depends on the nature (i.e. functional form) of demand. For a monopolist, Hotelling's rule is that marginal revenue, not price, will grow at the rate of interest. Then, whether the price rises more rapidly (and depletion occurs more slowly) depends on the relationship between price and marginal revenue.

More recent contributions to the literature have focused on the general characteristics of demand required for a monopolist to deplete more slowly. In particular, it has been shown that, if the elasticity is decreasing as quantity increases, the monopolist will deplete more slowly.[124] Oligopolistic depletion has also been considered in a number of articles.[125]

124 Tracy R. Lewis (1976), "Monopoly Extraction of an Exhaustible Resource," *3 Journal of Environmental and Economic Management 198* and P. S. Dasgupta and Geoffrey M. Heal (1974), "The Optimal Depletion of Exahstible Resources," *25 Review of Economic Studies 3*.

125 See, for example, Salant (1976).

A.5 Production Externalities: Common Pool Problems

A.5.1 Introduction

In most industries, where there is competition between individuals for the use of scarce resources, some rules or criteria must exist to resolve the conflict. These rules are known as property rights. There is a large literature on the economics of property rights. In private property, the delineation of the right to use is expressed in dimensions or characteristics inherent in the property itself. These rights are exclusive to some individual and are freely transferable. Such individuals have strong incentives to use their property efficiently since they fully bear the costs and enjoy the benefits derived from their property.

Important elements of the oil and gas industry have common property characteristics. Specifically, more than one company can have access to an oil and gas resource pool. In general, the division of property rights generates competition between firms for migratory oil and gas lodged in subsurface reservoirs. Under the common-law rule of capture, private property rights to the hydrocarbons are assigned only upon extraction. Production rights are granted to firms through leases from those who hold the mineral rights, surface landowners or governments in the case of offshore rights. Each firm has an incentive to maximize the economic value of its leases rather than the reservoir as a whole (e.g., Peterson (1975), Smith (1987) and Liebcap (1998)).

Such common pool problems are a special case of the classic "common property" problem. In these situations, no one has the right or ability to exclude the other firm from using its portion of the resource pool. The result is inefficient outcomes known, in specific applications as one (or more) of: common-resource problems, public-goods problems, free-rider problems or tragedy of the commons problems.

Extra uses will be made with an increased realized total value that is less than the cost added, that is, the social value is not maximized. This occurs because the marginal yield is less than the average to each user, to which each user responds. So, use occurs to the point where the average yield is brought down to marginal cost, with the consequence that the marginal yield is less than the marginal cost – and overuse or over exploitation occurs (e.g., Alchian (1998)). In other words, the "prize" has no exclusive claimant and its value will be dissipated or absorbed by the costs dedicated to its winning.

A.5.2 The Incentive Effect of Common Pool Problems: A Prisoner's Dilemma

Common pool problems have been discussed in detail in the context of the oil and gas industry (e.g. Libecap and Smith (1999)). Absent any type of cooperative effort, each firm determines the number of wells it will drill and sets output from each well so as to maximize its private profits, ignoring the costs and production externalities it inflicts on other producers. It raises overall costs by releasing natural gas or other substances during production, thereby reducing the underground pressures that push oil to the surface. As pressures fall, pumping and injection of other propellants become necessary. Further, the firm's production encourages migration of oil from elsewhere in the reservoir, allowing it to extract its neighbour's oil. Since all firms recognize these conditions, they have an incentive to competitively drill and drain the reservoir.[126] The result is that fewer resources are ultimately captured and more capital is expended than is optimal.

There is some commentary in the economic literature on the magnitude of common pool problems. Libecap and Wiggins (1985) cite an estimate in *Oil Weekly* that "early unitisation [a form of cooperative resource exploitation] of solution gas fields would increase recovery from two to five times that of unconstrained production." Libecap and Wiggins (1985) also comment on evidence revealed by aggregate figures on well productivity to support the argument that unconstrained competition leads to efficiency losses. They note that U.S. wells produce only an average of 16 barrels per day while Canada's wells averaged 71 barrels per day, Venezuela's wells 426 barrels per day, and Saudi Arabia's 13,124 barrels per day.

The common pool problem can be modelled as a so-called "prisoner's dilemma," which can be illustrated as follows. Each firm has a private incentive to drill competitively even though this action reduces the total value of the pool. That is, the payoffs are as in Table 17.

Table 17: The Common Pool Prisoner's Dilemma

	Player 2: Drill Competitively	Player 2: Drill Cooperatively
Player 1: Drill competitively	(-5, -5)	(1, -10)
Player 1: Drill cooperatively	(-10, 1)	(0, 0)

126 From a technological perspective, these problems have been well-known for many years. Indeed, as early as 1929, the Gas Conservation Bill was passed in California to facilitate corrective action to remedy concerns that competitive oil and gas extraction was "wasting gas." The contribution of the more recent economic literature is to characterize these well-known phenomena in a systematic manner (e.g. a game theoretic representation) that allows for analysis of institutional responses (such as so-called "unitization" agreements).

In this situation, drill competitively is a dominant strategy. That is, even if the parties could achieve a tenuous agreement to drill cooperatively, each would have an incentive to "deviate" from that agreement and drill competitively. The Pareto efficient outcome (both drill competitively) is not reached. The resulting equilibrium outcome is less efficient both from the point of view of the firms and the economy as a whole.

When one considers repeated interaction between the players, asymmetries between the firms will often make it even harder to reach an efficient solution than in the standard case. Firms often have private information on the likely amount of resources contained under their share of the pool (to the extent that can be defined), and this can make it difficult for the parties to achieve sharing arrangements. An efficient outcome may require more drilling to take place on some tracts than others, which means that simple repetition of the efficient outcome would not be in even the long-term interest of some parties (absent side payments). If tracts differ in their relative proportions of oil and gas, this creates additional conflicts of the interests of the parties.

8.3.3. Conclusion

The well-known "common pool" problem implies that unrestrained competition in oil and gas production is inefficient both from the point of view of the individual firms and the economy as a whole. The fact that competitive drilling is a dominant strategy means that firms will have considerable difficulty achieving the efficient outcome without some sort of explicit cooperative agreement to align their interests. There is scope for inter-firm agreements to be privately profitable (and efficient) even if there are no market power effects in final consumer markets.

A.6 Exploration Problems: Informational Externalities

A.6.1 Information as a Public Good

When considering a good such as "information" that potentially has characteristics associated with "public goods," it is useful to note two main dimensions of these possible properties. Such goods can be either **nonrival** or **nonexclusive** (or a combination of both). With a **nonrival** good, consumption by one person does not reduce the quantity that can be consumed by others.[127] With a **nonexclusive** good, once the good is produced, it is accessible to all consumers; no one can be excluded from consuming the good.[128] The presence of these externalities has been understood in the literature for several years (e.g. Leitzinger and Stiglitz (1984)).

Information about the probability of striking oil is certainly nonrival. It is also nonexclusive - at least to some degree - when one firm's exploratory well strikes oil, this information can be observed by other firms. This raises two economic issues. First, information collection efforts are inherently duplicative (even if the interpretation and resulting decisions that firms would optimally make in response to it differ). That is, the least cost way of acquiring information (for the economy as a whole) would be for a single entity (firm or government) to collect information at a zero incremental price. This reflects the non-rival nature of the good.

Second, firms can free ride. That is, once the information is collected, it is difficult for a firm to exclude other firms from benefiting from it.[129] Specifically, if one firm is observed to strike oil (or not) on a particular tract, firms that have acquired the mineral rights can update their prior beliefs on the amount of oil in the pool. In some cases, a firm may be able to effectively by-pass the exploration stage (and associated costs) when a neighbour strikes oil first. This is called an informational externality - i.e. the firm that engages in exploration activity first generates an external benefit that it cannot appropriate.

127 An example of a good that is nonexclusive but rival is a picnic table at a national park. Once the table is constructed, anyone can sit at it. It is rival, however, because when one party is sitting at the table, no one else can sit there.

128 An example of a nonrival but exclusive good is a pay-TV channel. The cable company can control who has access to the product, but one person's consumption in no way impedes the enjoyment others can capture from their own consumption of the same good.

129 Of course, antitrust laws may make it difficult for a firm to deliberately share information in any case.

Given these externalities, there is an incentive for each firm to wait and hope that the other firm makes an irreversible decision to drill and reveal information.[130] On the other hand, waiting can be costly since a tract that could produce valuable output is sitting idle and, if there are common pool externalities, actions by other adjacent firms could reduce the amount of hydrocarbons that are ultimately recovered.

A.6.2 The Incentive Effect of Exploration Problems: A Prisoner's Dilemma

These two incentives create the following one-shot game.

Table 18: The Exploration Prisoner's Dilemma

	Firm 2: Choose to Exploration Drill	Firm 2: Choose not to Explore
Firm 1: Choose to Exploration Drill	(E*[V] – D, E*[V] – D)	(E*[V] – D, E*[V])
Firm 2: Choose not to Explore	(E*[V], E*[V] – D)	(E [V], E[V])

Where E[V] denotes the expected value of production prior to any drilling, E*[V] denotes the update based on at least one firm drilling an exploration well and D is the cost of drilling the exploration well. Both E[V] and E*[V] are positive since, at worst, the firm can cut its losses (i.e. the sunk costs of acquiring the rights plus the sunk costs of any exploration activity) and simply abandon the site.[131]

Assuming this is a non-trivial case where at least one D is economic (given the necessary risk premium discussed in section A2), the off-diagonal elements (where only one firm explores) are Pareto optimal. However, each firm's optimal response depends on its beliefs on what the other firm will do. If a firm believes that the other firm will choose to drill, it should always choose "not drill." This creates a "free-rider" problem as each firm waits for the other to provide the "public good."

