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Glen Howard Copplestone

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LA THÈSE A ÉTÉ
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IMPLICATIONS OF
CANADIAN OIL TAX POLICIES

by
Glen H. Copplestone
Department of Economics

Submitted in partial fulfillment
of the requirements for the degree of
Doctor of Philosophy

Faculty of Graduate Studies
The University of Western Ontario
London, Ontario
September, 1983

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ABSTRACT

The purpose of the thesis is to examine some of the implications of the policy initiatives taken by both levels of government during the 1974-80 period (i.e., from the OPEC oil embargo and subsequent quadrupling of posted world oil prices to the introduction of the National Energy Program, or NEP). A survey of the fiscal instruments employed by both the federal and the oil-producing provincial levels of government to distribute the oil revenues generated in Canada is presented. The focus of this survey is primarily on the pre-NEP regime and the immediate post-NEP regime. The remainder of the thesis then deals with some of the distributional and efficiency aspects of these tax regimes.

One of the distributional implications of the intergovernmental revenue-sharing from oil production, as defined by the underlying tax regime in place, is that the pre-NEP tax regime, for example, will have repercussions for provincial revenues (for both the "have" and the "have-not" provinces). With respect to the revenues of the have-not provinces the thesis examines the ramifications of the pre-NEP regime on the equalization program (in place at that time). Specifically, the implications for the magnitude and the funding of the equalization payments are examined. Correspondingly, a recommendation favouring an alternative system of equalization -- a two-tier program with the second tier taking the form of an interprovincial revenue-sharing pool (and focusing essentially on revenues under sole provincial control) -- is presented and evaluated.

The thesis also examines the economic efficiency aspects of the pre- and post-NEP tax regimes. In particular, we address the issue of an inefficient allocation of resources within the oil industry itself.
That is, based on the assumption that the pure-profits tax is economically efficient (i.e., optimal) then the pre- and post-NEP tax regimes are predicted to distort the allocation of exploration and development capital employed in the production of alternative types of oil (e.g., conventional, secondary, tertiary, non-conventional and frontier oil). The result therefore, is an efficiency loss incurred by Canada. An attempt to illustrate the magnitude of this efficiency loss is also presented.

Finally, the thesis examines the nature of an "optimal" tax regime. Employing a separate utility function to represent the development objectives of both the federal and the oil-producing provincial levels of government and imposing (industry) profit-maximizing production constraints on the government, the optimal tax rates are derived. This exercise is performed employing two alternative behavioural assumptions. Initially, it is assumed each level of government takes the other level of government's tax and subsidy rates as given (i.e., a Nash behaviour) and secondly, we assume they act in a co-operative fashion and maximize their joint utility. Exercises attempting to measure for the 1972-81 period (i.e., from the revisions to the Canadian Income Tax Act to immediately following the introduction of the NEP) the revealed policy preferences of the federal government, the costs of non-cooperative taxing behaviour on the part of the federal and provincial levels of government and the impact of varying the relative importance of the arguments assumed to appear in the federal government's utility function, conclude the thesis.
ACKNOWLEDGEMENTS

For their individual efforts, I am indebted to my committee, each of whom has made a unique contribution. To Professor Thomas Courchene, I wish to express my gratitude for his sincere interest and for his many valuable suggestions. In addition, I am grateful to Professor Courchene for permitting me to include, as Chapter 3 of this thesis, our joint paper on "Alternative Equalization Programs: Two-Tier Systems." I would also like to express my deep appreciation to Professor Jim Markusen, my chief advisor, for his guidance and assistance which has been very important at every stage. Thanks must also go to Professor David Burgess for his numerous constructive comments.

I also wish to gratefully acknowledge the financial support from the Canada Council during the early research stages and as well, from Huron College for the preparation of the final draft of the thesis.

Finally, words cannot adequately convey my indebtedness to my parents and the rest of my family for their love and moral support. As well, the debt to my patient and inspiring wife, Catherine, to whom I lovingly dedicate this thesis, extends far beyond these pages -- without her, this manuscript would not have been completed.
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CHAPTER 1

INTRODUCTION AND OVERVIEW

1.1 OUTLINE OF THE THESIS

The world energy crisis of the 1970's initiated a series of federal and provincial, and inter-provincial, confrontations in Canada. Central to these debates were the issues of pricing our domestic oil resources and the sharing (or distribution) of the resulting oil revenues. Both the federal and oil-producing provincial governments over the period beginning in 1973/74 up to the introduction of the National Energy Program (October 1980), or NEP, employed their respective legal powers of taxation to impose significantly higher tax and royalty rates on oil and gas operations in Canada in order to extract a greater share of the growing resource revenues. This increased tax effort was imposed by both levels of government, too often with not much co-ordination between the two.

It is the purpose of this thesis to examine some of the implications of the policy initiatives taken by both levels of government during this period. In particular, the thesis attempts to evaluate these initiatives (especially the NEP) with respect to its realization of the two major objectives of economic policy -- efficiency and equity (i.e., distributional issues).

Previous analysis of the NEP has addressed to varying degrees and employing various techniques some of the efficiency and equity aspects of the NEP. For example, Daniel and Goldberg (1981), Helliwell and McRae (1981) and Helliwell (1980) have employed comprehensive models of Canadian energy supply and demand to analyze the impact of the NEP on the pattern
of energy supply and demand and on the distribution of rents. Alternatively, Scarfe (1981) has presented a diagrammatical representation of the efficiency losses (on both the demand and supply side) that result from maintaining domestic oil prices below world levels. Finally, Stabback and Waddingham (1981), in their analysis of the financial aspects of the NEP (on a typical project), and Watkins (1981), in his analysis of the pricing provisions of the NEP, suggest that distortions -- in the form of encouraging relatively high cost reserves at the expense of low cost reserves--may be introduced.

Although this thesis is not intertemporal as are the models of Daniel and Goldberg (1981), Helliwell and McRae (1981) and Helliwell (1980), there are nevertheless, some significant advantages to the model employed in this thesis. Perhaps most striking is the degree of disaggregation with respect to the type of oil produced and the choice of input combinations in this model (but more on this later).

Specifically, the organization of the thesis is as follows. Chapter 2, which serves as a backdrop for the analysis that follows, details the fiscal instruments employed by both the federal and oil-producing provincial levels of government (specifically Alberta) to distribute the oil revenues generated in Canada and summarizes the pricing decisions made by the federal government sometimes with, and sometimes without, the acceptance of the oil-producing provincial governments. In particular, in the second chapter, we survey the federal and provincial tax policies in place prior to the introduction of the National Energy Program and then identify the significant restructuring of federal oil tax policies as announced in NEP.

Chapter 3, which was written jointly with Thomas J. Courchene,
focuses on one of the major implications or repercussions associated with the distribution of energy rents underlying a given tax regime. Specifically, Chapter 3 examines the impact of the pre-NEP pricing and revenue-sharing policies on one of the major sources of provincial revenues (at least for the "have-not" provinces) -- Canada's system of equalization payments. In this chapter we show, given the existing tax programs and subsequently, therefore, the sharing of energy (i.e., oil and gas) rents, the corresponding ramifications for the present equalization system in terms of the magnitude and the funding of the equalization payments.

To highlight this interaction between energy revenue-sharing (as defined by the pre-NEP tax regime) and the equalization system, we present two equalization "balance sheets", one relating to the relationship between energy and the payments implicit in the 1979-80 equalization flows and the other focussing on the impact of a $1 per barrel increase in the price of domestic energy. The dramatic aspect of both these balance sheets is that the sources for funding equalization flows do not bear any resemblance to the increases in provincial revenues which generate these equalization payments. Based on our claim therefore, that there exists a funding inequity associated with the equalization program (where the producing provinces are not bearing their fair share of funding the equalization formula while the federal government is bearing too much of the responsibility for equalizing provincial revenues) we then recommend the adoption of a "two-tier" system of equalization payments -- with the "second tier" taking the form of an interprovincial revenue-sharing pool and focussing essentially on revenues under sole provincial control (i.e., particularly the resource revenues). An example of one such two-tier proposal is pre-
Chapter 4 of the thesis again draws on the survey provided in the second chapter and addresses the issue of economic efficiency associated with a given tax regime. In this chapter, although we assume oil is a homogeneous product, we recognize six alternative locations or methods of production. Oil (for the purposes of this chapter) can be classified as:

1) Old Conventional Oil (where the 'old' designation employed in this chapter is the same definition as the province of Alberta employs for royalty purposes — e.g., old oil is any oil produced from a reservoir discovered prior to April 1, 1974)

2) New Conventional Oil (i.e., discovered after April 1, 1974). Note, both types of conventional oil are assumed to be produced within the province of Alberta.

3) Secondary Oil — defined as the additional oil produced from a reservoir as a result of supplying energy (e.g., water flooding) to move the oil towards the producing well (also assumed to be produced in the province of Alberta).

4) Tertiary Oil — which is produced employing less technically proven techniques than secondary methods (for example, steam injection). In particular, in this chapter tertiary oil is taken to be synonymous with heavy oil production and therefore, is assumed to be located in the province of Saskatchewan.

5) Non-Conventional Oil — defined as crude produced from the oil sands (assumed to be located in the province of Alberta), and finally,

6) Frontier Oil — defined as any oil produced from areas in Canada which fall under federal (only) jurisdiction (e.g., the Yukon, the Northwest Territories, and the areas off Canada's coasts).

Given these definitions of alternative types of oil then in Chapter 4 we attempt to provide answers to the following questions:

1) Does the array of federal and provincial tax policies in place in both the pre-NEP and post-NEP periods distort our allocations of resources
employed in the production of these alternative types of oil? and, if so, 2) In which direction is the bias? In order to provide an answer to each of these questions we assume that the traditional pure-profits tax in economic theory represents an efficient (or optimal) tax environment. Consequently, any departures in the actual tax system from this pure-profits tax will represent a distortion.

Canadian energy policy has evolved in such a way as to produce two fundamental policy characteristics:

1) the domestic price of oil received by certain domestic oil producers is maintained below the international price (with the percentage of the world price received varying by the type of oil produced),

and 2) Rich tax incentives are made available to domestic oil producers.

The effect of the first policy is to reduce capital investment in the Canadian energy projects which receive the domestic price for their output, whereas, the intent of the tax incentives is clearly to promote capital investment in the domestic oil industry. These tax incentives, however, are not expected to be neutral with respect to the type of capital investment that may be undertaken for all types of oil produced (e.g., conventional (old and new), secondary, tertiary, non-conventional and frontier oil). That is, capital inputs (both exploration and development capital) effectively receive subsidies via the reduction in corporate income tax liabilities for incurring capital expenses, but not at equal rates. Nor, for that matter, do the same rates apply for all types of oil produced with the same type of capital.

Finally, following the introduction of the NEP the writeoff rates, or tax-based subsidy rates for the same type of capital employed in identical regions (e.g., frontier oil areas) may now vary, not as a
result of cost differences, but simply according to the degree of Canadian ownership of the firms producing the oil. As a consequence, we expect to see a factor bias introduced in the domestic oil industry with the result that oil output will be influenced.

In addition, as a result of these distortions in the volume of output of each type of oil, relative to the pure-profits tax, there is an efficiency loss -- defined as the net change in industry profits plus the change in net government oil tax revenues -- incurred by Canada. It is also the purpose of Chapter 4 then, to offer a highly simplified, but suggestive assessment of the ensuing efficiency loss.

Chapter 5, which continues the theme of addressing economic efficiency issues, re-examines the central assumption of the previous chapter. In particular, we suggest a framework which enables us to address the issue of whether or not the pure-profits tax is, in fact, the optimal tax regime. The methodology adopted in this chapter employs a simpler version of the model of the domestic oil industry presented in Chapter 4 (for example, in contrast to the earlier chapter, in Chapter 5 we assume only one type of oil is produced -- conventional old oil) and introduces two utility functions -- one for the federal government and one to represent the preferences of the oil-producing provincial governments (specifically, Alberta). The utility functions for these two levels of government need not contain the same arguments reflecting the assumed differences in the development objectives of the citizens they are expected to serve. The optimal tax and subsidy regime for a given level of government then is the set of rates which maximizes its respective utility function subject to the industry's value of marginal product constraint holding.
This exercise is performed employing two alternative behavioural assumptions. Initially, we assume each level of government takes the other level of government's tax and subsidy rates as given (i.e., a Nash behaviour) and secondly, we investigate the pattern of optimal tax and subsidy rates for each level of government if we assume they act in a cooperative fashion and maximize their joint utility.

1.2 PRINCIPAL FINDINGS

1) With respect to the distributional issues, the significant findings of the thesis are that the actual tax regimes in place, while very complex, have significant ramifications for the magnitude and funding aspects of the federal equalization program. More specifically, given the underlying revenue-sharing implied by the pre-NEP tax and price régime, there exists a funding inequity -- Ottawa is bearing too much of the responsibility for equalizing provincial revenues. Consequently, we feel a two-tier approach to equalization (where the second tier is an inter-provincial revenue-sharing pool) which combines the dual principles of "ability to pay" and "cooperative federalism" has a great deal of merit. In terms of our illustration of how a two-tier scheme may operate (which admittedly is exploratory at best), we find for example, to generate comparable total equalization flows as the existing program, but under a two-tier scheme, the government of Alberta would have been called upon to share with the other provinces in Canada at most, slightly more than $1.1 billion in 1980 or $551 per resident of Alberta -- representing a little more than 25% of their total oil revenues for the same year.
2) As well, the tax regimes of both levels of government have serious implications for the efficient (or optimal) allocation of resources within the oil industry itself. For example, relative to the pre-NEP tax regime, we find (admittedly under rather restrictive assumptions) that the introduction of the NEP results in an increase in the employment of both exploration and development capital for Canadian firms in the production of old conventional oil while simultaneously causing the reduction in employment of both types of capital in the case of foreign-owned firms producing old conventional oil. Based on these findings, it appears that the federal government's National Energy Program may be successful in Canadianizing the domestic oil industry -- at least, that segment which produces old conventional oil.

3) Unfortunately, however, the factor employment effects of the NEP derived in this thesis suggest the likelihood of Canadianizing the domestic oil industry in the case of all other types of oil is far less promising (unless the vehicle the federal government wants to employ to bring this about is the takeover route. However, estimates presented in Chapter 4 suggest even this route may be insufficient).

4) Furthermore, the analysis in Chapter 4 suggests that the National Energy Program, given existing foreign ownership rates and our model's predictions with respect to factor employment effects, may have serious repercussions for achieving the federal government's goal of oil self-sufficiency. For example, the results generated in Chapter 4 indicate that the NEP tends to encourage the development of relatively very expensive types of oil (e.g., non-conventional and frontier oil) at the expense of less costly, and perhaps, more certain sources of oil (e.g., in particular, conventional and secondary oil). The consequences of
this in terms of oil self-sufficiency for Canada is that in the situation of falling world oil prices (which since the writing of Chapter 4 the world is now facing) the future supplies of these more expensive oil sources may not materialize.

5) Finally, with respect to Chapter 4, the admittedly highly simplified attempt at quantifying the efficiency loss generated as a result of the introduction of the NEP indicates that the NEP is expected to increase the value of the efficiency loss (arising from the bias introduced in factor employment decisions) incurred by the Canadian economy for all types of oil produced by foreign firms. The sole exception is in the case of the efficiency loss associated with the employment of development capital in non-conventional oil production. In the case of Canadian firms, the results generated indicate a reduction in the efficiency loss associated with the NEP tax regime with respect to the employment of exploration capital in the production of old and new conventional oil and non-conventional oil, but an increase in the efficiency loss associated with exploration capital employment in the case of frontier, secondary and tertiary oil production. As well, the efficiency loss associated with the employment of development capital by Canadian firms increases for all types of oil following the introduction of the NEP.

6) The framework presented in Chapter 5 for analyzing the notion of optimal tax regimes, suggests that if the model of the oil industry employed is appropriate and the utility functions for both levels of government are properly specified (i.e., the federal government's utility function contains two arguments -- federal oil revenues and oil production, to reflect the desire for oil self-sufficiency, whereas, the provincial government's utility function contains but one argument -- provincial
oil-related revenues) then the pure-profits tax regime is not expected to be the optimal tax regime regardless of the behavioural assumption employed.

7) It is also demonstrated in Chapter 5 that cooperatively set tax rates will generate a lower combined tax effort than non-cooperatively (i.e., Nash) set tax rates and consequently, Canada's oil production will be higher.

8) The presence of and the more importance afforded oil production in the federal government's utility function (e.g., the more concerned the federal government is assumed to be with oil self-sufficiency) the lower the combined tax rates will be again, regardless of the behavioural assumption employed. At the same time, however, it is demonstrated in Chapter 5 with only one tax instrument available for each level of government, in a non-cooperative (Nash) setting, although the combined tax effort declines, the provincial revenue tax rate will increase while the federal revenue tax rate falls.

9) As well, it is demonstrated that the reduction in combined tax effort due to the presence of oil production as an argument in the federal government's utility function will be more pronounced in an atmosphere of cooperation than in non-cooperation.

10) Also in Chapter 5 we attempt to quantify, for illustrative purposes, using the results of our model, the potential costs as a result of the federal government varying its implied emphasis on the importance of oil self-sufficiency (i.e., the relative importance of oil production in the federal government's utility function) over the 1974-81 period.

With respect to the post-1974 period we estimate, in the context of our Nash model, that the federal government could have imposed a revenue tax rate of approximately 17% which is slightly over one-half
of the effective rate (30%) in effect at the time, if Ottawa had main-
tained the same implicit importance for oil self-sufficiency as indicated
in 1972 (prior to the quadrupling of world oil prices). Similarly, for
the period just prior to the introduction of the NEP (1980) our results
indicate that the federal government's revenue tax rate could have been
dropped to 22% from the effective rate of 27% if the federal government
maintained a constant emphasis on oil self-sufficiency.

Interestingly, our results for the post-NEP period (i.e., 1981)
indicate in the case of Canadian firms the actual rate in effect conforms
almost exactly to the implied rate. That is, in the case of Canadian
oil producers, the weight attached to the self-sufficiency argument in
the federal utility function is virtually the same value after the intro-
duction of the NEP as it was back in 1972 before the world energy crisis
emerged.

However, in the case of foreign-owned firms this is not the case.
The federal revenue tax rate according to our results, would have to be
reduced to 22% from its actual value of 35%, if a constant relative
importance of oil self-sufficiency was to be maintained.

Finally, in Chapter 5, we also attempt to quantify, again, for
illustrative purposes, using the results of our model, the implications
of assumed non-cooperative taxing behaviour on the part of the federal
and provincial levels of government during the 1974-81 period. Unfortu-
ately, the results of this exercise are quite model-specific. For ex-
ample, if we assume that each level of government possesses only one tax
instrument (e.g., a revenue tax rate) and if we further assume a value
for the output elasticity of 1/4, then the combined tax effort in a
cooperative setting for 1974 could have been 42% lower than it actually
was. Similarly, for 1980 (i.e., pre-NEP) the potential lowering of combined tax rates is in the neighbourhood of 39% while the potential reduced tax effort for 1981 (post-NEP) would be approximately 25% (i.e., the cooperatively set tax rates could have been 25% lower than the actual combined tax effort).

In the model with two tax instruments for each level of government, however, the results indicate (as a result of an implied negative value for the federal government of the ratio of marginal utilities of oil production to federal oil revenues) that cooperatively set tax rates would actually imply a higher combined revenue tax rates.

1.3 POLICY IMPLICATIONS

The major policy implications of the thesis are as follows:
1) with respect to the nature of the tax regimes, their complexity and equally as important, the frequency of alterations, should be avoided. Given the time lag involved in the oil industry from the exploration stage to the ultimate production and sale of the oil produced, altering the rules under which the oil industry operates may have serious repercussions with respect to the actual (rather than anticipated) oil production levels. (For example, to get a feel for the frequency of tax changes introduced by the federal government, consult the Appendix to Chapter 2).

2) In a related vein, the federal and provincial governments should place more emphasis on the economic efficiency aspects (e.g., the factor bias and the oil production bias, by type of oil, introduced with changes in a given tax regime). In particular, the public sector should re-examine the tax system with respect to the apparent bias that is present in favour of relatively more expensive (and maybe less secure) sources of
oil. In addition, the government should undertake to calculate and publish the efficiency loss and factor employment effects of deviations from the pure-profits tax.

3) Furthermore, it is preferable that both levels of government state their policy objectives explicitly (for example, the relative importance of oil self-sufficiency relative to say, federal, oil revenues) so that the economic efficiency of government policies can be tested and the costs quantified more easily.

4) As well, both levels of government (i.e., the federal government and the oil-producing/provincial levels of government) should recognize and attempt to assess the efficiency costs of non-cooperative tax regimes, and finally,

5) with respect to the equalization program, the federal government should undertake to calculate and publish the distributional implications of alternative tax policies.
CHAPTER 2

A SURVEY OF THE FEDERAL AND PROVINCIAL TAX TREATMENT OF THE
CANADIAN OIL INDUSTRY: PRE- AND POST- NATIONAL ENERGY PROGRAM

2.1 INTRODUCTION

There currently exists a threat to Canadian unity that in the minds of many may pose a greater threat than the separatist movement in Quebec. This threat has resulted from the emergence of massive oil and gas revenues in Canada triggered by a change in the relative price of oil (and gas). This alone need not be a problem, but considering the volume and the distribution of these revenues across Canada, then the issue at stake is critically important to the survival of the Canadian federation as we know it today. The value of domestic oil and gas production in 1980 topped $16 billion (even at Canadian prices). Claiming entitlement to this flow of revenues are the western producing provinces, the federal government and the oil and gas industry.

The producing provinces (principally Alberta) assert that they are entitled to a significant share of these revenues by virtue of the fact that Section 93 of The British North America Act (1867) assigns ownership of these resources to the provinces. Therefore, as landlords of these resources, the provinces are within their rights to impose royalties and taxes and to capture a share of these revenues as they so choose.

The federal government on the other hand, expresses its view and claim to the revenues, by arguing that it is the government for all
the people of Canada (e.g., the consuming provinces as well) and therefore, have a mandate to operate on their behalf to serve their best interests. In particular, the federal government may exercise its taxation powers in the resource field by interpreting, in its favour, a variety of sections of the Canadian constitution. For example, section 121 of the B.N.A. Act (the trade and commerce clause) gives the federal government authority over international and interprovincial trade and, therefore, the presumed ability to set the prices at which trade will occur. This has an indirect effect on federal tax revenues in the sense that by determining the domestic price of oil and gas, the federal government controls indirectly the volume (but not the percentage share) of tax revenues involved.

Alternatively, as an emergency measure, the federal government could employ the "peace, order and good government" clause of section 91 of the B.N.A. Act which allows it pre-emptive authority in matters of national concern. The argument here is that a potential energy shortage (for example) qualifies as a national concern and therefore, if the federal government invokes this clause it may impose a "self-sufficiency" tax at the wellhead and gather additional federal revenues. These additional revenues can then be used to purchase and/or subsidize oil imports and therefore avoid an energy shortage. This interpretation, however, has been challenged by the provincial governments and as yet, has not been interpreted by the courts.

The most direct and unchallenged power of the federal government to collect a percentage of resource incomes however, is still the corporate income tax. Both by varying tax rates and tax incentives, the federal government has been able to influence the rate, speed and
extent of exploration and development activity in the petroleum industry and, therefore, generate revenues for the federal coffers. For example, when the federal government in 1974 moved to disallow provincial royalty payments as a tax deduction, the end result was to completely stifle exploration and development activity in the west.

Finally, the oil and gas industry feels that it is entitled to these revenues because they are the ones finding, extracting and delivering these resources to the consumer.

Both the federal and provincial governments in recent years have employed their respective legal powers of taxation to impose significantly higher tax and royalty rates on oil and gas operations in Canada in order to extract a greater share of the growing resource revenues. This increased tax effort has been imposed by both levels of government, too often with not much coordination between the two. The net result of this action has been the creation of an efficiency loss for the Canadian economy. That is, given that royalties and taxes imposed by the two levels of government will and do exist, a distortion is introduced. Unlike the operation of a pure-profits tax in traditional economic theory, the after-tax, profit-maximizing, output levels and factor employment decisions of the firms in the industry are altered creating an inefficient allocation of the economy's resources. This then, is the source of the efficiency loss we will examine. This task (the identification of the factor market distortions and the ensuing efficiency loss), however, is deferred until Chapter 4 of the thesis.

The specific purpose of this chapter is to identify how the total oil revenues generated in Canada are distributed between the two
levels of government (the federal government and the oil-producing provincial governments) and the industry. More specifically, the fiscal instruments (and their properties) employed by the two levels of government to collect their respective shares of the oil and gas revenues generated are identified. In particular, in this chapter we will detail the federal and provincial tax policies in place prior to the introduction of the National Energy Program (October 1980), or NEP, and then identify the significant restructuring of federal oil tax policies as announced in NEP. We begin with a review of federal oil tax policies for the pre-NEP period.

2.2 THE FEDERAL GOVERNMENT'S TAX AND ROYALTY TREATMENT OF THE CANADIAN OIL INDUSTRY: PRE-NEP (i.e., as of January 1, 1980)

2.2.1 An Overview of the Computation of Federal Corporate Income Tax

The procedure for calculating the federal corporate income tax liability of a firm operating in the Canadian oil and gas industry (as of January 1, 1980) is outlined below in Table 2.1. The format displayed is of course an oversimplification. As is the case with any income tax calculations, there are many special situations or exceptions that would complicate the analysis. For the purposes of this thesis, it is not necessary to focus attention on these circumstances. Rather, it is preferred and sufficient to concentrate on the general thrust of the computations.

Some of the concepts identified in Table 2.1 requiring a more detailed explanation are discussed below (in the order that they appear).
### TABLE 2.1  COMPUTATION OF THE FEDERAL CORPORATE INCOME TAX LIABILITY OF A FIRM IN THE CANADIAN OIL INDUSTRY (as of January 1, 1980)

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Value of oil or gas produced in Canada</td>
<td>$XX</td>
</tr>
<tr>
<td>Less: - direct operating costs</td>
<td>$XX</td>
</tr>
<tr>
<td>- overhead</td>
<td>XX</td>
</tr>
<tr>
<td>- depreciation</td>
<td>XX</td>
</tr>
<tr>
<td>SUB-TOTAL 1</td>
<td>XX</td>
</tr>
<tr>
<td>Less: - Resource Allowance</td>
<td>$XX</td>
</tr>
<tr>
<td>(25% of Sub-total 1)</td>
<td></td>
</tr>
<tr>
<td>- Interest expense (attributable to exploration, development and production of oil or gas)</td>
<td>XX</td>
</tr>
<tr>
<td>- Canadian Development Expense</td>
<td>XX</td>
</tr>
<tr>
<td>- Canadian Exploration Expense</td>
<td>XX</td>
</tr>
<tr>
<td>SUB-TOTAL 2</td>
<td>XX</td>
</tr>
<tr>
<td>Less: - Earned Depletion Allowance</td>
<td>$XX</td>
</tr>
<tr>
<td>(maximum: 25% of Sub-Total 2)</td>
<td></td>
</tr>
<tr>
<td>- Supplementary Depletion</td>
<td>XX</td>
</tr>
<tr>
<td>- Frontier Exploration Allowance (to limit of income)</td>
<td>XX</td>
</tr>
<tr>
<td>TAXABLE INCOME</td>
<td>$XX</td>
</tr>
<tr>
<td>Rate of Federal Tax</td>
<td>@ 46%</td>
</tr>
<tr>
<td>BASIC FEDERAL TAX</td>
<td>$XX</td>
</tr>
</tbody>
</table>

**Deduct Provincial Abatement:**

- Taxable Income                                         $XX
- Weighting (based on Sales and Payroll in Province) (x)  XX
- Income Allocated to Province                           $XX
- Rate of Abatement                                      @ 10%  (XX)

**NET FEDERAL TAX**                                       $XX
i) Value of Oil and Gas Production:

This term represents the revenue of the firm from production but not processing of oil and gas operations in Canada. Included in this definition is the value of production diverted to the Crown or "phantom income." That is, if the producer is required to sell his production to a Crown agency for a price less than the fair market value, he is nevertheless deemed to have received the fair market value for income tax purposes. ³ This corresponds to the situation in British Columbia where all natural gas producers must sell their output to the British Columbia Petroleum Commission at a price lower than the "wellhead" price (i.e., so the difference in the two prices is simply a royalty payment).

Similarly, if the producer diverts to a Crown agency some of his production as payment in kind for a royalty, the taxpayer is deemed to have received fair market value. ⁴ This is the situation in Alberta where technically the producer makes his royalty payment to the provincial government in barrels of oil (or thousands of cubic feet of natural gas) instead of dollars. These additions to total revenue were necessary to ensure that a producer's royalty payments to a provincial government (regardless of their form) remain non-deductible for income tax purposes. ⁵

ii) Federal Resource Allowance:

The federal resource allowance was introduced in the federal budget of June 23, 1975. This allowance was designed to compensate the oil companies for increased tax liabilities due to the disallowance of
provincial royalties as a deduction from taxable income (effective as of May 7, 1974). In the preceding budget of November 18, 1974, the federal government had tried to compensate for this hardship by reducing the effective corporate tax rate by way of a federal tax abatement on oil and gas production. The federal government now felt that this approach was not adequate. Introduction of the tax abatement, after all, served to lessen the value of the government's tax deductions in place (i.e., the exploration and development expenses deductions and the earned depletion allowance which are discussed below) and was in direct contrast to the argument for their very existence (i.e., namely to encourage exploration and development activity).

Consequently, the resource allowance was introduced. The value of the allowance was defined to equal 25% of resource profits (i.e., net of operating costs and depreciation but before deducting interest, Canadian exploration and development expenses or earned depletion allowance). At the same time, (the June 1975 budget) the effective federal tax rate was increased so as to offset the loss of federal revenues due to the introduction of the resource allowance, and as well to increase the value of the tax incentives designed to encourage exploration and development activity. The effective corporate tax rate was altered by lowering the basic federal tax rate from 50% to 46% as well as eliminating the 15 percentage point abatement for resource income (introduced in the November 1974 budget -- to be effective for 1976). The net effect of these two changes was to increase the effective tax rate from 25% to 36% for 1976 returns.

The resource allowance then serves to reduce the marginal rate of federal corporate tax on current income to 27 per cent (i.e., 3/4 of
36 per cent). As well, the manner in which this resource allowance is to be calculated provides an incentive to increase exploration and development activity. Since the federal resource allowance is calculated before any deductions for exploration or development expenses, the value of this allowance is not reduced for a firm heavily involved in exploration activity. (As well the firm would also receive significant tax reductions in the form of exploration expenses).

iii) Canadian Exploration and Development Expenses:

Canadian exploration and development expenses were introduced as legitimate deductions from taxable income in the Income Tax Act of 1972. The rate at which these expenses can be written off has been altered since their inception. Initially, both these expenses were written off at a 100% per annum rate. The federal budget of May 6, 1974 proposed to reduce this maximum rate of tax writeoff to only 30 per cent per year for both types of expenses, however, this proposal was not acted upon due to the defeat of the Liberal government. It was not until later that same year (in the November 18, 1974 federal budget) that the present rates of writeoffs were determined -- namely, 30 per cent for development expenses and 100 per cent for exploration expenses. This measure placed the burden on the Department of Finance to define one type of expense in contrast to the other. These definitions were subsequently presented in sections 66.1 and 66.2 respectively of Bill C-56.

The technical implications of such a provision are discussed in more detail by James Roche (1977). Basically, however, the distinction between an exploration and development expense relates to time. If a well (for example) is begun in a given tax year but is not completed
by the end of the year in which it was begun, then it is classified as a development expense and subject to a 30 per cent deduction. It is still possible, however, according to Bill C-56 that even if the well is not finished within the same year but within six months of the end of that year -- it may still qualify as an exploration expense provided: (a) the well is from a new pool not previously known to exist and is commercially producible in that time, or (b) if after completion it is "reasonable" to assume that the well will not come into production within twelve months.\(^\text{10}\) If either (a) or (b) is true (or the well is completed in the year in which it was begun) then the amount expended will be considered to be an exploration expense and is fully deductible. This distinction, although presented here in its simplified form, is subject to certain anomalies, as is the case with most income tax provisions. For example, for some northern Canadian wells that might clearly be a development well (i.e., an additional well on a previously discovered field) might still be classified as an exploration expense. This result can occur if production from this well does not develop for at least 12 months after the well is completed due to (for example) waiting for a regulatory ruling on say, price, or waiting for completion of a pipeline, or even due to weather problems.\(^\text{11}\) In fact, the potential problems of interpretation of this distinction is acknowledged in section 66 (13), which, surprisingly, seems to say that if a taxpayer cannot decide which category a particular expense should fall into, he can take his choice.\(^\text{12}\)

Nevertheless, the implications of this differential treatment of expenses introduces potential distortions. For example, drilling a series of (exploratory) wells in the offshore area on the east coast, before actual production commences, is preferable (in terms of maximiz-
ing the present value of tax deductions and for determining the maximum potential output of the whole region) even if it is already proven to be commercially "viable".

More importantly, however, the distinction between exploration and development expenses provides an incentive in favour of new exploration activity at the expense of secondary recovery operations. As of the November 16, 1978 federal budget, secondary or recompletion costs are now recognized as development expenses (but not exploration expenses). To see why this results in the creation of a distortion, consider the two options facing a producer once primary production from a given reserve ceases. He can either abandon the well and explore in new areas (whereby any money spent will qualify as exploration expenses) or he can expend additional funds on the well in order to obtain secondary production. To the extent that he follows this latter course of action, he will receive a credit of only 30 cents per dollar spent (the rate of deduction for development expenses). On top of this, his earned depletion allowance will be different (as we shall see below). Therefore, one consequence of the differential rates of tax writeoffs for exploration and development expenses is that a misallocation of funds may result due to the generous tax incentives given to some exploration expenses but not to "others" (i.e., secondary recovery costs).

Finally, it should be noted that the definitions of exploration and development expenses have undergone some significant alterations over the past five years. One such alteration relates to the treatment of expenses made to acquire resource properties. Since the federal budget of May 25, 1976, the cost of any resource property acquired after
May 6, 1974 and paid to a government in Canada, is now to be treated as a Canadian development expense. However, the rate at which these expenses can be written off is only 10 per cent, not 30 per cent, as is the case for all other development expenses. Secondly, with respect to synthetic oil sands operations, the November 16, 1978 budget moved to recognize expenses incurred in developing these mines as an exploration expense (instead of a development expense as was previously the case). 16

iv) **Earned Depletion:**

The present system, whereby a taxpayer has to earn his depletion allowance, evolved from the Income Tax Act of 1972. Previously, resource companies were allowed to deduct automatically one-third of resource income as compensation for depleting their stock of reserves. The new provision required the oil firms to "earn" this depletion allowance by engaging in exploration and development activities. Effective after May 7, 1974, the taxpayer would receive $1 of depletion allowance for each $3 of "eligible expenditures" incurred in Canada. 17 These expenses would be allowed to accumulate from November 7, 1969 to permit the oil firms to accumulate a substantial earned depletion "base" in order to ease the transition from the automatic depletion to the earned depletion system.

There currently exists a ceiling on the value of this deduction. A taxpayer may deduct earned depletion equal to the lesser of his unclaimed earned depletion base or 25 per cent of his resource profits before the deduction (sub-total 2 in Table 2.1). 18 Almost all exploration and development expenses are included in the earned depletion
base, but there are two exceptions. One pertains to the treatment of interest costs. Capitalized interest and financing charges are excluded from the earned depletion base. This ensures that those firms that borrow to finance the necessary expenses would not be placed in a more advantageous position with respect to their earned depletion base than those who would finance their programs from current or retained earnings. 19

The cost of acquiring a resource property is also excluded from the earned depletion base (even though it is considered a development expense). Presumably, the rationale for this move was to encourage actual exploration and development activities rather than mere acquisition of potentially-producible properties. 20

To summarize, therefore, given the federal corporate tax rate is 36 per cent for operations on "provincial" lands the earned depletion allowance permitting 1/3 of exploration and development expenses to be deducted from production income in calculating taxable income represents a 12 per cent investment tax credit. In addition, as we will see below, the earned depletion allowance will also reduce provincial income tax liabilities and, therefore, can add up to another 5 per cent to the effective rate of tax credit from earned depletion.

v) Supplementary Depletion:

On April 10, 1978, the federal government announced a new system whereby depreciable assets used in secondary and tertiary recovery operations would generate an enhanced earned depletion allowance. Prior to this date, assets such as water injection and steam injection systems for building up reservoir pressure, did not qualify for depletion allow-
ances. Under the new system, the cost of depreciable assets used in secondary and tertiary recovery will earn depletion at a 50 per cent rate. In contrast, assets used in primary production (such as oil pumps and collector lines for example) still will not earn depletion of any kind. 22

Also effective on this date, the supplementary depletion base will be augmented by the cost of oil sands assets (although still at a rate of 33 1/3 per cent). That is, these assets will no longer enter the earned depletion base. This will represent a more generous treatment of these costs since the ceiling on supplementary depletion is 50 per cent of income from all sources not just resource profits. 23

In summary, therefore, a firm that incurs $1 of costs on depreciable assets used in either secondary or tertiary recovery will receive, effectively, an 18 per cent investment tax credit (based on a federal tax rate of 36 per cent). That same dollar, if spent on a depreciable oil sands asset, however, would enjoy only a 12 per cent investment tax credit.

vi) Frontier Exploration Allowance:

The frontier exploration allowance or the "super-depletion" allowance (as it is more commonly referred to) was introduced in the federal budget of March 31, 1977. It was designed to be a temporary (effective from April 1, 1977 to March 31, 1980) 24 and experimental incentive to assist in the financing of high risk exploratory wells in Canada.

A well qualifies as a frontier exploration well because of its cost, not because of its location. Any individual well that costs in
excess of $5 million will qualify. The allowance is equal to 66 2/3 per cent of the excess costs (over $5 million) and can be deducted from income from any source. This allowance is to be in addition to the 100 per cent exploration expense writeoff and the 33 1/3 per cent writeoff for earned depletion already in effect. In other words, for qualifying expenses, a firm may receive a tax deduction approaching twice the value of the expense incurred.

The "super-depletion" allowance has received (not surprisingly) favourable reviews by the oil companies (in particular Dome Petroleum) and has also been the subject of growing criticism in political circles. Critics assailing this incentive, claim it favours exploration in the Beaufort Sea as opposed to the East coast, Dome Pétroleum, and rich taxpayers.

Since it costs significantly more to drill a well in the Beaufort Sea area as opposed to say the offshore areas of the east coast (or even the Arctic Islands), and certainly more than in the province of Alberta, the super-depletion allowance tends to favour drilling in the Beaufort Sea area. For example, suppose the costs per well in each area are the following:

- Beaufort Sea: $50 million
- East Coast: $15 million
- Alberta: $5 million

Then, the total value of the tax writeoffs permitted are:

- Beaufort Sea: $96.7 million
- East Coast: $26.7 million
- Alberta: $6.7 million

The value of the tax savings per well in each area are, then, $44.5
million, $12.3 million and $2.4 million respectively.28 In other words, a firm (such as Dome Petroleum) that drills an exploratory well in the Beaufort Sea is left to finance only $5.53 million (or 11.1 per cent of the total cost of the well). whereas, firms drilling in the East coast region would have to put up $2.73 million (or 18.2 per cent of the total cost of the well). In contrast, the firm drilling in Alberta would be required to finance $2.6 million or 52 per cent of the total cost of the well.29 Alternatively, this firm in Alberta must outlay approximately the same amount of money (per well) as does the firm drilling in the east coast area despite the fact that this offshore well might cost three times as much (as in this example).

The effect, then, of the super-depletion allowance is clear. It provides a tremendous tax savings for very expensive wells such as those in the Beaufort Sea. In fact, the higher the cost of an exploratory well in federal lands, the net cost to the firm of this well approaches 8 per cent (i.e., the firm's tax savings approach twice the federal tax rate). Therefore, it is quite possible that an inefficient allocation of capital funds may occur since there is a greater subsidy involved with frontier exploration as opposed to conventional areas.

These extremely generous tax benefits can also accrue to individuals. In fact, rich taxpayers that form a drilling pool can quite easily recover all of their investment (via tax rebates) without one drop of oil ever being discovered. Consider an investor with a marginal tax rate, for example, of 50 per cent. For every $10,000 he invests in a drilling fund, he receives in return roughly the same amount in tax rebates (provided he had existing resource income in order to claim the earned depletion allowance). Alternatively, for an
investor with a marginal tax rate of 60 per cent, he can receive $12,000 in tax rebates from the federal government for the same $10,000 he invested, a handsome 20 per cent return on his investment without any oil being discovered.

It is because of these generous tax incentives that Dome has been able to finance the majority of its exploration activity in the Beaufort Sea without giving up a significant share of its interests in the area. The tax incentives alone have been sufficient to induce investors to supply the necessary funds. The net result being that Dome is left to accumulate the vast majority of any net profits that might emerge from the area, while they themselves actually pay a very small share of the costs of the operation -- instead, the Canadian taxpayer finances the major share of the operation. No doubt this has helped to enable Dome to assert itself as the dominant force in the Beaufort Sea.

2.2.2 The Impact of the Federal Corporate Income Tax System: An Illustration

The federal corporate tax treatment of the oil and gas industry, as of January 1980, discussed above, has developed over a comparatively short period of time (since the Income Tax Act of 1972). It is interesting to note that the pattern of development since the May 6, 1974 budget has been one of concession on the part of the federal government. Each successive budget has moved in the direction of reducing the federal share of oil and gas revenues from corporate income taxes. To see this, refer to Appendix I (below).
For our purposes, however, it is more important to establish
that firms producing oil and gas in Canada will not all face the same
effective federal corporate income tax liability due to the adoption
of different production techniques. In Canada, crude oil is currently
and potentially produced by conventional methods, secondary and tertiary
recovery methods, constructing synthetic oil sands plants, and from
frontier areas. It is clear from the preceding discussion (summarized
in Table 2.2 below) that these methods of production do not receive
equal tax treatment. Table 2.2 lists the major tax deductions available
to producers of each type of oil. For example, production of conven-
tional oil is eligible for the federal resource allowance, deductions
for exploration and development expenses (at the relevant rates) and
the earned depletion allowance. The federal tax treatment of oil sands
projects differs from conventional oil operations in that any develop-
ment expenses are to be included as exploration expenses (by virtue of
the November 1978 federal budget) and these projects earn supplementary
depletion instead of the earned depletion allowance (although still at
a rate of 33 1/3 per cent). Tertiary production, on the other hand,
differs from the treatment of conventional oil projects since the costs
of depreciable assets employed in tertiary production qualifies for
supplementary depletion at a 50 per cent rate. If and when production
from frontier areas is realized, (according to the federal tax policies
in effect as of January 1980), the producers of this oil will be able
to reduce their taxable income an additional 66 2/3 per cent of the
value of their exploration expenses via the frontier exploration allow-
ance. As well, since the frontier areas are by law considered to be
"federal lands", the federal tax rate will be 46 per cent and not the
FACING ALTERNATIVE OIL PROJECTS
A SUMMARY OF THE ELIGIBLE INCOME TAX DEDUCTIONS

TABLE 2.2
standard 36 per cent for the other types of production (i.e., there will not be a provincial tax abatement applied in this case). Finally, the additional costs associated with the production of oil using secondary recovery techniques, although not recognized as legitimate exploration expenses, will qualify as development expenses and as such will also earn supplementary depletion at a rate of 50 per cent.

To illustrate how the effective tax liabilities vary by the type of oil produced, we will make the following simplifying assumptions;

1) exploration expenses for all types of oil will be a fixed proportion of the producer's net income (i.e., total revenue less operating costs).

Specifically,

\[ E = \alpha \cdot Y \]

where \( E = \) exploration expenses
\( Y = \) net income

and \( 0 < \alpha < 1 \). In particular, we will assume that \( \alpha = 0.22 \).

2) development expenses for all types of oil will be a fixed proportion of the producer's net income. That is,

\[ D = \beta \cdot Y \]

where \( D = \) development expenses
\( 0 < \beta < 1 \). In particular, we will assume the value of \( \beta \) is 0.12.

3) In order to calculate the supplementary depletion allowance on secondary, tertiary and synthetic oil production, we assume, for simplicity, that the value of the depletion base (i.e., the cost of depreciable assets used in secondary, tertiary or synthetic oil production) can be approximated by the value of development expenses incurred for each type of production.
Given these simplifying assumptions and the procedure for calculating federal corporate income tax liabilities (summarized in Table 2.2) the producer of conventional oil will face a federal tax liability of:

\[ T = 0.36[(1 - 0.25)Y - E - 0.30D - 0.333(E + D)] \]

where \( T \) = federal corporate income taxes owed, or simply (given our assumptions of the values of \( E \) and \( D \)),

\[ T = 0.36 \times [0.3808 Y] \]

Therefore, a conventional oil producer will pay 13.7 cents per dollar of net income in federal corporate income taxes. The effective tax liabilities (per dollar of net income) for the other types of oil production have been calculated in the same manner and the results are summarized in Table 2.3 below.34

**TABLE 2.3**

**EFFECTIVE CIT LIABILITIES PER DOLLAR OF NET REVENUES BY TYPE OF OIL**

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>Liability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Oil</td>
<td>13.7 ¢</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>21.2 ¢</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>10.8 ¢</td>
</tr>
<tr>
<td>Synthetic Oil</td>
<td>13.3 ¢</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>15.6 ¢</td>
</tr>
</tbody>
</table>

The conclusion of this section is clear. The federal tax system in place as of January 1980 provides differential tax liabilities for alternative sources of oil supply. Consequently, as we shall see later, the implicit incentives contained in the federal tax policy can
produce an inefficient allocation of (scarce) resources and therefore, an efficiency loss for Canada.

2.2.3 Federal Royalties on Production from Canada Lands

The federal government has an additional means for capturing a share of the resource revenues besides the federal corporate income tax. This alternative is the federal royalty to be applied against oil and gas production derived from federal or "Canada" lands. The formula for calculating this royalty, although proposed in Bill C-20 (Canada Oil and Gas Act), has yet to be passed into law. 35 Effectively, the formula contained in Bill C-20 computes the federal royalty in two parts:

(a) a 10 per cent basic royalty on total production

and (b) a progressive incremental royalty of 40 per cent of oil and gas production profits.

The value of annual profits subject to the progressive royalty will be total revenues less: operating expenses; the basic royalty; a capital allowance (a depreciation deduction); an allowance for a return on funds invested; and a notional federal income tax charge. 36 The capital allowance deduction a firm may claim is limited to one-sixth of the firm's "eligible investments" -- which for our purposes can be thought of as simply the value of the exploration and development expenses incurred. As well, the federal government also permits a firm to claim an allowance for a return (at a rate of 25 per cent) on their eligible investments. Finally, the federal government permits the firm to deduct from income subject to the progressive royalty, an estimate of the federal corporate income taxes owed on this income. The federal government, therefore, avoids double taxation of this income.
A numerical example showing how the federal royalties payable on production from Canada Lands are calculated appears in Table 2.4 below. The assumptions underlying these calculations are detailed in the accompanying notes to the table. In particular, we have assumed that a producer of oil from the Canada Lands has received the world price -- estimated to be approximately $33 (Canadian) as of January 1980 -- for his output. However, given the assumptions in our example, a firm producing in the frontier regions (or federal lands) will pay 30.3 per cent of the gross value of production, or $9.99 per barrel, to the federal government in the form of a royalty payment.

2.3 PROVINCIAL TAXATION OF OIL INCOMES (as of January 1980)

2.3.1 Provincial Royalties

The story related so far applies only to the taxation policies of one level of government. The provincial governments of the producing provinces also collect revenues from the oil companies by exercising their ownership rights and imposing taxes and royalties on oil production.

