AN EVALUATION OF THE ECONOMIC IMPACTS ASSOCIATED WITH THE MACKENZIE VALLEY GAS PIPELINE AND MACKENZIE DELTA GAS DEVELOPMENT

EXTENDED ANALYSIS AND UPDATE

Prepared For

INDUSTRY, TOURISM AND INVESTMENT
GOVERNMENT OF THE NORTHWEST TERRITORIES

Prepared By

WRIGHT MANSELL RESEARCH LTD.

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INTRODUCTION

In 2004, the Government of the Northwest Territories (GNWT) and TransCanada PipeLines Ltd. (TCPL) requested an assessment of the economic impacts associated with the development and production of gas reserves in the Mackenzie Delta and the construction and operation of a pipeline running from the Mackenzie Delta down the Mackenzie Valley to an interconnect with the TCPL system in northern Alberta. In response to that request, **Wright Mansell Research Ltd. (WMR) completed the study *An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Gas Development: An Update***, dated June 30, 2004 (**hereafter referred to as the *2004 Mackenzie Valley Study***).

Earlier this year Imperial Oil Resources Ventures Limited filed information with the National Energy Board in which the **costs associated with the Mackenzie Gas Project were updated. This shows substantially higher investment costs** for facilities and pipelines which alone would decrease the financial flows to governments and the producers. However, **since 2004 an era of substantially higher gas prices** than in the past **appears to have emerged** and the expectation is that these higher gas prices will prevail in the future given prospects in global energy markets. Further, a new version of the Statistics Canada model incorporating updated coefficients is now available.

In light of the number and significance of these changes, **the Government of the Northwest Territories (GNWT) requested an update of the economic impacts. This study provides that update for the impacts using the same general format and methodology as outlined in the 2004 Mackenzie Valley Study. This study also includes a case where the pipeline capacity is expanded to handle volumes significantly higher than those considered in the previous study.**

BACKGROUND

The federal government opened up northern Canada to oil and gas exploration in the 1960s and exploration in the Mackenzie Delta area began in that decade. The majority of the exploration drilling in the region to date took place in the 1970s and 1980s in response to rapidly rising energy prices. Nearly 200 exploration wells have been drilled in the area with close to 30% of these wells being successful. The largest gas discoveries have been at Taglu, Parsons Lake and Niglintgak with estimated recoverable gas reserves of 3.0 Tcf, 1.8 Tcf and 0.9 Tcf respectively. Total discovered marketable reserves in the Mackenzie Delta / Beaufort Sea region are estimated to be 9 Tcf, with undiscovered resources believed to be in the range of 52 Tcf, making for an ultimate resource potential of 61 Tcf.

Gas development in the region has been constrained by relatively low gas prices over much of the last decade or so and, most importantly, by the lack of pipeline access to major gas markets. With expectations of stronger gas prices into the future, a joint venture between the Mackenzie Delta Producer Group (which includes Imperial Oil Resources, Shell Canada, ConocoPhillips Canada and ExxonMobil Canada) and the Aboriginal Pipeline Group (which represents the Aboriginal peoples of the NWT) has recently been formed and has committed $600 million or more to take a proposed gas development and pipeline construction project to the permit stage before the National Energy Board. Further, a recent bid of $585 million by Imperial Oil / Exxon for drilling in the deeper offshore area of the Beaufort Sea, bids by ConocoPhillips and by Chevron for onshore and shallow Beaufort Sea drilling and a recently announced oil discovery in the shallow Beaufort Sea by Devon have all been encouraging signs of greater hydrocarbon potential in the area and greater interest in developing these resources.

MAIN CASES

There are key uncertainties with respect to the dimensions of this gas development and pipeline project and the energy price environment within which it would be constructed and operate. These are taken into account through the use of sensitivity analyses and scenarios or cases. The first scenario, Case 1, assumes that only the gas from the Anchor fields will be available. Volumes are consequently about 826 MMcf/d but go into decline after 14 years. The second scenario, Case 2, assumes that other presently known gas and discoveries from exploration are sufficient to operate the pipeline at 1.2 Bcf/d for about 15 years before the volumes go into decline.

The third scenario, Case 3, assumes that other known gas plus new discoveries from exploration are sufficient to operate the gas pipeline at 1.2 Bcf/d for about 25 years. The fourth scenario, assumes that there will even greater gas discoveries than in Case 3 over the longer term to increase volumes to 1.8 Bcf/d by 2024 and sustain that production level until 2040. The main elements of the various scenarios are summarized below.

CASE	Gas Volumes (approx)	Gas Prices (in 2006$)	Direct Investment (I) and Revenues (R) (in Billions 2007$)
Case 1-6	800 MMcfd from 2015 to 2027, declining to 200 MMcfd by 2035	$6 US/Mcf at Chicago, remaining constant in real terms	I = $16.1B R= $32.3B Period = 2002-2035
Case 1-8	800 MMcfd from 2015 to 2027, declining to 200 MMcfd by 2037	$8 US/Mcf at Chicago, remaining constant in real terms	I = $16.1B R = $46.5B Period = 2002-2037
Case 2-6	1200 MMcfd from 2015 to 2028, declining to 400 MMcfd by 2040	$6 US/Mcf at Chicago, remaining constant in real terms	I = $27.1B R= $53.4B Period = 2002-2040
Case 2-8	Same as Case 2-6	$8 US/Mcf at Chicago, remaining constant in real terms	I = $27.1B R=$74.9B Period = 2002-2040
Case 3-6	1200 MMcfd from 2015, then averaging 1100 MMcfd to 2040	$6 US/Mcf at Chicago, remaining constant in real terms	I =$37.3B R=$63.6B Period = 2002-2040
Case 3-8	Same as Case 3-6	$8 US/Mcf at Chicago, remaining constant in real terms	I = $37.3B R=$89.4B Period = 2002-2040
Case 4-6	1200 MMcfd from 2015-2021, rising to 1800 MMcfd by 2024	$6 US/Mcf at Chicago, remaining constant in real terms	I = $50.4B R=$84.1B Period = 2002-2040
Case 4-8	Same as Case 4-8	$8 US/Mcf at Chicago, remaining constant in real terms	I = $50.4B R=$118.2B Period = 2002-2040

GAS PRICE AND VOLUME CASES

- **Two gas price scenarios** ($6US and $8US/Mcf) are analyzed in this report. These prices are for Chicago and, as a point of reference, the average price in that market for the 2003-2007 period was just over $7US. In both scenarios gas prices in Chicago are assumed constant in real terms (that is, in 2006$) over the duration of the analysis period. These scenarios are referred to as **the $6 US gas price scenario and the $8 US gas price scenario.** Although the gas price scenarios are defined in terms of 2006US$, **all impact results are reported in 2007 Cdn$.** It can be noted that **in the 2004 study**, given lower long term expectations of gas prices at the time, **gas price scenarios of $3US and $4US were used.** Also, while the 2004 study used an exchange rate of $1Cdn=$0.75US, this study assumes $1Cdn =$0.90US.

- **Case 1 involves production only from Niglintgak, Parsons Lake and Taglu (hereafter referred to as the anchor fields).** Production over the early years of the project would be about 826 MMcf/d and would continue until 2035 in the $6US gas price scenario and until 2037 in the $8US gas price scenario.

- **In Case 2, it is assumed that gas from other fields already identified in the Mackenzie Delta, as well as from several new discoveries, would be available for production by 2015 so as to achieve gas production of roughly 1.2 Bcf/d over the early years of the project.** Through continued exploration and development activity, gas production would be maintained near 1.2 Bcf/d until 2028, after which it would decline. Impacts are evaluated through to 2040.

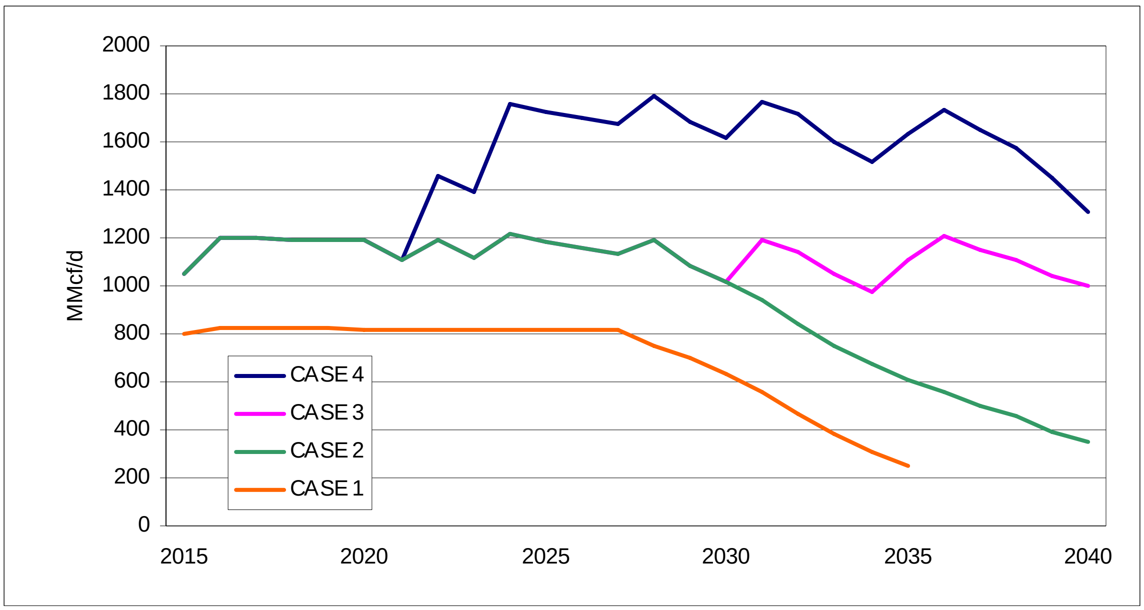
- **In Case 3, gas production is assumed at or near 1.2 Bcf/d for the duration of the analysis period (to 2040).** In order to achieve these production levels, continued exploration and development activity would be required. **The first three volume scenarios (Cases 1, 2 and 3) correspond to those set out in the 2004 study.**

- WMR was asked by the GNWT to evaluate a further case in which volumes would exceed those assumed in Case 3. **Case 4 involves an increase in gas production from 1.2 Bcf/d in 2021 to 1.8 Bcf/d by 2024 and maintenance of this production level over the period to**

2040. Substantial and sustained exploration and development activity would be required over the long term in order to achieve these production levels.

- **Four gas and natural gas liquid** (NGL) **volumes cases** are considered in the analysis. Production would commence in 2015 under all cases and gas production profiles are illustrated in Figure 1.

FIGURE 1: GAS PRODUCTION PROFILES UNDER THE THREE VOLUME CASES: 2015-2040



Given the four volume cases and two gas price scenarios described above, there are effectively eight cases considered in this report. These are denoted in the analysis with, first, reference to the Volume scenario and, second, reference to the Price scenario. That is:

- CASE 1-6 = Case 1 volumes and $6US gas price; CASE 1-8 = Case 1 volumes and $8US gas price
- CASE 2-6 = Case 2 volumes and $6US gas price; CASE 2-8 = Case 2 volumes and $8US gas price
- CASE 3-6 = Case 3 volumes and $6US gas price: CASE 3-8 = Case 3 volumes and $8US gas price.

- CASE 4-6 = Case 4 volumes and $6US gas price: CASE 4-8 = Case 4 volumes and $8US gas price.

ECONOMIC IMPACTS AND VIABILITY

- Various dimensions of the economic impacts associated with these cases are summarized in the following sections. It is important to note at the outset that in a number of these cases the overall project would not likely be economic and, hence, the impacts associated with those cases are unlikely to materialize.

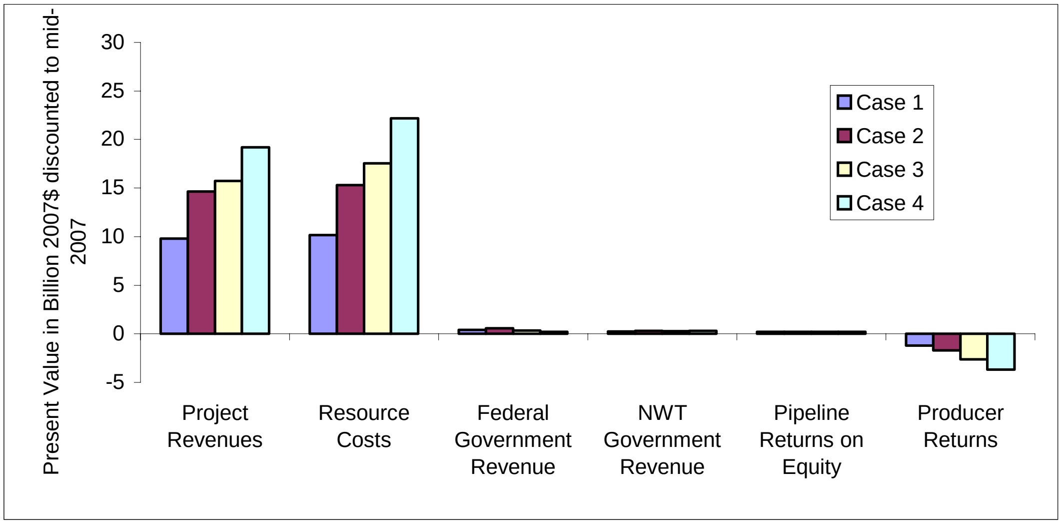
- To be viable, the project must generate sufficient revenues to cover all capital and operating costs (including payments to governments) associated with the exploration, development, production, processing and transportation of the gas and gas liquids. This viability also requires a rate of return sufficient to attract the large amounts of equity and debt capital needed to proceed with a project subject to considerable risks, including construction cost and schedule risk, supply risk, market risk, regulatory risk and operating risk. While the expected rates of return needed to support a decision to construct have not yet been defined, an illustrative rate of return of 8% (real) is used in the analysis. The NEB approved rates of return for regulated pipelines, which have less risk than what producers face, are in the range of 10% to 12% nominal (or around 8% to10% in real terms).

- Although a detailed evaluation of viability was not undertaken, the results on rates of return summarized below suggest the risk-adjusted rates of return would be insufficient to attract the required capital unless average long term gas prices were substantially higher than $6US and/or costs were significantly lower than those used in the analysis.

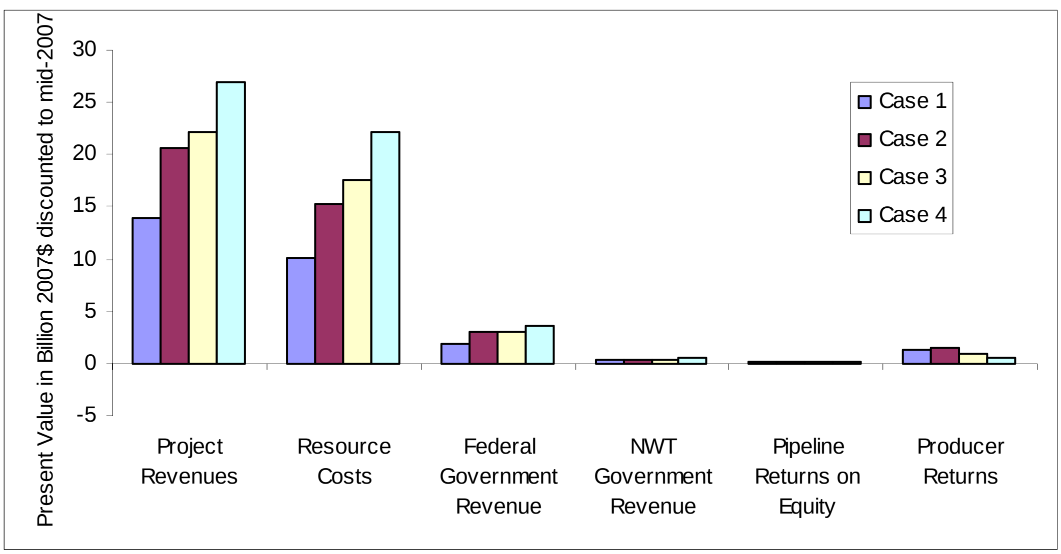
- One method of estimating the returns on investment is to calculate the present value of the returns using an appropriate discount rate that reflects the opportunity cost of funds used by the investor. Present values of the various revenue and cost categories are calculated using an 8% real after-tax discount rate and the results are summarized in Figure 2. Given the risk profile of the project, a significantly higher discount rate may be justified.

FIGURE 2: PRESENT VALUE OF CUMULATIVE PROJECT REVENUES AND COSTS GIVEN AN 8% AFTER TAX REAL DISCOUNT RATE: 2015-2040

$6US GAS PRICE SCENARIO



$8 US GAS PRICE SCENARIO



- In the $6US gas price scenario, the present value of the capital and operating costs exceeds the present value of the revenues under all volume cases. Producers would find themselves with negative returns given the illustrative 8% after tax real rate of return that would be required. The present values of the net cash flow to producer equity are positive in the $8US gas price scenario.

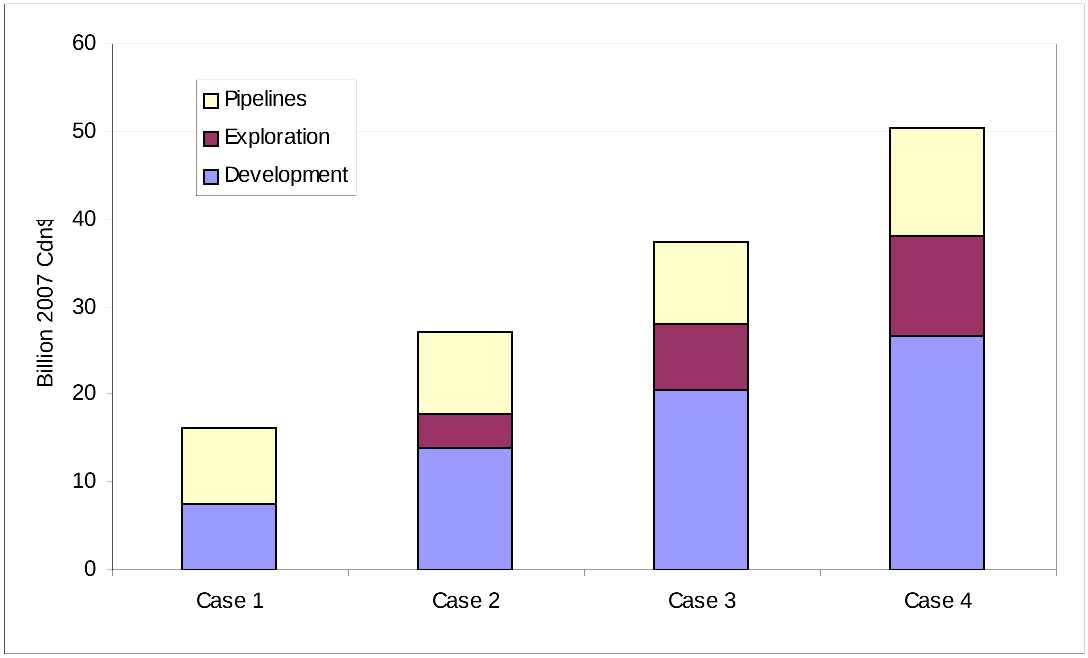
- Expressed differently, the internal rate of return on producer sector investment is less than 5% in the $6US gas price scenario and this would clearly not be sufficient to attract financing for the project. In the $8US gas price scenario, the internal rate of return ranges between 8% and 12%.

FINANCIAL FLOWS AND DIRECT IMPACTS OF THE PROJECT

- Direct investment associated with the project is summarized in Figure 3 and is expected to range from $16.1 billion to $50.4 billion. Pipeline sector investment includes expenditures on a gas pipeline from the Mackenzie Delta to the NWT/Alberta border (the Mackenzie Valley gas pipeline), a natural gas liquids (NGL) pipeline from the Mackenzie Delta to Norman Wells and incremental facilities on the TCPL Alberta system and at Norman Wells to handle project volumes. Under all volume cases, gas producers would construct a gathering system and an Inuvik area gas plant as well as develop the anchor fields. Additional exploration and development expenditures would be made in Cases 2, 3 and 4.

- The estimates of direct investment used here are roughly double those incorporated in the 2004 study and reflect significant input cost increases for major development projects in the Canadian oil and gas industry in the last three years as well as global price increases in materials such as steel.

FIGURE 3: EXPLORATION AND DEVELOPMENT EXPENDITURE BY GAS PRODUCERS AND PIPELINE SECTOR INVESTMENT: 2002-2040



- In Case 1, the majority of the investment (including all pipeline investment) would occur prior to 2015 and would peak between 2011 and 2014. The magnitude of the investment in these years is very large compared to current overall activity levels in the NWT and would likely involve an influx of short-term workers into the region. Projects of this type and magnitude must be properly managed to maximize the benefits to the region and to avoid the introduction of any excessive variability to the regional economy.

- In Cases 2 and 3, ongoing exploration and development expenditures would have to be made to ensure that there would be sufficient productive capacity to fill the pipeline over time. These are spread over a longer time period and, with the resulting smaller annual magnitudes and greater sustainability, impacts could be much more easily absorbed by the NWT economy.

- In Case 4, substantial investment would need to occur over the period 2020-2023 to boost pipeline capacity to 1.8 Bcf/d as well as to increase gas production capability. Without significant in-migration over time and/or accelerated skill development in the NWT labour force, the more intense periods of investment would likely involve large inflows of workers similar to those in the 2011-2014 period.

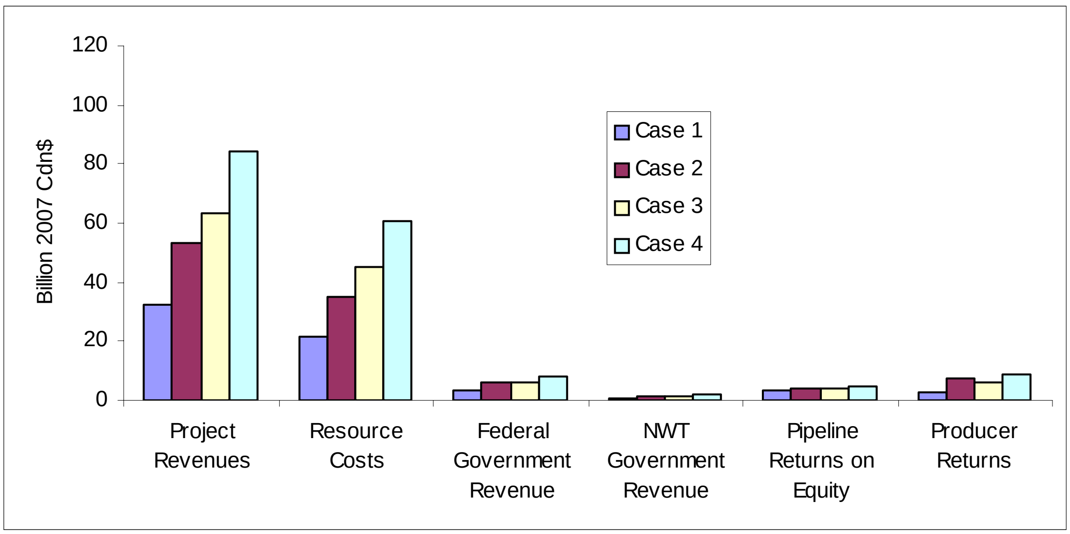
- The total direct revenues generated by the project would include netback revenues to producers (i.e. revenues from the sale of the produced gas and NGLs minus the transportation costs of moving the products to market) as well as the revenues from transporting these products to market.

- Overall direct revenues would range from $32.2 billion to $118.2 billion depending on the case and the distribution of these revenues is illustrated in Figure 4. The relative magnitude of these revenues in the NWT context is noteworthy. The average annual direct revenues range from $1.5 billion to $4.5 billion per year and are equivalent to between 35% and 110% of the value of total current annual output in the NWT.

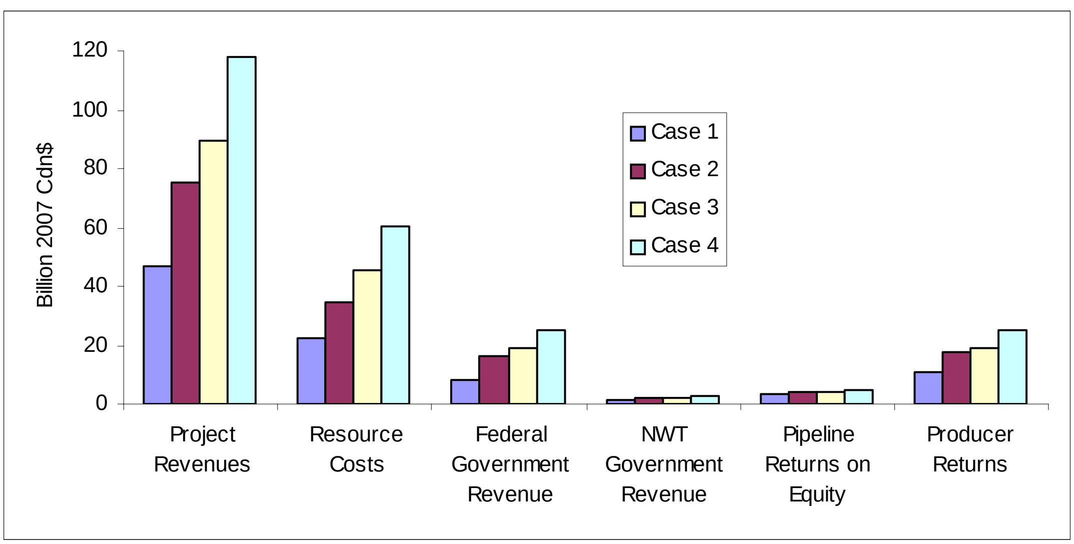
- Between 65% and 75% of the overall revenues would go towards capital and operating costs (the costs of labour, capital and other inputs to develop, produce, process and transport the gas) in the $6US gas price scenario. The remainder of the revenues would be split fairly evenly between cash flow to pipeline equity, cash flow to producer equity and to the federal government, while flows to the NWT government would be small.

FIGURE 4: DISTRIBUTION OF CUMULATIVE PROJECT REVENUES AND COSTS: 2015-2040

$6US GAS PRICE SCENARIO



$8US GAS PRICE SCENARIO



- **In the $8US gas price case**, resource costs (capital and operating costs) and cash flow to pipeline equity would change only slightly in absolute terms compared to the $6US gas price scenario (but would fall in percentage terms), while **cash flow to producer equity ($10.8 billion to $24.9 billion) and to the federal government ($8.3 billion to $25.3 billion) would be higher given the larger netback revenues.**

- **The federal government would receive more than 80% of the total government revenues depending on the case.** The federal government would directly collect royalties on gas production and income taxes from both gas production and pipeline transportation. In addition, due to current fiscal arrangements between the federal and NWT governments it is assumed that a significant percentage of any revenue raised by the NWT government would result in a grant reduction to the territorial government and in this way produce a further benefit for the federal government. While these issues around revenue sharing are not dealt with in this report, it can be noted that discussions about the devolution of some federal powers and enhanced northern revenue sharing are ongoing.

- **Although the size of the cash flow to producer equity may seem quite substantial in the $8 US gas price scenario, both the pipeline and producer sectors (and any private sector investor for that matter) must make a competitive return in order to attract the necessary financial capital.** In order to be competitive for this capital, the risk adjusted after tax real rate of return may have to be in excess of 10% to 12% . This would require long-term gas prices significantly higher than $8US and / or costs below those used in the analysis.

- The last of the direct economic impacts associated with the project involves the construction and operating employment that would be created. **Between 16,800 and 41,500 person years of direct employment would be generated by the project, depending on the case.** Construction employment would range from 12,700 to 33,200 person years and operating employment from 4,100 to 8,300 person years.

- **Construction employment would overwhelmingly take place in the NWT but the sheer magnitude of the personnel requirements would result in many of these jobs being filled** by individuals who would otherwise live outside the region. This is an important consideration in the economic impact analysis.

- Operating employment is expected to be split primarily between the NWT and Alberta. However, unlike some of the construction phase employment impacts, it is expected that the operating phase jobs in the NWT would be taken by NWT residents and these represent another long term sustainable benefit for the people of the region that would be attributable to the project. Many construction-related jobs associated with ongoing exploration and development activity in the NWT beyond 2015 would also be taken by NWT residents.

ECONOMIC IMPACTS OF THE PROJECT

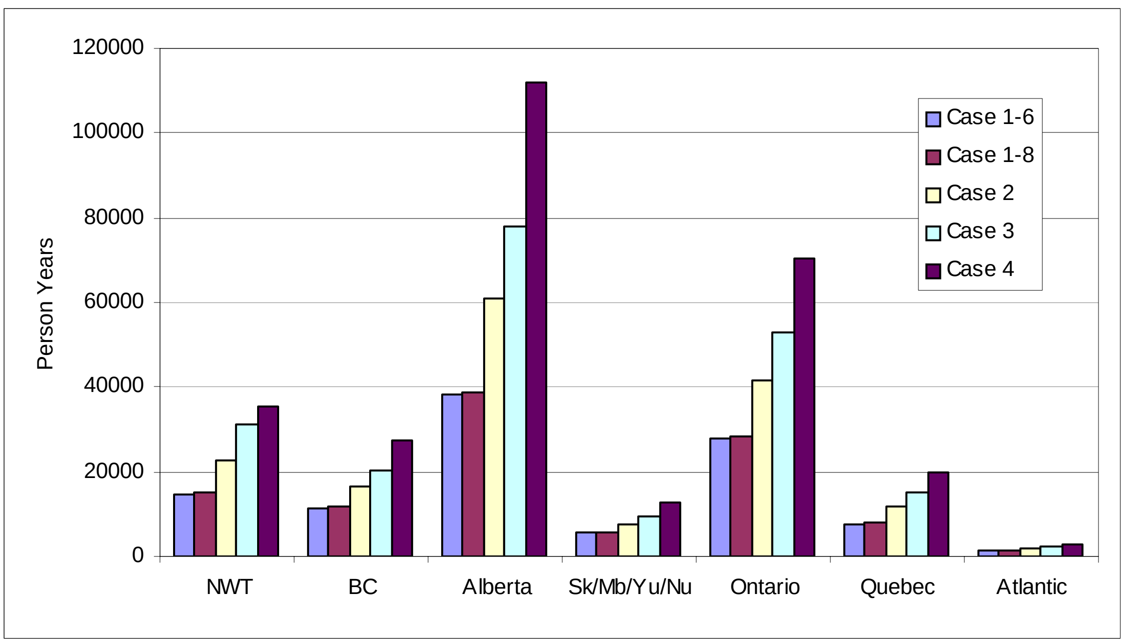
- An extensive socio-economic agreement is in place to guide the management of opportunities and impacts associated with the project. This includes programs and strategies to optimize the employment of Aboriginal Persons and Residents of the NWT during the construction and operations phases. As well, Access and Benefit agreements between the Producers and Aboriginal organizations are being negotiated and these will confirm and enhance the opportunities for Aboriginal and other NWT residents. These and other initiatives being advanced will help maximize the income, employment and economic development benefits of the project to the region.

- The direct and indirect impacts of the project on variables such as Gross Domestic Product (GDP or value added), labour income, government revenues and employment in the economies of the NWT, other Canadian regions, and Canada as a whole are evaluated. Separate evaluations of the impacts associated with four distinct portions of the project (pipeline construction, gas field exploration and development, pipeline operation and gas/NGL production) are presented. Construction phase impacts are adjusted to take account of imports of labour and other inputs to NWT to meet project requirements. The overall impacts are summarized in Figures 5 to 8.

- Employment attributable to the project would range from 107,000 person years to 281,000 person years. The distribution of the employment across regions is shown in Figure 5. Labour income impacts would be between $9 billion and $24 billion and distributed in largely the same manner as the employment impacts.

- In the NWT, employment generated by the project would range from 14,000 to 36,000 person years or between 500 and 1000 jobs on an average annual basis. Even with significant growth in the population and labour force, these employment impacts could effectively keep the NWT economy operating at or very close to full employment.

FIGURE 5: OVERALL EMPLOYMENT IMPACTS OF THE PROJECT: 2007-2040



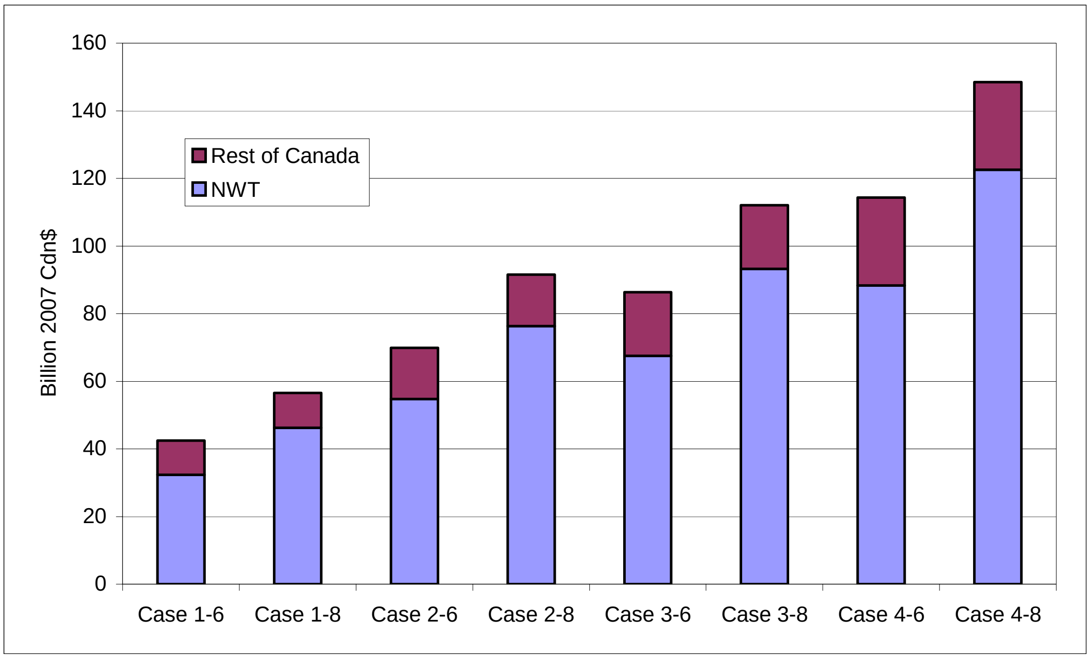
- Employment impacts would be widely distributed across Canada, with the largest impacts occurring in Alberta (38,000 to 112,000 person years). Aside from the direct operating employment that would be generated in the province, much of the project management and engineering during the construction phase of the project would be sourced in Alberta. In addition, most of the direct construction phase jobs in the NWT that would be taken by workers from outside the region would likely be filled by Alberta workers given the nature of the work and the proximity of Alberta to the NWT. Overall, between 35% and 40% of the total employment impacts could be expected in Alberta.

- Ontario would also experience significant employment impacts (28,000 to 70,000 person years). In fact, these would exceed those for the NWT and represent roughly one quarter of the overall employment impacts. These would arise from the capacity of the province to directly and indirectly supply manufactured inputs for the project, but also because of the extensive economic linkages the province has throughout Canada. Other regions of Canada would also see significant impacts, especially in relation to their relative economic size.

- Relative to the employment and labour income impacts (which would be expected to be widely distributed across Canada), GDP and government revenue impacts would be more concentrated in the NWT.

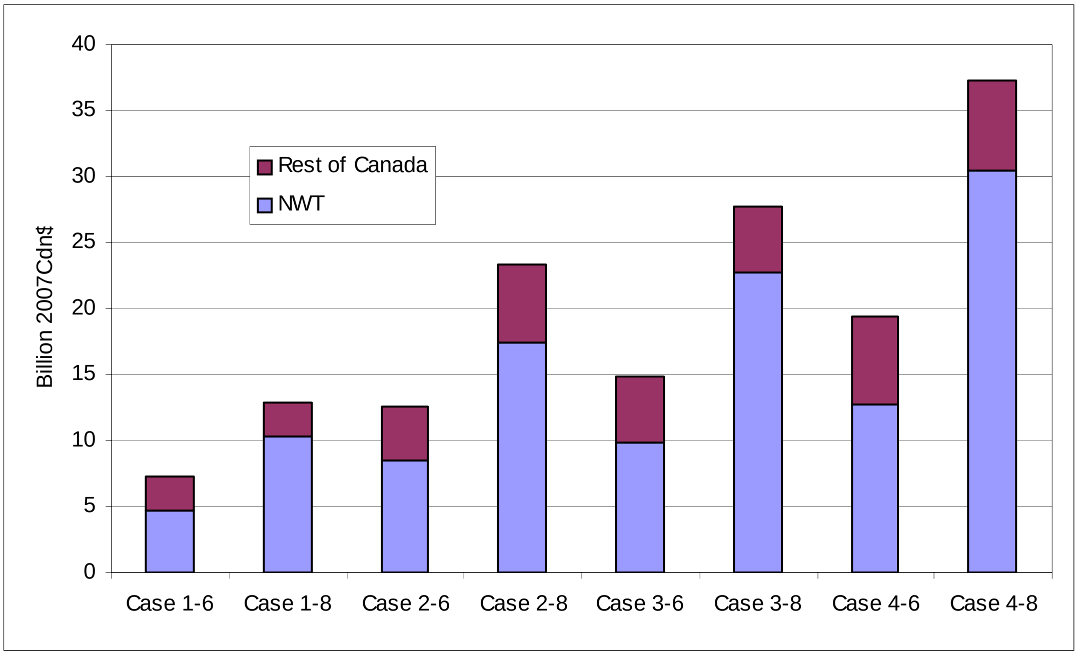
- Figure 6 illustrates the GDP impacts in the NWT and the rest of Canada for the various cases. Overall GDP impacts would range from $42 billion to $148 billion and between 75% and 85% of these would occur in the NWT. On an average annual basis, GDP in the NWT would rise by between $1.1 billion and $3.4 billion as a result of the project. This would represent an increase of between 25% and 85% over current levels of GDP in the region.