130 This assumes, of course, that the decision to drill is sunk. If most or all of the action can be costlessly reversed, moving first does not substantially disadvantage the first-mover.

131 In this illustration, for simplicity it is implicitly assumed that one firm's drilling efforts is a perfect substitute for the other firm's. More realistically, one firm's drilling activity would be an imperfect signal that has some value (and thus the risky decision can be made with a higher expected value) but not completely duplicative, and thus even if one firm is unsuccessful, sequential search may be optimal. Hendricks and Porter (1993) consider the latter (more realistic) case in detail.

Hendricks and Porter (1993) model this problem as a "war of attrition" where firms faced with this free-rider problem attempt to wait each other out. In the example they employ, the game is solved recursively to find a symmetric mixed strategy equilibrium (there are also pure strategy asymmetric equilibria). To get this result, the authors use a finite game (reflecting the five-year limit at which the rights to an unexplored tract revert to the government) and derive hazard rates that summarize the predicted drilling patterns (described in probabilistic terms since it is a mixed strategy). The theoretical result is a special case of the usual externality result -- information is under-provided (or provided later than is optimal).

There is an important distinction to be drawn between these "informational" externalities and those arising due to "common pool problems." Indeed, they can affect behaviour in opposite directions. For example, in some cases, the optimal response to informational externalities is to delay drilling – i.e. instead of risking the expense of drilling an exploratory well, wait until another firm drills on an adjacent (or reasonably close) tract to see whether this is a high or low probability event. At the same time "common pool" externalities can give rise to the opposite incentive – i.e. drill as soon as possible so that as much of the common resource can be captured.

A.6.3 Empirical Importance

In an empirical test, Hendricks and Porter (1996) conclude that there is substantial noncooperative (and inefficient) behaviour in the oil and gas industry in regard to the decision of when to drill production wells. That is, firms are observed to delay investment decisions in order to "free-ride" on information externalities from other firm's drilling. They characterize this as a puzzle, but note that the answer may lie in the inability of firms to use unitisation agreements due, for example, to asymmetries of information. In the bidding game, information heterogeneities are present as firms interpret seismic information differently, and this may inhibit the willingness of firms to enter joint ventures. Also, Hendricks and Porter (1996) observe, an obstacle to coordination in the exploration phase may be concerns on the part of the firms that they may be sacrificing informational, or expertise, advantages in future interactions.

A.7 INCOMPLETE CONTRACTS AND HOLD-UP PROBLEMS

There are numerous contributions to the economics of incomplete contracts and hold-up problems. A "hold-up" problem can be described as follows. Suppose that at date 1 a supplier invests in cost reduction (his investment lowers the cost of production) and a buyer invests in a value enhancement. These investments are assumed to be investment-specific. Absent long-term contracts, the outcome is of course inefficient since the party investing does not capture all the cost savings generated by the investment. The other party can use the threat of not trading (i.e., "holding-up") to appropriate some of these savings. Long-term contracts can be used to solve these problems (Klein (1996)).

As noted above, this problem is most acute where there are specialized (or transaction-specific) assets, for example, when pipelines and related facilities must be constructed in order to bring the product to market. Absent a long-term contract, no firm would be likely to have an incentive to incur the large fixed (and sunk) costs of making such investments since, once the investments are made, the firm is at the mercy of the resource producer who needs to use the transportation facilities. Indeed, if there are large transactions costs involved in writing and enforcing a sufficiently long-term contract, the only effective way to assure that efficient investment decisions are made would be for the firm to vertically integrate.[132]

In reality, it is usually impossible to lay down each party's obligations completely and unambiguously in advance so most real world contracts are seriously incomplete. Among other things, incompleteness can lead to inefficiencies even when there are no informational asymmetries (though informational asymmetries magnify the potential problems). Firms will seek to mitigate these problems through a number of institutional responses. Vertical integration as well as contracts (or other forms of inter-firm cooperation) that align parties' interests (i.e. "self-enforcing") are often the efficient response.

A.8 INSTITUTIONAL RESPONSES TO EXTERNALITIES

The key conclusion from the economics literature is that imperfections in the manner in which property rights are defined give rise to externalities. Exactly how large these externalities are depends on the institutional framework (e.g., how large tracts are) and geological factors.[133] Anecdotal evidence suggests that the effects can be quite large in some cases, but the magnitude will vary from case to case.

Economic theory also suggests that, when faced with such externalities, firms will seek to develop institutions to mitigate or eliminate the externalities (e.g., Coase (1960)).[134] However, the extraction of hydrocarbons involves considerable uncertainty and it is often simply impractical to devise a complete contingent contract (Libecap and Smith (1999)). The most obvious sources of uncertainty are the amount of hydrocarbons ultimately found in a reservoir and the cost of recovering them. Other important sources of uncertainty are the prices of oil and gas (and their relative values) and the timing and value of primary vs. secondary recovery operations.

132 Reputation can be shown to support an efficient outcome over time (when there is incomplete contracting).

133 Libecap and Smith (1999) report several studies showing that the regulatory environment in a particular jurisdiction affects the incidence of unit agreements.

134 See Farrell (1987) for a useful discussion.

The important point is that these forms of uncertainty affect various rights owners differently. Even if the concerned firms could achieve an explicit or tacit agreement at the time when extraction is initiated, these firm-specific sources of uncertainty would affect the willingness of the firms to stick to their bargain. Thus, any institutional response to externalities in hydrocarbon extraction must confront a problem not present in the standard Coasian response - the response must be incentive compatible for the parties for a long period during which there is considerable uncertainty.

A common institutional response in this industry is a "unitization" agreement. These agreements typically establish a unit operator to whom day-to-day operational decisions are delegated.[135] They also have elaborate governance mechanisms such as voting rules, grievance and arbitration procedures, unit operator reporting and accounting rules, a sharing formula and other operational definitions and practices. Most importantly, the agreement typically establishes a profit-sharing mechanism. The effect of this is to give the parties an interest in the performance of the overall pool rather than some portion.[136]

By their very nature, it is impossible to provide a complete assessment and categorization of firms' responses to externality problems in the oil and gas industry. Some jurisdictions require information to be filed, but in others the arrangements are a private transaction between the firms. Anecdotal evidence shows, however, that such agreements are quite important (e.g., ARCO and Exxon leases in the Prudhoe Bay, as documented by Libecap and Smith (1999)).

In sum, the economics literature supports the conclusion that common pool externalities give rise to a legitimate efficiency rationale for inter-firm agreements in this industry. Furthermore, the length of the time-frame over which production would likely occur and the degree of firm-specific uncertainty suggests that aligning of interests through a sharing formula will likely be a key aspect that an agreement would have to contain in order to achieve efficiency benefits.

135 Typically the firm with the largest stake in the pool is designated as the unit operator. Other parties remain as minority participants with well-defined rights and obligations.

136 See Libecap and Smith (1999) for a detailed description of unitization agreements using the example of the Prudhoe Bay Unit.

A.9 REFERENCE LIST

Adelman, M.A. (1990), “Mineral Depletion with Special Reference to Petroleum,” *72 Review of Economics and Statistics 1*.

Allvine, F. and J. Paterson (1972), *Competition Limited: The Marketing of Gasoline* (Bloomington, Indiana: Indiana University Press).

Arrow, Ken (1964), “The Role of Securities in the Optimal Allocation of Risk Bearing,” *31 Review of Economic Studies 91*

Bain, Joe S. (1947), *The Economics of the Pacific Coast Petroleum Industry*, Part III (Berkley: University of California Press).

Coase, Ronald H (1960), “The Problem of Social Cost,” *3 Journal of Law and Economics 1*.

Dasgupta, P. S. and Geoffrey M. Heal (1974), “The Optimal Depletion of Exhaustible Resources,” *25 Review of Economic Studies 3*.

Devarajan, Shantayan and Anthony C. Fisher, “Hotelling’s ‘Economics of Exhaustible Resources,: Fifty Years Later, *29 Journal of Economic Literature 65.*

Farrow, Scott (1999), “Real Options and Government Policy for the Outer Continental Shelf Lands,” *Mimeo.*, Center for the Study and Improvement of Regulation, Carnegie Mellon University and the Marine Policy Center, Woods Hole Oceanographic Institution.

Fisher, Franklin M. (1964), *Supply and Costs in the U.S. Petroleum Industry: Two Econometric Studies* (Baltimore: Johns Hopkins Press).

Federal Trade Commission (1973), In the Matter of Exxon Corporation et al., Docket No. 8934, Complaint.

Farrell, Joseph (1987), “Information and the Coase Theorem,” *1 Journal of Economic Perspectives 113.*

Griffin, James M. and David Teece eds. *OPEC Behaviour and World Oil Prices* (London: George Allen & Unwin).

Grossman, S and O. Hart (1986), “The Costs and Benefits of Ownership: A Theory of Vertical and Lateral Integration,” *94 Journal of Political Economy 691*.

Hendricks, Kenneth and Robert H. Porter (1996), “The Timing and Incidence of Exploratory Drilling on Offshore Wildcat Tracts,” *86 American Economic Review 388.*

Hendricks, Kenneth and Robert H. Porter (1993), “Determinants of Exploratory Drilling on Offshore Wildcat Tracts,” *NBER Working Paper 4605.*

Hendricks, Kenneth and Robert H. Porter (1992), "Joint Bidding in Federal OCS Auctions, *82 American Economic Review 506*.

Hendricks, Kenneth, Joris Pinkse and Robert H. Porter (2001), "Empirical Implications of Equilibrium Bidding in First-Price, Symmetric, Common Value Auctions, *Mimeo*.