It is the purpose of this section of the paper then to focus on the tax and royalty structure of the producing provinces. In the analysis that follows below, we assume that conventional, secondary and synthetic oil are produced in the province of Alberta whereas, tertiary oil production is assumed to be located in the province of Saskatchewan (i.e., where the majority of the heavy oil deposits are located) and finally, frontier oil production, as indicated in the preceding section, is assumed to take place on federal lands. Consequently, it is necessary in this section to focus on both the
TABLE 2.4
AN ESTIMATE OF THE FEDERAL ROYALTIES PAYABLE
PER BARREL OF OIL PRODUCED FROM THE CANADA LANDS
(as of January 1960)

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Basic Royalty</td>
<td>$3.00</td>
</tr>
<tr>
<td>Income Eligible for Progressive Royalty:</td>
<td></td>
</tr>
<tr>
<td>Gross Revenues</td>
<td>$33.00</td>
</tr>
<tr>
<td>Less: Operating expenses</td>
<td>6.12</td>
</tr>
<tr>
<td></td>
<td>26.88</td>
</tr>
<tr>
<td>Less: Basic Royalty</td>
<td>3.30</td>
</tr>
<tr>
<td></td>
<td>23.38</td>
</tr>
<tr>
<td>Less: Capital Allowance</td>
<td>1.51</td>
</tr>
<tr>
<td></td>
<td>21.87</td>
</tr>
<tr>
<td>Less: Allowance for return on investments</td>
<td></td>
</tr>
<tr>
<td>Income taxes</td>
<td>2.27</td>
</tr>
<tr>
<td></td>
<td>19.60</td>
</tr>
<tr>
<td>Less: Allowance for Federal Corporate</td>
<td></td>
</tr>
<tr>
<td>Income taxes</td>
<td>2.87</td>
</tr>
<tr>
<td>ELIGIBLE INCOME</td>
<td>16.73</td>
</tr>
<tr>
<td>Federal Progressive Royalty</td>
<td></td>
</tr>
<tr>
<td></td>
<td>6.68</td>
</tr>
<tr>
<td>TOTAL FEDERAL ROYALTIES</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$9.94</td>
</tr>
</tbody>
</table>

Notes:

a. The basic royalty is 10 per cent of gross revenues.

b. Operating expenses are assumed to be four times the operating costs of conventional oil. The National Energy Program (page 95) estimates the operating expenses for conventional oil producers in 1979 and 1981 to be $1.37 and $1.78 per barrel, respectively. In our example, we have simply taken the average of these two figures (times four) to represent the value of operating expenses for frontier oil.

c. The capital allowance is one-sixth of eligible investments, which are assumed to be equal to the value of exploration and development expenses. We have retained our earlier assumption that exploration and development expenses are 22% and 12% respectively of net revenues.

d. The allowance for a return on investment is 5% of the eligible investments (i.e., exploration and development expenses).

e. Any production from Crown lands is assumed to come from frontier regions where the federal corporate income tax liability is assumed to be 10.76% of net revenues (see Table 2.3).

f. The federal progressive royalty rate is 40% of "eligible revenues".
Alberta and Saskatchewan governments' royalty structures (i.e., the federal royalty structure to be applied against frontier oil producers was reviewed above). In addition, however, although the production of synthetic oil is assumed to be located in Alberta, the royalty formula applied to these megaprojects differ from the formulae applied to conventional (and secondary) oil producers. Therefore, we will also discuss the synthetic oil royalty formulae.

i) The Alberta Conventional (and Secondary)\(^{37}\) Oil Royalty Schedule:

Following the rapid escalation of world crude oil prices in 1973-74, the Alberta government reacted by significantly increasing the royalty rates on domestic oil and gas production. The previous royalty arrangements, which called for a basic rate of about 22 per cent, was replaced with a split royalty rate scheme. The new royalty structure distinguished between "old" and "new" oil where new oil was simply any oil produced from a pool that was discovered after April 1, 1974. The motivation of the split royalty scheme was to capture, for the Alberta government, a greater share of the economic rent from old oil and at the same time, recognize the higher costs involved with the production of new oil.

The actual formula employed in determining the required royalty payment is set out in Regulation 93/74 of the Petroleum Royalty Regulations. The formula calculates royalties due from conventional and secondary oil on a per well basis and is given by,\(^{38}\)

\[
(1) \quad R = S + k \cdot S \cdot \frac{(A - B)}{A}
\]

where \(R = \text{royalty per month in barrels of oil,}
\]
S = number of barrels of oil (as determined below),
k = royalty factor (as determined below),
A = par price of crude oil (set by the Alberta government),
and B = select price of crude oil (set by the Alberta government).

This legislated formula, in essence, is made up of two parts -- a base royalty (S), and a supplemental royalty \[ k \cdot S \cdot (A - B) / A \]. The characteristics of the base and supplemental royalties and their components is the subject we now address, beginning with the base royalty.

a) **The Base Royalty (S):**

The base royalty is entirely dependent upon monthly oil production. That is, the base royalty rate will rise as monthly oil production rises from a minimum rate of 5 per cent of output for very small wells to a maximum rate of 25 per cent of output for very large wells. In particular, for wells producing in excess of 1200 barrels per month, the base royalty (S) will be given by;

\[
S = 180 + 0.25(Q - 1200) \\
\text{or} \quad S = 0.25(Q) - 120
\]

where Q represents monthly production of oil per well (in barrels).

Therefore, for the "average" oil well, as defined by the Alberta government, producing 3600 barrels of oil per month, the base royalty will amount to 780 barrels of oil or approximately 22 per cent of output.

b) **The Supplemental Royalty:**

The supplemental royalty is expressed as a percentage of the base royalty (S) and is influenced by the classification of oil (old versus
new) and by the degree to which the current domestic price of oil (or more specifically, the par price of oil (A) which is equivalent to the wellhead price of oil plus a transportation component of 32 cents per barrel), exceeds the select price of oil, B (which is determined by the Alberta government (currently fixed at $4.71 per barrel) and in effect, represents a non-OPEC oil price). In other words, if the mark-up in the domestic price of oil (relative to the select price) accounts for, say, 75 per cent of the market price then for a given value of the royalty factor (k), (i.e., for old oil as well as new oil) the supplemental royalty will represent an additional liability to the producer equal to 75 per cent of the base royalty. Furthermore, as the domestic price of oil rises, this component of the supplemental royalty will imply an increased liability for the oil producer.

The supplemental royalty, however, is also influenced by the classification of the oil produced. A separate royalty factor, k, is applied to both old oil and new oil production. The royalty factor (k) which appears in the legislated formula (i.e., equation (1)) is determined in conjunction with an intent formula established by the Alberta government. The intent formulae, one for old oil and one for new oil, capture for the Alberta government a share of the market value of a barrel of oil in varying proportions. For example, in the case of old oil, the intention is to capture 22 per cent of the first $4.40 of the wellhead price, 65% of the next $2.10, and 50% of the remaining difference that prevails between the wellhead price and $6.50 per barrel. In the case of new oil, however, the Alberta government captures 22 per cent of the first $4.40 per barrel but then only 35% of the remaining difference between the wellhead price and $4.40 per barrel.
With the total royalty take captured by the Alberta government as described above, the average royalty rate then per barrel is defined simply as the total royalties paid expressed as a percentage of the wellhead price. That is,

\[ \bar{R}_o = \frac{0.22(4.40) + 0.65(2.10) + 0.50(P - 6.50)}{P} \]  

(3) Average Royalty Rate - Old Oil

and

\[ \bar{R}_n = \frac{0.22(4.40) + 0.35(P - 4.40)}{P} \]  

(4) Average Royalty Rate - New Oil

With the average royalty rates for old and new oil calculated in this fashion (given the wellhead price of oil, \( P \)), the respective royalty factor is determined by applying these average rates in the legislated formula (equation (1)) for the "average" oil well (producing 3600 barrels of oil per month) and solving for \( k \).

That is, given that we are dealing with the "average" well and given the par and select prices of oil, by solving each of the following expressions for \( k_o \) and \( k_n \) (the only unknowns), the royalty factor for old and new oil respectively is determined:

\[ \bar{R}_o(3600) = \bar{S} + k_o \cdot \bar{S} \cdot (A-B)/A \]  

(5) Old Oil: \( \bar{R}_o(3600) = \bar{S} + k_o \cdot \bar{S} \cdot (A-B)/A \)

and

\[ \bar{R}_n(3600) = \bar{S} + k_n \cdot \bar{S} \cdot (A-B)/A \]  

(6) New Oil: \( \bar{R}_n(3600) = \bar{S} + k_n \cdot \bar{S} \cdot (A-B)/A \)

where

- \( \bar{R}_o \) = average royalty rate for old oil as defined in equation (3),
- \( \bar{R}_n \) = average royalty rate for new oil as defined in equation (4),
- \( \bar{S} \) = value of base royalty for "average" well (in barrels) as defined in equation (2),
- \( \bar{R}_o(3600) \) = average royalty for old oil production (in barrels),
- \( \bar{R}_n(3600) \) = average royalty for new oil production (in barrels).
and \( R_n(3600) \) = average royalty liability for new oil production (in barrels).

It should be noted that the value of \( k \) is price sensitive and therefore, will change as the wellhead price changes (i.e., since a wellhead price increase will cause the average royalty rates and the par price of oil to change) but it changes in such a fashion so as to preserve a 50 per cent marginal royalty rate for old oil and a 35 per cent marginal royalty rate for new oil.

c) Royalty Tax Credit and Royalty Tax Rebate:

The gross royalty liability of an oil firm, as discussed above, is reduced by the Alberta government via the following two mechanisms:

i) the royalty tax rebate which refunds the provincial income tax payable (in excess of the federal resource allowance) as a result of the non-deductibility of provincial royalties. In other words, to calculate the value of the royalty tax rebate, one would simply apply the Alberta provincial corporate income tax rate to the net amount of provincial royalties paid less the value of the federal resource allowance.

and ii) the royalty tax credit which is intended to partially compensate for the additional federal tax liability resulting from the disallowance of provincial royalties as a tax deduction. The credit is equal to 25 per cent of any royalty paid to the Alberta government with a maximum credit of $1 million a year.

d) Effective Oil Royalties:

In the analysis that follows it will be useful to express the gross royalty liability of an oil producer (i.e., before the royalty tax credit or the royalty tax rebate) as a percentage of his total revenues. This exercise is performed below for the "average" well producing 3600 barrels of oil per month. To derive this expression (for the gross royalty liability for an oil producer in Alberta),
which is price sensitive, we combine equations (5) and (6) respectively with equations (3) and (4) and simplify to obtain:

\( k_o = \frac{[(0.50 - 0.917/P)3600 - \bar{S}] A}{(A-B) \cdot \bar{S}} \)

and

\( k_n = \frac{[(0.35 - 0.572/P)3600 - \bar{S}] A}{(A-B) \cdot \bar{S}} \)

Then plugging these expressions for the royalty factors \( (k_o \text{ and } k_n) \) into the legislated formula (equation (1)) and simplifying yields the following expressions for royalties (in barrels):

\( R_o = [50.0 - 0.917/P] \cdot 3600 \)

and

\( R_n = [35.0 - 0.572/P] \cdot 3600 \)

or, recognizing that the average output \( (Q) \) is 3600 barrels per well per month, then the gross royalty liability for the average well, expressed as a percentage of total gross revenues is given by:

\( R_o = [0.50 - 91.7/P] \)

and

\( R_n = [0.35 - 57.2/P] \)

or, in general, for the average well, the royalty liability for old and new oil respectively (in dollars) can be represented as:

\( R_o = \theta_o \cdot P \cdot Q \)

and

\( R_n = \theta_n \cdot P \cdot Q \)

where in this case, \( \theta_o \) and \( \theta_n \) are given by equations (11) and (12) respectively.
(ii) Royalties on Production of Tertiary Oil

The structure of royalties discussed above applies to the production of oil employing both conventional and secondary recovery techniques. Royalties, however, are also imposed on tertiary oil production. Since the majority of tertiary (or heavy) oil projects are (or will be) located in Saskatchewan, for the purposes of this thesis, we will assume that the royalties applied to tertiary oil can be calculated from the Saskatchewan oil royalty schedule.

Actually, Saskatchewan imposes charges on petroleum production in two forms:

a) a royalty on production from crown lands,

and b) the oil well income tax on production from all acreage. The first is allowed as a credit against the second, so a producer effectively computes both levies, and pays the higher of the two. This is usually the oil well income tax. However, since the Saskatchewan oil well income tax and the regulations to it are complex pieces of legislation, in the interest of simplicity, we will assume the producers pay royalties to the Saskatchewan government at least equal to the value determined by applying the formula outlined below. 43

Saskatchewan, like Alberta, calculates the royalties payable on a per well basis and technically receives its royalties in barrels of oil. The royalty formula is set out in Saskatchewan regulation 8/69. 44 Briefly stated, in the case of "old" oil, if monthly production exceeds 300 barrels, the Saskatchewan government will take 56.7 per cent of the oil produced less an allowance of 70 barrels of oil which will be exempt from royalties.

For new oil, Saskatchewan will capture 36.85 per cent of the oil
produced less a royalty-free 45.5 barrels of oil. Specifically,

for old oil: \( R_o = 0.567 Q - 70.0 \)

for new oil: \( R_n = 0.368 Q - 45.5 \)

where \( Q \) represents the monthly production of oil.

The Saskatchewan government has elected to follow the example of the Alberta government and offer a royalty tax rebate. This rebate compensates the producers for paying provincial income taxes as a result of the non-deductibility of royalty payments in calculating taxable income. The value of the royalty rebate is arrived at by applying the provincial corporate tax rate (14 per cent for Saskatchewan) to the net amount of the royalties paid to the province less the federal resource allowance deduction. However, unlike Alberta, Saskatchewan has so far chosen not to introduce a royalty tax credit to compensate the oil producers for the federal income taxes paid due to the non-deductibility of royalty payments.

(iii) Royalties on Non-Conventional Oil Projects

The royalties payable to the producing provinces from oil sands projects are determined individually by negotiations between the producers and the province. The royalty schedule as applied to the Syncrude operation, according to federal Energy, Mines and Resources officials, is approximately equal to 22 per cent of the value of gross production. Therefore, in the analysis that follows, we will assume that the royalties payable on oil sands projects will be equal to 22 per cent of the gross value of production.
2.3.2 Provincial Corporate Income Taxes

Considered by itself, the royalty arrangements, although somewhat less so for new oil, manage to capture a significant portion of the oil revenues for the producing provinces. But this is not the end of the story, for the provinces also capture additional revenues via the provincial corporate income tax. Since the producing provinces, as of January 1980, are still "agreeing" provinces, the tax base for the provincial corporate income tax is identical to the federal tax base (described above). The current provincial tax rates applied to this base are 11 and 14 per cent for Alberta and Saskatchewan respectively.46

2.3.3 Provincial Drilling Incentives

Both the Alberta and Saskatchewan governments offer exploration drilling incentives which take the form of a credit or grant for each foot of qualified exploratory drilling. In the case of the incentives offered by Alberta, the amount of the credit earned depends on the depth of the well, its location within the province and the results of drilling of earlier wells within three miles and one-and-one-half miles of the well.47 Deepening of a well can generate credits just as can the drilling of a separate well.

'The first two thousand feet of well depth earns no credit but wells from 2,000 to 18,000 feet deep can earn a marginal credit ranging from $20 per additional foot up to $575 per additional foot.48 Because these incentives vary so much and depend to a large extent on the characteristics of each individual well, it is very difficult for our purposes to explicitly include these drilling incentives into our
analysis. For this reason, at least for now, we will simply recognize their existence and point out that because of these incentives, the provincial share of resource revenues we will look at later on, must be viewed as a maximum.

2.4 CHANGES IN FEDERAL ENERGY POLICY: THE NATIONAL ENERGY PROGRAM

On October 28, 1980 the federal government introduced the National Energy Program (NEP). This program, as we shall see below, proposed several significant changes in federal energy policy. The purpose of this section of the chapter is to highlight the changes introduced which are relevant for this thesis. Briefly, the features of NEP that we are interested in are: a) the new oil pricing regime announced; b) changes in federal tax policy; and c) the introduction of federal incentive payments for certain qualifying expenditures.

2.4.1 Pricing

The federal government introduced in NEP a new schedule of prices for domestic oil production and a new price system which will blend the costs of different sources of oil and establish a weighted-average price to consumers. This single price of oil, the "made-in-Canada-price", will be a weighted average of the prices of conventional oil, synthetic oil (oil sands), tertiary oil, frontier oil and imported oil.

The National Energy Program calls for staged increases in the prices of each type of oil (except imported oil). The price of conventional oil at the wellhead (whether "old", "new" or secondary oil), which as of January 1, 1981 was $17.75 per barrel, will increase $1 every six
months until the end of 1983. During 1984 and 1985 the wellhead price will increase at a faster rate -- namely, $2.25 per barrel every six months. 

The federal government, at the same time, introduced "reference prices" for both synthetic and tertiary oil. The reference price for synthetic oil, as of January 1, 1981, was fixed at $38.00 per barrel (approximately the world price of oil in Canadian funds prevailing at the start of 1981) but is scheduled to increase annually by the general rate of inflation (as measured by the percentage change in the Consumer Price Index). A similar approach was also applied to tertiary oil, except that the real price (or reference price) for this type of oil was to be only $30.00 per barrel as of January 1, 1981. Unfortunately, the National Energy Program did not announce a reference price for frontier oil. In the analysis, which follows below, however, the reference price for frontier oil will be assumed to be identical to the reference price for synthetic oil.

The costs of imported oil will be incorporated into the "made-in-Canada" price by introducing a new federal tax -- the Petroleum Compensation Charge. The revenue collected from this tax is designed to offset the cost of imported oil and cover the cost of subsidies effectively given to synthetic, tertiary and frontier (when applicable) oil producers to make up the difference between the "made-in-Canada" price and their respective reference prices.

In summary, it is important to note (for our purposes) that the National Energy Program continues the practice of artificially setting the domestic price of oil. In fact, there is an even greater trend towards artificiality in that the production of synthetic oil (and
presumably tertiary and frontier oil as well) is no longer guaranteed the price of oil as determined in the world market. 54

2.4.2 New Federal Taxes Introduced in NEP

The National Energy Program introduced one new tax (the Petroleum and Gas Revenue Tax), granted the legal authority for Petro-Canada to "expropriate" a 25 per cent interest in all operations (regardless of their start-up date) on Canada Lands, significantly altered the earned depletion and supplementary depletion allowances and declined to re-introduce the frontier exploration allowance.

The federal government due to past policies found itself receiving (in its opinion) "too small" a share of the resource revenues. The exploration incentives in place, while significantly reducing the cost of exploration and thereby aiding potential domestic supplies, also reduced federal revenues. In order to increase its share of the resource revenues the federal government could have reduced these incentives but the cost of doing so would be a reduced supply potential. Instead, the federal government introduced a new tax -- the Petroleum and Gas Revenue Tax (PGRT). The PGRT taxes the net oil and gas production revenues of a producer. In particular, a tax rate initially established at 8 per cent is applied to net operating revenues (the tax base). 55

There are no deductions permitted for exploration expenses, development expenses, capital cost allowances or interest expenses. This tax, in other words, is not an income tax. Furthermore, this tax is not deductible for income tax purposes so a firm will end up paying income taxes on taxes (PGRT) paid to the federal government.
The National Energy Program also introduced significant changes to the earned depletion allowance. Effective January 1, 1981 a firm operating on provincial lands will not be able to claim as generous an earned depletion allowance as before. For 1981, one-third of exploration expenses only net of any incentive payments received (discussed below), may be claimed.\textsuperscript{56} That is, the earned depletion base no longer includes any allowance for development expenses incurred.

After 1981, the earned depletion allowance available to producers of conventional oil on provincial lands will be phased out. The rate at which exploration expenses incurred will earn a depletion allowance will drop to 20 per cent in 1982, to 10 per cent for 1983 and finally, to 0 per cent in 1984.\textsuperscript{57}

The earned depletion allowance available to producers of synthetic oil will continue to be available (at a rate of 33 1/3 per cent of qualifying expenditures) as before. However, the earned depletion base will now be net of any incentive payments received.\textsuperscript{58}

The supplementary depletion allowance applying to both secondary and tertiary oil recovery projects is also significantly altered by NEP. The rate at which qualifying expenditures may be deducted is no longer 50 per cent but is now 33 1/3 per cent.\textsuperscript{59} Again, the qualifying base is calculated to be net of any incentive payments received. More importantly, this depletion allowance will only be available to projects which are entitled to receive incentive prices. The implication of this last statement is that since secondary oil production receives the conventional wellhead price and not the tertiary oil reference price, then it must be inferred that secondary oil no longer qualifies to receive an earned depletion allowance in any form.\textsuperscript{60}
The National Energy Program also introduces changes in federal tax policy as it applies to frontier regions (or the Canada Lands). Most notable among these changes is the decision not to re-introduce the frontier exploration allowance (which expired on April 1, 1980) and the granting to Petro-Canada of a 25 per cent "back-in" interest on all operations on the Canada Lands.\(^6\) The federal government also changed the earned depletion allowance available to producers on the Canada Lands. As is the case for producers of conventional oil on provincial lands, only exploration expenses (net of any incentive payments received) will enter the depletion base (i.e., development expenses are excluded). But, unlike the situation for producers of conventional oil, the rate at which these expenses can be deducted will not be reduced over time but rather remain at a rate of 33 1/3 per cent.\(^6\)

2.4.3 Federal Incentive Payments: The Petroleum Incentives Program

In an attempt to compensate the oil producers for altering the earned depletion allowance (which, according to the federal government, favoured larger, foreign-owned firms) and in order to encourage more investment by Canadian companies, a new system of direct incentives for exploration and development was introduced. The incentive payments will vary by the type of expenses (exploration or development), by location of activity (provincial lands or Canada Lands), by the type of oil produced (synthetic, tertiary, conventional or frontier oil) and by the degree that the firm is Canadian owned and controlled.

Table 2.5 below summarizes the schedule of incentives as
outlined in the National Energy Program. A "foreign" firm (less than 50 per cent Canadian owned and controlled) operating in the provinces will not receive any incentive payments for exploration or development. A firm operating in the provinces that is between 50 per cent and 75 per cent Canadian owned and controlled will not qualify for an incentive payment until 1982. For 1982 and 1983 the grant will equal 10 per cent of approved exploration costs, however, beginning in 1984, the rate increases to 15 per cent. This same firm will also be eligible for incentive payments for development expenses (although not until 1982), but at a 10 per cent rate thereafter. Finally, a "Canadian" firm (more than 75 per cent Canadian owned and controlled) operating in the provinces will receive an incentive payment for exploration activity equal to 35 per cent of their exploration expenses (effective in 1981 and thereafter) and an incentive payment for development activity equal to 20 per cent of their development expenses (again, effective beginning in 1981).

In the case of tertiary or synthetic oil production, a "foreign" firm will not qualify for any incentive payments. Alternatively, if this firm was a "Canadian" firm, then it would receive an incentive payment equal to 20 per cent of the approved capital expenditures incurred in 1981 and thereafter.

Finally, production activity by foreign firms in the frontier regions (or Canada Lands) will qualify for an incentive payment for their exploration activity but not their development activity. This firm would receive a grant equal to 25 per cent of their exploration expenses. A Canadian firm, on the other hand, operating on the Canada Lands would receive an incentive payment for exploration
### Table 2.5: Petroleum Incentive Payments under the National Energy Program

#### A. Conventional Oil from Provincial Lands:

<table>
<thead>
<tr>
<th>Exploration</th>
<th>Depletion</th>
<th>0 - 50%</th>
<th>50 - 75%</th>
<th>75% +</th>
</tr>
</thead>
<tbody>
<tr>
<td>1981</td>
<td>33 1/3</td>
<td>Nil</td>
<td>36</td>
<td></td>
</tr>
<tr>
<td>1982</td>
<td>20</td>
<td>Nil</td>
<td>35</td>
<td></td>
</tr>
<tr>
<td>1983</td>
<td>10</td>
<td>Nil</td>
<td>35</td>
<td></td>
</tr>
<tr>
<td>1984</td>
<td>Nil</td>
<td>10</td>
<td>35</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Development</th>
<th>Depletion</th>
<th>0 - 50%</th>
<th>50 - 75%</th>
<th>75% +</th>
</tr>
</thead>
<tbody>
<tr>
<td>1981</td>
<td>Nil</td>
<td>Nil</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>1982</td>
<td>Nil</td>
<td>Nil</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>1983</td>
<td>Nil</td>
<td>10</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>1984</td>
<td>Nil</td>
<td>10</td>
<td>20</td>
<td></td>
</tr>
</tbody>
</table>

#### B. Synthetic and Tertiary Oil from Provincial Lands:

<table>
<thead>
<tr>
<th>Depletion</th>
<th>0 - 50%</th>
<th>50 - 75%</th>
<th>75% +</th>
</tr>
</thead>
<tbody>
<tr>
<td>1981</td>
<td>33 1/3</td>
<td>Nil</td>
<td>20</td>
</tr>
<tr>
<td>1982</td>
<td>33 1/3</td>
<td>Nil</td>
<td>20</td>
</tr>
<tr>
<td>1983</td>
<td>33 1/3</td>
<td>10</td>
<td>20</td>
</tr>
<tr>
<td>1984</td>
<td>33 1/3</td>
<td>10</td>
<td>20</td>
</tr>
</tbody>
</table>

#### C. Production from Canada Lands:

<table>
<thead>
<tr>
<th>Exploration</th>
<th>Depletion</th>
<th>0 - 50%</th>
<th>50 - 75%</th>
<th>75% +</th>
</tr>
</thead>
<tbody>
<tr>
<td>1981</td>
<td>33 1/3</td>
<td>25</td>
<td>35</td>
<td>80</td>
</tr>
<tr>
<td>1982</td>
<td>33 1/3</td>
<td>25</td>
<td>45</td>
<td>80</td>
</tr>
<tr>
<td>1983</td>
<td>33 1/3</td>
<td>25</td>
<td>45</td>
<td>80</td>
</tr>
<tr>
<td>1984</td>
<td>33 1/3</td>
<td>25</td>
<td>50</td>
<td>80</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Development</th>
<th>Depletion</th>
<th>0 - 50%</th>
<th>50 - 75%</th>
<th>75% +</th>
</tr>
</thead>
<tbody>
<tr>
<td>1981</td>
<td>Nil</td>
<td>Nil</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>1982</td>
<td>Nil</td>
<td>Nil</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>1983</td>
<td>Nil</td>
<td>10</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>1984</td>
<td>Nil</td>
<td>10</td>
<td>20</td>
<td></td>
</tr>
</tbody>
</table>

---

**Notes:**

(a) As a percentage of allowable expenditures.

(b) Depletion will be earned on qualifying expenditures net of any incentive payments.

**Source:** Adapted from The National Energy Program, Energy, Mines and Resources, 1976, page 40.
activity equal to 80 per cent of the exploration expenses incurred, and a grant for development activity equal to 20 per cent of the firm's development expenses.

It is important to point out that the incentive payments for development activity are the same no matter what the firm's ownership structure is, or whether it produces on provincial lands or Canada Lands. There is a big difference, however, in the treatment of exploration activity. The federal government has imposed significantly more generous incentives for exploration activity in Canada Lands than for provincial lands. In part, this can be attributed to the higher risks associated with exploration activity in the frontier regions; in part, due to the incentives already offered by the producing provinces for exploration activity on provincial lands; and in part, it compensates for the Crown expropriating a 25 per cent interest in every exploration right, at any time, without directly contributing to costs incurred by the firm in the past. More importantly, however, the generous grants offered to producers operating in the Canada Lands provide an investment incentive favouring federal areas. The consequence of this action is that the revenues that will be derived in the future from the current investment decisions, will to a large extent, accrue to the federal government via the federal corporate income tax and the federal basic and progressive incremental royalty. In other words, the federal government is undertaking an "investment" (offering generous exploration incentives for federal areas) and hopes to receive a lucrative return on this "investment" in the future (in the form of an increased share of resource revenues). This "investment" strategy, however, may come at
the expense of more secure, but less profitable (for the federal government) sources of oil located on provincial lands.

2.5 ALTERATIONS TO PROVINCIAL OIL TAX POLICIES

Since the introduction of the National Energy Program there has occurred only one alteration to the producing provinces taxation policies. The Alberta government has since begun to administer its own corporate income tax. Despite this decision, the approach taken to derive corporate taxable income in Alberta has not been significantly altered. Therefore, in the analysis that follows we will assume that the calculation of Alberta corporate taxable income is identical to the method outlined above.

2.6 CONCLUSIONS

The purpose of this chapter of the thesis was to survey federal and provincial taxation policies as they apply to the domestic oil industry, in both the pre-NEP and (immediate) post-NEP periods. This survey is intended to be used as an input in attempting to provide answers to these questions: 1) Does the array of federal and provincial tax policies in place distort our allocation of resources? and if so, 2) in which direction is the bias? and finally, 3) What are the efficiency costs to the Canadian economy arising from these (distortive) tax policies? We will address these issues in Chapter 4 but first, we examine the underlying distributional effects of the pre-NEP tax regime on the federal equalization program in the next chapter.

2. Table 2.1 represents a simplified version of Table 1 appearing in Holland, Schulli and Kemp, Canadian Taxation of Oil and Gas Income: An Analytical Evaluation, C.C.H. Canadian Ltd., Toronto, 1979, p. 21.

3. I.b.i.d., p. 25.

4. I.b.i.d., p. 25.

5. The federal government's policy with respect to provincial royalty payments has been, since May 7, 1974, to not recognize these payments as a qualified deduction from producers' income for tax purposes.

6. Initially, this tax abatement was to be 10 percentage points for 1974 tax returns but increase to 12 per cent and 15 per cent for 1975 and 1976 respectively. This implied that the federal corporate income tax rate would be reduced in stages from 30 per cent in 1974 to 25 per cent by 1976.

7. See Holland, Schulli and Kemp (1979), pages 43 and 44.

8. See James Roche (1977), page 365.


11. I.b.i.d., page 359.


13. Secondary oil, strictly speaking, is any additional oil obtained by supplying energy to supplement or replace the energy of primary recovery. Examples of secondary recovery include the methods of waterflooding and gas injection. Tertiary recovery, or enhanced recovery, on the other hand, refers to third generation methods and include such methods as steam injection and fire-flooding. (Source: The National Energy Program, Energy, Mines and Resources, 1980, page 28).

14. In fact, this provision was to be retroactive to May 8, 1974.

15. See Roche (1977), page 363.

16. Examples of costs that would qualify as exploration expenses would be clearing, removing overburden and dripping. See Holland,
17. Actually, the Income Tax Act of 1972 called for the introduction of the earned depletion allowance for the 1976 tax year. The federal government, however, changed this date and introduced the earned depletion allowance immediately following the May 7, 1974 federal budget.


19. See Roche (1977), page 362. This also explains why the definition of resource profits, against which earned depletion may be claimed, excludes interest costs. In fact, a firm that borrows to finance his exploration program faces a lower ceiling for his earned depletion allowance than a taxpayer who finances his activities from retained earnings. That is, Sub-total 2 in Table 2.1 is higher for a firm who finances his exploration program from retained earnings rather than borrowing the necessary funds.


21. It should be noted that despite the differential rates of tax write-offs for exploration and development expenses, both expenses are included equally in the earned depletion base.

22. See Holland, Schulli and Kemp (1979), page 175.

23. I.b.i.d., page 175.

24. The federal government allowed the super-depletion allowance to expire as planned on March 31, 1980. However, since Table 2.1 surveys the computation of federal tax as of January 1, 1980, the super-depletion allowance is still included.


26. Since Table 2.1 examines the tax treatment of the Canadian oil and gas industry as of January 1, 1980 when the super-depletion allowance was still in effect, the discussion below, ignores the fact that this allowance has since expired.

27. For the Beaufort Sea (for example) the total value of tax write-offs will be the value of the exploration expense (at 100 per cent), or $50 million, plus the earned depletion allowance of $16.67 million (33 1/3 per cent of $50 million), plus the frontier exploration allowance of $30 million (54 2/3 per cent of $45 million). Similarly, the tax write-offs available for the East coast well will be $75 million (100 per cent of the cost of the well), plus a $5 million earned depletion allowance (33 1/3 per cent of $15 million), plus a super-depletion allowance of $6.67 million (66 2/3 per cent of $10 million). Finally, in the case of the well drilled in Alberta, the value of the tax write-offs will simply be the sum of the basic 100 per cent deduction and the earned depletion allowance (i.e., $5 million and 33 1/3 per cent of $5 million respectively, or $6.67 million in total).
28. Since the Beaufort Sea and the offshore areas of the Canadian east coast are (in the eyes of the federal government) federal lands, there is no provincial tax abatement (See Table 2.1). Therefore, the federal tax rate in these areas will be 46 per cent, whereas, the federal tax rate for the well drilled in Alberta will be 36%.

29. Actually, the net cost to the firm drilling in Alberta is overestimated here. We have not yet taken into consideration the provincial exploration incentives that may be available. (See the next section on Provincial Taxation for this discussion).

30. Refer to footnote 13 (above) for the definitions of secondary and tertiary recovery methods.

31. This figure was derived by taking the ratio of expenditures on exploratory drilling in Canada (1978) to marketable Canadian production of crude oil (1978). Source: The Crude Petroleum and Natural Gas Industry, Statistics Canada, Catalogue No. 26-213, 1978, Table 3, line 3 page 16 and Table 5, line 1, page 18.


33. The argument for excluding exploration expenses from the supplementary depletion base for secondary, tertiary and synthetic oil projects is that the base is supposed to represent the cost of depreciable production assets only. Therefore, we have chosen to proxy the supplementary depletion base by including only development expenses incurred by the firms.

34. The tax liability expressions for the other sources of oil production are given as:
   i) For Secondary Oil Production:
      \[ T = 0.36[(1-0.25)Y - 0.30(E+D) - 0.50(D)] \]
   ii) For Frontier Oil Production:
      \[ T = 0.46[(1-0.25)Y - E - 0.30(D) - 0.333(E+D) -0.667(E)] \]
   iii) For Oil Sands (Synthetic Oil):
      \[ T = 0.36[(1-0.25)Y - (E+D) - 0.333(D)] \]
   and iv) For Tertiary Oil Production:
      \[ T = 0.36[(1-0.25)Y - E - 0.30(D) - 0.50(D)] \]

35. The National Energy Program announced in October 1980, and discussed below, calls for the reintroduction of the federal royalty as described in Bill C-20.

37. The royalty formula applied to secondary oil production is simply the new conventional oil royalty formula discussed below.

38. See Holland, Schulli and Kemp (1979), page 341.


40. The base royalty, $S$, is given by either;
   
   $S = 180^\circ + 0.25 (Q - 1200)$

   when output ($Q$) exceeds 1200 barrels per well per month, or;

   $S = (Q / 120 + 5) Q/100$

   for smaller wells where the output is less than 1200 barrels per month.

   Then, representing $S$ as a percentage of output yields;

   (a) if output exceeds 1200 barrels per well per month:
   
   $S = 25 - 1200/Q$

   so as the output of each well gets very large the value of $S$ will approach 25%. In other words, the maximum base royalty rate is 25 per cent for very large wells.

   or (b) if output is less than 1200 barrels per well per month:
   
   $S = 5 + Q/120$

   or, in words, as the output of the well gets very small (approaching zero) the value of $S$ approaches 5 per cent. Therefore, the minimum base royalty rate is 5 per cent for very small wells.

41. For the "average" oil well producing 3600 barrels of oil per month the base royalty, $S$, expressed as a percentage of output yields;

   $S = [180^\circ + 0.25 (3600 - 1200)]100/3600$

   or $S = 21.7\%$

   Therefore, the base royalty rate for the "average" well is 21.7 per cent which translates to a base royalty payment of 780 barrels per month. Note, the definition of an "average" oil well was provided by Energy, Mines and Resources officials in a telephone conversation.

42. That is, if $(A - B)/A = 0.75$. At the prevailing domestic price of oil in 1980, $(A - B)/A = 0.74$.

43. This simplifying assumption can be justified by recognizing that the main purpose of the Saskatchewan petroleum royalty formula is to protect the province's revenues in case the oil well income tax is found to be unconstitutional. (See Holland, Schulli and Kemp (1979), page 358). It seems very likely then that the royalty formula and the oil well income tax approach must generate roughly equal flows of revenues for Saskatchewan. Therefore, we will adopt the more straight-forward royalty formula.
44. See Holland, Schulli and Kemp (1979), page 358.

45. This information was provided in a telephone conversation with Energy, Mines and Resources officials.

46. Since we have already assumed that tertiary oil production will be subject to the Saskatchewan royalty schedule, we must, therefore, to be consistent, also apply the Saskatchewan corporate tax rate to any profit emerging from tertiary oil production.

47. See Holland, Schulli and Kemp (1979), page 345.


49. For a more detailed discussion and evaluation of NEP see Reaction: The National Energy Program, The Fraser Institute, 1981.


52. I.b.i.d., page 28.

53. Actually, the subsidy is given to the oil refiners who purchase these high cost oils at their respective reference prices. The subsidy they receive is just enough to reduce the cost of these oils to the "made-in-Canada" price.

54. That is, prior to the introduction of the NEP, output from the oil sands projects as well as any tertiary oil or possibly frontier oil, was guaranteed the world price of oil.


56. I.b.i.d., page 39.

57. I.b.i.d., page 39.

58. The ceiling for the earned depletion allowance for synthetic (and tertiary) oil will now be 25 per cent of resource income. This represents a reduction from the previous arrangements. The ceiling previously was 50 per cent of any income.


60. Note that since expenditures incurred to produce secondary oil are recognized, for tax purposes, as development expenses and not exploration expenses, and furthermore, since development expenses no longer earn depletion allowances, therefore, it follows that secondary oil projects must fail to qualify for ordinary depletion allowances as well.


63. When the federal government exercises this right, via Petro-Canada (or some other Crown corporation), the Crown will then share in any future profits and costs according to their 25 per cent interest.

64. For this reason, it is felt that Helliwell's analysis of the distributional changes in the sharing of energy rents following the introduction of the NEP is deficient. That is, Helliwell's model (see, for example, J.F. Helliwell and R.N. McRae, "Energy Policy and the Budget", in Canadian Public Policy, Winter 1981) excludes frontier oil production and therefore, ignores the considerable rents that will accrue to the federal government as a result of the initiatives in the NEP but which will not be realized for some time to come.
APPENDIX TO CHAPTER 2

THE IMPACT OF 1974-78 FEDERAL BUDGETS ON THE SHARE OF ENERGY REVENUES ACCRUING TO THE FEDERAL GOVERNMENT

In order to examine the impact of the federal budgets over the period 1974 - 78 on the federal government's share of energy revenues, consider Table 2.6. This table summarizes the key features of the federal budgets presented during this time period. The impact of each of these budgets on the federal corporate income taxes is discussed briefly below beginning with the May 6, 1974 budget.

1) The Federal Budget of May 6, 1974:

The rapid escalation of world crude oil prices (beginning in October 1973), initiated a series of alterations in the tax treatment of resource incomes. Despite the fact that both the federal government and the provincial governments agreed in principle that the additional revenues from higher oil prices should revert to the government sector, rather than the industry, they disagreed on how this additional revenue should be allocated between the two levels of government. This dispute went through a series of stages. The federal government agreed to increase the price of domestic oil (to $6.50 per barrel initially), at the same time, it exercised its right to control international trade and imposed and collected an export tax on oil equal to the difference of the world price and the Canadian price of oil. The proceeds of the export tax were then directed to subsidizing oil imports into eastern Canada to maintain a uniform
domestic price for oil. The producing provinces, under the impression, that the federal government had collected their "entitled" share of the revenues, felt they were then legally able (by way of Section 93 of the BNA Act) to claim whatever percentage of the remaining yield per barrel ($6.50) they wished. Consequently, the producing provinces substantially increased the royalty rate on oil production. This resulting division of additional oil revenues, however, was deemed to be unacceptable to the federal government and consequently, the federal budget of May 6, 1974 was introduced.

The federal government believed that the oil companies were not bearing a reasonable burden of the tax (especially in light of the increased provincial royalties and the subsequent reduction in the federal tax base). As a result, the federal government initiated three amendments which all had the effect of increasing the federal tax base and, therefore, also their revenues.

The first of these measures, and the most important, was the decision to make all provincial oil and gas royalties payable to producing provinces ineligible for deduction in calculating taxable income. This provision was to be effective immediately and was a deliberate attempt by the federal government to prevent a serious erosion of the corporate tax base due to increases in provincial royalties. The implication of this move was to force the oil companies to now pay federal and provincial (corporate) taxes on tax paid in the form of royalties to the provincial government.

The other key features of this budget called for the reduction in the rate of the tax writeoff permitted for exploration and development activity to 30 per cent per annum from 100 per cent, and the
immediate introduction of the earned depletion allowance (instead of after 1976, as previously announced). Finally, the federal corporate tax rate was also lowered to 30 per cent from 40 per cent in this budget.

To examine the impact of these proposals on federal corporate tax revenues, let:

\[ X = \text{net income (revenues less operating costs)} \text{ for an oil firm in a given tax year,} \]

\[ E = \text{the exploration expenses of this representative firm,} \]

\[ D = \text{the development expenses of this firm, and} \]

\[ R = \text{the royalties paid to the producing provinces by this firm.} \]

We will further assume that the values of \( X, E \) and \( D \) (taken individually) are constant pre- and post-budget (that is, we are focusing on the impact effects only of each federal budget). Furthermore, we will assume a 40 per cent royalty rate so,

\[ R = 0.40 X \]

Therefore, the income tax base \( (B) \) for this firm before the introduction of this budget may be approximated by:

\[ B_0 = (X - 0.40X) - E - D - 0.333X \]

where the last term represents the unearned depletion allowance which is equal to one-third of net income.

The tax base that would apply as a result of the introduction of the proposals contained in the May 6, 1974 budget can be approximated by:

\[ B_1 = X - 0.30E - 0.30D - 0.333(E + D) \]

where the last term represents the earned depletion allowance (as described in the chapter). Therefore, the change in the federal corporate
tax base due to the May 6, 1974 budget proposals will be:

\[ (B_1 - B_0) = \Delta B = 0.73X + 0.37E + 0.37D \]

which implies the resulting change in the federal government's tax revenues will be given by:

\[ (T_1 - T_0) = t_1 B_1 - t_0 B_0 \]

or, adding and subtracting \( t_0 B_1 \) on the right-hand-side and rearranging terms yields,

\[ (T_1 - T_0) = \Delta T = t_0 \Delta B + B_1 \Delta t \]

where \( T = \) federal corporate tax revenues,

\( t = \) federal corporate tax rate,

\( B = \) federal corporate income tax base (i.e., taxable income),

\( \Delta B = \) the change in the federal corporate tax base (i.e., \( B_1 - B_0 \)),

\( \Delta T = \) the change in the federal corporate tax rate (i.e., \( t_1 - t_0 \)).

Therefore, noting that \( \Delta t = -0.10 \) then,

\[ \Delta T = 0.192X + 0.211E + 0.211D \]

In words, federal corporate tax revenues unambiguously increase by 19 cents for every $1 of net income and by 21 cents for every dollar spent on exploration or development activity if the proposals contained in the federal budget of May 6, 1974 were adopted.

ii) The Federal Budget of November 18, 1974:

The proposals contained in the May 6, 1974 budget did not become law because of the defeat of the federal government. But following re-election of a majority Liberal government in July 1974, a new budget was presented on November 18, 1974. This budget re-introduced to a large extent the provisions contained in the May budget. In particular, the federal government chose to re-introduce non-deductibility
of provincial royalties (effective from May 6, 1974) from taxable income. This new provision, however, went one step further. Now included in expenses classified as non-deductible (effective budget night) were any expenses related to the acquisition, development or ownership of a resource property. Previously, the cost of acquiring any Canadian resource property was fully deductible.

There were also two provisions contained in the November budget that provided some relief not present in the May budget. These provisions reinstated full deductibility of Canadian exploration expenses (while retaining only a 30 per cent per annum writeoff for Canadian development expenses) and as well, provided for an expanded federal abatement on oil and gas production from the 10 percentage points that was to apply for 1974 tax returns to 12 per cent and 15 per cent for 1975 and 1976 respectively. This implied that the federal corporate income tax rate would be reduced in stages from 30 per cent in 1974 to 25 per cent by 1976.

These changes produced an increased tax base for the federal government. That is, relative to the pre-May 6, 1974 situation where,

\[ B_0 = (X - 0.40X) - E - D - 0.333X \]

the new tax base is now given by:

\[ B_1 = X - E - 0.30D - 0.333(E + D) \]

so,

\[ \Delta B = 0.73X - 0.333E + 0.37D \]

and since the federal corporate tax rate for 1975 was to be reduced to 28 per cent from 30 per cent then,

\[ \Delta T = 0.1990X - 0.0724E + 0.1236D \]

or, roughly 20 cents of every dollar of net income and 12 cents of
every dollar of development expenses will be added to federal corporate
tax revenues. Offsetting this, however, due to the immediate introduction of the earned depletion allowance and the change in the federal corporate tax rate, is a fall in federal corporate tax revenues by approximately 7 per cent of the value of exploration expenses incurred. Nevertheless, overall, federal revenues would be expected to increase relative to the pre-May 6, 1974 situation (since E is expected to be less than X).

Comparing the provisions contained in the November budget with those proposed in the May budget, however, indicates that federal tax revenues will decrease by:

\[ \Delta T = 0.013 D - 0.020 X - 0.183 E \]
or by 2 per cent of net income (due to the reduced tax rate) and by 18 per cent of the value of the exploration expenses (primarily due to the deductibility in full, of exploration expenses). Therefore, the pattern of the federal government conceding additional benefits to the oil and gas industry begins with the federal budget of November 1974, but as we shall see, is consistently present in every federal budget of this time period.

iii) The Federal Budget of June 23, 1975:

There were two key features introduced in the federal budget of June 23, 1975. The first was the introduction of the federal resource allowance (equal to 25 per cent of net resource revenues) which was designed to compensate the oil companies for increased tax liabilities due to the disallowance of provincial royalties as a deduction from taxable income. The second major provision called for an increase in
the federal tax rate to help offset the loss of federal revenues due to 
the introduction of the resource allowance plus to increase the value of 
the various tax incentives in place to encourage exploration and development activity. The effective tax rate (for 1976) was increased from 25 
per cent to 36 per cent.

As a result of these measures the new tax base can be approximated by:

\[ B_1 = X - 0.25 X - E - 0.30 D - 0.333(E + D) \]

so the change in the federal tax base (relative to the preceding budget) 
is simply;

\[ \Delta B = - 0.25 X \]

Therefore, the net effect on federal tax revenues will be given by;

\[ \Delta T = -0.010 X - 0.1064 E - 0.0504 D \]

or, in words, unambiguously, federal corporate tax revenues fall by 1 
per cent of net income, just over 10 per cent of exploration expenses 
and by approximately 5 per cent of the value of a firm's development 
expenses.

iv) The Federal Budget of May 25, 1976:

There were relatively minor changes initiated as a result of this 
federal budget. Very briefly, the purpose of the changes introduced 
was to encourage further exploration and development activities. One of 
the measures introduced, permitted all taxpayers (individuals now as 
well as corporations) to write off in full the value of Canadian explor-
ation expenses in the year incurred. Previously, only those corporations 
principally involved in resource activities received this privilege.