FIGURE 6: CUMULATIVE GDP IMPACTS OF THE PROJECT: 2007-2040



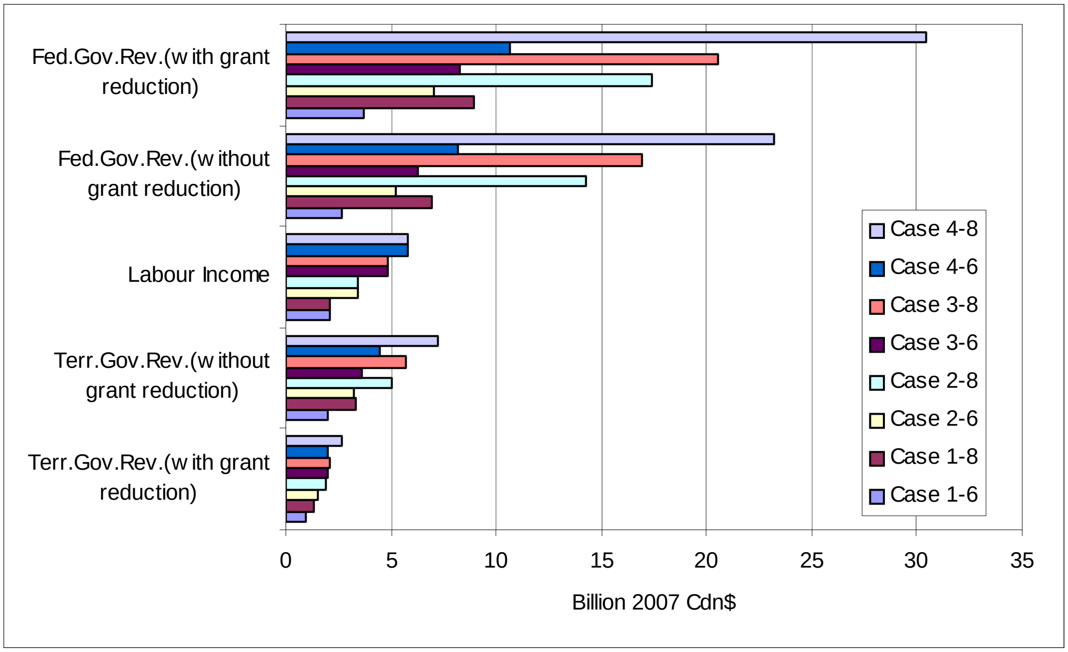
- Figure 7 illustrates that between 60% and 85% of the total government revenues generated by the project would originate in the NWT. However, under the current fiscal arrangements between the NWT and federal governments, the vast majority of any additional government revenue accruing initially to the NWT government is effectively transferred back to the federal government via grant reduction.

FIGURE 7: POINT OF ORIGIN CUMULATIVE GOVERNMENT REVENUE IMPACTS OF THE PROJECT: 2007-2040 (EXCLUDING GRANT REDUCTION IMPACTS)



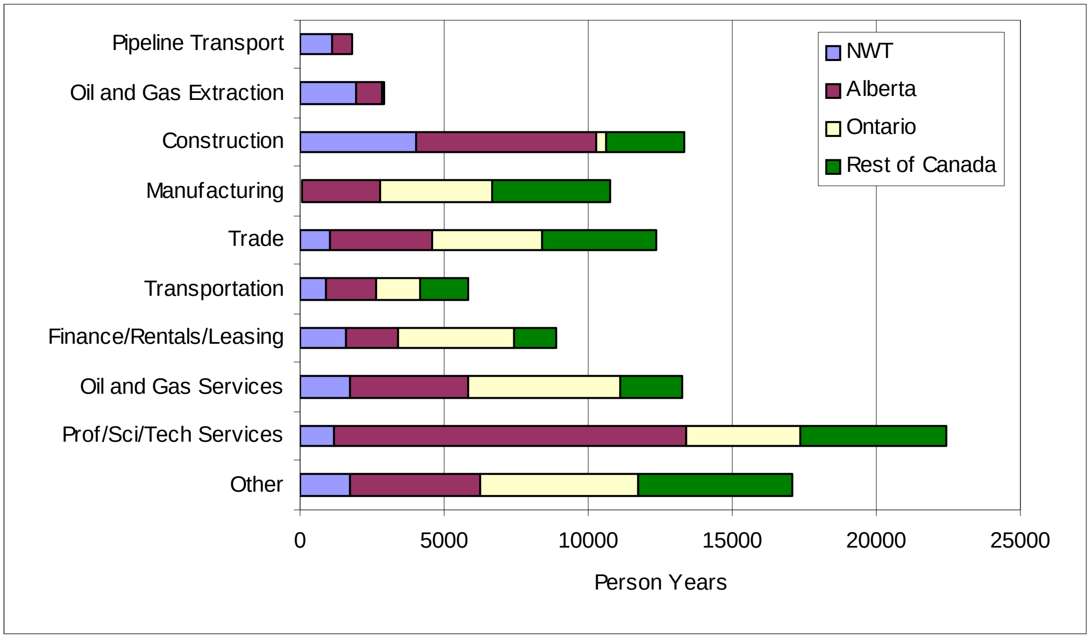
- Figure 8 shows territorial and federal government revenue with and without grant reduction. After grant reduction and assuming current arrangements, the impacts on NWT government revenue would be modest, with increases ranging from $1.0 billion to $2.6 billion depending on the gas price scenario. On an average annual basis, these impacts would amount to between $36 million and $76 million per year and would represent about a 3%-7% increase above current annual territorial government revenues. In part because of grant reduction, the federal government would be the recipient of between 70% and 90% of the overall government revenue generated by the project.

FIGURE 8: CUMULATIVE GOVERNMENT REVENUE AND LABOUR INCOME IMPACTS IN THE NWT: 2007-2040



- The economic impacts associated with the project would be widely distributed across Canada's regions and, **as illustrated in Figure 9, for case 1-8, across industries and sectors in the economy**. The only **direct employment impacts** shown are those related to pipeline transport, oil and gas extraction, and construction. Together, they **would constitute less than 20% of the overall employment impacts.**

FIGURE 9: SECTORAL DISTRIBUTION OF TOTAL EMPLOYMENT IMPACTS FOR CASE 1-8: 2007-2037



- **Employment in manufacturing is expected to represent over 10% of the total employment impact in each of the cases and it would be widely distributed across southern Canada.** The manufacturing industry in the NWT is currently very small, typically serves only local markets, and does not produce the types of items specifically required for this project. However, if the scale of the oil and gas industry in the NWT were to become sufficiently large in the future, it may become viable to locally produce various manufactured inputs for the industry. The GNWT is actively evaluating opportunities for secondary industry development in the region around the Mackenzie Gas Project.

- **Some of the largest indirect impacts would occur in oil and gas service industry as well as in industries that provide professional, scientific and technical services.** Roughly 20% of the overall employment impacts could be expected in the latter industries, with Alberta-based businesses experiencing about half of this impact (much of the project related engineering and management would be sourced in Alberta). For other industries, sizable impacts would be expected in many regions across Canada. The wide distribution of the employment impacts across a variety of sectors in the NWT makes it all the more likely that NWT residents would widely benefit from the project on a sustainable basis.

OTHER IMPACTS AND IMPLICATIONS OF THE PROJECT

- There is another category of economic impacts referred to as induced impacts that relate to the spending of portions of labour income, corporate profits and government revenues generated by an activity. With respect to the spending of labour income created by the project, the induced GDP and employment impacts are estimated to be up to an additional $0.5-$1.5 billion and 6,700-18,900 person years in the NWT and, up to an additional $6.3-$16.9 billion and 107,000-287,000 person years in Canada. These induced employment impacts related to the spending of labour income would increase the overall employment impacts noted in the previous section by about 50% for the NWT and 100% for Canada.

- Another important source of induced effects relates to the reinvestment of corporate profits. In recent years, the percentage of oil and gas industry net revenue (that is, revenues minus royalties and operating costs) that has been spent on exploration and development in Canada has averaged close to 60%. Applying this percentage to the net revenues generated in the project and taking into consideration additional induced impacts related to the labour income that would be created in the exploration and development process, the total impacts associated with reinvestment of Mackenzie Delta net revenues could add up to a further $7 billion to $48 billion in terms of GDP, while additional employment impacts could range between 77,000 and 496,000 person years.

- Further induced impacts could be anticipated as the resources that are discovered in the exploration and development process would eventually give rise to additional oil and gas production. Similarly, induced effects related to spending of government revenues could be expected to be quite pronounced given the $7 billion to $37 billion in government revenues that would be directly and indirectly generated by this project.

- The measurement of these induced impacts is much less precise than for direct and indirect impacts. Nevertheless, the key point is that the full income and employment impacts of the project can be expected to be significantly larger than just the direct plus indirect impacts noted previously.

- The Inuvik area gas plant could be expected to recover roughly 90% of the pentanes plus and about 50% of the butanes contained in the raw gas. The remainder of these products as well as any propane and ethane, would remain entrained in the gas stream that would flow through the Mackenzie Valley gas pipeline and eventually into the TCPL Alberta system. At some point these remaining liquids could be extracted and upgraded into high value petrochemical products.

- To date, the amount of money raised in sales of mineral rights in the NWT has been minimal in comparison to that raised in other regions in Canada that have oil and gas resources. This has been primarily due to the absence of a pipeline to transport the gas (and oil) to market. Rights in the NWT have been issued by the federal government for work commitments and the winning bidders have not had to pay cash bonuses (as is normally the case in southern Canada). The introduction of the Mackenzie Valley pipeline could be expected to change this situation, potentially in a rather dramatic fashion. The federal government and perhaps Aboriginal organizations could benefit substantially from cash bonuses should this occur.

- The transport of the NGLs extracted from Mackenzie Gas would result in substantial reductions in unit costs on the Norman Wells oil pipeline. This reduction in oil transportation costs would significantly improve the profitability of Norman Wells oil production and extend the life of those resources. Further benefits would arise if the gas could be used to pressurize some wells in the area and thereby increase and extend production. As well, there would be benefits from the provision of additional gas service to the town of Norman Wells.

- Portions of the southern and central NWT may also experience increased exploration activity once the Mackenzie Valley pipeline was completed. Areas that may contain gas reserves may currently be ignored from an exploration perspective simply because there is no way to deliver production to markets. This would change if the Mackenzie Valley pipeline could at some point be accessed by such supplies. It is entirely possible that there would be a major increase in exploration activity which would quickly fill the pipeline to its capacity of 1.8 Bcf/d (with the addition of compression). Further, although the extent and viability of northern gas hydrate resources are yet to be defined, the potential for this resource may be very large and the prospects for developing it would be greatly improved with the completion of the Mackenzie Valley pipeline.

- Households in some NWT communities along the Mackenzie Valley pipeline route or in the Mackenzie Delta could potentially realize a significant benefit if they could access Mackenzie Delta gas for home heating use. Given the heating requirements for a typical household, it is possible that significant savings could to be realized by switching from diesel oil to natural gas.

- Gas pipeline infrastructure south of sixty is running below capacity and is likely to that the rates of capacity utilization would be even lower in the future. The introduction of 800 to 1,800 MMcf/d of northern Canadian gas will significantly improve the utilization of existing southern pipeline infrastructure, to the benefit of consumers and producers.

- To the extent that the supply augmentation provided by Mackenzie Delta gas supplies could alleviate gas price increases and thereby help to promote a trend away from the use of higher greenhouse gas emitting fuels such as coal and oil in electricity generation and heating, additional benefits to society may be created. For example, assuming that the entire volume of Mackenzie Delta gas would be used to fire new electricity generation that in the absence of this gas would be fired by coal, society would benefit by somewhere between $80 million to $1.3 billion annually due to avoided greenhouse gas emissions.

- In summary, the Mackenzie Gas Project has similarities to other major national projects that have been critical to Canada's economic development. While the cost is high, so are the prospective impacts and benefits. It can be anticipated that if the project is economically viable and proceeds, it would have significant positive impacts on the overall Canadian economy and would generate major economic benefits for the NWT and other regions. These benefits would be widely distributed among the project stakeholders, as well as among industrial sectors and regions.

1.0 INTRODUCTION

In 2004, the Government of the Northwest Territories (GNWT) and TransCanada PipeLines Ltd. (TCPL) requested an assessment of the economic impacts associated with the development and production of gas reserves in the Mackenzie Delta and the construction and operation of a pipeline running from the Mackenzie Delta down the Mackenzie Valley to an interconnect with the TCPL system in northern Alberta. In response to that request, Wright Mansell Research Ltd. (WMR) completed the study ***An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Gas Development: An Update***, dated June 30, 2004 (hereafter referred to as the *2004 Mackenzie Valley Study*).

Earlier this year Imperial Oil Resources Ventures Limited (IORVL) filed information with the National Energy Board in which the costs associated with the Mackenzie Gas Project were updated. This has significantly increased investment costs in facilities and pipelines, which alone would tend to decrease the financial flows to governments and the producers. However, since 2004 an era of substantially higher gas prices than in the past has emerged and the expectation is that these higher gas prices will prevail in the future given prospects for global energy markets. Further, a new version of the Statistics Canada model incorporating updated coefficients is now available.

In the 2004 study, three volume scenarios were evaluated and these are again analyzed in this report. The first scenario, Case 1, assumes that only the gas from the Anchor fields will be available. Volumes are consequently about 826 MMcf/d but go into decline after 14 years. The second scenario, Case 2, assumes that other presently known gas and discoveries from exploration are sufficient to operate the pipeline at 1.2 Bcf/d for about 15 years, before the volumes go into decline. The third scenario, Case 3, assumes that other known gas plus new discoveries from exploration are sufficient to operate the gas pipeline at 1.2 Bcf/d for about 25 years.

In addition, for this study, WMR was asked by GNWT to evaluate a case where production expanded sufficiently to use the full capacity of the pipeline. Case 4 assumes the addition of compression to the line and involves an increase in gas production from 1.2 Bcf/d in 2021 to 1.8 Bcf/d by 2024 and maintenance of this production level over the period to 2040.

Comparison of Assumptions in 2004 Mackenzie Valley Study and Present Study	
2004 Mackenzie Valley Study	Present Study
three cases of volumes: approx. 826 MMcf/d for 14 years + decline, 1.2 Bcf/d for 15 years + decline, and approx. 1.2 Bcf/d for 25 years.	same three 2004 cases + a fourth case where production rises from 1.2 Bcf/d from 2015-2021 to approx. 1.8 Bcf/d over the period 2024-2040
pipeline operations begin in 2010 and end in 2028/2030 in Case 1, and end in 2035 in Cases 2 and 3	pipeline operations begin in 2015 and end in 2035/2037 in Case 1, and end in 2040 in Cases 2, 3 and 4
foreign exchange rate: 1 Cdn$ = 0.75 US$	foreign exchange rate: 1 Cdn$ = 0.90US$
gas prices US$3/Mcf and US$4/Mcf in Chicago	gas prices US$6/Mcf and US$8/Mcf in Chicago
calculations in 2004 Cdn constant dollars	calculations in 2007 Cdn dollars
total investment costs range from $ 7.7 billion to $18.2 billion Cdn, depending on case	total investment costs range from $16.2 billion to $50.4 billion Cdn, depending on case
employed 2000 version of Statistics Canada Input Output Model	employs new (2003) version of Statistics Canada Input Output Model.

It might be noted that most of the increases in investment costs are related to increases in the costs of construction rather than to substantial changes in the nature of the project. The latter were generally small and insignificant, particularly in terms of the overall impact of the project. The Inuvik Plant was moved a bit further south, thereby lengthening the gathering pipe and shortening the main gas and NGL pipes. As well, it appears that the pressure in the gathering system was increased, perhaps requiring a thicker wall pipe.

In light of the number and significance of the changes in the table above, the Government of the Northwest Territories requested an update of the economic impacts and the evaluation of additional cases. This study provides that update and extended analysis for the impacts using the same general format and methodology as outlined in the previous study (i.e. the 2004 Mackenzie Valley Study).

1.1 BACKGROUND

The federal government opened up northern Canada to oil and gas exploration in the 1960s and exploration in the Mackenzie Delta area began in that decade. The majority of the exploration drilling in the region to date took place in the 1970s and 1980s in response to rapidly rising energy prices. Nearly 200 exploration wells have been drilled in the area with close to 30% of these wells being successful. The largest discoveries have been at Taglu and Parsons Lake with estimated recoverable gas resources of 2.8 Tcf and 1.9 Tcf respectively. Total discovered marketable reserves in the Mackenzie Delta / Beaufort Sea region are estimated to be 9 Tcf, with undiscovered resources believed to be in the range of 52 Tcf, making for an ultimate resource potential of 61 Tcf.[1]

The first production from the region commenced in 1999 with gas from the Ikhil field being produced to serve consumer needs in nearby Inuvik. This to date represents the only gas production from the region as further development has been constrained by relatively low gas prices and the lack of access to major gas markets.

With higher recent gas prices in recent years, there has been renewed interest in the development of fields in the Mackenzie Delta. In 1999, the Northern Oil and Gas Directorate of the federal government's Department of Indian Affairs and Northern Development announced that rights to explore several different areas throughout the Mackenzie Delta region had been granted to two parties with work-bid commitments totaling over $180 million. Another call for bids in 2000 resulted in rights being granted for ten exploration parcels with work-bid commitments of just under half a billion dollars.

The increased interest in the region reflects the belief that future gas prices could finally justify the construction of a pipeline to connect Mackenzie Delta supplies to the overall North American gas market. The Mackenzie Gas Project (MGP) has already committed over $600 million to take the proposed gas development and pipeline construction project to the permit stage before the National Energy Board. Further, there have been some encouraging responses to a 2007 Call for

Bids. A bid of $585 million was made by Imperial Oil / Exxon in the deeper offshore area of the Beaufort Sea. Other (smaller) bids were in the onshore and shallow Beaufort Sea by ConocoPhillips and by Chevron. In addition, Devon declared a recent oil discovery in the shallow Beaufort Sea and this has also been an encouraging sign of the hydrocarbon potential in the area.

The cost data used in this study has been provided by Imperial Oil Resources Ventures Limited in submissions to the National Energy Board in March and May of 2007. It is the most up-to-date and comprehensive now available, and it covers pipeline investment costs, gas plant and gathering system costs, gas field development costs, as well as operating costs for the facilities. Exploration costs have been estimated based on the previously filed GLj study and updated to reflect the present cost environment.

1.2 Study Objectives

The industrial, regional and national economic impacts associated with the construction and operation of the Mackenzie Valley pipeline and Mackenzie Delta field development (hereafter referred to as **the project**) could be expected to be very substantial. Consequently, they are likely to form an important consideration in evaluating the public interest aspects of the project and in ensuring that its location, design and timing are such that the economic benefits are maximized and that any dislocations or other such costs are minimized.

Recognizing this, and recognizing the significant changes in the amount and detail of information concerning the project, the Government of the Northwest Territories asked Wright Mansell Research Ltd. to update and extend the assessment of the economic impacts. This study is the response to that request.

The specific objectives in this study are to update and analyze the following for an extended range of volume and price scenarios:

(i) the financial or cash flows generated, their distribution among the various stakeholders, and the direct or first-round impacts on variables such as investment, employment, and government revenues.

[1] See National Energy Board, *Canada's Conventional Natural Gas Resources–A Status Report* (April 2004).

(ii) the direct and indirect impacts on variables such as Gross Domestic Product (value added), labour income, government revenues and employment in the economies of the Northwest Territories (NWT), other Canadian regions, and Canada as a whole.

(iii) induced impacts in these economies and impacts on existing pipeline transportation infrastructure in Canada.

(iv) impacts on natural gas liquid supply in Canada and value added opportunities that could result.

(v) effects on values of mineral rights in the NWT and exploration interest in parts of the region outside the Mackenzie Delta.

(vi) benefits to natural gas consumers in the NWT and in Canada overall arising from access to Mackenzie Delta gas supplies.

(vii) benefits to society due to the potential replacement of less environmentally friendly energy sources such as coal with natural gas.

1.3 Outline

Section 2 includes a summary of the assumptions and cases used in the analysis and an outline of the key dimensions of the project. The financial flows associated with the project and their direct impacts on selected variables are also presented.

In Section 3, the regional economic impacts within Canada and overall Canadian economic impacts are described. Considerable attention is focused on the implications of the project for economic growth and development in the NWT.

Section 4 deals with other impacts that could be expected from the project. These include additional induced economic impacts, and issues related to natural gas liquids, mineral rights values in the NWT, exploration interest in the NWT outside the Mackenzie Delta, gains from higher capacity utilization rates on existing southern pipeline infrastructure, consumer benefits due to augmented gas supply, and environmental benefits.

2.0 FINANCIAL FLOWS

The objective in this section is to translate the basic parameters of the project into a series of financial / cash flows and direct economic impacts. These outline the magnitude and allocation of monetary flows to the participants and to the main components (purchase of inputs, returns, taxes etc.) within the various sectors. In addition to providing a measure of the direct (or first-round) impacts of the project, these financial flows serve as inputs to the analyses set out in subsequent sections.

2.1 ASSUMPTIONS

In order to estimate the financial flows and the various economic impacts, it is necessary to make assumptions concerning certain dimensions of the projects and the general economic environment. The assumptions employed are set out in this section.

Gas and Natural Gas Liquid (NGL) Volumes

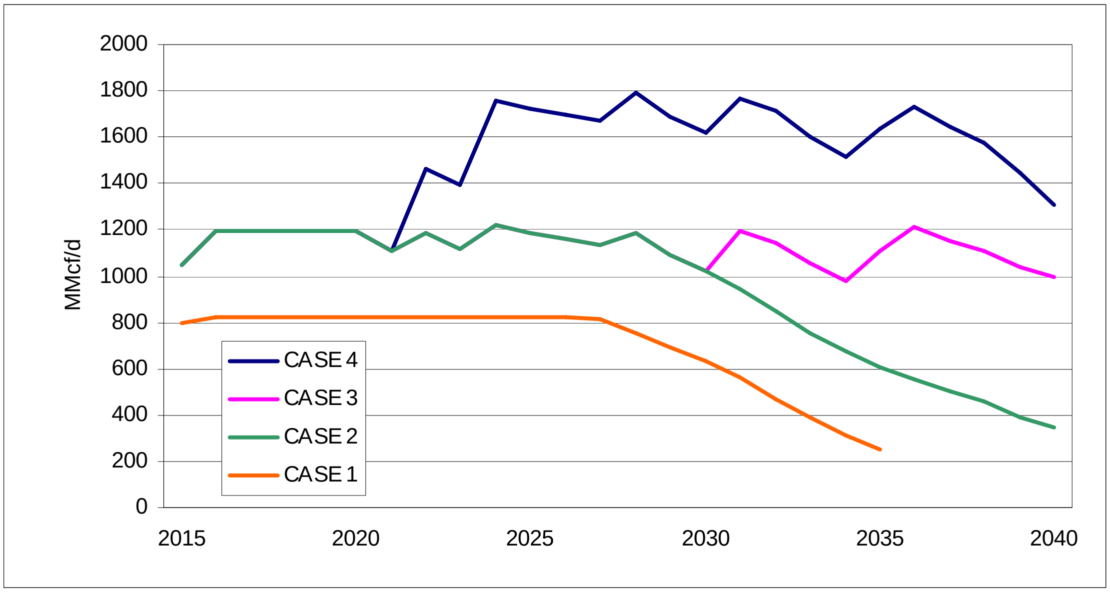
There are four gas and NGL volume cases analyzed in this report. These are summarized below.

Case 1 - Anchor Fields Only

Three 'anchor' fields underpin the Mackenzie Delta gas development project - Niglintgak, Parsons Lake and Taglu. In Case 1, it is assumed that only gas and NGLs from these fields would be produced over the life of the project. The project sponsors have previously provided detailed production profiles for the anchor fields and the overall gas production profile is illustrated in Figure 2.1 and in Appendix Table A.1. Production is anticipated to commence in 2015 with peak gas production of roughly 826 Mmcf/d (or 302 Bcf/yr). Annual gas production is expected to be relatively constant until 2027, after which the average decline rate is anticipated to be about 14% per year.

Significant NGL production is also expected from the anchor fields. NGL production profiles are illustrated in Figure 2.2 and are also shown in Appendix Table A.2. In Case 1, NGL production is expected to start at a rate of over 10,000 barrels/day in 2015 with more significant production declines occurring earlier than for gas production. Between 2025 and 2040, the average decline rate of NGLs is anticipated to be about 9% per year.

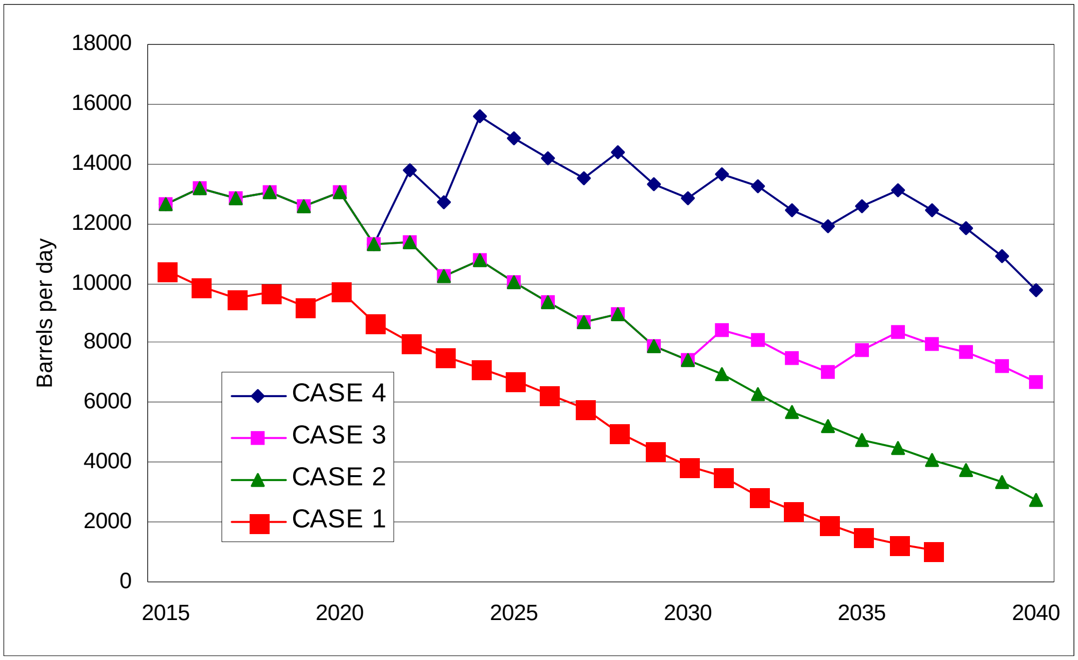
FIGURE 2.1: GAS PRODUCTION PROFILES UNDER THE FOUR VOLUME CASES



Case 2 - Anchor Fields + Other Known Gas and Some New Discoveries

For Case 2, it is assumed that gas from other fields already identified in the Mackenzie Delta as well as from several new discoveries would be available for production by 2015. Volumes from these sources plus the anchor fields would total approximately 1.2 Bcf/d (or 438 Bcf/yr) during the initial years of production. The complete production profile is illustrated in Figure 2.1 (and is also shown in Appendix Table A.1). It can be observed that significant production decline is expected to begin by 2029. The decline rate is anticipated to average about 10% per year between 2028 and 2040 (the end of the analysis period).

FIGURE 2.2: NGL PRODUCTION PROFILES UNDER THE THREE VOLUME CASES



NGL production in Case 2 is shown in Figure 2.2 and in Appendix Table A.2. NGL production over the first six years (2015-2020) is expected to be in the range of 13,000 barrels/day. Then, as in Case 1, significant production declines would begin earlier than for gas production, with an average annual decline rate of about 9% through to 2040.

<u>Case 3 - '1.2 Bcf/d' Case</u>

The third scenario for gas volumes has additional new discoveries made in later years of the project such that gas production could be maintained near 1.2 Bcf/d until 2040. Case 3 gas volumes and NGL volumes are illustrated in Figures 2.1 and 2.2 respectively and also appear in Appendix Tables A.1 and A.2. Case 2 and Case 3 volumes are identical until 2030, after which Case 3 volumes are higher. While gas production in Case 3 is expected to range between 1 Bcf/d and 1.2 Bcf/d for the duration of the project, it is anticipated that NGL production levels at the end of the analysis period would be roughly 50% of those observed over the first few years of production.

It can be noted that the 3 cases evaluated in the 2004 Mackenzie Project study involved similar production profiles in the respective cases described to this point with production assumed to start in 2010 and continue through to 2035 in Cases 2 and 3.

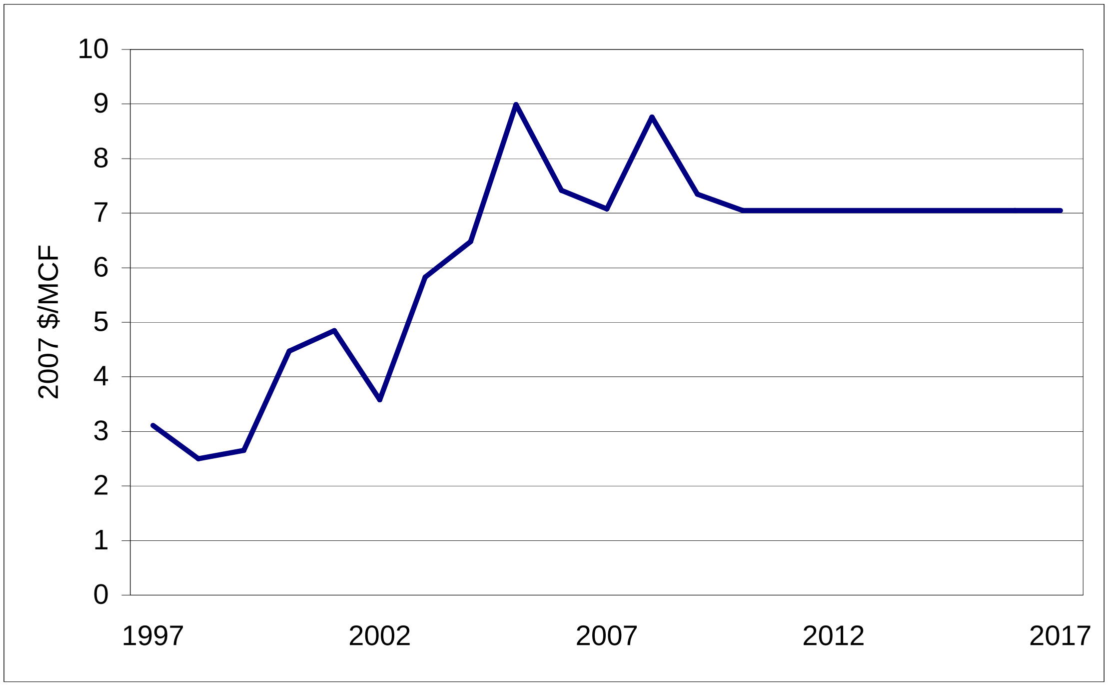
Case 4 - '1.8 Bcf/d' Case

In the fourth gas volume scenario, pipeline capacity is expanded from 1.2 Bcf/d to 1.8 Bcf/d over the period 2021-2023. Case 4 gas volumes and NGL volumes are illustrated in Figures 2.1 and 2.2 respectively and also appear in Appendix Tables A.1 and A.2. Gas volumes are assumed to be identical to those under Cases 2 and 3 until 2021 but then rise to roughly 1.8 Bcf/d by 2024 and stay near that level until 2040. Gas production over the period from 2024-2040 is expected to average over 1.6 Bcf/d. As in the other cases, NGL production would decline to a greater degree than gas production over the duration of the project.

Gas and NGL Prices

Economic impacts are evaluated for two gas price scenarios - $6US/Mcf and $8US/Mcf (2006$). In each of these scenarios it is assumed that the real price remains constant over time in the analysis. Hereafter, these scenarios are referred to as the $6US gas price scenario and the $8US gas price scenario. In the 2004 Mackenzie Project study, the two gas price scenarios were $3US/Mcf and $4US/Mcf, reflecting long term gas price expectations at the time. As shown in Figure 2.3, since 2003 gas prices have ranged from $5.83US to $8.99US per MMBtu, and have averaged $7.16US over the 2003 to 2007 period. The Sproule forecast shown in Figure 2.3 is representative of current gas price forecasts with long term prices expected to be somewhere between $6US/Mcf and $8US/Mcf. As noted later, the assumed exchange rate in this analysis is $0.90 US= $1 Cdn, compared to $0.75 US = $1 Cdn in the 2004 WMR Study. Other things being equal, this higher exchange rate has the effect of reducing the gas price expressed in Cdn dollars.

FIGURE 2.3: NATURAL GAS PRICES (ANNUAL AVERAGE AT HENRY HUB), 1997-2017



Note : Actuals to 2007; Sproule Forecast from 2008-2017

Source: Sproule and Associates Price Report, June 2007

It is anticipated that the NGLs produced from the Mackenzie Delta fields will consist primarily of condensate/pentanes plus. Prices for these products tend to be very similar to oil prices and for analytical purposes it is assumed that the prices will be identical. Oil prices are also assumed constant in real terms over time and equal $43.50 US/barrel (2006$) in Chicago for the $6US gas price scenario and $58.00 US/barrel in the $8US gas price scenario.

Exchange Rates and Inflation Rates

The US$/Cdn$ exchange rate is assumed to be $0.90US/Cdn$ throughout the period of analysis. Inflation in both countries is assumed to be 2% annually. Although the gas price scenarios are defined in terms of 2006$, **all of the economic impact results indicated in the report are shown in 2007$.**

Producer Netbacks

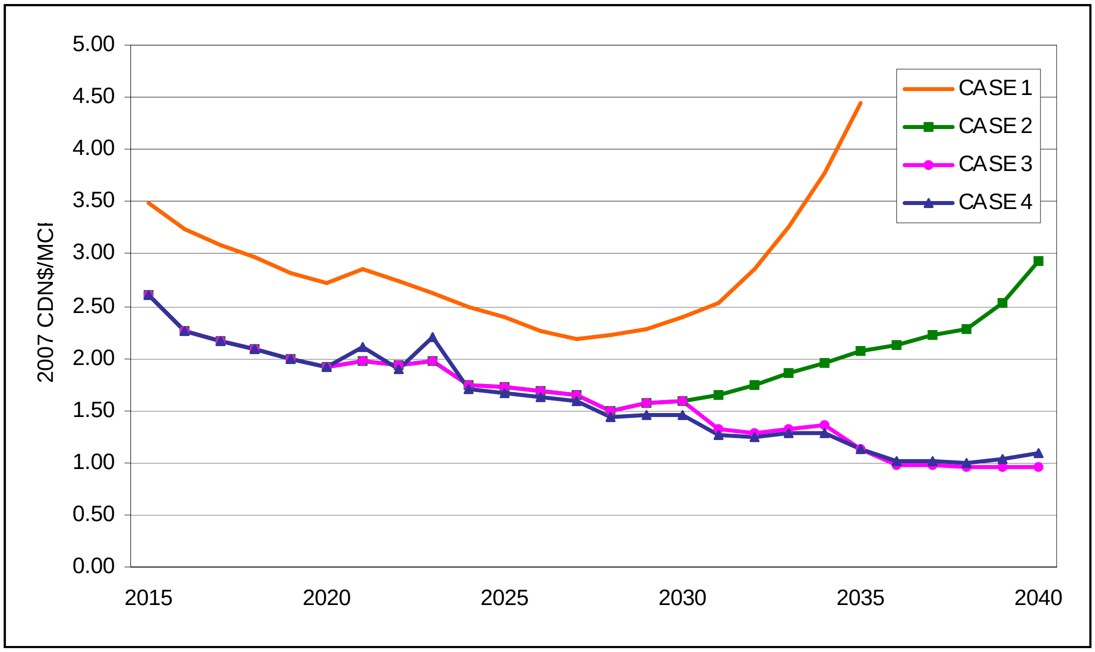
The cost of pipeline transportation to ship gas from the Alberta Border (or AECO) to Chicago is assumed to be $1.00 Cdn/Mcf (2006$) in both gas price scenarios and this is assumed to remain constant over time in real terms. This translates into AECO prices of $5.67 Cdn/Mcf in the $6US Gas Price case and $7.89 Cdn/Mcf in the $8US Gas Price case.

Further, the assumed toll on the TCPL Alberta system from AECO to the anticipated interconnect with the Mackenzie Valley pipeline at the Alberta/NWT border is $0.33 Cdn/Mcf (also remaining constant in real terms over the duration of the project). Consequently, the gas prices at the Alberta/NWT border would be $5.34 Cdn/Mcf in the $6US gas price scenario and $7.56 Cdn/Mcf in the $8US gas price scenario.

In order to arrive at a netback price for Mackenzie Delta gas producers, the toll on the proposed Mackenzie Valley gas pipeline must be subtracted from the price at the Alberta/NWT border.

The expected tolls on the Mackenzie Valley gas pipeline in the $6US gas price scenario are shown in Figure 2.4 for the four volume cases described previously. It can be observed that the tolls in Case 1 are expected to be roughly $0.75/Mcf higher than in the other cases over much of the analysis period. This is the result of the significantly lower volumes in Case 1 with only anchor field production combined with the fact that the incremental capital costs associated with transporting 1.2 Bcf/d of gas versus 0.8 Bcf/d are anticipated to be relatively small (see pipeline

FIGURE 2.4: PROJECTED TOLLS ON THE MACKENZIE VALLEY GAS PIPELINE IN THE $6 US GAS PRICE SCENARIO: 2015-2040*



* tolls in the Case 1-8 gas price scenario are slightly different than shown here for Case 1-6

capital cost description below). Although the annual cost of service would be higher in Cases 2 and 3 because of the additional compression necessary, the overall costs are spread over greater volumes resulting in a lower per unit toll.

Case 4 also involves additional compression expenditures and larger gas volumes in comparison to either Case 2 or 3. The design of the pipeline allows for a relatively inexpensive expansion to boost capacity from 0.8 Bcf/d to 1.2 Bcf/d with only 2 additional compressor stations needing to be added. In contrast, there would be 11 additional compressor stations required to raise capacity from 1.2 Bcf/d to 1.8 Bcf/d and consequently a much higher incremental capital cost between Cases 2/3 and Case 4 than between Case 1 and Cases 2/3 (see pipeline capital cost description below). Even though volumes would be significantly higher under Case 4 than under Case 3, capital costs would rise almost proportionately and as a result the unit tolls would be roughly the same under the two cases.

As production declines in Case 1 beyond 2025, the deviation between the Case 1 tolls and the tolls in the other cases becomes larger over time. Similarly, Case 2 and Case 3 tolls would no longer be identical beyond 2028 since production from additional discoveries assumed in Case 3 but not in Case 2 allow the allocation of identical cost of service over greater volumes in Case 3. Given the toll patterns illustrated in Figure 2.4, producer netbacks are expected to vary substantially on a year-to-year basis as well as between scenarios. Figure 2.5 shows the average producer netback on gas sales under each of the situations. Given the four volume cases and two gas price scenarios described above, there are effectively eight cases in this report. These are denoted in the analysis that follows by first referring to the volume case and then referring to the gas price scenario. For example, Case 1-6 refers to a situation with Case 1 volumes and the $6US gas price scenario. Figure 2.5 illustrates that the average producer netback on gas sales varies from $2.64/Mcf in Case 1-6 to $6.48/Mcf in Case 4-8. The average netbacks in the $8 gas price scenario are roughly $2.40/Mcf higher than in the $6 gas price scenario across all cases.

FIGURE 2.5: AVERAGE PRODUCER NETBACKS AT INUVIK ON GAS SALES: 2015-2040

Note: Case 1-6 is volume case 1 and $6 US gas at Chicago; Case 1-8 is volume case 1 and $8 US gas at Chicago; Other Cases are similarly defined with the first number indicating the volume case and the second number indicating the price case.