Hugart, David (1975), "Informational Assymetry, Bidding Strategies and the marketing of Offsore Petroleum Leases," *83 Journal of Political Economy 969.*

Klein, Benjamin and Kevin M. Murphy (1997). "Vertical Integration as a Self-Enforcing Contractual Arrangement," *87 American Economic Review 415.*

Krishna, V and J Morgan (1997) "(Anti-) Competitive Effects of Joint Bidding and Bidder Restrictions", *Princeton Woodrow Wilson School Discussion Paper in Economics*, No.184

Leland, Hayne E (1978), "Optimal Risk Sharing and the Leasing of Natural Resources with Application to Oil and Gas Leasing on the OCS," *92 Quarterly Journal of Economics 413*.

Leitzinger and J. Stiglitz (1984), "Information Externalities in Oil and Gas Leasing," *12 Contemporary Policy Issues 44.*

Lewis, Tracy R. (1976), "Monopoly Extraction of an Exhaustible Resource," *3 Journal of Environmental and Economic Management 198.*

Libecap, Gary D. (1998), "Unitisation," in Peter Newman ed., *New Palgrave Dictionary of Law and Economics* (New York: Oxford University Press).

Libecap, Gary D. and James L Smith (1999), "The Self-Enforcing Provisions of Oil and Gas Unit Operation Agreements: Theory and Evidence," *12 Journal of Law, Economics and Organization 526*.

Libecap, Gary D and Steven N. Wiggins (1985), "The Influence of Private Contractual Failure on Regulation: The Case of Oil Field Unitisation," *93 Journal of Political Economy 690.*

Libecap, Gary D. and Steven N. Wiggins (1984), "Contractual Responses to the Common Pool" Prorationing of Crude Oil Production," *74 American Economic Review 87*.

MacAvoy, Paul W. (1983), *Energy Policy: An Economic Analysis* (New York: W.W. Norton).

McKie, James (1960), "Market Structure and Uncertainty in Oil and Gas Exploration," *74 Quarterly Journal of Economics 543*.

Moody, C.E. Jr and W. J, Kruvant (1988), "Joint Bidding, Entry and the Price of OCS Leases," *19 Rand Journal of Economics 276.*

Paddock, J., D. Siegel and J. Smith (1998), "Option Value of Claims on Real Assets: The Case of Offshore Petroleum Leases," *103 Quarterly Journal of Economics 479*.

Peterson, Franklin M. (1975), "Two Externalities in Petroleum Exploration," in G. M. Brannon ed., *Studies in Energy Tax Policy* (Cambridge Ma: Ballinger).

Porter, Robert H. (1995), "The Role of Information in U.S. Offshore Oil and Gas Lease Auctions," *63 Econometrica 1*.

Reece, D.J. (1978), "Competitive Bidding for Offshore Petroleum Leases," *9 Bell Journal of Economics 369.*

Reiss, Peter C. (1990), "Economic and Financial Determinants of Oil and Gas Exploration Activity," in R. Glenn Hubbard ed., *Asymmetric Information, Corporate Finance and Investment*, (Chicago: University of Chicago Press).

Rockwood, Alan (1983), "The Impact of Joint Ventures on the Market for OCS Oil and Gas Leases," *31 Journal of Industrial Economics 453*.

Salant, Steven W. (1976), "Exhaustible Resources and Industry Structure: A Cournot-Nash Approach to the World Oil Market," *84 Journal of Political Economy 1079*.

Schmalensee, Richard (1976), "Resource Exploitation Theory and the Behaviour of the Oil Cartel," *7 European Economic Review 257*.

Smith, James L (1987), "The Common Pool, Bargaining, and the Rule of Capture," *25 Economic Inquiry 631.*

Smith, J. L. and L. M. DeBrock (1983), "Joint Bidding, Information Pooling and the Performance of Petroleum Lease Auctions," *14 Bell Journal of Economics 395*.

Smith, James L, Daniel Siegel and C S Agnes Chan (1988), "Failure of the Net Profit Share Leasing Experiment for Offshore Petroleum Resources," *70 Review of Economics and Statistics 199.*

Solow, Robert M. (1974), "The Economics of Resources or the Resources of Economists," *64 American Economic Review 1*.

Teece, David J. (1976), *Vertical Integration and Vertical Divestiture in the U.S. Oil Industry* (Stanford, Conn.: Institute for Energy Studies).

Wiggins, Steven N. and Gary D. Libecap (1985), "Oil Field Utilization: Contractual Failure in the Presence of Imperfect Information," *75 American Economic Review 368*.

Williamson, Oliver (1979), "Transaction-Cost Economics: The Governance of Contractual Relations," *22 Journal of Law and Economics 233.*

APPENDIX B: WELFARE ANALYSIS IN VERTICALLY RELATED MARKETS

An important general result noted in section 8.2.1 is that, in a set of vertically related markets, the welfare changes in any one of those markets arising from a change in supply or demand conditions are equivalent to the welfare changes to society. In other words, by quantifying the consumer and producer welfare losses arising from a delay in the development of Pohokura in the market for gas production, we also capture the net welfare effects in all downstream markets. This result is convenient because the quantification of welfare changes in all markets influenced directly or indirectly by natural gas is likely to be a complex exercise.

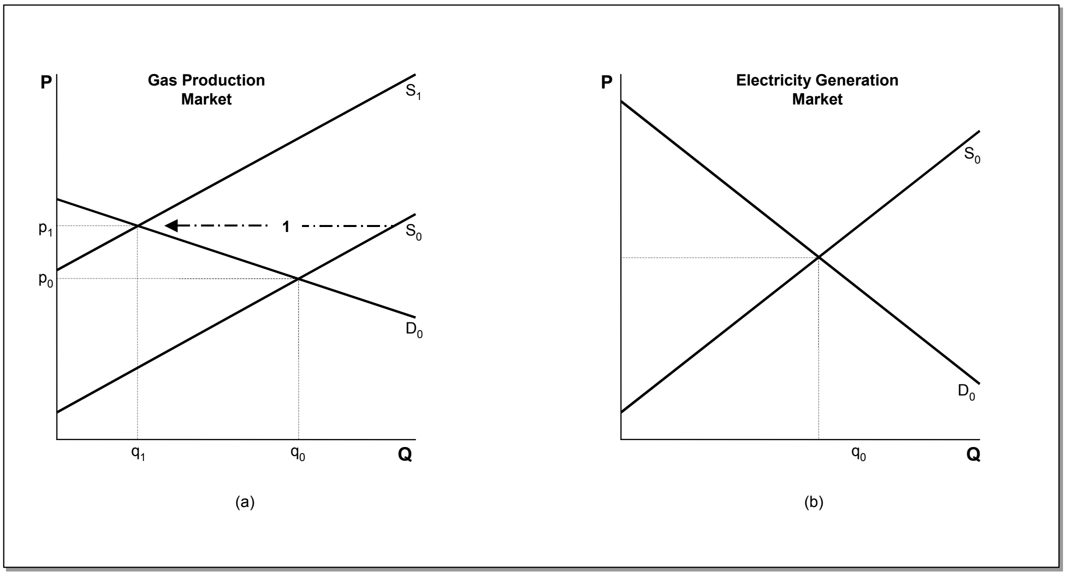
The concept of an equilibrium demand curve is central. Equilibrium demand is different to ordinary demand: the latter reflects an equilibrium without regard to other affected markets. On the other hand, an equilibrium demand curve captures the equilibrium changes in vertically related markets. Changes in up- and downstream markets feed back into the market where the original change occurred, further adjusting the equilibrium. The equilibrium demand curve reflects these feedback effects, and therefore captures net welfare effects in related markets. For example, when the supply of natural gas is constricted, we might expect that this would change supply conditions in downstream markets, such as the market for electricity generation. These changes affect producers in these markets who, in a vertically related market, are consumers upstream.[137] An equilibrium demand curve captures the price and quantity effects of up- and downstream changes. It also captures welfare changes in a vertically related industry. Where that industry is assumed to have no impact on the prices and quantities sold for other products, the welfare effects of the affected market are equivalent to total welfare.

We first show graphically how the equilibrium demand curve for the gas production market is derived.

In a particular year (for example, 2006), the delay in production from Pohokura can be represented by a leftward shift in the supply curve, as demonstrated in Figure 11(a).

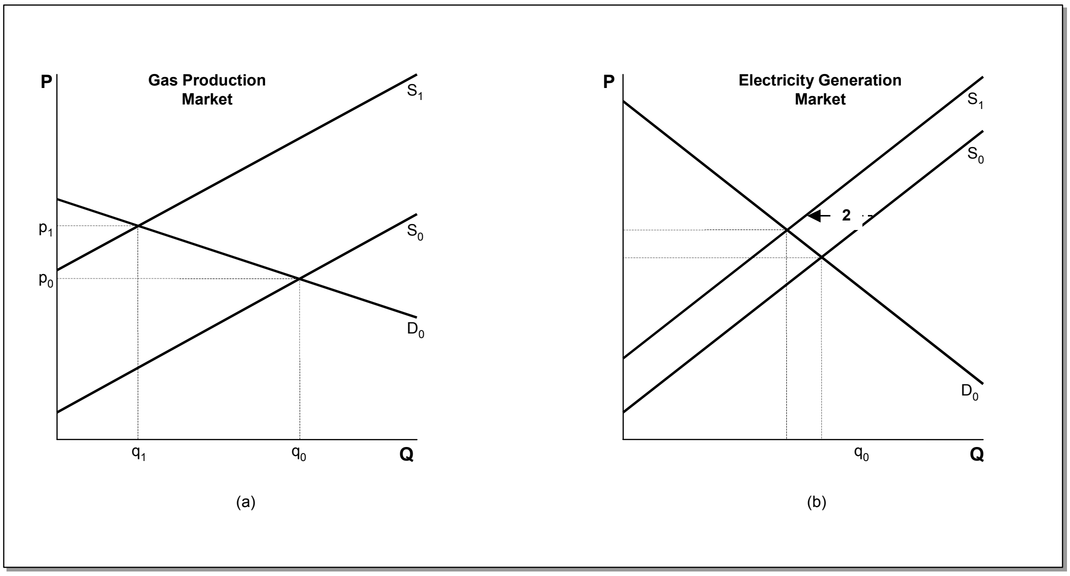
137 For example, if Pohokura is delayed then producers in downstream industries will be forced to pay a higher price, reduce purchases of natural gas, and/or exit their markets. In a vertically-related market, producers in downstream markets, for example electricity generation, are consumers in upstream markets, such as the market for gas production.