Secondly, the cost of any resource property acquired after May 6,
1974 and paid to a government in Canada was now to be included in Canadian development expenses. Therefore, to the extent that a firm acquires resource properties, its federal tax base, and hence federal corporate tax revenues, will now be reduced (ceteris paribus).

v) The Federal Budget of March 31, 1977:

The most significant feature of the March budget relating to the taxation of resource incomes was the introduction of the frontier exploration allowance (or super-depletion allowance) which further reduced federal tax revenues relative to the previous budget. That is, if we assume that a firm qualifies for the super-depletion allowance and assume further that the well costs are very large so that the additional writeoff for exploration expenses is approximately equal to the full 66 2/3 per cent, then the revised tax base, due to the introduction of this budget, for a firm would be:

\[ B_1 = X - 0.25 X - E - 0.30 D - 0.333(E + D) - 0.67 E \]

so that the change in the tax base (relative to, say, the June 23, 1975 budget) is simply:

\[ \Delta B = 0.67 E \]

Given that the oil and operations currently engaged on federal lands (e.g., the Beaufort Sea, Arctic Islands, and the offshore area along the eastern Canadian coastline) are the most likely to qualify for this allowance and that these operations are subject to a federal tax rate of 46 per cent (i.e., no provincial abatement available), then federal tax revenues will fall by approximately 30 per cent of the value of exploration expenses incurred on these federal lands (or frontier areas).
\[ \Delta T = -0.67 E (0.46) = -0.3082 E \]

vi) The Federal Budget of April 10, 1978:

The April 10, 1978 federal budget marked a major revision in the treatment of expenditures on secondary and tertiary recovery operations. Now, with the introduction of supplementary depletion, the cost of depreciable assets used in secondary and tertiary recovery will earn depletion at a 50 per cent rate. As mentioned earlier, the supplementary depletion base will also be augmented by the cost of oil sands assets but still at a rate of 33 1/3 per cent (as previously). The effective ceiling, however, for these expenses was raised to 50 per cent of income from all sources instead of just 25 per cent of resource profits. For our purposes, if we assume that the ceiling was non-binding before, then this alteration, as it applies to oil sands projects, will not affect federal resource revenues.

The net effect on federal tax revenues from secondary and tertiary recovery operations, however, is clearly adverse. The tax base for a firm will be reduced by 50 per cent of the costs of qualifying assets which implies federal tax revenues will be reduced by 18 per cent of the costs of these assets.

vii) The Federal Budget of November 16, 1978:

The federal government announced in this budget a major change in the tax treatment of oil sands operations. Now expenses incurred in developing these mines qualify as an exploration expense (instead of as a development expense as previously was the case), the result of which was to reduce the federal tax base by 70 per cent of the qualifying
expenses. Therefore, once again, the pattern of reducing the share of federal resource revenue is reinforced. As a result of this budgetary provision, federal resource revenues will be lowered by approximately 25 per cent of the costs of oil sands assets eligible for exploration expenses.

\[ \Delta T = t \cdot \Delta B = 0.2520 \cdot C_{os} \]

where \( C_{os} \) represents the costs of oil sands assets eligible for exploration expenses.

This budget also introduced a more generous treatment of secondary and tertiary operations. Expenses incurred in secondary or tertiary recovery projects will now be included in development expenses which will reduce the federal tax base by 30 per cent of the value of these expenses. Federal tax revenues, as a consequence, will fall by approximately 11 per cent of the value of these expenses.

Overall, therefore, the net effect of the provisions contained in the November 16, 1978 federal budget serve to reduce (once again) the federal share of resource revenues.

viii) Conclusions:

In summary, then, every federal budget from the May 6, 1974 federal budget to the November 16, 1978 budget, has moved in the direction of reducing the federal government's share of oil and gas revenues. In fact, the provincial government's share of oil and gas revenues (at least from provincial corporate income taxes) has fallen, as well since the producing provinces employ the same tax base for corporate taxes as the federal government. The implication, therefore, is that if the provincial royalty structure has remained unchanged during this period
(as far as its percentage share of resource revenues) and if we ignore the impact of land bonus payments, then there has emerged (since May 6, 1974) a shifting of the percentage share of oil and gas revenues away from the public sector and towards the private sector (the oil and gas industry). This trend has no doubt been largely responsible for the very rapid increase in drilling activity in Canada since 1974. As well, it also helps in understanding the industry's bitter opposition and condemnation of the federal government's dramatic reversal via the introduction of the National Energy Program.
## Table 2.6 Summary of Federal Tax Treatment of the Canadian Oil Industry by Federal Budget 1974 - 1979

<table>
<thead>
<tr>
<th>Year</th>
<th>Income Tax</th>
<th>Capital Gains</th>
<th>Corporation Income</th>
<th>Depreciation Exclusions for Oil Sands (1974-79) and (1980-81)</th>
<th>Corporation Income</th>
<th>Depreciation Exclusions for Oil Sands (1974-79) and (1980-81)</th>
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</thead>
<tbody>
<tr>
<td>1974</td>
<td></td>
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<td>1981</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Notes:**
- Capital gains are subject to tax rates on a case-by-case basis.
- Corporation income includes all types of business income with specific exclusions for oil sands.
- Depreciation exclusions for oil sands apply to capital expenditures on oil sands projects.

**Explanations:**
- **Income Tax:** Rates and schedules affecting income tax for the years specified.
- **Capital Gains:** Calculation and tax implications for capital gains.
- **Corporation Income:** Summary of income outside of capital gains and income tax rates.
- **Depreciation Exclusions for Oil Sands:** Special provisions for tax deductions related to oil sands capital expenditures.

**Additional Notes:**
- The table reflects the Federal Budgets for the years specified, reflecting changes in tax policy and rates.
- The details may include specific rates, brackets, and exemptions that evolve over time.
- Consult the relevant sections of the Income Tax Act for precise details and current rates.
CHAPTER 3

ALTERNATIVE EQUALIZATION PROGRAMS: TWO-TIER SYSTEMS

(written jointly with Thomas J. Courchene)

3.1 INTRODUCTION

The purpose of this chapter is to present and evaluate alternative approaches to Canada's system of equalization payments. In particular, the principal focus will be on alternatives which might be labelled "two-tier systems" in that they argue for the provinces taking an increased share of responsibility for the funding of the program. Specifically, the second tier of the program would take the form of an interprovincial revenue-sharing pool. In turn, this implies that in the present structure of equalization payments there exists some presumption that Ottawa is bearing too much of the responsibility for equalizing provincial revenues. Hence, a substantial portion of the paper is devoted to attempting to establish the case for a "funding inequity" and, therefore, a rationale for moving towards some sort of two-tier approach.

As the reader is no doubt aware, the details of equalization are immensely complicated and one has only to scratch the surface of the program to become mired in a welter of computational and conceptual problems. Therefore, even though we attempt to provide some numerical calculations relating to possible alternatives, these examples necessarily gloss over some important issues (a few of which will be highlighted) and must be viewed more as indicative of possible future directions that the equalization program can take rather than as being in any way definitive.

Prior to proceeding with the outline of the chapter, it is import-
ant to recognize at the outset that the equalization program cannot be viewed in isolation. On the one hand, it is at the same time a means of bolstering revenues of the poorer provinces and a major element in Canada’s approach to combat regional disparities. On the other hand, and probably more important in the current policy context, the equalization program has become part of the overall energy debate in this country. Indeed, as will be demonstrated below, the principle rationale for a two-tier approach to equalization stems from the manner in which energy rents are currently shared and the implications of these rents on the magnitude and funding of equalization payments. Alternative rent-sharing scenarios would have significant ramifications for the present equalization system, let alone any of the alternatives incorporated in the chapter. Thus it is important to realize that major alterations in the current approach to energy pricing and rent-sharing may have corresponding major implications with respect both to the perceived problems besetting equalization payments and to the list of possible alternatives.

The outline of the chapter is as follows. The second section presents, in as brief a manner as possible, the outline of the current equalization system. Included here will be estimates of payments for fiscal year 1979-80, as well as a listing of the many changes which have taken place in the system since 1967. Concluding this section will be a comparison of the operations of the current system with the original philosophy underlying equalization payments. It is hoped that this comparison will serve to tend some perspective to the current magnitude of equalization flows and the various modifications of the program through the years.
The third section will present the interaction between the rising energy rents and the system of equalization payments. As part of this interaction, we shall present the case for altering the current funding of the program and, in particular, shall argue for a two-tier approach. The analysis will take the form of presenting equalization "balance sheets" for the oil and natural gas components as they relate both to the 1979-80 estimates and to future increases in the price of domestic energy.

The fourth section focuses on a two-tier alternative to the present equalization program. Prefacing the section is a description of equalization in the Federal Republic of Germany, which embodies a two-tier concept. In the proposal outlined for Canada, the second tier is an interprovincial revenue-sharing pool encompassing revenues from natural resources. The first tier operates along present lines and includes all the remainder of the revenue categories that currently qualify for equalization. However, the proposal carries with it some implications which extend well beyond the equalization program. The remainder of the section, and the conclusion as well, focuses on some of these broader issues, such as the interaction among alternative energy rent-sharing scenarios, domestic energy price increases and the system of equalization payments. The only clear issue is that it is high time to present an agenda for rethinking and reworking Canada's system of equalization payments.

3.2 THE MECHANICS OF EQUALIZATION: THE EQUALIZATION FORMULAS

3.2.1 The Per-Capita-Base Formulation

Revenues from 29 revenue sources are currently eligible for
equalization (see Table 3.1 for a listing of these revenue sources). A tax base, representative of current taxation practices, is calculated for each of these revenue sources, regardless of whether or not the provinces utilize the tax base (e.g., even though Alberta has no sales tax, for purposes of the equalization program it is assigned a sales tax base calculated in the same manner as the sales tax base for the remaining provinces). Under the per-capita-base formulation, the equalization formula can be seen to ensure that each province has access to revenues which are essentially equivalent to the revenues which would be obtained from applying "national average tax rates" to "national average tax bases." "Rich" provinces will have access to more revenue, but the poorer ones are to be brought up to this level. More formally, for each revenue source $i$:

\[
E_{ij} = t_{ic} \left( \frac{B_{ic}}{P_c} - \frac{B_{ij}}{P_j} \right)
\]

where

\( E_{ij} \) = per capita equalization entitlement for province $j$ from revenue source $i$;

\( B_{ic} \) = the "all-province" per capita base for revenue source $i$; subscript $c$ refers to "all provinces" or Canada;

\( B_{ij} \) = the average per capita base for revenue source $i$ in province $j$;

\( t_{ic} \) = the national (all-province) average tax rate for revenue source $i$. This tax rate equals total provincial revenues from revenue source $i$, (TR$_i$), divided by the total provincial tax base, (B$_{1c}$). In turn TR$_i$ equals the sum of provincial tax rates multiplied by provincial tax bases,
\[ TR_i = \sum_{j=1}^{10} t_{ij} B_{ij}, \text{ and } B_{ic} = \sum_{j=1}^{10} B_{ij} \]

From equation (1), a province has a positive equalization entitlement if the bracketed term is positive, that is, if the national average per capita base exceeds the province's per capita base for the revenue source in question. In the jargon of the equalization program, when the bracketed term is positive a province is said to have a "fiscal deficiency" or said to be a "have-not" province for this particular revenue source. Conversely a "rich" province will have a negative bracketed term (i.e., a "fiscal excess") and its entitlement will be negative.

For each province, these equalization entitlements are summed over the 29 revenue sources. If the resulting total is positive, this is the equalization payment due to that province. If the total is negative the province is deemed, overall, to be a "rich" or "have" province and the equalization payment is set equal to zero. The monies for equalization come out of Ottawa's consolidated revenue. No province contributes its negative entitlement toward the funding of the program; in other words, the equalization program is not an interprovincial revenue-sharing pool.

3.2.2 The Population Share Formulation

The alternative (but equivalent) way of expressing the equalization formula focuses on the difference between the province's share of the revenue source in question and its share of total population. Under this approach, a province is deemed to be a have-not province if its
population share exceeds its tax base share. To establish equalization entitlements this differential is then multiplied by total revenues arising from this revenue source. In symbols, the equalization entitlement for province \( j \) from revenue source \( i \) can be expressed as follows:\(^3\)

\[
E_{ij} = TR_i \left[ \frac{P_j}{P_c} - \frac{B_{ij}}{B_{ic}} \right],
\]

where
\[
\frac{P_j}{P_c} = \text{province } j\text{'s share of total population},
\]
\[
\frac{B_{ij}}{B_{ic}} = \text{province } j\text{'s share of the tax base for revenue source } i,
\]
\[
TR_i = \text{total revenues arising from revenue source } i, \text{ as defined beneath equation (1)}.
\]

As in the previous formulation, the bracketed term represents the concept of a "fiscal deficiency" if positive or a "fiscal excess" if negative. Likewise, these entitlements are summed and the total, if positive, represents the equalization payment, and if negative, is set equal to zero.

The various properties of the equalization program are easily derivable from the formulas. Answers to questions such as what happens to a province's equalization payment when it raises its tax rate on a revenue source for which it is poor or what happens when a province's tax base increases or what happens when a province's population grows, etc., are easily derivable.\(^4\) While interesting, they do not appear to be crucial to the overall purpose of this chapter which is to analyse the current system of payments and suggest some alternative approaches. Prior to looking at these current equalization estimates for fiscal
year 1979-80, however, it is appropriate to document, albeit very briefly, the manner in which the formula has been modified over the recent past and, in particular, the manner in which energy revenues have led to alterations in the equalization system.

3.2.3 Recent Modifications of Equalization Payments

Prior to 1962, equalization was determined on the basis of the two provinces with the highest per capita yield for the three "standard taxes" (the personal income tax, the corporate income tax and succession duties). As a result of the 1962 Fiscal Arrangements the standard taxes were evaluated at the "national average" per capita yield rather than the yield in the highest two provinces. In addition, however, 50 percent of a three-year moving average of the per capita yield from natural resource revenues entered the formula.

The 1967 Fiscal Arrangements really represent the basis for the current formula. Equalization was extended to most of the provincial revenues (16 in all) and equalization proceeded according to the formulas outlined above. The only major alterations prior to 1974 were the addition of a few more revenue categories. The unwritten principle involved here appeared to be that whenever several provinces began to derive revenues from a new revenue source, this source was admitted into the formula. Thus, among the new revenue sources which entered the formula during these years were race track revenues, hospital and medical care insurance premiums and, with the move by some provinces to centralize education financing, school purpose taxes.
The 1974 Amendment

With the quadrupling of world oil prices, which began in the fall of 1973, Ottawa was faced with some hard policy decisions. One of its first initiatives was to levy an export tax on our oil exports to the United States. In large measure, the revenues from this tax were used to subsidize imported oil east of the Ottawa Valley in order to maintain a uniform domestic price. The producing provinces reacted both to Ottawa's move in imposing the export tax and to the general increase in the price of oil by scaling dramatically upward their royalties from oil and natural gas production. In turn, Ottawa moved to disallow these royalty payments for purposes of computing corporate income taxes.

The latter two initiatives had substantial implications for the system of equalization payments. Rising energy royalties would generate large equalization entitlements which Ottawa would have to finance. Ottawa could not tax these rising royalties (Section 125 of the BNA Act) and if, in addition, they were allowed to be deductible for purposes of corporate income tax calculations, the end result might well be that Ottawa would be unable to derive much money from the energy sector, even though energy revenues would generate large increases in equalization payments. In the event, a compromise was struck. Ottawa agreed to offer some generous additional write-offs for exploration (but maintained nondeductibility) and also agreed to allow the domestic energy price to rise, in graduated amounts, toward the world price level. This measure ensured that the industry would not face marginal tax rates arising from the combination of royalty payments and corporate income tax that exceed 100 per cent. In fact, the provisions were so generous that if the companies devoted 50 cents of each additional dollar increase
in the domestic oil price to exploration, they could effectively avoid paying any additional corporate income taxes as a result of the price increase. Consequently, Ottawa was still left with the financial implications for the system of equalization payments of its decision to allow the domestic prices to rise towards world levels. If the formula were left unchanged, a movement to world prices prevailing in 1974 would have implied a tripling in the annual flow of equalization payments -- a financial burden the magnitude of which can be best appreciated by noting that it would have required an increase in personal income tax rates of 25 per cent. Clearly, something had to give, and that something was the equalization formula.

Accordingly, in the fall of 1974 Ottawa decreed that henceforth the amount of energy royalties which would enter the equalization formula for any future year would be restricted to:

1. the level of royalties which prevailed in 1973-74,
2. 1/3 of any energy revenues above the 1973-74 level.

This was a significant departure in terms of the formula, because it represented the first time that the "full" equalization concept embodied in the 1967 formula was abandoned. The fact that most of the have-not provinces were also beneficiaries under the Oil Import Compensation Program represents an important offset, but nonetheless, this unilateral amendment remains very significant in terms of the recent historical development of Canada's equalization program.

1977 Fiscal Arrangements Act

The significance for future federal-provincial financial relations of the 1977 Fiscal Arrangements Act probably relates more to the changes
ushered in with respect to the shared-cost program than to the equalization system. However, there were some important modifications to the equalization program. The number of revenues eligible for equalization was increased to 29, but no new revenue sources were admitted; in other words, the increase resulted from actions such as breaking down the previous category of alcohol revenues into its three components, beer, wine and spirits. Tax bases were also adjusted to become more "representative"; they were redefined to reflect more precisely the actual taxing practices of the various provinces. The most important change here was the broadening of the corporate income tax base to include the profits of provincially owned profit-making enterprises. This action closed a previous loophole whereby a province could reduce its corporate income tax base for equalization purposes by "nationalizing" or "provincializing" a privately owned enterprise. For present purposes, however, the most important modifications related to energy and to these we now turn.

Henceforth, 50 per cent of revenues from nonrenewable resources industries would be eligible for equalization (nonrenewable resources comprise the six energy categories, rows 16 through 21 of Table 3.1, plus mineral revenues, resource category 22 of Table 3.1). This replaced the 1974 provisions whereby the energy revenues eligible for equalization in any given year equalled the 1973-74 revenue level plus 1/3 of any revenues beyond this level. The decision to include mineral revenues as part of the energy-related amendment reflected Ottawa's desire to treat all "nonrenewable" revenue sources in an identical fashion. For fiscal year 1976-77 the amount of energy-related revenues which would have been allowed to enter the formula under the 1977 provision was roughly equivalent to that allowed under the 1974 amendment. What this
means is that the new provision is far more generous; after 1977, 50 per cent rather than 33 1/3 per cent of energy revenue increases are eligible for equalization. Offsetting this is the fact that only one-half of mineral revenues now enter the formula. However, this offset is trivial (to date at least) in terms of the dollar value of equalization payments (see Table 3.1). In short, the net result of the 1977 revision was to treat energy royalties far more generously for equalization purposes. Not only did this imply that equalization payments would escalate rapidly with the rise in the domestic energy price, but it also meant that Ontario would quickly join the ranks of the have-not provinces.

The second significant provision embodied in the 1977 Fiscal Arrangements Act for purposes of the paper was that the proportion of total equalization payments which could arise from resources (renewable as well as nonrenewable) was limited to 1/3. In other words, equalization payments arising from revenue sources 15 through 23 of Table 3.1 cannot exceed 33 1/3 per cent of total equalization payments. In effect, this measure puts a "cap" on equalization payments which can arise from the resource sector, particularly from energy royalties. In the "regulations" pursuant to the Fiscal Arrangements Act Ottawa defined the manner in which this 1/3 limit would become operational. Specifically, equalization entitlements arising from resource revenues for the seven traditional have-not provinces (i.e., all provinces except for British Columbia, Alberta and Ontario) were to be summed and expressed as a fraction of total equalization payments. From Table 3.1 (to be discussed below) this amounts to summing the entitlements for categories 15 through 23 which appear in the column "receiving provinces" and expressing this sum as a percent of $3,007 million, the total value of
equalization payments for 1979-80. Currently this ratio equals 31 per cent, just shy of the 33 1/3 per cent limit. It can be argued that this is a very peculiar way to define the limit. As will be pointed out below, Ontario is currently a have-not province, but its huge energy entitlements (see rows 16 through 21 for Ontario) are excluded for purposes of computing this ratio. In part the rationale is obvious: including Ontario's entitlements for resources in calculating the resource limit would drive the ratio above 60 per cent. Scaling this ratio down to the 33 1/3 per cent level would in effect require that the level of resource revenues allowed to enter the formula be reduced until Ontario was pushed back into the have category. This would serve to decrease overall equalization payments and probably ensure that the precise 1/3 limit would never be achieved. Likewise, Saskatchewan's inclusion is arbitrary, because although it may soon join the ranks of the "have" provinces, its energy entitlements will continue to be included for defining this ratio. The fact that Saskatchewan's entitlements are negative (see the resource revenue entitlements for this province in Table 3.1) will generate higher overall equalization payments, because a larger amount of resource revenues are permitted to enter the formula before the resource cap becomes binding.

This has been a rather technical discussion of the manner in which Ottawa decided to implement the 1/3 limit. It is important, however, because Ottawa's approach in effect allowed Ontario to become a have-not province and receive large equalization payments (principally because of the entitlements arising from the energy categories, as will be pointed out below) without running the overall program into its legislated resource limit. Our hunch is that this was of no great con-
cern to our policy-makers because they did not believe that the fiscal position of Ontario, with respect to the equalization program, would deteriorate as much and/or as rapidly as it actually did. When it became obvious (in late 1978) that Ontario was headed for have-not status under the equalization formula, the federal response was immediate, in the form of Bill C-26.

**Bill C-26**

Bill C-26 represented a further watershed in the development of the operational philosophy underlying Canada's equalization program. The first of its two provisions was directed to ensuring that Ontario (with that province's approval!) would not be eligible to receive an equalization payment, even if it qualified for one under the operations of the equalization formula. Specifically, it provided that any province whose per capita income exceeded the national average level in the current year, as well as in the previous two years, would be ineligible to receive an equalization payment. Moreover the provision was to be retroactive to the beginning of the 1977 Fiscal Arrangements Act (i.e., it was to apply to the two previous fiscal years as well as to the current and future years), so that it anticipated that Ontario would otherwise have qualified for payments in previous years as well. The requirement that the per capita income level exceed the national average for three consecutive years was presumably to prevent provinces like Saskatchewan from being ineligible. On occasion, Saskatchewan's per capita income does exceed the Canadian average level, but not normally for a consecutive three-year period. This point is rather academic, since in any case, with the current resource boom, it will not be long before
Saskatchewan becomes a have province.

The second provision was directed squarely at reducing equalization payments. In the wake of the restraint ushered in during the late summer and fall of 1978, the federal government was anxious to extend its expenditure paring to federal-provincial financial flows. The provinces balked at Ottawa's proposal to alter the shared-cost programs of the 1977 Fiscal Arrangements Act. Ottawa responded, in Bill C-26, by phasing out the revenue source "Sales of Crown Leases" (revenue source 20 in Table 3.1) from the equalization program. It can be seen in Table 3.1 that this tax source generated $147 million in equalization payments in fiscal year 1979-80, so the saving would have been substantial.

Bill C-26 did not become law; it died on the order paper when Parliament was dissolved for the 1979 election. Nonetheless, it represented the federal government's thinking with respect to the equalization program and it embodied some fairly important implications. The attempt to drop a particular revenue category not only emphasized the increasing arbitrariness of the formula but also reconfirmed to the provinces (if the point was not already very apparent in the wake of the 1974 amendment) that the equalization program was, in fact, a federal program and could be changed at will by Ottawa. The provision relating to per capita income and the eligibility for equalization may have certain superficial appeal, but as will be pointed out later, it represented a new interpretation of the philosophy underlying equalization payments. We shall devote a short section to this "philosophy" after presenting some estimates relating to the equalization program for fiscal year 1979-80.
3.2.4 Equalization in Action: 1979-80

Table 3.1 presents an overview of the operations of the equalization program for fiscal year 1979-80. The approach in this table is modelled after equation (2) above. Total revenues by revenue source, \((TR_i)\), appear as the third-last column of the table. For the nonrenewable resource categories (16 through 22) these figures represent one-half of actual provincial total revenues, reflecting the 1977 changes to the equalization program. Population shares are contained in row A. The matrix of equalization entitlements appears in row Panel B. These are the dollar entitlements by province for each revenue source, that is, the fiscal deficiencies or excesses \((\frac{P}{P_C} - \frac{B}{B_{IC}})\) multiplied by total revenues \((TR_i)\). The sum of the entitlements appear in row C. Note that the sum across provinces of these entitlements is zero, reflecting the fact that at the entitlement level, positive and negative flows are exactly offsetting.

Eight provinces have positive entitlements, including Ontario with $172 million. Although Ontario is a rich province for many revenue categories (especially personal income taxes with a negative entitlement of $450 million), this fact is offset by massive positive entitlements for the oil and gas revenues (rows B.16 through B.21). Alberta and B.C. are the only rich provinces, the former acquiring an overall negative entitlement of just over $2.5 billion.

Equalization payments appear in row D. We have assumed for purposes of this table that Ontario will not receive its equalization entitlement. Hence the payments for Alberta, British Columbia and Ontario are set equal to zero. Total equalization payments amount to $3 billion, with Quebec garnering just over one-half of this total. In per capita
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<td>9</td>
<td>678</td>
</tr>
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<td>10</td>
<td>901</td>
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**Table 3.1**

**Real Estate Investments**

- 1979 - 90 ($ million)
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<th>Year</th>
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<th>2nd Reserve</th>
<th>3rd Reserve</th>
<th>4th Reserve</th>
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<td>60</td>
<td>30</td>
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<tr>
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**TABLE 3.1 (CONTINUED)**
terms (row E), however, Quebec garners only $241, compared to $620 for P.E.I. Ontario’s entitlement is $20 per person while Alberta has a negative per capita entitlement of $1,293.

Rows F and G lend some perspective to the role of equalization payments. Total per capita provincial revenues appear in row F, with equalization as a per cent of these revenues in row G. For the Atlantic provinces equalization payments account for over 25 per cent of total revenues (including these payments). It is instructive to take a closer look at the figures on per capita provincial revenues. With $1,646 in fiscal year 1978-79 Ontario has the lowest revenue per capita of all the provinces, and less than half the Alberta total.

The reason that Ontario ends up with a smaller per capita revenue than some of the "less advantaged" provinces is that, apart from the influence of federal transfers, it has a lower tax effort (i.e., lower tax rates on many revenue sources). In terms of the comparison between Ontario and Alberta it should be noted that these figures substantially underestimate Alberta’s potential revenues because (1) this province has an even lower tax effort than Ontario on many traditional revenue sources (e.g., if Alberta had Ontario’s sales tax it would receive an extra $250 per capita) (2) the current revenue from energy royalties does not take account of the fact that our domestic price is currently over $10 below the world price; and (3) it excludes the interest revenues of the Heritage Fund which, at 10 per cent, would mean about $250 per person for the current year.

In order to highlight the comparison of the rapid shift in the fortunes of Ontario and Alberta, row H of the table presents equalization entitlements for 1972-73, just prior to the mushrooming of energy
prices. Ontario emerges as the richest province, with a negative entitlement of $514 million compared to the $332 million negative entitlement for Alberta. Of interest also is that the total value of equalization payments has tripled over the past seven years. Yet this increase from $1 billion in 1972-73 to $3 billion in 1979-80 is not nearly as large as it would have been had the formula not been altered. The last row of the table presents estimates for 1979-80 on the assumption that there were no changes in the equalization formula, that is, there were "full" equalization of oil royalties and no limit on the portion of equalization payments which can arise from resource revenues. In this scenario, equalization payments would be $5 billion, with Ontario garnering $1 billion of this amount. Saskatchewan would qualify as a have province, while Alberta's negative entitlements would exceed $4 billion. By comparing rows D and I one can obtain an appreciation of the impact on equalization flows of the recent energy-related amendments to the formula.

The second-last column of the table (labelled "receiving provinces") contains the amounts of equalization flows received by the seven recipient provinces broken down by revenue source. This column sums to the $3,007 million total appearing in row D. Not all of these entries are positive. Tobacco taxes, for example, decrease equalization payments by $3 million, because overall the seven provinces qualify as rich provinces for this revenue source.

The final column of the table presents the average equalization arising from each dollar that enters the formula (it is the ratio of the previous two columns). It is immediately apparent that for the energy categories this ratio is very high; for example, each dollar of
Crown gas revenues eligible for equalization generates 43 cents in equalization payments (if Ontario were included, this figure would rise to 79 cents). Contrast this finding to the 7 cents which arises from each dollar of personal income tax or the fall in equalization payments by 20 cents for each dollar of water power rentals eligible for equalization (as noted in the previous paragraph this means that the have-not provinces are rich for this revenue category). This situation exists because most of the recipient provinces have a zero tax base for oil. Hence, from equation (2), they are eligible to receive their population share of the energy revenues that enter the formula.

3.2.5 The Philosophy Underlying Equalization

We have now reviewed the mechanics of equalization and the magnitude and provincial distribution of payments for 1979-80. How well does all this rest with respect to the philosophy underlying equalization, and in turn, how have the recent modifications to equalization squared with this philosophy?

Toward this end, we shall assume that the role for equalization is unchanged from that enunciated in 1966 by Finance Minister Mitchell Sharp:

"Where circumstances -- whether natural or man-made -- have channelled a larger than average share of the nation's wealth into certain sections of the country, there should be a redistribution of that wealth so that all provinces are able to provide to their citizens a reasonably comparable level of basic services, without resorting to unduly burdensome levels of taxation."

More recently, Finance Minister Donald Macdonald reiterated this position: Equalization payments are designed to "ensure that all provinces are able to provide reasonably comparable levels of public services with-
out resorting to unduly high levels of taxation.\textsuperscript{10} And Douglas Clark has traced this dual concern with basic services and unduly high tax rates back to the Report of the Rowell-Sirois Commission.\textsuperscript{11}

In this sense the philosophy underlying equalization is really akin to compensating provinces for what Clark\textsuperscript{12} refers to as fiscal need -- a concept which would take account of both "expenditure needs" and "revenue means." The 1967 version of equalization payments essentially attempted to offset differences in revenue-raising capacity (i.e., it attempted to equalize revenues), whereas, fiscal need grants would attempt to offset "financial needs." Both types of grants take account of differences in revenue-raising capacity. However fiscal need grants would "go further by attempting to take account as well of differences in the needs for such services by the public which these governments serve."\textsuperscript{13}

One of the difficulties which arises in trying to evaluate whether the amendments to the formula over the years are consistent with the original philosophy is that nowhere has there been any explicit attempt to define just what constitutes this "basic level of public services" or what constitutes "unduly high tax rates." Yet, they are defined implicitly. Consider the definition of fiscal needs:

\begin{equation}
(3) \quad \text{Fiscal Expenditure Need} \div \text{Revenue Needs} \div \text{Means}
\end{equation}

Now let us take equation (1), multiply $t_{ic}$ through the bracketed term and sum the expression over the $n$ revenue sources:

\begin{equation}
(4) \quad E_j = \sum_{i=1}^{n} \frac{t_{ic} B_{ic}}{P_{ij}} - \sum_{i=1}^{n} t_{ic} B_{ij}
\end{equation}
In words, equation (4) states that the per capita equalization payment to province \( j \) equals the national average per capita revenues (derived from applying national average tax rates to national average tax bases) minus the per capita revenues that would be derived from applying national average tax rates to the province's own tax bases. Therefore, in terms of equation (3) the first term of equation (4) in effect represents "expenditure needs" and the second term represents "revenue means." In other words, in the equalization formula developed in 1967 expenditure needs are assumed to be identical to per capita revenue resulting from the application of national rates to national bases, that is, expenditure needs across provinces are identical in per capita terms. Expressed differently, the thrust of the 1967 equalization formula was simply to equalize revenue capacity or more explicitly to bring all have-not provinces up to the level of national average per capita revenues.14

From a theoretical standpoint, this deficiency is easily remedied. One would simply multiply the first term of equation (4) by an index of need, \( N_j/N_c \), where this term would be defined as the degree by which expenditure needs in province \( j \) to provide the basic level of services exceed the national average need, that is \( N_j/N_c \) would have the dimension of a pure number and would equal 1.00 for a province with expenditure needs equal to the national average and would be greater than unity for a province whose expenditure need was above the national average, etc. Yet from a practical viewpoint, it is perhaps not too surprising that fiscal need has not been incorporated in the Canadian equalization formula.15 First, one would have to define "basic services" and then determine the unit cost of supplying these basic services across the ten
provinces. The latter exercise would be especially delicate -- one would have to sort out the effects on providing these services of such factors as economies of scale, urban agglomeration, topography and weather, working age populations, income levels, etc. Even if this were to be accomplished the resulting calculations would apply to specific categories of basic services and would then have to be assigned differing weights across provinces, because equalization payments are unconditional grants and can be spent as the provinces wish throughout the various expenditure categories.

These conceptual and practical problems aside, the absence of definitions for fiscal need, basic services, and unduly high tax rates poses a problem in terms of evaluating the current formula. For example, suppose that Saskatchewan wants to provide a level of social services for its citizens which is well above that of any other province -- in other words, beyond "basic." Under the current formula, if Saskatchewan pays for this improvement by raising tax rates on a revenue source for which it is a have-not province, its equalization payment will increase; so too will that of Nova Scotia or any other have-not province for this particular tax base. Ideally, if the philosophy underlying the system is adhered to, equalization should not be paid to provinces for that portion of the level of public services which exceeds the "basic" level. Yet without a definition of basic services, total revenues implicitly define expenditure needs and the equalization program is internally driven (abstracting, of course from the recent amendments).

Slippery as the underlying philosophy of equalization may be, it is quickly becoming very important. Presumably one reason for no longer permitting full equalization for energy royalties is that while
abandonment of the concept does violate the 1967 operational approach of bringing all provinces up to per capita national average revenues, it is also true that it probably is consistent with the philosophy underlying equalization. Just because Alberta now receives about $4 billion in energy royalties, it does not mean that the cost to, say, Nova Scotia of providing this basic or reasonably comparable level of public services has risen commensurately. But precisely what per cent of these royalties ought to be eligible for equalization? Is deleting Crown Leases from the formula consistent as well? What revenue category is likely to be next in line for deletion? Consider also the other provisions of Bill C-26, namely that having a per capita income above the national average level precludes a province from receiving equalization payments. It seems to us that this concept has no rightful place in an equalization program designed to equalize only revenue-raising capacities. Yet it might make eminent sense within the context of a fiscal-need philosophy. Essentially it amounts to saying that any province with an above average income has a value of \( N_j/N_c \) equal to zero as a multiplier of the first term of equation (4).

In other words, the current equalization formula has become increasingly arbitrary not only in the sense that Ottawa has made several unilateral and far-reaching amendments to it, but also because there is no standard against which to evaluate these various amendments. This situation is very important for an understanding of the remainder of this chapter. In the following section we argue that in fact the principal reason for these amendments has been the funding problem that the system has created for Ottawa. We also argue that it appears that the energy-rich provinces are not bearing their fair share of the
responsibility for financing these transfers. But does this imply that
if for some reason the producing provinces agree to a revenue-sharing
pool then Canada ought to move again in the direction of "full" equal-
ization? We do not think so and our reasons will be delineated later
in the paper. The essential point, however, is that even though there
exist no definitions of what might constitute a "reasonably comparable
level of public services" or "unduly high tax rates," in one way or
another these concepts are ultimately given some implicit definition
which is expressed in the mechanics of the current equalization formula.
We return to some of these issues in the conclusion of the chapter.

3.3 EQUALIZATION AND ENERGY: THE RATIONALE FOR A TWO-TIER SYSTEM

As indicated in the previous section, the practical reason for
Ottawa's move to limit the equalization arising from energy\textsuperscript{17} probably
related more to the financing implications than to any philosophy as
to the appropriate level of these payments. The purpose of this section
is to focus on this financial interaction between energy royalties and
the equalization system. In particular, we shall present two equalization
"balance sheets," one relating to the relationship between energy and
the payments implicit in the 1979-80 estimates and the other focusing
on the impact of a $1 per barrel increase in the price of domestic
energy. As background for these balance sheets it is useful to note
again that provinces do not contribute directly to the funding of equal-
ization, and since there are no specific taxes earmarked to finance the
program, the money is provided from Ottawa's consolidated revenue fund.
Therefore, even though provinces do not contribute directly to the
funding, indirectly their citizens do contribute according to the provincial distribution of Ottawa's general revenues. Row A of Table 3.2 presents an estimate of this provincial distribution of Ottawa's revenues. It is important to recognize the heroic nature of the assumptions underlying this calculation, and the reader is encouraged to consult the notes beneath the table.

One could, of course, construct a hypothetical balance sheet for the entire equalization program focusing on who benefits and who pays. But for many of the revenue sources there is a rough-and-ready semblance of equity underlying its operation. Take, for example, personal income tax revenues, a revenue source which is shared between Ottawa and the provinces. If equalization payments rise as a result of increasing income tax revenues, Ottawa's revenues rise as well, thereby not only providing the funds to cover the increased equalization but in addition ensuring that the residents of the provinces whose tax revenues have increased (and, thereby, generated increased equalization) are precisely the ones who are now contributing more toward Ottawa's general revenues. This concept of equity, namely that there ought to be a fairly close geographical correspondence between the rise in provincial revenues (which generates equalization) and the source of Ottawa's funds to finance these equalization payments, is, of course, not the only concept that could be employed. Indeed, it is possible to argue that the balance-sheet analysis which follows is entirely misguided. No matter what the level or distribution of equalization payments, taxpayers in like circumstances (e.g., income bracket, family status) face the same level of federal taxes regardless of their province of residence. If this is the preferred equity concept, then there is no reason to be
concerned about the potential of a funding inequity associated with the equalization program. However, we are proceeding on the premise that for certain categories of revenues, namely those under provincial control, it is preferable to focus on whether or not individual provinces are pulling their weight in contributing to the funding of the program as it relates to the equalization payments derived from these specific provincial revenue sources.

3.3.1 An Equalization Balance Sheet

Within our chosen framework, a potential equity problem does arise with respect to the equalization program, because Ottawa has undertaken to equalize revenues that are under provincial control. This is particularly the case for the rapidly rising energy royalties, because they are so concentrated geographically and, therefore, generate substantial equalization flows for each dollar of revenue equalized. Moreover, Ottawa has found it very difficult to obtain what it deems to be a "fair" share of these energy revenues. To a large degree, this was the rationale behind disallowing energy royalties as a deduction for corporate income tax purposes. If the domestic price were allowed to rise and the producing provinces allowed to pocket the increased royalties, the result would be (and has been) a very substantial rise in equalization payments. If, in addition, royalties paid to the provinces were deductible from corporate income, Ottawa might find itself in a situation where its equalization responsibilities would increase substantially but its revenues would not, and specifically, it would not be able to exact much revenue from the very provinces that were becoming wealthy and thereby causing overall equalization
payments to increase. Hence the rationale for the disallowance of royalties as a corporate expense and, indeed, for modifying the equalization program as it applied to energy.

In spite of these initiatives, a potential funding inequity still exists (largely because Ottawa still derives very little revenue from the energy sector). Panel B of Table 3.2 presents an equalization balance sheet as it relates to energy. Row B.1 contains the producing provinces' revenues arising from the six oil and natural gas revenue sources (categories 16 through 21 in Table 3.1). Of the $4.75 billion, fully $4 billion or 80 per cent accrues to Alberta. Row B.2 presents the equalization flows generated by the revenues in Row B.1. These figures reflect the fact that only 50 per cent of the energy revenues are allowed to enter the equalization formula. In effect they are merely the sum, for the have-not provinces, of the entitlements for categories 16 through 21 which appear in Table 3.1. The exception is that Ontario's figure has been set at zero, reflecting the fact that it will probably not be allowed to receive an equalization payment. 18

As indicated by the final column, these energy categories resulted in equalization payments of $889 million for fiscal year 1979-80. Note that this includes the negative entitlement of $77 million assigned to Saskatchewan; in other words, this province's equalization payments fell by $77 million, because it is a have province for the energy revenues. Row B.3 then allocates this $889 million by province according to the percentages appearing in Row A.

The final rows of Panel B present the "net balance" -- production revenues plus equalization payments minus contributions toward funding the program. Ontario is the only province with a negative figure
NOTES TO ACCOMPANY TABLE 3.2 -- THE FUNDING OF EQUALIZATION, 1979-80

These shares were calculated as follows. Ottawa's tax revenues come principally from three sources: personal income taxes, corporate income taxes and indirect taxes. We then made the simplifying assumption that all of Ottawa's revenues come from these three sources. Next we allocated provincial shares of these taxes according to the tax base shares (derived from the equalization tables) for personal income taxes, business income taxes, and general sales taxes respectively. The provincial shares in row A.1 are the result of applying weights (summing to unity and based on the share of federal revenue) and summing the three provincial categories. Adapted from Provincial Fiscal Equalization Tables: Second Estimate, 1979-80 (Ottawa: Department of Finance, July 1979). Row B.1 plus B.2 minus B.3. Ontario is assumed to be ineligible to receive equalization payments. These figures are based on 1978 consumption levels and are calculated as the sum of the costs of crude oil and its equivalent, natural gas, and LPGs. The crude oil consumption levels by province are taken from the December 1978 issue of Refined Petroleum Products (Statistics Canada, 45-004), Table 3 (utilizing "domestic disappearance"). Natural gas consumption by province is taken from the December 1978 issue of Crude Petroleum and Natural Gas Production (Statistics Canada: 26-006), Table 5, lines 18 through 24. Data for LPG consumption by province (net of that reported from the crude oil and equivalent sources) was estimated from NEB data. The price of natural gas was assumed to increase by 85 per cent of the heat equivalent increase in oil. Specifically $1 per barrel increase in oil was assumed and a 14.65¢ increase (per MCF) in natural gas. Assumes roughly $1 billion in revenues to the oil and gas industry. Royalties are assumed to average 42 per cent, yielding $420.8 million total. Revenues from corporate income taxes are excluded for this calculation. Gas equivalent price increase assumed to be 15¢ per MCF. This would be the increment to Ontario's equalization payments (and, therefore, to total equalization flows) if Ontario were eligible to receive equalization. Assumes Ontario will not receive equalization payments. The net balance equals C.2 + C.3 - C.1 - C.4.
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**Notes:**
- Current: $per capita
- Former: $million

1. Cost to provinces ($million)
2. Royalties for producing provinces
3. Resettlement expenditures increase
4. Funding allocation for resettlement
5. Net balance ($million)

**Source:** A Balance Sheet for $ per barrel

**Panel A: The allocation of federal revenue**
(-$345 million) while Alberta has a positive total of just under $4 billion. In dollar terms, the province of Quebec ends up with a considerably higher net balance than do two of the producing provinces; British Columbia and Saskatchewan: Quebec receives $639 million in equalization payments and its residents contribute $209 million toward funding, for a net balance of $430 million. In per capita terms, however, this situation no longer holds. Quebec's net balance is $68 compared, say, to $256 for Saskatchewan. Ontario has a deficit of $41 per person compared with a $1,935 surplus for Alberta. One anomaly still remains: Prince Edward Island does as well as British Columbia in the per capita net balance.

The Ontario figures merit further attention. If Ontario were deemed eligible to receive equalization payments, then the entry for this province in row B.2 should be its energy entitlement, $860 million (obtained by summing categories 16 through 21 for Ontario from Table 3.1), even though Ontario's actual equalization payment for 1979-80 would be $172 million, which would then be allocated across provinces in row B.3. This result would change every province's net balance slightly. For Ontario, however, the net balance would be altered from minus $352 million to a positive $450 million or, in per capita terms, to $53. The dramatic aspect of panel B of Table 3.2 would be reduced, since Ontario would no longer appear on the negative side of the ledger, but the general thrust of the table would remain unaltered: the sources for funding equalization flows (row B.3) do not bear any resemblance to the increases in provincial revenues which generated these equalization payments.
3.3.2. A Second Balance Sheet: The Impact of a $1 Per Barrel Rise in Energy

Panel C focuses on a second balance sheet and one that, in the current Canadian context, is drawing increasing attention; namely the impact on provinces of a $1 per barrel rise in the price of domestic energy. Specifically, we assume that the price of domestic oil rises by $1 per barrel and the price of natural gas by 14.65 cents per thousand cubic feet (i.e., 85 per cent of the heat-equivalent oil increase). Row C.1 represents an estimate of the cost, by province, of this rise in the price of domestic energy. These are not costs to provincial treasuries but rather transfers from Canadian consumers to the energy sector. Consumption levels are assumed to remain unchanged, as are the current prices of other forms of energy (e.g., hydro power). The total transfer goes to the domestic energy sector, since much of the oil consumed east of Ontario is imported. Ontario's share is $323.3 million, which is close to the estimate incorporated in Ontario Premier Davis's position paper on energy. Row C.2 of the table presents an estimate of royalties accruing to the producing provinces. Underlying these figures is the assumption that total revenues to the domestic energy sector will amount to $1 billion. In turn this assumes that Canada's exports of natural gas will also rise in price. Since they are already sold at world prices, the row C.2 figures implicitly assume a $1 per barrel equivalent rise in the world price of natural gas.

Under current royalty arrangements, approximately 42 per cent of total industry revenues will accrue to the producing provinces. The remaining $600 million accrues principally to the energy sector with perhaps 10 per cent directed to Ottawa, although with sufficient exploration
expenditure Ottawa's revenues from corporate income taxes can easily fall to zero, as will be pointed out below. These industry and federal government totals are not incorporated into Table 3.2: only the $420.8 million total for producing provinces' revenues are shown (a sum which relates only to royalties and does not include provincial corporate income taxes).

Rows C.3 and C.4 contain estimates of the equalization payments arising from the royalty increases and the allocation of the cost of these payments across provinces in accordance with the funding shares in row A. Equalization payments for the traditional recipient provinces equal $78.1 million. If Ontario is allowed to receive payments, this total rises to $153.5 million (see the bracketed figures beneath row C.3). Alberta's contribution (from its taxpaying residents) toward the funding of the $78.1 million equalization bill is less than $10 million, despite its receipt of over $360 million in royalties. Once again Ontario is on the losing side, especially if a provision along the lines of Bill C-26 is reintroduced to disqualify it for payments, even though it falls into the have-not category. Moreover, even the $78.1 million may exceed the amount of revenues Ottawa would get from the $1 per barrel energy increase under current royalty and tax arrangements. Table 3.3 indicates that Ottawa's share of incremental revenues can range from 27 per cent (with no additional exploration on the part of the oil industry) to 3 per cent with additional exploration equal to 50 per cent of additional revenues. Historically, the federal government's share has been about 10 per cent. Considering that incremental revenues to the domestic energy industry were assumed to be $1 billion, equalization payments (excluding Ontario) represent 7.8 per cent of this
increment -- more than Ottawa's share of the revenue. It should be noted that these equalization calculations assume that the 1/3 resource cap (referred to above in the context of the 1977 Fiscal Arrangements Act) on equalization does not become binding. Since the current ratio of resource-related equalization flows to total equalization flows in the neighbourhood of 31 per cent, however, it is likely to be the case that this 1/3 resource limit will become binding after one or two more $1 per barrel increases in the price of domestic energy. Once this limit is reached, further energy price increases will not add to the level of equalization payments unless the nonresource portion of equalization begins to rise.

The final row of Table 3.2 presents the net balance. Only Alberta finishes on the positive side of the ledger. (This result is somewhat misleading, because the overall balance across provinces has to come out on the negative side, since industry revenues and those of the federal government are excluded from the table.) The overall cost to Ontarians is $352.3 million. More interesting under the scenario implicit in the table -- namely that Ontario qualifies as a have-not province but is deemed ineligible to receive equalization -- Ontario's residents are called upon to contribute $30.2 million in equalization funding as a result of the accrual by the energy-producing provinces of $420.8 million.