Producer netbacks on NGLs are calculated in a similar manner to the gas netbacks. Tolls from Chicago to Edmonton ($1.50 US/barrel constant in real terms (2006$), Edmonton to Zama ($1.44 Cdn/barrel constant in real terms), Zama to Norman Wells and Norman Wells to the Mackenzie Delta (both of which were modelled using a cost of service methodology) are deducted from the Chicago NGL price to arrive at the producer netback. Given the overall volume of NGLs relative to the gas volumes (as shown in Table 2.1) and the respective netback prices for the two commodities, the revenues associated with gas production amount to over 95% of the producer revenues in all cases.

Table 2.1 shows that roughly twice as much gas would be produced in Case 3 compared to Case 1 under either gas price scenario and close to three times more gas would be produced in Case 4 versus Case 1. Substantially higher gas volumes can be expected to produce significantly greater economic impacts and this will be illustrated in Section 3 of this report. Furthermore, the more attractive netbacks available at the $8US gas price versus the $6US gas price would result in greater gas production in Case 1 because fields could continue to operate for an additional year or two before becoming uneconomic and being shut in.

TABLE 2.1: OVERALL GAS AND NGL PRODUCTION IN THE VARIOUS CASES: 2015-2040

Case	1-6	2-6	3-6	4-6	1-8	2-8	3-8	4-8
Gas Production (Tcf)	5.36	8.93	10.72	14.19	5.50	8.93	10.72	14.19
NGL Production (million barrels)	49.1	80.6	91.4	122.5	49.9	80.6	91.4	122.5

Note: Case 1-6 is volume case 1 and $6 US gas at Chicago; Case 1-8 is volume case 1 and $8 US gas at Chicago; Other Cases are similarly defined with the first number indicating the volume case and the second number indicating the price case.

Royalty Rates

Federal royalty rates on frontier gas are estimated in the following manner. The royalty as a percentage of gross revenue is one percent when production begins, rising by one percentage point every 18 months to a maximum of five percent of gross revenue until payout.[2] After payout, the royalty is the greater of 30% of net revenue or 5% of gross revenue.[3]

Tax Rates

It is assumed that the federal income tax rate will be 19%, reflecting announcements in the 2006 Federal Budget. The gas producers are assumed to be subject to the recent changes in the federal income tax regime, whereby royalties will be deductible in calculating taxable income, and the tax rate will be reduced to a federal rate of 19%. The corporate income tax rates in the NWT and Alberta are assumed to remain at 11.5% and 10% respectively.

Property tax estimates for various components of the project are based on information provided by the assessment division of the Department of Municipal and Community Affairs of the Government of the Northwest Territories.[4]

Grant Reduction in the Territories

Government revenue raised in the NWT (and in the Yukon and Nunavut) by the territorial government would affect the Territorial Formula Financing Grant from the federal government. It is assumed that for every $1 of territorial government revenue created by the pipeline and gas development projects, the tax back rates for the following revenue items would be: corporate income taxes: 76%; personal income taxes: 108%; miscellaneous indirect taxes: 75%; and

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[2] Payout occurs where cumulative gross revenues equal cumulative cost base. Cumulative cost base is the total of allowable capital and operating costs. See http://inac.gc.ca/oil/roy (Department of Indian and Northern Affairs - Government of Canada website) for a detailed description of the royalty regime.

[3] Net revenue is gross revenue minus allowable capital and operating costs.

[4] Estimates were provided for the applied-for Mackenzie Gas Project (Case 1). Property taxes in the other cases were scaled using the ratio of capital expenditures for each project component between the particular case and Case 1.

property taxes: 0% (currently not subject to any tax back rate). With the tax back rate of 76% on corporate income taxes, for example, the net effect of an extra $1 in territorial corporate tax revenue on territorial government revenue would be $0.24 with the $0.76 going to the federal government in the form of a grant reduction to the territorial government.

It can be noted that discussions on the devolution of some federal powers and enhanced northern revenue sharing are ongoing. However, no attempt is made in this analysis to incorporate any possible changes to the formulas or arrangements regarding federal grants and transfers or incorporate new elements that may arise as Mackenzie Delta resource development plans proceed.

2.2 Direct Investment

The overall project involves substantial investment by both the pipeline and gas producer sectors. A description of the various components of the project and costs is provided in this section.

Mackenzie Valley Gas Pipeline

According to information provided by the project sponsors, the capital cost of a gas pipeline running from the Mackenzie Delta to the NWT/Alberta border would be $7.2 billion (2007$) in Case 1 when maximum gas production would be roughly 826 Mmcf/d. Additional compression would be required in Cases 2 and 3 to bring the pipeline capacity up to 1.2 Bcf/d and this would cost roughly $800 million. As a result, under Cases 2 and 3 the Mackenzie Valley gas pipeline cost would be approximately $8.0 billion. These capital cost estimates are roughly twice as large as those used in the 2004 WMR study and reflect significant input cost increases in major development projects in the Canadian oil and gas industry in the last three years as well as global price increases in materials such as steel.

In Case 4, substantial additional compression would be required in order to increase the capacity of the pipeline from 1.2 Bcf/d to 1.8 Bcf/d. It is estimated that $2.8 billion would need to be spent in the period 2021-2023 in order to accommodate the volume increase. This would raise the cost of the Mackenzie Valley gas pipeline to $10.8 billion under Case 4.

NGL Pipeline from Inuvik to Norman Wells

Another component of the overall project is an NGL pipeline that would run from the Mackenzie Delta to Norman Wells. This pipeline would have a capacity of approximately 20,000 barrels/day and would cost approximately $970 million in Cases 1, 2 and 3. As with the gas pipeline, the estimate incorporated in this analysis is close to double that used in the 2004 WMR study. In Case 4, it is assumed that additional pumping facilities would be required once volumes increase on the pipeline beyond 2021 and an extra $100 million in spending is incorporated in the analysis to bring the total spending on the NGL pipeline to just under $1.1 billion.

Downstream Pipeline and Facility Requirements

The NGL pipeline from the Mackenzie Delta would connect to the existing Norman Wells pipeline that transports oil to Zama, Alberta. The project sponsors have estimated that approximately $40 million (2007$) would have to be spent on various facilities upgrades at Norman Wells in order to accommodate Mackenzie Delta NGLs under all of the cases.

In addition, TCPL had indicated in a June 2006 submission to the Alberta Energy and Utilities Board that given the current supply, demand and capacity situation on the TCPL Alberta system, roughly $212 million (2006$) in capital expenditures would be required to accommodate the Mackenzie Delta gas volumes.[5] This compares to a figure of $150 million (2004$) assumed in the 2004 WMR study. Given the significant cost escalation in other components of the project as estimated by Imperial, the implicit average annual escalation percentage for the TCPL Alberta facilities between 2004 and 2006 was applied to the 2006 estimate to arrive at a value of $250 million (2007$).[6] This value is incorporated in the analysis for Cases 1, 2 and 3. Given the additional capacity requirements beyond 2021 in Case 4, another $50 million in spending is assumed to be required resulting in total TCPL Alberta capital expenditure of $300 million in this case.

[5] See TCPL 2007 Annual Report.
[6] See Imperial Oil Ventures Limited, Mackenzie Gathering System / Mackenzie Valley Pipeline : Updated Costs, Tolls and Fees (March 2007) and Mackenzie Project Update (May 2007), both submissions to the National Energy Board.

It is well known that gas pipeline infrastructure south of sixty is running below capacity and capacity utilization rates are likely to be even lower in the future. The introduction of 800 to 1,200 MMcf/d of northern Canadian gas will improve the utilization of existing southern pipeline infrastructure, to the benefit of the transmission companies and the southern gas producing industry. In addition it should be noted that the additional NGLs available at Norman Wells will significantly improve the utilization of the existing Norman Wells oil pipeline.

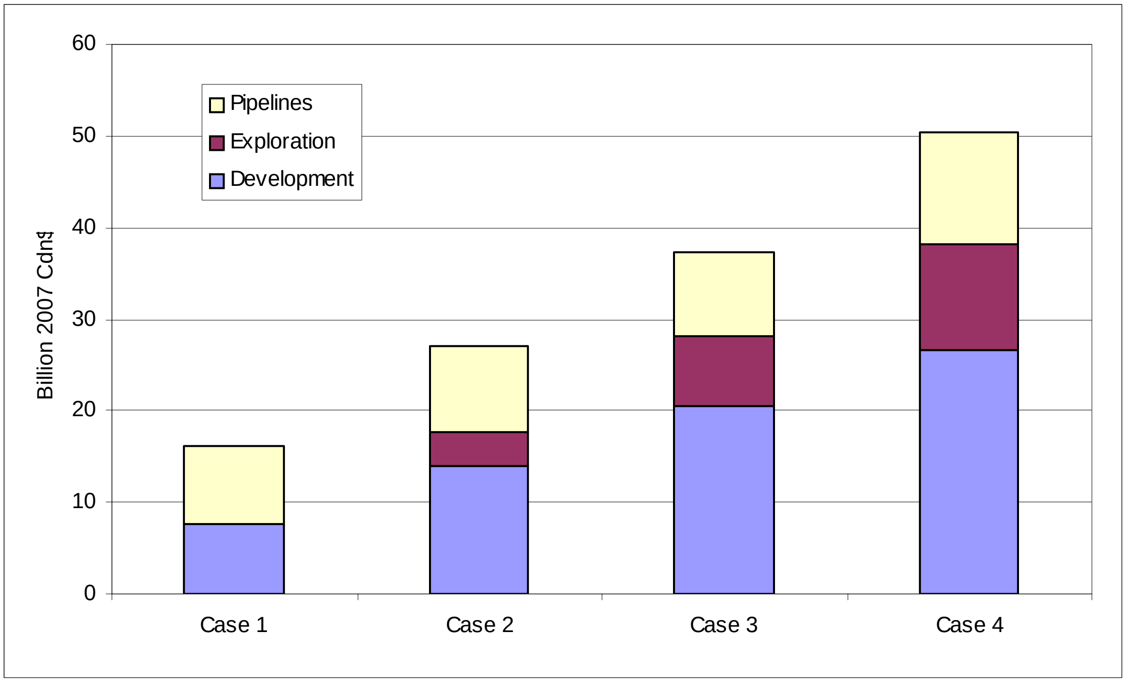
Given the various expenditures by the pipeline sector, it is estimated that its total investment would equal \$8.5 billion in Case 1, \$9.3 billion in Cases 2/3 and \$12.7 billion in Case 4. These amounts are illustrated in Figure 2.6 along with gas producer investments as described below.

Gas Field Exploration and Development Costs

In Case 1 where only the anchor fields (Niglintgak, Parsons Lake and Taglu) would be developed, the total capital cost is estimated to be \$7.6 billion (2007\$). This figure includes the cost of development drilling and the construction of a gathering system, various field facilities and a gas plant at Inuvik. As with the capital costs for the pipeline portion of the project, this figure is roughly twice that used in the 2004 WMR study. Exploration costs associated with the anchor fields have already been spent (i.e. are sunk) and consequently the economic impacts related to these expenditures are not included in this analysis.

In Case 2, other known gas fields in the Mackenzie Delta would have to be developed and there would also be expenditures on exploration and development of new discoveries necessary to bring initial gas volumes up to roughly 1.2 Bcf/d. It is estimated that an additional \$14.0 billion would have to be spent on development activity and that exploration expenditures would amount to \$3.8 billion. As a result, the total capital expenditure by the gas producer sector in Case 2 would amount to \$17.8 billion.

FIGURE 2.6: EXPLORATION AND DEVELOPMENT EXPENDITURES BY GAS PRODUCERS AND PIPELINE SECTOR INVESTMENT: 2002-2040



In Case 3, additional exploration and development expenditure would be required in the later years of the project to maintain gas production capacity near 1.2 Bcf/d. In comparison to Case 2, another \$3.7 billion in exploration spending and \$6.5 billion in development spending would be required bringing the total investment by the gas producer sector to \$28.1 billion in Case 3.

Case 4 would involve even more substantial investment by the producer sector in order to achieve and maintain a gas production level of 1.8 Bcf/d by 2024. In total, \$11.5 billion in exploration spending and \$26.7 billion in development spending would be needed resulting in gas producer sector investment of \$38.2 billion in Case 4.

Total Investment

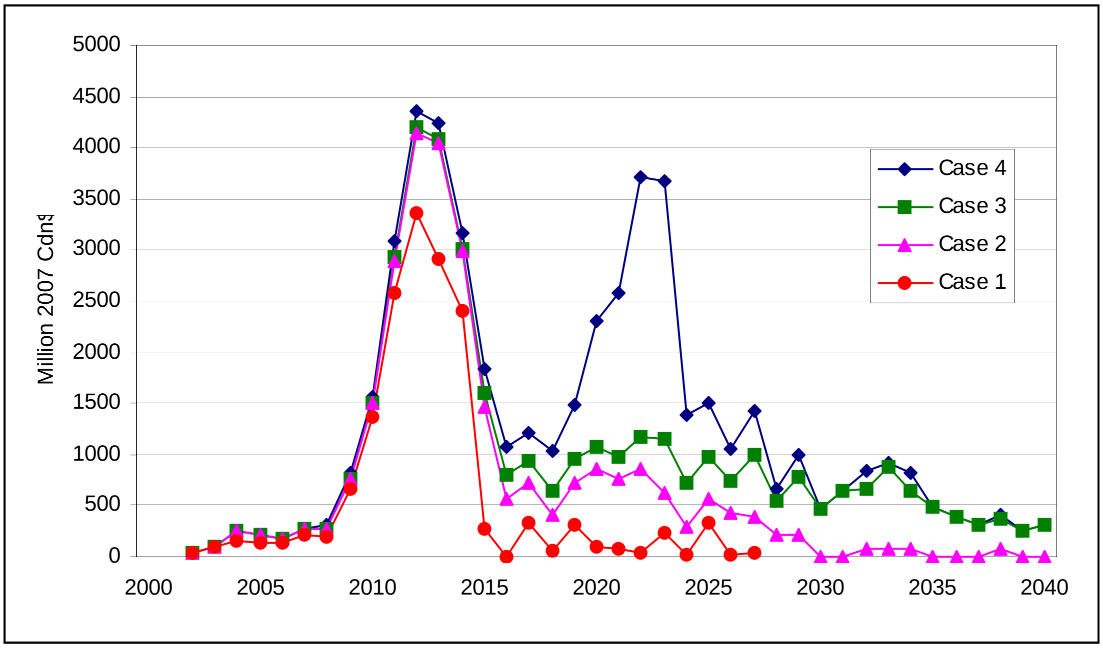
Figure 2.6 shows the total investment by both the gas producer and pipeline sectors over the entire analysis period. Total direct investment is estimated to range between $16.2 billion and $50.4 billion ($2007). The investment in Case 4 is equivalent to roughly 17% of the total investment in Canada in 2006.[7] Almost all of the investment in each of the cases would occur in the NWT. The investment under Case 1 alone amounts to almost four times the total Gross Domestic Product (GDP) of the NWT in the year 2006.

Total direct investment by year is illustrated in Figure 2.7 and is described in more detail in Appendix Table A.2. The peak investment years are expected to be 2011-2014, with investment amounts in those years ranging from $2.4-$3.4 billion in Case 1 and from $2.9-$4.4 billion in Cases 2, 3 and 4. The investment in 2012 alone (the peak construction year of the project) under Cases 2, 3 and 4 is virtually equal to NWT's 2006 GDP.

The economic impacts arising from expenditures of these magnitudes can be expected to be large and diverse and should provide excellent opportunities for NWT residents. At the same time, however, projects of this type and magnitude must be properly managed so as to avoid the introduction or amplification of economic instability. For example, the labour requirements of the project between 2010 and 2015 under all of the cases almost certainly could not be met exclusively by NWT residents, so an influx of short to medium term workers could be expected. A similar situation could be anticipated until perhaps 2027 in Case 4 where annual investment levels would remain high for at least another decade, with particularly intense levels between 2020 and 2023. Infrastructure and social pressures could easily be created unless otherwise mitigated. These issues are discussed in more detail in Section 3.7.

[7] See Canadian Statistics section of Statistics Canada website - www.statcan.ca.

FIGURE 2.7: DIRECT PROJECT INVESTMENT BY YEAR: 2002-2040



Although the direct investment in the project would be concentrated in the 2011-2014 period, a significant percentage of the overall investment in Cases 2, 3 and 4 would occur on an ongoing basis later in the analysis period. In Cases 3 and 4 in particular, exploration and development expenditures would be required essentially throughout the entire operating period of the project in order to ensure there was enough gas production to keep the pipeline operating near or at capacity. In Case 3 for example, it is expected that about $18.5 billion in exploration and development spending would be required during the operating period of the project, or roughly $710 million per year on average. The smaller magnitudes and sustainability of such investment represent impacts that could be much more easily absorbed by the NWT economy without any serious dislocations. This would provide the opportunity for the development of a truly propulsive industry that can set the stage for more broadly based economic prosperity in the NWT.

For example, the Alberta economy was very similar to the Saskatchewan economy until the late 1940s and the discovery of oil at Leduc. In fact, up to that point the population of Saskatchewan (between 800,000 and 950,000 in the 1930s and 1940s) exceeded that of Alberta. The development of the oil and gas industry has been the principal reason that Alberta currently has a population of over 3 million, while Saskatchewan's population remains barely above 1930s levels. Such a propulsive industry creates income and employment opportunities that provide reasons for individuals to remain in the region and for individuals to migrate to the region (with the intention of staying). This industry requires but also develops highly educated, highly skilled and highly paid workers.[8] Considerable opportunities for NWT residents can be expected to develop with this project.

Case 4 appears to offer more opportunities than Case 3 for NWT residents but the sheer scale of development under Case 4 would likely make it more difficult to accommodate the additional activity between 2016-2027 compared to Case 3. Only if there was significant in-migration and/or accelerated skill development of existing NWT residents would many of the opportunities arising in that period actually be taken by NWT residents. Alternative scenarios are described in Section 3.7.

2.3 Direct Revenues

Direct revenues associated with the project are summarized in Figure 2.8, with additional detail provided in Appendix Figures A.1-A.16. Under the $6US gas price scenario it is expected that the operation of the various pipelines and the production of gas and NGLs would generate between $32.2 billion and $84.1 billion (2007 Cdn$) in direct revenues, depending on the volume case. On an annual average basis, direct revenues over the operating period of the project would amount to between $1.5 billion/year and $3.2 billion/year, equivalent to between 35% and 80% of NWT's 2006 GDP.

Between 65% and 75% of the revenues would go towards resource costs (the costs of labour, capital and other inputs to develop, produce and transport the gas). The remainder of the revenues would be split roughly 60-40 between private sector returns and government revenues. However, the distribution of each of these could be expected to be skewed towards particular

[8] Educational attainment levels in Alberta are currently the highest of any region in Canada. Further, average annual earnings in the oil and gas industry in Canada were just under $72,000 in 2001. This was more than double the average annual earnings across all industries in Canada of about $35,000 (see Statistics Canada Catalogue 72-002).

stakeholders. For example, federal government revenues would amount to between $3.1 billion and $8.3 billion and comprise about 10% of total revenues in the $6US gas price scenario in each of the volume cases. On the other hand, after grant reduction the NWT government would receive between $0.9 billion and $1.9 billion or roughly 2% of total revenue under any of the volume cases. With respect to the private sector, there would be a net cash flow of between $3.4 billion and $4.7 billion (or between 6% and 11% of total revenue) to pipeline equity. The net cash flow to producer equity under the $6US gas price scenario ranges from $2.9 billion to $8.5 billion or between 9% and 13% of total revenue.

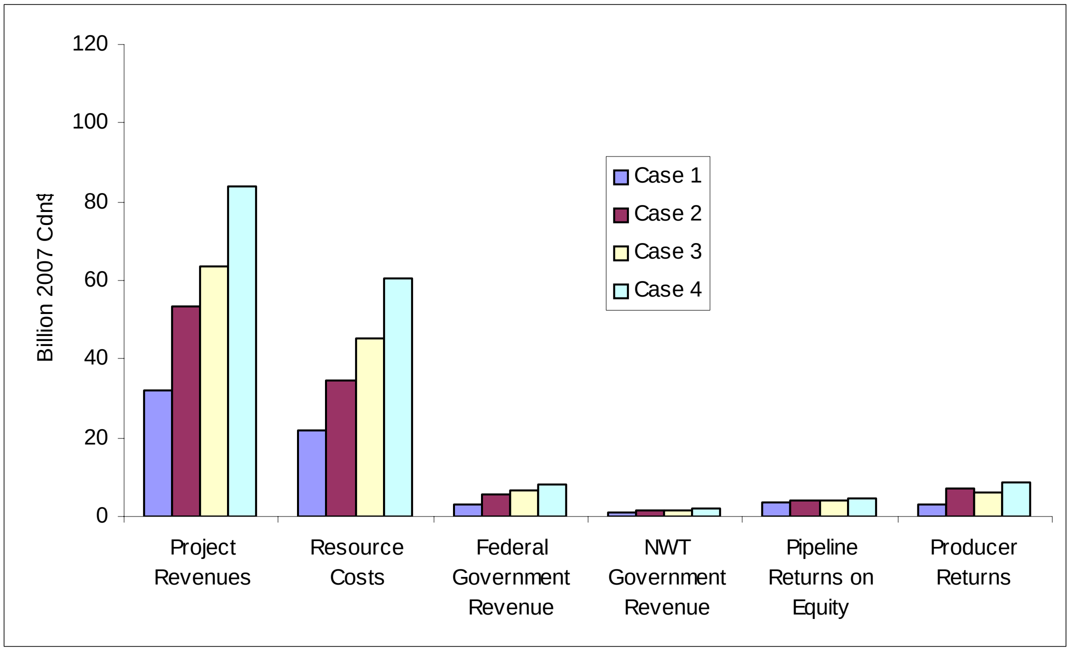
It should be noted that given the methodology and assumptions used in the analysis the producer sector profitability appears worse in Cases 3 and 4 than in Case 2. This is the result of the fact that many of the fields assumed to be developed later in the analysis period under either Case 3 or 4 in order to allow for greater volumes until 2040 would still have significant productive capacity as of 2040. For example, under Case 2 there would be 380 Bcf of gas discovered but unproduced as of the end of 2040. Under Cases 3 and 4, the equivalent volumes would be 3231 Bcf and 3634 Bcf respectively. As a result, the Case 3 and 4 results are biased downward. If the time frame in these cases was extended such that the discovered but unproduced gas at the end were similar to that under Case 2, internal rates of return for the producer sector under Case 3 would be more similar to those under Case 2.

The distribution of revenues and costs for the $8US gas price scenario is also shown in Figure 2.8.

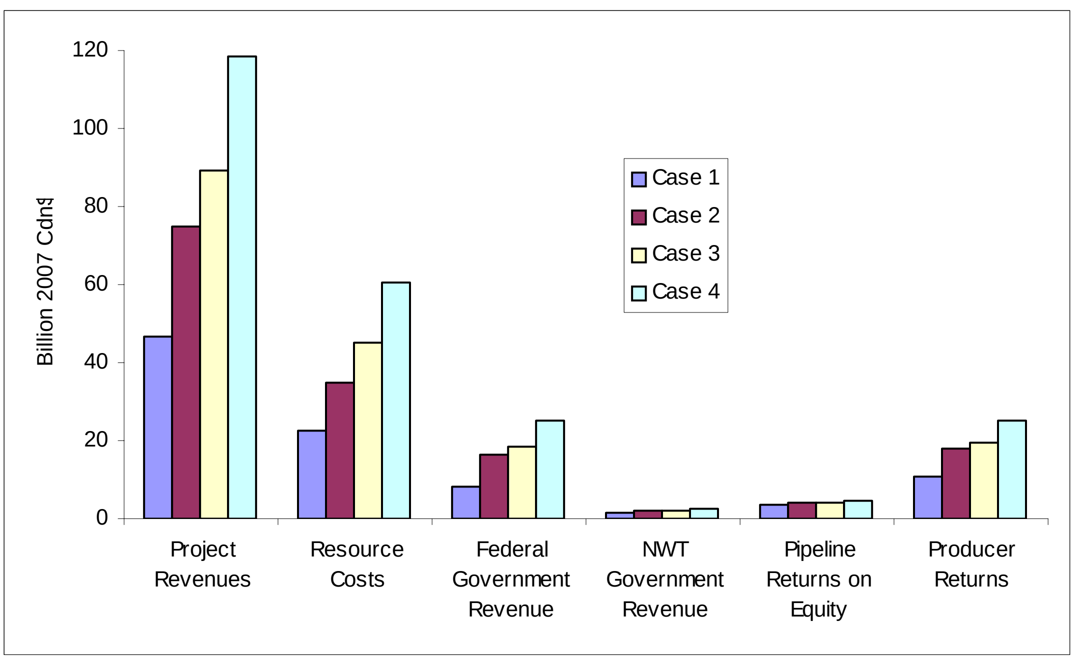
Government revenues, net cash flow to producer equity and overall direct revenues are significantly higher in the $8US gas price scenario. Revenues could be expected to range from $46.4 billion to $118.2 billion over the different volume cases. On an average annual basis, this would amount to between $2.2 billion and $4.5 billion.

FIGURE 2.8: DISTRIBUTION OF CUMULATIVE PROJECT REVENUES AND COSTS: 2015-2040

$6US GAS PRICE SCENARIO



$8US GAS PRICE SCENARIO



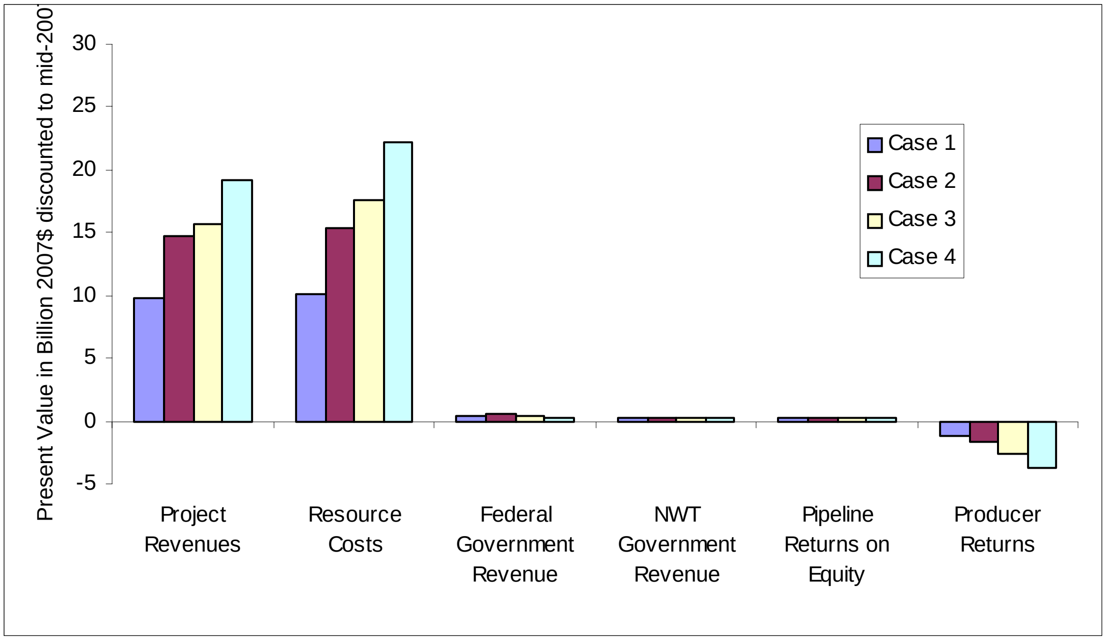
Under the $8US gas price scenario, capital and operating costs and cash flow to pipeline equity change only slightly in absolute terms from the $6US gas price scenario, but decrease relatively to roughly 50% and 4-8% respectively of total revenues. With $8US gas the higher netbacks would be shared by the governments and the producers. Federal government revenues and cash flow to producer equity are roughly equivalent in all volume cases and each comprise 18% to 24% of total revenues depending on the case. NWT government revenues after grant reduction would amount to between $1.3 and $2.5 billion or about 2% of revenues in the different cases. Cash flow to producer equity ranges from $10.8 billion to $24.9 billion in the various cases and amounts to between 21% and 24% of total revenues in the $8US gas price scenario.

Although the size of the cash flow to producer equity may seem quite substantial in this scenario, the analysis of the distribution of revenues to this point ignores an important factor. Both the pipeline and producer sectors (and any private sector investor for that matter) must make a competitive return on any investment in order to attract the necessary financial capital. This is not taken into account by simply looking at the distribution of revenues. One method of estimating the returns on investment with this factor included is to calculate the present value of the net cash flows using an appropriate discount rate that reflects the opportunity cost of money used by the investor. Present values of the various revenue categories depicted in Figure 2.8 are calculated using an illustrative 8% real after-tax discount rate and the results are summarized in Figure 2.9.

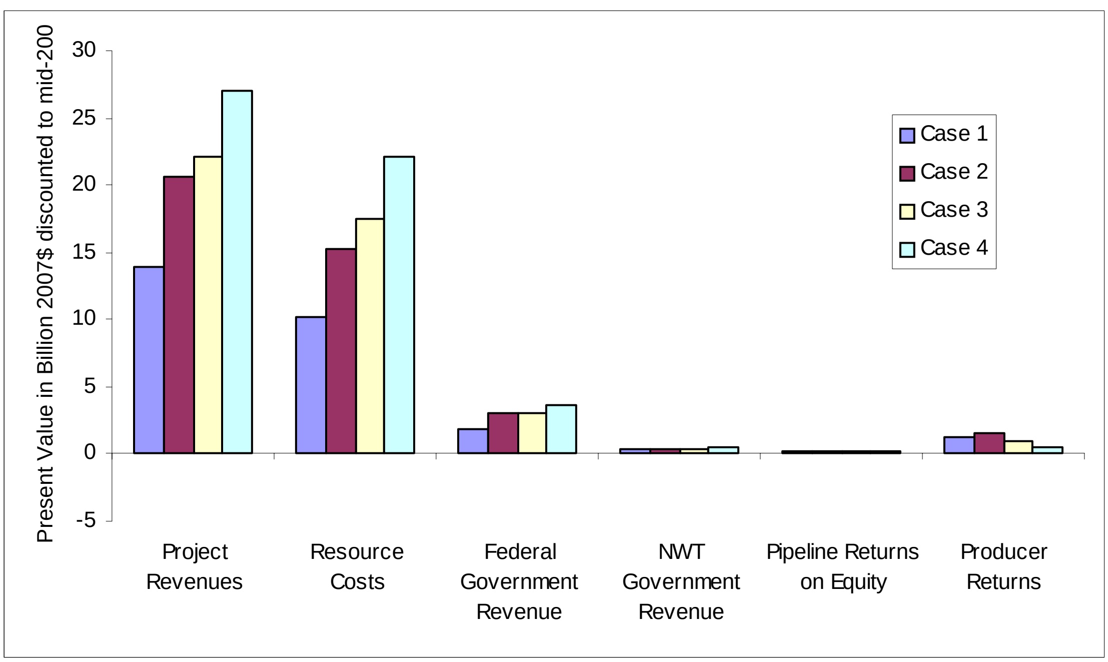
To be viable, the project must generate sufficient revenues to cover all capital and operating costs (including payments to governments) associated with the exploration, development, production, processing and transportation of the gas and gas liquids. This viability also requires a rate of return sufficient to attract the large amounts of equity and debt capital needed to proceed with a project that has substantial risks such as construction cost and schedule risk, supply risk, market risk, regulatory risk and operating risk. While the expected rates of return needed to support a decision to construct have not yet been defined, an illustrative rate of return of 8% (real) is used in this analysis. The NEB approved rates of return for regulated pipelines, which have less risk than what producers face, are in the range of 10% to12% nominal (or about 8% to 10% in real terms). Given the risk profile of this project, a real discount rate significantly higher than 8% may be justified.

FIGURE 2.9: PRESENT VALUE OF CUMULATIVE PROJECT REVENUES AND COSTS GIVEN AN 8% AFTER TAX REAL DISCOUNT RATE: 2002-2040

$6US GAS PRICE SCENARIO



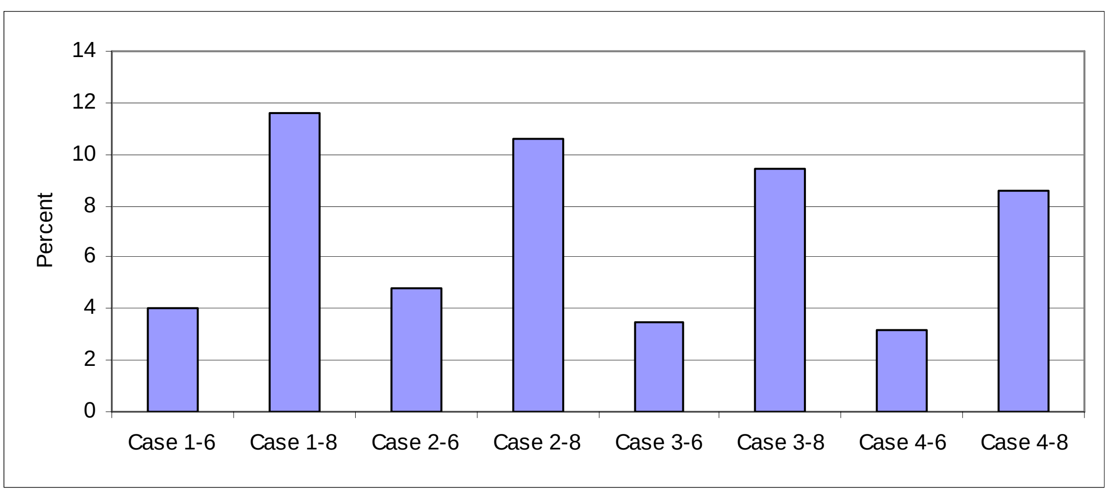
$8US GAS PRICE SCENARIO



In the $6US gas price scenario the present value of the capital and operating costs exceeds the present value of the revenues under all volume cases. Producers would be faced with negative returns given the assumed hurdle rate of an 8% after tax real rate of return. The present values of the cash flow to producer equity are positive in the $8US gas price scenario.

Expressed differently, the internal rate of return on producer sector investment (including exploration costs where applicable) is shown in Figure 2.10. The internal rate of return on producer sector investment would be between 3% and 5% in the $6US gas price scenario and this would clearly not be sufficient to attract financing for the project. Even in the $8US gas price scenario, the internal rate of return only ranges between 8% and 12%. Depending on the capital structure of the project and the relative risk of the investment, higher sustained gas prices and/or lower costs may be required to make the project economic. Although a detailed evaluation of viability was not undertaken, the results on rates of return suggest the risk-adjusted rates of return would be insufficient to attract the required capital unless average long term gas prices were higher than $7US and/or costs were significantly lower than those used in the analysis.

FIGURE 2.10: REAL INTERNAL RATE OF RETURN ON PRODUCER INVESTMENT: 2002-2040



The results described above reflect the rates of return that would be earned in the overall producer sector. Given that the owners of the anchor fields have been among the main proponents of the project and that their decisions will be critical in terms of the project actually coming to fruition, the profitability of the anchor fields alone under the various cases is worth reviewing. The internal rates of return for the various cases, along with the effects of different exchange rate assumptions, are shown in Table 2.2.

In the $6US gas price scenario, the real internal rate of return for the anchor fields never exceeds 12.5% under exchange rates ranging from $0.75 US/Cdn$ to $1.05 US/Cdn$. Depending on the volume scenario, the rate of return declines by between 0.25% points and 0.35% points with every 1 cent appreciation of the Canadian dollar. Rates of return in the ranges shown would only just be satisfactory at the lowest exchange rates. Overall the returns in this Case are unlikely to be sufficient to justify proceeding with the project.

In the $8US gas price scenario, the real internal rate of return for the anchor fields ranges from 8% to 18%. The rate of return in this gas price scenario is slightly less sensitive to the exchange rate assumption, with rate of return dropping by about 0.2% points with every 1 cent appreciation of the Canadian dollar.

TABLE 2.2: REAL INTERNAL RATE OF RETURN FOR THE ANCHOR FIELDS IN THE VARIOUS CASES: 2015-2040

Exchange Rate (US$/Cdn$)	1-6	2-6	3-6	4-6	1-8	2-8	3-8	4-8
0.75	9.1	12.5	12.5	12.5	15.2	17.8	17.8	17.8
0.80	7.4	11.2	11.3	11.3	14.0	16.6	16.6	16.6
0.87	5.0	9.5	9.6	9.6	12.4	15.0	15.0	15.0
0.90	4.0	8.7	8.8	8.8	11.6	14.4	14.5	14.4
0.92	3.3	8.1	8.3	8.3	11.2	14.0	14.0	14.0
0.97	1.6	6.9	7.2	7.2	10.0	12.9	13.0	13.0
1.00	0.5	6.1	6.4	6.4	9.3	12.5	12.5	12.5
1.05	-1.4	4.9	5.2	5.3	8.0	11.6	11.7	11.6

Additional information on the sensitivity of the rates of returns to changes in the exchange rate is provided in Table 2.3. This gives the nominal after-tax and after-royalty rates of return for the anchor fields for the four cases and for an additional case of $7US gas prices.

TABLE 2.3: NOMINAL AFTER –TAX AND AFTER-ROYALTY INTERNAL RATE OF RETURN FOR THE ANCHOR FIELDS IN VARIOUS CASES: 2015-2040

Rate of Return for Anchor Fields with US$6/Mcf Gas Price				
Exchange Rate Cdn/US$	**Case 1**	**Case 2**	**Case 3**	**Case 4**
0.75	11.3%	14.7%	14.7%	14.7%
0.80	9.5%	13.4%	13.5%	13.5%
0.87	7.1%	11.7%	11.8%	11.8%
0.90	6.1%	10.9%	11.0%	11.0%
0.92	5.4%	10.3%	10.5%	10.5%
0.97	3.5%	9.0%	9.3%	9.3%
1.00	2.5%	8.2%	8.5%	8.5%
1.05	0.6%	7.0%	7.3%	7.4%
Rate of Return for Anchor Fields with US$7/Mcf Gas Price				
Exchange Rate Cdn/US$	**Case 1**	**Case 2**	**Case 3**	**Case 4**
0.75	14.8%	17.6%	17.6%	17.6%
0.80	13.5%	16.4%	16.4%	16.4%
0.87	11.6%	14.8%	14.9%	14.8%
0.90	10.8%	14.1%	14.2%	14.2%
0.92	10.2%	13.7%	13.8%	13.8%
0.97	8.7%	12.6%	12.7%	12.7%
1.00	7.8%	12.0%	12.1%	12.1%
1.05	6.3%	10.9%	11.0%	11.0%
Rate of Return for Anchor Fields with US$8/Mcf Gas Price				
Exchange Rate Cdn/US$	**Case 1**	**Case 2**	**Case 3**	**Case 4**
0.75	17.5%	20.2%	20.2%	20.2%
0.80	16.3%	18.9%	18.9%	18.9%
0.87	14.6%	17.3%	17.3%	17.3%
0.90	13.8%	16.7%	16.8%	16.7%
0.92	13.4%	16.3%	16.3%	16.3%

It is important to note that the impacts of the changes in the exchange rate that are shown reflect only the effects on the revenue side. In other words, effects of changes in the exchange rate on the cost of imported goods and services used for construction or operations are not taken into account. There is insufficient information available to incorporate these cost effects. It would be necessary to obtain from the project sponsors estimates of costs and procurement patterns for each alternative exchange rate assumption in order to incorporate the exchange rate effects on project costs.