Figure 11: Calculating Welfare Losses – Step 1



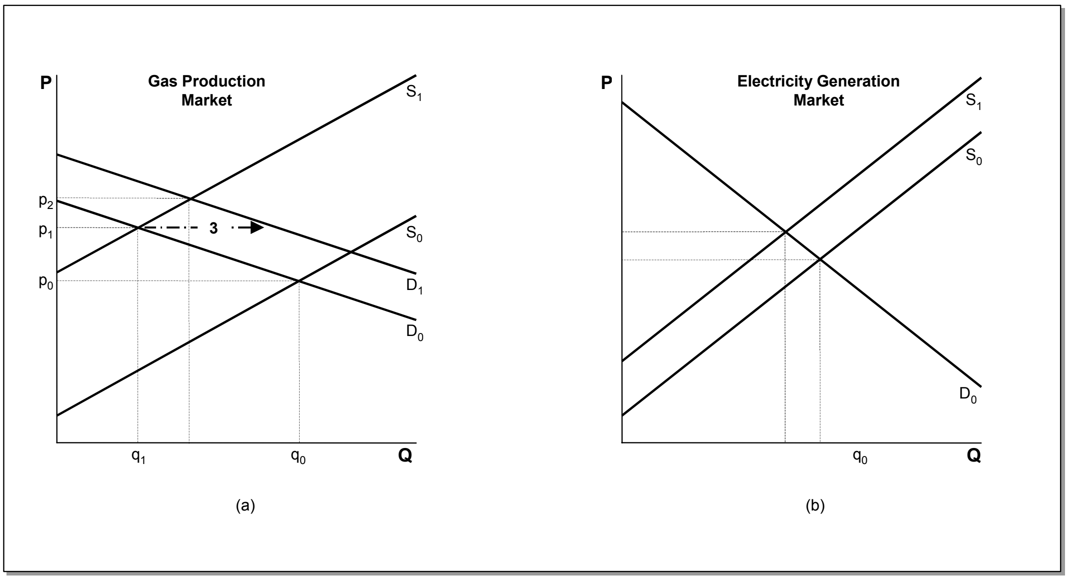
The effect of the supply constraint is reflected in the downstream market for electricity generation. The cost of producing electricity at a given level has increased, shifting the supply curve left in that market, and raising prices (Figure 12(b)).

Figure 12: Calculating Welfare Losses – Step 2



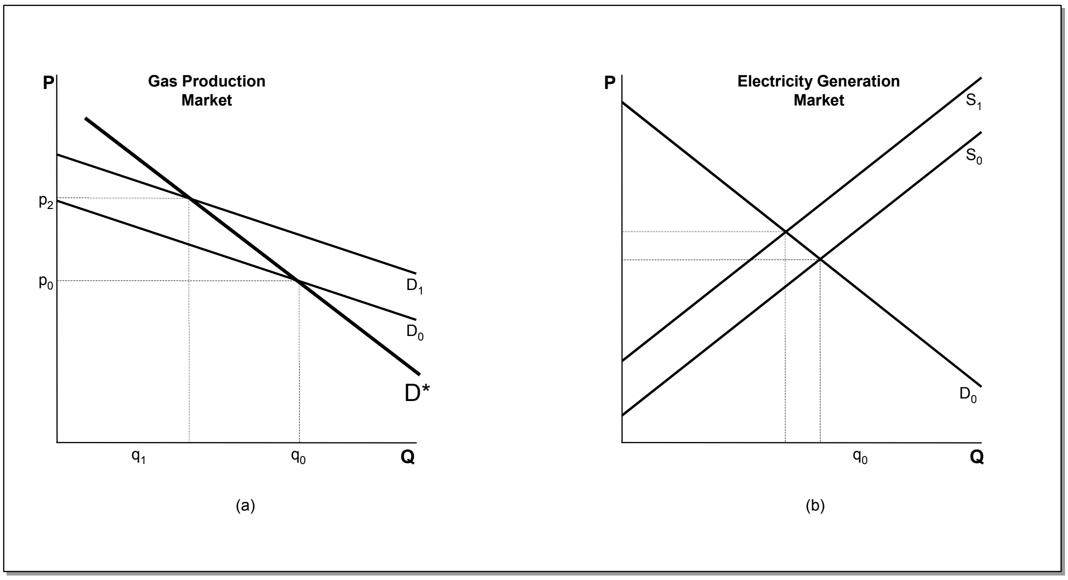
Increased prices in the electricity generation market stimulate supply by generators, increasing demand by those generators in upstream markets. This shifts the demand curve in the gas production market (Figure 13(a)) to the right.

Figure 13: Calculating Welfare Losses – Step 3



Each of the preceding three steps occurs instantaneously, and intermediate steps are not observed directly. Furthermore, the underlying demand curves in Figure 13(a) are not observed directly. Rather, the locus of points between shifted demand and supply curves are observed. Connecting these observed points in Figure 13(a) gives rise to the equilibrium demand curve, denoted D* in Figure 14(a). For clarity, we do not show the position of the supply curves in Figure 14(a).

Figure 14: Calculating Welfare Losses – Step 4



We now show that the welfare implications for vertically related markets (for example, gas production, electricity generation and electricity retailing) can be calculated by analysing the gas production market only. A more formal analysis can be found in Just, Hueth and Schmitz (1982).[138]

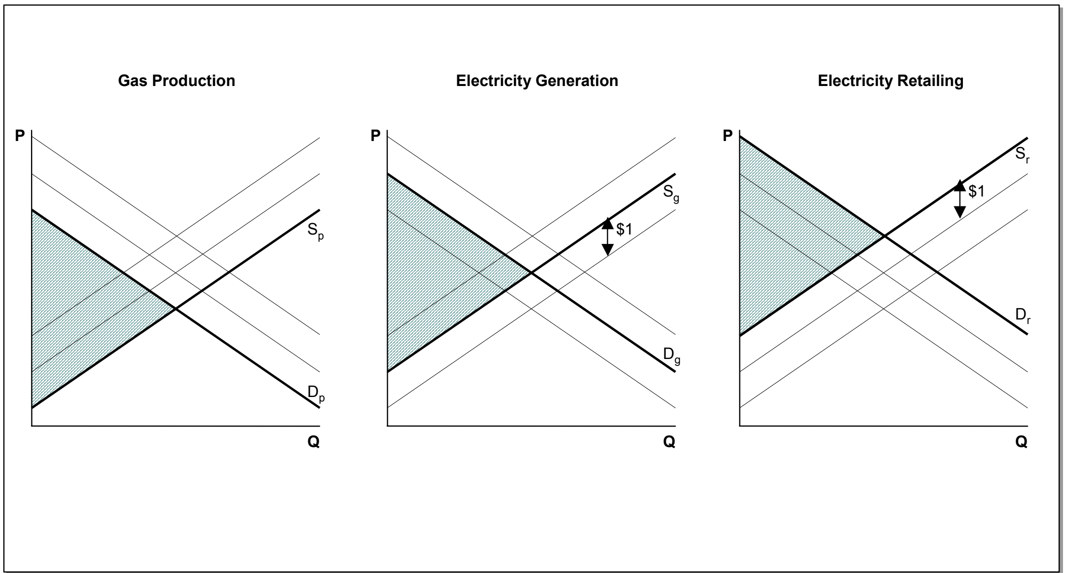
Figure 15 illustrates the gas production, electricity generation and electricity retailing markets. Consider the derivation of the retailing supply curve, S_r. Assume that the cost of supplying the marginal unit of electricity to a retail consumer is equal to the long run marginal cost of generating electricity[139] plus the cost of providing a unit of the other required inputs to retailing, which we will assume has a constant cost of \$1.00 per unit.[140] Therefore, adding \$1.00 to the supply curve in the generation market (S_g) give society's marginal cost of retailing electricity.

138 Just, R, D Hueth and A Schmitz (1982) *Applied Welfare Economics and Public Policy*, Prentice-Hall. See in particular chapter 9 and Appendix D.

139 We assume that the supply curve in the electricity generation market is upward sloping.

140 We note that if the price of any input exceeds long run marginal cost, the *level* of social surplus would be underestimated. However, this would not affect our estimate of the *change* in welfare if we assume that the mark-up over long run marginal cost is the same with or without a delay in development of Pohokura.

Figure 15: Equivalence of Changes in Welfare in Three Markets



A similar analysis shows that adding $1.00 to the supply curve in the gas production market (S_p) gives society's marginal cost of generating electricity.

Now consider the derivation of the demand curve in the gas production market, D_p (which is equivalent to D*). D_p is a derived demand curve, and so we start with the demand in the electricity retailing market, D_r. If the purchasers of generated electricity (i.e., the retailers) either purchase their other input at long run marginal cost or are integrated so they supply it to themselves at marginal cost, then the demand curve for generated electricity, D_g, is equal to the demand curve for retail electricity, D_r, minus $1.00, the cost of the other input. This assumes that the retailers of electricity do not have market power.[141]

D_p is derived from D_g using a similar analysis.