The Table 3.2 figures place in bold relief the magnitude involved in the current energy debate. Since the price is roughly $10 below world levels, the impact of moving to world prices is massive indeed. Although rising energy prices will curtail demand, a rough indication
of the implications of world energy prices for Canadians can be obtained by multiplying these figures by a factor of 10. This exercise will not apply to the equalization figures in the table, since the program will run into its 1/3 resource limit well before Canada reaches world prices. Seen from this perspective, it is clear that the system of equalization payments is not the critical issue in the policy debate, since it relates to energy price increases. In the 1973-74 era concern over equalization payments was much more prominent, because the formula was then open-ended and 100 per cent of royalty revenues were eligible to enter the formula. Indeed, modifying the formula was, in effect, a precondition for allowing domestic prices to move towards world levels. In short, the present call from many quarters for greater rent sharing relates more to lines C.1 and C.2 of Table 3.2 than to the implications relating to equalization. Nonetheless, in our opinion there do exist grounds for arguing that the producing provinces are not bearing their fair share of funding the equalization formula.

3.3.3 Offsets to the Balance Sheet Approach

The claim that the producing provinces should shoulder more responsibility does not hold much water if Ottawa is also a major beneficiary of rising energy prices. As Table 3.3 indicates, Ottawa does not garner much corporate income revenue arising from domestic price increases. But what about other energy-related revenues? Principal among its sources of energy revenues are (1) the 7 cents per gallon excise tax on motor and aviation fuel, (2) the 9 per cent manufacturers’ sales tax which applies to some energy products, (3) the “oil sands levy” which is earmarked to cover the cost of guaranteeing
that the output of the oil sands (Syncrude and Great Canadian Oil Sands Ltd.) receives the world price level (thus implying that there is no "net" revenue generation for Ottawa from this levy), and (4) the oil export tax. Offsetting the latter revenue source is Canada's Oil Import Compensation Program which subsidizes offshore oil flowing into the Atlantic and Quebec region in order to maintain a uniform domestic price. For 1979 taxable exports were in the neighbourhood of 80 million barrels, whereas compensatable imports were about 140 million barrels. With a $10 per barrel difference between the domestic and world price level, the net cost of Ottawa's export and import programs will be in the range of $600 million. Elsewhere Courchene has estimated that annual revenues from (1) and (2) above would amount to just under $1 billion per year, at present rates of energy consumption. Overall, then, Ottawa does not emerge as a major financial beneficiary from energy.

On the producing provinces' side, the case that they should bear more responsibility is not as clear-cut as it might otherwise appear. Their argument is that they are already forgoing massive revenues because the domestic price is well below the world level. From row C.2 of Table 3.2, and assuming current consumption levels, the foregone income at world prices is over $4 billion. Expressed somewhat differently, the benefit to Canadian consumers from each dollar per barrel that we are below the world price is in the neighbourhood of $1 billion (see row C.1 of Table 3.2). Much of this sum materializes as a transfer from the producing provinces to consuming Canadians. The provinces can also point out that in order to collect their royalties they have had to undertake major expenditures (roads, infrastructure, etc.).
### TABLE 3.3 DISTRIBUTION OF INCREMENTAL ENERGY REVENUES

<table>
<thead>
<tr>
<th></th>
<th>With no additional exploration</th>
<th>With additional exploration equal to 50% of additional revenues</th>
</tr>
</thead>
<tbody>
<tr>
<td>Federal government</td>
<td>27.0%</td>
<td>3.0%</td>
</tr>
<tr>
<td>Provincial governments</td>
<td>48.4%</td>
<td>44.0%</td>
</tr>
<tr>
<td>Industry share:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reinvested</td>
<td></td>
<td>50.0%</td>
</tr>
<tr>
<td>Not reinvested</td>
<td>24.6%</td>
<td>3.0%</td>
</tr>
<tr>
<td></td>
<td>100.0%</td>
<td>100.0%</td>
</tr>
</tbody>
</table>


These costs and foregone revenues are in addition to their concern over Ottawa's decision during the initial world price rise to take the proceeds of the export tax on oil. While one can have sympathy with these views it is important to note that the transfer of rents from the energy sector to Canadian consumers as well as the concern over the loss of revenue to Ottawa arising from the oil export tax will disappear if and when the domestic price reaches the world level. In our opinion, these arguments, relate more to who should get the energy rents, rather than to the narrower issue of whether or not there exists
an inequity in the funding of the equalization program. We believe
that there is an inequity and we now turn to some alternative approaches
to equalization.

3.4 ALTERNATIVE APPROACHES TO EQUALIZATION

Accepting the proposition that there does exist an inequity re-
lating to the funding of the energy components of equalization does not
take one very far in designing alternative approaches to equalization.
Indeed, at the extreme the federal government could simply levy an in-
direct tax equal to $1 per barrel in lieu of the next domestic price
increase and earmark this sum for the equalization program. Such an
action would net Ottawa about $1 billion (i.e., it would coincide with
the revenue underlying row C.2) and approximately offset the $889 million
equalization bill for fiscal year 1979/80. Alternatively, the whole
equalization program could be restructured, as was suggested in a
paper by Paul Davenport. The approach taken in this chapter is motivated
in large measure by the fact that there has been a long tradition in
this country of federal government assumption of financial responsibility
for equalization, and it seems unreasonable to jettison this approach
entirely. Accordingly, we shall proceed under the assumption that Ott-
awa will continue to equalize a subset of the revenue sources which
presently enter the equalization formula. This subset, to be defined
later, will comprise the "first tier" of the program. The "second tier"
will take the form of an interprovincial revenue-sharing pool and, to
anticipate the analysis, will focus essentially on revenues under sole
provincial control -- particularly the resource revenues. In other
words, we shall argue for a two-tier system for equalization payments. Although the concept of an interprovincial revenue-sharing pool for part of the equalization program has been suggested before, it does represent a major departure from the status quo. This being the case, it seems appropriate to preface the analysis with a review of the operations of a two-tier system in one of our sister federations, the Federal Republic of Germany.

3.4.1 Equalization in Germany: A Two-Tier System in Action

The First Tier: Vertical Equalization

Like the Canadian federation the Federal Republic of Germany levies some taxes which are specifically earmarked for the federal government, some taxes which are earmarked for the state governments and some taxes which are shared. For 1971 the federal taxes yielded DM 30 billion while the state taxes generated DM 10.1 billion. By far the largest portion of revenues for both the federal government (DM 63.6 billion) and the states (DM 46.4 billion) came from shared taxes. Three of the four shared taxes (i.e., wage and assessed income tax, other income taxes, and the trade tax) were shared equally between the two levels. The amounts received by the various states depended on the local yields of those taxes. The fourth tax, the value-added tax, is shared 70:30 between the federal government and the states. Of the states' share (i.e., of the 30 per cent) 75 per cent is distributed to the individual states on a population basis and the remaining 25 per cent is to used to assist the financially weak states. Specifically, this 25 per cent is designed to assist states with below-average tax
receipts to reach at least 92 per cent of the all-state average. This portion amounted to just over DM 3 billion with total value-added taxes distributed to the state equalling DM 13 billion for 1971. 26

The treatment of shared taxes in Germany differs considerably from current Canadian practice. First, tax rates on shared taxes are uniform across Germany. Secondly, in Canada we distribute the shared taxes in accordance with local receipts of these taxes and they are then equalized to the national average level. Payments for equalization in Canada come from consolidated revenue, not from an earmarked shared tax. The 25 per cent portion of the value-added tax in Germany resembles an equalization payment and the remaining 75 per cent, which is distributed on a per capita basis, also tends to equalize revenue. In fact, both amount to a redistribution of a given tax source, whereas in Canada we generate additional tax revenue to provide for equalization.

Interstate Revenue-Sharing Pool: Horizontal Equalization

The second tier of the German equalization program is an interstate revenue-sharing pool. Conceptually the approach is rather straightforward, although the details of this interstate transfer are somewhat complicated.

The first step in the procedure for formulating the interstate contributions is to calculate what Hunter refers to as the "adjusted tax capacity," 27 ATC, where i refers to the state in question. This is accomplished by obtaining the state's tax capacity TC, which is the sum of (a) state taxes, (b) the state's share of joint taxes according to local yields, (c) the state's share of the value-added tax, and (d) some element of the yields of municipal taxes. The important point
to note is that the tax capacity definition includes the "equalizing" carried out in the first tier. Deductions are then made for any special burdens or extraordinary expenditures facing the state. The result is the adjusted tax capacity:

\[ ATC_i = TC_i - S_i \]

where \( S_i \) is the special burden associated with state \( i \).

The next step is to calculate the "equalization yardstick." This is defined as

\[ Y_i = \frac{TC_i}{P_i} \]

where \( \frac{TC_i}{P_i} \) = the all-state average taxable capacity per capita, defined as

\[ \frac{1}{P} = \left( \frac{\sum TC_i}{n} \right) \]

where \( P_i \) is the population of the \( i \)th state, and \( n \) is the number of states, and \( w_i \) = a weight designed to take into account the higher revenue needs assumed to be associated with large population densities.

The determination of the value of the weights, \( w_i \), essentially depends on population densities. They start on a sliding scale with a value of \( w = 1.00 \) for cities with 5,000 people and move up by steps to a valuation of 1.35 for cities with 500,000 people. The city state of Hamburg, for example, has a weight of 1.35, as does Bremen, the other city state in the Republic. Over and above these adjustments, there are extra allocations to coincide with population densities which range from 2 per cent (i.e., \( w = 1.02 \)) where there are between 1,500 and 2,000 persons per square kilometre to 6 per cent where there are more than 3,000 persons per square kilometre. The weights assigned
to the cities and to the overall population density for states are combined (weighted by the relevant population) to attain the overall \( w_i \) for each state. Generally these weights serve to lessen the magnitude of flows in the second tier, because usually the wealthier states have the large population densities and therefore have larger values for \( w_i \).

In general, one can evaluate whether a state is rich or poor by comparing its adjusted tax capacity with the equalization yardstick:

\[
PE_i = (TC_i - S_i) - \left[ \frac{TC_i}{w_i P_i} \right] 
\]

or

\[(7) \quad PE_i = ATC_i - Y_i,\]

where \( PE_i \) is used to designate a state's potential equalization. For poor states \( PE_i \) is negative; in other words, its adjusted tax capacity is less than the equalization yardstick, and vice versa for rich states. Alternatively one could express this formula in per capita terms, which would imply that per capita potential equalization would equal per capita adjusted tax capacity minus the national average capacity where the latter term is adjusted by \( w_i \).

Actual equalization payments are not identical to potential equalization, \( PE_i \). States that are "poor" are allowed to draw revenues from the pool equal to their \( ATC_i \) minus 95 per cent of the equalization yardstick:

\[(8) \quad AE_i = ATC_i - 0.95Y_i, \quad \text{for } PE_i < 0\]

where \( AE_i \) is actual equalization payments to state \( i \).

The contribution into the pool of rich provinces begin only after they have a surplus in excess of 102 per cent of the equalization
yardstick. For surpluses between 102 per cent and 110 per cent they contribute 70 per cent of the excess and beyond 110 per cent they contribute 100 per cent of the excess: thus,

\[ AE_i = 0.7(\text{ATC}_i - 1.02Y_i) \text{ for } PE > 0 \text{ and } 1.02Y_i < \text{ATC}_i < 1.10Y_i, \]

\[ AE_i = 0.7(\text{ATC}_i - 1.02Y_i) + (\text{ATC}_i - 1.10Y_i) \text{ for } PE > 0 \text{ and } \]

\[ \text{ATC}_i > 1.10Y_i \]

Hunter provides an example, utilizing rough estimates for Lower Saxony and Hesse, which will help clarify the operation of the revenue-sharing pool. 29

<table>
<thead>
<tr>
<th>Lower Saxony</th>
<th>Hesse</th>
</tr>
</thead>
<tbody>
<tr>
<td>(\text{TC}_i) = DM 4,500 m.</td>
<td>DM 5,000 m.</td>
</tr>
<tr>
<td>(S_i) = DM 200</td>
<td>zero</td>
</tr>
<tr>
<td>(\text{TC}_g) = DM 46,000 m.</td>
<td>DM 46,000 m.</td>
</tr>
<tr>
<td>(P_g) = 60 m.</td>
<td>60 m.</td>
</tr>
<tr>
<td>(P_i) = 7.1 m.</td>
<td>5.4 m.</td>
</tr>
<tr>
<td>(w_i) = 1.02</td>
<td>1.05</td>
</tr>
</tbody>
</table>

From equation (8), for Lower Saxony (a "poor" state):

\[ AE_i = 4,300 - 0.95 (5,552) \]

\[ = -974. \]

Hence, Lower Saxony can draw DM 974 m. from the revenue-sharing pool. For Hesse, a "rich" state, the potential equalization or surplus from equation (7) equals

\[ PE_i = 5,000 - 4,347 \]

\[ = \text{DM 653 m.} \]
Since this is in excess of 100 per cent of the equalization yardstick, equation (9) applies:

\[ AE_i = 0.7(4,782 - 4,434) + 5,000 - 4,782 \]
\[ = \text{DM} \ 462 \text{ m.} \]

Hesse must contribute DM 462 m. into the revenue-sharing pool.

Overall, these interstate transfers accounted for between 4 and 5 per cent of state tax revenues in 1971.\(^3\)\(^0\) In terms of individual states, however, these payments ranged as high as 14 per cent of revenues for Saarland. It should be mentioned that prior to 1970 these interstate flows were considerably larger. They have been reduced because of the introduction of the tax sharing for the value-added tax, referred to in the first tier discussion. Obviously, the more "equalization" accomplished in the first tier the lesser will be the role for the interstate revenue-sharing pool. As stated earlier, this analysis relates to equalization in Germany as of 1971.

The particular manner in which equalization payments operate in other federations need not have much to say about how they ought to operate in this country. Moreover, equalization payments are but one aspect of overall federal-provincial financial relations. There is a considerable element of "equalizing" incorporated into the new shared-cost aspect of the 1977 Fiscal Arrangements Act: the switch from 50 per cent cost-sharing to what essentially amount to per capita grants generally bestowed relative benefits on the have-not provinces.\(^3\)\(^1\) A comprehensive comparison of the two countries would of necessity require one to take full account of these various federal-state or federal-provincial grants. Nonetheless, the German system of equalization payments does provide a motivation for pursuing the implications of a two-
3.4.2 Two-Tier Systems: An Application to Canada

The First Tier

Deciding which of the revenue categories should come under the federal tier and which should be subject to interprovincial revenue sharing is essentially an arbitrary exercise. One decision rule might be that Ottawa should undertake to equalize only those revenues which it shares jointly with the provinces. This would put the personal income tax and business income³² categories from Table 3.1 in the first tier. The breakdown we have chosen is the inclusion of all but the resource revenues (renewable as well as nonrenewable) in the first tier. In other words, revenue categories B.15 through B.23 of Table 3.1 enter the interprovincial revenue-sharing pool and the remainder fall into the first tier. Our rationale for including so many revenue categories in the first tier would be that by and large the distribution of revenues for these tax categories does differ little from the distribution of Ottawa's sources of revenues (i.e., row A of Table 3.2). We repeat, however, that the breakdown is arbitrary.

Calculation of the entitlements from this first tier is very straightforward: they are simply the sum of the entitlements for the nonresource revenue categories of matrix panel B of Table 3.1. These entitlements appear as column 1 of Table 3.4. Ontario, B.C. and Alberta are the have provinces for this first tier. Total entitlements for the seven recipient provinces amount to just over $2 billion -- approximately $1 billion less than the actual equalization payments for fiscal year 1979-80. Ottawa tooks after the funding of these flows
<table>
<thead>
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<td>27</td>
<td>99</td>
<td>21</td>
<td>14</td>
<td>77</td>
<td>119</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>98</td>
<td>25</td>
<td>27</td>
<td>92</td>
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<td>176</td>
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<td>69</td>
<td>27</td>
<td>99</td>
<td>21</td>
<td>14</td>
<td>77</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Table 3.4**

A TWO-EQUILIBRION SYSTEM: SOME ESTIMATES FOR 1979-80.
and the implicit allocation across provinces of the funding shares borne by taxpaying Canadians would be in rough accordance with the ratios in row A of Table 3.2. Since the three rich provinces are the only provinces with funding ratios in excess of their population share, they (or rather their residents) are bearing a greater share of the funding than are the residents of the have-not provinces. Overall, the recipient provinces' revenues are brought up to national average per capita levels. Since the rich provinces do not contribute directly to the funding, they end up with above average per capita revenues. This aspect will be important in implementing the second tier.

The Second Tier: An Interprovincial Revenue-Sharing Pool

The second tier can be approached in several ways. For example, one could simply calculate the entitlements which would result from the application of the current formula to the resource revenues. Negative entitlements would imply that these provinces would be net contributors by this amount and vice versa. Our approach is slightly different. We aggregate all resource categories together into a single category and define entitlements in terms of the shortfall or excess of a province's per capita resource revenue compared to the national average resource revenues. Specifically,

\[
(10) \quad \frac{RE_j}{P_j} = a \left[ \frac{RR_c}{P_c} - \frac{RR_j}{P_j} \right],
\]

where \( \frac{RE_j}{P_j} \) = per capita resource entitlements for province \( j \),

\( \frac{RR_c}{P_c} \) = national average per capita revenues from resources,
\( \frac{RR_j}{P_j} \) = per capita provincial revenues from resources

and \( \alpha \) = the equalization parameter, that is, the fraction of the per capita excess or deficiency which is eligible for equalization.

All resource revenues would enter the formula (i.e., not only 50 per cent as in the case for the current formula). The value of the equalization coefficient, \( \alpha \), will determine the degree to which resource revenues are equalized. A value of unity for \( \alpha \) would be a confiscatory plan -- all provinces would end up with the same per capita revenues from resources. Obviously this is too high a value for \( \alpha \). Table 3.4 presents the entitlements which would arise with \( \alpha = 1/3 \), \( \alpha = 0.4 \) and \( \alpha = 0.5 \), with the corresponding total entitlements (i.e., the sum of either the positive or negative entitlements) appearing as the last row. Note that in Table 3.4 we are utilizing the equalization data which arise from the relevant renewable and nonrenewable resource revenue categories. These data are no doubt very inadequate, because many resource revenues escape the calculation. For example, one would also want to include the profits (as well as any royalties on rentals) arising from water or nuclear power, such as the profits of Ontario Hydro and Quebec Hydro. Currently these figures appear as part of business income and enter the first tier. In this sense the data that follow relating to the second tier are exploratory at best and, in particular, will overpresent the oil-producing provinces' share of overall resource revenues.

At this juncture the question arises as to whether the two tiers ought to be independent of one another. This question relates principally to Ontario. Consider the case for \( \alpha = 1/3 \). Ontario's entitle-
ments from the second tier amount to $621 million. Should it be eligible to receive this money in spite of the fact that its revenues (at national average rates) in the first tier exceed the national per capita average by $776 million? The answer depends on how one views this second tier. Our approach here is to argue that the two tiers should not be independent: Ontario will receive a positive payment from the second tier only when its second-tier entitlement exceeds $776 million. From both a conceptual and a practical point of view, this is a very important decision. The approach we are taking can be seen as implicitly making Ontario contribute this $776 million from the first tier toward equalization, and it is allowed to receive payments only when the second-tier entitlement exceeds its first-tier fiscal excess. However, there are sufficient data presented in Tables 3.4 and 3.5 for the reader to calculate the implications of treating the two tiers as independent. Saskatchewan is the other outlier—a rich province for the second tier but a recipient province for the first tier. We propose to allow Saskatchewan to pay into the second tier in line with its resource wealth and also to be eligible to receive its first-tier entitlements.

Accordingly, columns 5, 6 and 7 present the actual equalization flows emanating from the second tier. The payment to Ontario will be zero until its entitlement surpasses its negative figure in the first tier. In effect, this means that it qualifies for a payment only when \( \alpha = 0.5 \) in Table 3.4 (i.e., in column 7). For comparison purposes its net position appears in brackets in columns 5 and 6, although in reality its equalization flow would be set equal to zero. Since equalization payments for tier two are considerably less than equalization entitlements for this tier, the payments into the fund for the three rich prov-
ences have been scaled down proportionately in order to preserve the property that payments into the pool are equal to withdrawals.

Total equalization payments -- the sum of the two tiers -- appear in columns 8, 9 and 10 for the various values of \( \alpha \). The final column of the table reproduces equalization payments for 1979-80 from row D of Table 3.1. Let us focus attention on the payments for \( \alpha = 0.5 \) (i.e., column 10). Total equalization payments are somewhat larger under the two-tier system -- $3,190 million compared to $3,007 million. These figures should be fairly close, since the current equalization program essentially allows 50 per cent of resource revenues into the formula and the second tier with \( \alpha = 0.5 \) does roughly the same. Part of the difference in the totals arises because column 10 includes a payment to Ontario of $156 million whereas the actual equalization flows show Ontario with a zero payment. If Bill C-26 is not resurrected, the actual payment to Ontario for 1979-80 would be $172 million, as reflected in row C of Table 3.1. Most of the remaining difference arises from the payments to Newfoundland, which are $22 million larger for the two-tier system. This occurs in part because of the different treatment of water power rentals (resource category 23 of Table 3.1). In the present equalization formula the base for this revenue source is a volume base -- that is, the kilowatt hours of power generated. Newfoundland emerges as a have province for this category (i.e., it has a negative entitlement for category 23 in Table 3.1). Under the two-tier proposal, however, the tax base for all resources is in terms of revenues, not production volumes. Since Quebec, not Newfoundland, gets much of the revenues from the hydro power generated in Labrador, Newfoundland ends up with a higher equalization payment.34
In terms of the interprovincial payments into the equalization program, Alberta's contribution of $1,106 million is far and away the largest with British Columbia contributing $5 million and Saskatchewan $79 million. Overall, however, Saskatchewan is a net positive recipient since its $126 million from tier one leaves it with a net position of $47 million.

Table 3.5 presents some further financial implications of the two-tier proposal. The first three columns present the per capita values of equalization corresponding to columns 1, 7 and 10 of Table 3.4. The per capita value of total equalization in Table 3.5 can be compared with row E of Table 3.1. Alberta's contribution to the second tier is $550 per capita. Under the current provisions, Alberta's per capita revenue is 163 per cent of the national average (columns 4 and 5 of Table 3.5). Under the two-tier example its per capita revenue would drop to 139 per cent of the national average (and the national average revenue would also fall, reflecting this transfer from Alberta). In terms of its revenue from resources, the two-tier proposal would require Alberta to contribute roughly 27 per cent of its resource revenues to the interprovincial revenue-sharing pool. The reason this total is nowhere near 50 per cent, even though the value of \( \alpha \) is set at one-half, is that Ontario is deemed eligible to receive only $156 million of its $932 million entitlement because it is a rich province for tier one. Once Ontario becomes eligible, however, Alberta would contribute roughly 50 per cent of its additional revenues under the provision of the two-tier system with \( \alpha = 0.5 \).

If one were to apply the 1/3 resource limit to the two-tier proposal, it would mean that the payments from the second tier should at
TABLE 3.5
SOME FURTHER FINANCIAL IMPLICATIONS OF THE TWO-TIER PROPOSAL (\$ per capita)

<table>
<thead>
<tr>
<th>Province</th>
<th>First Tier ($000)</th>
<th>Second Tier ($000)</th>
<th>Total Provincial Revenue, % of Total Provincial Revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average</td>
<td>$6,000</td>
<td>$8,000</td>
<td>$14,000</td>
</tr>
<tr>
<td>per capita</td>
<td></td>
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</tr>
</tbody>
</table>
the limit equal half of the first-tier payments. For $\alpha = 0.5$ this limit is exceeded, because Ontario's payment is included and Saskatchewan's negative entitlement is excluded from the second-tier totals. It would be a simple matter, should one so desire, to apply the existing regulation with respect to resource revenues within the context of a two-tier system. With respect to this issue, given that the resource cap will soon become effective under the current system, there seems to be no good reason to reintroduce that aspect of Bill C-26 which proposed the dropping of the Crown leases category. The resulting savings to Ottawa would be only temporary. In this regard as well, we feel that there is no good reason to exclude Ontario from becoming a recipient, since the operational thrust behind the program is to equalize resource revenues. With some provinces receiving over $600 per capita in equalization, it is hard to refuse Ontario the $18 per capita it is due (see row 3 of Table 3.5). Finally, our preferred interpretation of the resource cap within the current system would be to include the lessor of (1) a province's equalization payment arising from energy, and (2) its overall equalization payment. Within the context of the two-tier system, the Ontario figure of $152 million (rather than its resource entitlement of $932 million then would be the relevant total for purposes of implementing the resource cap.

3.4.3 Equalization Payments as a Rent-Sharing Device

Thus far the analysis of the two-tier proposal has focused principally on the case where $\alpha$ is set at 0.5. This was by design, since it is probably not reasonable to discuss alternatives to the present scheme which have the recipient provinces faring considerably worse
than the status quo -- as do the variants of the two-tier scheme with \( \alpha \) set at 1/3 and 0.40 (compare columns 8 and 9 of Table 3.4 with column 11). Since the \( \alpha = 0.5 \) variant of the proposal leaves the total equalization as well as the distribution across provinces virtually unchanged, it follows that Ottawa (or rather, the federal taxpayers) is a net beneficiary of the scheme to the tune of roughly $1 billion -- that is, the first tier is $1 billion less than the 1979-80 level of equalization. We believe that this is a desirable feature of the two-tier system, since an integral part of the argument that there currently exists a funding inequity was the argument that Ottawa is bearing too much of the cost of equalizing revenues that do not come under its control.

However, if one espouses the principle that not all of the saving should go to Ottawa, then it is possible to entertain lower values for \( \alpha \). For example, if \( \alpha = 0.4 \), the second tier would cost the producing provinces $827 million rather than $1,190 million and Ottawa could utilize some of its $1 billion saving to "top up" equalization to the \( \alpha = 0.5 \) levels. Indeed, the lower the level of \( \alpha \) the more likely it is that the producing provinces would agree to a two-tiered system. One can even suggest that the 1/3 resource limit be jettisoned and that the second tier of the equalization program could be the vehicle for sharing the energy rents as Canada moves towards the world price for energy.

Intriguing as this last suggestion might be, it is addressing an issue that really goes beyond the confines of this paper. In part, however, it does bring us back to our earlier discussion of the philosophy underlying equalization. Is the role of equalization to equalize provincial revenues or is it to ensure that provinces have sufficient funds to provide some (undefined) level of public services without
resorting to unduly high tax rates? If it is the latter, then there should be no presumption at all that energy rents ought to be shared within the context of a redesigned equalization program. Sharing the rents which will accrue as the domestic energy price rises (if there is to be any rent sharing at all) should be addressed independently of the equalization program, especially since the 1/3 limit will become effective with one or two more $1 per barrel price increases. If there is to be such sharing, it is not clear that the provinces are the obvious recipients of these funds. As panel C of Table 3.2 indicated, there are enormous adjustment costs as the price of energy rises. In our opinion, the federal government is in a better position than the provincial governments to utilize any revenues for mounting programs to encourage conservation, to achieve energy self-sufficiency, to provide incentives for development of alternative energy sources, and to offset undue hardship arising from the energy price increases. The purpose of this paper was much narrower. We focussed on the funding of the equalization program, found it to be wanting, and proposed an alternative to the current program which we feel combines the dual principles of "ability to pay" and "cooperative federalism."

3.5 CONCLUSION

Is there any chance that a two-tier proposal would ever be agreeable to the resource-rich provinces? Obviously we really do not know. But it does seem logical to us that in general the greater the degree of autonomy granted the provinces within the federation, the more responsibility they must bear. And in particular, the more that decisions relating to all aspects of resource management, including the rev-
enues derived therefrom, fall under provincial domain the less (more) would appear to be the rationale for the Canadian taxpayer (resource-rich provinces) to undertake to offset the revenue "shortfalls" for resource-poor provinces. The two-tier approach to equalization payments is meant to be reviewed from this perspective. As noted above, the details of the particular example illustrated in this paper are exploratory at best. The fact that the revenues from, say, Ontario Hydro and other energy Crown corporations were deleted from the second tier because we restrict ourselves to resource revenues as defined by the equalization program implies that the example was excessively punitive to the resource-producing provinces, in particular to Alberta. Moreover, it should also be recognized that what is eligible for the second tier are "net" revenues or royalties -- provinces should be able to deduct expenses undertaken in order to generate these royalties or revenues and the net figure is what should be utilized in the second tier.

The equalizing program has become progressively more arbitrary since the quadrupling of net prices in 1973: and the difficulties arising from energy are likely to continue. Very soon the 1/3 resource limit will become binding. Then if Alberta moves to reduce its corporate income tax rates substantially the limit will reduce equalization payments on two counts: (1) the equalization arising from corporate income taxes will fall, and (2) because it will reduce the equalization arising from the nonresource categories, it will also reduce the resource revenues that can be allowed to enter the formula to prevent exceeding the 1/3 limit. Indeed, Alberta's lower tax rates already have a major impact on the formula: with no sales tax, the lowest income tax rate in Canada, the recent reduction in motor fuel taxes, etc., millions of
dollars already bypass the formula. Perhaps some of this could be offset by allowing the interest on the Heritage Fund to enter the formula under the "business income" category, since it might qualify as the "profits" of a provincially run enterprise. But then why should Ottawa be called upon to finance the resulting equalization from consolidated revenue, especially since these interest revenues are exempt from federal tax? And so on.

More generally, while there may be grounds for concern relating to the operation of the equalization formula, there is even more concern related to the overall role that rising energy rents are playing in the federal-provincial financial area. Unlike the German federation, which maintains uniform tax rates, Canada is moving in the direction of progressively diverging tax rates. This has implications which far exceed those relating to the particular problems it creates for the operation of the equalization program. Moreover, the manner in which these broader issues are eventually resolved may well have major implications for the type of equalization program which suits the needs of the country. It is within the more general context that the question of equalization ought to be addressed. Since the basic parameters of this broader solution are unfortunately still unclear, we directed our attention in this chapter to the much narrower question of redesigning the existing equalization program. Within this rather narrow context, we feel that the two-tier proposal has a great deal of merit.

Finally, with respect to the overall thrust of the thesis this chapter was intended to provide some insight into one of the major distributional implications concerning the pre-NEP tax regime -- namely, the effect on rent distribution via the federal equalization program.
In fact, one could argue that the repercussions of the pre-NEP tax regime on the equalization program was partly responsible for the introduction of a new federal tax regime, the NEP, which significantly increased the revenue share (or distribution of rents) in favour of the federal government. In the remaining two chapters of this thesis we leave the distributional aspects of oil tax policies and focus our attention on the efficiency aspects of Canadian oil tax policies -- both the pre- and post-NEP tax regimes.
1. A significant portion of the analysis in early parts of this paper also appears in Thomas J. Courchene, "Energy and Equalization," in Energy Policy for the 1980's: An Economic Analysis, Ontario Economic Council, Toronto, 1980. As well, this chapter of the thesis was written in the fall of 1979 (and subsequently published in Richard Bird (ed.), Fiscal Dimensions of Canadian Federalism, Toronto, Canadian Tax Foundation, 1980) and appears in this final draft of the thesis unchanged. Consequently, several of the statements appearing in the text may not be valid today (for example, statements relating the domestic price of oil to the world price of oil, etc.). In fact, since the writing of this chapter the federal equalization program has been altered significantly. Once again, however, there is no attempt made in this chapter to deal with the new equalization system since one of the purposes of the chapter is to focus on the distributional effects of the pre-NEP tax regime on the federal equalization program existing at that time.

2. Because of the series of modifications beginning in 1974, this interpretation is no longer strictly correct. As will be detailed below, provinces are currently guaranteed only half the national average revenues from natural resource revenues.

3. Noting that $t_i = TR_i/B_i$, it is simply a matter of substitution and cross-multiplication to derive equation (2) from equation (1).


6. "Anticipated," in the sense that it was only earlier in 1979 that the final estimates for 1977-78 were completed and Ontario was shown to be eligible for an equalization payment. Earlier estimates for 1977-78 always placed it among the rich provinces.

7. When this paper was written, the position of the Ontario government was that it would look favourably upon the reintroduction of a measure like Bill C-26, which would prohibit Ontario from receiving equalization payments. For this reason it was assumed for the analysis that follows that Ontario would not be eligible to receive equalization payments. However, as a result of Ontario's failure to have its ideas with respect to oil prices prevail at the First Ministers Conference on Energy (November 12, 1979), it now appears that the Ontario government may be more receptive to the idea of embracing have-not status and collecting equalization.
8. In the table, we are comparing 1979-80 equalization payments with 1978-79 revenues. The statement in the text is still correct if the comparison is made with 1978-79 flows for equalization.


12. In this section we rely considerably on the work of Clark; op. cit.


14. This analysis could also be carried out in terms of formulation (2), above, of the equalization formula. It would indicate that the implicit definition of "expenditure needs" for each province is its population share of total revenues from all sources, while its "revenue means" would equal its own revenues from all sources, with equalization payments providing the difference. Not surprisingly, this approach yields results that are identical to those from the per capita base approach.

15. However, it is incorporated in the German system of equalization payments described later in this paper. And George Carter provides evidence of it being included in U.S. conditional grants. See G.E. Carter, Canadian Conditional Grants Since World War II, Canadian Tax Paper no. 54 (Toronto: Canadian Tax Foundation, 1971).


17. Unless otherwise specified, the word "energy" will refer to oil and natural gas and not to hydro-electric, nuclear, or other sources of energy.

18. Later in the text we shall present data that indicate Ontario's energy entitlement, which for 1979-80, equalled $860 million.

19. This part of an overall balance sheet, namely the transfer of funds from the consumers to the energy sector, was neglected in the Panel B exercise.

20. Indeed, as long as one assumes that the world price remains unchanged, part of this transfer will go to Ottawa, since the cost of subsidizing imported oil will fall by $1 per barrel. Likewise, Ottawa's
Export tax on oil exports will fall by $1 per barrel. Since compensated imports exceed taxable exports by some 60 million barrels, Ottawa would gain roughly $60 million. However, if the world price rises along with the domestic price, there is no change in Ottawa's financial position.


23. Paul Davenport, "Equalization Payments and Regional Disparities," paper presented to the 13th Annual Meeting of the Canadian Economics Association, Saskatoon, May 30, 1979. Space does not allow more than the barest sketch of Davenport's proposal. Essentially, he would have Ottawa transfer to the provinces sufficient tax room to allow them to collect the revenues that are now required to finance the equalization program. Then the program would be restructured as an interprovincial revenue-sharing pool based on what he refers to as adjusted personal income (i.e., the sum of personal income, business income, and natural resource revenues). Pay-out and pay-in rates would be set so as to ensure, initially at least, that the net position of recipient provinces does not differ much from their current position vis-à-vis the equalization formula. One difference from the program which we outline is that under Davenport's scheme no province would be a net contributor to equalization as long as its adjusted personal income was below the national average level. This might be an appealing characteristic. Another feature is that there would be no net saving for Ottawa as a result of his restructured program whereas we do allow Ottawa to benefit. Nonetheless, both his and our proposals are fairly flexible in that by altering such parameters as pay-out rates one can obtain a variety of solutions.


26. The figures in this paragraph are from Table 4 of i.b.i.d.

27. I.b.i.d., page 76.

28. Note that these weights, \( w_i \), correspond closely to the need index \( N_j/N_c \) discussed above.

29. I.b.i.d., page 87.

30. Hunter's data for 1971 indicate that transfers into the pool equal withdrawals. This does not follow automatically from the character-
istics of the formula, however.

31. See Courchene, Réfinancing the Canadian Federation, op. cit., chapter 2.

32. The "business income" category in Table 3.1 is essentially corporate income tax revenues, supplemented by profits of provincial government profit-making enterprises.


34. As an aside, we feel that defining the tax base for water power rentals in terms of output rather than revenue for purposes of the present formula is inappropriate.

35. This is not to suggest that the two-tier system removes the arbitrariness. On the contrary, the selection of the value of alpha is also arbitrary. But this is a somewhat different concept of "arbitrary" than in implied in the text.

36. As it has done since this paper was written.
CHAPTER 4

A FRAMEWORK FOR ESTIMATING THE FACTOR DISTORTION AND EFFICIENCY ASPECTS ASSOCIATED WITH FEDERAL AND PROVINCIAL OIL TAX POLICIES

4.1 INTRODUCTION

In Chapter 2 of the thesis a survey of the existing federal and provincial tax policies as they apply to the Canadian oil industry was presented. The conclusion that emerged from this analysis was that the existing tax legislation, given all its complexities, would in all likelihood create distortions. It is the intention of this chapter of the thesis to focus on the identification and estimation of these distortions.

Specifically, the purposes of this chapter are:

1) to analyze the distortions introduced by the tax system as to the choices among alternative inputs in the production of domestic oil (e.g., exploration capital versus development capital),

2) to analyze the distortions introduced by the tax system as to the profitability of different types of oil production,

3) to offer an overall assessment as to the combined effect of the distortions on the output of each type of oil,

4) to analyze the changes in the various distortions introduced by the National Energy Program (October 1980), or NEP, and finally,

5) to offer a highly simplified but suggestive assessment of the effects of the distortions on total resource rents (or on industry profits plus government revenues).
The benchmark employed in this chapter to measure the distortions will be the pure-profits tax in traditional economic theory.

Actually, it is not obvious a priori that this presumption of distortions being created as to the choices of alternative inputs, or the production of different types of oil, should be valid. Canadian energy policy has evolved in such a way as to produce two fundamental policy characteristics:

i) the domestic price of oil received by certain domestic oil producers is maintained below the international price with the percentage of the world price received varying by the type of oil, and

ii) rich tax incentives are made available to domestic oil producers.

The effect of the first policy is to reduce capital investment in the Canadian energy projects which receive the domestic price for their output, whereas, the intent of the tax incentives is clearly to promote capital investment in the domestic oil industry.

These tax incentives, however, are not expected to be neutral with respect to encouraging capital investment for all types of oil produced (i.e., conventional (old and new), secondary, frontier, non-conventional and tertiary oil). The reason for this is quite simple. Capital inputs (exploration and development capital) effectively receive subsidies via the reduction in corporate income tax liabilities for incurring capital expenses but not at equal rates. For example, in the pre-NEP period, production capital expenses incurred in conventional areas receive a 30 per cent writeoff plus an earned depletion allowance (at a 33 1/3 per cent rate) whereas, exploration capital expenses, also
incurred in the production of conventional oil, will receive a 100 per cent writeoff plus the earned depletion allowance (at a 33 1/3 per cent rate).

These implicit subsidy rates for the same type of capital expense may also differ according to their employment location. For example, in the case of frontier oil, exploration expenses will also likely qualify for the frontier exploration allowance at a 66 2/3 per cent rate (for the pre-NEP period) which is in addition to the basic 100 per cent writeoff and the 33 1/3 per cent writeoff for the earned depletion allowance afforded exploration expenses in conventional areas.

Finally, following the introduction of the NEP the writeoff rates, or tax-based subsidy rates for the same type of capital employed in identical regions (e.g., frontier areas) may now vary not as a result of cost differences, but simply according to the degree of Canadian ownership of the producers.

To reiterate, therefore, the impact of the tax treatment of the Canadian oil industry is quite possibly to create a non-optimal allocation of resources within the industry itself relative to a pure profits tax and it is the purpose of this chapter of the thesis to focus on the identification of these distortions.

In order to avoid confusion, it should also be made clear at the outset what issues will not be addressed in this chapter:

1) Although there are several types of distortions created as a result of the tax system, these other distortions will not be considered. Among these alternative distortions that exist but will not be dealt with here include:
   a) the distortion created on the demand side of the economy since
Canadian oil consumers purchase oil at prices below the world level, b) the distortion created in the allocation of capital inputs between the Canadian petroleum industry relative to all other domestic industries, c) the distortion created in international trade flows. For example, these tax policies may generate a lower (greater) production effort now, relative to the optimal level, with the associated need to import (export) more oil now and possibly export (import) more in the future, and finally, d) in an intertemporal framework, the distortions created by differences in the evaluation of private and social discount rates will not be dealt with here. Similarly, distortions relating to the intertemporal reallocation of exploration and production capital (e.g., premature exploration of the Arctic) will not be considered.

2) In fact, the dynamic nature of the problem (e.g., the optimal rate of extraction or the optimal dynamic path of the inputs employed) will not be dealt with here. Given the specific purposes of this chapter (identified above), which are complex enough, it is felt that this omission is warranted (that is, inclusion of the dynamic implications will serve to greatly complicate and lengthen the analysis). Intertemporal considerations, while obviously of great importance, deserve a thesis-length treatment in their own right.

3) Finally, it must be stressed that the purpose of the chapter is not to offer an empirical estimate of the welfare issues (for this see, for example, Hellwell's efforts\(^2\)) but to disentangle the distort-
ionary characteristics of the tax system.

The outline of the rest of the chapter then is as follows. In section 4.2 of this chapter the model employed to identify these distortions is described. In section 4.3 the factor employment effects of the collection of tax instruments will be estimated, followed in section 4.4, by the identification and quantification, for illustrative purposes only, of the ensuing efficiency loss (defined as the change in net tax revenues of the public sector and the net change in profits of the domestic oil industry) associated with these factor employment distortions. The final section of the chapter summarizes the results of this exercise and presents our conclusions.

4.2 THE MODEL

To investigate the distortions created by the tax policies instituted by both levels of government we initially employ a simple model of the oil industry where we identify six different regions or types of oil production (conventional (old and new), secondary, frontier, non-conventional and tertiary oil). The producers of each type of oil are assumed to be "integrated" firms (i.e., engaged in exploration, development and production activities) and will strive to maximize their net returns. For our purposes, net returns will be defined as total revenues less operating costs, less both exploration and development (capital) expenses, less federal and provincial (when applicable) corporate income taxes, less the Petroleum and Gas Revenue Tax (for the post-NEP period) and finally, less any royalty payments to either level of government.
The output of oil type \( j \) at time \( t \) \( (Q_{j,t}) \) is assumed to be a function of the stock of development capital employed at time \( t \) in the production of oil type \( j \) \( (K_{p_{j,t}}) \), the volume of operating inputs (henceforth called "labour services") employed at time \( t \) in the production of oil type \( j \) \( (L_{j,t}) \) plus the stock of oil reserves existing at time \( t \) for oil type \( j \) (e.g., "proven" oil reserves, or \( R_{j,t} \)). That is,

\[
Q_{j,t} = Q_{j,t} (K_{p_{j,t}}, L_{j,t}, R_{j,t})
\]

where the stock of (proven) oil reserves at time \( t \) is defined as the stock of reserves existing at the end of the previous period (i.e., the stock at the beginning of the previous period, \( R_{j,t-1} \)) less production of oil type \( j \) during the previous period, \( Q_{j,t-1} \) plus any addition to the current stock of reserves brought about as a result of the employment of exploration capital in the previous period \( (K_{e_{j,t-1}}) \). That is,

\[
R_{j,t} = R_{j,t-1} + H(K_{e_{j,t-1}}) - Q_{j,t-1}
\]

Furthermore, it is assumed that \( H_{j} > 0 \) while \( H_{j} < 0 \).

Alternatively, then, the stock of oil reserves at time \( t \) may also be expressed as:

\[
R_{j,t} = \overline{R}_{j,0} + \sum_{i=1}^{t-1} H(K_{e_{j,i}}) - \sum_{i=1}^{t-1} Q_{j,i}
\]

where \( \overline{R}_{j,0} \) is the initial stock of oil reserves of oil type \( j \).

Therefore, substitution of (3) into (1) yields the following expression for the production of oil type \( j \) at time \( t \),

\[
Q_{j,t} = Q_{j,t} (\overline{R}_{j,0}, K_{e_{j,t}}, K_{p_{j,t}}, L_{j,t})
\]
where \( K_{p,j,t}^*, K_{e,j,t}^*, \) and \( L_{j,t}^* \) are vectors of past input streams (with the dimensions of \( K_{p,j,t}^* \) and \( L_{j,t}^* \) being \( [t \times 1] \) while the dimension of \( K_{e,j,t}^* \) is \( [(t-1) \times 1] \).

To express the present discounted value of oil production (of type \( j \)) from equation (4) as simply a function of the present discounted values of the three input streams (denoted by the scalars \( \hat{K}_{p,j,t}, \hat{K}_{e,j,t}, \hat{L}_{j,t} \)) in general would not be accurate since the characteristics of each input stream over time would influence the present discounted value of the oil output generated. That is, in general, it is not going to be the case that,

\[
(5) \quad \sum_{i=1}^{T} (1+r)^{-i} Q_{j,i} = \hat{Q}(\hat{K}_{e,j,t}, \hat{K}_{p,j,t}, \hat{L}_{j,t}, \hat{R}_{j,o})
\]

where the \( \hat{Q} \) function now contains the present discounted values of past input streams as its arguments (as well as the initial stock of oil reserves).

However, a sufficient condition where this aggregation can be made is the following. If it is assumed that each factor price remains constant over time then it is possible to aggregate the stream of each input into a composite input (i.e., employing an extension of the composite commodity theorem) where each composite input can be viewed as the present discounted value of each input stream.

Alternatively, since the intertemporal distortion of the input streams is not of interest in this chapter (although admittedly these distortions may be very important), then the vectors of input streams will be treated in the following analysis as scalars (rather than vectors) -- where these scalars represent the present discounted value.
of each input stream.

Henceforth, therefore, for convenience, the vector notation will be dropped and oil production of type $j$ will be represented simply as:

$$Q_j = G_j(K_{e_j}, K_{p_j}, L_j, R_{j, o})$$

or simply,

$$(6) \quad Q_j = F_j(K_{e_j}, K_{p_j}, L_j)$$

where $Q_j$, $K_{e_j}$, $K_{p_j}$, and $L_j$ are scalars as noted above and represent the present discounted value of the respective input stream evaluated over the relevant time horizon.

Additional assumptions made in this model include:

1) the absence of uncertainty -- both technical uncertainty and uncertainty with respect to future tax rates and oil prices. The justification for assuming a perfect-certainty model (at least with respect to technical uncertainty) is that the analysis performed below concentrates on the impact effects of a given tax regime (pre- or post-NEP) on the employment decisions of a producer of a given type of oil (i.e., no cross-oil comparisons are made). In other words, since the probability of success in finding oil from drilling an additional exploratory well will be the same whether you are operating under a given tax regime or an alternative, the results below should not be substantially altered in a more complex model explicitly introducing technical uncertainty. (The assumption of no uncertainty with respect to the future values of tax rates and/or oil prices is made in the interest of simplification.)

2) With respect to factor prices the small country assumption is employed. Specifically, it is assumed that the rental rates (or implicit rental rates in the case where the capital stock is owned by the
firm)\(^4\) for both types of capital are given and will be equal for all types of oil produced\(^5\) i.e.,

\[ r_{p_j} = \bar{r}_p \]

and

\[ r_{e_j} = \bar{r}_e \]

for all \( j \).

With respect to the wage rate paid to labour, it is assumed that the wage rate is given, but need not be equal for all regions (i.e., \( w_j \) represents the wage rate paid to labour employed in the production of oil type \( j \)).

3) It is also assumed that the firm undertaking the exploration or development activity will be the sole recipient of the benefits if any oil is found. In other words, there are no spillovers from one well to the next (i.e., the lots sold are big enough so that the firm owns the whole pool of oil). Consequently, the producer will not underdevelop his land leases to avoid passing on information to his neighbour. Specifically, then, the optimal private rate of exploration (for a given land lease) will equal the socially optimal rate of exploration. This assumption of no market failures will simplify the analysis considerably.