The exchange rate of $0.90 US/Cdn$ used in the analysis is significantly lower than the current value of the Canadian dollar. The key determinants of this value relative to the US dollar (and most other currencies) are the level of real commodity prices, interest rate differentials, and overall economic growth and productivity differentials. Very strong commodity prices along with weaknesses in the US dollar have combined to dramatically increase the value of the Canadian dollar in recent periods. While one cannot rule out the possibility of these factors continuing to support such a high value for a number of years, it is reasonable to expect that over the long term covered by the analysis in this study the Canadian dollar would trade at a discount to the US dollar. The long standing gap between US and Canadian productivity levels, combined with a recovery of the US economy and the fact that increases in commodity prices are unlikely to be sustainable for long periods, would suggest a regression of the Canadian dollar to values closer to long run historical levels.

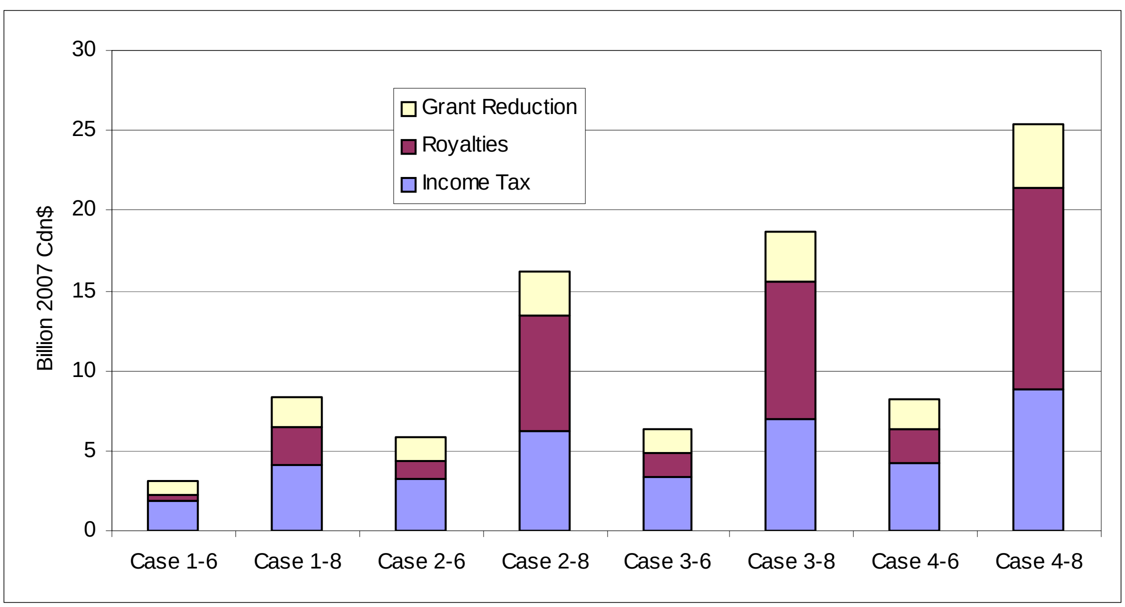
As noted earlier, a real after-tax return of 8% (or approximately 10% in nominal terms) has been used as a benchmark for evaluating the economics of the project and it has been suggested that a key determinant of whether the project proceeds may be the rate of return to anchor field producers rather than the expected overall return on existing plus yet-to-be-discovered fields. That is, for the anchor fields the explorations expenditures are sunk. They do not have exploration risk and the decision by the anchor field producers to proceed with the project (or not) may or may not be consistent with all ensuing exploration investments meeting a particular hurdle rate. As such, the rates of return for Cases 1-6 and 1-8 may be the key in the decision to proceed. Expressed differently, a higher hurdle rate may be required to justify Case 2 to 4 levels of development than to justify a Case 1 level of development.

2.4 Direct Government Revenues

Appendix Table A.3 provides a detailed breakdown of government revenues by type for the various levels of government. Given the fact that federal government revenue would comprise more than 75% of the total direct government revenues in either gas price scenario, it is useful to examine the breakdown of that revenue. This is illustrated in Figure 2.11.

Income taxes would make up the largest portion of direct federal government revenue in each of the cases, ranging from 35% to 65% of the total. Royalties would comprise less than 35% of direct federal government revenue in the $6US gas price scenario but would be substantially larger with an $8US gas price. In that situation, royalties would range from $2.4 billion in Case 1 to $12.6 billion in Case 4 and would respectively represent about 30% and 45% of overall direct federal government revenue. In addition to the income taxes and royalties, the federal government would also benefit from grant reduction to the NWT and these amounts range from roughly 15-20% of the total in the $8US gas price scenario to roughly 25% of the total in $6US gas price scenario.

FIGURE 2.11: DISTRIBUTION OF DIRECT FEDERAL GOVERNMENT REVENUES: 2015-2040



With respect to other levels of government, as indicated in Table A.3, the Alberta government would collect property and income taxes amounting to between $99 million and $140 million depending on the case.[9] The NWT government revenues after grant reduction were noted earlier and they would translate into between $42 million and $72 million per year in the $6US gas price scenario and between $55 million and $98 million per year in the $8US gas price scenario. Given that the annual NWT government revenues in recent years have been just over $1 billion, this is not an insignificant amount.[10]

2.5 Direct Employment

The final dimension of the direct impacts associated with the project involves the direct employment that would be generated. Appendix Table A.4 contains breakdowns by sector (pipeline vs producer), by project phase (construction vs operation) and by region (NWT vs Alberta). In addition, Figure 2.12 summarizes the overall direct employment that could be expected under the various cases.

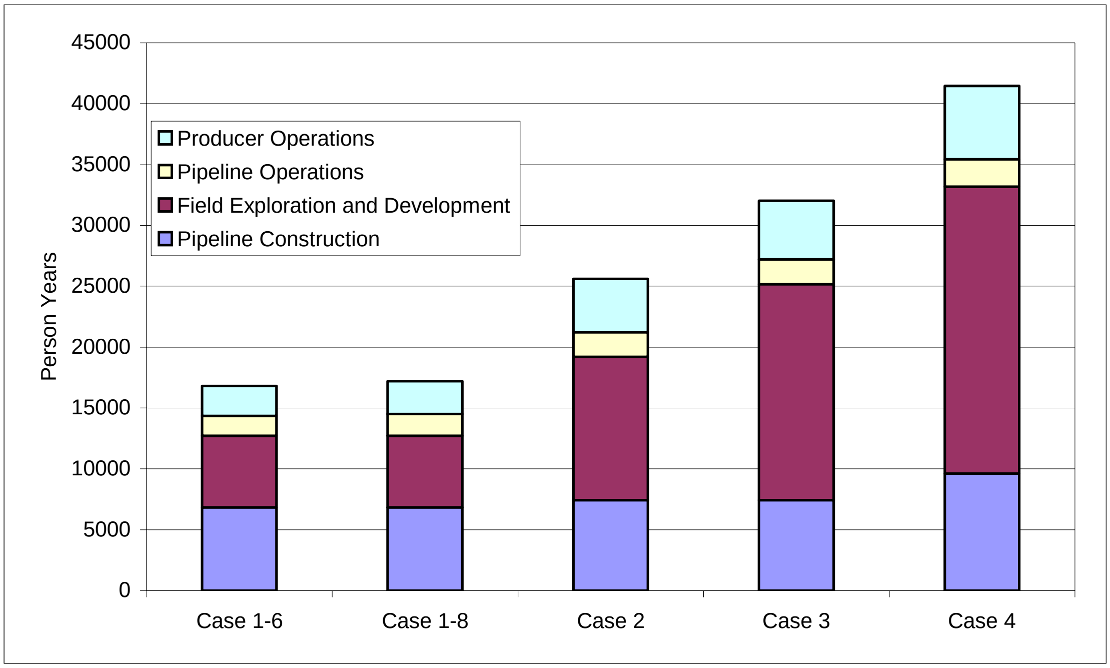
It is anticipated that cumulative direct employment would range from roughly 17,000 person years to about 41,000 person years. In each of the scenarios, direct employment would be dominated by construction phase employment. Pipeline construction (which would include the Mackenzie Valley gas pipeline, the NGL pipeline from the Mackenzie Delta to Norman Wells, and additional facilities on the TCPL Alberta system and at Norman Wells) would create between 6,800 and 9,600 person years of employment, with the larger amounts occurring in Cases 2, 3 and 4 where more compression would be required on the Mackenzie Valley gas pipeline.

Direct employment related to field development in Case 1 (where only the anchor fields would be developed) is estimated to be about 5,900 person years. In the other cases, additional fields would have to be developed and exploration would also have to take place resulting in direct employment of between 11,800 to 23,600 person years. In total, construction phase employment is expected to

[9] Because Alberta provincial government revenue is so small in terms of overall direct revenues, it would not have been noticeable in Figure 2.4 as a separate category and was included in resource costs to ensure the total impact was accurate.
[10] See Territorial Government Finance section of the NWT Bureau of Statistics website - www.stats.gov.nt.ca.

range between 12,700 person years and 33,200 person years and would constitute roughly three-quarters of all direct employment created under any of the scenarios

FIGURE 2.12: TOTAL DIRECT EMPLOYMENT BY PROJECT PHASE AND SECTOR: 2010-2040



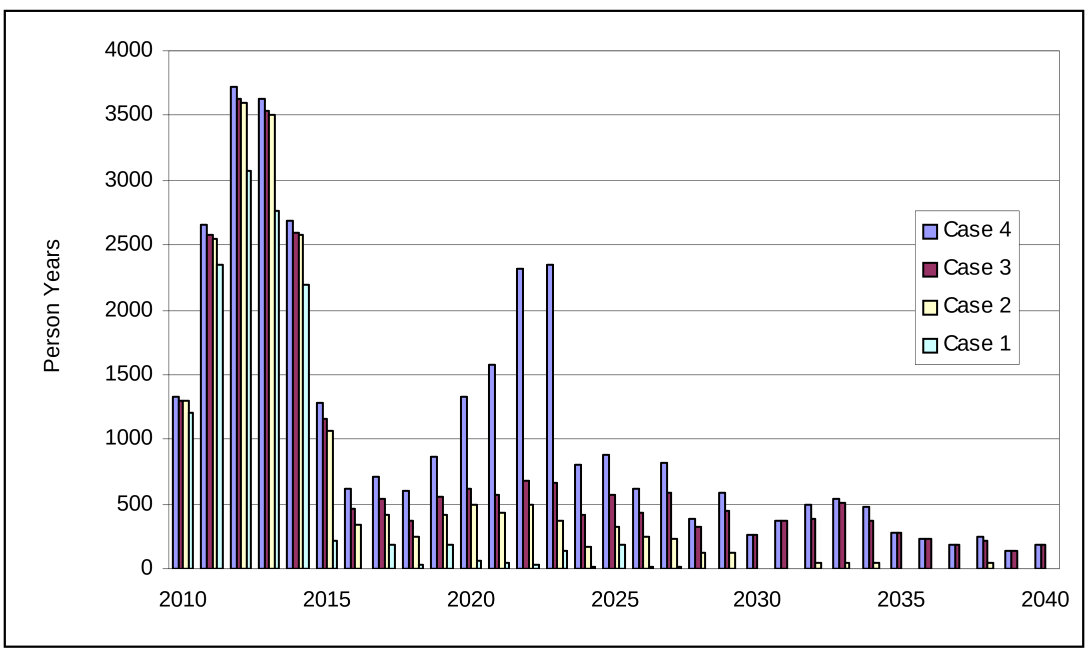
The total direct employment arising from the operation of pipeline and producer facilities is also shown in Figure 2.12. Between 1600 and 2300 person years of employment would be created through the operation of various pipeline facilities over the course of the project. The operation of the pipeline facilities is expected to generate between 75 to 90 jobs annually over the duration of the project (depending on the case), with about 65% of these jobs located in the NWT and 35% in Alberta.

Operation of producer facilities could be expected to range more widely between scenarios given the more extensive development that would be necessary moving from Case 1 to Case 4. Total employment related to operation of producer facilities would range from 2500 person years to 6000 person years, depending on the scenario. This would translate into average annual employment levels of between 120 jobs in Case 1 to about 230 jobs in Case 4. More than 70% of the jobs would be located in the NWT and slightly less than 30% in Alberta.

In total, direct employment related to operations of project facilities is expected to range from 4100 person years to 8300 person years, or between about 190 and 320 jobs annually. Although training may be required for many of these positions, these would be long-term jobs and about 70% would require residence in the NWT and could likely be accommodated given the labour supply in the region.

In contrast, with respect to construction phase employment, it is expected that a significant number of temporary workers from other parts of Canada would have to be brought into the NWT to aid in pipeline construction and field exploration and development. Figure 2.13 illustrates the direct project employment by year in the various cases.

FIGURE 2.13: ANNUAL DIRECT PROJECT EMPLOYMENT: 2010-2040



Construction employment would be concentrated in the period 2011-2014 when the bulk of the pipeline construction and the development of the anchor fields (and other known gas in the other cases) would take place. Depending on the case, between 3100 and 3700 person years of employment would be created in 2012 alone, along with anywhere from 2300 to 3600 person years in 2011, 2013 and 2014.

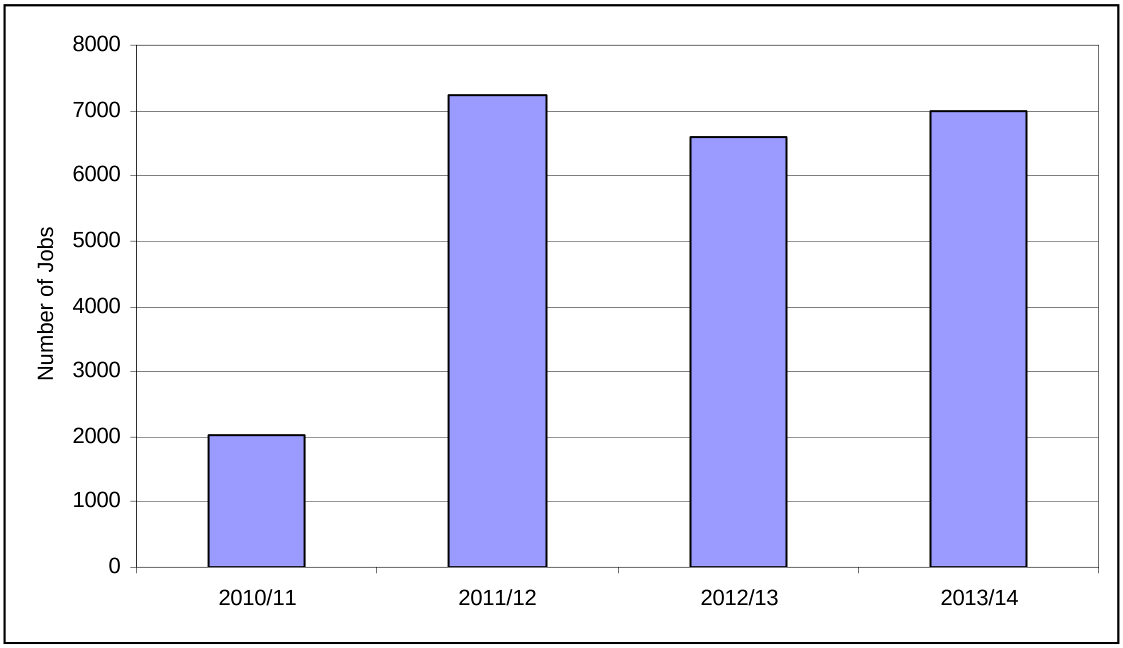
Given that almost all of this impact would occur in the NWT and that in the last year the region had a total of 1,300 people who were officially unemployed (many of whom would not have adequate skills to take the particular types of jobs that the project would create), a significant number of temporary workers from other parts of Canada would have to be brought into the NWT.[11] Further, the extent of the requirement for labour 'imports' into the NWT during the peak construction phase is actually understated in Figure 2.13 where annual direct employment impacts are summarized. Both pipeline construction and field development would have to be carried out primarily in the winter and over a relatively short season of typically less than three months. Since each person working during the season would actually only work less than a third of a person year, significantly more people would be required than is suggested in Figure 2.12 over the peak construction period. This is illustrated in Figure 2.14 where the personnel requirements over the main construction seasons are shown for Case 1. Thousands of workers would be required in the winter seasons of 2011/2012, 2012/2013 and 2013/2014 and this increases the extent to which workers from outside the NWT would have to brought in during the peak construction phase. This issue is addressed in detail in Section 3.7.

Beyond the peak construction period, there is a much greater possibility that ongoing construction employment would be filled by NWT residents, especially in the later years of the project since many would have already been trained and gained experience. Figure 2.15 illustrates the overall direct employment (construction and operating) generated by the project beyond 2015 (or beyond the peak construction period) by case. Even in Case 1 where there would be limited field development after 2015, over 900 person years of ongoing construction employment would be

[11] Data from NWT Bureau of Statistics, *Statistics Quarterly* (December 2001). While the general pool of unemployed people in the NWT may be able to find work as labour or camp workers quite readily during project construction, the project would also require welders, machine and heavy equipment operators, supervisors, inspectors, etc. who would all need to have sufficient training and skill to perform these jobs. It is unlikely that the total requirements for these types of positions could be filled by NWT residents.

created over time in addition to the operating employment described earlier. However, in the other cases the amount ongoing construction employment would be much more substantial as additional exploration and development activity would occur. For example, in Case 2 average annual ongoing construction employment between 2016 and 2023 would be about 400 person years.

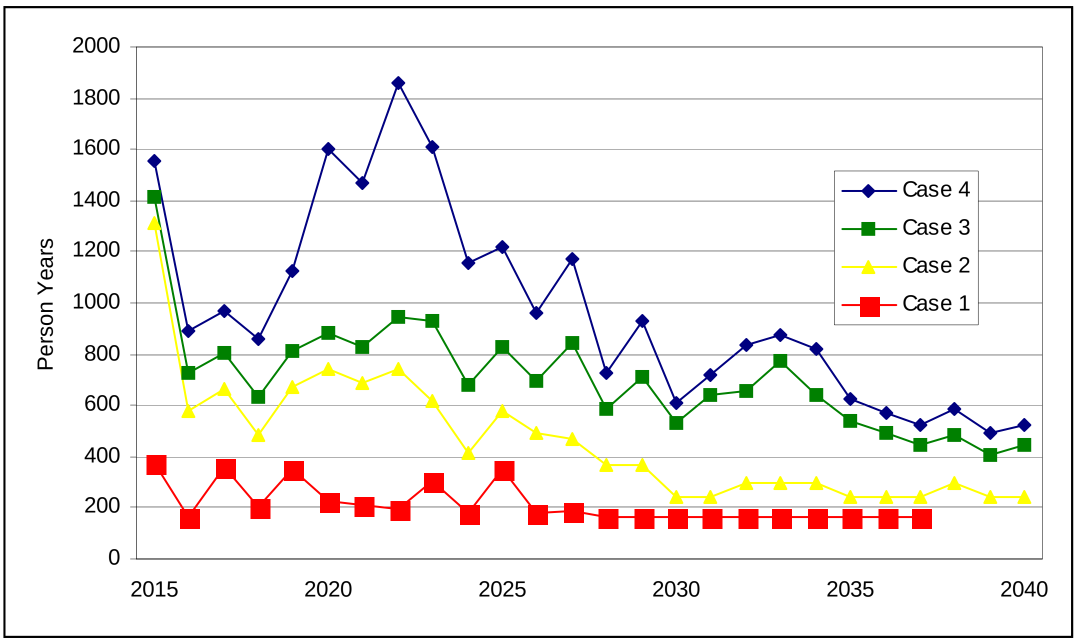
FIGURE 2.14: PERSONNEL REQUIREMENTS BY SEASON FOR PROJECT CONSTRUCTION IN CASE 1: 2010-2014



Exploration and development activity would be even more extensive under Case 3 where quite significant ongoing construction employment would be generated through most of the analysis period. Under Case 3 in particular very significant job opportunities would be created for NWT residents beyond 2015. Although some of the ongoing construction jobs would be seasonal in nature, there are not nearly as many as during the peak construction period and it could be expected that a much greater proportion of these jobs would be taken by NWT residents than in the peak construction period, especially once training occurs and experience is gained.

The level of exploration and development required under Case 4 would likely create a second period over which significant numbers of imported workers would be required. Although Figure 2.13 illustrates that by far the largest labour requirements would occur over the 2020-2023 period, it could be expected that temporary workers from other regions would be needed until about 2027 unless the NWT experienced some rather substantial population growth over the next few decades. This may be a possibility given the impetus for growth provided by the project and various potential outcomes for Case 4 are outlined in Section 3.7.

FIGURE 2.15: ONGOING DIRECT PROJECT EMPLOYMENT BEYOND THE PEAK CONSTRUCTION PERIOD: 2015-2040



*includes employment associated with exploration and development

3.0 DIRECT AND INDIRECT ECONOMIC IMPACTS

In addition to the direct impacts outlined in the previous section, the Mackenzie Valley pipeline and Mackenzie Delta field development can be expected to generate a wide variety of indirect impacts in the NWT and throughout Canada. This section deals with the indirect and total impacts in Canada overall and in individual regions.

3.1 METHODOLOGY

The effects of the project can be expected to be widely distributed geographically and extend well beyond the NWT and northern Alberta where the project is physically located. In addition, industries other than just the pipeline and gas production industries are likely to experience changes because of the project. In order to determine the ultimate effects, it is necessary to take into account the many complex sectoral and regional interactions that exist in the economy.

Many of the direct inputs involved in the projects would be purchased from other regions and from outside Canada. Purchases from foreign suppliers represent 'leakages' from a Canadian perspective and will produce no additional impacts in the domestic economy. However, if demand for direct inputs is satisfied by Canadian suppliers, this creates various indirect impacts in Canada. For example, demand for pipe in the NWT could lead to increased steel pipe production in Saskatchewan. This, in turn, would lead to additional purchases of inputs from Saskatchewan, other regions in Canada and foreign sources.

The standard method of measuring the net impacts after all complex actions and reactions are complete involves the use of an interregional input-output model. An input-output model simulates the effect on the economy when overall output of an industry changes in a specific region or when final demand for a particular commodity changes in a specific region (these changes are referred to as shocks). The latest Statistics Canada Interprovincial Input-Output Model (2003 Version) is utilized in this study to estimate economic impacts. The 2004 Mackenzie Valley Study employed an earlier (2000) version. The model offers a high level of disaggregation (719 commodities, 286 industries and 13 regions) and, hence, offers the flexibility to allow the incorporation of project specific information to the greatest extent possible.

This type of analysis relies on several fundamental assumptions. First, production technologies are assumed fixed. In other words, each industry is assumed to use the same proportions of inputs to produce its output regardless of the quantity of outputs produced. Consequently, any impacts calculated will reflect the average effect in a region, in contrast to the marginal effect of a particular project which quite possibly could differ. For example, the introduction of what may be a new industry to a region or the large scale expansion of an existing industry may significantly affect the inter-industry relationships within and outside the region. This is an important issue in this analysis because some of the industries that are being 'shocked' in the analysis are not yet highly developed.

Second, increases in demand from different sectors are assumed to have no effect on the prices of goods. For this assumption to apply it is critical that infrastructure and supporting industries would be able to respond to increases in demand without incurring any significant increases in average costs should expansion be necessary.

Third, the input-output model is by nature a static model with all of the relationships estimated for a specific, past time period. To the extent there have been significant changes in the relationships in the economy since the estimation period, the model results may not provide the most accurate representation of what would actually happen in the current or future environment.

It should also be noted that input-output models can also be used to estimate so called induced effects. The direct and indirect effects created by a project will produce additional labour income, government revenues and corporate profits which can then be spent / reinvested and this will set off another round of impacts. These induced effects are not explicitly considered in the detailed quantitative analysis of this section but could be expected to be quite pronounced, especially in terms of the additional oil and gas exploration, development and ultimately production that may arise through the reinvestment of profits accruing to gas producers. Further, the government revenue impacts would be very significant and this could allow governments to either spend more in the economy or to pay down debt and perhaps set the stage for lower tax rates in the future - something that would also produce additional induced impacts. Finally, the spending of labour income in general would set off even more impacts. The potential induced impacts associated with the project are discussed in Section 4.1 and in certain cases, rough approximations of the magnitudes of such impacts are provided.

In this evaluation of the direct and indirect impacts associated with the Mackenzie Valley pipeline and Mackenzie Delta field development, there are three industries (as defined by Statistics Canada) that would experience changes depending on the project phase (construction vs operation) and the sector (pipeline vs. gas production) that is being considered. These industries are oil and gas facility construction, natural gas pipeline transportation, and oil and gas production. Table 3.1 illustrates the input structure of these industries for Canada.[12] The numbers shown are per $100 of industry output and illustrate input usage by industry. For example, for every $100 spent on oil and gas facility construction, Table 3.1 indicates that $20.21 would go towards purchases of services incidental to mining.

The key difference between oil and gas facility construction and either natural gas pipeline transportation or oil and gas production is the overall percentage of purchased inputs (other than direct labour) that make up the total value of output. In oil and gas facility construction, purchased inputs comprise about 69% of the value of output, compared to roughly 27% in oil and gas production and only 18% in natural gas pipeline transportation. All of the indirect impacts that are calculated by an input-output model are related to these purchased inputs.

Consequently, a large proportion of construction phase impacts would be indirect whereas operating phase impacts would be dominated by direct impacts associated with the high proportion of direct GDP that is typical of the industries involved on the operations side. In addition, during the construction phase there is the potential for far more leakages from the domestic economy in

[12] It should be noted that for a number of reasons, adjustments may be necessary to either the shock given to an input-output model or the results produced by the model. First, it may be that the level of aggregation in the model, even in its most detailed form, is not sufficient to accurately portray what would happen in a particular scenario. This is especially important for pipeline construction because this type of construction is lumped into the oil and gas facility construction category (i.e. along with the drilling of oil wells, the construction of oil and gas production facilities, etc.) in the Statistics Canada model. Material inputs differ significantly in pipeline construction versus general oil and gas facility construction and this must be taken into account when shocking the input-output model. Second, if an industry is not well developed in a particular region, results from the input-output may not provide a reasonable portrayal of the impacts of a project. This is often apparent by observing the extent to which the actual direct impacts expected from a project differ from the calculated direct impacts in the input-output model. To account for these differences, adjustments may be required either to the shock given to the model or the final results produced by the model.

the form of imports than in the operations phase because of the high proportion of purchased inputs.

TABLE 3.1: DISTRIBUTION OF INDUSTRY INPUTS AND EXPENDITURES PER $100 OF INDUSTRY OUTPUT*: CANADA - 2003

Input/Expenditure Item	Oil & Gas Facility Construction	Natural Gas Pipeline Transportation	Oil & Gas Production
PURCHASED INPUTS			
Services Incidental to Mining	20.21		4.67
Natural Gas		1.41	
Steel Pipes and Tubes	7.98		
Metal Tanks	1.14		
Valves	4.03		
Construction and Mining Machinery	1.35		1.01
Measuring and Controlling Instruments	2.54		
Repair Construction, Machinery & Equipment Repair		1.95	
Finance, Insurance and Real Estate	1.89	4.99	4.77
Wholesale Margins	2.89		
Electric Power			1.21
Architectural, Engineering & Scien. Services	11.77		
Other Business Services**	1.67	3.52	5.23
Operating Supplies***	5.99	1.14	5.29
Other Purchased Inputs	7.84	4.85	5.23
Total Purchased Inputs	69.30	17.86	27.41
DIRECT GDP			
Labour Income	25.36	10.22	5.83
Operating Surplus****	2.91	66.54	65.55
Indirect Taxes	2.43	5.38	1.22
Total Direct GDP	30.70	82.14	72.59

* Inputs where value is less than 1% of output placed into Other Purchased Inputs unless otherwise noted
** Architectural, Engineering & Scien. Services for Pipeline and Oil and Gas Production included here
*** Includes Rentals of Machinery and Equipment, Spare Parts, Maintenance and Office Supplies
**** Includes interest, depreciation, depletion allowances, royalties, income taxes and after tax profit

Source : Statistics Canada Input-Output Division

For the construction of producer/field facilities, direct GDP would represent about 45% of the total (direct plus indirect) GDP impact. The comparable value for construction of the pipeline would also be 45% with a range of about 40%-50%, depending on the amount of compression added. For the operating phase impacts for both the producing and pipeline components, direct GDP would represent between 92% and 93% of the total (direct plus indirect) impacts.

Although the Statistics Canada model contains coefficients that reflect the average import content of the purchases made by a given industry, the project sponsors have provided detailed sourcing information for major expenditure items during the construction phase and this was used wherever possible in order the evaluate economic impacts. The results are outlined in the next four subsections.

3.2 Pipeline Construction Impacts

Table 3.2 summarizes the impacts associated with the construction of the Mackenzie Valley gas pipeline in the NWT, the NGL pipeline from the Mackenzie Delta to Norman Wells, and additional facilities on the TCPL Alberta system and at Norman Wells. In order to ship anchor field gas exclusively, capital expenditures would amount to \$8.5 billion (2007 Cdn\$) in Case 1. Additional compression would be necessary in the other cases and expenditures between \$9.3 billion (Cases 2 and 3) and \$12.2 billion (Case 4) would be required. These expenditures could be expected to generate an increase in Canadian Gross Domestic Product (GDP) ranging from \$6.3 billion to \$8.6 billion. The overall GDP intensity ratio (GDP / capital cost) is between 0.7 and 0.75 in the two cases and this reflects the fact that a significant portion of the materials required for pipeline construction would have to be imported. In particular, facilities related to compression would have a relatively large import component yielding lower intensity ratios in Cases 2, 3 and 4 than in Case 1. Total direct and indirect imports would range from \$2.0 billion to \$3.4 billion, or between 20% and 30% of the total investment involved in this phase of the project.

The overall labour income impacts of between \$4.0 billion and \$5.7 billion represent just under two thirds of the overall GDP impacts, with slight variations in this percentage across regions. Similarly, the ratio of the total government revenues (between \$1.4 billion and \$1.9 billion overall) to GDP is about one quarter for Canada as a whole with minor variations in this ratio between individual regions.

TABLE 3.2: IMPACTS OF MACKENZIE VALLEY PIPELINE CONSTRUCTION: 2002-2016*

(millions of 2007 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	8236		250					8486
Gross Domestic Product	2837	253	1491	150	1196	316	37	6279
Labour Income	1662	184	1004	119	782	204	15	3970
Federal Government Revenue	360	43	242	24	210	41	5	926
Terr./Prov. Government Revenue	169	18	104	10	115	51	3	469
Grant Reduction	150			2				151
Adjusted Terr./Prov. Gov. Rev.	20	18	104	8	115	51	3	318
Adjusted Federal Gov. Rev.	510	43	242	26	210	41	5	1077
Total Government Revenue	529	61	345	34	325	92	8	1395
Employment	12757	3684	12892	2269	12452	3726	324	48105
CASES 2/3	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Direct Output	9040		250					9290
Gross Domestic Product	2936	270	1771	161	1257	332	39	6765
Labour Income	1770	197	1193	126	822	214	16	4340
Federal Government Revenue	378	46	287	26	221	43	5	1006
Terr./Prov. Government Revenue	176	19	123	10	120	54	3	505
Grant Reduction	157			2				158
Adjusted Terr./Prov. Gov. Rev.	20	19	123	9	120	54	3	347
Adjusted Federal Gov. Rev.	535	46	287	28	221	43	5	1165
Total Government Revenue	554	65	410	36	341	97	9	1512
Employment	13562	3932	15129	2400	13103	3922	343	52391
CASE 4	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Direct Output	11947		300					12247
Gross Domestic Product	3300	334	2806	199	1483	393	46	8561
Labour Income	2185	246	1902	151	971	254	20	5728
Federal Government Revenue	444	56	456	32	261	51	7	1306
Terr./Prov. Government Revenue	204	22	194	13	141	63	4	641
Grant Reduction	185			2				186
Adjusted Terr./Prov. Gov. Rev.	20	22	194	11	141	63	4	454
Adjusted Federal Gov. Rev.	629	56	456	33	261	51	7	1492
Total Government Revenue	648	78	650	44	402	114	10	1946
Employment	16484	4849	23435	2887	15510	4650	412	68227

* Expected leakages of economic impacts from the NWT to other regions due to labour market constraints are not incorporated in this table

** Saskatchewan / Manitoba / Yukon / Nunavut

Between 35% and 45% of the overall GDP impact would be felt in the NWT, a range which may seem surprisingly low given that over 95% of the capital costs are attributable to the region in any of the cases. However, for small economies like that of the NWT, many of the indirect impacts (especially those related to manufactured materials) are transferred to other regions. Ontario, for example, could be expected to supply much of the pipe and other materials used in the project. Furthermore, many of the costs relating to project engineering, development and management that are allocated to the NWT would likely be sourced in Alberta. These factors contribute to a wide distribution of pipeline construction impacts across regions of Canada.

Despite the factors noted above, the NWT would still experience the greatest impacts of any region and the magnitudes of these impacts relative to the size of the economy are impressive. The GDP impact is equivalent to between 70% and 80% of the region's 2006 GDP level while the employment impact is equivalent to between 55% and 75% of the NWT's total employment in 2006.

However, it must be noted that the values shown in Table 3.2 do not reflect the potential leakages associated with regional labour force constraints during the peak construction phases of the project and the 'imports' of labour (as discussed in Section 2.5). This issue is addressed in detail in Section 3.7 where the NWT impacts as well as the impacts in other regions shown in Table 3.2 are adjusted to reflect the degree to which labour from other regions would ultimately contribute to the project requirements in the NWT.

3.3 Field Exploration and Development Impacts

The impacts associated with the development of the Mackenzie Delta gas fields (including a gathering system and a gas plant at Inuvik) as well as exploration expenditures in Cases 2, 3 and 4 are shown in Table 3.3. Capital expenditures in Cases 1, 2, 3 and 4 of $7.6 billion, $17.8 billion, $28.1 billion and $38.2 billion respectively could be expected to produce GDP impacts of $4.4 billion, $10.5 billion and $16.7 billion and $22.7 billion under the four cases. The GDP impact relative to the capital expenditures would be lower than for pipeline construction since close to quarter of exploration and development spending in each of the cases would involve direct imports of materials and, combined with the indirect imports that could be anticipated, about 40% of the spending would involve items from foreign sources.

TABLE 3.3: IMPACTS OF MACKENZIE DELTA GAS FIELD EXPLORATION AND DEVELOPMENT: 2002-2040*

(millions of 2007 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	7611							7611
Gross Domestic Product	1947	174	1185	91	797	205	24	4423
Labour Income	1391	127	799	62	521	133	10	3043
Federal Government Revenue	272	29	192	14	141	27	3	678
Terr./Prov. Government Revenue	124	12	82	7	79	33	2	338
Grant Reduction	113			1				114
Adjusted Terr./Prov. Gov. Rev.	10	12	82	6	79	33	2	224
Adjusted Federal Gov. Rev.	385	29	192	15	141	27	3	792
Total Government Revenue	396	42	274	21	219	60	5	1017
Employment	8558	2526	10209	1237	8292	2434	204	33459

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	17781							17781
Gross Domestic Product	4499	410	3004	212	1853	477	55	10509
Labour Income	2866	301	2091	141	1211	308	22	6941
Federal Government Revenue	785	69	496	31	327	62	8	1778
Terr./Prov. Government Revenue	275	28	210	16	184	77	4	794
Grant Reduction	247			3				249
Adjusted Terr./Prov. Gov. Rev.	28	28	210	14	184	77	4	545
Adjusted Federal Gov. Rev.	1031	69	496	34	327	62	8	2028
Total Government Revenue	1060	97	706	48	511	139	12	2573
Employment	17488	5951	26190	2823	19297	5654	473	77877

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	28050							28050
Gross Domestic Product	7075	649	4840	333	2919	751	87	16654
Labour Income	4304	476	3446	221	1909	485	35	10876
Federal Government Revenue	1291	109	810	49	515	98	12	2885
Terr./Prov. Government Revenue	426	44	341	26	290	121	7	1255
Grant Reduction	380			4				384
Adjusted Terr./Prov. Gov. Rev.	47	44	341	22	290	121	7	871
Adjusted Federal Gov. Rev.	1670	109	810	53	515	98	12	3269
Total Government Revenue	1717	153	1151	75	805	219	19	4140
Employment	26099	9409	42733	4424	30410	8906	745	122727

CASE 4	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	38173							38173
Gross Domestic Product	9614	884	6650	454	3971	1021	118	22711
Labour Income	5725	649	4771	300	2596	660	48	14748
Federal Government Revenue	1803	148	1118	67	701	133	16	3987
Terr./Prov. Government Revenue	576	60	470	35	394	165	9	1709
Grant Reduction	511			5				516
Adjusted Terr./Prov. Gov. Rev.	65	60	470	29	394	165	9	1193
Adjusted Federal Gov. Rev.	2313	148	1118	72	701	133	16	4503
Total Government Revenue	2378	209	1588	102	1095	298	25	5696
Employment	34612	12818	58957	6002	41364	12112	1014	166879

* Expected leakages of economic impacts from the NWT to other regions due to labour market constraints during the main construction phase (prior to the beginning of operations) are not incorporated in this table

** Saskatchewan / Manitoba / Yukon / Nunavut

*** Since exploration expenditures for the anchor fields have already been made, only development related impacts are considered in this analysis

Even so, the proportion of the GDP impact that would be felt in the NWT is expected to be very similar to that observed for pipeline construction and is just under 45% in all of the cases. Labour income, government revenue and employment impacts in the NWT would represent anywhere from 20-45% of the corresponding national impacts (depending on the case) and it can be observed that impacts in Alberta and Ontario would in some situations be larger than those in the NWT. Furthermore, given that the effect of labour supply constraints in the NWT is not taken into account in Table 3.3, the overall impacts in the NWT would be smaller than indicated in the table. However, unlike in pipeline construction, these impacts would be spread over nearly 30 years so there is a much higher tendency for sustainable benefits from field exploration and development going to northern residents. As the industry became established in the Mackenzie Delta region, it would be a key driver in the local economy.

The impacts shown in Table 3.3 for the rest of Canada follow a pattern observed in pipeline construction. Indirect impacts tend to be concentrated in larger provinces and those closer to the NWT. In addition, it can be observed that labour income impacts tend to constitute roughly two-thirds of the total GDP impacts in any region. This is in stark contrast to the impacts arising from the operation phase of the pipelines and operations associated with natural gas and NGL production.