Refer now again to Figure 15. Note that the social surplus in each figure is the same. This is because the demand and supply curves in each market are just those curves in the other markets translated by $1.00. Therefore changes in surplus will also be the same.

141 If the retailers do have market power, then the problem is harder because the demand curve for generated electricity is not just the retail demand less the costs of other inputs. Rather, each firm's demand is its marginal revenue less the cost of the other input. This results in a smaller demand than that generated by subtracting input costs from retail demand. Using an independent estimate of demand for natural gas will therefore always produce an underestimate of overall welfare. Furthermore, it will result in an underestimate of the size of the deadweight loss from a reduction in output (or more correctly the failure to increase output) by estimating the deadweight loss in the gas production market as opposed to the retail electricity market.

APPENDIX C: ESTIMATING LOSSES

C.1 INTRODUCTION

This appendix describes the development of the Pohokura loss quantification. Specifically, it discusses the:

- Assumptions and parameters;
- Estimated welfare losses;
- Sensitivity analysis;[142]
- Scenario testing;[143]
- Implications of Methanex's participation or non-participation; and
- Welfare losses when water shortages are combined with limited gas supplies.

The present value of default scenario losses for the years 2004-9 is \$204.1M. The default scenario assumes, most critically, that Methanex's participation in the market is limited once current gas supply contracts to Methanex end in 2005, demand for gas by electricity generators increases by 2% per annum starting at 123PJ in 2005, and the price of Pohokura gas will be \$4.00/GJ. If Pohokura is delayed but Methanex participates fully in the market, then the present value of losses for the years 2004-9 increase to \$451.1M. Losses generally increase over time as Pohokura production increases and Maui production gradually declines towards depletion. Smaller losses in 2008 are attributable to the anticipated commencement of production from the Kupe gas field, partly offsetting welfare losses from the delay in Pohokura.

C.2 ASSUMPTIONS AND PARAMETERS

Assumptions and parameters in the model are that:

---

142 All calculations are carried out in an Excel spreadsheet.

143 The model tests variations from the baseline scenario in two ways. Sensitivity testing changes each parameter of the model by 1 percent and records the percentage change in the loss. Scenario testing adjusts the model away from the baseline scenario by setting parameters to specific values suited to the scenario, for example, comparing high to low elasticity of demand by varying the elasticity between -2.0 and -0.25.

- Actual field supplies are scaled by 0.85 to account for the share of supply going to consumers other than generators, Methanex and other petrochemical companies (these other consumers are not included in demand);

- Price for Maui gas is $[ ]/GJ (2002 dollars);

- Sale price of Pohokura is $[ ]/GJ;

- Only Pohokura changes volumes in the counterfactual scenario - there are no changes in other fields' output;

- The price cap for natural gas is $[ ], which is the price at which a generator would be indifferent between purchasing natural gas and coal;[144]

- Price of gas from smaller fields is $[ ]/GJ;

- Inflation is ignored, and all costs and revenues are expressed in 2002 dollars;

- Demand is set using two data points. Firstly, at the estimated quantity and willingness to pay of electricity generators ($[ ]/GJ, 126 PJ in 2006). Secondly, the reserve price of Methanex. We assume Methanex and other petrochemicals production operates at full capacity in 2004, consuming 98PJ per annum. In 2005, production is assumed to operate at a minimum of 50% (49PJ per annum) following the re-determination of the remaining supplies of Maui, plus additional consumption if gas can be purchased at or less than $[ ]/GJ. After 2005, we assume that Methanex and other petrochemical production operates at full capacity if natural gas is available at less than $[ ]/GJ, and at 50% of capacity (about 30PJ/pa) at a price between $[ ]/GJ and $[ ]/GJ. Above a price of $[ ]/GJ for gas, we assume all petrochemicals production including Methanex is shut down;

- The combined quantity of gas consumed by Methanex and other petrochemical companies if operating at full production is assumed to be unchanged in 2004-2009 (98 PJ per annum);

- Demand elasticity is for electricity generators only, which we set to an initial value of –0.5. Sensitivity analysis will confirm the importance or otherwise of this assumption; and

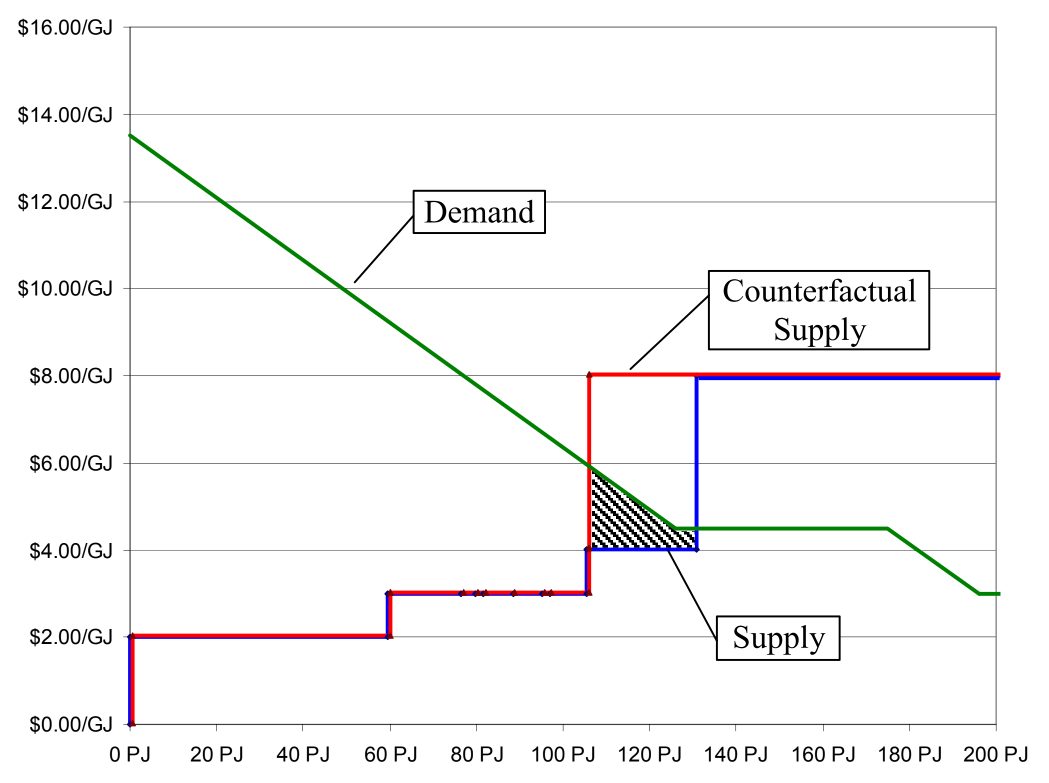
- Alternative energy sources are in "normal" supply. In particular, we assume average lake levels used for hydro generation. If hydro generation is limited by falling lake levels, demand for gas by generators will increase. We discuss the welfare implications of this demand increase below.

---

144 The derivation of this price is provided in Appendix E.

Figure 16 depicts the demand and supply curves reflecting these assumptions and parameters.

Figure 16: Demand and Supply Curves for Base Case Modelling (2006)



The welfare loss is the area between the default and counterfactual supply curves and to the left of the demand curve.

C.3 Sensitivity Analysis

The following sensitivities were recorded for each adjustable data variable in the model.

Table 19: Sensitivity Analysis

Increased by 1%	Resulting Effect on Loss	Explanation
Counterfactual Multiplier (Maui)	-6.6%	Increased production from Maui in the counterfactual (compensating for the loss of Pohokura) reduces the magnitude of the loss substantially.
Demand Initial Quantity	+4.3%	Determines the position of the electricity generation demand curve. A small increase in gas demand leads to a large expansion of welfare loss.
Demand Initial Price	+3.6%	Determines the position of the electricity generation demand curve. Small changes in gas demand lead to large welfare changes.