4) Finally, it should be noted that the production function represented by equation (6) above, is not assumed to exhibit constant returns to scale in all three inputs \((K_{e_j}, K_{p_j}, L_j)\). That is, the value of output is not completely exhausted by payments to these three factors. There is an excess leftover which represents "rents" to the landowners (imputed returns to the scarce resource).
4.2.1 Producers' Net Returns

Given our assumption that each producer is striving to maximize his net returns we need to derive an expression for the net returns for each type of oil. To do so, we will draw on our survey of the tax treatment of the oil industry presented in the second chapter and summarized in Tables 4.1 and 4.2 below (for the pre- and post-NEP periods respectively). For illustrative purposes, we will generate a net returns expression for conventional old oil producers here and refer the reader to the appendix for the net returns for all other types of oil (pre- and post-NEP).

Given that conventional old oil producers in the pre-NEP period:

a) are subject to federal and provincial corporate income taxes (where the base is identical) but will qualify for the Federal Resource Allowance, a 100 per cent writeoff for exploration expenses incurred, a 30 per cent writeoff for development expenses incurred and an earned depletion allowance of 33 1/3 per cent of the value of exploration and development expenses,\(^6\)

b) must make royalty payments to the Alberta government (since we assume that conventional oil production occurs in Alberta) as outlined in the second chapter, and

c) receive only a fraction \(\delta_c\) of the world price \(P\),

then the net returns for conventional old oil producers will be given by:

\[
\pi_c = \delta_c PF_c(K_{e_c}, K_{p_c}, L_c) - r e_k e_c - r p_k p_c - w_c L_c - \delta_o \delta_c PF_c(K_{e_c}, K_{p_c}, L_c) \\
+ [\delta_o \delta_c PF_c(K_{e_c}, K_{p_c}, L_c) - (\delta_c PF_c(K_{e_c}, K_{p_c}, L_c) - w_c L_c)^{sRA}] t_p
\]
TABLE 4.1
Summary of Federal and Provincial Tax Revenues as Applied to the Canadian Oil Industry by Type of Oil (Pre-1971)

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>Non-Conv. Royalties</th>
<th>Posterior FTE 1970</th>
<th>Posterior 1971</th>
</tr>
</thead>
<tbody>
<tr>
<td>Primary</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Secondary</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tertiary</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Year</td>
<td>Sales</td>
<td>Net Revenue</td>
<td>Current Development Expenditures</td>
</tr>
<tr>
<td>------</td>
<td>-------</td>
<td>-------------</td>
<td>---------------------------------</td>
</tr>
<tr>
<td>1981</td>
<td>$577.75</td>
<td>$572.00</td>
<td>366.75</td>
</tr>
</tbody>
</table>

**Table 2.2:** Summary of Taxable and Non-Taxable Features as Applied to the Canadian Oil Industry by Type of Oil (Post-1980)
\[ \text{SPRC} \left[ \theta \delta_{0} \delta_{C} \left( K_{Ec}, K_{Pc}, L_{C} \right) \right] - \left( t_{f} + t_{p} \right) \left[ \left( \delta_{C} \delta_{Pc} \left( K_{Ec}, K_{Pc}, L_{C} \right) \right) \right] - \omega \cdot L_{C} \left( 1 - s_{RA} \right) - s_{E} e_{Ec} - s_{D} d_{Pc} - s_{ED} \left( r_{E} e_{Ec} + r_{P} p_{pc} \right) \]

where

- \( \delta_{C} \) = the fraction of the world price (P) received by conventional oil producers,
- \( \theta \) = the fraction of total revenues paid to the Alberta government in royalty payments (as defined in the second chapter, i.e., equals 0.43783 for the pre-NEP period),
- \( t_{p} \) = the provincial corporate income tax rate (i.e., equals 0.11),
- \( t_{f} \) = the federal corporate income tax rate (i.e., equals 0.36),
- \( s_{RA} \) = the rate applied to the federal resource allowance (i.e., equals 0.25),
- \( s_{E} \) = the rate of deduction permitted for exploration expenses (i.e., equals 1.00),
- \( s_{D} \) = the rate of deduction permitted for development expenses (i.e., equals 0.30),
- \( s_{ED} \) = the rate of deduction permitted for the earned depletion allowance (i.e., equals 0.333), and
- \( \text{SPRC} \) = the rate applicable for the provincial Royalty Tax Credit (available in Alberta only and equals 0.25).

It is worth noting that the fifth, sixth and seventh terms together in the net returns expression represent the net royalty liability facing conventional oil producers after both the Alberta royalty tax rebate and the royalty tax credit have been applied and that we are implicitly assuming that the ceiling on the royalty tax credit (\$1 million per firm per year) is non-binding.

Simplifying this expression for net returns we obtain:
\[ \pi_c = \delta_c PF_c(K_{e_c}, K_{p_c}, L_c)[1 - \theta_o(1 - t_p - s_{PRC}) - t_p s_{RA} - (t_f + t_p)(1 - s_{RA})] \\
- r e_{e_c} K_{e_c} [1 - (t_f + t_p)(s_E + s_{ED})] - r p_{p_c} K_{p_c} [1 - (t_f + t_p)(s_D + s_{ED})] \\
- w_{c,c} L_c [1 - t_p s_{RA} - (t_f + t_p)(1 - s_{RA})] \]

or letting;

\[ T_c = e_o^* (1 - t_p - s_{PRC}) + t_p + t_f(1 - s_{RA}) \]

\[ t_{e_c} = (t_f + t_p)(s_E + s_{ED}) \]

\[ t_{p_c} = (t_f + t_p)(s_D + s_{ED}) \]

and \[ t_{L_c} = t_f(1 - s_{RA}) + t_p \]

Then the net returns for conventional old oil producers will be given by;

\[ \pi_c = \delta_c PF_c(K_{e_c}, K_{p_c}, L_c)[1 - T_c] - r e_{e_c} K_{e_c} [1 - t_{e_c}] - r p_{p_c} K_{p_c} [1 - t_{p_c}] - w_{c,c} L_c [1 - t_{L_c}] \]

or, in general, for oil type \( j \), the net returns will be given by;

\[ \pi_j = \delta_j PF_j(e_{e_j}, K_{p_j}, L_j)[1 - T_j] - r e_{e_j} K_{e_j} [1 - t_{e_j}] - r p_{p_j} K_{p_j} [1 - t_{p_j}] - w_{j,j} L_j [1 - t_{L_j}] \]

for both the pre- and post-NEP periods.

The remaining net return expressions by the type of oil produced (in both the pre- and post-NEP periods) have been generated in a similar fashion (see the accompanying appendix) and the resulting values of \( T_j, t_{e_j}, t_{p_j}, t_{L_j} \) and \( \delta_j \) are summarized in Tables 4.3 and 4.4 below.

Table 4.3 provides the values of the output tax (\( T_j \)), the subsidy rates (\( t_{e_j}, t_{p_j} \) and \( t_{L_j} \)) and the price parameters (\( \delta_j \)) in the pre-NEP period.
while Table 4.3 provides the same information for the post-NEP period for both Canadian (panel A) and foreign firms (panel B) respectively.  

As Tables 4.3 and 4.4 reflect, producers of conventional oil (both new and old) and secondary oil do not receive the world price for their output. In the pre-NEP period (e.g., as of January 1980) the domestic price, which these producers received, represented only 53 per cent of the world price. However, with the introduction of the National Energy Program's pricing schedule, the proportion of world price received by these same producers actually fell. This result occurred since the world price rose much more quickly than the increase in the domestic price that had occurred as of January 1981 (i.e., taken as the start of the post-NEP period). In the case of frontier oil and non-conventional oil producers, we have assumed that in both periods they would receive the world price for their output. Therefore, $\delta_{F} = \delta_{N} = 1.0$ for both periods. In the case of tertiary oil producers, however, as a result of the introduction of the National Energy Program, they are no longer guaranteed the world price for their output but rather now receive a tertiary reference price, which as of January 1981 was $30$ per barrel, or approximately, 79 per cent of the world price at that time.

Meanwhile, the output tax ($T_{j}$) and the implicit subsidy rate available for incurring labour (operating) expenses ($t_{C}$) for both Canadian and foreign firms in the post-NEP period has increased for all types of oil due to the introduction of the new Petroleum and Gas Revenue Tax (PGRT) to be applied against all oil producers' activities and the new "Petro-Canada tax" to be applied in frontier regions.

The only differences between Canadian and foreign firms that
<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>$\delta_j$</th>
<th>$T_j$</th>
<th>$t_{e_j}$</th>
<th>$t_{p_j}$</th>
<th>$t_{L_j}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>0.5270</td>
<td>0.6602</td>
<td>0.6265</td>
<td>0.2975</td>
<td>0.3800</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>0.5270</td>
<td>0.5792</td>
<td>0.6265</td>
<td>0.2975</td>
<td>0.3800</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>0.5270</td>
<td>0.5792</td>
<td>0.1410</td>
<td>0.3760</td>
<td>0.3800</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>1.0000</td>
<td>0.6670</td>
<td>0.7187</td>
<td>0.3414</td>
<td>0.6070</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>1.0000</td>
<td>0.5208</td>
<td>0.4700</td>
<td>0.6265</td>
<td>0.3800</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>1.0000</td>
<td>0.7161</td>
<td>0.5000</td>
<td>0.4000</td>
<td>0.4100</td>
</tr>
<tr>
<td>Type of Oil</td>
<td>$\delta_j$</td>
<td>$T_j$</td>
<td>$t_{e_j}$</td>
<td>$t_{p_j}$</td>
<td>$t_{L_j}$</td>
</tr>
<tr>
<td>--------------------------</td>
<td>------------</td>
<td>---------</td>
<td>-----------</td>
<td>-----------</td>
<td>-----------</td>
</tr>
<tr>
<td>Conventional - Old</td>
<td>0.4670</td>
<td>0.7469</td>
<td>0.7572</td>
<td>0.3128</td>
<td>0.4600</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>0.4670</td>
<td>0.6634</td>
<td>0.7572</td>
<td>0.3128</td>
<td>0.4600</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>0.4670</td>
<td>0.6634</td>
<td>0.3128</td>
<td>0.3128</td>
<td>0.4600</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>1.0000</td>
<td>0.8103</td>
<td>0.9069</td>
<td>0.5497</td>
<td>0.7653</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>1.0000</td>
<td>0.6008</td>
<td>0.5760</td>
<td>0.7012</td>
<td>0.4600</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>0.7895</td>
<td>0.7961</td>
<td>0.6000</td>
<td>0.4532</td>
<td>0.4900</td>
</tr>
</tbody>
</table>

Panel B: Foreign Firm

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>$\delta_j$</th>
<th>$T_j$</th>
<th>$t_{e_j}$</th>
<th>$t_{p_j}$</th>
<th>$t_{L_j}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>0.4670</td>
<td>0.7469</td>
<td>0.6265</td>
<td>0.1410</td>
<td>0.4600</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>0.4670</td>
<td>0.6634</td>
<td>0.6265</td>
<td>0.1410</td>
<td>0.4600</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>0.4670</td>
<td>0.6634</td>
<td>0.1410</td>
<td>0.1410</td>
<td>0.4600</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>1.0000</td>
<td>0.8103</td>
<td>0.6510</td>
<td>0.4371</td>
<td>0.7653</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>1.0000</td>
<td>0.6008</td>
<td>0.4700</td>
<td>0.6265</td>
<td>0.4600</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>0.7895</td>
<td>0.7961</td>
<td>0.5000</td>
<td>0.3165</td>
<td>0.4900</td>
</tr>
</tbody>
</table>
arise due to the introduction of the National Energy Program is the value of the available subsidy rates for exploration and development capital inputs, due to the introduction of the Petroleum Incentive Payments program. For Canadian firms, the subsidy rate available for incurring exploration expenses rises in the post-NEP period for all types of oil. In fact, in the case of Canadian frontier oil producers which qualify for an 80% per cent grant for exploration expenses plus the basic (100%) writeoff (net of the incentive grant received) and the earned depletion allowance writeoff (at a rate of 33 1/3 per cent and also net of any incentive grants) for income tax purposes, the subsidy rate is approximately 91 per cent. That is, a Canadian firm operating on federal lands pays only 9¢ (on a net basis) of every dollar spent on exploration activity.

In the case of the implicit subsidies available for development capital inputs, we see that for all types of oil, except secondary oil, these rates also rise as a result of the incentive grants (equal to 20% of qualifying expenses) available for Canadian firms which more than compensates for the removal of the development capital expenses in the base for calculating the earned depletion allowance (i.e., the earned depletion allowance represented an implicit subsidy for development capital expenses of 33 1/3 per cent times the sum of the federal and provincial corporate income tax rates, or simply, 75.65 per cent of development capital expenses in the case of a conventional oil producer). For Canadian secondary oil producers, however, since they fail to qualify for incentive payments (since they do not receive an incentive price for their output) the net effect is to lower the subsidy rate available for development capital.
In the case of foreign producers the implicit subsidy rate for exploration capital expenses is unchanged for all types of oil (except frontier oil) since they do not qualify for exploration incentive grants. In the special case of foreign frontier oil producers the implicit subsidy rate for exploration expenses falls following the introduction of the NEP. This result occurs predominantly due to the introduction in NEP of what we refer to as, the "Petro-Canada tax" or the reservation for the Crown of a back-in privilege in every right on Canada or frontier lands.

Specifically, the provision, as announced in the National Energy Program, assigns a 25 per cent carried interest to Petro-Canada (or any other federal Crown corporation) on any existing or future resource field in frontier regions (or the Canada Lands). The carried interest is convertible to a working interest (which implies a full partner sharing in all revenues and costs) at any time the government elects until a frontier field is to begin production. Energy Minister, Marc Lalonde, has stated publicly\(^10\) that the federal government intends on converting this carried interest to a working interest at the development stage only (i.e., after the discovery has been made) and therefore, the Canadian public will be paying its 25 per cent share of the development and operating costs of any particular project (but not directly contributing at the time of exercising this right for current or past exploration expenses).\(^11\)

The effect of this provision when exercised (and implicitly, the model assumes it is exercised immediately since it is contained in the net returns expression for foreign frontier oil producers) then is to make the Crown an active partner sharing (at a rate of 25 per cent) in
all revenues and costs (except exploration capital expenses). Consequently, in the case of foreign producers, despite the introduction of a 25 per cent exploration incentive grant (in the post-NEP period), the implicit subsidy available for incurring exploration expenses falls primarily as a result of the elimination of the very generous frontier exploration allowance.

Foreign firms producing conventional and secondary oil face a reduction in the subsidy rate available for production capital expenses incurred since these foreign firms will not qualify for development incentive payments and, as well, the development expenses incurred will no longer be eligible for the earned depletion allowance. In the case of foreign tertiary oil producers, who do not qualify to receive development expense grants, these producers will see their subsidy rate on production capital expenses fall due to the reduced rate of depletion allowance permitted (i.e., the post-NEP rate is only 33 1/3 per cent of qualifying expenses instead of 50 per cent as under the pre-NEP regime). Finally, it should be pointed out that the implicit subsidy rate applied against development expenses for a foreign frontier oil producer increases in the post-NEP period as a result of the introduction (and assumed implementation) of the "Petro-Canada tax" (i.e., the federal Crown corporation is now directly contributing 25 per cent of the development costs).

4.3 FACTOR EMPLOYMENT EFFECTS OF THE PRE- AND POST-NEP TAX REGIMES

In this section of the paper we will compare the factor employment decisions made by oil producers under each regime (pre- and post-
NEP) relative to an efficiency case where we define our efficiency
case as an environment where output taxes and subsidy rates are all set
equal to zero and where all producers (of all types of oil) receive the
world price for their output (i.e., $\sigma_j = 1.0$ for all $j$). As well, we
will consider the factor employment effects from moving to the post-NEP
regime from the pre-NEP regime by the type of oil produced.

To begin, consider the net returns expression for an oil producer
of type $j$ (equation (7)). This oil producer is assumed to hire $K_{e_j}, K_{p_j}$
and $L_j$ in order to maximize this expression. i.e.,

$$\text{Maximize } \Pi_j = \delta_jPF_j(K_{e_j}, K_{p_j}, L_j)[1-T_j] - r_eK_{e_j}[1-t_e_j] - r_pK_{p_j}[1-t_p_j] - w_jL_j[1-t_L_j]$$

The resulting first-order-conditions are then;

$$\frac{\partial \Pi_j}{\partial K_{e_j}} = \delta_jPF_j[1-T_j] - r_e[1-t_e_j] = 0$$  \hspace{1cm} (8)

$$\frac{\partial \Pi_j}{\partial K_{p_j}} = \delta_jPF_j[1-T_j] - r_p[1-t_p_j] = 0$$  \hspace{1cm} (9)

$$\frac{\partial \Pi_j}{\partial L_j} = \delta_jPF_j[1-T_j] - w_j[1-t_L_j] = 0$$  \hspace{1cm} (10)

Totally differentiating (8), (9) and (10) setting $dr_e = dr_p = dw_j = 0$,
yields:
\[
\begin{bmatrix}
F_{K_e j} & K_{e j} & F_{K_e j} & K_{e j} L_j \\
F_{K_p j} & K_{e j} & F_{K_p j} & K_{e j} L_j \\
F_{L_j} & K_{e j} & F_{L_j} & K_{e j} L_j \\
\end{bmatrix}
\begin{bmatrix}
dK_{e j} \\
dK_{p j} \\
dl_j \\
\end{bmatrix}
= 
\begin{bmatrix}
\frac{r_e A_j}{\delta_j} & p^2 (1-T_j)^2 \\
\frac{r_p B_j}{\delta_j} & p^2 (1-T_j)^2 \\
\frac{w_j c_j}{\delta_j} & p^2 (1-T_j)^2 \\
\end{bmatrix}
\]

Where,

\[
A_j = (1-t_{e j}) \delta_j P dT_j - \delta_j P (1-T_j) d t_{e j} - (1-t_{e j}) P (1-T_j) d \delta_j - (1-t_{e j}) \delta_j (1-T_j) d P
\]

\[
B_j = (1-t_{p j}) \delta_j P dT_j - \delta_j P (1-T_j) d t_{p j} - (1-t_{p j}) P (1-T_j) d \delta_j - (1-t_{p j}) \delta_j (1-T_j) d P
\]

\[
C_j = (1-t_{L j}) \delta_j P dT_j - \delta_j P (1-T_j) d t_{L j} - (1-t_{L j}) P (1-T_j) d \delta_j - (1-t_{L j}) \delta_j (1-T_j) d P
\]

Then using Cramer's rule to solve for \(dK_{e j}\) (for example) when all the tax parameters are changing (i.e., so we can compare the pre- and post-NEP regime to each other or each separately to our efficiency regime) yields;

\[
\begin{bmatrix}
A_j & \frac{r_e}{\delta_j} & p^2 (1-T_j)^2 & F_{K_e j} & K_{p j} & F_{K_e j} L_j \\
B_j & \frac{r_p}{\delta_j} & p^2 (1-T_j)^2 & F_{K_p j} & K_{p j} & F_{K_p j} L_j \\
C_j & \frac{w_j}{\delta_j} & p^2 (1-T_j)^2 & F_{L_j} & K_{p j} & F_{L_j} L_j \\
\end{bmatrix}
\begin{bmatrix}
dK_{e j} \\
\end{bmatrix}
= \frac{1}{H}
\]
where

\[
\begin{vmatrix}
F_{e_j e_j} & F_{e_j p_j} & F_{e_j L_j} \\
F_{p_j e_j} & F_{p_j p_j} & F_{p_j L_j} \\
F_{L_j e_j} & F_{L_j p_j} & F_{L_j L_j}
\end{vmatrix}
\]

\( |H| = \begin{vmatrix}
F_{p_j e_j} & F_{p_j p_j} & F_{p_j L_j} \\
F_{L_j e_j} & F_{L_j p_j} & F_{L_j L_j}
\end{vmatrix} \)

Expanding along row 1 we obtain:

\[
\frac{dK_{e_j}}{d\tau_j} = r_e A_j \left[ F_{p_j L_j} - F_{K_{p_j p_j}} \right] \frac{\delta_j \cdot p^2 \cdot (1-T_j)^2}{|H|}
\]

\[
+ r_p B_j \left[ F_{L_j K_{e_j p_j}} - F_{K_{e_j p_j}} \right] \frac{\delta_j \cdot p^2 \cdot (1-T_j)^2}{|H|}
\]

\[
+ w_{jC} C_j \left[ F_{L_j K_{e_j p_j}} - F_{K_{e_j p_j}} \right] \frac{\delta_j \cdot p^2 \cdot (1-T_j)^2}{|H|}
\]

If our second-order conditions hold then it follows that \(|H|\) must be negative, and if we assume all our cross-partial are positive (i.e., our factors of production are complements) then the \([F_{ij}] / |H|\) term will be negative. Therefore, it follows that the sign of \(dK_{e_j} / d\tau_j\) where \(d\tau_j\) represents the change in the entire tax regime \((\tau)\) for oil type \(j\) must be the opposite sign to the values of \(A_j\), \(B_j\) and \(C_j\) provided \(A_j\), \(B_j\) and \(C_j\) all have the same sign. That is, if \(A_j\), \(B_j\) and \(C_j\) are all positive (negative) then \(dK_{e_j} / d\tau_j\) will be negative (positive). If however, \(A_j\), \(B_j\) and \(C_j\) are not all signed the same then the resulting
sign of $dK_{p_j}/d\tau_j$ will be ambiguous. In this situation the sign of $dK_{p_j}/d\tau_j$ will depend on the values of the unmeasured $F_{ij}$ terms.

By adopting this same approach (using Cramer's rule) we can derive the following expressions for $dK_{p_j}/d\tau_j$ and $dL_j/d\tau_j$:

(12) \[
\frac{dK_{p_j}}{d\tau_j} = \frac{r e_A j [F_{K_p} K_j L_j L_j F_j K_j - F_{K_p} K_j F_j L_j L_j]}{\delta_j^2 p^2 (1-T_j)^2 |H|} \\
+ \frac{r p B_j [F_{K_p} K_j L_j L_j F_j K_j - F_{K_p} L_j L_j K_j]}{\delta_j^2 p^2 (1-T_j)^2 |H|} \\
+ \frac{w_j C_j [F_{K_p} L_j L_j F_j K_j - F_{K_p} K_j F_j L_j L_j]}{\delta_j^2 p^2 (1-T_j)^2 |H|}
\]

and

(13) \[
\frac{dL_j}{d\tau_j} = \frac{r e_A j [F_{K_p} K_j L_j L_j F_j K_j - F_{K_p} K_j F_j L_j L_j]}{\delta_j^2 p^2 (1-T_j)^2 |H|} \\
+ \frac{r p B_j [F_{K_p} K_j L_j L_j F_j K_j - F_{K_p} L_j L_j K_j]}{\delta_j^2 p^2 (1-T_j)^2 |H|} \\
+ \frac{w_j C_j [F_{K_p} K_j F_j K_j - F_{K_p} K_j F_j K_j]}{\delta_j^2 p^2 (1-T_j)^2 |H|}
\]

Again, if $A_j$, $B_j$ and $C_j$ all have the same sign, given our assumption that all the cross-partialis are positive and the second-order conditions hold, then $dK_{p_j}/d\tau_j$ and $dL_j/d\tau_j$ will have the oppos-
ite sign. In other words, if \( A_j, B_j \) and \( C_j \) are all positive (negative) then the employment of all factors will decline (increase) for oil type \( j \).

To determine the factor employment effects of the federal and provincial tax policies we need to evaluate \( A_j, B_j \) and \( C_j \) for each oil type \( j \). This exercise has been performed for the efficiency regime versus the pre-NEP period, the efficiency regime versus the post-NEP regime and finally, for the pre-NEP versus post-NEP periods. The resulting estimate of \( A_j, B_j \) and \( C_j \) are presented in Tables 4.5, 4.6 and 4.7 below.\(^{13}\) In Table 4.5 the factor employment effects of the pre-NEP period relative to our efficiency regime indicates that there will be an unambiguous decline in usage of all factors of production in conventional oil (old and new), secondary oil and tertiary oil production. In the case of frontier and non-conventional oil production however, the results indicate an ambiguous effect since \( A_j, B_j \) and \( C_j \) are not all of the same sign for these types of oil.

However, if we consider the restrictive case where all the cross-partialials are zero then we can see by reconsidering equations (11), (12) and (13) and the results presented in Table 4.5, that in the production of frontier oil, there would be an overemployment of exploration capital (since \( A_j \) is negative for frontier oil) but an underemployment of both development capital and labour services. This result is not surprising considering the existence of the very generous frontier exploration allowance available for exploration expenses (only) incurred in frontier regions.

For non-conventional oil production, however, given the strict assumption of zero cross-partialials, we observe an overemployment of
### TABLE 4.5 DETERMINATION OF FACTOR EMPLOYMENT EFFECTS FOR PRE-NEP PERIOD RELATIVE TO EFFICIENCY REGIME

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>$A_j$</th>
<th>$B_j$</th>
<th>$C_j$</th>
<th>Employment Effect&lt;sup&gt;(a)&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>14.188</td>
<td>23.400</td>
<td>21.090</td>
<td>Negative</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>11.919</td>
<td>21.131</td>
<td>18.821</td>
<td>Negative</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>25.513</td>
<td>18.933</td>
<td>18.821</td>
<td>Negative</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>- 1.448</td>
<td>9.117</td>
<td>1.680</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>1.442</td>
<td>- 2.960</td>
<td>3.942</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>6.050</td>
<td>8.850</td>
<td>8.570</td>
<td>Negative</td>
</tr>
</tbody>
</table>

<sup>(a)</sup> Where $R_i = K_e$, $K_p$, and $L$
### TABLE 4.6  DETERMINATION OF FACTOR EMPLOYMENT EFFECTS FOR POST-NEP PERIOD RELATIVE TO EFFICIENCY REGIME

**Panel A: Canadian Firm**

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>( A_j )</th>
<th>( B_j )</th>
<th>( C_j )</th>
<th>Employment Effect ((dR_{ij}/d\gamma_j))</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>19.863</td>
<td>36.751</td>
<td>31.158</td>
<td>Negative</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>16.687</td>
<td>33.576</td>
<td>27.982</td>
<td>Negative</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>33.576</td>
<td>33.576</td>
<td>27.982</td>
<td>Negative</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>-3.674</td>
<td>9.901</td>
<td>1.710</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>0.942</td>
<td>-3.816</td>
<td>5.350</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>15.450</td>
<td>21.028</td>
<td>19.630</td>
<td>Negative</td>
</tr>
</tbody>
</table>

**Panel B: Foreign Firm**

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>( A_j )</th>
<th>( B_j )</th>
<th>( C_j )</th>
<th>Employment Effect ((dR_{ij}/d\gamma_j))</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>24.830</td>
<td>43.280</td>
<td>31.158</td>
<td>Negative</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>21.655</td>
<td>40.104</td>
<td>27.982</td>
<td>Negative</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>40.104</td>
<td>40.104</td>
<td>27.982</td>
<td>Negative</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>6.052</td>
<td>14.179</td>
<td>1.710</td>
<td>Negative</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>4.970</td>
<td>-0.977</td>
<td>5.250</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>19.250</td>
<td>26.223</td>
<td>19.630</td>
<td>Negative</td>
</tr>
</tbody>
</table>

*(a) Where \( R_{ij} = K_{e}, K_{p} \) and \( L \).*
development capital and an underemployment of both exploration capital and labour services. Again this result is not unrealistic since development expenses incurred by synthetic oil producers in the pre-NEP period are recognized as exploration expenses for tax purposes and therefore, are written off in full.

We derive the same qualitative results if we compare the post-NEP regime to our efficiency regime in the case of a Canadian firm (as displayed in Panel A of Table 4.6). In the situation of a foreign firm, however, producing any type of oil (except non-conventional oil where the results conform to the same pattern indicated above) the results of the National Energy Prógram relative to our efficiency regime are unambiguous. Employment of all factors of production are reduced in all types of oil production (as indicated in Panel B of Table 4.6).

4.3.1 Factor Employment Effects of the NEP Relative to the Pre-NEP Period

One of the major objectives of the NEP was the promotion of Canadian ownership of the petroleum industry. The primary policy instrument introduced to achieve this objective was the introduction of a set of incentive payments (discussed above) which discriminates against foreign oil producers operating in Canada. To provide an estimate of the impact of this attempt to "Canadianize" the oil industry refer to Table 4.7 below. In the case of conventional oil (new and old), frontier oil and non-conventional oil, employment of all factors of production (\(K_e\), \(K_p\) and \(L\)) unambiguously increase for Canadian firms whereas, the employment effects of the NEP for foreign firms, unfortunately, is ambiguous (except for the case of non-conventional oil where the employment of all three
<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>A_j</th>
<th>B_j</th>
<th>C_j</th>
<th>Employment Effect(a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>0.633</td>
<td>0.035</td>
<td>0.364</td>
<td>Positive</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>0.912</td>
<td>0.284</td>
<td>0.663</td>
<td>Positive</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>1.297</td>
<td>0.225</td>
<td>0.663</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>1.564</td>
<td>1.493</td>
<td>1.209</td>
<td>Positive</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>2.775</td>
<td>1.955</td>
<td>2.656</td>
<td>Positive</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>0.258</td>
<td>0.222</td>
<td>0.002</td>
<td>Uncertain</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>A_j</th>
<th>B_j</th>
<th>C_j</th>
<th>Employment Effect(a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>0.022</td>
<td>0.827</td>
<td>0.364</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>0.100</td>
<td>0.783</td>
<td>0.663</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>0.231</td>
<td>1.292</td>
<td>0.663</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>0.822</td>
<td>0.444</td>
<td>1.209</td>
<td>Uncertain</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>1.353</td>
<td>0.953</td>
<td>2.656</td>
<td>Positive</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>0.537</td>
<td>1.308</td>
<td>0.002</td>
<td>Uncertain</td>
</tr>
</tbody>
</table>

(a) Where \( R_j = K_e, K_p \) and L.
inputs increase). Therefore, the success of the NEP to Canadianize the oil industry, which depends on the net effects (i.e., whether or not the increased Canadian activity exceeds the possible increase in foreign firm activity) is unclear.

In an attempt to evaluate the Canadianization aspects of the NEP more fully we can employ the very restrictive assumption that all the cross-partialities in equations (11), (12) and (13) are zero. If this were the case, then we can derive the factor employment effects of the NEP by the type of factor employed and by the type of oil produced for both Canadian and foreign oil producers. The results of this exercise are summarized in Table 4.8.

In this situation we see that foreign oil producers will reduce their employment of both exploration and development capital used in the production of conventional old oil. In contrast, the NEP encourages Canadian producers of conventional old oil to increase their employment of both exploration and development capital. Admittedly, this result is valid under a very restrictive assumption, but if this were the case, the conclusion is that the NEP will be successful in Canadianizing the production of old conventional oil (especially if we identify ownership shares according to the value of capital employed by each type of firm).

However, with respect to the alternative types of oil produced, the results displayed in Table 4.8 indicate an ambiguous effect on the Canadianization of the oil industry following the introduction of NEP. That is, none of the alternative oil sources indicate an unambiguous reduction in the stock of capital employed (both exploration and development capital) by foreign firms while also predicting an unambiguous increase in the stock of capital employed by Canadian firms.
TABLE 4.8 RELATIVE FACTOR DISTORTIONS BY TYPE OF OIL ASSUMING ALL CROSS-PARTIALS ARE ZERO (Pre-versus Post-NEP)

Panel A: Canadian Firm

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>$dK_{ej}/d\tau_j$</th>
<th>$dK_{pj}/d\tau_j$</th>
<th>$dL_j/d\tau_j$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>$+$</td>
<td>$+$</td>
<td>$+$</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>$+$</td>
<td>$+$</td>
<td>$+$</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>$+$</td>
<td>$-$</td>
<td>$+$</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>$+$</td>
<td>$+$</td>
<td>$+$</td>
</tr>
<tr>
<td>Non-conventional Oil</td>
<td>$+$</td>
<td>$+$</td>
<td>$+$</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>$+$</td>
<td>$-$</td>
<td>$+$</td>
</tr>
</tbody>
</table>

Panel B: Foreign Firm

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>$dK_{ej}/d\tau_j$</th>
<th>$dK_{pj}/d\tau_j$</th>
<th>$dL_j/d\tau_j$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>$-$</td>
<td>$-$</td>
<td>$+$</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>$+$</td>
<td>$-$</td>
<td>$+$</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>$+$</td>
<td>$-$</td>
<td>$+$</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>$-$</td>
<td>$+$</td>
<td>$+$</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>$+$</td>
<td>$+$</td>
<td>$+$</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>$-$</td>
<td>$-$</td>
<td>$+$</td>
</tr>
</tbody>
</table>
Our conclusion, therefore, is that the success of the NEP in Canadianizing the domestic oil industry will be very limited (even in the restrictive case where the value of the cross-partial s are all zero). This conclusion is valid provided the vehicle for bringing about the increased Canadianization of the oil industry is the relative encouragement of Canadian firms (and not foreign firms) to develop our oil resources. However, a second vehicle available to achieve increased Canadian ownership and control in the domestic oil industry is the takeover of foreign firms by either the Canadian, private or public sector.

In the first six months of 1981 this alternative vehicle was well used. The Petroleum Monitoring Agency estimates that approximately $6.5 billion was spent (or agreed to be spent) in the first six months of 1981 (i.e., immediately after the introduction of the NEP) on major takeovers. As a result, the PMA estimates that the percentage of foreign ownership and control of the petroleum industry (based on petroleum-related revenues) fell from 74.0 to 69.5 per cent and 81.5 to 74.3 per cent respectively. In other words, as the PMA goes on to point out, on average, for each $1 billion spent on foreign acquisitions, foreign ownership and control of the Canadian petroleum industry falls by approximately 0.7 and 1.1 percentage points respectively.

If these estimates are accurate the implication for our analysis is clear. In order for the NEP to achieve 50 per cent Canadian ownership of the domestic oil industry by 1990, the takeover vehicle is likely to be incapable of attaining the desired goal. That is, a reinterpretation of the PMA estimates implies, in order to achieve 50 per cent Canadian ownership by 1990, Canadian firms (or the Canadian public sector) would have to invest in the neighbourhood of $28 billion.
in addition to the monies already spent and in addition to any funds they
may commit to the search, development and production of new oil reserves.
The likelihood of this occurring, in the opinion of the author, is remote.

Consequently, in order to achieve the federal government's target
of 50 per cent Canadian ownership by 1990 the first vehicle suggested
above (encouraging Canadian firms to significantly expand their activit-
ies via the Petroleum Incentive Payments program) must be relied on
heavily. Unfortunately, as we indicated above, this also appears to be
unlikely. Therefore, we must conclude that our analysis places the
Canadianization objective of the NEP in serious jeopardy.

4.3.2 The National Energy Program in Action: Preliminary Estimates

The Petroleum Monitoring Agency has recently released the results
of their monitoring survey covering the first six months of 1981. In
particular, in the schedules appearing in the Appendix to this report,
the PMA presents estimates of the percentage change in the value of
capital expenditures (in 1981 over the corresponding six month period
of 1980) by the type of oil produced and in some instances, by the type
of firm (foreign or Canadian). Unfortunately, however, for our purposes,
the breakdown by the type of oil is not as detailed as our definitions
of oil types. For example, the PMA figures do not distinguish between
old and new conventional oil or secondary oil. Instead, the PMA has
produced estimates only of exploration and development capital expend-
itures in the first six months of 1981 incurred on "provincial lands"
(schedule C). Furthermore, these estimates are not disaggregated by
the type of firm. This is also the situation for frontier (or Canada
Lands) oil exploration expenses -- there are no estimates available for
the exploration expenditures incurred by foreign or Canadian firms.

Nevertheless, despite these unfortunate shortfalls in the survey results (for our purposes) we can still derive some preliminary support for the predicted direction of factor employment effects generated by our model for the type of oil and type of firm (as displayed in Table 4.9 below). In constructing Table 4.9 we have interpreted the estimates in Schedule C (i.e., exploration expenditures on provincial lands) to represent exploration expenditures on old conventional oil (again, note the possible error in this interpretation discussed above). Having made this interpretation, we see that the value of these exploration expenditures fell by 27.2 per cent in the first six months of 1981. In our model, we predicted a negative response for foreign firms and a positive response for Canadian firms (see Table 4.8). Although the PMA estimates do not distinguish between Canadian or foreign firms' expenditures, it is quite possible, given the existing ownership structure of the domestic oil industry, that the observed overall reduction in "conventional old" oil exploration expenses is heavily influenced by the (predicted) negative response of foreign firms.

With respect to the development expenditures incurred by Canadian and foreign firms in the production of conventional old oil, the results in Table 4.9 correspond to the predictions derived in our model. That is, as predicted, Canadian firms increase their development expenditures on conventional old oil after the introduction of the NEP (by 79.3 per cent according to Table 4.9) while foreign firms reduce their development expenditures by 3.4 per cent (according to Table 4.9).

Unfortunately, as noted above, the expenditures on exploration activity in frontier, or Canada, lands is not disaggregated by the firm's
These expenditures constitute a large parcel of development expenditures, however, the author has interpreted

expenditures on development projects which are not included in the table of development expenditures, however, the author has interpreted

(f) However, in most countries, the total of expenditures on development projects which are not included in the table of development expenditures, however, the author has interpreted

(g) However, in most countries, the total of expenditures on development projects which are not included in the table of development expenditures, however, the author has interpreted

(h) However, in most countries, the total of expenditures on development projects which are not included in the table of development expenditures, however, the author has interpreted

(i) However, in most countries, the total of expenditures on development projects which are not included in the table of development expenditures, however, the author has interpreted

4. Notes:

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>Capital Expenditures as % of Oil and Liquefied Fuels (1981)</th>
<th>Table A.9</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.6</td>
<td>3.6</td>
<td>Total</td>
</tr>
<tr>
<td>3.6</td>
<td>3.6</td>
<td>Goods</td>
</tr>
<tr>
<td>30%</td>
<td>4%</td>
<td>Capital</td>
</tr>
<tr>
<td>27.6</td>
<td>27.6</td>
<td>Finance</td>
</tr>
<tr>
<td>2.1%</td>
<td>2.1%</td>
<td>Other</td>
</tr>
</tbody>
</table>

(1) Percent changes refer to the change in the First six months of 1981 relative to the same period in 1980.
nationality. Consequently, the PMA estimates can not confirm (nor reject) our prediction that Canadian firms would be induced to increase their exploration activity in frontier regions while foreign firms would reduce their exploration activity. The PMA estimates show frontier exploration activity has increased by almost 34% per cent in the first six months of 1981 (or from $71 million to $317 million). Given the magnitude of the increase however, it is quite conceivable that our hypothesis concerning Canadian firms is substantiated but, unfortunately, our prediction regarding foreign firms' exploration activity can not be proven or disproven.

Finally, with respect to non-conventional oil (i.e., oil sands) and tertiary (or heavy) oil producers, the PMA survey indicates an increase in capital expenditures by foreign firms yet a reduction by Canadian firms (for both types of oil). These estimates conform to the model's predictions for foreign non-conventional oil producers and Canadian tertiary oil producers but unfortunately, this is not the case for Canadian non-conventional oil producers nor foreign tertiary oil producers.

To summarize, therefore, although the predictions of our model do not meet with total agreement with the PMA survey results, the figures displayed in Table 4.9 do conform fairly well with our model's predictions. Consequently, our earlier proposition that the NEP will likely fail to achieve its objective of 50 per cent Canadian ownership of the domestic oil industry by 1990, receives additional support.
4.3.3 The NEP and the Prospects for Oil Self-Sufficiency for Canada

While the NEP is predicted to enjoy little success in Canadianizing the domestic oil industry, the results displayed in Tables 4.8 and 4.9 also indicate that it may very likely cause serious repercussions in the production of oil both now and in the future. For example, in the case of conventional old oil, as indicated above, the capital employment of foreign firms declines but increases for Canadian firms. If the net result is an overall reduction in the value of capital employed in the production of conventional old oil (which may very well occur considering the present foreign ownership level in the domestic oil industry) then current conventional old oil output may fall thereby increasing Canadian dependence on imported oil.

In the case of tertiary and frontier oil, Canadian firms will be encouraged to increase their employment of exploration capital while foreign firms will reduce their exploration activity. If the net effect of these two results is to reduce overall exploration activity in these areas (which may well be the case considering the present ownership distribution) then the stock of proven oil reserves ($R_j$ in equation (1)) will increase at a slower rate after the introduction of the NEP. The significance of this conclusion is that this may imply a delay in the achievement of oil self-sufficiency for Canada (since frontier and tertiary oil are considered to be two of the most promising areas of activity in the future). Alternatively, this may increase our reliance on foreign oil imports in the future as well.

In a related matter, the strict interpretation of the NEP will have serious repercussions on activity in the offshore east coast oil
and gas plays (e.g., Hibernia) if the provinces, notably Newfoundland, succeed in their dispute with Ottawa to claim ownership of these oil reserves. That is, if the east coast oil and gas fields are considered to be owned by the provinces and therefore classified as "provincial" and no longer federal or Canada lands then both Canadian and foreign producers will find their incentive payments (for undertaking exploration and development activity) will be significantly reduced to be in line with the other oil producers operating on provincial lands. As well, their earned depletion allowance will likely be phased out since the NEP suggests it is only to be retained for projects operating on Canada or federal lands.

In fact, the Newfoundland government has even expressed a concern that if they do succeed in claiming ownership of these reserves that the federal government may respond by no longer offering oil producers in these areas the frontier oil price (assumed to be the same as the oil sands reference price, or approximately, the world price of oil for 1981) but rather the conventional oil price. Whether or not this concern would be proven to be the case is open to speculation but nevertheless, the NEP, strictly interpreted, would be predicted (according to our model) to result in a reduction of exploration and development activities relative to the pre-NEP period for both Canadian and foreign firms if the provinces are granted ownership of these reserves.

Finally, the NEP, according to our results, does unambiguously encourage increased exploration and development activity of non-conventional oil for both Canadian and foreign firms. It is possible, therefore, that the concern expressed above regarding Canada's potential for a net increased reliance on oil imports may overall be unfounded.
What may simply occur is the oil mix consumed in Canada and the trade flow over time may be significantly altered. Again, however, it must be remembered that these results are valid under the very restrictive assumption that all the cross-partial in our production function equals zero. 21

To summarize, therefore, the NEP does unambiguously encourage the development of very expensive oil sources (i.e., non-conventional and frontier oil). 22 This encouragement, however, may quite possibly be at the expense of more certain, and less costly types of oil (e.g., in particular, conventional and secondary oil). 23 The consequences of this for Canada's oil self-sufficiency objective is that if in the future, the world price of oil fails to keep pace with the federal government's projections (which has occurred since the writing of this chapter) 24 then the future supplies of these more expensive sources of oil may not materialize (i.e., firms may pull out or postpone their activities).

4.4 AN ILLUSTRATION OF THE EFFICIENCY LOSS ASSOCIATED WITH THE FACTOR EMPLOYMENT DISTORTIONS

In our analysis of the factor employment effects of the pre-NEP (or post-NEP) policy regime relative to our efficiency regime, we concluded that for most types of oil produced the actual factor employment pattern was distortive. As a consequence, therefore, an efficiency loss for the Canadian economy will be created. It is the purpose of this section of the chapter to identify this efficiency loss by the type of oil produced. For example, suppose as a result of a given tax regime
being introduced, the input of exploration capital, for illustrative purposes, employed in the production of oil type \( j \), falls from \( K_{e0} \) to \( K_{e1} \) in Figure 4.1 below and if we assume the new value of the marginal product in the new equilibrium position has increased to \( r_1 \) (for this result to occur it follows from the first-order conditions that \( \delta_j (1-T_j) < (1-t_{e_j}) \)) then the true value of the efficiency loss could be represented by the shaded area in Figure 4.1 (i.e., the value of additional output foregone from the employment of exploration capital, relative to our efficiency case, in excess of exploration costs evaluated at world prices).

**FIGURE 4.1 ESTIMATE OF THE EFFICIENCY LOSS ASSOCIATED WITH A REDUCTION IN EMPLOYMENT OF EXPLORATION CAPITAL**

The path the value of marginal product of exploration capital takes over the interval \( K_{e0} \) to \( K_{e1} \) is traced out by considering the effects of introducing an entirely new tax and subsidy regime. Since this path is uncertain (i.e., it need not be linear, nor in fact, it need not be everywhere upward sloping), we will adopt the simplifying
assumption that this path will be linear. In other words, we can theoretically identify the two end points (before and after the new tax regime is introduced) but can not identify the path joining these two points -- consequently, we make the simplifying assumption that the path is linear. It should be made clear at the outset, however, that since the actual path is unknown then the bias in our results by making this assumption is not clear. It may either over- or under-estimate the value of the actual efficiency loss depending on whether the true path lies above or below our linear approximation for the path.

In fact, we will show that the efficiency loss associated with oil type \( j \) (i.e., equaling the sum of the shaded areas depicted in Figure 4.1, for each input employed) equals the sum of the change in the value of industry net returns (for oil type \( j \)) plus the change in government net tax revenues (both the federal and provincial levels) after the introduction of the new tax regime (pre- or post-NEP relative to our efficiency case) in the situation where oil prices (both domestic and world prices) initially do not change. In the situation where oil prices are permitted to change we will see that there is an additional couple of terms to consider in our expression for the efficiency loss. But, first, let us examine the constant oil price situation.

Recall our expression for industry net returns for oil type \( j \) (equation (7) above).

\[
\pi_j = \delta_j P F_j (K_{e_j}, K_{p_j}, L_j)[1-T_j] - r_e K_{e_j} [1-t_e_j] - r P K_{p_j} [1-t_p_j] - w_j L_j [1-t_L_j]
\]

where \( P \) is the world price of oil (initially assumed to be constant) and \( r_e, r_p \) are the world prices of exploration and development capital inputs.
respectively (and are both constant). As well, we assume that the price of labour services in region j \( (w_j) \) will also be constant. Finally, the fraction of the world price of oil received by oil producers of type j is represented by \( \delta_j \), whereas, the ad valorem tax rate on output of type j will equal \( T_j \), and \( t_{ij} \) represents the ad valorem writeoff rate on input \( i \) (where \( i = K_{e_j}, K_{p_j}, \text{and} \ L_j \)).

Totally differentiating equation (7) setting \( dr_e = dr_p = dw_j = 0 \) and as well, \( d\delta_j = dP = 0 \) for now, then we obtain;

\[
\begin{align*}
d\pi_j & = [\delta_j PF_{K_{e_j}} (1-T_j) - t_{e_j} + \delta_j PF_{K_{p_j}} (1-T_j) - r_p (1-t_{p_j})]dK_{e_j} + [\delta_j PF_{K_{p_j}} (1-T_j) - r_p (1-t_{p_j})]dK_{p_j} \\
& + [\delta_j PF_{L_j} (1-T_j) - w_j (1-t_{L_j})]dL_j - \delta_j PF_{J}dT_j + r_{e_j} e_j dt_{e_j} + r_{p_j} p_j dt_{p_j} \\
& + w_j L_j dt_{L_j}
\end{align*}
\]

From the first-order conditions for maximizing net returns, we see that each of the expressions in the square brackets above will equal zero, therefore, the change in net returns for oil type j will be given by;

\[
\begin{align*}
d\pi_j & = -\delta_j PF_{J}dT_j + r_{e_j} e_j dt_{e_j} + r_{p_j} p_j dt_{p_j} + w_j L_j dt_{L_j}
\end{align*}
\]

The government sector (both federal and provincial levels) in this model receives the proceeds of the output tax and finances the subsidy rates offered for each type of input. Although the public sector also provides subsidies (on a per unit basis) to those oil producers who have been promised a price for their output exceeding the domestic price of oil \( (\delta_j P) \), the burden of financing these subsidies falls on the consumer. The federal government has introduced a Petroleum Compensation Charge.
(PCC) which is a per unit tax on the domestic consumption of oil and is intended to just cover the cost of domestic oil price subsidies as well as covering the cost of subsidizing oil imports for the Canadian consumer. Therefore, in the analysis that follows, we will ignore the price subsidies made available to some oil producers on the grounds that they represent no net alteration to government revenues.