3.4 Pipeline Operation Impacts

Table 3.4 summarizes the economic impacts associated with the operation of the Mackenzie Valley gas pipeline, the NGL pipeline from the Mackenzie Delta to Norman Wells, as well as the incremental cost of service on the TCPL Alberta system and at Norman Wells to accommodate Mackenzie Delta volumes over the period 2015-2040. Since many impacts would overwhelmingly be concentrated in the NWT, results are shown just for the NWT and for the rest of Canada (denoted as ‘other’ in the table). More detail regarding the distribution of impacts in the rest of Canada can be found in Appendix Tables A.5 and A.6.

The total cost of service would range from roughly $18.1 billion to $26.3 billion depending on the case. As was noted earlier in the study, the operating period is 21 years (2015-2035) in Case 1-6,

TABLE 3.4: IMPACTS OF PIPELINE OPERATIONS: 2015-2040

(millions of 2007 Cdn$, employment in person years)

	$6 US GAS PRICE			$8 US GAS PRICE		
CASE 1	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	17187	919	18106	17738	1006	18745
Gross Domestic Product	16364	1446	17810	16865	1565	18430
Labour Income	528	457	986	566	488	1054
Federal Government Revenue	1067	200	1267	1094	216	1309
Terr./Prov. Government Revenue	854	165	1020	892	179	1071
Grant Reduction	476	0	476	488	0	488
Adjusted Terr./Prov. Gov. Rev.	379	165	543	404	178	582
Adjusted Federal Gov. Rev.	1543	201	1743	1581	216	1798
Total Government Revenue	1921	366	2287	1986	394	2380
Employment	5427	8249	13676	5800	8785	14585
CASE 2	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	19929	1138	21066	19929	1138	21066
Gross Domestic Product	19057	1693	20751	19057	1693	20751
Labour Income	585	500	1085	585	500	1085
Federal Government Revenue	1208	230	1438	1208	230	1438
Terr./Prov. Government Revenue	1025	194	1219	1025	194	1219
Grant Reduction	540	0	541	540	0	541
Adjusted Terr./Prov. Gov. Rev.	485	193	678	485	193	678
Adjusted Federal Gov. Rev.	1748	231	1979	1748	231	1979
Total Government Revenue	2233	424	2657	2233	424	2657
Employment	5968	8906	14874	5968	8906	14874
CASE 3	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	19936	1138	21073	19936	1138	21073
Gross Domestic Product	19060	1696	20757	19060	1696	20757
Labour Income	587	502	1088	587	502	1088
Federal Government Revenue	1209	232	1441	1209	232	1441
Terr./Prov. Government Revenue	1025	194	1219	1025	194	1219
Grant Reduction	540	0	541	540	0	541
Adjusted Terr./Prov. Gov. Rev.	485	193	679	485	193	679
Adjusted Federal Gov. Rev.	1749	232	1981	1749	232	1981
Total Government Revenue	2234	426	2660	2234	426	2660
Employment	5988	8941	14929	5988	8941	14929
CASE 4	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	24973	1295	26268	24973	1295	26268
Gross Domestic Product	23898	1987	25885	23898	1987	25885
Labour Income	705	588	1293	705	588	1293
Federal Government Revenue	1441	268	1709	1441	268	1709
Terr./Prov. Government Revenue	1239	224	1464	1239	224	1464
Grant Reduction	645	1	646	645	1	646
Adjusted Terr./Prov. Gov. Rev.	594	224	818	594	224	818
Adjusted Federal Gov. Rev.	2086	269	2355	2086	269	2355
Total Government Revenue	2680	493	3172	2680	493	3172
Employment	7200	10644	17844	7200	10644	17844

23 years (2015-2037) in Case 1-8 and 26 years (2015-2040) in Cases 2, 3 and 4. These differences are the primary reason that the pipeline operation impacts vary from case to case. Overall GDP impacts would be between $17.8 billion and $25.9 billion and correspond in each case to a GDP intensity ratio (GDP / direct output) of 0.98. These ratios are very high and reflect the fact that in pipeline operations, most of the cost of service is direct GDP (direct value added).

With only limited inputs being purchased by the pipeline companies during the operating phase, there would be little need for imports of materials. Overall imports related to pipeline operations would amount to less than $0.4 billion over the entire operating period in any of the cases. Further, given that the bulk of the GDP impact would be direct, it would also be concentrated in the regions where the pipeline services would be provided. Consequently, the NWT would receive over 90% of the GDP impacts associated with pipeline operations in each of the cases.

Government revenue impacts for this portion of the project also follow the same pattern, with more than 85% of the government revenues shown in Table 3.4 being government revenues that would be directly created by the operation of the pipelines (the property and income taxes payable by the pipeline companies). Total government revenues would range from $2.3 billion to $3.2 billion depending on the case. It is noteworthy that the grant reduction that arises for the NWT under current fiscal arrangements is much less significant (in relative terms) than was shown in either of the construction phase impact tables. This reflects the fact that property taxes generated in the NWT are not subject to any federal government clawback.

While GDP and government revenue impacts would be concentrated in the NWT, Table 3.4 shows that employment and labour income impacts would be more dispersed across the country. As noted in Section 2.5 and in Table A.4, the direct employment associated with pipeline operations is only expected to be between 1600 and 2300 person years in the various cases and would constitute less than 15% of the overall employment impact regardless of the case. As a result, the bulk of the employment impacts shown in Table 3.4 would be indirect and these tend to be more widely dispersed geographically. Still, roughly 40% of the employment impacts and just over 50% labour income impacts would be observed in the NWT.

Given the more substantial employment impacts in other parts of the country, it is useful to examine the distribution of these impacts more carefully. Table 3.5 shows employment impacts related both to the pipeline operation and the gas and NGL production (described more completely in the following section). Most of the indirect employment impacts would occur in Ontario (over one quarter of the total employment impacts) with significant impacts also expected in Alberta, B.C. and Quebec.

TABLE 3.5: DISTRIBUTION OF EMPLOYMENT IMPACTS: 2015-2040

(employment in person years)

PIPELINE OPERATION	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Case 1-6	5427	1698	2195	355	3329	574	198	13676
Case 1-8	5800	1804	2352	377	3431	610	211	14585
Case 2	5968	1812	2445	379	3446	613	212	14874
Case 3	5988	1820	2452	380	3460	616	212	14929
Case 4	7200	2198	2807	459	4179	743	257	17844
GAS AND NGL PRODUCTION	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Case 1-6	4064	831	1895	151	3674	853	71	11538
Case 1-8	4421	900	2060	164	3977	923	77	12521
Case 2	6612	1247	2979	227	5513	1279	107	17965
Case 3	7038	1281	3136	233	5662	1314	110	18775
Case 4	9880	1978	4422	360	8745	2029	170	27585

* Saskatchewan, Manitoba, Yukon and Nunavut

Overall employment impacts associated with pipeline operations could be expected to range from 14,000 to 18,000 person years depending on the case. Relative to the construction phase impacts, these impacts appear quite modest. For example, Mackenzie Delta field exploration and development in Case 2 is estimated to create 96,000 person years of employment given a capital expenditure of about $17.8 billion (an amount equivalent to Case 1-6 pipeline operation revenue).

However, in contrast to the construction phase impacts, it is reasonable to assume that essentially all of the labour income and employment impacts shown for the operating phase in the NWT would in fact be felt by residents of the region. Once this factor is taken into account, the labour income and employment impacts associated with the operating phase are clearly significant in the overall picture and represent sustainable long term impacts that are arguably more beneficial to an economy than the more concentrated impacts during the peak construction phase.

3.5 Gas and NGL Production Impacts

Impacts relating to the production of Mackenzie Delta gas and NGLs are shown in Table 3.6. As with the pipeline operation impacts described above, results are shown for the NWT and for the rest of Canada. Appendix Tables A.7 and A.8 show the regional impacts in more detail.

Depending on the case considered, overall employment impacts associated with gas and NGL production would range from 11,500 person years to 27,600 person years. In contrast to the GDP and government revenue impacts, employment and labour income impacts vary mainly by volume case as opposed to gas price scenario and involve primarily indirect impacts. As was noted in Section 2.5, direct employment related to field operations is expected to range from 2500 to 6000 person years and would constitute between 20% and 25% of the overall employment impacts in this portion of the project.

As was observed for pipeline operations, employment and labour income impacts associated with gas and NGL production would tend to be widely dispersed across the country. In fact, there is less of a concentration of these impacts in the NWT compared to those shown for pipeline operations, with only about one third expected to occur in the NWT. Table 3.5 (above) also contains employment impacts by province related to hydrocarbon production from the Mackenzie Delta and it can be observed that more than 30% of the impacts would be expected to be in Ontario, over 15% in Alberta and close to 7% in both B.C. and Quebec.

TABLE 3.6: IMPACTS OF GAS AND NGL PRODUCTION: 2015-2040

(millions of 2007 Cdn$, employment in person years)

	$6 US GAS PRICE			$8 US GAS PRICE		
CASE 1	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	14178		14178	27700		27700
Gross Domestic Product	13199	709	13907	26639	768	27408
Labour Income	478	506	983	520	548	1068
Federal Government Revenue	1332	124	1457	5532	135	5666
Terr./Prov. Government Revenue	932	75	1006	2268	81	2349
Grant Reduction	426	0	426	1415	0	1415
Adjusted Terr./Prov. Gov. Rev.	506	75	580	853	81	934
Adjusted Federal Gov. Rev.	1758	124	1883	6946	135	7081
Total Government Revenue	2264	199	2463	7800	216	8016
Employment	4064	7474	11538	4421	8100	12521
CASE 2	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	32305		32305	53879		53879
Gross Domestic Product	30820	1079	31899	52394	1079	53473
Labour Income	778	774	1552	778	774	1552
Federal Government Revenue	3297	294	3591	12331	294	12625
Terr./Prov. Government Revenue	1956	168	2124	3736	168	3904
Grant Reduction	1009	0	1009	2362	0	2362
Adjusted Terr./Prov. Gov. Rev.	947	168	1115	1374	168	1542
Adjusted Federal Gov. Rev.	4306	294	4600	14693	294	14987
Total Government Revenue	5252	462	5715	16067	462	16529
Employment	6612	11353	17965	6612	11353	17965
CASE 3	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	42531		42531	68335		68335
Gross Domestic Product	40997	1117	42114	66802	1117	67919
Labour Income	828	804	1632	828	804	1632
Federal Government Revenue	3803	301	4104	14481	301	14782
Terr./Prov. Government Revenue	2113	172	2284	4260	172	4432
Grant Reduction	1071	0	1072	2704	0	2704
Adjusted Terr./Prov. Gov. Rev.	1041	171	1213	1557	171	1728
Adjusted Federal Gov. Rev.	4874	301	5175	17184	301	17486
Total Government Revenue	5915	473	6388	18741	473	19214
Employment	7038	11736	18775	7038	11736	18775
CASE 4	**NWT**	**Other**	**Total**	**NWT**	**Other**	**Total**
Direct Output	57799	0	57799	91971	0	91971
Gross Domestic Product	55478	1677	57155	89650	1677	91327
Labour Income	1162	1194	2355	1162	1194	2355
Federal Government Revenue	5128	397	5525	20148	397	20546
Terr./Prov. Government Revenue	2691	232	2923	5410	232	5642
Grant Reduction	1397	0	1398	3464	0	3464
Adjusted Terr./Prov. Gov. Rev.	1294	232	1525	1946	232	2178
Adjusted Federal Gov. Rev.	6525	398	6923	23612	398	24010
Total Government Revenue	7819	629	8449	25559	629	26188
Employment	9880	17704	27585	9880	17704	27585

While total employment and labour income impacts related to gas and NGL production in the rest of Canada would exceed those in the NWT, GDP and government revenue impacts would generally be much larger in the NWT. Although gas production does involve higher operating costs and, consequently, more indirect imports than pipeline operation, leakages from the local economy are quite small (even in the case of the NWT) and the ratio of GDP to value of production in the NWT would range from 0.98 to 0.99 depending on the case.

Table 3.6 illustrates the effect of higher gas prices and improved pipeline capacity utilization, both of which increase netback revenue and boost GDP and government revenue impacts. GDP impacts could be expected to range from $13.9 billion to $57.2 billion in the $6US gas price scenario and from $27.4 billion to $91.3 billion in the $8US gas price scenario. Government revenue impacts in the $6US gas price scenario would be equivalent to roughly 15% of the GDP impacts while the higher netbacks in the $8US gas price case would raise government revenues to almost 30% of GDP impacts. Clearly these impacts are extremely sensitive to both gas price and pipeline load factors.

Finally, like the pipeline operation impacts, all impacts associated with gas and NGL production in the Mackenzie Delta that are indicated as NWT impacts in Table 3.6 would remain in the region and would provide a sustainable long term benefit to the residents of the NWT

3.6 Unadjusted Overall Impacts

The results described in the previous sections for the various elements of the project can be combined in order to illustrate overall impacts. Appendix Tables A.9 and A.10 contain detailed results by region. As noted in Sections 3.2 and 3.3, a portion of the impacts that are attributed to the NWT during the construction phase of the project would likely be felt by residents of other regions as labour from outside the NWT is brought in to meet project requirements. An estimation of these effects follows in Section 3.7 and detailed regional results are presented given the necessary adjustments for the expected leakages of economic impacts from the NWT to other regions that arise from labour market constraints in the NWT.

Prior to that analysis, a brief summary of the overall project impacts in the various cases is shown below in Table 3.7. GDP impacts could be expected to range from $42.3 billion to $148.5 billion and represent between 85% and 90% of the value of direct output associated with the project. Labour income generated by the project would be between $9.0 billion and $24.1 billion and would constitute anywhere from 15% to 25% of the overall GDP impact. Total government revenues would range from $7.2 billion to $37.0 billion while the total employment created by the project would be between 107,000 and 281,000 person years. It is clear that the economic impacts associated with the project would be substantial regardless of which scenario may actually unfold.

TABLE 3.7: OVERALL PROJECT IMPACTS: 2002-2040

(millions of 2007 Cdn$, employment in person years)

	$6US GAS PRICE				$8US GAS PRICE			
	Case 1	Case 2	Case 3	Case 4	Case 1	Case 2	Case 3	Case 4
Direct Output	48381	80442	100945	134487	62542	102016	126749	168660
Gross Domestic Product	42420	69924	86290	114312	56541	91498	112094	148485
Labour Income	8983	13917	17935	24125	9135	13917	17935	24125
Total Government Revenue	7161	12455	14700	19264	12807	23270	27525	37003
Employment	106779	163107	208822	280534	106779	163107	208822	280534

3.7 Adjustments to Impacts Related to Labour Market Constraints

The results shown throughout Section 3 to this point reflect impacts that would occur in Canada's various geographic regions without taking into account imported labour. These estimates of labour income and employment impacts would only accrue to citizens of a particular region should there be sufficient numbers of people in the region with sufficient skills to fill all of the jobs that would be created there.

For the NWT it is necessary to re-examine the impacts given the small and widely dispersed population but also taking into account the various planned initiatives to optimize the opportunities for Aboriginal Persons, Residents of NWT and NWT businesses. The latter are set out in an extensive agreement outlining the policies and strategies for the management of the opportunities and impacts during both the construction and operations phases of the project.[13] As well, negotiations are underway to establish Access and Benefit agreements between the Producers and Aboriginal organizations that would confirm and enhance the opportunities and benefits for Aboriginal and other NWT residents.

As of the first quarter of 2007, the population of the NWT was approximately 41,800.[14] The labour force has averaged 24,000 in the last two years and the NWT participation rate (labour force as a percentage of working age population) has been 77%, significantly higher than the national average of 68%. Over the past two years, the number of unemployed people in the NWT has averaged 1300 with an unemployment rate of 5.4% (below the national average of 6.3%).[15]

The additional employment opportunities associated with the pipeline and gas development projects considered in this analysis would be valuable in ameliorating some of the unemployment in the region, especially during the operating phase when more of the employment is of a long-term, stable nature. However, the magnitude and labour requirements of the projects in the construction phase are so large that the unemployed labour pool in the NWT and the normal growth in the labour force is not expected to be sufficient to meet all of the labour requirements. Some of this would be due to skill issues, but the sheer numbers of workers required is a factor as well. For example, Figure 2.14 illustrated that during the main construction seasons during the winters of 2011/12, 2012/13 and 2013/14 roughly 7,000 workers are likely to be required. This number is equivalent to almost a third of the entire 2007 NWT labour force.

Clearly there would be significant opportunities for local participation in the construction of the pipeline facilities and in gas field exploration and development. The extent depends on the size, location and mobility of the unemployed or underemployed labour pool in the NWT, along with skill

[13] See *Mackenzie Gas Project Socio-Economic Agreement* between The Government of the Northwest Territories, Imperial Oil Resources Ventures Limited, ConocoPhillips Canada (North) Limited and Shell Canada Energy, dated January 19, 2007.
[14] Data from current indicators section of NWT Bureau of Statistics website.
[15] Data from from current indicators section of NWT Bureau of Statistics website. Unemployment and unemployment rate data from the same source and from www.statcan.ca.

requirements for the various positions. In this regard, environmental and socioeconomic consultants to the MGP have performed some detailed analysis for the project sponsors and the results have been used in this report to make estimates of the extent to which employment generated by the project in the NWT would be taken by NWT residents.[16]

During the peak construction period from 2010-2015, roughly 20% of the direct and indirect employment could be expected to be taken by NWT residents in Case 1, given worker skill levels and labour market constraints in the region. In Cases 2, 3 and 4, additional exploration and development expenditures beyond that expected in Case 1 would also occur during the peak construction period and all employment related to such activity is assumed to be filled by workers from outside the NWT.

There would also be some exploration and development activity prior to the peak construction period in Cases 2, 3 and 4 where significantly fewer workers would be required. Labour market constraints would not be as much of a factor in those periods but skill issues would still exist. Given these assumptions, the amount of employment that could be expected to accrue to NWT residents is summarized in Table 3.8 for the various cases.

Over the period 2007-2015, about 3,900 person years of construction direct and indirect construction employment in the NWT could be expected to be taken by NWT residents out of total employment ranging from 20,100 to 25,900 person years. In each of the cases, this amounts to less than one fifth of the overall employment impact in the region and reflects the huge labour requirements of the project relative to the skill levels and size of the labour force in the NWT. Between 16,200 and 22,000 person years of employment in the region could be expected to be taken by workers from outside the NWT in this period.

[16] See *Estimated Economic Impacts of the Mackenzie Gas Project – Construction and Operations Update with Revised Capital Expenditure*, prepared by Ellis Consulting Services for AMEC Earth and Environmental Services (May 2007).

TABLE 3.8: CONSTRUCTION EMPLOYMENT IN THE NWT GIVEN LABOUR MARKET CONSTRAINTS: 2007-2040

(all values in person years)

2007-2015	Case 1	Case 2	Case 3	Case 4
Total Direct and Indirect Employment in the NWT	20064	24709	25251	25907
Employment for NWT Residents	3864	3864	3864	3864
Employment Leakages to Other Regions	16200	20845	21387	22043
2016-2040	**Case 1**	**Case 2**	**Case 3**	**Case 4**
Total Direct and Indirect Employment in the NWT*	1432	7265	16491	28328
Employment for NWT Residents	1251	6341	14410	14669
Employment Leakages to Other Regions	181	924	2081	13659
OVERALL	**Case 1**	**Case 2**	**Case 3**	**Case 4**
Total Direct and Indirect Employment in the NWT*	21496	31974	41742	54235
Employment for NWT Residents	5115	10205	18274	18533
Employment Leakages to Other Regions	16381	21769	23468	35702

* includes certain direct construction impacts allocated to Alberta in Table 3.3

However, beyond 2015 construction employment is significantly lower on an annual basis and labour market constraints are not expected to be such a significant factor. In order to estimate the amount of construction related employment that would accrue to NWT residents after 2015, figures relating to the maximum potential NWT resident participation during the peak construction period (figures which reflect skill constraints) were extrapolated out to the end of the analysis period using population projections from the NWT Bureau of Statistics.[17] Given these annual maximum participation estimates, direct and indirect employment related to pipeline and gas field operations were subtracted in order to arrive at the potential number of workers with appropriate skills that could take the construction related jobs created on an ongoing basis.[18] If the number of jobs in any given year exceeded the available number of workers, it was assumed that the jobs would have to be taken by non-NWT residents.

[17] See Population Projections by Community for the NWT (2006-2021) on the NWT Bureau of Statistics website. The average annual population growth rate of roughly 1% was used to extrapolate the potential NWT resident participation in project related employment on an annual basis.

[18] As noted in Sections 3.4 and 3.5, it is assumed that much of the direct and indirect operating related employment would be taken by NWT residents.

In both Case 1 and Case 2, over 85% of the direct and indirect construction employment that would be generated by the project beyond 2015 could be accommodated by the NWT labour force, even given a relatively modest population growth rate of 1% annually. It is likely that with the project proceeding the population growth rate could be significantly larger. For example, recent population growth rates in the very strong Alberta economy have averaged roughly 2% over the last few years.[19] It would be much easier for a region with a small population, such as the NWT, to experience a similar or higher population growth rate given an expansion in economic activity.

Consequently, with the significantly higher levels of exploration and development in Cases 3 and 4, a population growth rate of 2% is assumed to estimate leakages of construction employment in the NWT beyond 2015. In Case 3, the result is that leakages of employment to other regions would also be relatively minor (less than 15% of the total direct and indirect construction employment in the NWT). Only in Case 4 would there be significant leakages given the intensity of activity, particularly over the 2020-2023 period. Roughly half of the construction related employment in the NWT over the 2015-2040 period would be taken by workers from outside the NWT in Case 4. This result is sensitive to the population growth rate assumption, with every extra 1% in average annual NWT population growth assumed allowing for about 1000 extra person years of employment for NWT residents. However, leakages would still likely be substantial even with very high population growth because of the concentration of construction activity in the 2020-2023 period. Clearly it is difficult to predict exactly how the project would transform the NWT economy but the leakages shown in Table 3.8 can be used to approximate expected overall employment impacts.

For the overall period, these estimates suggest that between 5,100 and 18,500 person years of construction related employment in the NWT would go NWT residents. Given that the total construction related employment in the region would range from 21,500 to 54,200 person years, NWT residents could be expected to capture between 20% and 45% of these employment impacts, depending on the case. This would leave between 16,400 and 35,700 person years of employment to be allocated among workers in other regions.

[19] See Statistics Canada website www.statcan.ca.

Given the nature of the project, regional shares of overall oil and gas exploration and development expenditures over the last decade along with information in the AMEC/Ellis report are used to allocate impacts which would leak out of the NWT to other regions.

Although the discussion has focused on the employment impacts, the leakages would also involve labour income, GDP and government revenue impacts. Tables 3.9 and 3.10 contain the estimates of overall impacts associated with the project once NWT labour market constraints are taken into account.

GDP and government revenue impacts in the NWT would be far greater than in any single province. In the $6US gas price scenario, more than 75% of the overall GDP impact would be felt in the NWT and this percentage would rise to about 80% in the $8US gas price scenario. On an average annual basis, GDP in the NWT would rise by between $1.1 billion and $3.4 billion (depending on the case) as a result of the project. This would represent an increase of between 25% and 85% over current levels in the region.

Anywhere from 60% to 85% of the total government revenue impacts associated with the project would occur in the NWT. Between 75% and 90% of the overall government revenue impacts (which would range from $7.3 billion to $37.2 billion) would be received by the federal government. It can be noted that the government revenue impacts would be substantially larger in the $8 US gas price scenario given the significantly higher netbacks that would be generated.

TABLE 3.9: OVERALL IMPACTS AFTER ADJUSTMENTS FOR NWT LABOUR MARKET CONSTRAINTS - $6US GAS PRICE SCENARIO: 2002-2040

(millions of 2007 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	47212		1169					48381
Gross Domestic Product	32337	934	5207	464	2667	655	156	42420
Labour Income	2050	773	3462	391	1768	429	110	8983
Federal Government Revenue	2710	169	862	80	473	86	27	4407
Terr./Prov. Government Revenue	1958	68	412	35	265	108	13	2859
Grant Reduction	1034	0	0	4	0	0	0	1038
Adjusted Terr./Prov. Gov. Rev.	924	68	412	30	265	108	13	1820
Adjusted Federal Gov. Rev.	3744	169	862	84	473	86	27	5445
Total Government Revenue	4668	237	1274	115	739	194	40	7266
Employment	14605	11504	38207	5510	27877	7702	1373	106779

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	79055		1388					80442
Gross Domestic Product	54776	1312	7995	651	3991	986	213	69924
Labour Income	3463	1075	5417	530	2642	645	145	13917
Federal Government Revenue	5261	235	1433	110	708	130	36	7913
Terr./Prov. Government Revenue	3280	94	673	49	398	162	18	4674
Grant Reduction	1788	0	0	6	0	0	0	1794
Adjusted Terr./Prov. Gov. Rev.	1492	94	673	43	398	162	18	2880
Adjusted Federal Gov. Rev.	7049	235	1433	116	708	130	36	9708
Total Government Revenue	8541	329	2106	159	1106	292	53	12587
Employment	22786	16500	60917	7755	41656	11617	1876	163107

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	99557		1388					100945
Gross Domestic Product	67472	1563	9891	780	5074	1264	247	86290
Labour Income	4892	1263	6829	616	3351	825	160	17935
Federal Government Revenue	6265	278	1759	129	900	166	40	9538
Terr./Prov. Government Revenue	3585	111	808	59	506	207	20	5296
Grant Reduction	1980	0	0	8	0	0	0	1987
Adjusted Terr./Prov. Gov. Rev.	1605	111	808	51	506	207	20	3309
Adjusted Federal Gov. Rev.	8245	278	1759	137	900	166	40	11525
Total Government Revenue	9850	389	2567	188	1406	373	61	14835
Employment	31300	20092	77994	9414	52940	14911	2171	208822

CASE 4	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	132892		1595					134487
Gross Domestic Product	88337	2164	13978	1080	6735	1676	343	114312
Labour Income	5824	1767	9899	855	4455	1096	229	24125
Federal Government Revenue	8183	386	2463	180	1195	220	57	12683
Terr./Prov. Government Revenue	4473	152	1103	82	672	275	28	6786
Grant Reduction	2482	0	0	10	0	0	0	2492
Adjusted Terr./Prov. Gov. Rev.	1991	152	1103	72	672	275	28	4294
Adjusted Federal Gov. Rev.	10665	386	2463	190	1195	220	57	15175
Total Government Revenue	12656	538	3566	262	1867	495	85	19469
Employment	35614	27400	111764	12718	70261	19767	3010	280534

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE 3.10: OVERALL IMPACTS AFTER ADJUSTMENTS FOR NWT LABOUR MARKET CONSTRAINTS - $8US GAS PRICE SCENARIO: 2002-2040

(millions of 2007 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	61285		1256					62542
Gross Domestic Product	46279	946	5313	466	2715	664	158	56541
Labour Income	2129	781	3487	393	1800	435	111	9135
Federal Government Revenue	6936	171	876	81	482	87	27	8659
Terr./Prov. Government Revenue	3332	69	423	35	270	109	13	4253
Grant Reduction	2035	0	0	4	0	0	0	2039
Adjusted Terr./Prov. Gov. Rev.	1297	69	423	31	270	109	13	2213
Adjusted Federal Gov. Rev.	8971	171	876	85	482	87	27	10698
Total Government Revenue	10268	240	1299	115	752	197	40	12912
Employment	15336	11679	38529	5545	28382	7808	1392	108671

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	100629		1388					102016
Gross Domestic Product	76351	1312	7995	651	3991	986	213	91498
Labour Income	3463	1075	5417	530	2642	645	145	13917
Federal Government Revenue	14295	235	1433	110	708	130	36	16947
Terr./Prov. Government Revenue	5060	94	673	49	398	162	18	6454
Grant Reduction	3141	0	0	6	0	0	0	3147
Adjusted Terr./Prov. Gov. Rev.	1919	94	673	43	398	162	18	3307
Adjusted Federal Gov. Rev.	17436	235	1433	116	708	130	36	20095
Total Government Revenue	19355	329	2106	159	1106	292	53	23402
Employment	22786	16500	60917	7755	41656	11617	1876	163107

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	125362		1388					126749
Gross Domestic Product	93277	1563	9891	780	5074	1264	247	112094
Labour Income	4892	1263	6829	616	3351	825	160	17935
Federal Government Revenue	16943	278	1759	129	900	166	40	20216
Terr./Prov. Government Revenue	5732	111	808	59	506	207	20	7444
Grant Reduction	3612	0	0	8	0	0	0	3619
Adjusted Terr./Prov. Gov. Rev.	2120	111	808	51	506	207	20	3825
Adjusted Federal Gov. Rev.	20555	278	1759	137	900	166	40	23836
Total Government Revenue	22675	389	2567	188	1406	373	61	27660
Employment	31300	20092	77994	9414	52940	14911	2171	208822

CASE 4	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	167065		1595					168660
Gross Domestic Product	122509	2164	13978	1080	6735	1676	343	148485
Labour Income	5824	1767	9899	855	4455	1096	229	24125
Federal Government Revenue	23203	386	2463	180	1195	220	57	27704
Terr./Prov. Government Revenue	7192	152	1103	82	672	275	28	9505
Grant Reduction	4548	0	0	10	0	0	0	4558
Adjusted Terr./Prov. Gov. Rev.	2644	152	1103	72	672	275	28	4946
Adjusted Federal Gov. Rev.	27752	386	2463	190	1195	220	57	32262
Total Government Revenue	30395	538	3566	262	1867	495	85	37209
Employment	35614	27400	111764	12718	70261	19767	3010	280534

* Saskatchewan / Manitoba / Yukon / Nunavut

Given the leakages of construction phase employment and labour income from the NWT as well as the fact that the impacts on these items would primarily be indirect given the project characteristics, only about 15% of employment and 25% of labour income impacts would be felt by NWT residents. Nevertheless, the additional employment generated by the project would range from 14,000 to 36,000 person years or between 500 and 1000 jobs on an average annual basis[20]. These employment impacts could effectively reduce the NWT unemployment rate to half the current level. However, it might be expected that the improved economic environment in the region would draw discouraged workers back into the labour force and this combined with natural increase in the population and perhaps a greater incentive for in-migration to the NWT would likely prevent the unemployment rate from falling to unsustainably low levels that are associated with high levels on inflation.

The largest employment and labour income impacts associated with the project could be expected in Alberta, with gains ranging from 38,000 to 112,000 person years. Aside from the direct operating employment that would be generated in the province, much of the project management and engineering during the construction phase of the project would be sourced in Alberta. In addition, most of the direct construction phase jobs in the NWT that would be taken by workers from outside the region would likely go to Alberta workers given the nature of the work and the proximity of Alberta to the NWT. Overall, between 35% and 40% of the total employment and labour income impacts could be expected in Alberta.

Ontario would also experience significant employment and labour income impacts, in fact exceeding those for the NWT. Employment impacts would range from 28,000 to 70,000 person years and would constitute roughly one quarter of the overall employment impacts. Other regions of Canada would also see significant impacts, especially given the relative size of the various regional economies in the country.

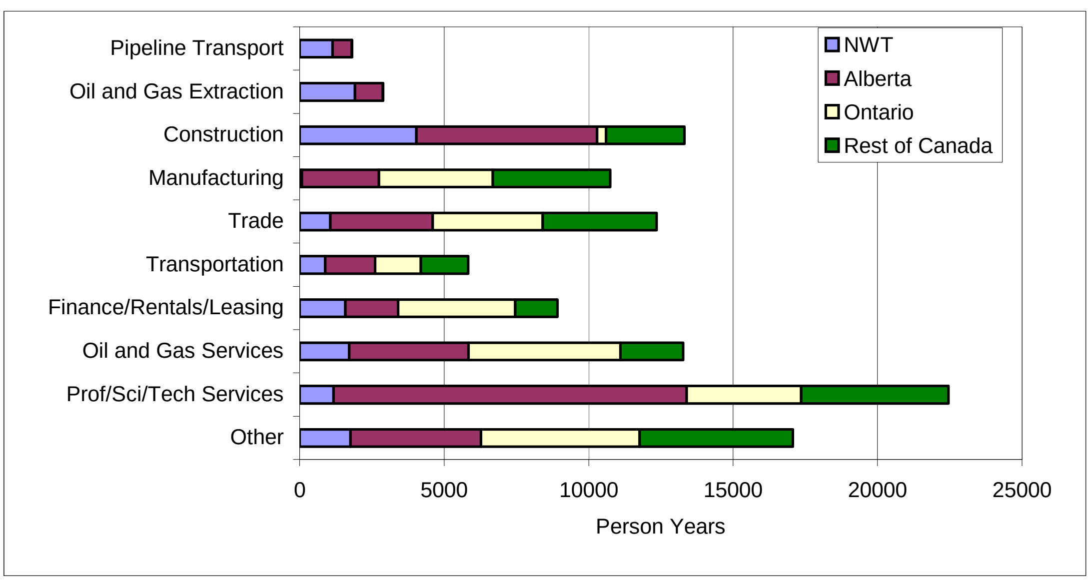
Not only would the employment and labour income impacts be dispersed quite widely across regions Canada, they would also be distributed broadly across a variety of industries. Appendix Tables A.11 and A.12 contain the employment distributions by sector and region for the various

[20] These and subsequent average annual impacts are estimated for the period starting in 2007.

cases while Figure 3.1 illustrates the employment distribution for Case 1-8. Although overall employment impacts are significantly higher in Cases 2, 3 and 4, the relative distribution of employment between industries and regions is very similar in all of the cases.

Figure 3.1 illustrates the distribution of employment generated by the project across various sectors and industries. Employment impacts in industries where direct employment would occur as a result of the project are indicated by the top three bars in Figure 3.1. It can be observed that employment impacts in the pipeline transport and oil and gas extraction industries would effectively only be in the NWT and Alberta. These impacts consist almost entirely of direct operating employment and are relatively small given the size of impacts in other industries (less than 3% of the total in any of the cases). Construction employment would comprise roughly 10% of the overall employment generated by the project in each of the cases. Employment effects in construction would occur primarily in the NWT (even with the significant leakages described in this section) and Alberta but it is anticipated that workers from other parts of the country with drilling and/or pipeline construction experience would be drawn to the project as well.

FIGURE 3.1: SECTORAL DISTRIBUTION OF TOTAL EMPLOYMENT IMPACTS IN CASE 1-8: 2007-2037



Although classified as indirect activity throughout the report, the manufacturing of pipes, compressors, valves and other products represents a key component of the overall economic impact. Employment in manufacturing is expected to represent slightly more than 10% of the total employment impact in each of the cases. Many items related to oil and gas facilities would be manufactured in Alberta but there would also be significant activity in Ontario and the rest of the country. The NWT would not be expected to produce the manufactured inputs specifically required for this type of project (i.e. large and small diameter pipe, valves, fittings, metering equipment, vessels, wellheads, etc.) given the current structure of the economy. However, if the scale of Mackenzie Delta field development were to become sufficiently large in the future, it may become viable to produce some manufactured inputs locally. It is useful to note here that the GNWT is actively engaged in evaluation of opportunities to expand the manufacturing sector to maximize the economic development potential of the Mackenzie Gas Project.

Some of the largest indirect impacts would occur in oil and gas service industry as well as in industries that provide professional, scientific and technical services. Over 20% of the overall employment impacts could be expected in the latter industries with Alberta based businesses experiencing about half of this impact (much of the project related engineering and management would be sourced in Alberta). For industries such as finance, rentals and leasing as well as miscellaneous other industries, sizable impacts would be expected in many regions across Canada.

In summary, the broad distribution of employment impacts over a variety of sectors in the NWT would make it all the more likely that residents of the NWT would widely benefit from the project on a sustained basis.

4.0 OTHER IMPACTS AND IMPLICATIONS

There are a variety of impacts relating to the construction and operation of the Mackenzie Valley pipeline and Mackenzie Delta gas fields beyond those explicitly modelled in Sections 2 and 3 which could be quite significant. These impacts as well as other potential implications of the project are discussed in this section.

4.1 INDUCED ECONOMIC IMPACTS

As noted in Section 3.1, there is another category of economic impacts called induced impacts that relate to the spending of portions of labour income, corporate profits and government revenues generated by an activity. The induced impacts related to the spending of labour income are often incorporated in input-output analysis. For example, the NWT government has an input-output model that can produce 'closed' model results which include this type of induced impact.

The ultimate impact resulting from the spending of labour income associated with an activity depends on the perspective taken. For example, in a small region within a country, a large proportion of consumer spending would be on items that were not produced in that region and this would tend to limit the induced impacts generated in that region. However, if the perspective is broadened to the country, it is more likely that consumer spending would be on items that were produced in the country and larger induced impacts could be expected on a country-wide basis vs. the regional basis.

For the NWT, it appears that the induced GDP associated with any activity is approximately equal to between 20% and 30% of the direct plus indirect labour income generated by the project.[21] In comparison, for Alberta this ratio rises to about 45% and for Canada as a whole, our experience suggests that the ratio is closer to 70%.[22] Further, using the same sources, the ratios of induced

[21] These percentages were derived using various results presented in Canadian Energy Research Institute, *A Comparison of Natural Gas Pipeline Options for the North*, October 2000.

[22] In Alberta Treasury's Alberta Economic Multipliers, intensity ratios are presented for the open (direct + indirect impacts only) and closed (direct + indirect + labour spending related induced impacts) versions of the Alberta input-output model. The difference in GDP intensity ratios for any given industry under the open and closed models is consistently about 45% of the direct and indirect labour income. The percentage for the national economy was derived from several studies that WMR has performed over the last few years.

employment per million dollars of induced GDP in the NWT, Alberta and Canada are approximately 13, 19 and 17 respectively.

Given the results presented in Tables 3.9 and 3.10 that reflect the direct and indirect impacts associated with the project in the various cases and the percentages and ratios noted above, induced GDP and employment impacts related to the spending of labour income would be as follows: an additional $0.5-$1.5 billion and 6,700-18,900 person years in the NWT; an additional $1.6-$4.5 billion and 29,600-84,600 person years in Alberta; and, an additional $6.3-$16.9 billion and 107,000-287,000 person years in Canada. The induced employment impacts related to the spending of labour income would increase the overall employment impacts shown in Table 3.10 by about 50% for the NWT, 75% for Alberta and 100% for Canada.

Another important source of induced effects relates to the reinvestment of corporate profits. The oil and gas industry in particular reinvests a very high proportion of overall earnings in the form of exploration and development expenditures. In the last decade, the percentage of net revenue (that is, revenues minus royalties and operating costs) that has been spent on exploration and development in Canada has averaged close to 60%.[23] Given the values shown in Figures A.1-A.8 for the Mackenzie Delta gas producers in the various cases, it could be expected that between $9 and $55 billion would be reinvested over the life of the project on exploration and development somewhere in Canada.