Increased by 1%	Resulting Effect on Loss	Explanation
Supply Volume (Maui)	-2.6%	Increased output from Maui reduces the output required from higher priced Pohokura. This reduces welfare losses in the event Pohokura is delayed.
Price (Pohokura)	-2.6%	As the cost of Pohokura gas increases, its value to society is reduced. In other words, as the cost of production increases society will miss Pohokura's absence less. Hence, higher price for Pohokura gas at the margin reduces the welfare loss.
Counterfactual Multiplier (Kapuni)	-1.5%	Greater output from an alternate field in the counterfactual scenario reduces welfare losses from the elimination of Pohokura.
Supply Volume (Kapuni)	-0.7%	Greater output from an alternate field in the counterfactual scenario reduces welfare losses from the elimination of Pohokura.
Demand Elasticity	-0.7%	Elasticity changes pivot the demand curve about the observed demand point. The pivot point of the demand curve (determined by the initial price and demand of electricity generators in 2006) is located inside the area of welfare loss. Pivoting the demand curve around a point inside the welfare loss, in this case, produces limited welfare effects.
Counterfactual Multiplier (Rimu)	-0.6%	If the counterfactual scenario in which Pohokura produces nothing is associated to an increase in the output of other gas fields, then welfare losses will be reduced.
Counterfactual Multiplier (Mangahewa)	-0.6%	Greater output from an alternate field in the counterfactual scenario reduces welfare losses from the elimination of Pohokura.
Counterfactual Multiplier (TAWN)	-0.6%	Greater output from an alternate field in the counterfactual scenario reduces welfare losses from the elimination of Pohokura.
Demand Growth	+0.5%	Increased demand expands welfare loss by leaving a greater share of demand unsatisfied by the delay in Pohokura.
Supply Volume (Pohokura)	+0.4%	Increased output from Pohokura, compared to a counterfactual of zero output, increases the welfare benefit of the timely development of Pohokura, or, equivalently, the welfare losses resulting from Pohokura's delay.
Supply Volume (Rimu)	-0.4%	Greater output from an alternate field in the counterfactual scenario reduces welfare losses from the elimination of Pohokura.
Supply Volume (Mangahewa)	-0.3%	Greater output from an alternate field in the counterfactual scenario reduces welfare losses from the elimination of Pohokura.
Supply Volume (TAWN)	-0.3%	Greater output from an alternate field in the counterfactual scenario reduces welfare losses from the elimination of Pohokura.
Counterfactual Multiplier (McKee)	-0.3%	Greater output from an alternate field in the counterfactual scenario reduces welfare losses from the elimination of Pohokura.
Supply Volume (McKee)	-0.1%	Greater output from an alternate field in the counterfactual scenario reduces welfare losses from the elimination of Pohokura.
Counterfactual Multiplier (Kaimiro)	-0.1%	Greater output from an alternate field in the counterfactual scenario reduces welfare losses from the elimination of Pohokura.
Counterfactual Multiplier (Ngatoro)	-0.1%	Greater output from an alternate field in the counterfactual scenario reduces welfare losses from the elimination of Pohokura.
Supply Volume (Kaimiro)	-0.1%	Greater output from an alternate field in the counterfactual scenario reduces welfare losses from the elimination of Pohokura.
Supply Volume (Ngatoro)	-0.1%	Greater output from an alternate field in the counterfactual scenario reduces welfare losses from the elimination of Pohokura.

The welfare losses are sensitive to changes in the above variables. The losses are insensitive to the following variables:

Table 20: Variables for Which the Result is Insensitive

Supply Volume (Kauhauroa)	Supply Volume (Kupe)	Price (Maui)
Methanex Price Step 1	Counterfactual Multiplier (World)	Price (Kaimiro)
Counterfactual Multiplier (Kupe)	Price (Ngatoro)	Price (McKee)
Counterfactual Multiplier (Pohokura)	Price (Mangahewa)	Price (World)
Price (TAWN)	Price (Kauhauroa)	Counterfactual Multiplier (Kauhauroa)
Methanex Percent Step 1	Price (Kupe)	Methanex Price Step 2
Price (Rimu)	Supply Volume (World)	Price (Kapuni)
Methanex Full Production Quantity		

C.4 Beyond 2004

The following supply profiles are taken from Appendix F for Maui and Pohokura.

Table 21: Expected Extraction Profiles for Maui and Pohokura

Field	Estimated production in 2004	Estimated production in 2005	Estimated production in 2006	Estimated production in 2007	Estimated production in 2008	Estimated production in 2009
Maui	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Pohokura	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]

C.5 Scenario Testing

The model allows for scenario testing and production of estimates under various situations. Table 22 shows a collection of conceivable scenarios with losses for each scenario estimated.

Table 22: Scenario Testing

Description	2004	2005	2006	2007	2008	2009	Total	NPV[145]	
Original Scenario	51.0m	79.2m	27.7m	72.5m	36.5m	34.9m	301.9m	204.1m	
Eliminates Methanex from market	51.0m	79.2m	26.8m	69.6m	36.4m	34.9m	298.0m	201.7m	
Methanex gets cheap gas first	51.0m	102.0m	102.0m	187.0m	136.0m	136.0m	714.0m	451.1m	Max Loss
Very Price Sensitive (ε=-2)[146]	23.1m	29.4m	16.5m	35.7m	21.9m	21.5m	148.0m	97.9m	Min Loss
Price Sensitive (ε=-1)	39.8m	46.0m	20.2m	47.9m	26.8m	26.0m	206.7m	139.5m	
Price Insensitive (ε=-0.25)	51.0m	101.9m	42.7m	110.7m	56.1m	52.8m	415.2m	275.4m	
Generator demand grows 7% pa from current levels (103 PJ)	51.0m	102.0m	93.1m	180.9m	134.0m	135.9m	697.0m	440.1m	
Initial Position of demand curve shifted down (Price -0.5)[147]	51.0m	59.1m	17.8m	50.3m	24.5m	23.5m	226.2m	155.8m	
Initial Position of demand curve shifted up (Price +0.5)[148]	51.0m	94.0m	41.1m	98.3m	52.3m	50.1m	386.8m	257.1m	
Zero electricity generator demand growth from 2006	51.0m	76.5m	22.2m	57.7m	24.5m	21.4m	253.3m	175.4m	
5% electricity generator demand growth from 2006	51.0m	82.9m	38.0m	99.0m	63.5m	69.1m	403.7m	263.3m	

145 Discounted to 2002 at a rate of 10 per cent.

146 Default price elasticity of demand is –0.5.

147 Reduction in demand is simulated by reducing the price at which a given quantity is demanded. This is equivalent to reducing the quantity demanded at a given price.

148 Demand is increased by raising the price at which a given quantity is demanded. See footnote 103.

Description	2004	2005	2006	2007	2008	2009	Total	NPV[145]	
10% producer demand growth from 2006	51.0m	88.3m	54.8m	140.7m	106.0m	119.2m	560.0m	354.3m	
Pohokura price reduced 50c/GJ	57.4m	92.0m	40.5m	95.9m	53.5m	51.9m	391.1m	260.5m	
Pohokura price increased 50c/GJ	44.6m	66.5m	15.0m	49.1m	19.5m	17.9m	212.6m	147.8m	
Gas price cap reduced 50c	44.6m	77.3m	27.7m	72.5m	36.5m	34.9m	293.5m	197.4m	
Gas price cap increased 50c	57.4m	79.2m	27.7m	72.5m	36.5m	34.9m	308.3m	209.4m	
Pohokura output reduced by 30%	42.0m	68.7m	25.5m	60.3m	22.4m	21.1m	239.9m	164.6m	
Pohokura output increased by 30%	78.0m	102.0m	34.5m	81.4m	43.4m	42.1m	381.3m	261.2m	
Smoothed run-down of Maui supplies (remaining supplies consumed evenly 2004-9)	51.0m	96.1m	27.0m	28.0m	17.0m	17.0m	236.0m	168.4m	

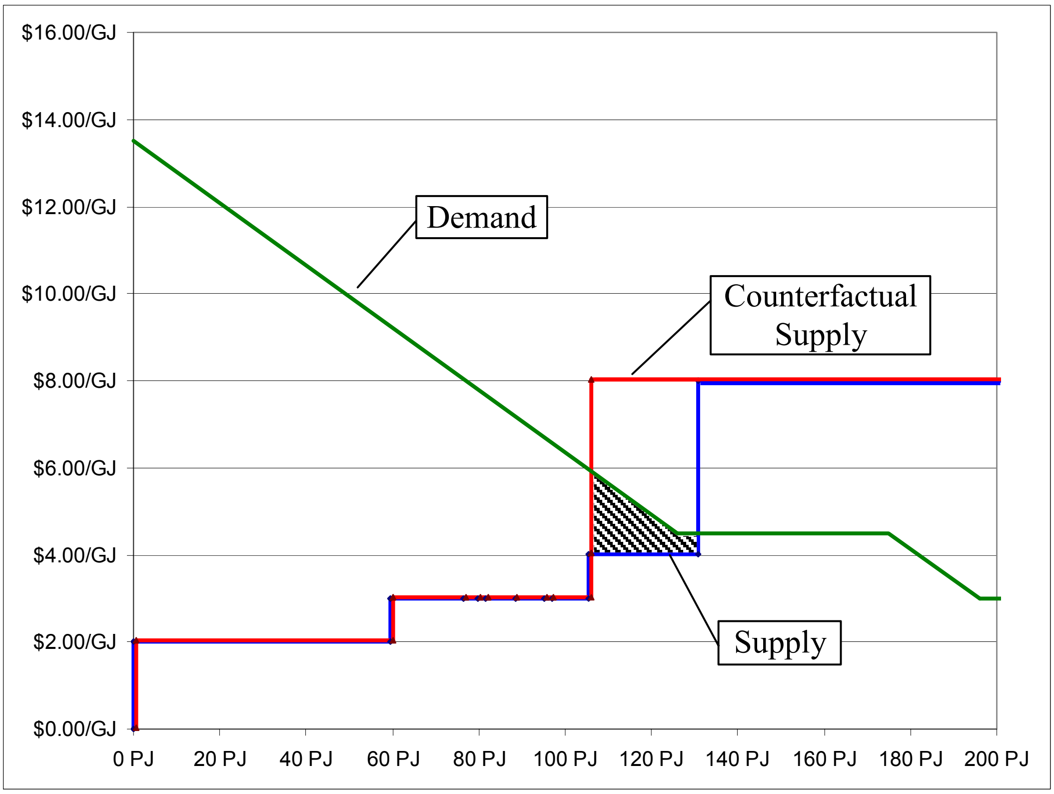
C.6 METHANEX

Welfare losses from a delay in production from Pohokura are affected by whether Methanex and other petrochemicals production continues to consume natural gas in New Zealand between 2006 and 2009. Methanex and other petrochemical firms currently consume around 42% of the natural gas produced in New Zealand and we assume they will continue to do so in 2004. Intuitively, the welfare effect of reductions in the supply of natural gas is likely to be more severe the greater is the demand for gas. The quantification model confirms this.