Therefore, the value of net government revenues under tax regime \( \tau \), derived from oil production of type \( j \), will be given by:

\[
(15) \quad \tau_j = \delta_j P F_j T_j - r e_j e_j - r p_j p_j - w_j L_j t_L \]

Totally differentiating then the net government revenue expression (again setting \( dr_e = dr_p = dw_j = 0 \), and as well, \( dP = d\delta_j = 0 \)) we obtain;

\[
(16) \quad d\tau_j = [\delta_j P T_j F_j K_{e_j} - r e_j e_j] dK_{e_j} + [\delta_j P T_j F_j K_{p_j} - r p_j p_j] dK_{p_j} \\
+ [\delta_j P T_j F_j L_j - w_j L_j t_L] dL_j + \delta_j P F_j dT_j - r e_j e_j d\tau_j \\
- r p_j d\tau_j - w_j L_j d\tau_L \\
- r p_j d\tau_j - w_j L_j d\tau_L \\
+ [\delta_j P T_j F_j L_j - w_j L_j t_L] dL_j \\
\]

Then summing the change in industry net returns for oil type \( j \) (equation 14) and the change in net government revenues derived from the production of oil type \( j \) (equation 16) we obtain;

\[
(17) \quad d\pi_j + d\tau_j = [\delta_j P T_j F_j K_{e_j} - r e_j e_j] dK_{e_j} + [\delta_j P T_j F_j K_{p_j} - r p_j p_j] dK_{p_j} \\
+ [\delta_j P T_j F_j L_j - w_j L_j t_L] dL_j \\
\]
or if we note that;

\[ r_{e}t_{e_{j}} = r_{e} - r_{e}(1 - t_{e_{j}}) \]
\[ r_{p}t_{p_{j}} = r_{p} - r_{p}(1 - t_{p_{j}}) \]

and

\[ w_{j}t_{L_{j}} = w_{j} - w_{j}(1 - t_{L_{j}}) \]

Furthermore, noting;

\[ \delta_{j}PT_{j}F_{e_{j}} = \delta_{j}PF_{e_{j}} + \delta_{j}P(1 - T_{j})F_{e_{j}} \]
\[ \delta_{j}PT_{j}F_{p_{j}} = \delta_{j}PF_{p_{j}} - \delta_{j}P(1 - T_{j})F_{p_{j}} \]
\[ \delta_{j}PT_{j}F_{L_{j}} = \delta_{j}PF_{L_{j}} - \delta_{j}P(1 - T_{j})F_{L_{j}} \]

Then substituting these expressions into (17) and recognizing that the first-order conditions are given by equations (8), (9) and (10), then we obtain;

\[ (18) \ [dn_{j} + d\tau_{j}] = [\delta_{j}PF_{e_{j}} - r_{e}]dK_{e_{j}} + [\delta_{j}PF_{p_{j}} - r_{p}]dK_{p_{j}} + [\delta_{j}PF_{L_{j}} - w_{j}]dL_{j} \]

which, taking the integral of equation (18), defines the area of the efficiency loss depicted in Figure 4.1 above. Therefore, the efficiency loss for oil type \( j \) associated with either the pre- or post-NEP regime relative to our efficiency regime will be given by the integral of the sum of \( [dn_{j} + d\tau_{j}] \); i.e.,

\[ (19) \ E.L. : j = \int [dn_{j} + d\tau_{j}] = \int [\delta_{j}PF_{e_{j}} - r_{e}]dK_{e_{j}} + \int [\delta_{j}PF_{p_{j}} - r_{p}]dK_{p_{j}} + \int [\delta_{j}PF_{L_{j}} - w_{j}]dL_{j} \]
where the $dK_{e_j}$, $dP_{j}$, and $dL_{j}$ in each integral is interpreted as the total change in $K_{e_j}$, $P_{j}$, and $L_{j}$, respectively, in response to the total change in the tax regime.

To reiterate, therefore, the total efficiency loss ($E.L_{j}$) in the fixed price case associated with the production of oil type j, brought about by the introduction of a given tax regime, will be the sum of the efficiency loss associated with each input employed (i.e., $K_{e_j}$ and $L_{j}$ as well as $K_{p_j}$) as identified in Figure 4.1 and summarized in equation (19).

If, however, output prices, both the world price ($P$) and the domestic price (reflected by $\delta_{j}P$) are permitted to change, we see that the additional terms to be considered from totally differentiating equations (7) and (15) will be:

$$PF_{j}d\delta_{j} + \delta_{j}F_jdP$$

Therefore, our expression for the efficiency loss when oil prices change with the introduction of a new tax regime is given by simply adding these two terms (integrated) to equation (19).26

4.4.1 Generation of an Estimate of the Efficiency Loss Associated with the Production of Oil Type J

As indicated in the previous section, the value of the efficiency loss associated with the production of oil type j will depend on the location of our new equilibrium point. In particular, we have to first
determine whether or not the use of a given input increases or decreases after all the changes in the tax regime are introduced. Secondly, we must determine whether the value of marginal product of this given factor at its new employment level has increased or decreased relative to the value of its given factor price (i.e., is \( r_1 > r_e \) in Figure 4.1).

The answer to the first question was provided in section 4.3 of this chapter when the factor employment effects of alternative tax regimes were calculated. To derive an answer to the second question we must reconsider the first-order-conditions (equations (8), (9) and (10)). By rearranging terms we can obtain the following expressions for the new value of marginal product for each input:

\[
\begin{align*}
PF_{K_e} &= r_e (1-t_{e_j})/\delta_j (1-T_j) \\
PF_{K_p} &= r_p (1-t_{p_j})/\delta_j (1-T_j) \\
PF_{L_j} &= w_j (1-t_{L_j})/\delta_j (1-T_j)
\end{align*}
\]

That is, in the case of exploration capital, the new value of the marginal product will have increased under the new tax regime if

\[
[(1-t_{e_j})/\delta_j (1-T_j)] > 1
\]

Therefore, in general, the efficiency loss associated with the production of oil type \( j \) will be approximated by:

\[
\begin{align*}
E.L. j &= [r_e (1-t_{e_j}) - r_e \delta_j (1-T_j)] \\
&\quad + [r_p (1-t_{p_j}) - r_p \delta_j (1-T_j)] \frac{(dK_{e_j}/d\tau_j)}{2 \delta_j (1-T_j)} + \frac{(dK_{p_j}/d\tau_j)}{2 \delta_j (1-T_j)} + (PF_j (d\delta_j) + \delta_j F_j (dP) - w_j \delta_j (1-T_j)] \frac{dK_p}{d\tau_j} + PF_j (d\delta_j) + \delta_j F_j (dP).}
\end{align*}
\]
where \( \frac{dK_{ej}}{d\tau_j}, \frac{dK_{pj}}{d\tau_j} \) and \( \frac{dL_j}{d\tau_j} \) are given by equations (11), (12) and (13) respectively.

Unfortunately, this expression for the efficiency loss associated with the production of oil type \( j \) does not allow for an estimate of the dollar value to be derived. For example, even if we take the very restrictive case where all the cross-partial are zero, the efficiency loss associated with the production of oil type \( j \) will be given by:

\[
(21) \quad E.L. \ j = \left[ \frac{r_e^2 \left[ 1 - t_e^j \right] A_j \left( F_{K_e j} K_e j F_{L_j L_j} L_j \right)}{2 \ \delta_j^3 \ (1 - T_j)^3 \ p^2 \ |H|} \right]
\]

\[
+ \left[ \frac{r_p^2 \left[ 1 - t_p^j \right] B_j \left( F_{K_p j} K_p j F_{L_j L_j} L_j \right)}{2 \ \delta_j^3 \ (1 - T_j)^3 \ p^2 \ |H|} \right]
\]

\[
+ \left[ \frac{w_j^2 \left[ 1 - t_L^j \right] C_j \left( F_{K_L j} K_L j F_{K_e j} K_e j \right)}{2 \ \delta_j^3 \ (1 - T_j)^3 \ p^2 \ |H|} \right]
\]

\[
+ \left( \frac{PF_j d\delta_j}{dP} + \delta_j F_j dP \right)
\]

The absolute value was taken in the above expression since the initial minus the new equilibrium value of marginal product for a given input may be positive or negative (i.e., \( r_1 \) could be \( \geq r_e \) in Figure 4.1) and as well, the change in employment of the factor may be positive or negative for a given factor and given oil type \( j \).

Equation (21) however, is not measurable since we do not know the value of the \( F_{ij} \) terms, the value of \( |H| \), nor the value of the factor
prices. All that we can conclude from looking at equation (21) is what will happen to the efficiency loss in region j as we change the various tax parameters.

4.4.2 An Alternative Approach to Estimating the Efficiency Loss

Our preferred approach suggested above unfortunately will not provide a numerical estimate of the efficiency loss for us. Therefore, it is necessary to derive an alternative approximation for this efficiency loss. To begin, reconsider Figure 4.1. After the introduction of the new tax regime we have (by assumption) increased the value of marginal product in the new equilibrium and reduced our employment of exploration capital used in the production of oil type j. The resulting efficiency loss associated with the employment of exploration capital then is:

$$E.L.\_j = \frac{1}{2} (r_1 - r_e) (K_e^0 - K_e^1)$$

where

$$r_1 = r_e (1 - t_{e_j}) / \delta_j (1 - T_j)$$

If we let $s_0$ denote the value of the slope of our (assumed) linear path, then our expression for the efficiency loss simplifies to:

$$E.L.\_j = \frac{1}{2} (1 - t_{e_j} - \delta_j (1 - T_j))^2 r_e^2 \frac{r_1^2}{\delta_j^2 (1 - T_j)^2 s_0}$$

and by multiplying the right-hand side of this expression by $r_1 K_{e_j}^1 / r_1 K_{e_j}^1$ where $r_1$ is defined as above, permits us to express the efficiency loss associated with the employment of exploration capital in conjunction with the production of oil type j as:
\[ E.L. j = \frac{1/2[1 - t_0 j - \delta_j (1-T_j)]^2 r_e k^1 e_j \eta^1 e_j}{\delta_j (1-T_j) (1-t_e j)} \]

where \( \eta^1 e_j \) denotes the percentage change (or responsiveness) in the employment of exploration capital with respect to the percentage change in the value of marginal product of the input brought about by the introduction of the new tax regime (and evaluated at our new equilibrium point). This 'elasticity' parameter, it should be noted, is not only unmeasurable but a priori, it is not even possible to sign (positive or negative) this parameter. That is, given a particular tax regime, it is possible that the new value of the marginal product may increase (i.e., \( r_1 > r_e \)) and employment of the factor may increase as well. This situation may arise when there exists a particularly high writeoff rate for this input relative to the other inputs.

Fortunately, however, the results of our previous exercise permit us to sign this 'elasticity' parameter to be negative. For the pre-NEP period we have calculated the new values of marginal products for each of the inputs and for each of the oil types and have observed that in all but two cases, the employment of exploration capital in the frontier oil and the employment of development capital in the production of non-conventional oil, the new value of marginal product is higher than the initial value (i.e., \( r_1 > r_e \) in Figure 4.1 in all but these two cases).

This observation together with the results of the factor employment effects from introducing the pre-NEP tax regime relative to our efficiency regime, which indicated a reduction in all inputs for all oil types except frontier and non-conventional oil (see Table 4.5) implies that this 'elasticity' parameter will be negative for all inputs and for all
types of oil except frontier and non-conventional oil.

This elasticity parameter for the inputs employed in the production of these two types of oil unfortunately, in general, can not be signed since the factor-employment effects were ambiguous. However, if we adopt our restrictive assumption that all the cross-partial derivatives are zero, then in the case of frontier oil this elasticity parameter for each input will be negative. That is, we would have a negative effect on the employment of development capital and labour services combined with an increase in the new value of marginal product of each input. Similarly, the employment of exploration capital would increase while the new value of marginal product is lowered, thus ensuring this elasticity parameter would also be negative. Similarly, in the case of non-conventional oil since we would have (given this restrictive assumption) a negative employment effect on exploration capital and labour services (with an associated increase in the new value of marginal product) whereas for development capital the opposite results are observed, then again, this 'elasticity' parameter will be negative for all inputs and for all types of oil.

By adopting the same approach for the other factors of production and permitting the possibility that oil prices may change following the introduction of a new tax regime (e.g., the NEP), we can obtain the following expression for the efficiency loss associated with oil type j;

\[
\text{E.L.}_j = \frac{[1-t_e - \delta_j (1-T_j)]^2 r_e K_{e_j} n_{e_j}}{2 \delta_j (1-T_j) (1-t_{e_j})} + \frac{[1-t_p - \delta_j (1-T_j)]^2 r_p K_{p_j} n_{p_j}}{2 \delta_j (1-T_j) (1-t_{p_j})} \\
+ \frac{[1-t_{L_j} - \delta_j (1-T_j)]^2 w_j L_{L_j} n_{L_j}}{2 \delta_j (1-T_j) (1-t_{L_j})} + \text{PF}_j d\delta_j + \delta_j F_j dP
\]
In equation (23) the efficiency loss estimate is generated for the new regime relative to our efficiency regime. Consequently, therefore, the values taken on by $\delta_j$, $t_{e_j}$, $t_{p_j}$, $t_{L_j}$ and $T_j$ would be, for example, either the pre-NEP or post-NEP values.

Given this formulation for the efficiency loss we can readily express our estimate of the efficiency loss generated by the introduction of the new tax regime as a function of the relative shares of factor payments. That is, recognizing that $k_{e_j}$, $k_{p_j}$ and $l_{L_j}$ in equation (23) represent the actual stocks of exploration capital, production or development capital and the quantity of labour services respectively employed in the production of oil type $j$ under the new tax regime and $r_e$, $r_p$ and $w_j$ are the corresponding (fixed) factor prices, then the efficiency loss associated with the production of oil type $j$ expressed as a percentage of total (gross) factor payments will be given by:

\[
(24) \quad \text{E.L.}_j = \frac{[1-t_{e_j} - \delta_j(1-T_j)]^2 \theta_{e_j} \eta_{e_j}}{[r_{e_j} K_{e_j} + r_{p_j} K_{p_j} + w_{j L_j}]} \frac{2}{\delta_j (1-T_j) (1-t_{e_j})} \left[ \frac{[1-t_{p_j} - \delta_j(1-T_j)]^2 \theta_{p_j} \eta_{p_j}}{2 \delta_j (1-T_j) (1-t_{p_j})} \right] + \frac{[1-t_{L_j} - \delta_j(1-T_j)]^2 \theta_{L_j} \eta_{L_j}}{2 \delta_j (1-T_j) (1-t_{L_j})} + \frac{\delta_j F_{j} d\delta_j}{[r_{e_j} K_{e_j} + r_{p_j} K_{p_j} + w_{j L_j}]} + \frac{\delta_j F_{j} d\delta_j}{[r_{e_j} K_{e_j} + r_{p_j} K_{p_j} + w_{j L_j}]} \]
\]
where $\theta_j^e$, $\theta_j^p$, $\theta_j^l$ are the shares of total factor payments going to exploration capital, development capital and labour services respectively. The coefficients on the $\theta_j$'s have been calculated for the pre- and the post-NEP tax regimes and are presented in Tables 4.10 and 4.11 below.

As can be seen from Tables 4.10 and 4.11 (or equation (24)), the size of the efficiency loss associated with the new tax regime relative to our efficiency regime varies directly with the (unmeasured) value of our elasticity parameters ($\eta^e_j$, $\eta^p_j$ and $\eta^l_j$). However, in the interest of attempting to assess (for illustrative purposes only) the efficiency effects of the distortions on total resource rents (i.e., industry profits and net government revenues), let us assume that these elasticity parameters all take on the value of unity. Consequently, the efficiency loss associated with the pre-NEP tax regime in the production of old conventional oil (for example) expressed as a percentage of total factor payments and relative to the efficiency regime will be:

- 28 per cent of the share of factor payments going to exploration capital,

plus

- 109 per cent of the share of factor payments accounted for by development capital, and

plus

- just under 88 per cent of the share of factor payments accounted for by labour services (i.e., operating expenses).

Alternatively, if we further assume, for illustrative purposes, that the shares of total factor payments in the pre-NEP period (for conventional old oil) were approximately:

- 45 per cent for exploration capital,

- 20 per cent for development or production capital,

and

- 35 per cent for labour services (i.e., operating expenses in our model).
<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>$n_{e_j}$</th>
<th>$n_{p_j}$</th>
<th>$n_{L_j}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>28.26</td>
<td>108.90</td>
<td>87.56</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>13.90</td>
<td>74.17</td>
<td>57.67</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>106.58</td>
<td>58.46</td>
<td>57.67</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>1.43</td>
<td>24.17</td>
<td>1.38</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>0.51</td>
<td>3.12</td>
<td>3.34</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>16.45</td>
<td>29.32</td>
<td>27.96</td>
</tr>
</tbody>
</table>
# Table 4.11: Estimates of the Efficiency Loss as a Percentage of Total Factor Payments—In Terms of Factor Payment Shares (Post-NEP)

## A. Canadian Firm:

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>$\eta_{e_j} \theta e_j$</th>
<th>$\eta_{p_j} \theta p_j$</th>
<th>$\eta_{L_j} \theta L_j$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>.27.05</td>
<td>199.34</td>
<td>139.41</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>9.59</td>
<td>130.01</td>
<td>86.31</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>130.01</td>
<td>130.01</td>
<td>86.31</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>26.45</td>
<td>39.73</td>
<td>2.27</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>0.18</td>
<td>4.23</td>
<td>4.60</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>44.35</td>
<td>84.54</td>
<td>74.18</td>
</tr>
</tbody>
</table>

## B. Foreign Firm:

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>$\eta_{e_j} \theta e_j$</th>
<th>$\eta_{p_j} \theta p_j$</th>
<th>$\eta_{L_j} \theta L_j$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>73.84</td>
<td>270.31</td>
<td>139.41</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>39.84</td>
<td>182.36</td>
<td>86.31</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>182.36</td>
<td>182.36</td>
<td>86.31</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>19.15</td>
<td>65.18</td>
<td>2.27</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>4.04</td>
<td>0.22</td>
<td>4.60</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>71.38</td>
<td>124.05</td>
<td>74.17</td>
</tr>
</tbody>
</table>
then the efficiency loss in the pre-NEP period (relative to our efficiency regime) would be estimated to be approximately 65 per cent of the value of total pre-NEP factor payments. (Again, the reader is cautioned -- this result is a highly simplified (but suggestive) assessment of the effects of the distortions on total resource rents.) Similarly, the corresponding figures for the post-NEP efficiency loss associated with the production of old conventional oil (assuming for simplicity that the factor payment shares are unchanged) would be virtually all (i.e., 100.8 per cent) of the actual post-NEP total factor payments in the case of Canadian firms and 136 per cent of total post-NEP factor payments in the case of foreign-owned firms. Clearly then, viewed in this light, both the pre- and post-NEP tax regimes imply a substantial value of the efficiency loss relative to a (non-distortive) pure-profits tax rate regime.29

Unfortunately, the statement above does not necessarily imply the efficiency loss associated with the production of old conventional oil increases following the introduction of the NEP because the efficiency loss estimates above are quoted in percentage terms with respect to total (actual) factor payments in either the pre-NEP or post-NEP period (that is, the elasticities are evaluated at our final (pre-NEP or alternatively, post-NEP) equilibrium positions -- see Figure 4.1). Therefore, since the pre-NEP and post-NEP total factor payments are not constant we can not infer from the results above that the efficiency loss increases following the introduction of the NEP.

There is however, an alternative method of deriving our estimate of the efficiency loss that will permit a direct comparison of the efficiency losses associated with the pre- and post-NEP periods for each
type of oil. To begin, reconsider equation (22). If we had multiplied the right-hand side of this expression by \( r_\text{e} K^0_{e_j} / r_\text{e} K^1_{e_j} \) instead of \( r_\text{e} K^1_{e_j} / r_\text{e} K^1_{e_j} \) (i.e., how evaluate our elasticity parameters \( \eta_{ij}^0 \) at our initial equilibrium point) we would derive the following expression for the efficiency loss:

\[
\text{E.L.}_j = \frac{[1-t_{e_j} - \delta_j(1-T_j)]^2 r_{e_j} K^0_{e_j} \eta_{e_j}^0}{2 \delta_j^2 (1-T_j)^2} + \frac{[1-t_{p_j} - \delta_j(1-T_j)]^2 r_{p_j} K^0_{p_j} \eta_{p_j}^0}{2 \delta_j^2 (1-T_j)^2} + \frac{[1-t_{L_j} - \delta_j(1-T_j)]^2 w_{j-L_j} L^0_{L_j} \eta_{L_j}^0}{2 \delta_j^2 (1-T_j)^2} + \frac{\text{PF}_j d\delta_j + \delta_j dP}{\delta_j^2 dP}
\]

where in this case the values of \( K^0_{e_j}, K^0_{p_j} \) and \( L^0_j \) would all be equal (for a given \( j \)) whether we are comparing the pre- or post-NEP tax regime to our efficiency regime. Therefore, to compare the efficiency loss under both tax regimes (relative to our efficiency regime) simply requires the evaluation and comparison of the coefficients on the \( r_{e_j} K^0_{e_j}, r_{p_j} K^0_{p_j} \) and \( w_{j-L_j} L^0_j \) terms in equation (25) for a given value of the elasticity parameters. This exercise has been performed and the results are summarized in Tables 4.12 and 4.13 below.

4.4.3 The Results

In the case of a Canadian firm, under the post-NEP regime (relative to the pre-NEP regime) we observe from our highly simplified but suggestive assessment of the efficiency effects of the distortions generated that:

a) with respect to the employment of exploration capital the efficiency loss is reduced under the NEP for a Canadian firm for conventional (old and new) and non-conventional oil. However,
### Table 4.12: Estimates of the Coefficients on Factor Inputs in the Efficiency Loss Expressions (Pre-NEP)

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>$\eta_{e_j e_j}$</th>
<th>$\eta_{p_j p_j}$</th>
<th>$\eta_{L_j L_j}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>0.5894</td>
<td>4.2720</td>
<td>3.0316</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>0.2340</td>
<td>2.3493</td>
<td>1.6122</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>4.1282</td>
<td>1.6448</td>
<td>1.6122</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>0.0121</td>
<td>0.4781</td>
<td>0.0162</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>0.0056</td>
<td>0.0243</td>
<td>0.0432</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>0.2896</td>
<td>0.6197</td>
<td>0.5811</td>
</tr>
</tbody>
</table>
### TABLE 4.13 ESTIMATES OF THE COEFFICIENTS ON THE FACTOR INPUTS IN THE EFFICIENCY LOSS EXPRESSIONS (Post-NEP)

**A. Canadian Firm:**

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>$\eta^{0}<em>{e} r^{0}</em>{e} K^{0}_{e}$</th>
<th>$\eta^{0}<em>{p} r^{0}</em>{p} K^{0}_{p}$</th>
<th>$\eta^{0}<em>{Lj} W^{0}</em>{j} L^{0}_{j}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>0.5557</td>
<td>11.5919</td>
<td>6.3702</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>0.1481</td>
<td>5.6829</td>
<td>2.9645</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>5.6829</td>
<td>5.6829</td>
<td>2.9645</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>0.1985</td>
<td>1.4408</td>
<td>0.0377</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>0.0019</td>
<td>-0.0316</td>
<td>0.0622</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>1.1019</td>
<td>2.8713</td>
<td>2.3497</td>
</tr>
</tbody>
</table>

**B. Foreign Firm:**

<table>
<thead>
<tr>
<th>Type of Oil</th>
<th>$\eta^{0}<em>{e} r^{0}</em>{e} K^{0}_{e}$</th>
<th>$\eta^{0}<em>{p} r^{0}</em>{p} K^{0}_{p}$</th>
<th>$\eta^{0}<em>{Lj} W^{0}</em>{j} L^{0}_{j}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional - Old</td>
<td>2.3336</td>
<td>19.6476</td>
<td>6.3702</td>
</tr>
<tr>
<td>Conventional - New</td>
<td>0.9464</td>
<td>9.9643</td>
<td>2.9645</td>
</tr>
<tr>
<td>Secondary Oil</td>
<td>9.9643</td>
<td>9.9643</td>
<td>2.9645</td>
</tr>
<tr>
<td>Frontier Oil</td>
<td>0.0749</td>
<td>2.8128</td>
<td>0.0377</td>
</tr>
<tr>
<td>Non-Conventional Oil</td>
<td>0.0537</td>
<td>0.0021</td>
<td>0.0622</td>
</tr>
<tr>
<td>Tertiary Oil</td>
<td>2.2170</td>
<td>5.2665</td>
<td>2.3497</td>
</tr>
</tbody>
</table>
the efficiency loss associated with the input of exploration capital increases for frontier, secondary and tertiary oil production.

and b) with respect to the employment of development capital and labour services, the NEP increases the efficiency loss for all types of oil.

In the case of a foreign firm after the introduction of the NEP, the results are even more pronounced. With the sole exception of development expenditures incurred in non-conventional oil production, the efficiency loss increases (relative to the pre-NEP period) for all types of oil and for all inputs.

4.5 SUMMARY AND CONCLUSIONS

In this chapter we have attempted to identify and compare, employing a very simplified model of the domestic oil industry, the employment distortions and the associated efficiency loss generated from these distortions for the pre- and post-NEP tax regimes based on the assumption that the traditional pure-profits tax rate in economic theory characterizes an efficient (non-distortive) tax regime. Within the context of this highly simplified model, our results indicate that the NEP is expected to have very limited success in Canadianizing the domestic oil industry (except in the case of production of conventional oil). Furthermore, we also indicated that the NEP may raise serious questions regarding the Canadian oil self-sufficiency objective. These doubts arise with respect to the relative discouragement (by the NEP) of less costly and possibly more secure sources of oil (e.g., conventional and secondary oil). At the same time, concern was expressed regarding the desirability of encouraging more expensive sources of oil (e.g., frontier
and non-conventional oil) if the world price of oil fails to rise as rapidly in the future as the government has predicted. If this occurs, then the viability of these oil projects is significantly reduced and therefore, the potential output from these sources may not materialize in the future as planned. In addition, of special concern is the Hibernia oil fields if the Newfoundland government succeeds in obtaining ownership of these resources, for as we indicated above, under provincial ownership we expect to see a decline in both exploration and development activity by both Canadian and foreign firms in the post-NEP period. Consequently, a potential to increase Canada's reliance on foreign oil imports both now and in the future is introduced.

Finally, our highly simplified but suggestive attempt at quantifying the implied efficiency loss generated as a result of the introduction of the NEP reveals that in the vast majority of cases the National Energy Program increases the efficiency loss to the Canadian economy. Consequently, even in this very simplified model, the desirability of the National Energy Program is seriously in doubt.
1. In this chapter we identify six types of oil -- conventional (old and new), secondary, tertiary, non-conventional and frontier. The definitions we employ for each type of oil are consistent with the National Energy Program's classification of oil (see Energy, Mines and Resources, The National Energy Program, Ottawa, page 28). In particular, conventional oil is defined as any oil produced from a reservoir which utilizes the natural energy of the reservoir to move the oil towards the producing wells. The old/new conventional distinction employed here is the same as the Alberta government's definition -- namely, old oil was discovered prior to April 1, 1974 whereas new oil has been discovered since that date. Secondary Oil is defined as the (additional) oil produced from a reservoir as a result of supplying energy to move the oil towards the producing wells. Examples of this method of production include waterflooding and gas injection (which are already technically and economically proven methods of production). Tertiary oil, on the other hand, is produced employing third generation methods which are newer, less technically proven techniques than secondary methods. An example of tertiary oil production would be steam injection. In particular, tertiary oil, in this chapter, is taken to be synonymous with heavy oil production. Finally, non-conventional oil is defined as crude produced from the oil sands, whereas, frontier oil is defined as any oil produced from areas in Canada which fall under federal (only) jurisdiction (this currently includes the areas off Canada's coasts, the Yukon and the Northwest Territories).

2. See for example, J.F. Helliwell and R.N. McRae, "Energy Policy and the Budget," in Canadian Public Policy, Winter 1981, pp. 15-23, and Helliwell, J.F., "An Economic Evaluation of the National Energy Program," paper presented to the Annual Conference of the Canadian Tax Foundation, Montreal, November 1980. In these (and other) papers Helliwell employs a comprehensive regionally-based model of the non-frontier oil and gas industry to calculate for example, the effects of the NEP on the distribution of oil and gas rents among Canadian energy consumers, domestic producers and the federal and oil-producing provincial levels of government. The rents attributed to each party in Helliwell's model is the value of compensated consumer surpluses (for Canadian energy consumers), the value of producers' surpluses (for domestic producers) and finally, the rents accruing to the federal and oil-producing provincial levels of government are the (discounted present) value of net oil-related tax revenues. These rents are calculated in present value terms and consider all past (dating back to the Leduc discovery in Alberta) and future (into the early twenty-first century) costs and returns (measured at the end of a given base year (e.g., 1980). Consequently, Helliwell must forecast the values of future world and domestic oil prices, Canadian inflation rates and domestic real GNP growth rates. As a result, the estimates generated must be viewed as illustrative.
only.
Although the model employed in this thesis is not intertemporal as
is the model Helliwell utilizes (and therefore, our results with
respect to the estimates of the efficiency aspects of the NEP must
be viewed as being even less an actual characterization than Helli-
well's estimates), there are nevertheless, some significant advan-
tages to the present formulation. Perhaps most striking is the
degree of disaggregation with respect to the type of oil produced
and the choice of input combinations in my model. For example,
Helliwell's model excludes the frontier regions and does not dis-
tinguish between secondary or tertiary oil or even old and new
conventional oil production. His model does however, estimate the
rents generated from the production of non-conventional oil (e.g.,
oil sands) but in this case, Helliwell simply assumes a sequence
of oil sands plants will come on stream at five year intervals.
Finally, Helliwell's model essentially assumes fixed capital shares
since it is assumed that all future expenditures are treated as
being 50 per cent exploration capital and 50 per cent development
capital (this essentially amounts to aggregating the two types of
capital).

3. For a dynamic model which explicitly introduces exploration activity
into the firms' decision portfolio see, for example, Robert S.
Pindyck, "The Optimal Exploration and Production of Nonrenewable
Resources," Journal of Political Economy, Volume 86, No. 5 (October
1978), pp. 841 - 861. In Pindyck's model the firm by engaging in
exploration activity builds the reserve base up so that extraction
costs are reduced. Consequently, the firms must simultaneously
determine the optimal rates of exploration activity and rates of
production over time in order to maximize the present discounted
value of profits. Pindyck's analysis which seeks a solution to
this problem for competitive and monopolistic markets ignores,
however, the effects of government tax and subsidy policies on
the firms' choice of exploration activity and production flows.

4. This formulation for capital expenditures (both exploration and
development capital) will, unfortunately, not exactly parallel the
tax treatment described earlier in the situation where the firm
owns the capital stock but it will reflect the tax structure for
those firms that lease or rent their capital equipment. To attempt
to modify our model to handle situations where the firm owns rather
than leases the capital equipment, however, would complicate the
analysis unnecessarily.

5. Although conceivably the supply curve of exploration and development
capital may, at least in the short-run, be less than perfectly
elastic, in the 'empirical' work that follows (where we assume all
cross-partialials are zero) the assumption of fixed factor prices will
not qualitatively change our results concerning the efficiency losses
associated with a given tax regime.

6. To be consistent with the present value presentation of the production
function, we should analyze the present value of the earned depletion
allowance and development expense writeoffs. This transformation,
however, has not been performed here. The error in estimating subsidy rates by not making this transformation (based on, say, an 8 per cent discount rate) would be approximately only 10 per cent.

7. A Canadian firm is defined as one that is more than 75 per cent Canadian owned and controlled and therefore, will qualify for the maximum incentive payment as announced in the National Energy Program (see, Energy, Mines and Resources, Op.cit., page 40). A foreign firm, on the other hand, is defined as a firm which is less than 50 per cent Canadian owned and controlled and therefore, qualifies for the minimum incentive payment available.

8. The "Petro-Canada tax" is the term employed in this chapter to represent the back-in privilege afforded Petro-Canada in the NEP (or any other federal Crown corporation) for any oil and gas play on federal or, as the NEP refers to as, the "Canada Lands." This provision is discussed in more detail below.

9. The comparable figures for the net after-tax, after-incentive costs of exploration investment for a Canadian firm operating in conventional areas will be roughly 24 cents for each dollar spent.


11. Lalonde argues that the existence of the frontier exploration allowance (prior to NEP) followed by the existence of incentive grants (since the introduction of NEP) has provided substantial government subsidies for any exploration activities undertaken and therefore, no additional compensation is necessary.

12. In the following chapter of the thesis we will re-examine the assumption made here that the pure-profits tax is optimal. Further, it is implicitly assumed that the Canadian tax rates (as described by either the pre-NEP or post-NEP regime) will be binding. That is, foreign-owned firms which submit their total tax payments in part to foreign governments, and in part, to the Canadian government (with the amount paid to the foreign government acting as a credit against Canadian taxes owed), ultimately face the higher effective tax rate of the two countries. Here the implicit assumption is that the Canadian tax rates are higher and therefore, any changes to the Canadian tax rates will influence the firms' behaviour.

13. Note from our definitions of $A_j$, $B_j$, and $C_j$ that the parameters estimated in Tables 4.5, 4.6 and 4.7 (below) allow for $d_{L_j}$, $d_{L_j}^e$, $d_{M_j}$, $d_{M_j}^e$, $d_{P_j}$, and $d_{P_j}$ to be positive, negative or zero depending on the actual values of the input subsidy rates, output tax rates and price parameters in both the pre- and post-NEP periods.

14. Specifically, the federal government's goals are:
   a) at least 50 per cent Canadian ownership of oil and gas production by 1990,
   b) Canadian control of a significant number of the larger oil and gas firms,

15. A second instrument introduced to achieve this objective is the back-in privilege afforded Petro-Canada, or an alternative federal Crown corporation, (and discussed above) for any frontier or Canada Lands oil and gas play.


17. I.b.i.d., page 7.

18. However, it is possible that the Canadian firms may acquire equity in exchange for debt and consequently, move towards successfully Canadianizing the domestic oil industry (i.e., debt financing).

19. There is still one possible avenue available for the federal government to achieve its ownership objective and this instrument is the back-in privilege afforded for a Crown corporation. The impact of this feature may be sufficient to bring about the 50 per cent ownership objective but one can only speculate.

20. Since the writing of this chapter, the PMA has published its monitoring survey for all of 1981 and the first six months of 1982. The figures for these other two surveys and the shortcomings of this data (with respect to our purposes) however, are still virtually unchanged.

21. Our results are also strictly true provided neither the tax regime nor the world or domestic price of oil change (i.e., we are examining the impact effects of the NEP). For example, as seen by our definitions of $A$, $B$, and $C$, if the world price begins to fall then $A$, $B$, and $C$ will "each rise", implying a reduction in employment of all factors for each type of oil.

22. Frontier oil sources are encouraged to the extent that frontier oil activities become significantly Canadian controlled (i.e., by way of increased activity by, for example, Dome Petroleum and the implementation of Petro-Canada's back-in privilege.

23. Energy Minister Marc Lalonde recently admitted that the NEP will encourage the more expensive forms of oil. In Lalonde's words: "...I also believe the program will promote energy investment where it is needed most: in the nonconventional and tertiary projects and in frontier and offshore areas, where the bulk of future oil supplies will be found."


The relative discouragement of less costly oil sources (in particular oil produced employing secondary recovery techniques) has been
noted by Bruce Wilkinson,
"... I am surprised that secondary recovery
techniques receive no special mention in the
budget. The government's assumption must be
that the proposed prices for conventional oil
are adequate to stimulate whatever additional
reserve recovery is possible by such techniques."
(See B. Wilkinson, "The 1980 Federal Budget, Energy Policy and All
and as well by A.R. Nielsen;
"... One may easily conclude that the federal
government is writing off western Canada as
a future supply of oil... The government in
Ottawa may, however, be making a serious
mistake. There is still oil to be found in
the Western Canadian sedimentary basin...
But the federal government appears to have
no further interest in these resources."
(See A. R. Nielsen, "The Impact of the October 28 Budget: A Producer's

24. As well, there have also occurred significant changes in the federal
and provincial tax regimes as a result of, for example, the 1981
(September) Alberta-Ottawa energy pricing and taxation agreement.
No attempt however, was made here to deal with these later changes--
this instead, will be left for future research.

25. That is, our estimate of the efficiency loss represents an estimate
of the first term in a Taylor series expansion.

26. It should be noted that these additional terms (for dP, and dσ) will
be included in equation (19) in this section of the chapter--so
that we will be consistent in assuming both the domestic and world
prices change as the NEP is introduced (i.e., this same assumption
underlies the earlier results reported on factor employment effects).

27. Because of data limitations it was not possible to present estimates
of the value of the last two terms in equation (24) in Tables 4.10
and 4.11 (i.e., the dσ and dP terms) so the efficiency loss estimates
in Tables 4.10 and 4.11 are understated.

28. In 1980 total industry exploration capital expenditures amounted to
$4,135 million, development and production capital expenditures
amounted to $2,131 million and operating expenses (proxied as labour
expenses in our model) amounted to $3,400 million. In percentage
terms, this implies the following shares of total factor payments:
exploration capital, 43 per cent, development/production capital,
22 per cent, and operating expenses, 35 per cent. (Source: Canadian
Petroleum Industry, Monitoring Survey 1981, Petroleum Monitoring
Agency, Department of Energy, Mines and Resources, Schedule A and
Schedule C).

29. The corresponding figures for the other types of oil were not re-
ported since the assumed factor payment shares suggested above may
be inappropriate in reflecting the actual distribution of factor payments amongst exploration capital, development capital and labour services for the other types of oil (Recall from the previous footnote that the estimate of factor shares reported were based on total industry observations). For example, in the case of secondary oil production where we expect virtually all of the capital expenditures to be classified as development capital expenditures (given the interpretation of the Finance Department discussed in Chapter 2), the fixed factor shares assumption (e.g., implying 45 per cent of the factor payments are for exploration capital etc.,) would be totally inappropriate and misleading.

30. That is, $r_{e}^{K_{e}}$ refers to the value of exploration capital expenditures when there are neither input subsidies or output tax rates in our model (i.e., our efficiency regime).

31. As was the case in Tables 4.10 and 4.11, due to data limitations we do not report the values of the last two terms in equation (25). Consequently, our estimates of the efficiency loss will be understated.

32. It should be re-emphasized that the conclusions that follow are valid given the assumptions made in our model. In particular, we found that deviations from the pure-profits tax were considered distortionary, in part, because we assumed there were no market failures. For example, no spillover effects from exploration activity were assumed to exist which would typically lower the social costs (relative to the private costs) of exploration activity. If, instead, spillover effects were present, it may be non-distortionary to offer a high subsidy rate on exploration activity relative to the output tax in order to bring private costs of exploration activity in line with the social costs of exploration activity.

33. Since the writing of this chapter the federal government is now confronted with this situation.
APPENDIX I TO CHAPTER 4

THE NET RETURNS EXPRESSIONS BY TYPE OF OIL: PRE- AND POST-NEP

To derive the net returns expressions for each type of oil produced for both Canadian and foreign-owned firms (post-NEP period only) in both the pre- and post-NEP periods we let:

\( j \) = type of oil (i.e., \( j = \text{OC}, \text{NC}, \text{S}, \text{F}, \text{and} \ T \)) where,

- \( \text{OC} \) = old conventional oil,
- \( \text{NC} \) = new conventional oil,
- \( \text{S} \) = secondary oil,
- \( \text{F} \) = frontier oil,
- \( \text{N} \) = non-conventional or synthetic oil,
and \( \text{T} \) = tertiary oil.

\( \theta_j \) = gross royalty rate for each type of oil.

\( t_p \) = the relevant provincial corporate income tax rate (i.e., 11% for Alberta and 14% for Saskatchewan),

\( s_{\text{PRC}} \) = Alberta provincial royalty tax credit (i.e., equals 0.25). Available only in the province of Alberta.

\( s_{\text{RA}} \) = rate of federal resource allowance (i.e., equals 0.25),

\( t_f \) = the relevant federal corporate income tax rate (i.e., 36% for provincial areas and 46% for frontier regions),

\( s_E \) = the relevant rate of deduction by type of oil for exploration capital expenses (see Tables 4.1 (Pre-NEP) and 4.2 (Post-NEP)),

\( s_D \) = the relevant rate of deduction by type of oil for development capital expenses (see Tables 4.1 and 4.2),

\( s_{ED} \) = the relevant rate of earned depletion allowance by type of oil (see Tables 4.1 and 4.2),

\( s_{SD} \) = the relevant rate of supplementary depletion allowance by type of oil (see Tables 4.1 and 4.2),
\[ s_{FE} = \text{the rate of frontier exploration allowance (assumed to be applicable in frontier regions only and only in the pre-NEP period),} \]

\[ t_{RT} = \text{the Petroleum and Gas Revenue Tax rate (i.e., equals 0.08 -- relevant for the post-NEP period only),} \]

\[ t_{PC} = \text{the "Petro-Canada tax" rate (i.e., representing the "back-in" privilege afforded Petro-Canada (or an alternative federal Crown corporation) on all plays in the frontier regions (at a rate of 25% and to be applied in the post-NEP period only),} \]

\[ E_{FF} = \text{the rate of Petroleum Incentive grant to be applied against foreign-owned firms' exploration expenses in the frontier regions (see Table 4.2),} \]

\[ E_{Cj} = \text{the relevant rate of Pétroleum Incentive grant to be applied against Canadian-owned firms' exploration expenses by type of oil (see Table 4.2),} \]

and

\[ D_{Cj} = \text{the relevant rate of Petroleum Incentive grant to be applied against Canadian-owned firms' development expenses by type of oil (see Table 4.2).} \]

1. **THE NET RETURNS BY TYPE OF OIL - PRE-NEP**

**A. Conventional Old and New Oil:**

The net returns expression for conventional old oil is provided in the text of Chapter 4. The only difference in treatment between old and new conventional oil is with respect to the provincial royalty rate. The pre-NEP royalty rates for an "average" size well (as defined by the Alberta government -- see Section 2.3.1 of the thesis) and given the prevailing producer prices (see Table 4.1) and for both types of oil are determined to be:

\[ \theta_{OC}^* = 0.43783 \]

and

\[ \theta_{OC}^* = 0.31122 \]
B. Secondary Oil:

The relevant provincial oil royalty rate for secondary oil production is the Alberta 'new' conventional oil royalty rate (i.e., $\delta_s^* = 0.31122$ for the pre-NEP period). Therefore, given the information in Table 4.1, the net returns for secondary oil producers is given by:

$$
\Pi_s = \delta_s^* p_S (K_e, K_p, L_s) - r_k - r_p - w_s L - \delta_s^* p_S (K_e, K_p, L_s)
$$

$$
+ \epsilon_p \left[ \delta_s^* p_S (K_e, K_p, L_s) - \delta_s^* p_S (K_e, K_p, L_s) - w_s L_s \right] s_{RA}
$$

$$
+ \delta_s^* p_S (K_e, K_p, L_s) - (t_f + t_p) \left[ \delta_s^* p_S (K_e, K_p, L_s) - w_s L_s \right] (1-s_{RA}) - s_D (r_k + r_p) - s_{SD} p_s
$$

So,

$$
T_s = \delta_s^* (1-t_p + s_{PRC}) + t_p + t_f (1-s_{RA})
$$

$$
t_{e_s} = (t_f + t_p) s_D
$$

$$
t_{p_s} = (t_f + t_p) (s_{SD} + s_D)
$$

and

$$
t_{L_s} = t_p + t_f (1 - s_{RA})
$$

C. Frontier Oil:

The federal basic and progressive oil royalty formula (as discussed in section 2.2.3 of the thesis) applies to oil firms producing on frontier regions. Noting that labour costs are our proxy for operating expenses and retaining the assumptions underlying Table 2.4, then the total federal oil royalties ($R_f$) payable to the federal government on production from frontier regions will be given by:
\[ R_F = \theta_F^* P_F (k_e F, k_p F, l_F) + 0.2013 \, r_e e_F - 0.0502 \, r_p p_F - 0.2620 w_{F} l_F \]

where \( \theta_F^* = 0.3220 \).

Consequently, net returns for frontier oil producers (for the pre-NEP period) will be given by:

\[
\Pi_F = P_F (k_e F, k_p F, l_F) - r_e e_F - r_p p_F - w_{F} l_F - t_F [(P_F (k_e F, k_p F, l_F) - w_{F} l_F) (1 - s_{RA})]
- s_e r_e e_F - s_p r_p p_F - s_{ED} (r_e e_F + r_p p_F) - s_F e_F - \theta_F^* P_F (k_e F, k_p F, l_F)
- 0.2013 \, r_e e_F + 0.0502 \, r_p p_F + w_{F} l_F (0.2620)
\]

where in the case of frontier oil production,

\[ t_F = 0.46 \]

Therefore,

\[ T_F = t_F (1 - s_{RA}) + \theta_F^* \]

\[ t_e F = t_F (s_e + s_{ED} + s_{FE}) - 0.20133 \]

\[ t_p F = t_F (s_p + s_{ED}) + 0.0502 \]

and \[ t_l F = t_F (1 - s_{RA}) + 0.2620 \]

D. Non-Conventional Oil:

We have assumed a gross royalty rate for synthetic oil production (\( \theta_N^* \)) of 22 per cent (see Section 2.3.1 of the thesis). Therefore, net returns for non-conventional (or synthetic) oil production will be estimated to be:

\[ \Pi_N = \Pi_N (k_e N, k_p N, l_N) - r_e e_N - r_p p_N - w_{N} l_N - \theta_N^* P_N (k_e N, k_p N, l_N) \]
\[ + t_p \left[ e_N^* PF_N(K_{e_N}^*, \kappa_{p_N}^*, L_N^*) - (PF_N(K_{e_N}, K_{p_N}, L_N^*) - w_{L^*}L_N^*)s_{RA} \right] + s_{PRC} \left[ e_N^* PF_N(K_{e_N}^*, \kappa_{p_N}^*, L_N^*) - (PF_N(K_{e_N}, K_{p_N}, L_N^*) - w_{L^*}L_N^*)s_{RA} \right] - s_E (r_{e_{e_N}} + r_{p_{p_N}}) \]

where in the case of non-conventional oil,

\[ s_{SD} = 0.333 \]

(i.e., see Table 4.1).