The overall economic impacts associated with this activity would be roughly proportional (given the respective capital costs) to those shown in Table 3.3 for Mackenzie Delta field development. For Canada as a whole, between $5 billion and $33 billion in GDP impacts would be generated and employment impacts ranging from 37,000 to 241,000 person years could be expected. The additional induced GDP impacts related to spending of the labour income associated with this additional exploration and development would amount to between $2 billion and $15 billion, with additional induced employment ranging from 40,000 to 253,000 person years. In total then, the direct, indirect and induced impacts associated with reinvestment of Mackenzie Delta net revenues

[23] Data from the Canadian Association of Petroleum Producers *Statistical Handbook*. The average is for the 2000-2005 period.

would range from $7 billion to $48 billion in terms of GDP, while the employment impacts would be between 77,000 and 496,000 person years.

Further impacts could be anticipated as the reserves that are discovered in the exploration and development process would eventually give rise to additional oil and gas production. The estimation of these effects requires more detailed modelling and is beyond the scope of this study. Similarly, induced effects related to spending of government revenues could be expected to be quite pronounced given the $7 billion to $37 billion in government revenues that would be directly and indirectly generated by this project.

It is important to note that these measurements of induced impacts are much less precise than those for direct and indirect impacts. Nevertheless, the key point is that the full impacts of the project will include very significant induced impacts, with the result that the full impacts will be substantially greater than the direct plus indirect impacts presented in Section 3.

4.2 Value Added Opportunities Using Mackenzie Delta NGLs

The Inuvik area gas plant could be expected to recover roughly 90% of the pentanes plus and about 50% of the butanes contained in Mackenzie Delta raw gas. The remainder of these products as well as any propane and ethane would remain entrained in the gas stream that would flow through the Mackenzie Valley gas pipeline and eventually into the TCPL Alberta system. These liquids could be extracted at either Cochrane or Empress and this could provide opportunities to add value to the NGLs. Should there be substantial growth in Northern gas resources over the long term it is possible that more NGL upgrading could also occur in the NWT.

The use of ethane as petrochemical feedstock for the production of ethylene and subsequently polyethylene represents one of the most effective ways of adding value to Canada's natural resources. Furthermore, it has been one of the best examples of successful diversification in Canada. Alberta's ethane based petrochemical industry is now a world scale producer of ethylene and polyethylene and represents one of the key manufacturing industries in the province. Despite the fact that a significant portion of the Alberta's ethane supply is now exported on the Alliance pipeline without any upgrading into value added products in Canada, Alberta's ethane based petrochemical industry remains competitive and would surely welcome the opportunity to access additional NGL supplies.

4.3 MINERAL RIGHTS VALUES AND EXPLORATION OPPORTUNITIES IN THE NWT

Oil and gas producers in Canada have paid slightly more than $200 million for mineral rights in the NWT over the last 20 years.[24] Over the same period, these producers have spent nearly $19 billion on the acquisition of mineral rights in Alberta. Rights in the NWT have been issued by the federal government for work commitments and winning bidders have not had to pay cash bonuses as is normally the case in southern Canada. One of the reasons is that in many cases there has been no foreseeable method of delivering to markets the oil or gas that might be found in many parts of the region. The introduction of the Mackenzie Valley pipeline would change this situation, potentially in a rather dramatic fashion. The federal government and perhaps native bands could benefit substantially should this occur.

Access to a pipeline would certainly improve the expected profitability of any gas investment in the NWT. This impact would likely be most pronounced with respect to properties in the Mackenzie Delta but there is the possibility of opening up other potential supply sources. Known and yet to-be-discovered gas in the Colville Hills area and probable gas reserves in other portions of the central and southern NWT could be explored or developed as soon as a viable pipeline is available to connect them. At present there is no way to exploit gas reserves in the NWT except for small quantities going to Inuvik through the Ikhil Project, gas use in Norman Wells, and gas developments in the Liard area of the southern NWT. If the Mackenzie Valley pipeline could at some point be accessed by presently unconnected existing and potential supplies it would significantly increase further exploration and development, and the value of the relevant petroleum sub-surface rights. This type of activity could be very beneficial to the overall NWT economy as well as to smaller communities in the NWT because the scale of activity would not have to be particularly large to have a significant economic impact. It is the type of activity that, should new discoveries be made, can also give rise to a longer-term sustainable local industry. It might also be noted that while the potential for production of gas from gas hydrates in the region has yet to be

[24] Data from Canadian Association of Petroleum Producers *Statistical Handbook*.

defined, the existence of the Mackenzie Valley pipeline would greatly improve the prospects for tapping this resource over the longer term.

4.4 Benefits to NWT Residents of Access to Natural Gas

Households in NWT communities along the Mackenzie Valley pipeline route could potentially realize a significant benefit if they could access Mackenzie Delta gas for home heating use. Studies for the GNWT have been completed on the viability of providing this access to various communities and there is strong interest in seizing this opportunity.[25]

Currently heating oil (diesel oil) is the fuel of choice for heating the homes of many NWT residents and in 2001, the average annual bill for heating oil in Yellowknife was $1726.[26] Heating oil prices in 2005 were about 55% higher than in 2005. Consequently, an average annual heating bill of $2700 in Yellowknife is assumed to determine the potential savings by households that would switch to natural gas heating should the project proceed.

The average annual cost noted above must be adjusted to take into account where conversions to natural gas would likely take place in the NWT. It seems unlikely that consumers in Yellowknife would be able to access Mackenzie Delta gas for heating, given the distance between the city and the proposed Mackenzie Valley pipeline and the fact that any proposed lateral that would connect Yellowknife would have to pass through lengthy sections of surface bedrock. The most likely areas to see local natural gas service would be larger communities in the Mackenzie Delta and directly along the pipeline route.

Both Inuvik and Norman Wells currently have residential natural gas service. As noted in Section 1, Inuvik is served by gas from Ikhil that is approximately 50 km from Inuvik. The gas price for Inuvik consumers is roughly 85% of that for diesel oil on a heating equivalent basis. However, the fact that there is only a 15% saving using gas versus diesel oil may largely be due to unusually high infrastructure costs in that particular situation - namely, the requirement of a 50km dedicated pipeline from the gas field to Inuvik. In cases where the gas supply was closer to the population

[25] For example, see *Mackenzie Valley Gas Conversion- Feasibility Study II*, final report by CH Four Consulting Inc. for the Ministry of Industry, Tourism and Investment, Government of the Northwest Territories (April 24, 2006).

centre and essentially only distribution infrastructure would be required to provide service, it is possible that savings could be much greater.

For example, Fort Simpson and Fort Good Hope both lie directly on the proposed pipeline route. Further, it is possible that within the Mackenzie Delta region itself new fields would be discovered that are very close to population centres like Tuktoyaktuk or Aklavik.[27] In these cases the markup over the netback price in the gas field might not be as large as what is currently observed at Inuvik.

In order to establish a range of values, potential consumer savings in Fort Simpson and Tuktoyaktuk are evaluated. These centres are used because amongst the communities that might be candidates for natural gas service to consumers, they respectively have the lowest and highest cost of living. Compared to Yellowknife, the cost of living in Fort Simpson is about 15% higher while in Tuktoyaktuk it is roughly 40% higher.[28] In addition, Tuktoyaktuk is significantly further north than Yellowknife and measurably colder on average. As a result, it could be expected that average fuel use in Tuktoyaktuk would be higher than in Yellowknife. Given these considerations, it is estimated that current annual diesel oil costs would range from about $3100 to $4200 per year.

The expected cost of gas to residential consumers in the NWT is estimated by taking the netback gas price in the Mackenzie Delta and adding on a markup which would be mainly distribution margin but could include items like municipal fees as well.[29] Depending on the case, this would translate into an average gas price for residential consumers of between $10.00/GJ and

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[26] Data from a Statistics Canada 2001 *Family Expenditure Survey* for Yellowknife.

[27] Population in the various communities designated as potential candidates for natural gas service were as follows for 2006: Aklavik - 597; Fort Good Hope - 585; Tuktoyaktuk - 967; and Fort Simpson - 1211 (population data from NWT Bureau of Statistics,). While it may seem that it would be unlikely that any party would find it worthwhile to set up a gas distribution network in such small communities, Norman Wells with a population of 849 in 2006 currently has such infrastructure. The only other community of similar size in the Mackenzie Delta region is Fort McPherson with population of 787 in 2006. However, this community is smaller than Inuvik (population 3354 in 2006) and over 100 km from the proposed pipeline route (or further away from a gas source than Inuvik is from Ikhil).

[28] Data from NWT Bureau of Statistics, *Statistics Quarterly* (December 2001).

[29] The estimated markup is based on information contained in National Energy Board *Canadian Energy Supply and Demand 1993-2010* (December 1994) regarding fieldgate prices of gas and the price of gas to residential consumers in B.C. and the Territories. It is assumed that in real terms the markups evident there had remained constant over time. Converting to 2007$, the resulting markup is between $4-5/GJ. While the information may appear dated, the current markups by distributors in Alberta are virtually identical. For service in Fort Simpson and Tuktoyaktuk, this markup is inflated by the cost of living differential between those communities and Edmonton (the basis of all of the aforementioned cost of living comparisons). In addition, for Fort Simpson the cost of moving Mackenzie Delta gas along the Mackenzie Valley pipeline to Fort Simpson is also included in the estimated price to consumers.

$13.50/GJ. Given the annual heating requirements for the typical household, savings of between $1700 and $2300 per year could be realized by switching to natural gas. This represents roughly 55% of current heating costs. It seems likely that these sorts of savings would justify the cost of switching from an oil furnace to a gas furnace.

4.5 Impacts on Existing Pipeline Infrastructure

The gas pipeline infrastructure south of sixty is running below capacity and this underutilization will become more pronounced in the absence of northern gas supply and transmission development. In general, reductions in utilization rates translate into higher per unit tolls. The introduction of 800 to 1200 MMcf/d or more of gas from the North will significantly improve the utilization of southern pipeline infrastructure, to the benefit of gas consumers and producers. In addition, the new supply of NGLs available at Norman Wells will significantly improve the utilization of the existing Norman Wells oil pipeline. By significantly reducing the unit costs on the Norman Wells oil pipeline there would be gains in the profitability of oil production in the region and an extension of the benefits from the production of those resources.

Additional benefits would likely arise from the enhancement of gas supplies to Norman Wells. While this community currently has gas service from local supplies, these are not expected to be adequate to meet the needs for domestic use, the power plant, the Imperial Oil facilities and for pressurizing some wells in the region. By providing access to a long-term gas supply, the pipeline would likely generate very significant benefits for the community and benefits from the extension of oil production in the region.

4.6 Gains to Canadian Gas Consumers

There could be benefits to Canadian gas consumers in general as a result of the introduction of Mackenzie Delta volumes into the North American market. Between now and the anticipated start-up date of Mackenzie Delta flows, it is widely anticipated that there will be a significant increase in North American natural gas demand. The Energy Information Agency (EIA) of the U.S. Government's Department of Energy (DOE) projects that annual American demand will rise by approximately 3.3 Tcf between 2005 and 2015, or equivalently, show an average growth rate of about 1.4% per year.[30] Other forecasters indicate increases ranging from 1.4 Tcf to 4.4 Tcf on an annual basis over the period.[31] For Canada, the NEB forecasts end use demand for natural gas will rise by between 0.56 PJ to 0.59 PJ over the 2002-2015 period, or at an annual average rate of between 1.6% and 1.7%.[32]

Although rising demand is expected to be coupled to some extent with rising supply, the tightening of the natural gas market that began in 2000 is expected to persist over the longer term and keep natural gas prices at the higher levels that have been observed over the last five years. Figure 2.3 illustrated that the natural gas price at Henry Hub between 2003 and 2007 averaged over $7 US/MMBtu compared to roughly $2 US/MMBtu in the 1990s.[33] While some moderation in near term prices is generally expected, forecasters suggest that US natural gas prices could range from anywhere between $6US/ MMBtu (2006$) and $8US/ MMBtu by 2015.

In most of these forecasts, it is assumed that some amount of Mackenzie Delta gas will be flowing to North American gas markets by 2015. Without Mackenzie Delta gas, it is likely that continental natural gas prices would be higher than indicated in the forecasts. No detailed analysis has been performed with respect to the value of this gain to Canadian consumers associated with lower prices resulting from the addition of Mackenzie Delta gas.

4.7 Reductions in Greenhouse Gas Emissions

Under the Kyoto Protocol, Canada and other industrialized countries agreed in principle to cut greenhouse gas (GHG) emissions (emissions of carbon dioxide (CO2), methane and nitrous oxide) below 1990 levels by 2008-2012.[34] Currently, GHG emissions in Canada are substantially higher

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30 See U.S. Department of Energy, Energy Information Agency, *Annual Energy Outlook 2007* (January 2007) - http://www.eia.doe/gov/oiaf/aeo.

31 See Table 22 of U.S. Department of Energy, Energy Information Agency, *Annual Energy Outlook 2007* (January 2007) - http://www.eia.doe/gov/oiaf/aeo.

32 See National Energy Board, *Canada's Energy Future: Scenarios for Supply and Demand to 2025* (July 2003) - http://www.neb-one.gc.ca/SupplyDemand/2003. The range represents results over the NEB's Supply Push and Techno Vert scenarios.

33 Historical gas prices from Sproule Associates Limited website (www.sproule.com/prices/gas).

34 The Kyoto Protocol was signed in December 1997. Canada agreed to reduce GHG emissions to 6% below 1990 levels by 2008-2012. The agreement has not been ratified,

than 1990 levels and some significant progress on the emission reduction front would have to made if target levels are to be reached by the end of the decade.[35]

To this end, the replacement of coal with natural gas in electricity generation could provide major reductions in GHG emissions. For example, in Canada in 1995, roughly 88 MT of CO2-equivalent was emitted by the electricity generators that burned coal compared to only 10 MT of CO2-equivalent from those burning natural gas.[36] To a large extent this reflects the larger amount of electricity generated via coal versus natural gas (a ratio of about four to one in 1995) but it is also due to the fact natural gas combustion does not produce as many GHG emissions per unit of energy as coal.[37] Depending on the type of coal, CO2 emissions per energy equivalent are anywhere between 64% and 90% higher than for natural gas. This is somewhat offset by the fact that the ratio of total natural gas production to marketable gas production typically is somewhere between 1.15 to1.2 in Canada.[38] However, even with this factor incorporated, GHG emissions per unit of energy equivalent are significantly higher for coal than for natural gas.

Over the past few years, there has been a trend in North America towards proportionally greater gas fired electricity generation versus coal fired generation. In Alberta for example, a substantial portion of the electricity generation capacity added over the last few years is gas fired. This trend could be halted if the relative price of natural gas (that is, relative to coal prices) rises substantially over time. Consequently, to the extent that the supply augmentation provided by Mackenzie Delta gas supplies can alleviate gas price increases and thereby help to promote a trend away from the use of higher GHG emitting fuels in electricity generation (and in heating as well), additional benefits to society may be created.

There is significant uncertainty regarding the value of preventing GHG emissions. For example, the Alberta government has recently indicated that it would cap the price of emissions of CO2 equivalent at $15 per tonne. In contrast, information in the recent Stern report on the economics of climate change suggest a social cost of emissions of CO2 equivalent ranging from $25-$85 per

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[35] The increase in GHG emissions over the period 1990-1997 was approximately 13%.

[36] See Natural Resources Canada,, *Canada's Energy Outlook 1996-2000* (April 1997).

[37] The CO2 emissions per TJ of natural gas equal 49.68 T. Depending on the type of coal, CO2 emissions range from 81.6 to 94.3 T/TJ. The CO2 emissions for gasoline and oils range from 68 T/TJ to 74 T/TJ. Data from A.P. Jaques, *Canada's Greenhouse Gas Emission: Estimates for 1990*, Environment Canada (December 1992).

[38] See Canadian Association of Petroleum Producers (CAPP) *Statistical Handbook*.

tonne.[39] Using the midpoint of the range in the Stern report ($55/tonne) and the Alberta government's valuation to frame the range of values and assuming that the entire volume of Mackenzie Delta gas would be used to fire new electricity generation that in the absence of this gas would be fired by coal, society would benefit by somewhere between $80 million to $1.3 billion annually due to avoided GHG emissions depending on the valuation of emission reduction.

The general conclusion that access to northern gas can result in material reductions in GHG emissions in Canada and the U.S. has also been outlined in a recent study undertaken by Angevine Economic Consulting.[40] There it is estimated that development of Alaska and Mackenzie gas supplies, along with some imported LNG, could displace more carbon intensive fuels in Canada and the lower-48 states and result in cumulative reductions (over the period 2014-2025) of about 23 million tonnes of carbon in Canada and almost 260 million tonnes in the U.S.

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[39] Estimates have been made of the value of preventing GHG emissions in the context of an emission permit trading system. For example, see Charles River Associates, *Report of the Upstream Oil and Gas Working Group of the Industry Issues - Table to the National Climate Change Secretariat*. It is estimated that the value per tonne of CO2 equivalent in 2010 could range from $25.74 Cdn - $130.59 Cdn, depending on whether credit would be given to international reductions in GHG emissions. See also the executive summary of the 2007 Stern Review Report on the Economics of Climate Change at http://www.hm-treasury.gov.uk/media/4/3/Executive_Summary.pdf .

[40] See *An Assessment of Arctic Gas*, a study prepared for the Department of Industry, Tourism and Investment, Government of Northwest Territories, by Angevine Economic Consulting, August 2007.

APPENDIX

In this appendix, diagrams that trace the financial flows in the various cases are presented in Figures A.1 to A.8. The present values of the financial flows by case are also shown in Figures A.9 to A.16. While each figure has a common format, it is instructive to explain the flows with reference to a particular case - for example, Case 1-6 as shown in Figure A.1.

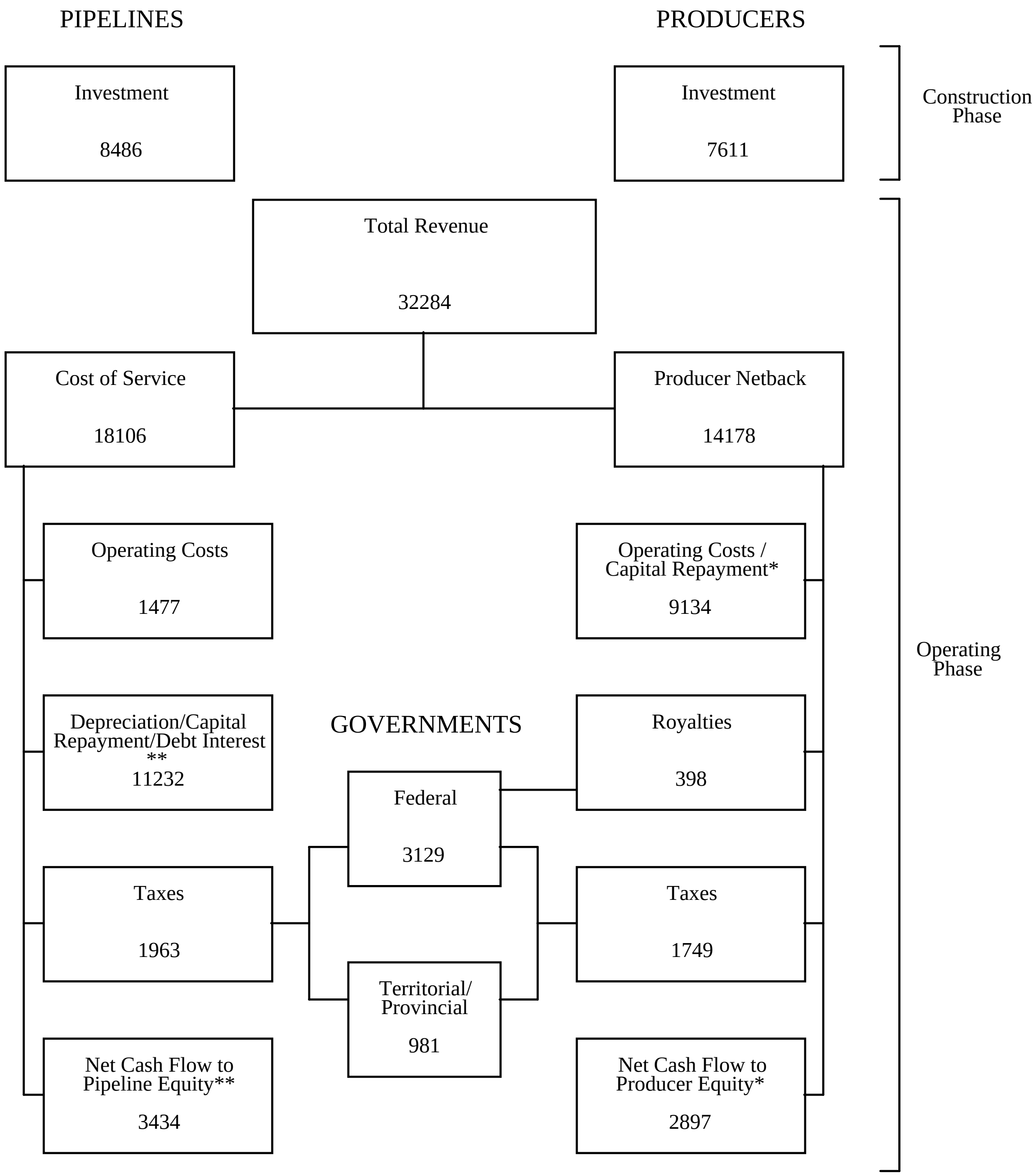
Initially, it should be observed that the pipeline sector (gas pipeline and NGL pipeline) is represented on the left hand side of the figure while the producer sector is depicted on the right hand side. The integration of these contributors is portrayed in the central boxes which measure the generation of income from the sale of gas and by-products and the allocation of taxation and royalty revenue to governments.

More specifically, if one starts at the top of Figure A.1, there is a construction phase in which investment in pipeline and production facilities creates an opportunity for producers to sell gas. The pipeline sector receives a cost of service ($18.1 billion 2007Cdn$) which is distributed to operating costs, depreciation and debt servicing, income and property taxes and a return on equity. In the producer sector, after paying for the cost of service, the netback revenue ($14.2 billion) is allocated to operating and other production costs, royalties, income and property taxes, and a return. From these activities, the government sector receives property taxes, income taxes and royalties totaling $4.110 billion. These are allocated according to jurisdiction.

FIGURE A.1

CASH FLOWS : CASE 1-6 (ANCHOR FIELDS ONLY, $6US GAS), 2002-2035

(millions of 2007 Canadian dollars)



* assumes 100% equity financing

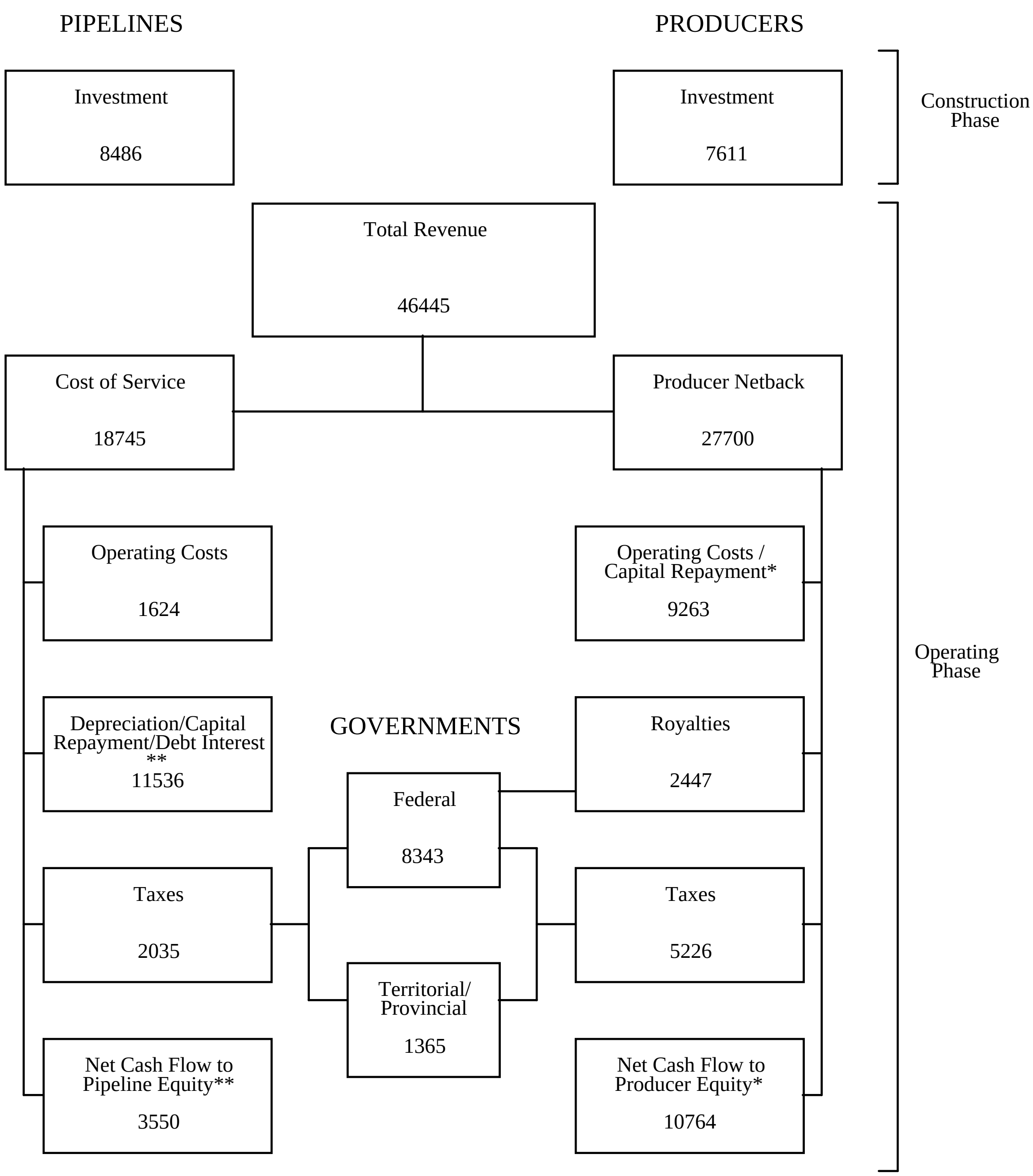
** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.2

CASH FLOWS : CASE 1-8 (ANCHOR FIELDS ONLY, $8US GAS), 2002-2037

(millions of 2007 Canadian dollars)



* assumes 100% equity financing

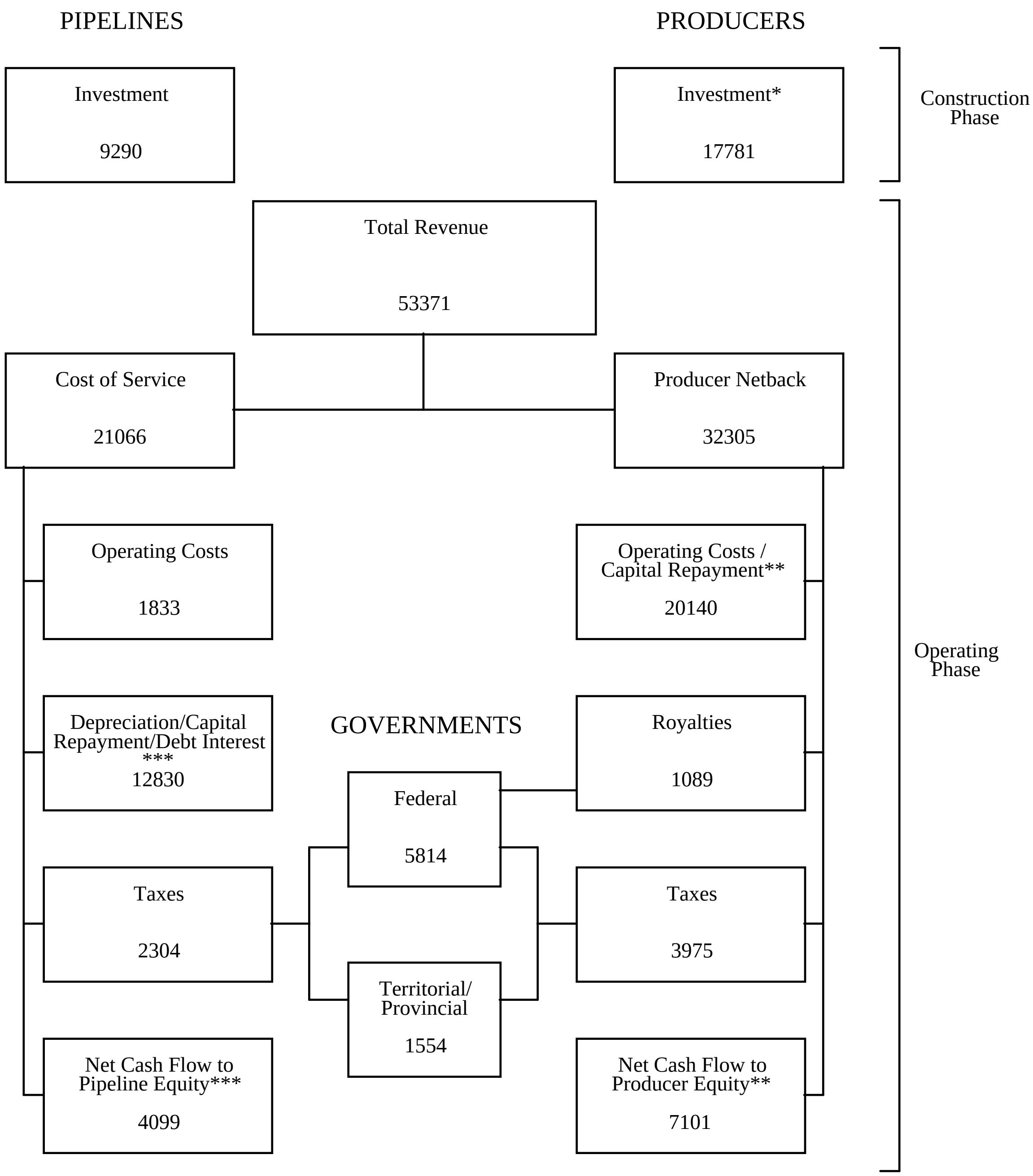
** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.3

CASH FLOWS : CASE 2-6 (1.2 BCF/D TO 2028, $6US GAS), 2002-2040

(millions of 2007 Canadian dollars)



* includes exploration expenditure (3812)

** assumes 100% equity financing

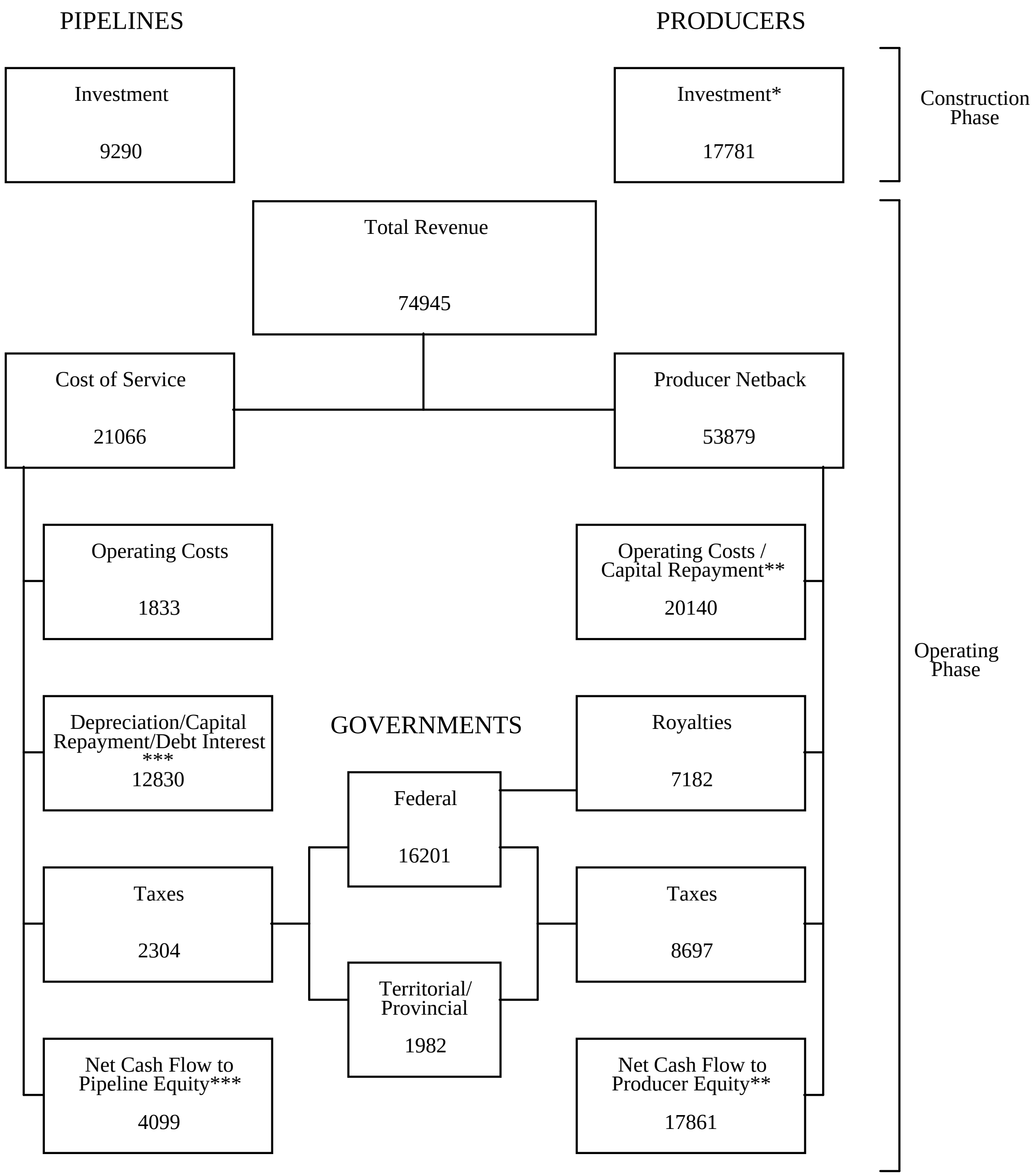
*** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.4

CASH FLOWS : CASE 2-8 (1.2 BCF/D TO 2028, $8US GAS), 2002-2040

(millions of 2007 Canadian dollars)



* includes exploration expenditure (3812)

** assumes 100% equity financing

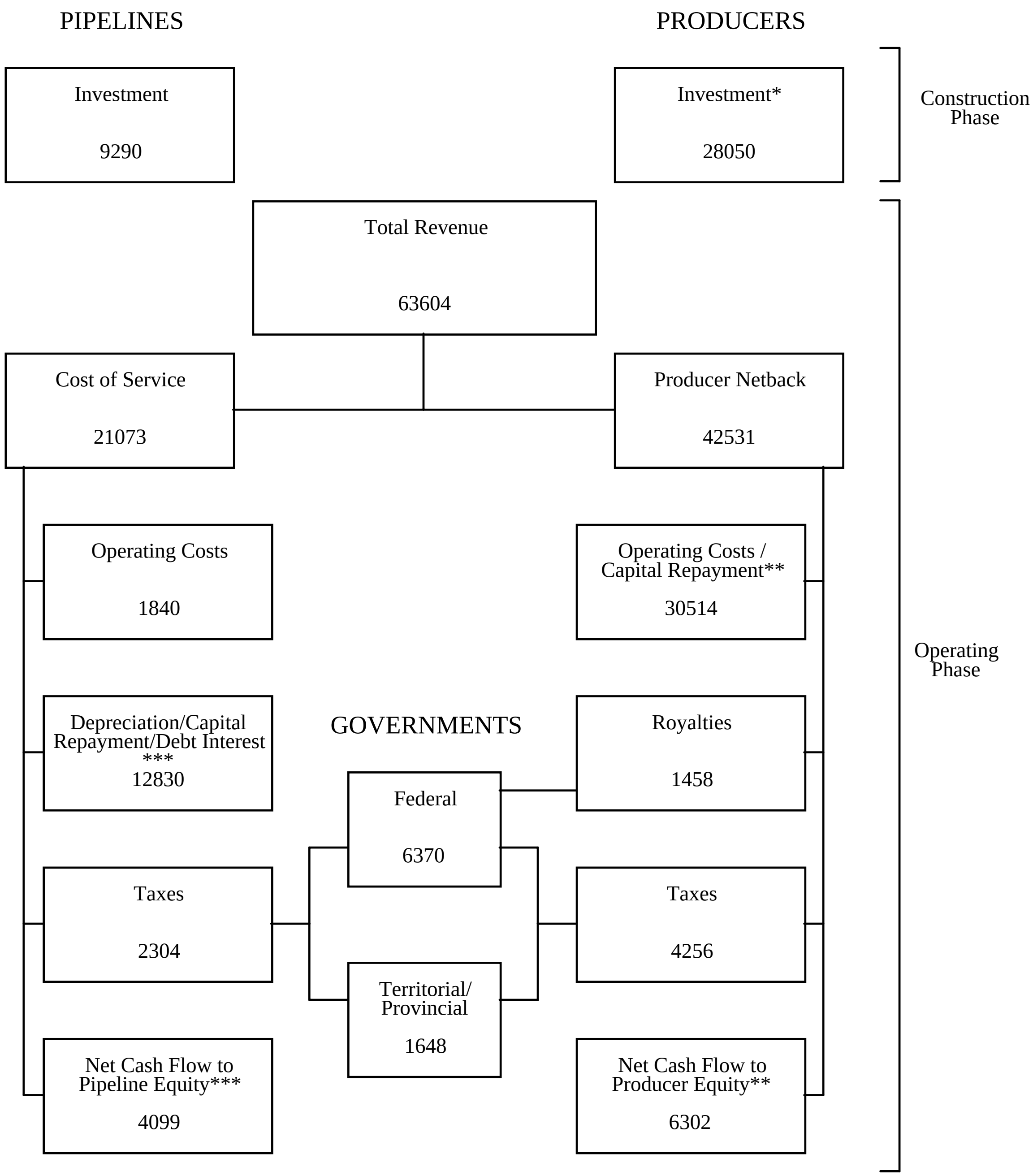
*** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.5

CASH FLOWS : CASE 3-6 (1.2 BCF/D TO 2040, $6US GAS), 2002-2040

(millions of 2007 Canadian dollars)



* includes exploration expenditure (7538)