The participation of Methanex and other petrochemical firms in the market requires the setting of a reserve price for them. The market price determined by the intersection of supply and aggregate demand for natural gas in the actual and counterfactual scenarios then determines their participation. The demand for gas by Methanex and petrochemical firms is modelled as a two-step demand curve. They reduce consumption of natural gas to 49PJ per annum, down from 98PJ per annum, if the market price for natural gas is between $[ ]/GJ and $[ ]/GJ. Beyond $[ ]/GJ, all petrochemicals production shuts down completely.

The contractual position of Methanex requires Methanex to consume most of the gas it purchases from the Crown. However, our base case modelling assumes that by 2006, following the Maui gas redetermination process currently underway, Methanex (and other petrochemical firms) will have been largely out-competed for gas by bidders willing to pay higher prices from increasingly limited remaining gas supplies: petrochemical companies including Methanex will hardly participate in the market after 2005 under our base case scenario. We also test for welfare losses if Methanex (and other petrochemical firms) operates at full production until 2009.

Figure 17: Methanex in the Market (2006)



In Figure 17, Methanex and other petrochemical firms are just consuming in the market for gas production (as indicated by the horizontal section added to the graph, some of which lies inside the joint marketing supply curve (labelled "Supply")).

To simulate the effect of Methanex and other petrochemical firms operating at full production through to 2009 as natural gas supplies decline, we set their reserve price to $10/GJ, which ensures their full participation in the market each year to 2009. Though this is unlikely to be representative of the actual willingness of these firms to pay for gas, this assumption forces them to consume natural gas even when other consumers are willing to pay substantially more. From the above scenario, it is clear that the full surplus derived from Pohokura is lost on delay, and a large welfare loss results (see Scenario Testing above).

C.7 WATER SHORTAGE

Gas generation is an alternative to hydro generation in New Zealand. In 2001, we understand that a record amount of gas was extracted from the Maui field to fuel gas-fired plants as lake levels fell.

If Methanex and other petrochemicals companies continues operations at or near full capacity, we anticipate substantial shortfalls in required gas supplies. Without sufficient gas supplies for electricity generation, and in the event of lakes falling to low levels, New Zealand faces the real possibility of electricity blackouts. An estimate of the considerable welfare losses arising from such an event is outside the scope of this report, but the possibility of electricity blackouts underlines the value of a timely replacement for the Maui field, and the potential costs of production delay from Pohokura.

APPENDIX D: CURRENT TARANAKI PETROLEUM PERMITS

Source: Ministry of Economic Development website.

D.1 TARANAKI BASIN ONSHORE (387XX)

D.1.1 Petroleum Prospecting and Exploration Permits

* = permit operator

Permit No.	Area	Term	
	Participating interests (%)		
PPL 38705	19.84 km^2	4 years from 01.08.98 (Third Term)	
	* Todd Taranaki Limited		100.00
PEP 38716	133.6612 km^2	5 years from 30.01.01 (Second Term)	
	*Marabella Enterprises Ltd		24.80
	Preussag Energie GmbH		24.00
	Swift Energy New Zealand Limited		15.00
	AWE New Zealand Pty Ltd		12.50
	Indo-Pacific Energy (NZ) Limited		7.30
	Euro-Pacific Energy Pty Limited		6.60
	PEP 38716 Limited		5.00
	Springfield Oil and Gas Limited		4.80
PEP 38718	115.55 km^2	5 years from 01.12.00 (Second Term)	
	* Shell Exploration NZ Ltd		50.00
	Swift Energy New Zealand Limited		20.00
	Origin Energy Resources NZ Limited		20.00
	Marabella Enterprises Limited		10.00
PEP 38719	201.4537 km^2	5 years from 12.08.01 (Second Term)	
	* Swift Energy New Zealand Limited		100.00
PEP 38722	127.656 km^2	5 years from 01.05.02 (Second Term)	

	Manti Resources Incorporated Ultra Oil & Gas Incorporated * Discovery Geo (Australia) Corporation MM Cone Incorporated King Operating Corporation		43.7500 21.8750 12.5000 10.9375 10.9375
PEP 38728	198.50 km^2	5 years from 17.08.98 (First Term)	
	* Marabella Enterprises Ltd Shell Exploration NZ Limited Origin Energy Resources NZ Limited Preussag Energie GmbH Springfield Oil and Gas Limited Petroleum Resources Ltd		30.00 30.00 15.00 15.00 5.00 5.00
PEP 38729	475.26 km^2	5 years from 06.11.98 (First Term)	
	* Petroleum Resources Ltd Origin Energy Resources Limited		75.00 25.00
PEP 38732	18.858 km^2	5 years from 14.07.99 (First Term)	
	* Westech Energy New Zealand		100.00
PEP 38734	38.86 km^2	5 years from 14.07.99 (First Term)	
	* Westech Energy New Zealand		100.00
PEP 38736	29.911 km^2	5 years from 14.07.99 (First Term)	
	Tap (New Zealand) Pty Ltd Millenium Oil and Gas Limited Claire Energy Pty Limited * Indo-Pacific Energy (NZ) Limited		30.00 25.00 25.00 20.00
PEP 38737	1099.59 km^2	5 years from 15.01.00 (First Term)	
	Shell (Petroleum Mining) Company Ltd Todd Petroleum Mining Company Ltd * Shell Todd Oil Services Ltd		50.00 50.00 0.00
PEP 38738	123.2528 km^2	5 years from 15.01.00 (First Term)	
	* Marabella Enterprises Ltd Springfield Oil and Gas Limited		95.00 5.00

PEP 38739	1381.75 km^2	5 years from 03.08.01 (First Term)	
	* Greymouth Energy Limited Greymouth Petroleum Ltd		50.00 50.00
PEP 38741	12.604 km^2	5 years from 24.05.02 (First Term)	
	* Indo-Pacific Energy (NZ) Limited Tap (New Zealand) Pty Ltd		50.00 50.00
PEP 38742	68.00 km^2	5 years from 19.07.02 (First Term)	
	Aspect Resources LLC * Geosphere Exploration Limited		90.00 10.00
PEP 38743	40.337 km^2	5 years from 8.08.02 (First Term)	
	* Discovery Geo (Australia) Corporation Manti Resources Incorporated MM Cone Incorporated		62.50 25.00 12.50
PEP 38744	101.457 km^2	5 years from 8.08.02 (First Term)	
	Preussag Energie GmbH * Origin Energy Resources (NZ) Limited		50.00 50.00
PEP 38745	50.498 km^2	5 years from 8.08.02 (First Term)	
	* Bridge Petroleum Limited		100.00
PEP 38746	79.373 km^2	5 years from 8.08.02 (First Term)	
	* Indo-Pacific Energy (NZ) Limited Tap (New Zealand) Pty Ltd AWE New Zealand Pty Ltd Magellan Petroleum (New Zealand) Limited		25.00 25.00 25.00 25.00
PEP 38747	26.959 km^2	5 years from 8.08.02 (First Term)	
	* Greymouth Petroleum Holdings Company		100.00
PEP 38748	30.302 km^2	5 years from 8.08.02 (First Term)	

	* Indo-Pacific Energy (NZ) Limited Tap (New Zealand) Pty Ltd Magellan Petroleum (New Zealand) Limited		37.50 37.50 25.00
PEP 38749	198.308 km^2	5 years from 8.08.02 (First Term)	
	Aspect Resources LLC * Geosphere Exploration Limited		90.00 10.00
PEP 38750	154.511 km^2	5 years from 8.08.02 (First Term)	
	Aspect Resources LLC * Geosphere Exploration Limited		90.00 10.00
PEP 38751	66.052 km^2	5 years from 8.08.02 (First Term)	
	* Bridge Petroleum Limited		100.00
PEP 38752	22.457 km^2	5 years from 8.08.02 (First Term)	
	* Bridge Petroleum Limited		100.00
PEP 38753	110.103 km^2	5 years from 8.08.02 (First Term)	
	* Indo-Pacific Energy (NZ) Limited Tap (New Zealand) Pty Ltd Magellan Petroleum (New Zealand) Limited		50.00 25.00 25.00
PEP 38754	64.211 km^2	5 years from 8.08.02 (First Term)	
	* Petroleum Resources Limited		100.00
PEP 38755	118.573 km^2	5 years from 8.08.02 (First Term)	
	* Petroleum Resources Limited		100.00
PEP 38756	32.914 km^2	5 years from 8.08.02 (First Term)	
	* Swift Energy New Zealand Limited		100.00
PEP 38757	29.447 km^2	5 years from 8.08.02 (First Term)	
	* Re-Source Exploration Limited		100.00

PEP 38758	99.317 km^2	5 years from 8.08.02 (First Term)
	* Re-Source Exploration Limited 100.00	
PEP 38759	82.546 km^2	5 years from 8.08.02 (First Term)
	* Swift Energy New Zealand Limited 100.00	
PEP 38760	160.101 km^2	5 years from 8.08.02 (First Term)
	* Todd Petroleum Mining Company Limited 100.00	

http://www.med.govt.nz/crown_minerals/petroleum/permits/current.html - top

D.2 TARANAKI BASIN OFFSHORE (384XX)

D.2.1 Petroleum Prospecting and Exploration Permits

* = permit operator

Permit No.	Area	Term
	Participating interests (%)	
PEP 38413	1336.14 km^2	5 years from 01.01.98 (Second Term)
	OMV New Zealand Limited 49.00 OMV Petroleum Pty Ltd 30.00 Todd Petroleum Mining Company Ltd 21.00 * Shell Todd Oil Services Ltd 0.00	
PEP 38459	394.43 km^2	5 years from 01.12.00 (Second Term)
	Preussag Energie GmbH 35.8618 Shell Exploration NZ Ltd 29.6673 Shell (Petroleum Mining) Company 18.3330 Todd Petroleum Mining Company Ltd 16.1379 *Shell Todd Oil Services Limited 0.0000	
PEP 38460	2816.46 km^2	5 years from 23.09.96 (Second Term)
	* Stewart Petroleum Company Ltd 40.00 WM Petroleum Limited 40.00 AWE New Zealand Pty Ltd 20.00	