So,

\[ t_N = e_N^* (1 - t_p r_{PRC}) + t_p + t_f (1 - s_{RA}) \]

\[ t_{e_N} = (t_f + t_p) s_E \]

\[ t_{p_N} = (t_f + t_p) (s_E + s_{SD}) \]

and \[ t_{L_N} = t_p + t_f (1 - s_{RA}) \]

E. Tertiary Oil:

Tertiary (or heavy) oil is assumed in this thesis to be produced in the province of Saskatchewan and therefore, is subject to the Saskatchewan corporate income tax rate (of 14 per cent) and the Saskatchewan (new) oil royalty formula (as described in section 2.3.1 of the thesis). In particular, the gross royalty liability for tertiary oil production (for the average well and the prevailing price of oil) is estimated to be:

\[ e_T^* = 0.35591 \]

Therefore, the net returns for tertiary oil producers is given by:

\[ \Pi_T = PF_T(K_{e_T}^*, K_{p_T}^*, L_T^*) - e_T^* e_{e_T}^* - r_{p_T}^* p_{T_T}^* - w_{L_T}^* L_T^* - e_T^* PF_T(K_{e_T}^*, K_{p_T}^*, L_T^*) \]
\[ + t_p [\theta^*_{PF_T}(K_{e_T}, K_{p_T}, L_T) - s_{RA}(PF_T(K_{e_T}, K_{p_T}, L_T) - w_T L_T)] \]
\[- (t_f + t_p)[(PF_T(K_{e_T}, K_{p_T}, L_T) - w_T L_T)(1-s_{RA}) - s_{ER} r K_{e_T} - s_{SD} r K_{p_T}] \]

So,

\[ T_T = \theta^*_T (1-t_p) + t_p + t_f (1-s_{RA}) \]
\[ t_{e_T} = (t_f + t_p)s_E \]
\[ t_{p_T} = (t_f + t_p)(s_D + s_{SD}) \]
and \[ t_{L_T} = t_p + t_f (1-s_{RA}) \]

2. POST-NEP NET RETURNS' EXPRESSIONS

A. Conventional Old and New Oil:

i) Foreign Firms:

The slightly modified oil royalty liabilities for conventional
oil producers are estimated to be:
\[ \theta^*_D = 0.44834 \]
\[ \theta^*_N = 0.31778 \]

Therefore, the net returns for foreign-owned conventional oil producers
(denoted by subscript, CF) will be given by;

\[ \Pi_{CF} = \delta^*_{CF}(K_{e_{CF}}, K_{p_{CF}}, L_{CF}) - r_{CF} K_{e_{CF}} - r_{CF} K_{p_{CF}} - w_{CF} L_{CF} - s_{RA}(PF_{CF}(K_{e_{CF}}, K_{p_{CF}}, L_{CF}) - w_{CF} L_{CF}) \]
\[ + t_p [\theta^*_{CF}(K_{e_{CF}}, K_{p_{CF}}, L_{CF}) - (\delta^*_{CF}(K_{e_{CF}}, K_{p_{CF}}, L_{CF}) - w_{CF} L_{CF})] \]
\[ + s_{ERC}(\theta^*_{CF}(K_{e_{CF}}, K_{p_{CF}}, L_{CF}) - (\delta^*_{CF}(K_{e_{CF}}, K_{p_{CF}}, L_{CF}) - w_{CF} L_{CF})) \]
\[ + s_{PRC}(\theta^*_{CF}(K_{e_{CF}}, K_{p_{CF}}, L_{CF}) - (\delta^*_{CF}(K_{e_{CF}}, K_{p_{CF}}, L_{CF}) - w_{CF} L_{CF})) \]
\[ (t_f + t_p)[(\delta^*_{CF}(K_{e_{CF}}, K_{p_{CF}}, L_{CF}) - w_{CF} L_{CF})(1-s_{RA}) - s_{D} r K_{e_{CF}} - s_{D} r K_{p_{CF}}] \]
\[ - (t_f + t_p)[(\delta^*_{CF}(K_{e_{CF}}, K_{p_{CF}}, L_{CF}) - w_{CF} L_{CF})(1-s_{RA}) - s_{D} r K_{e_{CF}} - s_{D} r K_{p_{CF}}] \]
\[-t_{RT}[\delta_{C}^{PF}CF(K_{eCC}, K_{PC}, t_{CF}) - w_{C}^{L_{CF}}]\]

So:

\[T_{\text{CF}} = \theta_i^\ast (1-t_p-s_{PRC}) + t_p + t_f(1-s_{RA}) + t_{RT}\]
\[t_{e_{CF}} = (t_f + t_p)(s_E + s_{ED})\]
\[t_{p_{CF}} = (t_f + t_p)s_D\]

and, \[t_{L_{CF}} = t_p + t_f(1-s_{RA}) + t_{RT}\]

where \(\theta_i^\ast\) = the old and new royalty liabilities respectively (i.e., \(i = \text{OC, NC}\))

ii) Canadian Firms:

A Canadian (old or new) conventional oil producer faces the same royalty liability as a foreign firm - but unlike the foreign firm, qualifies for exploration and development incentive grants. Therefore, the net returns for a Canadian (old or new) conventional oil producer will be given by:

\[\Pi_{CC} = \delta_{C}^{PF_{CC}}(K_{eCC}, K_{PC}, L_{CC}) - r_{eCC} - r_{p}K_{PCC} - w_{C}^{L_{CC}} - t_{RT}[\delta_{C}^{PF_{CC}}(K_{eCC}, K_{PC}, L_{CC}) - w_{C}^{L_{CC}}] + t_p[\theta_i^\ast \delta_{C}^{PF_{CC}}(K_{eCC}, K_{PC}, L_{CC}) + t_{f}\theta_i^\ast \delta_{C}^{PF_{CC}}(K_{eCC}, K_{PC}, L_{CC}) - w_{C}^{L_{CC}}(1-s_{RA})] + s_{PRC}[\theta_i^\ast \delta_{C}^{PF_{CC}}(K_{eCC}, K_{PC}, L_{CC}) - w_{C}^{L_{CC}}] + s_{ED}[\theta_i^\ast \delta_{C}^{PF_{CC}}(K_{eCC}, K_{PC}, L_{CC}) - w_{C}^{L_{CC}}(1-s_{RA})] - (s_E + s_{ED})(1-EG_{CC}r_{eCC} - s_{D}r_{p}K_{PC} - (1-DG_{CC}) + EG_{CC}r_{eCC} + DG_{CC}r_{p}K_{PCC}]

So:

\[T_{\text{CC}} = t_{RT} + \theta_i^\ast (1-t_p-s_{PRC}) + t_p + t_f(1-s_{RA})\]
\[ t_{eCC} = (t_f + t_p)(s_E + s_{ED})(1 - EG_{CC}) + EG_{CC} \]

\[ t_{pCC} = (t_f + t_p)s_D(1 - DG_{CC}) + DG_{CC} \]

and \[ t_{LCC} = t_{RT} + t_p + t_f(1-s_{RA}) \]

where \( EG_{CC} = 0.35 \) and \( DG_{CC} = 0.20 \).

B. Secondary Oil:

i) Foreign Firms:

The net returns expression for foreign secondary oil producers (given the features of the post-NEP tax regime as summarized in Table 4.2) is given by;

\[
\Pi_{SF} = \delta_{SF}^{PF}(e_{SF}^{K_p,SF}p_{SF}^{L_{SF}}) - e_{SF}^{K_p,SF} - r_{SF}^{K_p,SF} - w_{SF}^{L_{SF}} - t_{RT}^{[\delta_{SF}^{PF}(e_{SF}^{K_p,SF}p_{SF}^{L_{SF}}) - w_{SF}^{L_{SF}}]} \cdot e^*_{SF}^{[\delta_{SF}^{PF}(e_{SF}^{K_p,SF}p_{SF}^{L_{SF}}) - w_{SF}^{L_{SF}}]} + t_p^{[\delta_{SF}^{PF}(e_{SF}^{K_p,SF}p_{SF}^{L_{SF}}) - w_{SF}^{L_{SF}}]}s_{RA} \]

or;

\[
T_{SF} = t_{RT} + \delta_{SF}^{*}(1-t_p-s_{PRC}) + t_p + t_f(1-s_{RA}) \]

\[ t_{eSF} = (t_f + t_p)s_D \]

\[ t_{pSF} = (t_f + t_p)s_D \]

and \[ t_{LSF} = t_{RT} + t_p + t_f(1-s_{RA}) \]
ii) Canadian Firms:

Canadian-owned firms producing secondary oil qualify for a development grant (equal to 20 per cent of qualifying expenditures -- see Table 4.2) and face an Alberta oil royalty liability identical to the liability of a new conventional oil producer. Consequently, net returns for a (Canadian-owned) secondary oil producer is given by:

\[ \Pi_{SC} = \delta_{s}^{PF}_{SC}(K_{e_{SC}}, K_{p_{SC}}, L_{SC}) - r_{e_{SC}} + r_{p_{SC}} - w_{s_{SC}} - t_{RT}[\delta_{s}^{PF}_{SC}(K_{e_{SC}}, K_{p_{SC}}, L_{SC}) - w_{s_{SC}}] + t_{p}[\delta_{s}^{PF}_{SC}(K_{e_{SC}}, K_{p_{SC}}, L_{SC}) - w_{s_{SC}}]s_{RA} + s_{PRC}[\delta_{s}^{PF}_{SC}(K_{e_{SC}}, K_{p_{SC}}, L_{SC}) - w_{s_{SC}}]s_{RA}\]

\[ - s_{D}(r_{e_{SC}} + r_{p_{SC}})(1 - DG_{SC}) + DG_{SC}(r_{e_{SC}} + r_{p_{SC}}) \]

where \( DG_{SC} = 0.20 \) (i.e., see Table 4.2). Finally;

\[ T_{SC} = t_{RT} + \delta_{s}(1 - t_{p} - s_{PRC}) + t_{p} + t_{f}(1 - s_{RA}) \]

\[ t_{e_{SC}} = (t_{f} + t_{p})(1 - DG_{SC})s_{D} + DG_{SC} \]

\[ t_{p_{SC}} = (t_{f} + t_{p})(1 - DG_{SC})s_{D} + DG_{SC} \]

and \( t_{L_{SC}} = t_{RT} + t_{p} + t_{f}(1 - s_{RA}) \)

C. Frontier Oil:

i) Foreign Firms:

Frontier oil producers (both Canadian and foreign firms) are eligible to receive exploration incentive grants, have Petro-Canada
(or an alternative federal Crown corporation) "back-in" as a partner sharing in 25 per cent of the revenues and contributing 25 per cent of all costs (except for exploration costs).

The federal basic and progressive incremental royalty liability for a frontier oil producer will now differ by the type of firm (i.e., Canadian-owned or foreign-owned) operating on the Canada Lands (i.e., since one of the deductions from profits in the calculation of the progressive incremental royalty is notional federal corporate income taxes). Specifically, the total federal oil royalty liability for a foreign-owned firm (i.e., \( R_{FF} \)) operating in the frontier regions is estimated to be:

\[
R_{FF} = \theta_F^* \, P_{FF}(1-t_{PC}) - w_{FLFF}(0.2620)(1-t_{PC}) + \rho e_{e_{FF}}(0.07865)(1-E_{FF}) - r_p K_{p_{FF}}(0.11148)(1-t_{PC})
\]

where \( \theta_{FF}^* = 0.3220 \)

and \( t_{PC} = 0.25 \)

Therefore, the net returns for a foreign-owned frontier oil producer will be given by:

\[
\Pi_{FF} = P_{FF}(K_{e_{FF}}, K_{p_{FF}}, L_{FF})(1-t_{PC}) - r_p e_{e_{FF}} - (r_p K_{p_{FF}} + w_{FLFF})(1-t_{PC})
\]

\[
- t_{RT} [P_{FF}(K_{e_{FF}}, K_{p_{FF}}, L_{FF}) - w_{FLFF}(1-t_{PC}) - t_f [(P_{FF}(K_{e_{FF}}, K_{p_{FF}}, L_{FF})
\]

\[
- w_{FLFF}(1-s_{RA})(1-t_{PC}) - s_E r_p K_{e_{FF}}(1-E_{FF}) - s_D r_p K_{p_{FF}}(1-t_{PC})
\]

\[
- s_E r_p K_{e_{FF}} (1-E_{FF}) - q \, P_{FF}(K_{e_{FF}}, K_{p_{FF}}, L_{FF})(1-t_{PC})
\]

\[
- r_p K_{p_{FF}}(0.07865)(1-E_{FF}) + r_p K_{p_{FF}}(0.11148)(1-t_{PC}) + w_{FLFF}(0.2620)
\]

\[
(1-t_{PC}) + EG_{FF} r_p K_{e_{FF}}
\]
where $EG_{FF} = 0.25$ and $t_f = 0.46$. So:

$$T_{FF} = (t_{RT} + t_f(1-s_{RA}) + e_F^*)(1-t_{PC}) + t_{PC}$$

$$t_{e_{FF}} = EG_{FF} + (1-EG_{FF})[t_f(s_E + s_{ED}) - (0.07865)]$$

$$t_{p_{FF}} = [t_f s_D + 0.11148](1-t_{PC}) + t_{PC}$$

and

$$t_{L_{FF}} = [t_{RT} + t_f(1-s_{RA}) + 0.2620](1-t_{PC}) + t_{PC}$$

ii) **Canadian Firms:**

Canadian frontier oil producers qualify for development incentive grants and a much higher exploration incentive grant than foreign-owned firms. Consequently, total federal oil royalty liabilities for a Canadian-owned firm ($R_{FC}$) are given by:

$$R_{FC} = PF_{FC}(K_{e_{FC}},K_{p_{FC}}^{L_{FC}})(1-t_{PC})e_F^* + r_e e_{e_{FC}} (0.07865)(1-EG_{FC})$$

$$- r_p p_{FC} (1-t_{PC})(1-DG_{FC})(0.11148) - w_{L_{FC}}(1-t_{PC})(0.2620)$$

where $e_F^* = 0.3220$. So, net returns for a Canadian-owned firm operating in the frontier regions is given by:

$$\Pi_{FC} = PF_{FC}(K_{e_{FC}},K_{p_{FC}}^{L_{FC}})(1-t_{PC}) - r_e e_{e_{FC}} - r_p p_{FC} (1-t_{PC}) - w_{L_{FC}}(1-t_{FC})$$

$$- t_{RT}[PF_{FC}(K_{e_{FC}},K_{p_{FC}}^{L_{FC}}) - w_{L_{FC}}(1-t_{PC}) - t_e [PF_{FC}(K_{e_{FC}},K_{p_{FC}}^{L_{FC}})$$

$$- w_{L_{FC}}(1-s_{RA})(1-t_{PC}) - s_E e_{e_{FC}} (1-EG_{FC}) - s_D r_p p_{FC} (1-DG_{FC})(1-t_{PC})$$

$$- s_{ED} r_e e_{e_{FC}} (1-EG_{FC}) - r_F PF_{FC}(K_{e_{FC}},K_{p_{FC}}^{L_{FC}}) - r_e e_{e_{FC}} (0.07865)$$

$$+ r_p p_{FC} (1-t_{PC})(1-DG_{FC})(0.11148)+(0.2620)w_{L_{FC}}(1-t_{PC})$$
+ \text{DG}_{FC} \cdot r \cdot \text{p} \cdot \text{K}_{p_{PF}} \cdot (1-t_{PC})

where \text{DG}_{FC} = 0.20, \text{EG}_{FC} = 0.80 \text{ and } t_f = 0.46. \text{ Finally,}

\begin{align*}
T_{FC} &= [t_{RT} + t_f(1-s_{RA}) + \theta^*_F](1-t_{PC}) + t_{PC} \\
t_e_{FC} &= \text{EG}_{FC} + (1-\text{EG}_{FC})[t_f(s_E + s_{ED}) - 0.07865] \\
t_p_{FC} &= [t_f s_D(1-\text{DG}_{FC}) + 0.11148(1-\text{DG}_{FC}) + \text{DG}_{FC}](1-t_{PC}) + t_{PC}
\end{align*}

and

\begin{align*}
t_{L_{FC}} &= [t_{RT} + t_f(1-s_{RA}) + 0.2620](1-t_{PC}) + t_{PC}
\end{align*}

D. Non-Conventional Oil:

i) Foreign Firms:

Foreign-owned firms producing non-conventional oil fail to qualify for any incentive grants; consequently, their net returns expression is given by;

\begin{align*}
\Pi_{NF} &= \text{PF}_{NF}(K_{e_{NF}}, K_{p_{NF}}, L_{NF}) - r \cdot e_{NF} - r \cdot p \cdot p_{NF} - w \cdot L_{NF} - t_{RT} \cdot [\text{PF}_{NF}(K_{e_{NF}}, K_{p_{NF}}, L_{NF})] \\
&- w \cdot L_{NF} - e^*_{NF}(K_{e_{NF}}, K_{p_{NF}}, L_{NF}) + t_p \cdot [\theta^*_{NF}(K_{e_{NF}}, K_{p_{NF}}, L_{NF})] \\
&- (K_{e_{NF}}, K_{p_{NF}}, L_{NF}) \cdot s_{RA} \cdot s_{PRC} \cdot [\theta^*_{NF}(K_{e_{NF}}, K_{p_{NF}}, L_{NF})] \\
&- (t_f + t_p) \cdot [(K_{e_{NF}}, K_{p_{NF}}, L_{NF}) - w \cdot L_{NF}](1-s_{RA}) - s_E \cdot e_{NF} + r \cdot p \cdot p_{NF} \\
&- s_{SD} \cdot p \cdot p_{NF}
\end{align*}

where \theta^*_N = 0.220 \text{ and } s_{SD} = 0.333. \text{ Therefore,}

\begin{align*}
T_{NF} &= t_{RT} + \theta^*_N(1-t_p \cdot s_{PRC}) + t_p + t_f(1-s_{RA})
\end{align*}
\[ t_{e_{NF}} = (t_f + t_p)s_E \]
\[ t_{p_{NF}} = (t_f + t_p)(s_E + s_{SD}) \]

and
\[ t_{L_{NF}} = t_{RT} + t_p + t_f(1-s_{RA}) \]

ii) Canadian Firms:

A Canadian-owned firm producing non-conventional oil will qualify for an incentive grant equal to 20 per cent of qualifying expenditures (see Table 4.2). Consequently, the net returns expression is given by;

\[
\Pi_{NC} = \frac{PF_{NC}(K_{e_{NC}}, K_{p_{NC}}, L_{NC}) - r_p K_{p_{NC}} - r_p K_{e_{NC}} - w_{N_{NC}} - t_{RT} [PF_{NC}(K_{e_{NC}}, K_{p_{NC}}, L_{NC}) - w_{N_{NC}}]}{N_{NC}} + t_p [\hat{a}_{NC} PF_{NC}(K_{e_{NC}}, K_{p_{NC}}, L_{NC}) - w_{N_{NC}}] - \hat{a}_{NC} PF_{NC}(K_{e_{NC}}, K_{p_{NC}}, L_{NC}) + s_{PRC} [\hat{a}_{NC} PF_{NC}(K_{e_{NC}}, K_{p_{NC}}, L_{NC})]
\]

\[ - (t_f + t_p) [(PF_{NC}(K_{e_{NC}}, K_{p_{NC}}, L_{NC}) - w_{N_{NC}})(1-s_{RA}) - s_E r_p K_{e_{NC}} + r_p K_{p_{NC}}) (1-\epsilon_{NC}) - s_{SD}(r_p K_{p_{NC}} (1-\epsilon_{NC})) + \epsilon_{NC} [r_p K_{e_{NC}} + r_p K_{p_{NC}}] \]

where \( \epsilon_{NC} = 0.20 \) and \( \hat{a}_{NC} = 0.220 \). Then; 

\[ T_{NC} = t_{RT} + \hat{a}_{NC} (1-t_p s_{PRC}) + t_f (1-s_{RA}) + t_p \]

\[ t_{e_{NC}} = (t_f + t_p) s_E (1-\epsilon_{NC}) + \epsilon_{NC} \]

\[ t_{p_{NC}} = (t_f + t_p) (s_E + s_{SD}) (1-\epsilon_{NC}) + \epsilon_{NC} \]

and 

\[ t_{L_{NC}} = t_{RT} + t_f (1-s_{RA}) + t_p \]
E. Tertiary Oil:

i) Foreign Firms:

The (Saskatchewan) royalty liability of a tertiary oil producer is the same as in the pre-NEP period since \( \theta_T \) depends just on output (i.e., \( \theta_T^* = 0.35591 \)). The net returns expression then, of a foreign-owned tertiary oil producer is given by:

\[
\Pi_{TF} = \delta_T^{TF}(K_{c_{TF}}, K_{p_{TF}}, L_{TF}) - e_{c_{TF}} - r_p K_{p_{TF}} - w_{LT_{TF}} - t_{RT}[\delta_T^{PF_TF}(K_{c_{TF}}), K_{p_{TF}}, L_{TF} - \delta_T^{PF_TF}(K_{c_{TF}}), K_{p_{TF}}, L_{TF} + t_p[\delta_T^{PF_TF}(K_{c_{TF}}), K_{p_{TF}}, L_{TF} - s_{RA}(K_{c_{TF}}, K_{p_{TF}}, L_{TF} - w_{LT_{TF}}) - (t_f + t_p)[\delta_T^{PF_TF}(K_{c_{TF}}), K_{p_{TF}}, L_{TF} - w_{LT_{TF}}(1-s_{RA}) - s_D r_p K_{p_{TF}} - s_{SD} r_p K_{p_{TF}}]]
\]

where \( t_p = 0.14 \). So:

\[
T_{TF} = t_{RT} + \theta_T^*(1-t_p) + t_p + t_f(1-s_{RA})
\]

\[
e_{c_{TF}} = (t_f + t_p) s_E
\]

\[
t_{p_{TF}} = (t_f + t_p) (s_D + s_{SD})
\]

and,

\[
t_{L_{TF}} = t_{RT} + t_p + t_f(1-s_{RA}).
\]

ii) Canadian Firms:

A Canadian-owned firm producing tertiary or heavy oil in the post-NEP period will qualify for an incentive grant equalling 20 percent of qualifying expenditures (see Table 4.2). Therefore, the net returns expression is given by:

\[
\Pi_{TC} = \delta_T^{PF_{TC}}(K_{c_{TC}}, K_{p_{TC}}, L_{TC}) - e_{c_{TC}} - r_p K_{p_{TC}} - w_{LT_{TC}} - t_{RT}[\delta_T^{PF_{TC}}(K_{c_{TC}})
\]

\[ K_{p_{TC}}, L_{TC} - w_{-L_{TC}} \] - \[ \theta_T \delta_{T}^{PF_{TC}}(K_{e_{TC}}, K_{p_{TC}}, L_{TC}) + t_p \] \[ \delta_{T}^{PF_{TC}}(K_{e_{TC}}) \]

\[ K_{p_{TC}}, L_{TC} - s_{RA}(\delta_{T}^{PF_{TC}}(K_{e_{TC}}, K_{p_{TC}}, L_{TC}) - w_{-L_{TC}}) - (t_f + t_p) \] \[ \delta_{T}^{PF_{TC}}(K_{e_{TC}}) \]

\[ K_{p_{TC}}, L_{TC} - w_{-L_{TC}}(1-s_{RA}) - r e_{TC} e_{TC} (1-E_{G_{TC}}) - s_{DP} r_{DP} (1-E_{G_{TC}}) \]

\[ - s_{SD} r_{DP} (1-E_{G_{TC}}) + E_{G_{TC}}(r e_{TC} e_{TC} + r p_{DP}) \]

where \( E_{G_{TC}} = 0.20 \). So,

\[ T_{TC} = t_{RT} + \theta_T (1-t_p) + t_p + t_f(1-s_{RA}) \]

\[ t_e_{TC} = (t_f + t_p)s_{DP} (1-E_{G_{TC}}) + E_{G_{TC}} \]

\[ t_{P_{TC}} = (t_f + t_p)(s_{DP} + s_{SD})(1-E_{G_{TC}}) + E_{G_{TC}} \]

and,

\[ t_{L_{TC}} = t_{RT} + t_p + t_f(1-s_{RA}) \].
APPENDIX II TO CHAPTER 4

AN ALTERNATIVE DIAGRAMMATIC VIEW OF THE EFFICIENCY LOSS

It is the purpose of this appendix to derive an equivalent representation of the ensuing efficiency loss associated with the production of a given type of oil (j) and due to the imposition of a given tax regime as identified in Figure 4.1 in the text of the thesis. To simplify this alternative diagrammatic approach we assume that in order to produce oil type j, a firm employs but one variable input -- for illustrative purposes, let this input be exploration capital, \( K_{e_j} \).

Given this simplifying assumption, a profit-maximizing firm confronted with the value-of-marginal product curve identified as \( VMP_j \) in Figure A4.1 and facing a fixed input price \( (r_e) \), will employ \( K_{e_0} \) units of exploration capital. Consequently, the value of total resource rents (i.e., excess profits) associated with the production of oil type j in the absence of any taxes or subsidies will be given by area ABC in Figure A4.1. That is, the total value of production revenues are given by \( OBCK_{e_0} \), whereas total input costs are given by \( OACK_{e_0} \) generating a difference -- equalling the value of resource rents -- of area ABC.

**The Effects of Imposing a Pure-Profits Tax:**

Now suppose the government sector imposes a pure-profits tax on the production of oil type j, so the output tax rate \( (T_j) \) is set equal to the input subsidy rate \( (t_{e_j}) \). In Figure A4.1 this implies the VMP curve shifts inward to \( (1-T_j)VMP_j \) while the net cost of exploration inputs falls to \( (1-t_{e_j})r_e \). Consequently, with the imposition of a pure-profits tax (where \( T_j = t_{e_j} \)) the profit-maximizing employment level...
of exploration capital (after taxes) employed in the production of oil
type \( j \) remains unchanged at \( K_{e_0} \).

Furthermore, the efficiency loss associated with the production
of oil type \( j \) can be easily shown to be zero. Recalling the definition
of the efficiency loss in the text of the thesis as the change in the
value of total resource rents (i.e., industry profits plus net government
tax revenues), then following the introduction of a pure-profits tax
regime,

\[
\text{a) New Total Industry Profits: } = [OFEK_{e_0} - ODEK_{e_0}] = DFE
\]

and \( \text{b) New Government Tax Revenues = } [FBCE - DACE] = [ABC - DFE] \)

Therefore, the value of total resource rents after the introduction of
the pure-profits tax remains at \( ABC \) indicating no efficiency loss arising
from the imposition of a pure-profits tax (i.e., \( d[\Pi_j + \tau_j] = 0 \) using the
terminology employed in the text of the thesis).

FIGURE A4.1

THE EFFICIENCY EFFECTS OF A PURE-PROFITS TAX
The Efficiency Loss in the Case where $T_j > t_e_j$

As just indicated there is no resulting efficiency loss when the government sector imposes a pure-profits tax. But what will be the efficiency effects of imposing a non-pure-profits tax (i.e., either imposing $T_j > t_e_j$ or $T_j < t_e_j$)? Suppose for illustrative purposes, the public sector imposes a revenue tax rate ($T_j$) larger than the input subsidy rate. The efficiency effects of this new tax regime can be derived with the aid of Figure A4.2. With a larger revenue tax rate (i.e., $T_j > t_e_j$) the after-tax VMP curve will shift inward to a greater extent than the shift downward in the net input cost curve. Consequently, the profit-maximizing employment of exploration capital will fall to $K_{e_1}$ -- at point G in Figure A4.2 (i.e., the intersection of the after-tax VMP curve and the net after-subsidy cost of exploration capital).

The value of industry profits then will be given by the difference between total after-tax production revenues less total after-subsidy input costs. Or,

$$\text{Net Industry Profits} = [\text{OHGK}_{e_1} - \text{ODGK}_{e_j}] = \text{DHG}$$

$$(\Pi_j)$$

The total net tax revenues of the government sector will similarly be given by;

$$\text{Net Government Tax Revenues} = [\text{HBJG} - \text{DAKG}] = [\text{ABJK} - \text{DHG}]$$

$$(\tau_j)$$

Therefore, total resource rents after the imposition of this new tax regime, characterized by $T_j > t_e_j$, is given by;

$$[\Pi_j + \tau_j] = \text{ABJK}$$

Consequently, since the imposition of this new tax regime relative to
the pure-profits tax regime generates a lower value of total resource rents, by the area KJC, then according to our definition of the efficiency loss it follows:

$$E.L.\_j = d(\pi_j + \tau_j) = KJC$$

which is analogous to the shaded area (representing total efficiency loss) in Figure 4.1 in the text of the thesis.

FIGURE A4.2
THE EFFICIENCY LOSS IN THE CASE WHERE $t_j$ EXCEEDS $t_{ej}$
CHAPTER 5

A FRAMEWORK FOR ANALYZING OPTIMAL TAX AND SUBSIDY RATES

5.1 INTRODUCTION

In the previous chapter we presented a framework for identifying the factor employment effects resulting from the imposition of a given regime of tax and subsidy rates on the Canadian oil industry. In that essay we assumed that the pure-profits tax in traditional economic theory would be the optimal (non-distorting) tax regime. A comparison was then made of the implied factor employment pattern if a pure-profits tax were in effect and the factor employment pattern that emerges given the actual pattern on tax and subsidy rates is in effect. Any differences that were observed were classified, therefore, as being distortive and represented an efficiency loss for the Canadian economy. In this chapter, we re-examine the central assumption of the previous chapter. In particular, we present a framework which enables us to state that, in fact, the pure-profits tax may not be optimal for the Canadian oil industry.

Briefly, the methodology adopted in this chapter to address the issue of optimal tax regimes for the domestic oil industry is as follows. We employ a simplified version of the static model of the oil industry employed in the preceding essay and introduce two utility functions—one for the federal government and one to represent the preferences of the oil-producing provincial governments. The utility functions for these two levels of government need not contain the same arguments reflecting the (assumed) differences in the development objectives of the two levels of government. Then, by assuming each level of government attempts to
maximize their total utility, subject to a (profit-maximizing) production constraint for the firms in the domestic oil industry, we derive a pattern of optimal tax and subsidy rates for each level of government.¹

There are several possible arguments we could employ in our federal and provincial utility functions beyond simply including the own revenues of each level of government. For example, by including the total current oil output (Q) as an argument in the federal government's utility function we can represent the desires of the federal government to minimize our reliance on foreign oil supplies. Alternatively, we could envision the federal government as desiring to maximize the information available to the oil industry (as well as themselves) regarding the potential production characteristics of each pool of oil. To proxy this federal preference we could include as one of the arguments in the federal utility function the stock of exploration capital employed by the oil industry. Similarly, with respect to the federal government's utility function, we could include as one of the arguments in its utility function the ratio of "Canadian" firms' oil production to "foreign-owned" firms' oil production. By doing so, this ratio would reflect the significant shift in federal oil policy via the introduction of the Petroleum Incentives Program as announced in the NEP to Canadianizing the domestic oil industry.² Finally, it could also be possible depending of the type(s) of oil assumed to exist, that the federal government has in its utility function the production of frontier oil (only) reflecting its exclusive access to taxing these revenues.

In the case of the oil-producing provincial government (e.g. Alberta) we can also envision the presence of additional arguments in its utility function (beyond the inclusion of its own oil revenues). For example, we could include the flow of labour services employed in the production of oil as an argument in the provincial utility function. The rationale
for including labour services in the province's utility function assumes that the larger the labour force that is employed in the oil industry, the larger will be total provincial employment (i.e., either the provincial residents are employed directly in oil production or indirectly via the spin-off effects on the service industries) and therefore, the higher will be the total utility of the provincial government.

Although the potential utility arguments for both levels of government identified above warrant consideration, the inclusion of all these terms would introduce too many dimensions to the problem and present obstacles for generating any meaningful results. For example, with the three-input model used in the last chapter and the presence therefore, of three input subsidy rates as well as an output or revenue tax, produces a four-dimensional reaction function for each level of government which is clearly unworkable. Consequently, there is a need to simplify the analysis. Therefore, in this chapter, we begin with a very simple model (i.e., only one input in the production function, only one tax instrument for each level of government and one argument only in each utility function) and gradually introduce more generalizations into the analysis (such as more than one argument in the federal utility function, or more than one input, or more than one tax instrument for each level of government). At each stage, however, the results are identified and their significance discussed.

Each of these exercises is performed under two alternative behavioural assumptions. Initially, we assume that each level of government takes the other level of government's tax and subsidy rates as given (i.e., a Nash-type behaviour) and secondly, we investigate the pattern of optimal tax (and subsidy rates, where applicable) for each level of
government under the assumption they act co-operatively and therefore, maximize their joint (total) utility. A comparison of the optimal tax regime under both behavioural assumptions is then made, and our observations and conclusions are presented.

The outline of the remainder of this chapter is as follows. In section 5.2, the very simplified model initially employed (with only one input in the production function, one tax instrument and one argument in each government's utility function) is described. In section 5.3 we derive the pattern of Nash and co-operative tax rates for both levels of government. Included, as well, in this section will be a discussion of the impact of having more than one jurisdiction involved in taxing the revenues of the domestic oil industry. In section 5.4 we build on our analysis of section 5.3 by introducing an additional argument in the federal utility function and compare the resulting optimal tax regime with the optimal tax derived in section 5.3 (under both the Nash and co-operative behavioural assumptions). The analysis is extended once again in section 5.5 by introducing a second tax instrument (a subsidy rate) for each level of government while retaining the second argument in the federal government's utility function. Finally, in section 5.6, we summarize the results of the exercises performed in the three previous sections and analyze their empirical significance.

5.2 A VERY SIMPLE MODEL OF THE DOMESTIC OIL INDUSTRY

The model we employ in this exercise is a simplified version of the perfect-certainty model employed in the preceding chapter. In particular, rather than identify six types of oil (differentiated by the technique or
location of production) as we did in the previous chapter, we will assume in this chapter that there is only one type of oil. That is, in the analysis that follows, for illustrative purposes, we will focus on the production of (only) old conventional oil located in the province of Alberta.\textsuperscript{3}

Furthermore, we will simplify the model even more by assuming oil is produced using only one input (e.g., exploration capital) rather than the three inputs employed in the model used in the previous chapter. Therefore, the quantity of oil produced at any point in time will be a function of the stock of exploration capital employed (in present discounted value terms). i.e.,

\[ Q = F(K_e) \]

where \( Q \) = quantity of (old conventional) oil produced and \( K_e \) = the present discounted value of the stock of exploration capital employed and evaluated in the current period.

In addition, we also retain the following assumptions from the previous chapter;

i) Oil producers are assumed to be "integrated firms" engaged in exploration, development and production activities,

ii) the oil producer is assumed to be exploring, developing and producing on lots big enough so that the producer owns the whole pool of oil located on his property. In other words, there are no spillover effects from one producer's activities to influence his neighbour's decisions (i.e., no market failures).\textsuperscript{4}

iii) it is assumed that the production function identified above exhibits decreasing returns to scale,

iv) the producers are assumed to be facing a perfectly elastic supply of exploration capital so the factor price \( (r_e) \) is given and constant. This assumption rules out any possible factor supply constraints facing the producers and therefore, any input subsidy (designed to increase the employment of exploration capital) offered by either the federal or the oil-producing provincial governments will not be rendered ineffective by the existence of factor supply constraints,
and v) finally, we retain the assumption that oil producers strive to maximize their net returns where net returns are defined as total revenues less exploration capital expenses, and less any federal and/or provincial taxes and royalties.

Before proceeding with the analysis the reader must be forewarned to interpret the results presented below with caution. Since the notion of optimality for a given tax regime employed in this chapter will be based on the assumption that the respective level of government is attempting to maximize a specific utility function (subject to various constraints identified below) then the results generated can not be interpreted as being definitive. Rather they are to be interpreted as being the results of a hypothetical exercise (i.e., they are only definitive under the "what if" scenario suggested below). Specifically, the results will only be definitive if the arguments we assume to be contained in each government's utility function are appropriately summarizing the preferences of each level of government (regarding the development pattern of the domestic oil industry). As well, the results will only be definitive if our assumption concerning the behaviour pattern of the two levels of government is appropriate (i.e., a non-cooperative Nash-type behaviour or a co-operative, joint-utility-maximizing behaviour). Nevertheless, keeping this warning in mind, we can proceed with the analysis by identifying the assumed utility functions for both levels of government.

As suggested in the introduction to this chapter, there are a variety of potential arguments to be included in each level of government's utility function. However, initially, in this very simplified model we begin by simply assuming that each level of government attempts to maximize their own oil-related revenues. Specifically then, the utility functions for both the federal and provincial governments can be
represented as;

\[ U^f = U^f(R^f) \]

and

\[ U^P = U^P(R^P) \]

where \( R^f \) and \( R^P \) are the federal government's and provincial government's oil-related revenues respectively. To simplify the analysis, we have assumed that the oil revenues generated by each level of government are a result of imposing a revenue or output tax rate only. Letting the revenue tax for the federal and provincial governments be \( T^f \) and \( T^P \) respectively, then the definitions of \( R^f \) and \( R^P \) will be;

\[ R^f = P F(K_e) T^f \]

where \( P \) represents the price of oil

and

\[ R^P = P F(K_e) T^P \]

Within the context of the pre-NEP period this assumption is quite representative of the source of provincial oil revenues since the vast majority of provincial oil revenues are generated by the imposition of an oil royalty -- which is simply a revenue tax. Unfortunately, this simple definition of federal revenues is less representative since the major source of federal oil revenues is the corporate income tax which, of course, is a profits tax and not simply a revenue tax.\(^5\) We will return to this discussion in the final section of this chapter.

Given these assumptions and the specifications of the model, we can now turn to the task of deriving the optimal revenue tax rates for each level of government in both the Nash and co-operative models.

5.3. OPTIMAL PATTERN OF TAXES IN THE SIMPLE MODEL UNDER NASH AND CO-OPERATIVE BEHAVIOURAL ASSUMPTIONS

5.3.1 Nash Equilibrium

The federal government in our model under an assumption of Nash-
type behaviour attempts to maximize its own utility function assuming
the provincial government will not alter its tax rate in response to any
federal tax rate changes AND subject to the constraint that the oil in-
dustry maximizes its net returns (as defined above). Therefore, the
federal government attempts to solve the following programming problem:

Maximize \( U^f(R^f) = U^f(PF(K_e)T^f) \)

subject to \( PF'(1-T^f-T^p) = r_e \)

where \( T^p \) can be treated as a constant (as well as \( P; r_e \)) and where (2) is
the traditional value of marginal product condition for the oil firms
upon maximizing their net returns. Briefly, the solution to this problem
is obtained by first differentiating both (1) and (2) to obtain;

(1.1) \( dU^f = U^f' (PF(K_e) dT^f + PF'(K_e) T^f dK_e) \)

and

(2.1) \( PP'(1-T^f-T^p) dK_e - PF'(dT^f) = 0 \)

or from (2.1) we can obtain;

(2.2) \( \frac{dK_e}{dT^f} = \frac{F'((1-T^f-T^p)^{-1}}{F''} < 0 \)

Then dividing both sides of (1.1) by \( dT^f \) and substituting in (2.2) we
can write;

(1.2) \( \frac{dU^f}{dT^f} = \frac{U^f'[PF + PF'T^f F'((1-T^f-T^p)^{-1})]}{F''} = 0 \)

Therefore, from (1.2) the optimal federal tax rate is given to be;

(1.3) \( T^f = \frac{-FF''(1-T^f-T^p)}{F'^2} \geq 0 \)

or, letting \( \alpha = -FF''/F'^2 > 0 \), we can simplify (1.3) to become;

(1.4) \( T^f = \left[ \frac{\alpha}{1 + \alpha} \right] (1-T^p) \)

In words, since \( T^p \) is assumed to be constant (given the Nash behavioural
assumption then the optimal federal revenue tax will change as $\alpha$ changes which in turn, will generally change when the stock of exploration capital employed by the domestic oil industry changes. To see this, consider:

$$\frac{d\alpha}{dK_e} = \frac{d[-FF'']}{FF^2} = \frac{-F^2[F'F'' + F''F'] - FF'F''F''}{F^4}$$

Since $F'' < 0$ and $F'''$ is likely to be positive, then the sign of $d\alpha/dK_e$ is typically indeterminate. However, if we assume, for simplicity, that we have a Cobb-Douglas production function of the form:

$$F(K_e) = K_e^\beta$$

where $\beta < 1$

then

$$\alpha = \frac{-FF''}{F^2} = \frac{-K_e^\beta \beta(\beta-1)K_e^{\beta-2}}{\beta K_e^{(\beta-1)^2}}$$

or simplifying yields;

$$\alpha = \frac{(1 - \beta)}{\beta} > 0$$

Therefore, assuming a Cobb-Douglas production function, produces the result that $\alpha$ is a constant and is positive. The significance of this result is that the federal government's Nash reaction curve will then be linear (i.e., a constant slope). In fact, from (1.4) we can see that the slope of the federal government's reaction curve will be given by;

$$\frac{dt^f}{dt^p} = \frac{-\alpha}{1 + \alpha}$$

To summarize, therefore, the federal government's Nash reaction curve is linear, negatively sloped and its slope has an absolute value of less than one.

The Provincial Optimum Tax Rate -- Nash Model

If we repeat this procedure for the provincial government (i.e.,
maximize \( U^T(\theta^K, T^P) \) subject to (2) but now treat \( T^f \) as a constant) we will obtain the following expression for the optimal provincial revenue tax.

\[
(5) \quad T^p = \left[ \frac{\alpha}{I + \alpha} \right] (1 - T^f)
\]

so \( (5.1) \quad dT^p = \left[ \frac{\alpha}{I + \alpha} \right] dT^f \)

Again, however, assuming a Cobb-Douglas production function implies that the provincial government's Nash reaction curve will also be linear, negatively sloped, but now its slope has an absolute value greater than one.

**Diagramatic Representation of Nash Equilibrium**

Given the solutions for the optimal federal and provincial revenue taxes are given by (1.4) and (5) we can derive a Nash reaction curve (which we have already shown to be linear) for both the federal and provincial governments. These reaction curves denoted by \( RC_f \) and \( RC_p \) respectively, are displayed in Figure 5.1. The Nash equilibrium therefore, in this simple model will occur at the intersection of \( RC_f \) and \( RC_p \) and is denoted by point \( N \) in Figure 5.1 with the resulting optimal tax rates for the federal and provincial governments being \( T^f_N \) and \( T^p_N \) respectively.

**FIGURE 5.1 DIAGRAMATIC REPRESENTATION OF THE NASH EQUILIBRIUM (THE SIMPLE MODEL)**

![Diagram](image-url)
It should be noted that this Nash equilibrium is a stable equilibrium. That is, if for any reason we move away from point N (e.g., the province increases their revenue tax rate to $T^f_0$ then the new optimal federal tax rate in light of $T^f_0$ will be $T^f_0$ (which is denoted by point A on the federal government's reaction curve). Consequently, the provincial government, taking $T^f_0$ as the new federal revenue tax rate will adjust its rate to $T^f_1$ and as a result we will find the new combination of output taxes places us at point B on the provincial government's reaction curve. However, even at point B the federal government will be encouraged to alter its tax rates once again. In summary, therefore, if for some reason we found ourselves at a point like A, the responses of both levels of government will provide an adjustment, following a stepping-stone approach (i.e., points A, B, C etc.) which will return us to our Nash equilibrium at point N.

Finally, to obtain the value of $T^f_N$ and $T^D_N$ (our Nash equilibrium tax rates) we simply solve for the intersection of $RC_f$ and $RC_p$. Given the equations for the federal and provincial reaction curves are represented by;

$$RC_f: \quad T^f = \left[ \frac{a}{1 + a} \right] - \left[ \frac{a}{1 + a} \right] T^p$$

and

$$RC_p: \quad T^f = 1 - \left[ \frac{1 + a}{a} \right] T^p$$

the Nash equilibrium will imply that both the federal and the oil-producing provincial governments impose the same revenue tax rate. i.e.,

$$T^f + T^p = \left[ \frac{a}{1 + 2a} \right]$$

or substituting for $a$ from (4.1) yields,

$$T^f + T^p = \frac{(1 - \beta)}{(2 - \beta)}$$

where $\beta < 1$, so $T^f$, $T^p$ are $>0$. 
5.3.2 Co-operative Equilibrium Tax Rates -- Simple Model.

A Diagrammatic Representation:

In order to demonstrate the existence of an equilibrium set of co-operative revenue tax rates we can examine the utility functions of each level of government more closely and specifically, derive "tax indifference curves" for each level of government. By so doing, we can show by virtue of the properties of these indifference curves and given the diagrammatical representation of the Nash equilibrium, that an area of mutual gain exists. Consequently, if the two levels of government co-operate in setting their revenue tax rates both parties will be made better off.

To begin, the tax indifference curves defined below for the federal (provincial) government will be defined as combinations of federal and provincial revenue tax rates, $T^f$ and $T^p$, where the level of federal (provincial) total utility is held constant. Specifically, the federal tax indifference curves are generated by re-working the federal programming problem but now allowing $T^p$ to vary. Therefore, equation (2.1) becomes;

\[(2.1.1) \quad PF''(1-T^f+T^p)dK_e = PF'(dT^f + dT^p) = 0\]

so

\[(2.1.2) \quad dK_e = \frac{F'(1-T^f+T^p)^{-1}(dT^f + dT^p)}{F''} \]

Replacing $dK_e$ in (1.1) with this last expression we obtain;

\[(1.1.1) \quad dU^f = U^f\left[PFDT^f + PF'T^f(F'(1-T^f+T^p)^{-1}(dT^f + dT^p))\right]\]

Then setting $dU^f = 0$ (i.e., from the definition of the federal tax indifference curve) we then have;
\[(1.1.2) \quad \left[ F + \frac{T_{F}^{2}}{F''(1-T_{f}-T_{P})} \right] dT_{f} + \left[ \frac{T_{F}^{2}}{F''(1-T_{f}-T_{P})} \right] dT_{P} = 0 \]

Finally, multiplying both sides of (1.1.2) by \( F''(1-T_{f}-T_{P}) \) and then dividing through by \( F_{f}^{2} \) and rearranging, we can obtain the following expression for the slope of the federal government's tax indifference curve.

\[(1.1.3) \quad \frac{dT_{f}}{dT_{P}} \bigg|_{U_{f}} = -\frac{T_{f}}{\frac{FF''(1-T_{f}-T_{P}) + T_{f}}{F_{f}^{2}}} \]

Therefore, the slope of the federal government's tax indifference curve will depend on the sign of the denominator in (1.1.3). Specifically, the federal tax indifference curve will be positively sloped if and only if:

\[ T_{f} < -\frac{FF''(1-T_{f}-T_{P})}{F_{f}^{2}} \]

Or, iff,

\[ T_{f} < \frac{a}{1+a} (1-T_{P}) \]

Or, finally, a representative federal tax indifference curve will be positively sloped if and only if \( T_{f} \) is less than the Nash value of \( T_{f} \) (i.e., if the value of \( T_{f} \) lies below the federal Nash reaction curve). Alternatively, if the value of \( T_{f} \) is greater than the Nash value of \( T_{f} \), a representative federal tax indifference curve will be negatively sloped.

Therefore, the family of federal tax indifference curves will look like those displayed in Figure 5.2 below with the additional property that \( \bar{U}_{2} > \bar{U}_{1} > \bar{U}_{0} \).
If we repeated this analysis for the oil-producing provincial government (only setting \( dU^P = 0 \)) we could derive a family of provincial tax indifference curves displayed in Figure 5.3 below with similar properties to the federal tax indifference curves. That is,

i) a representative tax indifference curve of the provincial government will be positively sloped where \( T^P \) is less than the Nash value of \( T^P \),

ii) when \( T^P \) exceeds the Nash value of \( T^P \) the representative tax indifference curve for the provincial government will be negatively sloped, and finally,

iii) it follows that \( \bar{U}^P_2 > \bar{U}^P_1 > \bar{U}^P_0 \) in Figure 5.3 below.
Finally, by combining the tax indifference curves for both levels of government with the results of the Nash equilibrium summarized in Figure 5.1 above, we can show (in Figure 5.4) that there exists a region of $T_f^*$ and $T^P$ combinations which will be pareto superior to the Nash equilibrium rates (point N). Consequently, if both levels of government behave in a co-operative manner, the welfare of both parties can be improved. In other words, a co-operative solution exists and will be found in the hatched region of Figure 5.4 (such as point C).