** assumes 100% equity financing

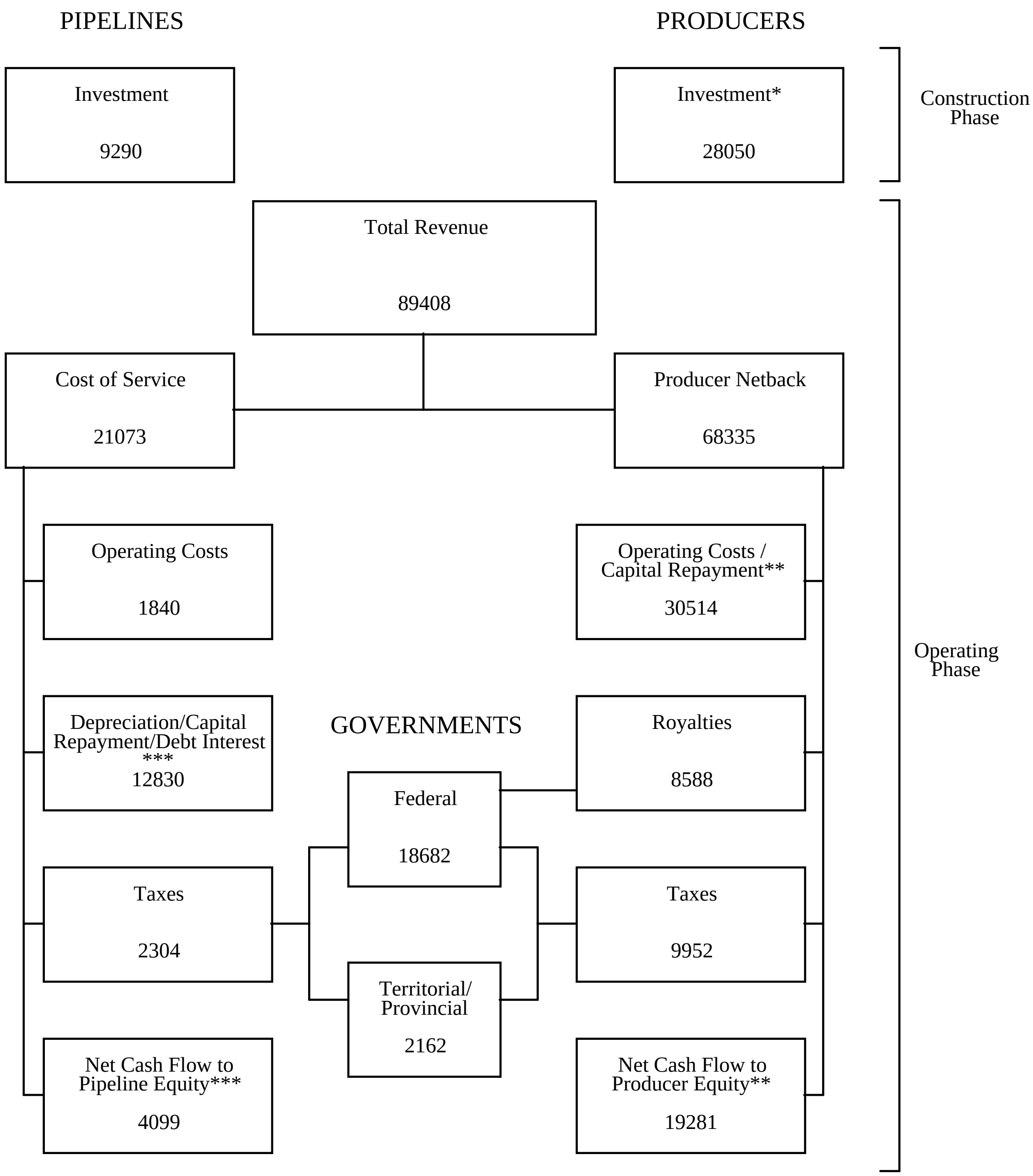
*** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.6

CASH FLOWS : CASE 3-8 (1.2 BCF/D TO 2040, $8US GAS), 2002-2040

(millions of 2007 Canadian dollars)



* includes exploration expenditure (7538)

** assumes 100% equity financing

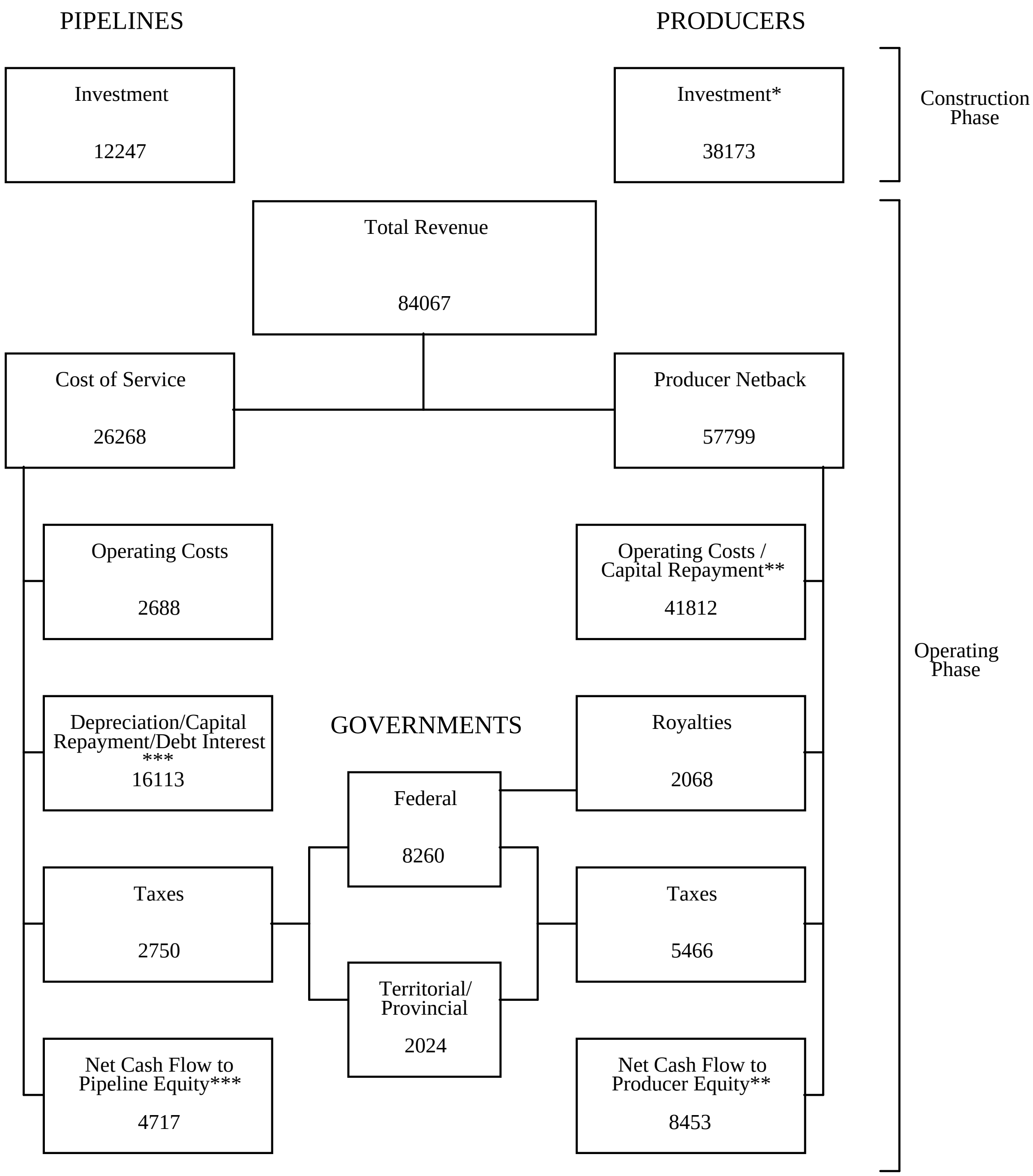
*** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.7

CASH FLOWS : CASE 4-6 (1.2 BCF/D TO 2023, 1.8 BCF/D 2024-2040, $6US GAS), 2002-2040

(millions of 2007 Canadian dollars)



* includes exploration expenditure (11459)

** assumes 100% equity financing

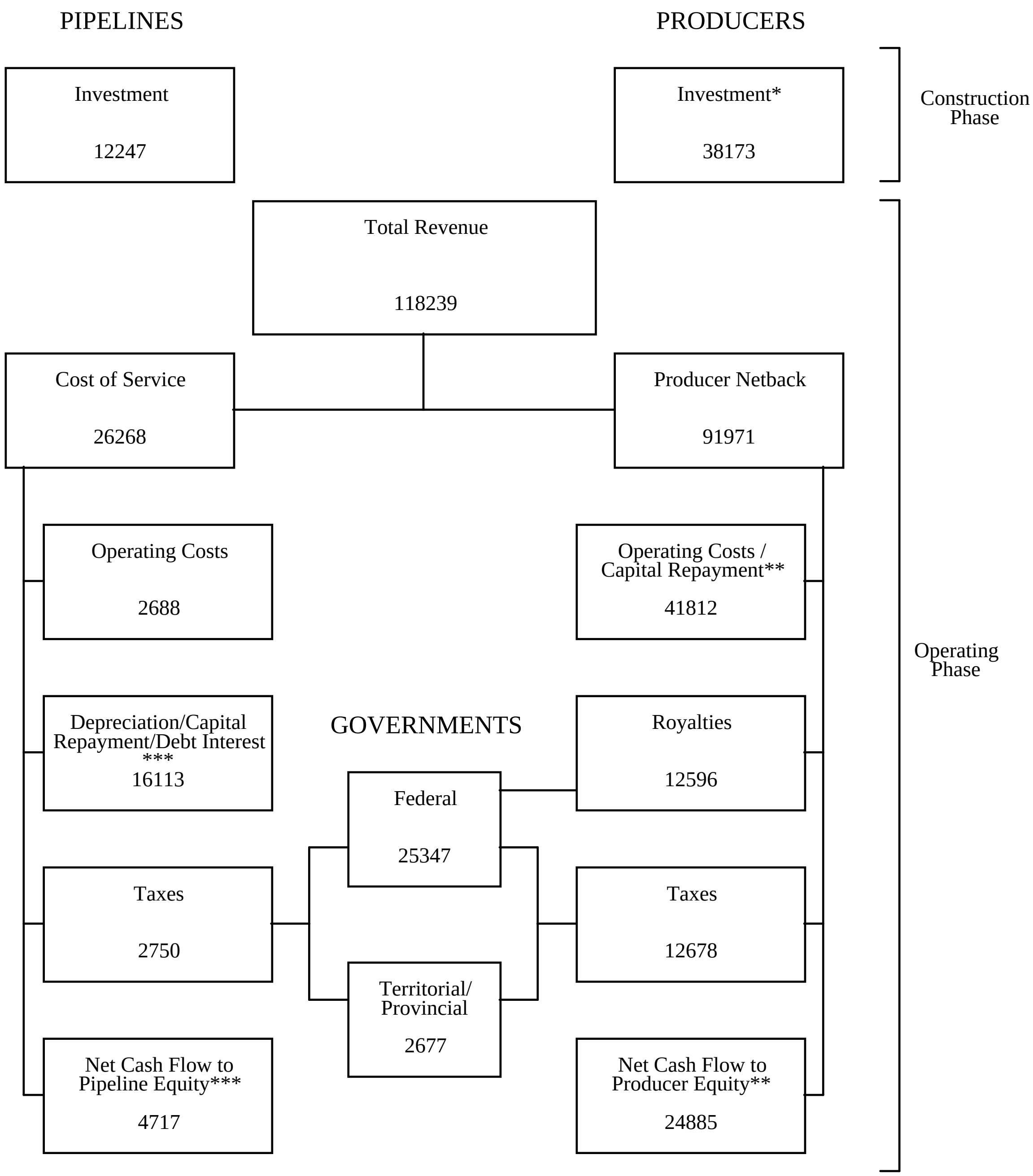
*** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.8

CASH FLOWS : CASE 4-8 (1.2 BCF/D TO 2023, 1.8 BCF/D 2024-2040, $8US GAS), 2002-2040

(millions of 2007 Canadian dollars)



* includes exploration expenditure (11459)

** assumes 100% equity financing

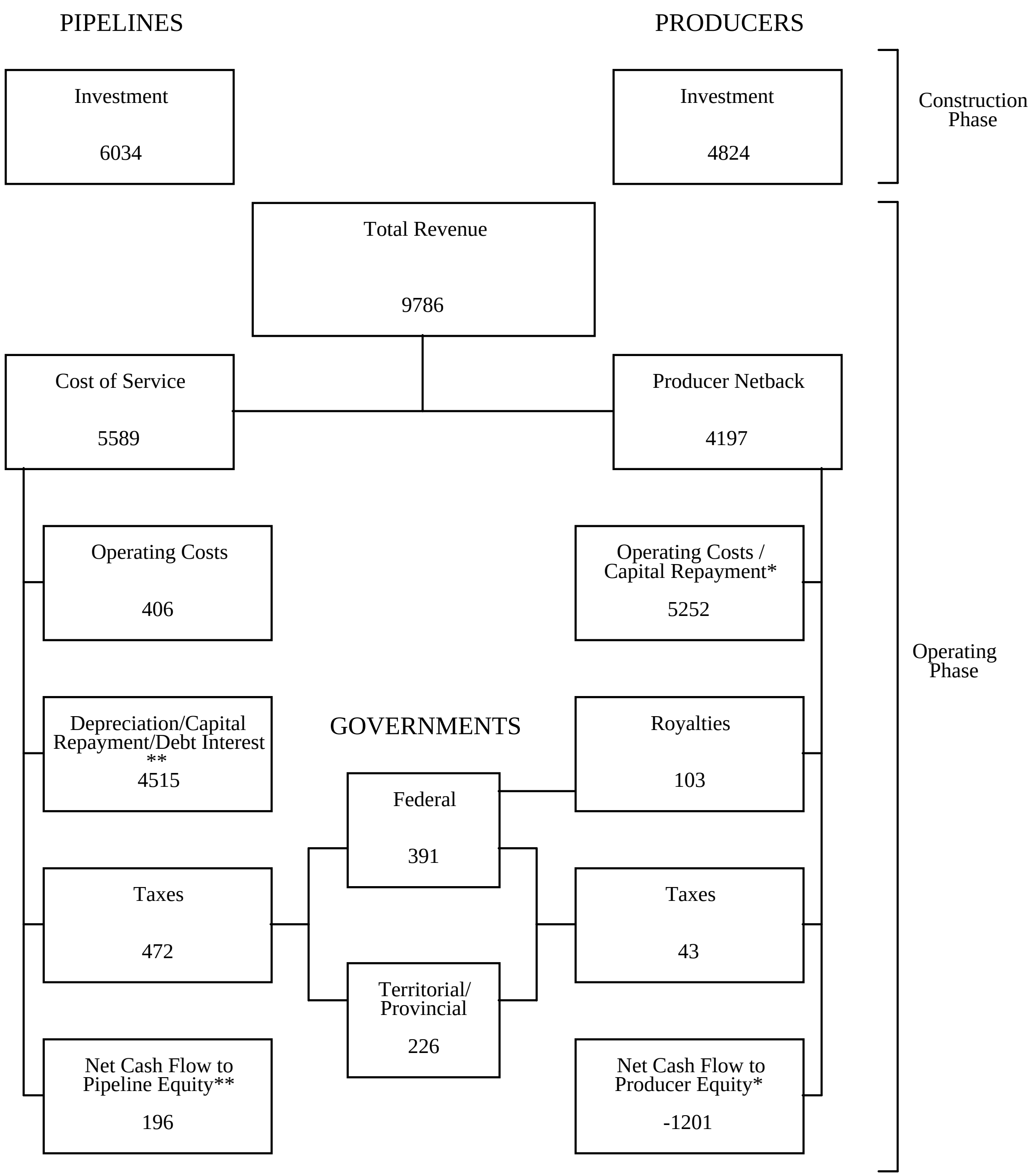
*** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.9

PRESENT VALUES OF CASH FLOWS : CASE 1-6
(ANCHOR FIELDS ONLY, $6US GAS), 2002-2035

(millions of 2007 Canadian dollars discounted at 8% to mid-2007)



* assumes 100% equity financing

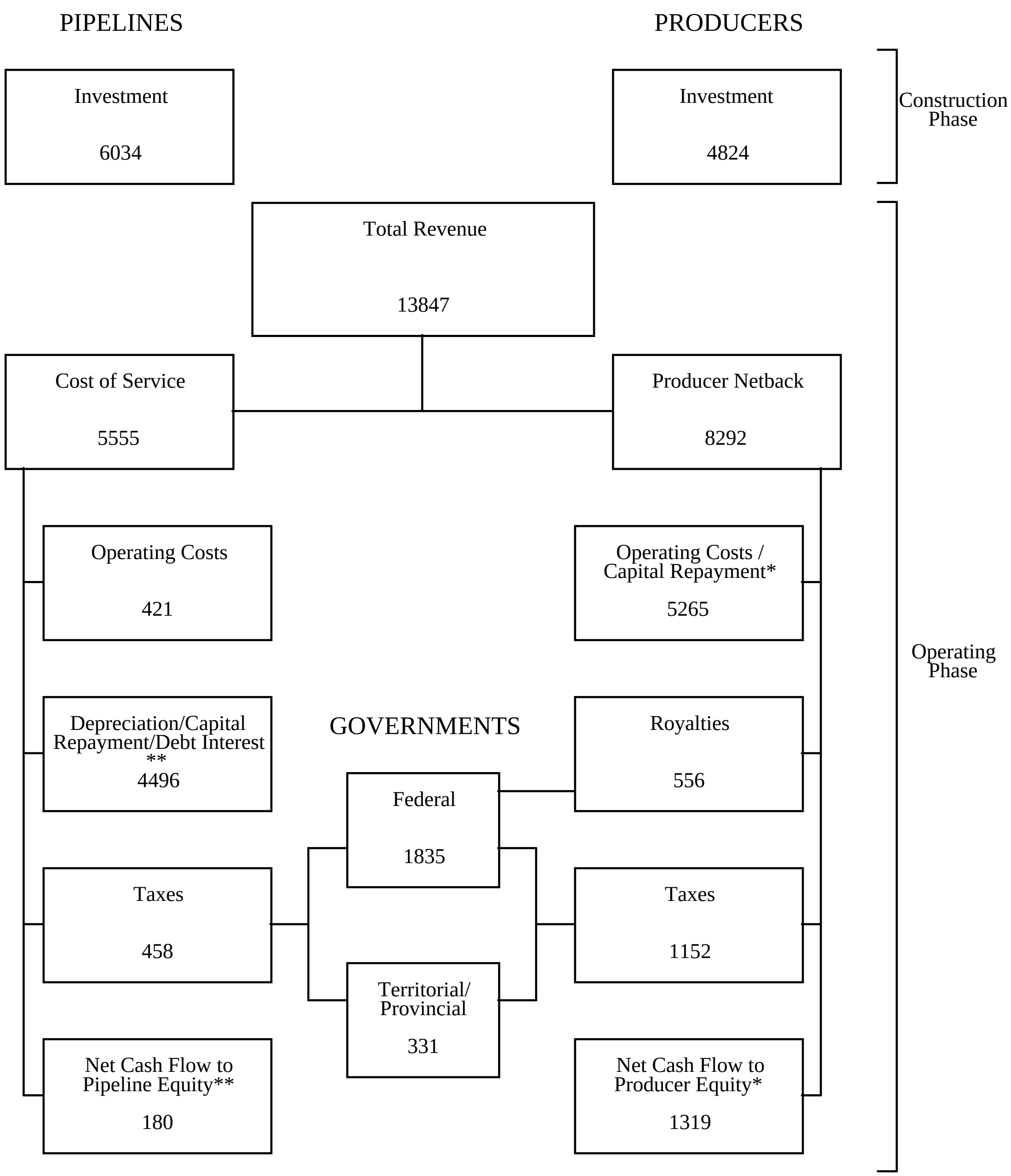
** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.10

PRESENT VALUES OF CASH FLOWS : CASE 1-8
(ANCHOR FIELDS ONLY, $8US GAS), 2002-2037

(millions of 2007 Canadian dollars discounted at 8% to mid-2007)



* assumes 100% equity financing

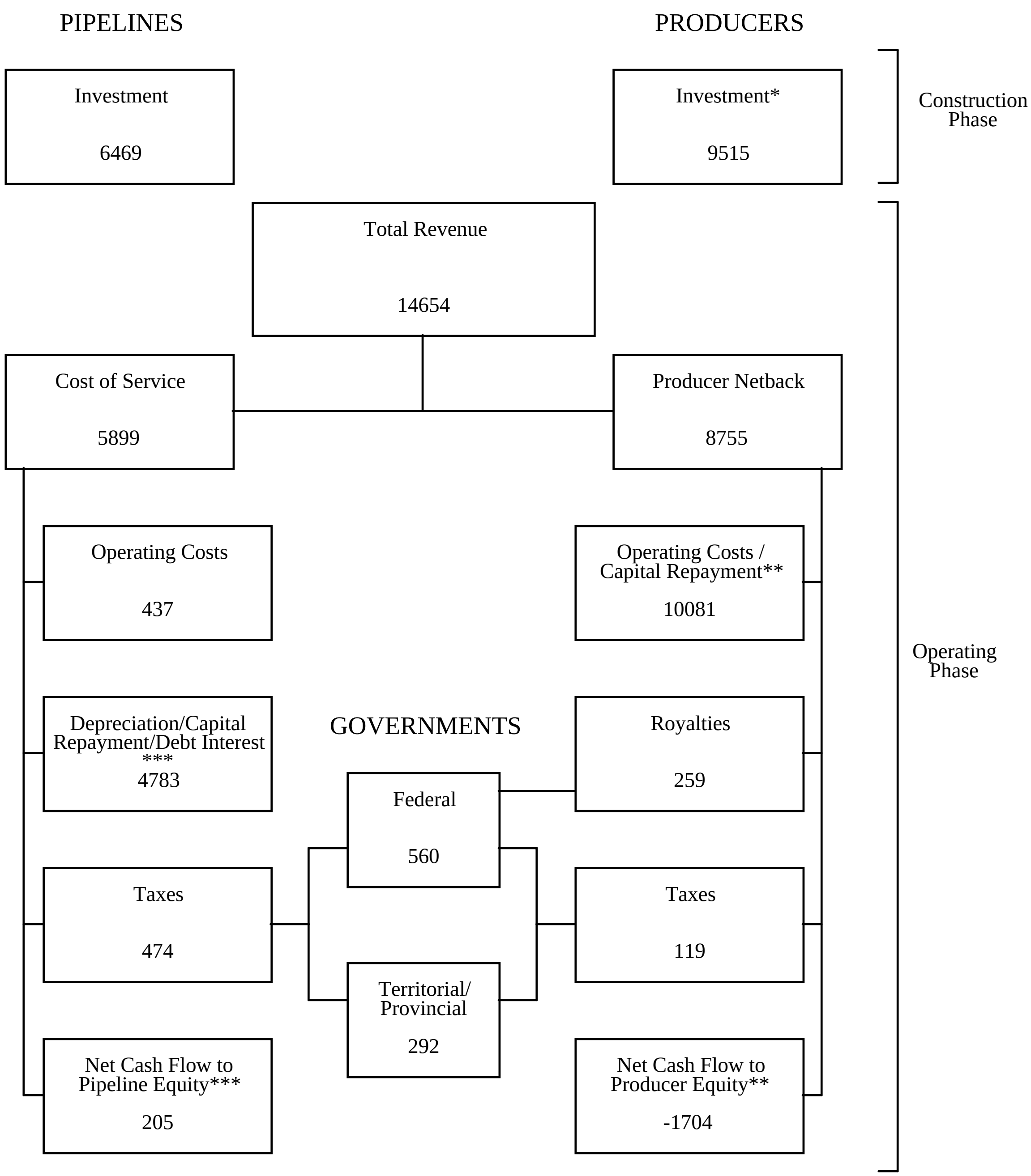
** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.11

PRESENT VALUES OF CASH FLOWS : CASE 2-6
(1.2 BCF/D TO 2028, $6US GAS), 2002-2040

(millions of 2007 Canadian dollars discounted at 8% to mid-2007)



* includes exploration expenditure (2172)

** assumes 100% equity financing

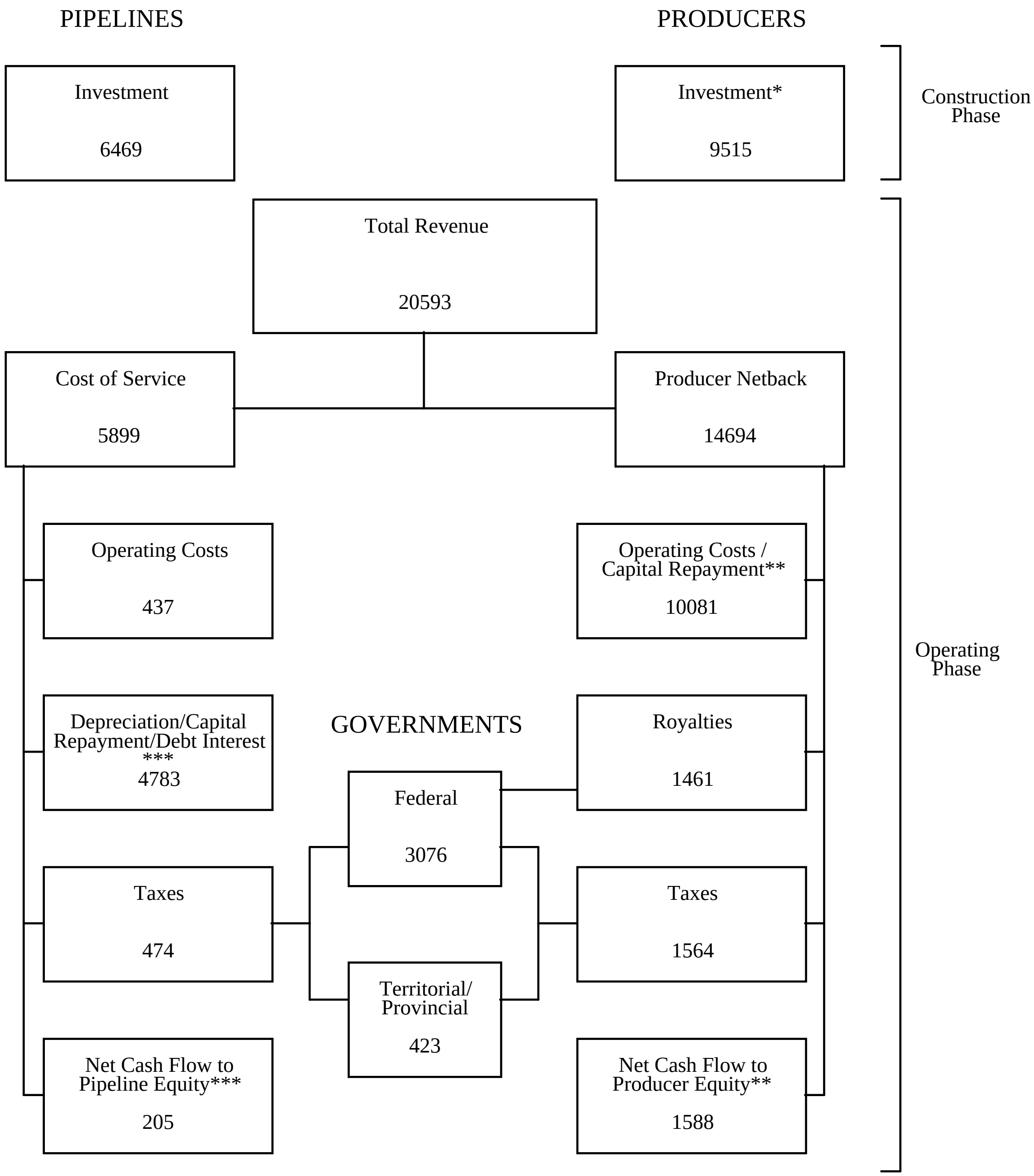
*** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.12

PRESENT VALUES OF CASH FLOWS : CASE 2-8
(1.2 BCF/D TO 2028 $8US GAS), 2002-2040

(millions of 2007 Canadian dollars discounted at 8% to mid-2007)



* includes exploration expenditure (2172)

** assumes 100% equity financing

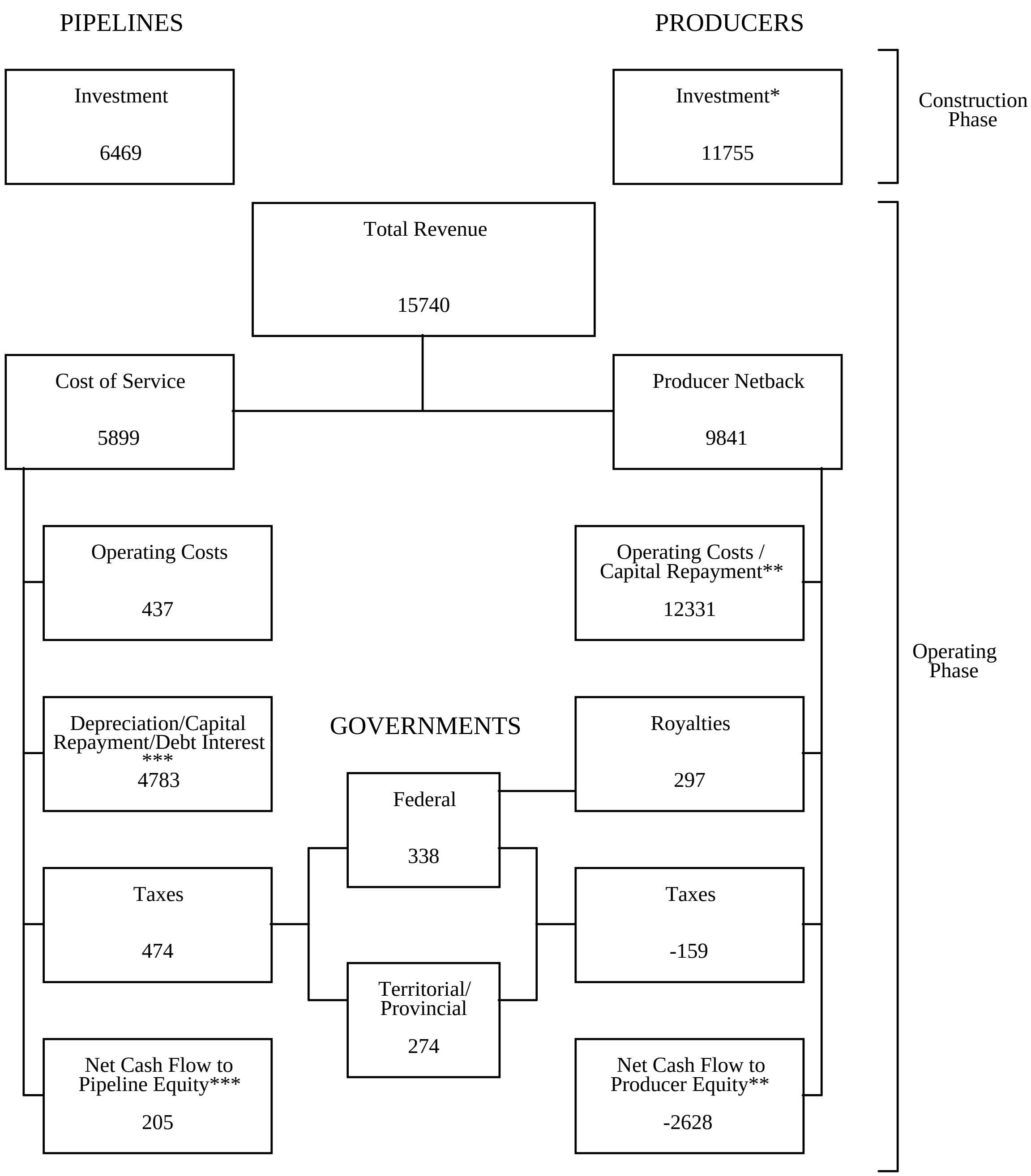
*** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.13

PRESENT VALUES OF CASH FLOWS : CASE 3-6
(1.2 BCF/D TO 2040, $6US GAS), 2002-2040

(millions of 2007 Canadian dollars discounted at 8% to mid-2007)



* includes exploration expenditure (3477)

** assumes 100% equity financing

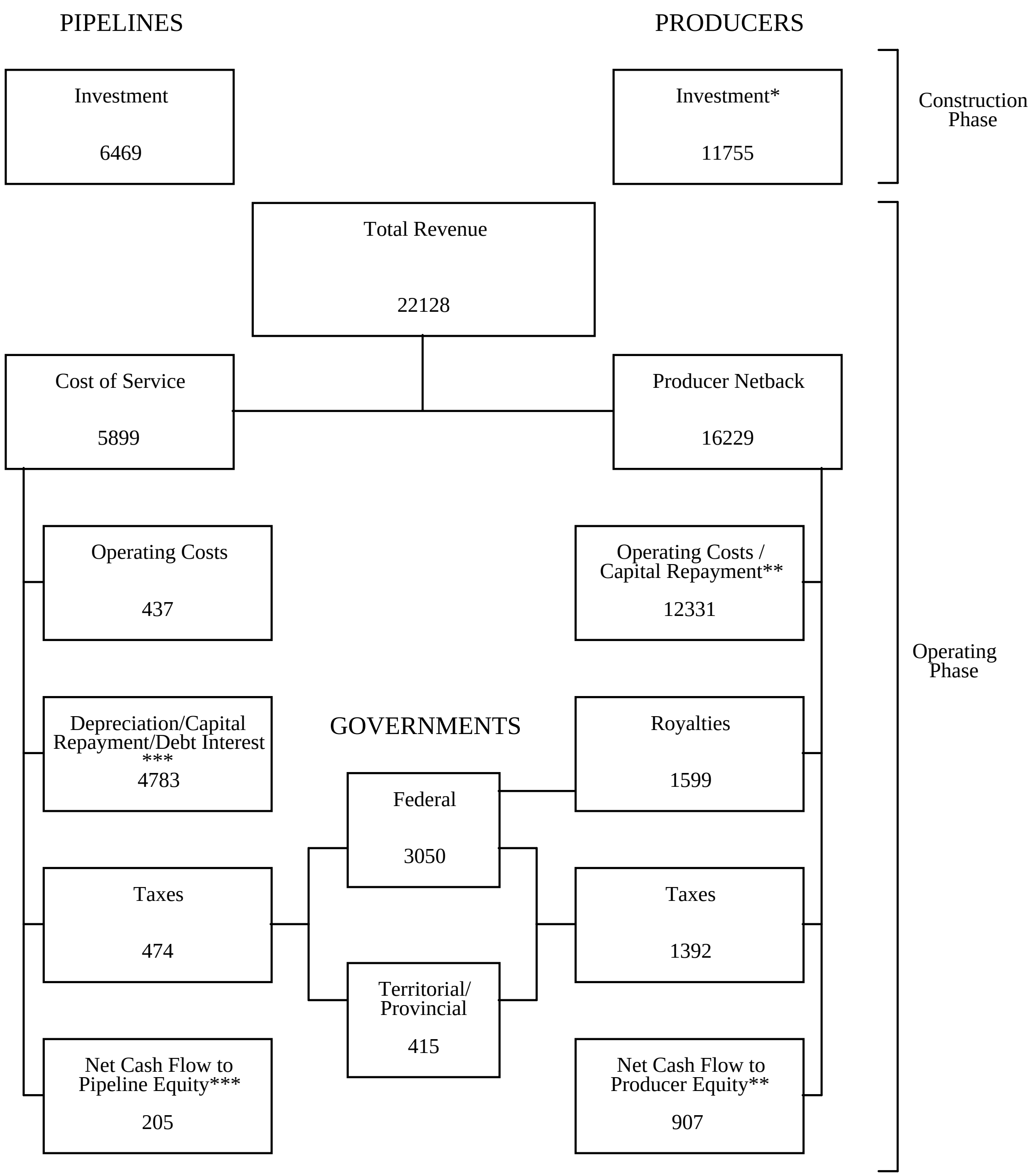
*** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.14

PRESENT VALUES OF CASH FLOWS : CASE 3-8
(1.2 BCF/D TO 2040, $8US GAS), 2002-2040

(millions of 2007 Canadian dollars discounted at 8% to mid-2007)



* includes exploration expenditure (3477)

** assumes 100% equity financing

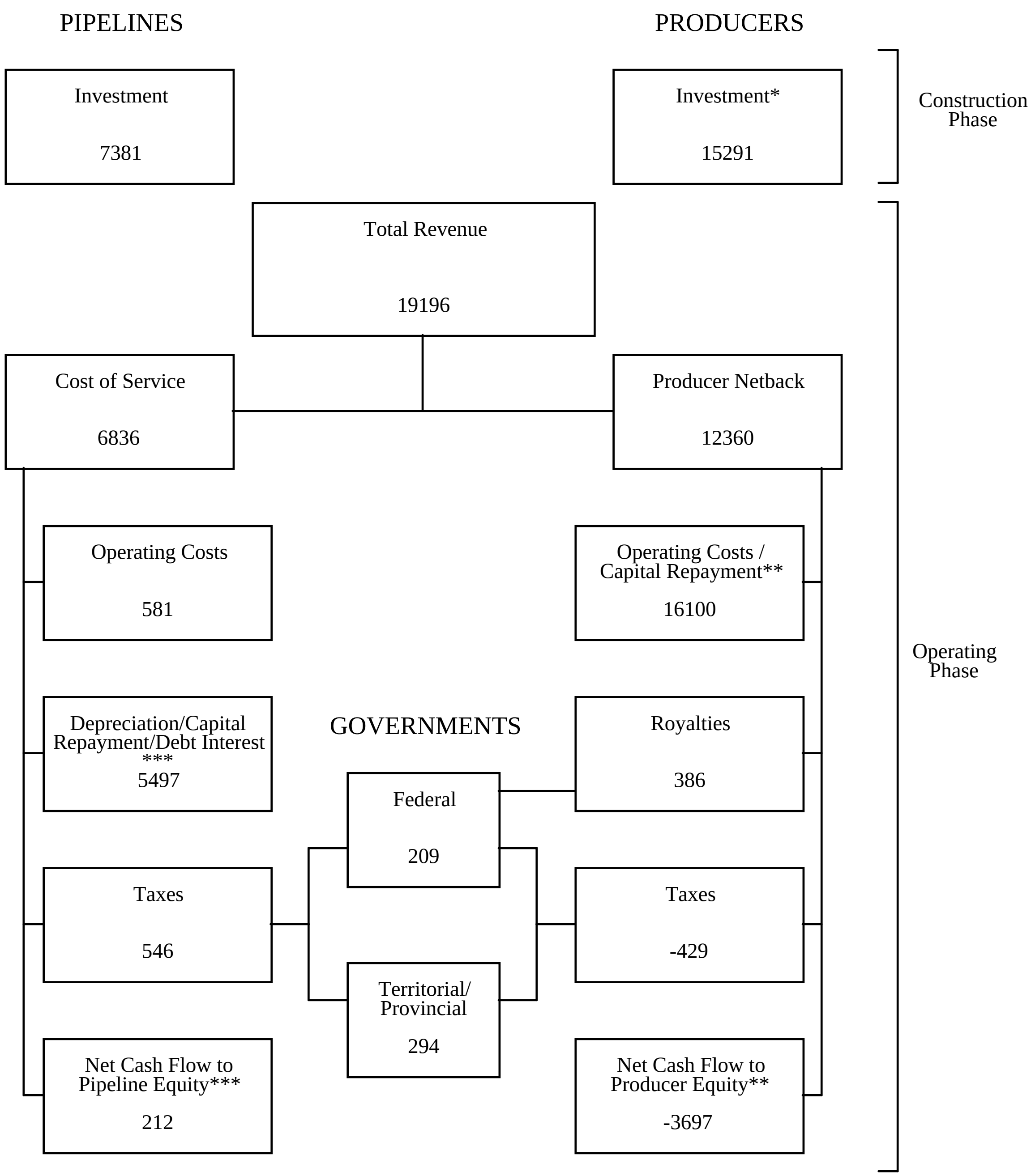
*** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.15