PEP 38464	106.651 km^2	5 years from 28.11.97 (First Term)
	Greymouth Energy Limited 50.00 * Greymouth Petroleum Ltd 26.00 Re-source Exploration Limited 22.00 Ngati Te Whiti Hapu Society Inc 2.00	
PEP 38471	267.06 km^2	5 years from 25.01.01 (First Term)
	Manti Resources Incorporated 43.750 Ultra Oil & Gas Inc 21.8750 * Discovery Geo (Australia) Corporation 12.5000 MM Cone Incorporated 10.9375 King Operating Corporation 10.9375	
PEP 38472	5098.103 km^2	5 years from 13.02.01 (First Term)
	* OMV Petroleum Pty Ltd 50.00 Stewart Petroleum Company Ltd 50.00	
PEP 38478	361.18 km^2	5 years from 31.08.02 (First Term)
	* Petroleum Resources Ltd 50.00 Origin Energy Resources NZ Limited 50.00	
PEP 38479	1527.96 km^2	5 years from 24.09.02 (First Term)
	*Discovery Geo (Australia) Corporation 100.00	
PEP 38480	314.690 km^2	5 years from 8.08.02 (First Term)
	*Indo-Pacific Energy (NZ) Ltd 100.00	
PEP 38481	2150.852 km^2	5 years from 8.08.02 (First Term)
	Shell Exploration NZ Limited 60.00 OMV Australia Pty Limited 25.00 Todd Petroleum Mining Company Limited 15.00 * Shell Todd Oil Services 0.00	
PEP 38482	2132.607 km^2	5 years from 8.08.02 (First Term)
	Shell Exploration NZ Limited 60.00 OMV Australia Pty Limited 25.00 Todd Petroleum Mining Company Limited 15.00 * Shell Todd Oil Services 0.00	

http://www.med.govt.nz/crown_minerals/petroleum/permits/current.html - top

D.2.2 Taranaki Basin Mining Licences and Permits

* = permit operator

Permit No.	Area	Term
	Participating interests (%)	
PML 38086	27.42 km^2	20 years from 11.11.83 (McKee)
	* Todd Taranaki Limited 100.00	
PML 38091	47.95 km^2	30 years from 04.04.84 (Kaimiro)
	* Greymouth Petroleum Acquisition Company Ltd 100.00	
PML 38138	14.9 km^2	29 years from 21.07.87 (Tariki)
	* Southern Petroleum (New Zealand) Exploration Ltd 96.76 Swift Energy New Zealand Limited 3.24	
PML 38139	15.10 km^2	29 years from 21.07.87 (Ahuroa)
	* Southern Petroleum (New Zealand) Exploration Ltd 96.76 Swift Energy New Zealand Limited 3.24	
PML 38140	22.86 km^2	29 years from 21.07.87 (Waihapa)
	* Southern Petroleum (New Zealand) Exploration Ltd 96.76 Swift Energy New Zealand Limited 3.24	
PML 38141	46.7 km^2	24 years & 3 months from 20.03.92 (Ngaere)
	* Southern Petroleum (New Zealand) Exploration Ltd 96.76 Swift Energy New Zealand Limited 3.24	
PML 38146	256.52 km^2	29 years & 8.4 months from 01.02.92 (Kupe)

	Kupe Mining (No. 2) Ltd Fletcher Challenge Kupe Holdings Ltd Kupe Mining (No. 1) Ltd National Petroleum Ltd Minister of Energy Delta Petroleum Ltd Nephrite Enterprises Ltd Petroleum Equities Ltd * Energy Exploration NZ Ltd	32.1875 20.0000 17.8125 12.7500 11.0000 2.5000 2.5000 1.2500 0.0000
PMP 38148	38.212 km^2	14 years from 23.12.96 (Ngatoro)
	Greymouth Petroleum Acquisition Company Ltd Southern Petroleum (Ohanga) Ltd * Petroleum Resources Ltd Australia & New Zealand Petroleum Ltd Ngatoro Energy Limited	29.78465 29.78465 20.43070 15.00000 5.00000
PMP 38150	44.36 km^2	18 years from 01.05.01 (Mangahewa)
	* Todd Taranaki Limited	100.00
PMP 38151	22.374 km^2	30 years from 30.01.02 (Rimu)
	* Swift Energy New Zealand Limited	100.00
PML 38839	218.98 km^2	42 years from 01.01.70 (Kapuni)
	Shell (Petroleum Mining) Co Ltd Todd Petroleum Mining Co Ltd * Shell Todd Oil Services Ltd	50.00 50.00 0.00
PML 381012	784.00 km^2	42 years from 28.06.73 (Maui)
	Shell Exploration NZ Ltd Energy Petroleum Investments Ltd Shell (Petroleum Mining) Company Ltd OMV New Zealand Limited Todd Petroleum Mining Company Ltd Taranaki Offshore Petroleum Company of NZ * Shell Todd Oil Services Ltd	38.75 20.00 18.75 10.00 6.25 6.25 0.00

APPENDIX E: DERIVATION OF EFFECTIVE GAS PRICE CAP

As noted in section 3.2 of this report, the most obvious substitute for gas as an input into future electricity generation in New Zealand is coal. Accordingly, the price of gas will be constrained by the price of coal.

In its modelling, the Ministry of Economic Development assumes that coal prices will rise "from around NZ$2.66/GJ in 1998 to NZ$3/GJ in 2010 before stabilising".[149] However, it is important to note that:

- The costs of producing electricity from a coal-fired plant are significantly greater than the costs of a gas-fired plant;
- The thermal efficiency of coal is lower than gas (in other words, a greater number of GJs of coal are needed to produce one unit of electricity); and
- The environmental externalities of burning coal are worse than those for gas, potentially meaning higher emission charges under any climate change policy response.

Accordingly, we would expect an electricity generator to be willing to pay more for a unit of gas than for a unit of coal.

We set out below the results of a simple model that estimates the long run marginal cost (LRMC) of generating electricity from a coal-fired plant and a gas-fired plant.[150] The data source for the cost figures is a recent report by East Harbour Management Services Ltd for the Ministry of Economic Development.[151] [ ][152]

Note that these calculations do not include an emission charge for either type of plant. Because coal has greater externalities, the emission charge for it is likely to be higher, which would therefore increase the differential between a generator's willingness to pay for gas and coal.

---

149 Ministry of Economic Development (2002) *Energy Data File*, 12.

150 We have assumed a 400MW conventional pulverised coal plant with flue gas desulphurisation, and LRMC is calculated on a normalised capacity.

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

152 This calculation is for a firm considering the decision to build a new plant. The willingness to pay for gas of an existing CCGT owner may be higher, because of sunk costs. This also makes our calculation of welfare losses conservative.

Figure 18: LRMC of Generating Electricity from Coal and Gas

[ ]

APPENDIX F: FUTURE GAS SUPPLIES IN NEW ZEALAND

Note that there is still considerable uncertainty around the expected annual production from Pohokura.

Table 23: Expected Extraction Profiles from Currently Discovered Fields

Field	Maui	Kapuni	Manga-hewa	McKee	TAWN	Kaimiro	Ngatoro	Poho-kura	Kupe	Rimu	Kau-hauroa
Equity Interest percentage	Shell: 83.75 Todd: 6.25 Unknown : 10	Shell: 50 Todd: 50	Todd: 100	Todd: 100	Swift: 96.76 Bligh: 3.24	Greymouth 100	Greymouth : 60 NZOG: 35 NEL: 5	Shell: 48 Preussag: 35.8618 Todd: 16.1379	Min of Energy: 11 NZOG: 19 Genesis: 70	Swift: 95 Marabella : 5	Westech: 100
Operator	STOS	STOS	STOS	STOS	Swift	Unknown	NZOG	STOS	Unknown	Unknown	Unknown
Production in 2000[153]	184.64	23.22	0	8.51	10.1	0.52	1.44	0	0	0	0
Estimated production, 2003	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]

153 The gas production figures for 2000 were taken from the Energy Data File July 2001 and relate to "Net Gas Production".

Field	Maui	Kapuni	Manga-hewa	McKee	TAWN	Kaimiro	Ngatoro	Poho-kura	Kupe	Rimu	Kau-hauroa
Estimated production, 2004	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Estimated production, 2005	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Estimated production, 2006	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Estimated production, 2007	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Estimated production, 2008	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Estimated production, 2009	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Estimated production, 2010[154]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ][155]	[ ][156]

154 The Commerce Commission stated that TAWN, Mangahewa and McKee would be between them producing 10 PJ p.a. post 2009. However, this does not fit with the Commission's view that both TAWN and McKee would be depleted by 2010.

155 The Commerce Commission considered that 10 PJ production p.a. was possible from Rimu and Kauhauroa post 2009.

156 The Commerce Commission considered that 10 PJ production p.a. was possible from Rimu and Kauhauroa post 2009.

Field	Maui	Kapuni	Manga-hewa	McKee	TAWN	Kaimiro	Ngatoro	Poho-kura	Kupe	Rimu	Kau-hauroa
Estimated production, 2015	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Estimated production, 2020	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]
Estimated 2P reserves[157] As at 1/1/2001	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ]	[ ][158]	[ ]	[ ]	[ ]

157 The 2P figures were taken from the Energy Data File July 2001 and are as at 1 January 2001 (net production).

158 This was the figure noted in Decision No.408 which FCE stated as Pohokura's current booked reserves (presumably at September 2000).