PRESENT VALUES OF CASH FLOWS : CASE 4-6
(1.2 BCF/D TO 2023, 1.8 BCF/D 2024-2040, $6US GAS) 2002-2040

(millions of 2007 Canadian dollars discounted at 8% to mid-2007)



* includes exploration expenditure (5181)

** assumes 100% equity financing

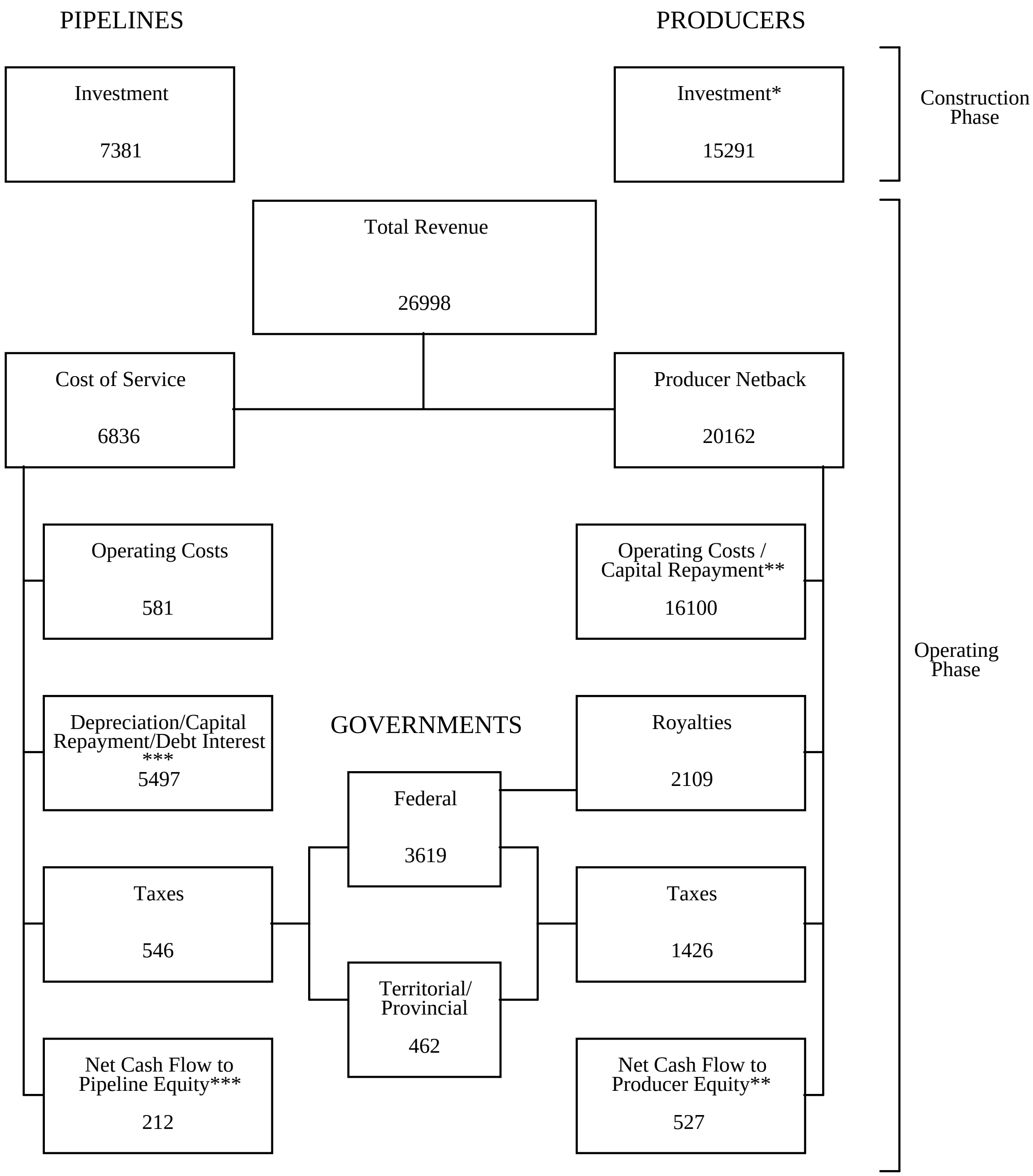
*** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

FIGURE A.16

PRESENT VALUES OF CASH FLOWS : CASE 4-8
(1.2 BCF/D TO 2023, 1.8 BCF/D 2024-2040, $8US GAS) 2002-2040

(millions of 2007 Canadian dollars discounted at 8% to mid-2007)



* includes exploration expenditure (5181)

** assumes 100% equity financing

*** assumes 70% debt / 30% equity financing

Note: for NGL line assumed financing is 65% debt / 35% equity, vs. the 70/30 split for the gas pipeline

TABLE A.1 - ANNUAL GAS AND LIQUIDS PRODUCTION BY CASE : 2015-2040

	Gas Production in Bcf					Liquids Production in Thousand Barrels				
	Case 1-6	**Case 1-8**	**Case 2**	**Case 3**	**Case 4**	**Case 1-6**	**Case 1-8**	**Case 2**	**Case 3**	**Case 4**
2015	291	291	383	383	383	3803	3803	4625	4625	4625
2016	302	302	437	437	437	3605	3605	4820	4820	4820
2017	302	302	437	437	437	3477	3477	4692	4692	4692
2018	300	300	435	435	435	3539	3539	4754	4754	4754
2019	300	300	435	435	435	3367	3367	4583	4583	4583
2020	299	299	435	435	435	3557	3557	4772	4772	4772
2021	299	299	405	405	405	3181	3181	4134	4134	4134
2022	299	299	434	434	534	2929	2929	4144	4144	5041
2023	299	299	409	409	509	2757	2757	3746	3746	4650
2024	299	299	445	445	641	2604	2604	3921	3921	5679
2025	299	299	433	433	629	2458	2458	3664	3664	5428
2026	299	299	423	423	619	2301	2301	3420	3420	5185
2027	297	297	414	414	610	2118	2118	3173	3173	4938
2028	275	275	434	434	654	1830	1830	3263	3263	5241
2029	254	254	397	397	615	1609	1609	2893	2893	4859
2030	230	230	372	372	591	1427	1427	2712	2712	4677
2031	205	205	343	435	645	1285	1285	2533	3081	4971
2032	170	170	308	418	626	1062	1062	2304	2961	4838
2033	141	141	275	384	585	880	880	2085	2742	4546
2034	114	114	246	356	553	712	712	1904	2561	4338
2035	90	90	221	403	597	573	573	1746	2841	4587
2036		75	204	441	632		475	1634	3058	4777
2037		62	183	421	601		398	1488	2912	4535
2038			168	405	576			1373	2797	4334
2039			143	380	528			1224	2648	3978

TABLE A.2 - DISTRIBUTION OF INVESTMENT BY SECTOR AND YEAR : 2002-2040

(millions of 2007 Cdn$)

	Case 1 Pipelines	Case 1 Producers	Case 1 Total	Case 2/3 Pipelines	Case 2 Producers	Case 2 Total	Case 3 Producers	Case 3 Total	Case 4 Pipelines	Case 4 Producers	Case 4 Total
2002	35	8	44	35	8	44	8	44	35	8	44
2003	79	19	98	79	19	98	19	98	79	19	98
2004	115	34	149	115	136	251	136	251	115	136	251
2005	99	34	133	99	116	215	116	215	99	116	215
2006	100	36	136	100	77	177	77	177	100	77	177
2007	111	106	217	111	157	268	157	268	111	157	268
2008	115	80	195	115	158	273	158	273	115	199	315
2009	429	239	668	429	342	771	342	771	429	398	827
2010	782	588	1370	782	718	1499	718	1499	782	787	1569
2011	1311	1273	2584	1311	1579	2890	1624	2935	1311	1771	3082
2012	1808	1548	3355	1808	2335	4142	2389	4197	1808	2545	4353
2013	1570	1349	2919	1570	2474	4044	2513	4083	1570	2669	4239
2014	1753	651	2405	1753	1236	2989	1263	3016	1753	1420	3174
2015	179	89	268	983	477	1461	627	1610	983	859	1842
2016		0	0		576	576	797	797		1076	1076
2017		326	326		715	715	937	937		1215	1215
2018		64	64		414	414	635	635		1030	1030
2019		311	311		726	726	948	948		1480	1480
2020		103	103		851	851	1073	1073		2298	2298
2021		70	70		757	757	979	979	510	2070	2580
2022		47	47		856	856	1171	1171	1020	2685	3705
2023		236	236		634	634	1150	1150	1427	2237	3664
2024		23	23		288	288	717	717		1395	1395
2025		324	324		570	570	974	974		1504	1504
2026		23	23		421	421	745	745		1063	1063
2027		31	31		387	387	1002	1002		1421	1421
2028					209	209	555	555		660	660
2029					209	209	775	775		1005	1005
2030							461	461		461	461
2031							649	649		649	649
2032					84	84	670	670		846	846
2033					84	84	880	880		921	921
2034					84	84	649	649		817	817
2035							482	482		482	482
2036							398	398		398	398
2037							314	314		314	314
2038					84	84	377	377		419	419
2039							251	251		251	251
2040							314	314		314	314
TOTAL	8486	7611	16097	9290	17781	27071	28050	37340	12247	38173	50421

TABLE A.3 - DISTRIBUTION OF DIRECT GOVERNMENT REVENUES : 2015-2040*

(millions of 2007 Cdn$)

	$6 US GAS PRICE				$8 US GAS PRICE			
CASE 1	**Prop. Tax**	**Inc. Tax**	**Royalties**	**Total**	**Prop. Tax**	**Inc. Tax**	**Royalties**	**Total**
Federal		1904	398	2302		4075	2447	6522
Alberta	55	44		99	60	48		108
NWT	621	1088		1709	680	2397		3077
-Grant Red.		827		827		1822		1822
Adj.NWT	621	261		882	680	575		1255
Adj. Federal		2731	398	3129		5897	2447	8344
Total	676	3036	398	4110	740	6520	2447	9707
CASE 2	**Prop. Tax**	**Inc. Tax**	**Royalties**	**Total**	**Prop. Tax**	**Inc. Tax**	**Royalties**	**Total**
Federal		3277	1089	4366		6218	7182	13400
Alberta	68	55		123	68	55		123
NWT	973	1906		2879	973	3686		4659
-Grant Red.		1449		1449		2801		2801
Adj.NWT	973	457		1430	973	885		1858
Adj. Federal		4726	1089	5815		9019	7182	16201
Total	1041	5238	1089	7368	1041	9959	7182	18182
CASE 3	**Prop. Tax**	**Inc. Tax**	**Royalties**	**Total**	**Prop. Tax**	**Inc. Tax**	**Royalties**	**Total**
Federal		3405	1458	4863		6953	8588	15541
Alberta	68	55		123	68	55		123
NWT	1048	1984		3032	1048	4131		5179
-Grant Red.		1508		1508		3140		3140
Adj.NWT	1048	476		1524	1048	991		2039
Adj. Federal		4913	1458	6371		10093	8588	18681
Total	1116	5444	1458	8018	1116	11139	8588	20843
CASE 4	**Prop. Tax**	**Inc. Tax**	**Royalties**	**Total**	**Prop. Tax**	**Inc. Tax**	**Royalties**	**Total**
Federal		4286	2068	6354		8779	12596	21375
Alberta	78	62		140	78	62		140
NWT	1281	2507		3788	1281	5226		6507
-Grant Red.		1905		1905		3972		3972
Adj.NWT	1281	602		1883	1281	1254		2535
Adj. Federal		6191	2068	8259		12751	12596	25347
Total	1359	6855	2068	10282	1359	14067	12596	28022

* Personal income taxes on direct labour income not included

TABLE A.4 - DIRECT EMPLOYMENT BY CATEGORY AND REGION

(millions of 2007 Cdn$)

	$6 US GAS PRICE			$8 US GAS PRICE		
CASE 1	**NWT**	**Alberta**	**Total**	**NWT**	**Alberta**	**Total**
Pipeline Construction	6648	195	6843	6648	195	6843
Pipeline Operation	1037	601	1638	1136	658	1794
Pipeline Total	7685	796	8481	7784	853	8637
Field Development	5866		5866	5866		5866
Producer Operation	1752	726	2478	1919	795	2714
Producer Total	7618	726	8344	7785	795	8580
Total Construction	12514	195	12709	12514	195	12709
Total Operation	2789	1327	4116	3055	1453	4508
Total	15303	1522	16825	15569	1648	17217
CASE 2	**NWT**	**Alberta**	**Total**	**NWT**	**Alberta**	**Total**
Pipeline Construction	7240	195	7435	7240	195	7435
Pipeline Operation	1284	744	2028	1284	744	2028
Pipeline Total	8524	939	9463	8524	939	9463
Field Development	11776		11776	11776		11776
Producer Operation	3143	1225	4368	3143	1225	4368
Producer Total	14919	1225	16144	14919	1225	16144
Total Construction	19016	195	19211	19016	195	19211
Total Operation	4427	1969	6396	4427	1969	6396
Total	23443	2164	25607	23443	2164	25607
CASE 3	**NWT**	**Alberta**	**Total**	**NWT**	**Alberta**	**Total**
Pipeline Construction	7240	195	7435	7240	195	7435
Pipeline Operation	1284	744	2028	1284	744	2028
Pipeline Total	8524	939	9463	8524	939	9463
Field Development	17744		17744	17744		17744
Producer Operation	3475	1335	4810	3475	1335	4810
Producer Total	21219	1335	22554	21219	1335	22554
Total Construction	24984	195	25179	24984	195	25179
Total Operation	4759	2079	6838	4759	2079	6838
Total	29743	2274	32017	29743	2274	32017
CASE 4	**NWT**	**Alberta**	**Total**	**NWT**	**Alberta**	**Total**
Pipeline Construction	9378	232	9610	9378	232	9610
Pipeline Operation	1518	744	2262	1518	744	2262
Pipeline Total	10896	976	11872	10896	976	11872
Field Development	23570		23570	23570		23570
Producer Operation	4377	1640	6017	4377	1640	6017
Producer Total	27947	1640	29587	27947	1640	29587
Total Construction	32948	232	33180	32948	232	33180
Total Operation	5895	2384	8279	5895	2384	8279
Total	38843	2616	41459	38843	2616	41459

TABLE A.5 - PIPELINE OPERATIONS IMPACTS - $6US GAS PRICE : 2015-2040

(millions of 2007 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	17187		919					18106
Gross Domestic Product	16364	110	960	25	288	45	17	17810
Labour Income	528	79	133	17	190	29	10	986
Federal Government Revenue	1067	19	118	4	51	6	3	1267
Terr./Prov. Government Revenue	854	9	115	2	31	7	1	1020
Grant Reduction	476	0	0	0	0	0	0	476
Adjusted Terr./Prov. Gov. Rev.	379	9	115	2	31	7	1	543
Adjusted Federal Gov. Rev.	1543	19	118	4	51	6	3	1743
Total Government Revenue	1921	28	233	6	82	13	4	2287
Employment	5427	1698	2195	355	3229	574	198	13676

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	19929		1138					21066
Gross Domestic Product	19057	118	1175	26	308	48	18	20751
Labour Income	585	84	154	18	203	31	10	1085
Federal Government Revenue	1208	20	142	4	55	6	3	1438
Terr./Prov. Government Revenue	1025	10	140	2	33	8	2	1219
Grant Reduction	540	0	0	0	0	0	0	541
Adjusted Terr./Prov. Gov. Rev.	485	10	140	2	33	8	2	678
Adjusted Federal Gov. Rev.	1748	20	142	4	55	6	3	1979
Total Government Revenue	2233	30	282	6	87	14	4	2657
Employment	5968	1812	2445	379	3446	613	212	14874

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	19936		1138					21073
Gross Domestic Product	19060	118	1175	27	309	49	19	20757
Labour Income	587	85	154	18	204	31	10	1088
Federal Government Revenue	1209	20	143	4	55	6	3	1441
Terr./Prov. Government Revenue	1025	10	140	2	33	8	2	1219
Grant Reduction	540	0	0	0	0	0	0	541
Adjusted Terr./Prov. Gov. Rev.	485	10	140	2	33	8	2	679
Adjusted Federal Gov. Rev.	1749	20	143	4	55	6	3	1981
Total Government Revenue	2234	30	283	6	88	14	4	2660
Employment	5988	1820	2452	380	3460	616	212	14929

CASE 4	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	24973		1295					26268
Gross Domestic Product	23898	143	1358	32	373	59	22	25885
Labour Income	705	102	169	21	246	37	13	1293
Federal Government Revenue	1441	24	161	5	66	8	3	1709
Terr./Prov. Government Revenue	1239	12	159	3	40	9	2	1464
Grant Reduction	645	0	0	1	0	0	0	646
Adjusted Terr./Prov. Gov. Rev.	594	12	159	2	40	9	2	818
Adjusted Federal Gov. Rev.	2086	24	161	5	66	8	3	2355
Total Government Revenue	2680	36	321	8	106	17	5	3172
Employment	7200	2198	2807	459	4179	743	257	17844

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.6 - PIPELINE OPERATIONS IMPACTS - $8US GAS PRICE : 2015-2040

(millions of 2007 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	17738		1006					18745
Gross Domestic Product	16865	117	1049	26	306	48	18	18430
Labour Income	566	84	144	18	202	31	10	1054
Federal Government Revenue	1094	20	128	4	55	6	3	1309
Terr./Prov. Government Revenue	892	10	125	2	32	8	2	1071
Grant Reduction	488	0	0	0	0	0	0	488
Adjusted Terr./Prov. Gov. Rev.	404	10	125	2	32	8	2	582
Adjusted Federal Gov. Rev.	1581	20	128	4	55	6	3	1798
Total Government Revenue	1986	30	253	6	87	14	4	2380
Employment	5800	1804	2352	377	3431	610	211	14585

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	19929		1138					21066
Gross Domestic Product	19057	118	1175	26	308	48	18	20751
Labour Income	585	84	154	18	203	31	10	1085
Federal Government Revenue	1208	20	142	4	55	6	3	1438
Terr./Prov. Government Revenue	1025	10	140	2	33	8	2	1219
Grant Reduction	540	0	0	0	0	0	0	541
Adjusted Terr./Prov. Government Re	485	10	140	2	33	8	2	678
Adjusted Federal Government Reve	1748	20	142	4	55	6	3	1979
Total Government Revenue	2233	30	282	6	87	14	4	2657
Employment	5968	1812	2445	379	3446	613	212	14874

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	19936		1138					21073
Gross Domestic Product	19060	118	1175	27	309	49	19	20757
Labour Income	587	85	154	18	204	31	10	1088
Federal Government Revenue	1209	20	143	4	55	6	3	1441
Terr./Prov. Government Revenue	1025	10	140	2	33	8	2	1219
Grant Reduction	540	0	0	0	0	0	0	541
Adjusted Terr./Prov. Gov. Rev.	485	10	140	2	33	8	2	679
Adjusted Federal Gov. Rev.	1749	20	143	4	55	6	3	1981
Total Government Revenue	2234	30	283	6	88	14	4	2660
Employment	5988	1820	2452	380	3460	616	212	14929

CASE 4	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	24973		1295					26268
Gross Domestic Product	23898	143	1358	32	373	59	22	25885
Labour Income	705	102	169	21	246	37	13	1293
Federal Government Revenue	1441	24	161	5	66	8	3	1709
Terr./Prov. Government Revenue	1239	12	159	3	40	9	2	1464
Grant Reduction	645	0	0	1	0	0	0	646
Adjusted Terr./Prov. Gov. Rev.	594	12	159	2	40	9	2	818
Adjusted Federal Gov. Rev.	2086	24	161	5	66	8	3	2355
Total Government Revenue	2680	36	321	8	106	17	5	3172
Employment	7200	2198	2807	459	4179	743	257	17844

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.7 - PRODUCER OPERATIONS IMPACTS - $6US GAS PRICE : 2015-2040

(millions of 2007 Cdn$, employment in person years)

CASE 1	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Direct Output	14178							14178
Gross Domestic Product	13199	54	204	12	358	74	7	13907
Labour Income	478	40	159	8	246	49	3	983
Federal Government Revenue	1332	9	37	2	65	10	1	1457
Terr./Prov. Government Revenue	932	4	16	1	39	14	1	1006
Grant Reduction	426	0	0	0	0	0	0	426
Adjusted Terr./Prov. Gov. Rev.	506	4	16	1	39	14	1	580
Adjusted Federal Gov. Rev.	1758	9	37	2	65	10	1	1883
Total Government Revenue	2264	14	53	3	104	24	2	2463
Employment	4064	831	1895	151	3674	853	71	11538

CASE 2	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Direct Output	32305							32305
Gross Domestic Product	30820	81	322	19	537	111	10	31899
Labour Income	778	60	255	11	369	74	5	1552
Federal Government Revenue	3297	14	163	3	98	15	2	3591
Terr./Prov. Government Revenue	1956	7	80	2	59	21	1	2124
Grant Reduction	1009	0	0	0	0	0	0	1009
Adjusted Terr./Prov. Gov. Rev.	947	7	80	1	59	21	1	1115
Adjusted Federal Gov. Rev.	4306	14	163	3	98	15	2	4600
Total Government Revenue	5252	21	242	4	157	36	2	5715
Employment	6612	1247	2979	227	5513	1279	107	17965

CASE 3	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Direct Output	42531							42531
Gross Domestic Product	40997	83	339	19	552	114	10	42114
Labour Income	828	61	270	12	379	76	5	1632
Federal Government Revenue	3803	14	166	3	101	16	2	4104
Terr./Prov. Government Revenue	2113	7	81	2	60	21	1	2284
Grant Reduction	1071	0	0	0	0	0	0	1072
Adjusted Terr./Prov. Gov. Rev.	1041	7	81	1	60	21	1	1213
Adjusted Federal Gov. Rev.	4874	14	166	3	101	16	2	5175
Total Government Revenue	5915	21	247	4	161	37	2	6388
Employment	7038	1281	3136	233	5662	1314	110	18775

CASE 4	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Direct Output	57799							57799
Gross Domestic Product	55478	128	476	29	852	176	16	57155
Labour Income	1162	95	369	18	585	118	8	2355
Federal Government Revenue	5128	22	190	4	155	24	2	5525
Terr./Prov. Government Revenue	2691	11	92	3	93	33	1	2923
Grant Reduction	1397	0	0	0	0	0	0	1398
Adjusted Terr./Prov. Gov. Rev.	1294	11	92	2	93	33	1	1525
Adjusted Federal Gov. Rev.	6525	22	190	5	155	24	2	6923
Total Government Revenue	7819	33	282	7	248	57	4	8449
Employment	9880	1978	4422	360	8745	2029	170	27585

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.8 - PRODUCER OPERATIONS IMPACTS - $8US GAS PRICE : 2015-2040

(millions of 2007 Cdn$, employment in person years)

CASE 1	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Direct Output	27700							27700
Gross Domestic Product	26639	58	222	13	388	80	7	27408
Labour Income	520	43	174	8	266	54	4	1068
Federal Government Revenue	5532	10	40	2	71	11	1	5666
Terr./Prov. Government Revenue	2268	5	17	1	42	15	1	2349
Grant Reduction	1415	0	0	0	0	0	0	1415
Adjusted Terr./Prov. Gov. Rev.	853	5	17	1	42	15	1	934
Adjusted Federal Gov. Rev.	6946	10	40	2	71	11	1	7081
Total Government Revenue	7800	15	57	3	113	26	2	8016
Employment	4421	900	2060	164	3977	923	77	12521

CASE 2	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Direct Output	53879							53879
Gross Domestic Product	52394	81	322	19	537	111	10	53473
Labour Income	778	60	255	11	369	74	5	1552
Federal Government Revenue	12331	14	163	3	98	15	2	12625
Terr./Prov. Government Revenue	3736	7	80	2	59	21	1	3904
Grant Reduction	2362	0	0	0	0	0	0	2362
Adjusted Terr./Prov. Gov. Rev.	1374	7	80	1	59	21	1	1542
Adjusted Federal Gov. Rev.	14693	14	163	3	98	15	2	14987
Total Government Revenue	16067	21	242	4	157	36	2	16529
Employment	6612	1247	2979	227	5513	1279	107	17965

CASE 3	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Direct Output	68335							68335
Gross Domestic Product	66802	83	339	19	552	114	10	67919
Labour Income	828	61	270	12	379	76	5	1632
Federal Government Revenue	14481	14	166	3	101	16	2	14782
Terr./Prov. Government Revenue	4260	7	81	2	60	21	1	4432
Grant Reduction	2704	0	0	0	0	0	0	2704
Adjusted Terr./Prov. Gov. Rev.	1557	7	81	1	60	21	1	1728
Adjusted Federal Gov. Rev.	17184	14	166	3	101	16	2	17486
Total Government Revenue	18741	21	247	4	161	37	2	19214
Employment	7038	1281	3136	233	5662	1314	110	18775

CASE 4	**NWT**	**BC**	**Alta**	**SMYN***	**Ont**	**Que**	**Atlantic**	**Total**
Direct Output	91971							91971
Gross Domestic Product	89650	128	476	29	852	176	16	91327
Labour Income	1162	95	369	18	585	118	8	2355
Federal Government Revenue	20148	22	190	4	155	24	2	20546
Terr./Prov. Government Revenue	5410	11	92	3	93	33	1	5642
Grant Reduction	3464	0	0	0	0	0	0	3464
Adjusted Terr./Prov. Gov. Rev.	1946	11	92	2	93	33	1	2178
Adjusted Federal Gov. Rev.	23612	22	190	5	155	24	2	24010
Total Government Revenue	25559	33	282	7	248	57	4	26188
Employment	9880	1978	4422	360	8745	2029	170	27585

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.9 - UNADJUSTED OVERALL IMPACTS - $6US GAS PRICE : 2002-2040

(millions of 2007 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	47212		1169					48381
Gross Domestic Product	34347	591	3840	278	2639	640	85	42420
Labour Income	4059	430	2096	205	1739	415	38	8983
Federal Government Revenue	3032	100	589	44	467	84	12	4328
Terr./Prov. Government Revenue	2078	44	316	20	263	105	7	2833
Grant Reduction	1164	0	0	3	0	0	0	1168
Adjusted Terr./Prov. Gov. Rev.	914	44	316	16	263	105	7	1666
Adjusted Federal Gov. Rev.	4196	100	589	47	467	84	12	5495
Total Government Revenue	5110	144	905	63	730	189	19	7161
Employment	30805	8739	27191	4013	27647	7587	797	106779

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	79055		1388					80442
Gross Domestic Product	57312	879	6271	417	3955	968	122	69924
Labour Income	5998	642	3693	296	2606	627	54	13917
Federal Government Revenue	5667	149	1088	64	701	127	18	7813
Terr./Prov. Government Revenue	3432	64	552	30	395	159	10	4642
Grant Reduction	1953	0	0	5	0	0	0	1957
Adjusted Terr./Prov. Gov. Rev.	1480	64	552	25	395	159	10	2685
Adjusted Federal Gov. Rev.	7619	149	1088	69	701	127	18	9771
Total Government Revenue	9099	212	1641	94	1096	286	27	12455
Employment	43631	12942	46743	5828	41359	11469	1135	163107

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	99557		1388					100945
Gross Domestic Product	70068	1120	8125	540	5037	1245	154	86290
Labour Income	7489	819	5064	376	3314	807	67	17935
Federal Government Revenue	6680	189	1406	82	892	163	22	9436
Terr./Prov. Government Revenue	3741	80	685	40	503	204	12	5264
Grant Reduction	2148	0	0	6	0	0	0	2154
Adjusted Terr./Prov. Gov. Rev.	1593	80	685	33	503	204	12	3109
Adjusted Federal Gov. Rev.	8828	189	1406	88	892	163	22	11590
Total Government Revenue	10421	270	2091	122	1395	367	34	14700
Employment	52687	16442	63450	7437	52636	14758	1410	208822

CASE 4	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	132892		1595					134487
Gross Domestic Product	92290	1489	11291	714	6679	1648	202	114312
Labour Income	9777	1092	7211	490	4399	1068	88	24125
Federal Government Revenue	8816	251	1925	108	1183	216	29	12528
Terr./Prov. Government Revenue	4710	105	915	53	668	270	16	6736
Grant Reduction	2738	0	0	8	0	0	0	2746
Adjusted Terr./Prov. Gov. Rev.	1972	105	915	45	668	270	16	3990
Adjusted Federal Gov. Rev.	11554	251	1925	116	1183	216	29	15274
Total Government Revenue	13526	356	2840	160	1851	486	45	19264
Employment	68177	21843	89621	9708	69798	19535	1852	280534

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.10 - UNADJUSTED OVERALL IMPACTS - $8US GAS PRICE : 2002-2040

(millions of 2007 Cdn$, employment in person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	61285		1256					62542
Gross Domestic Product	48289	603	3946	281	2686	649	86	56541
Labour Income	4138	438	2120	207	1771	421	39	9135
Federal Government Revenue	7258	102	602	44	476	85	12	8580
Terr./Prov. Government Revenue	3453	45	328	20	268	107	7	4227
Grant Reduction	2165	0	0	3	0	0	0	2169
Adjusted Terr./Prov. Gov. Rev.	1288	45	328	17	268	107	7	2059
Adjusted Federal Gov. Rev.	9423	102	602	47	476	85	12	10749
Total Government Revenue	10711	147	930	64	744	192	19	12807
Employment	31536	8914	27513	4047	28152	7693	816	108671

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	100629		1388					102016
Gross Domestic Product	78886	879	6271	417	3955	968	122	91498
Labour Income	5998	642	3693	296	2606	627	54	13917
Federal Government Revenue	14701	149	1088	64	701	127	18	16847
Terr./Prov. Government Revenue	5213	64	552	30	395	159	10	6422
Grant Reduction	3306	0	0	5	0	0	0	3311
Adjusted Terr./Prov. Gov. Rev.	1907	64	552	25	395	159	10	3112
Adjusted Federal Gov. Rev.	18006	149	1088	69	701	127	18	20158
Total Government Revenue	19913	212	1641	94	1096	286	27	23270
Employment	43631	12942	46743	5828	41359	11469	1135	163107

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	125362		1388					126749
Gross Domestic Product	95873	1120	8125	540	5037	1245	154	112094
Labour Income	7489	819	5064	376	3314	807	67	17935
Federal Government Revenue	17358	189	1406	82	892	163	22	20114
Terr./Prov. Government Revenue	5888	80	685	40	503	204	12	7411
Grant Reduction	3780	0	0	6	0	0	0	3787
Adjusted Terr./Prov. Gov. Rev.	2108	80	685	33	503	204	12	3625
Adjusted Federal Gov. Rev.	21139	189	1406	88	892	163	22	23900
Total Government Revenue	23247	270	2091	122	1395	367	34	27525
Employment	52687	16442	63450	7437	52636	14758	1410	208822

CASE 4	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Direct Output	167065		1595					168660
Gross Domestic Product	126462	1489	11291	714	6679	1648	202	148485
Labour Income	9777	1092	7211	490	4399	1068	88	24125
Federal Government Revenue	23836	251	1925	108	1183	216	29	27548
Terr./Prov. Government Revenue	7429	105	915	53	668	270	16	9455
Grant Reduction	4804	0	0	8	0	0	0	4813
Adjusted Terr./Prov. Gov. Rev.	2625	105	915	45	668	270	16	4642
Adjusted Federal Gov. Rev.	28640	251	1925	116	1183	216	29	32361
Total Government Revenue	31265	356	2840	160	1851	486	45	37003
Employment	68177	21843	89621	9708	69798	19535	1852	280534

* Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.11 - SECTORAL DISTRIBUTION OF EMPLOYMENT IMPACTS - $6US GAS PRICE : 2002-2040

(person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	1753	3	885	5	1	0	3	2650
Oil and Gas Services	1639	412	4084	232	5157	1417	86	13027
Construction	3957	1489	6253	808	309	107	305	13228
Manufacturing	73	900	2660	1189	3906	1762	188	10678
Trade	1025	1479	3511	913	3765	1373	131	12197
Pipeline Transportation	1037	3	614	1	2	1	0	1657
Transportation and Storage	835	670	1708	358	1536	462	123	5692
Finance / Rentals / Leasing	1484	608	1816	257	3928	503	69	8665
Prof / Scien / Tech Services	1129	3503	12208	735	3890	555	240	22260
Other	1673	2437	4469	1012	5384	1522	228	16724
Total	14605	11504	38207	5510	27877	7702	1373	106779

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	3144	5	1468	7	2	0	4	4631
Oil and Gas Services	2920	568	6033	321	7945	2182	118	20088
Construction	6375	1812	8268	983	428	144	370	18379
Manufacturing	140	1410	5187	1663	5926	2667	272	17265
Trade	1650	2207	5534	1334	5711	2082	188	18706
Pipeline Transportation	1284	4	765	2	2	1	0	2059
Transportation and Storage	1032	957	2567	496	2125	685	175	8037
Finance / Rentals / Leasing	2068	882	2814	362	5631	751	99	12607
Prof / Scien / Tech Services	1863	5128	21190	1108	5830	828	324	36272
Other	2308	3527	7092	1477	8056	2277	325	25064
Total	22786	16500	60917	7755	41656	11617	1876	163107

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	3477	7	1651	9	2	0	5	5151
Oil and Gas Services	4344	619	7281	352	10125	2779	129	25630
Construction	9813	1777	9272	965	502	161	360	22851
Manufacturing	244	1840	7296	2084	7716	3468	342	22989
Trade	2505	2769	7067	1682	7398	2705	225	24351
Pipeline Transportation	1284	6	772	3	3	1	0	2068
Transportation and Storage	1244	1174	3269	608	2587	875	217	9974
Finance / Rentals / Leasing	2469	1088	3583	439	6867	958	119	15523
Prof / Scien / Tech Services	2923	6475	28663	1407	7493	1052	375	48388
Other	2998	4339	9140	1865	10247	2909	399	31897
Total	31300	20092	77994	9414	52940	14911	2171	208822

CASE 4	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	4379	9	2060	13	3	0	7	6471
Oil and Gas Services	5149	937	10177	531	13532	3716	195	34237
Construction	10223	2682	13965	1456	691	227	546	29790
Manufacturing	257	2528	10905	2690	10196	4586	451	31613
Trade	2778	3774	10023	2237	9780	3562	312	32466
Pipeline Transportation	1518	8	781	4	4	2	0	2316
Transportation and Storage	1447	1575	4436	796	3390	1153	287	13085
Finance / Rentals / Leasing	3160	1471	5025	589	9139	1266	164	20815
Prof / Scien / Tech Services	3182	8572	41450	1920	9911	1404	510	66949
Other	3521	5843	12941	2483	13615	3850	538	42791
Total	35615	27400	111764	12718	70261	19767	3010	280535

*Saskatchewan / Manitoba / Yukon / Nunavut

TABLE A.12 - SECTORAL DISTRIBUTION OF EMPLOYMENT IMPACTS - $8US GAS PRICE : 2002-2040

(person years)

CASE 1	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	1920	4	956	5	1	0	3	2889
Oil and Gas Services	1713	412	4130	232	5254	1444	86	13271
Construction	4038	1490	6256	808	312	108	305	13317
Manufacturing	74	908	2672	1194	3935	1777	191	10750
Trade	1065	1501	3539	920	3810	1386	133	12354
Pipeline Transportation	1136	3	671	1	2	1	0	1814
Transportation and Storage	882	686	1728	363	1581	469	125	5834
Finance / Rentals / Leasing	1578	619	1832	260	4049	511	70	8920
Prof / Scien / Tech Services	1168	3559	12228	739	3952	566	246	22459
Other	1762	2498	4518	1023	5486	1547	231	17065
Total	15336	11679	38529	5545	28382	7808	1392	108671

CASE 2	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	3144	5	1468	7	2	0	4	4631
Oil and Gas Services	2920	568	6033	321	7945	2182	118	20088
Construction	6375	1812	8268	983	428	144	370	18379
Manufacturing	140	1410	5187	1663	5926	2667	272	17265
Trade	1650	2207	5534	1334	5711	2082	188	18706
Pipeline Transportation	1284	4	765	2	2	1	0	2059
Transportation and Storage	1032	957	2567	496	2125	685	175	8037
Finance / Rentals / Leasing	2068	882	2814	362	5631	751	99	12607
Prof / Scien / Tech Services	1863	5128	21190	1108	5830	828	324	36272
Other	2308	3527	7092	1477	8056	2277	325	25064
Total	22786	16500	60917	7755	41656	11617	1876	163107

CASE 3	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	3477	7	1651	9	2	0	5	5151
Oil and Gas Services	4344	619	7281	352	10125	2779	129	25630
Construction	9813	1777	9272	965	502	161	360	22851
Manufacturing	244	1840	7296	2084	7716	3468	342	22989
Trade	2505	2769	7067	1682	7398	2705	225	24351
Pipeline Transportation	1284	6	772	3	3	1	0	2068
Transportation and Storage	1244	1174	3269	608	2587	875	217	9974
Finance / Rentals / Leasing	2469	1088	3583	439	6867	958	119	15523
Prof / Scien / Tech Services	2923	6475	28663	1407	7493	1052	375	48388
Other	2998	4339	9140	1865	10247	2909	399	31897
Total	31300	20092	77994	9414	52940	14911	2171	208822

CASE 4	NWT	BC	Alta	SMYN*	Ont	Que	Atlantic	Total
Oil and Gas Extraction	4379	9	2060	13	3	0	7	6471
Oil and Gas Services	5149	937	10177	531	13532	3716	195	34237
Construction	10223	2682	13965	1456	691	227	546	29790
Manufacturing	257	2528	10905	2690	10196	4586	451	31613
Trade	2778	3774	10023	2237	9780	3562	312	32466
Pipeline Transportation	1518	8	781	4	4	2	0	2316
Transportation and Storage	1447	1575	4436	796	3390	1153	287	13085
Finance / Rentals / Leasing	3160	1471	5025	589	9139	1266	164	20815
Prof / Scien / Tech Services	3182	8572	41450	1920	9911	1404	510	66949
Other	3521	5843	12941	2483	13615	3850	538	42791
Total	35615	27400	111764	12718	70261	19767	3010	280535

* Saskatchewan / Manitoba / Yukon / Nunavut