**Figure 5.4  The Existence of a Co-operative Solution**

ii) The Co-operative Equilibrium -- The Simple Model:

To derive the co-operative equilibrium algebraically we must add to the federal government's programming problem (above) the constraint that $U^P = \bar{U}^P$. Therefore, the co-operative solution will be given by;

Maximize $U^f(R^f) = U^f(PF(K_e)T_f)$

subject to $PF'(1-T_f^*-T^P) = r_e$

and $U^P(PF(K_e)T^P) = \bar{U}^P$
Differentiating (1), (2) and (6) where now both $T^P$ and $T^f$ may vary yields:

\begin{equation}
(1.1) \quad dU^f = U^f (PFdT^f + PF'T^f dK_e) \tag{1.1}
\end{equation}

\begin{equation}
(2.3) \quad PF''(1-T^f-T^P) dK_e - PF'(dT^f + dT^P) = 0 \tag{2.3}
\end{equation}

and \begin{equation}
(6.1) \quad U^P (PFdT^P + PF'T^P dK_e) = 0 \tag{6.1}
\end{equation}

From (6.1) we have:

\begin{equation}
(6.2) \quad \frac{dT^P}{dK_e} = - \frac{F'T^P}{F} \tag{6.2}
\end{equation}

Dividing both sides of (2.3) by $dK_e$ and substituting (6.2) into this expression yields:

\begin{equation}
(2.4) \quad PF''(1-T^f-T^P) - PF' \frac{dT^f}{dK_e} + \frac{PF'T^P}{F} = 0 \tag{2.4}
\end{equation}

so

\begin{equation}
(2.5) \quad \frac{dT^f}{dK_e} = \frac{F''(1-T^f-T^P)}{F'} + \frac{F'T^P}{F} \tag{2.5}
\end{equation}

Finally, dividing (1.1) by $dK_e$ and substituting (2.5) yields:

\begin{equation}
\frac{dU^f}{dK_e} = U^f [PF(F''(1-T^f-T^P) + \frac{F'T^P}{F}) + PF'T^f] = 0 \tag{2.6}
\end{equation}

which gives us;

\begin{equation}
(2.6) \quad T^f = - \frac{PF''(1-T^f-T^P)}{F'^2} - T^P \tag{2.6}
\end{equation}

or, finally,

\begin{equation}
(2.7) \quad T^f = \left[T - \frac{\alpha}{1+\alpha}\right] - T^P \tag{2.7}
\end{equation}

Therefore, in the co-operative solution, the sum of the federal and provincial revenue tax rates, given the assumption of a Cobb-Douglas production function, will equal a constant $[\alpha/(1+\alpha)]$ or, from (4.1), (1-\beta), where $\beta < 1$. 
Diagrammatically, equation (2.7) defines a linear locus of potential co-operative equilibrium tax rates with a slope of -1 and a vertical intercept of $\alpha/(1+\alpha)$. This locus of points is referred to as CO in Figure 5.5 below.

**Figure 5.5** Diagrammatic Representation of a Co-operative Equilibrium

5.3.3 A Comparison of the Nash and Cooperative Equilibrium Tax Rates—In the Simple Model

From Figure 5.5, given the linear reaction curves and linear co-operative equilibrium locus, it is clear that by setting revenue tax rates co-operatively the combined tax rates (i.e., $T^f + T^p$) will be less than the resulting Nash equilibrium tax rates. One way we can demonstrate this is to assume in the co-operative situation the provincial government, for example, maintains its Nash revenue tax rate which was (equal to the federal Nash rate and) shown earlier to be:

$$T^p_N = \frac{-\alpha}{1 + 2\alpha}$$

Then, substituting this value of $T^p$ into (2.7) we can derive the result-
ing federal revenue tax rate in our co-operative model \( T_{CO}^{f} \) which will be:

\[
T_{CO}^{f} = \left[ \frac{\alpha}{1 + \alpha} \right] - \left[ \frac{\alpha}{1 + 2\alpha} \right]
\]

or

\[
T_{CO}^{f} = \left[ \frac{\alpha}{1 + \alpha} \right] \cdot \left[ \frac{\alpha}{1 + 2\alpha} \right]
\]

Therefore, since \( \alpha/(1+\alpha) \) is < 1, then the resulting federal revenue tax rate in the co-operative model is less than the corresponding federal rate in the Nash model. Consequently, the sum of the federal and provincial revenue tax rates in the co-operative model is, in fact, less than the sum of \( T_{CO}^{f} + T_{CO}^{p} \) in the Nash model.

Put another way, even in this very simple model with only one input in the production function, one tax instrument available for each level of government, and one argument in the utility function for each level of government we find that non-co-operative taxation leads to over-taxation (relative to the co-operative solution) and correspondingly, an underproduction of Canada's oil reserves. Or, yet again, given that in a co-operative situation we really only have one level of government effectively, then a corollary of this observation is that the existence of more than one level of jurisdiction with powers of taxation on the oil industry, will generate a higher combined tax effort than would occur if only one level of jurisdiction existed. In the context of Canadian energy policy this result implies that unless it can be demonstrated that the federal and oil-producing provincial governments (which are both awarded taxing powers over the domestic oil industry in the Canadian constitution) are behaving in a co-operative manner in establishing their tax rates then there will be an efficiency loss generated (due to the lower output rate).
We will elaborate further on this discussion in the concluding section of the chapter.

5.4 MODEL II: EXTENSION TO INCLUDE ADDITIONAL ARGUMENTS IN THE GOVERNMENT UTILITY FUNCTIONS

The conclusion from our analysis of the very simple model was that it is quite possible, in the Canadian context, that an efficiency loss exists -- that is, the domestic oil industry is overtaxed relative to a co-operative situation. In this section of the paper we wish to examine the impact of assuming one level of government, for example the federal government, is not simply interested in maximizing its own oil-related revenues. Rather, we will assume in this section that the federal government is also interested in maximizing current domestic oil production in order to minimize Canada's present reliance on foreign oil imports. Consequently, we replace the simple federal utility function employed in the last section with a federal utility function that includes both federal oil-related revenues and oil output. That is, the federal utility function is now given by:

\[ U^f = U^f(R^f, Q) \]

or, given our definitions of \( R^f \) and \( Q \),

\[ U^f = U^f(PF(K_e)T^f, F(K_e)) \]

Furthermore, we are going to make a further simplifying assumption with respect to this federal utility function. We will assume that \( U^f \) is an additive utility function so that the ratio of marginal utilities will be constant. Finally, with respect to the provincial government, we will retain our assumption that the province is intent on maximizing solely its own oil-related revenues.
5.4.1 The Nash Equilibrium -- Model II:

Therefore, the federal programming problem under the assumption of Nash-type behaviour on the part of the federal government is now described by;

Maximize  
(7)  \[ U^f(PF(K_e)T^f, F(K_e)) \]
\[ \{ T^f \} \]

subject to  
(2)  \[ PF'(1-T^f-T^p) = r_e \]

where \( T^p \) (from our Nash assumption) can be treated as a constant. Differentiating (7) and dividing both sides by \( U^f_1 \) (the marginal utility of federal own oil revenues) yields;

(7.1)  \[ \frac{dU^f}{U^f_1} = \left[ PFdT^f + (PF'T^f + q_2^f F')dK_e \right] = 0 \]

where \( q_2^f = U_2^f/U_1^f \) and given our assumption regarding the additive nature of \( U^f \), implies \( q_2^f \) will be a constant.

Differentiation of the value of marginal product constraint yields,

(2.1)  \[ PF''(1-T^f-T^p)dK_e - PF'dT^f = 0 \]

so

(2.2)  \[ \frac{dK_e}{dT^f} = \frac{F'(1-T^f-T^p)^{-1}}{F''} < 0 \]

Finally, dividing both sides of (7.1) by \( dT^f \) then substituting (2.2) and solving for \( T^f \) yields the following expression for the optimal federal revenue tax rate:

(7.2)  \[ T^f = \left[ \frac{\alpha}{1 + \alpha} \right] (1 - T^p) - \left[ \frac{q_2^f / p}{1 + \alpha} \right] \]

where \( \alpha \) is defined as \(-FF''/F'\) as before, or given our assumption of a Cobb-Douglas production function of the form \( F(K_e) = K_e^\beta \), then \( \alpha = (1 - \beta) / \beta \).
Since \( q^f_2 \) is a positive constant, then it follows, relative to the Nash equilibrium in our "simple" model (section 5.3 above), the presence of oil output in the federal utility function, as would be expected, induces the federal government to lower its revenue tax rate. This observation can be derived diagrammatically as well, and is done so in Figure 5.6 below. From (7.2) we can see that the slope of the federal reaction curve in this version of our model (denoted by \( RC^f_2 \)), which is \(-\alpha/(1+\alpha)\), is identical to the slope of the federal reaction curve in our simple model (denoted by \( RC^I_2 \)). However, in this second model, the vertical and horizontal intercepts have both shifted inwards as shown in Figure 5.6 relative to the simple model. In particular, the extent of the inward shift of the federal reaction curve critically depends on the value of \( q^f_2 \). The higher the value of \( q^f_2 \) (i.e., the higher the marginal utility of output relative to the marginal utility of revenue in the federal utility function) then the larger will be the shift inwards. Therefore, for any given value of \( T^p \), the new federal revenue tax rate now that output is an argument in the federal utility function will be lower than the corresponding value of \( T^f \) in the simple model.

The provincial government's reaction curve, on the other hand, given this version of the model is unchanged from the simple model analyzed in section 5.3 above. Therefore, the province's reaction curve, as we have already noted, will be linear and negatively sloped with the slope given by \(-((1+\alpha)/\alpha)\). This provincial reaction curve is also displayed in Figure 5.6 and is labelled \( RC^p \).

From Figure 5.6 it is clear then that the Nash equilibrium in this version of our model (referred to as model II whereas the simple model is denoted as model I) produces the following results:
i) a higher provincial revenue tax rate (i.e., $T^P_{II} > T^P_I$) since we are moving down along the provincial reaction curve from point $N_I$ to $N_{II}$.

ii) a lower federal revenue tax rate (i.e., $T^f_{II} < T^f_I$) again because we are moving along a negatively sloped provincial reaction curve. In fact, if the federal reaction curve had shifted in as far as $RC^f_{II}$ (i.e., if the federal government placed a high valuation on output or, alternatively, placed a strong emphasis on self-sufficiency relative to its own revenues, which in turn, implies a high value of $q^f_2$), then the optimal federal revenue tax rate would be zero!

and

iii) a lower combined tax rate (i.e., $T^f_I + T^P_I > T^f_{II} + T^P_{II}$). This result also is due to the movement in Figure 5.6 down along the provincial reaction curve. To see why this is so, recall that the slope (in absolute value terms) of this provincial reaction curve is greater than one. Therefore, as we move down $RC_p$, the change in the federal tax rate exceeds the change in the provincial tax.
rate. As a consequence then, it follows that Canada's output of oil will be higher. This conclusion, as we might expect is not surprising since in this version of the model output is now an argument in the federal utility function.

5.4.2 The Cooperative Equilibrium - Model II

In the preceding section we noted that the inclusion of output as an argument in the federal utility function produced tax relief for the domestic oil industry. That is, even in the non-cooperative Nash model, the combined tax effort was shown to decline relative to the case where output is excluded. In this section of the chapter we want to determine what the impact on the pattern of optimal tax rates will be given the inclusion of the self-sufficiency proxy in the federal utility function but now with a spirit of co-operation assumed to exist between the federal and provincial governments. In particular, we want to determine whether or not the combined tax effort still declines in this version of the model (i.e., model II) and if so, whether or not the reduction in the combined tax effort in model II will be greater or less in our co-operative model than the corresponding decline in combined tax effort already noted in our Nash model. Put another way, using the nomenclature of this chapter (recalling CO denotes co-operative values and N represents Nash values), we wish to provide answers to the following questions:

(1) Is \( [T_{II}^f + T_{II}^p]_{CO} \geq [T_{II}^f + T_{II}^p]_{N} \) ?

(2) Is \( [T_{II}^f + T_{II}^p]_{CO} \geq [T_{I}^f + T_{I}^p]_{CO} \) ? and

(3) Is \( [(T_{I}^f + T_{I}^p) - (T_{II}^f + T_{II}^p)]_{CO} \geq [(T_{I}^f + T_{I}^p) - (T_{II}^f + T_{II}^p)]_{N} \) ?

To begin the co-operative solution of tax rates in this version
of our model will be obtained by solving the following programming problem:

Maximize \( u^f(PF(K_e)T^f, F(K_e)) \)

\( \{T^f\} \)

subject to \( PF'(1-T^f-T^p) = r_e \)

and \( u^p(PF(K_e)T^p) = \tilde{u}^p \)

By following an identical approach to that adopted in section 5.3.2 where we generated the co-operative solution for the simple model -- we can solve for \( T^f \) and obtain:

\( T^f = \alpha - \left(\frac{q^f_{2/p}}{1 + \alpha} \right) - T^p \)

or

\( T^f + T^p = \alpha - \left(\frac{q^f_{2/p}}{1 + \alpha} \right) \)

Diagrammatically, equation (7.3) then represents a (linear) locus of potential co-operative equilibrium tax rates with a slope of \((-1\) and intercepts as noted in Figure 5.7 below. Again, as was the case in the Nash equilibrium, the relative size of \( q^f_{2} \) will alter our diagram. The larger the value of \( q^f_{2} \) (i.e., the more "important" output is in the utility function of the federal government) this locus of potential co-operative equilibrium points (denoted by \( CO_{11} \)) will lie closer to the origin.

By comparing Figures 5.5 and 5.7 with respect to the locus of potential co-operative equilibria we can see immediately one difference. As a result of including output in the federal utility function, the maximum revenue tax imposed by the provincial government (if the federal government did not choose to impose a tax) will now no longer be the same tax rate imposed by the province under the same circumstances in the
Nash model (i.e., the horizontal intercept of the locus of potential co-operative equilibria in Figure 5.7 is not the horizontal intercept of $R_{CP}$ as it is in Figure 5.5). In words, if the two levels of government are setting tax rates co-operatively and output is an argument in $U^f$, the province will take this into consideration and consequently, the maximum provincial tax rate that would be imposed will be lower than it would otherwise be if output did not appear as an argument in $U^f$.

The answer to our first question can also be readily determined from Figure 5.7 and equation (7.4). Specifically, the sum of the Nash tax rates is given by:

$$ (T_{II}^f + T_{II}^P)_{\text{Nash}} = \frac{2\alpha - (q_2^f/p)}{1 + 2\alpha} $$

whereas the combined tax rates under the co-operative assumption from equation (7.4) is:

$$ (T_{II}^f + T_{II}^P)_{\text{Coop}} = \frac{\alpha - (q_2^f/p)}{1 + \alpha} $$

Therefore, since $2\alpha/(1+\alpha)$ is greater than $\alpha/(1+\alpha)$ and $(q_2^f/p)/(1+2\alpha)$ is less than $(q_2^f/p)/(1+\alpha)$ then, unambiguously, the combined tax rates under
the co-operative behavioural assumption, is indeed, lower than the sum of the Nash revenue tax rates. So, as we noted in the simple model, co-operation produces a lower combined set of tax rates than no co-operation.

Furthermore, a comparison of (2.7) and (7.4) indicates that the inclusion of oil production as an argument in the federal utility function further reduces the combined tax effort. That is, our second question is now answered.

\[(T_{II}^f + T_{II}^d)_{Coop} < (T_I^f + T_I^d)_{Coop}\]

But, is it true that the reduction in combined tax rates given the inclusion of output in \(U^f\) will be more pronounced in a co-operative model? Given the results generated in this chapter so far this question can be answered affirmatively. The difference in combined tax rates in the Nash model as a result of including oil production as an argument in \(U^f\) was already shown to be:\(^{11}\)

\[(7.5) \quad = \quad \frac{(q_2^f/P)}{(1+2\alpha)}\]

In contrast, the difference in combined tax rates in the co-operative model as a result of introducing output in the federal utility function (from (2.7) and (7.4)) will be:\(^{12}\)

\[(7.6) \quad = \quad \frac{(q_2^f/P)}{(1 + \alpha)}\]

Therefore, it is clear from (7.5) and (7.6) that the inclusion of oil production in the federal utility function promotes a larger reduction in combined tax rates in a co-operative framework than it does in a Nash non-co-operative model.

To summarize the results noted so far to this point in the chapter then we have shown the following;
i) co-operative behaviour in setting revenue tax rates tends to lower the combined tax effort, or alternatively, increase Canada's oil production (ceteris paribus),

ii) the inclusion of oil production as an argument in the federal utility function also tends to lower the combined tax rates regardless of our behavioural assumption, and finally,

iii) the inclusion of oil production in the federal government's utility function will lower combined tax rates more (or provide a larger increase in Canada's oil production) in a co-operative model than it does in a non-cooperative (i.e., Nash) model.

Given the results of the analysis noted so far there are two alternative ways to proceed. We could investigate the impact of introducing more than one input in the production function. As it turns out, this exercise however, does not qualitatively change the results generated so far. A more interesting extension then is to investigate the impact of introducing a second tax instrument for each level of government -- in particular -- a subsidy rate. It is to the task of developing this extension of our analysis that we now turn.

5.5 MODEL III: EXTENSION TO INTRODUCE A SECOND SET OF TAX INSTRUMENTS

5.5.1 The Nash Model

In the previous version of our model we examined the impact of introducing additional arguments in the federal government's utility function -- in particular, current oil production. The results of this analysis indicated that the inclusion of this term will result in a lower combined tax effort by both levels of government (regardless of the degree
of co-operation under which these tax rates were formed). But there is an alternative way, and perhaps a more direct way, to stimulate oil production than by lowering revenue tax rates. The federal government could instead offer a subsidy rate on the value of exploration capital inputs employed. The advantage of this approach to the federal government would be that by offering the subsidy rate implies a direct investment in exploration capital must be undertaken by the firms (i.e., thereby, presumably, increasing expected oil output). On the other hand, the alternative of lowering revenue tax rates may not in practice result in the same level of capital investment being undertaken. It is possible, although it would not show in our simplified model, that part of the proceeds of the reduced revenue tax rate may be dispersed in the form of dividend payments. Consequently, the federal government may wish to introduce an explicit subsidy rate. In fact, as we indicated in the preceding chapter, if the federal government introduces a tax-based subsidy rate, then given the fact the oil-producing provincial governments define corporate taxable income identical to the federal government's definition (at least prior to 1982), then the province will also be seen to introduce a (tax-based) input subsidy rate as well. Letting these input subsidy rates be designated as \( t^f_e \) and \( t^p_e \) for the federal and provincial governments respectively, then in the Nash model the federal government solution will be given by:

\[
\text{Maximize } (8) \quad U^f(PF(K_e)T^f_e - r_eK_e t^f_e , F(K_e))\]

subject to (9) \( PF'(1-T^f_e-T^p_e) - r_e(1-t^f_e-t^p_e) = 0 \)

The first step in deriving a solution to this multi-dimensional programming problem is to differentiate both (8) and (9), employing the Nash assumption (i.e., \( dT^p = dt^p_e = 0 \)), and then divide both sides of the
(8.1) \[ \frac{dU_f^f}{U_1} = [PF'T^f - re_t^f + q^f_2]\frac{dK_e}{e} + PFdT^f - re_t^f + r_e dt^f = 0 \]

and

(9.1) \[ PF'(1-T_t^f-T^P)\frac{dK_e}{e} - PF'dT^f + re_t^f = 0 \]

Next, we consider the following sub-spaces -- \((T^f, K_e)\) and \((t_e^f, K_e)\) and equate the slopes of a representative federal indifference curve and the production constraint in each of these sub-spaces (obtained from (8.1) and (9.1)) and solving the resulting pair of equations for the optimal federal revenue tax rate yields: \(^{14}\)

(10) \[ T_f = \frac{(1-T^P)\frac{t_e^f}{1-t_e^f}}{(1-t_e^P)} \]

\[ \frac{(q^f_2/P)(1-t_e^f)}{(1-t_e^P)} \]

5.5.2 The Relationship of the Optimal Federal Tax/Subsidy Rates and the Pure-Profits Tax Rate

The optimal federal revenue tax/subsidy rates are implied by equation (10) above. It is worth noting that in general, given the assumptions of our model (specifically the specification of the federal utility function and the Nash behavioural assumption), the optimal tax and subsidy rates implied in (10) will not represent a pure-profits tax rate in traditional economic theory (where the output tax rate would be identical to the input subsidy rate). For example, for simplicity assume the provincial government is not involved in taxing the activities of the domestic oil industry (i.e., only one taxing jurisdiction exists -- the federal government) then from equation (10) the optimal federal tax/subsidy relationship becomes:

(10.1) \[ (T^f - t_e^f) = -(q^f_2/P)(1-t_e^f) \]
Therefore, a pure-profits tax rate would be optimal for the federal government, if and only if, $q_2^f = 0$ -- i.e., the federal government in our model attempted only to maximize net tax revenues. Rather the optimal federal exploration subsidy rate will exceed the federal revenue tax rate.

Suppose now, instead, the provincial government does actively engage in taxing and subsidizing domestic oil producers. In particular, assume the provincial government had chosen to impose a pure-profits tax rate (i.e., $t_p^*$). Again, however, equation (10) simplifies to:

$$
(10.2) \quad (T^f - t_e^f) = - \frac{(q_2^f/P)(1-t_e^f - t_p^*)}{1 - t_p^*}
$$

and therefore, the resulting optimal federal revenue tax rate will not equal the input subsidy rate (i.e., a federal pure-profits tax rate will not be optimal)\textsuperscript{15}.

5.5.3 Relationship of the Optimal Federal Tax/Subsidy Rates and the Actual Pre-NEP Rates

Since we are presently assuming that the federal government is behaving in a Nash fashion (i.e., taking the provincial government's tax and subsidy rates as given), it is possible to investigate the pattern of optimal federal rates when the rates taken as given by the federal government are the actual rates imposed by the provincial government. That is, for the pre-NEP period, for example, we can determine whether or not the federal tax and subsidy rates that were in effect were consistent with the implied optimal pattern generated in our model and summarized in equation (10).

In chapter 4, the provincial government's revenue tax rate and
exploration capital subsidy rate for the producers of old conventional oil for the pre-NEP period were estimated to be:

\[ T^P = 0.3902 \]

and \[ t_e^P = 0.1467 \]

Substituting these values into (10) and dividing both sides by \( t_e^f \) yields;

\[
\frac{T^f}{t_e^f} = 0.706 + \left( \frac{q_2^f}{P} \right) \left( t_e^f - 0.850 \right) / t_e^f (0.85)
\]

Therefore, if \( t_e^f \) (the federal input subsidy rate) is less than 0.850 then the second term in (10.3) will be negative ensuring that \( T^f / t_e^f \) will be less than one. That is, given the actual provincial revenue tax and exploration subsidy rates in effect in the pre-NEP period, the federal government should set its exploration subsidy rate higher than its revenue tax rate. This result is not very surprising, however, given the assumed presence of oil production as an argument in the federal utility function and the relatively high revenue tax rate (relative to their input subsidy rate) imposed by the provincial government at this time.

Nevertheless, as we noted in Chapter 4, the values of the federal revenue tax and exploration subsidy rate applied to old conventional oil production in the pre-NEP period (equalling 0.270 and 0.480 respectively) apparently conform to the optimal pattern we have noted above.

5.5.4. The Provincial Government's Optimal Tax/Subsidy Regime in the Nash Model

The provincial government is, by assumption, setting its tax and subsidy rate in order to maximize its own oil-related revenues subject to the value of marginal product condition holding for the domestic oil producers. That is, the provincial government now,
Maximizes \( U^P(PF(K^e_t)T^P - r^e_e t^P) \)

Subject to \( PF'(1-T^f - T^P) - r^e_e (1-t^f_e - t^P_e) = 0 \)

Following a similar approach to that employed above to obtain the solution for the federal revenue tax rate, we derive the following relationship between the optimal provincial input subsidy rate and the provincial revenue tax rate;

\[
\frac{t^P_e}{T^P} = \frac{(1 - t^f_e)}{(1 - T^f)}
\]

From equation (13) it is clear then that if the federal government was either:

a) not granted taxing authority over the domestic oil industry (i.e., if \( T^f = t^f_e = 0 \)),

or  

b) if the federal government imposed a pure-profits tax rate,

then the provincial government will respond with a pure-profits tax rate of their own.

However, if we assume the province takes as given the actual federal revenue tax and subsidy rates that were in place in the pre-NEP period for conventional oil producers, which in Chapter 4 were estimated to be;

\[ T^f = 0.270 \quad \text{and} \quad t^f_e = 0.480 \]

then the resulting optimal input subsidy-revenue tax rate relationship in (13) becomes:

\[
(t^P_e / T^P) < 1
\]

so, the province behaves in a manner that is consistent with our definition of optimality if they set a relatively high revenue tax rate (relative to their input subsidy rate). Again, however, this result may be predicted. Given the federal government is offering a relatively generous subsidy rate (in the pre-NEP period) and the province is assumed to be interested solely in revenues, we would anticipate a relatively high provincial rev-
enue tax rates being imposed. Nevertheless, our conclusion is that the oil-producing provincial government's pattern of tax and subsidy rates (but not necessarily their absolute values) in place prior to the introduction of the NEP appears to be consistent with the pattern of optimality identified in our model.

5.5.5 Full Nash Equilibrium -- Model III

So far we have essentially discussed the properties of the optimal federal and provincial tax and subsidy rates but have not calculated the actual Nash equilibrium values (i.e., in our two-dimensional model of the previous section the Nash equilibrium occurred at the intersection of the federal and provincial reaction curves). To solve for the Nash equilibrium then, we begin by rewriting equation (13) as:

\[(13.2) \quad (T^P - t_e^P) = (t_e^f T^P - t_e^P T^f)\]

and equation (10) as:

\[(10.4) \quad (T^f - t_e^f) + t_e^f T^f + (q^f_2/P)(1-t_e^f - t_e^P) = 0\]

Therefore, substitution of (13.1) into (10.4) yields:

\[(10.5) \quad (T^f + T^P) - (t_e^f + t_e^P) = -(q^f_2/P)(1-t_e^f - t_e^P)\]

or, in words, we have demonstrated that the pure profits tax will not be consistent with the Nash-optimal combined net tax effort. Rather the combined input subsidy rates will exceed the combined revenue tax rates. Furthermore, the higher the values of \(q^f_2\) (i.e., the more important oil output is in the federal utility function relative to federal oil revenues) then the higher will be the combined net input subsidy relative to the combined revenue tax rate. Alternatively, then, the conclusion of our Nash model when both governments have two tax instruments at their disposal, the production of oil will be higher than if the combined tax effort
resembled a pure-profits tax rate.

Unfortunately, however, the values indicated above for the actual values of the provincial and federal revenue tax and input subsidy rates in place in the pre-NEP period do not conform to this pattern. In particular,

\[(T^f + T^p)_{Pre-NEP} = 0.66\]

whereas,

\[(t_e^f + t_e^p)_{Pre-NEP} = 0.63\]

Therefore, if the case can be made that the federal government's utility function in this period did contain the arguments we have identified (namely, oil revenues and oil production), which implies \(q_2^f > 0\), AND the federal and provincial governments set their tax rates in a non-cooperative (Nash) fashion then the prevailing combined input subsidy rates were set too low (i.e., output was too low) prior to the introduction of the NEP. In other words, the actual tax and subsidy rates in place prior to 1980, given our assumptions, would be viewed as being non-optimal.

Alternatively, it is possible to reconcile the actual values of tax and subsidy rates and the implied optimal pattern of equilibrium tax/subsidy rates summarized in (10.5). That is, since the difference between the combined tax rates and the combined subsidy rates is virtually negligible, then if (10.5) is correct, it implies \(q_2^f\) is very close to zero -- output is not a very important argument in the federal utility function in the pre-NEP period. This prediction, or implication, would quite possibly be valid in the early part of the 1970's. Canada, at that time, was a net exporter of oil and consequently, we would expect to see a much lower weight, if any at all, given to the oil production argument in the federal utility function. However, this is not the case just prior to the introduction of the NEP -- Canada, by 1980, had become a net importer of oil.
Therefore, the interpretation of the value of $q_2^f$ being virtually zero is found in the relative importance of output. The implication of the pre-NEP period, then, if our assumptions are valid, is that the quest by the federal government for oil revenues completely dominated their interests in oil self-sufficiency and thereby drove the value of $q_2^f$ to approximately zero.

We will return to the analysis and evaluation of actual federal and provincial tax rates over time and their relationship to $q_2^f$ (the ratio of federal marginal utilities) in the concluding section of this chapter.

5.5.6 The Co-operative Equilibrium -- Model III

In the previous section we derived the optimal pattern of federal and provincial tax/subsidy rates under the assumption that both levels of government behave in a Nash-type fashion. We now want to change this last assumption and look at the pattern of optimal tax/subsidy rates that would emerge if both governments set their tax rates co-operatively. In terms of the programming problem we now have;

Maximize $\mathcal{U}^f(PF(K_e)T_e^f - r_e K_e t_e^f, F(K_e))$ subject to $PF'(1-T_e^f-T_P) - r_e(1-t_e^f-t_e^P) = 0$ and $\mathcal{U}^P(PF(K_e)T_P - r_e K_e t_e^P) - \mathcal{U}^P = 0$

The solution to this problem is obtained in a parallel fashion as in the Nash model -- i.e., we look at sub-spaces. Now, however, we can examine the slopes of representative indifference curves and constraints in four sub-spaces: $(K_e, T_e^f), (K_e, t_e^f), (K_e, T_P)$ and $(K_e, t_e^P)$. By differentiating our objective function and the constraints and setting the slopes of representative indifference curves and the constraints equal in each
sub-space, and simplifying, we obtain;

\[
(15) \quad \frac{T^p - T^f}{t^p - t^f} = \frac{(1-T^f\cdot T^p)}{(1-t^f\cdot t^p)} + \frac{q^f_2}{(t^p - t^f)}
\]

From equation (15) we can see that the sign of the left-hand-side will depend solely on the sign of \((t^p - t^f)\).\(^{16}\) If the province's input subsidy rate exceeds the federal subsidy rate (i.e., \((t^p - t^f) > 0\)) then the last term on the right-hand-side is positive (provided \(q^f_2\) does not equal zero), thereby ensuring,

\[
\frac{(T^p - T^f)}{(t^p - t^f)} > 0
\]

or, since we have assumed the denominator is positive, then it must be that \(T^p > T^f\). Therefore, in our co-operative model, we find that if the oil-producing provincial governments offer a relatively high subsidy rate (relative to the federal government's subsidy rate) then they will also impose a higher revenue tax rate then the federal government. On the other hand, if the federal government's subsidy rate is larger (i.e., \(t^f > t^p\)), so \((t^p - t^f) < 0\), as we noted it was in the pre-NEP period) then the sign of \((T^p - T^f)/(t^p - t^f)\) is ambiguous. The result depends on the magnitude of \(q^f_2\) — the ratio of the marginal utility of oil production to the marginal utility of federal revenues. For very large values of \(q^f_2\), the sum of the two terms on the right-hand-side of (15), given our assumption \(t^f > t^p\), will tend to be negative. Therefore, the result is that the provincial revenue tax rate should exceed the federal revenue tax rate.\(^{17}\) However, if \(q^f_2\) is very small, then it may not be optimal for the provincial revenue tax rate to exceed the federal revenue tax rate (given a higher federal input subsidy rate prevails).
5.5.7 Diagrammatical Representation of the Co-operative Equilibrium

The difficulty with attempting to depict the co-operative (or Nash) equilibrium tax/subsidy rates in a diagram is that as previously indicated, we are dealing in a multi-dimensional model. In order to present our analysis in diagrammatic form, however, we will make one simplifying assumption. We will assume that the possibility of transfer payments from one level of government to the other exists. That is, we could have just one level of government impose a revenue tax and input subsidy. Specifically, we will assume only the federal government will impose tax and subsidy rates (so \( t^P, t^C \) in (15) are set equal to zero) and then share via transfer payments the net proceeds of the tax and subsidy regime with the other level of government -- the provincial government in this case.

This assumption combined with the realization that there exists only one optimal co-operative tax regime, yet an infinite number of ways of obtaining this regime, will permit our depicting the co-operative equilibrium in a diagram.

Letting \( R \) represent total net government tax revenues collected by the federal government (collected on behalf of both levels of government) net of any combined subsidy payments, and \( Q \) represent total oil production, then we can visualize an opportunity locus as displayed in Figure 5.8 below and labelled \( RQ \). In fact, we can envision a family of opportunity loci. For example, \( RQ_0 \) would represent the opportunity locus facing the federal government if it did not share any of the oil revenues collected with the provincial government. But as the federal government offers transfer (lump sum) payments to the provincial government, the net revenues remaining with the federal government at any given oil output level will be
lowered, indicating a uniform shift downwards of the federal opportunity loci. In particular, therefore, from Figure 5.8, the closer the opportunity locus is to the horizontal axis, a greater volume of oil revenues collected are shared with the provincial government (i.e., RQ₂ indicates more oil revenues going to the provincial government then RQ₁ or alternatively, RQ₀ in Figure 5.8).

The co-operative equilibrium given our assumptions will be represented by a point of tangency between a representative federal indifference curve and one of these opportunity loci. The federal indifference curves, however, given our assumed additive (federal) utility function between federal revenues and output, will be negatively sloped and linear. Therefore, considering the opportunity locus RQ₀, for example, where no oil revenues are assumed to be shared with the provincial government, our co-operative equilibrium would be at point C with an output level higher than the oil production level if a pure-profits tax had been imposed. In fact, we can verify this result by looking at equation (15). Given \( t^p = t^p_e = 0 \) (as assumed on RQ₀), we see the net federal tax rate will not be a pure-profits tax rate. i.e.,

\[
(15.1) \quad (T^f - t^f_e) = -(q^f_e/p)(1-t^f_e)
\]

Correspondingly, the locus of potential co-operative equilibrium points will be represented by a vertical line (indicating a given level of output) going through point C.

It is also possible to illustrate the relationship of the Nash equilibrium and the co-operative equilibrium in this diagram. Suppose point S represented the co-operative equilibrium (after a transfer of oil revenues to the provincial government equalling the vertical distance SC was made). In this case the level of federal total utility would be
represented by, say, $U^f_1$. Similarly, the provincial government's level of welfare could also be depicted in this diagram by examining a representative provincial indifference curve. Since we have assumed the province is only interested in maximizing its oil-related revenues its family of indifference curves therefore, would resemble a set of horizontal lines. Consequently, the level of provincial welfare would be represented by $U^P_1$ (see Figure 5.8). Finally, given the co-operative equilibrium is pareto superior to the Nash equilibrium it follows that the Nash equilibrium must result in a lower welfare level for at least one level of government. For illustrative purposes, however, suppose both levels of government had a lower total welfare level associated with the Nash equilibrium. Then if the Nash equilibrium was represented by point N in Figure 5.8 (remember we have already indicated that the Nash equilibrium will generate a higher output level than a pure-profits tax, so it follows that point N must be to the right of the peak in the given opportunity locus) then the co-operative equilibrium (point S), given its pareto superior, will lie to the right of point N on the same opportunity locus. That is, the provincial

**FIGURE 5.8 THE CO-OPERATIVE EQUILIBRIUM -- MODEL III**
government's welfare at the co-operative equilibrium is higher \((U_1^p \text{ versus } U_1^{p'})\) and, as well, the federal government's welfare is also higher (now \(U_1^f \text{ versus } U_1^{f'}\)). Consequently, as Figure 5.8 indicates, our earlier observation that co-operatively set tax rates results in a higher output level of oil is reinforced.

5.6 SUMMARY AND EVALUATION OF RESULTS

The major findings of this chapter have been:

i) co-operatively set tax rates result in a lower combined tax effort than non-cooperatively (i.e., Nash) set tax rates,

ii) the presence of, and the more importance afforded, oil production in the federal government's utility function will lower combined tax efforts. This conclusion was valid regardless of the behavioural assumption employed. At the same time, however, we noted in the Nash model with only one tax instrument for each level of government, that although the combined tax effort falls as oil production is introduced in the federal utility function, the provincial revenue tax rate actually increases (while \(T_f\) falls). Therefore, the burden of lowering the combined tax effort is (more than) borne entirely by the federal government,

iii) As well, it was demonstrated that the reduction in combined tax effort due to the presence of oil production as an argument in the federal utility function (i.e., as \(q^e > 0\)) is more pronounced in an atmosphere of co-operation than in non-cooperation. Or, alternatively, a greater increase in oil production brought about by the inclusion of oil production as an argument in the federal utility function, is predicted when tax rates are co-operatively set rather than when they are non-cooperatively set, and finally,

iv) In a related matter, it was demonstrated in the tax and subsidy rate model (i.e., the two tax instrument per level of government case) that if the governments attempt to stimulate production by offering an exploration capital input subsidy, the optimal tax regime is not expected to be the pure-profits tax regime unless both governments are simply maximizing their own oil-related revenues (i.e., oil output will be higher under the optimal tax regime when \(q^e\) is greater than zero than it would be under a pure-profits tax regime). In fact, the more important oil output is in the federal utility function we have shown the higher the combined subsidy rate will be relative to the combined revenue tax rates.
Given these theoretical propositions, in terms of past Canadian energy policy it implies that:

a) if the two levels of government have not co-operatively set their tax and subsidy rates then the domestic oil industry is confronted with a higher combined (net) tax effort than would otherwise be the case and consequently, Canada's oil production would have been reduced,

and -b) if the federal government's emphasis on oil production as an argument in their utility function declines over time (e.g., at the expense of increased attention to the collection of federal oil revenues) then again, Canada's oil output is lowered relative to what it otherwise would have been (i.e., if \( q_2 \) had remained constant).

In this final section of the chapter we attempt to quantify these assertions and with the results of our model display the potential costs of both (assumed) non-cooperative taxing behaviour and varying emphasis on the value of \( q_2 \) by the federal government.

But, before we proceed with this exercise we first direct our attention to a brief evaluation of the major assumptions of our model.

5.6.1 The Empirical Validity of the Assumptions

The theoretical results noted above were generated in a model where several assumptions were made. Consequently, their validity depends on the reliability of the assumptions made. In particular, we assumed at least in our last model, the existence of an output tax rate and an input subsidy rate for both the federal and provincial levels of government. Furthermore, we assumed the oil-producing provincial government was only interested in maximizing its own oil-related revenues and finally, we made two alternative assumptions regarding the behaviour of the two levels of government (i.e., the Nash and the co-operative assumptions). To try and provide some support for the results noted above we wish to discuss these key assumptions in the context of Canadian energy policy as it has.
evolved from the early 1970's up to and including the introduction of the NEP (October 1980).

With respect to the assumed existence of revenue taxes for both the provincial and federal governments (i.e., $T^p$ and $T^f$ in our model) we see that there is a close parallel in place in Canada. The provincial government imposes a royalty rate on oil production with no provisions for deducting operating costs, for example, and therefore, can accurately be labelled a revenue tax. The rate of this royalty or revenue tax has been significantly altered only once in the 1972-80 period. As noted in Chapter 2, prior to the "energy crisis" of 1973/74 the royalty rate was approximately 22 per cent of the value of oil production. In 1974, however, the Alberta government introduced a split-rate royalty scheme (for old and new oil) with the effect of raising the effective royalty rate on old conventional oil (the type of oil assumed to be produced in our model) to approximately 40 per cent.

On the other hand, the presence of a federal revenue tax rate may, on the surface, be less apparent. There certainly exists a federal corporate income tax which at least in part, served to tax oil revenues but, in addition, the federal government in 1974 introduced a two-tier pricing scheme for Canadian oil production. A Canadian oil price was established below the prevailing world price and has remained below world levels ever since. Although the establishment of this Canadian oil price does not in the conventional sense represent a "tax" in that it does not represent actual revenues for the federal government, there is an alternative way of interpreting this two-price policy. This alternative interpretation views the establishment of a domestic oil price (less than world levels) as indeed the establishment of a federal revenue tax where the revenues
"collected" by this tax are then distributed back to domestic oil consumers. In the context of this latter interpretation then the case for the existence of a distinct federal revenue tax can indeed be supported. Moreover, as indicated in Chapter 2, with the introduction of the NEP the federal government has introduced the Petroleum and Gas Revenue Tax (PGRT) which again is simply a tax on net revenues (net of operating costs only -- not profits) and therefore, represents an additional federal revenue tax.

On the subsidy side the evidence from Canadian energy policy clearly predicts the existence of both a federal and provincial tax-based input subsidy. The corporate tax treatment of oil exploration inputs employed in the production of domestic oil was highlighted previously in Chapter 2. In this survey we found that the federal government (and consequently the provincial government as well by virtue of the fact that they define corporate taxable income in an identical fashion to the federal government) has often varied the tax-based subsidies afforded exploration capital inputs (the implication of which we will discuss further below). In summary, therefore, the central assumption of a distinct federal and provincial revenue tax and (tax-based) input subsidy existing can be supported with "empirical" evidence from Canada's past energy policy.

But what about our assumptions concerning the nature of the utility functions of the two levels of government? In particular, is it appropriate to view the provincial government as being solely interested in maximizing their oil-related revenues? What about the other possible arguments for the federal utility function that were suggested in the introduction to this chapter? The answers to these questions will not be definitive. With respect to the nature of the provincial govern-
ment's utility function there may be no consensus concerning the appropriate arguments appearing in their utility function. Nevertheless, the analysis contained in this chapter could easily be altered to accommodate any changes in the nature of their utility function if they are deemed necessary. In fact, the results developed in this chapter can be used to anticipate the alterations. For example, if the provincial government's utility function included the flow of labour services (for the reasons given in the introduction) the result would be a lower combined tax effort on the domestic oil industry (assuming, of course, we expand to a two-input production function model). 20

Alternatively, if the federal government was deemed to maximize a utility function with the stock of exploration capital as was suggested in the introduction, this would not produce any differences in the results noted above (certainly not so in the single input case). In summary, therefore, it is possible that alternative arguments may in fact be present in the utility functions of either level of government but the results of this chapter provide an acceptable framework to introduce these alterations and to some extent permit an accurate anticipation of the conclusions generated in a broader version of the model.

Finally, with respect to our assumptions regarding the behaviour of both levels of government (i.e., the Nash or co-operative assumption) a casual analysis of the 1972-80 period in Canadian energy policy may lead one to recommend the adoption of the non-cooperative (Nash) behavioural assumption as the appropriate assumption. Beginning in 1974, following the quadrupling of world oil prices, the federal government introduced the first of a series of energy policy initiatives -- the imposition of the federal oil export tax with the revenues from this tax to be used to
subsidize imported oil east of the Ottawa valley in order to maintain a uniform domestic price. In response to the introduction of both the federal oil export tax and the introduction of a domestic oil price (kept below world levels), the provincial government reacted by dramatically scaling upward their royalties from oil and gas production. In turn, Ottawa moved to disallow these royalty payments for purposes of computing corporate income taxes with the result of increasing, in the context of our model, the (federal) revenue tax rate. At the same time, the federal government in the May 1974 federal budget had proposed to introduce a lower writeoff rate for exploration capital inputs. Therefore, the scramble for oil-related revenues by the federal and oil-producing provincial governments had begun in earnest. This scramble continued and was culminated with the introduction by the federal government of the NEP. The combination of new taxes and new incentives (described in Chapter 2) generated a higher revenue share going to the federal government at the expense primarily of the domestic oil industry.

Although these incidents may indeed be consistent with a non-cooperative behaviour, it should be stressed we have not, nor was it the purpose of this thesis to scientifically "test" to see which behavioural assumption is most relevant.

5.6.2 An Illustration of the Revealed Policy Preferences of the Federal Government

It is possible given the specification and assumptions of our model to infer from the actual government taxing behaviour over the 1974 to 1981 period the relative importance afforded output in the federal government's utility function. Implicitly, we have so far assumed that the federal
government would receive positive utility from the production of oil (i.e., so the ratio of marginal utilities, \( q_2^f \) in our model, would be positively signed). However, as our results indicate below this may not always be the case.

To see why this may be so suppose that the federal and provincial tax rates in place conform to the pattern of optimality derived in our model III above (and represented by equations (10.5) -- for the Nash equilibrium, and (15) -- for the co-operative equilibrium). Then by plugging the actual values of \( T^f, T^d, t^f_e \) and \( t^d_e \) into these expressions we could solve for the value of \( q_2^f \) in both the Nash and co-operative models. This exercise (the results of which are displayed in Table 5.1 below) has been performed for the following four time periods:

i) 1972: representing the stance of Canadian energy policy just prior to the emergence of the world energy crisis,

ii) 1974: reflecting the changes in Canada's energy policy immediately following the quadrupling of world oil prices,

iii) 1980: just prior to the introduction of the NEP,

and iv) 1981: immediately following the introduction of the NEP.

(i) The Implied Value of \( q_2^f \) -- Nash Model

As indicated in Table 5.1 the interpretation of our results will be significantly influenced by the behavioural assumption adopted. For example, the results of our Nash model indicate that the ratio of marginal utilities appear to drop substantially between 1972 and 1974 with \( q_2^f \) actually becoming negative in 1974 and remaining relatively unchanged up to the time just prior to the introduction of the NEP. After the introduction of the NEP we then observe in our results a tremendous decline in the ratio of marginal utilities for foreign firms' oil production but a turnaround in the value of \( q_2^f \) (so \( q_2^f \) is now positive) for Canadian firms'
oil production. This last observation certainly seems to be consistent with our earlier discussion concerning the substantial tax incentives afforded Canadian firms in the NEP. It also appears to indicate or confirm, the sincerity of the federal government in its Canadianization objective.

TABLE 5.1 IMPLIED RATIO OF MARGINAL UTILITIES IF ACTUAL RATES CONFORM TO OPTIMALITY PATTERNS

<table>
<thead>
<tr>
<th>Time Period</th>
<th>Nash Model Implied $q_2$</th>
<th>Co-operative Model Implied $q_2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1972</td>
<td>0.5809</td>
<td>1.3658</td>
</tr>
<tr>
<td>1974</td>
<td>- 1.3358</td>
<td>1.5657</td>
</tr>
<tr>
<td>1980 (Pre-NEP)</td>
<td>- 1.3308</td>
<td>6.2455</td>
</tr>
<tr>
<td>1981 (Post-NEP)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Canadian Firm</td>
<td>0.7530</td>
<td>11.3164</td>
</tr>
<tr>
<td>- Foreign Firm</td>
<td>- 5.7218</td>
<td>4.8411</td>
</tr>
</tbody>
</table>

What is puzzling, however, about these results is explaining the apparent disutility for the federal government associated with oil production in the 1974-80 period. The rationalization of this observation is not clear. It may simply indicate the federal and provincial governments' tax and subsidy rates in place during this time were non-optimal. That is, the value of $q_2$ may in fact have been positive but the public sector's tax rates did not conform to the optimality pattern derived in our model. Alternatively, it may indicate that the specification of our model is inappropriate -- in particular, there may be additional argu-
ments present in either the federal or provincial government's utility function at this time that we have not included in our model. In other words, there are a variety of possible explanations. In fact, it may even be possible that during this period the federal government did indeed see its total utility diminish with higher production of oil. For example, for the 1974 period, Canada was a net exporter of oil and consequently, the disutility associated in our results with oil production may simply represent a strong conservationalist attitude on the part of the federal government.

This may be a possible explanation of our results for 1974 but the situation was soon to change. Canada, by 1980, was a net importer of oil so this rationalization is weakened. Furthermore, given the mounting financial burden that the oil import compensation program represented to the federal government (e.g., the domestic price of oil was only about one-half the value of the world oil price) it is difficult to explain why the federal government would experience a lower utility from increased oil production.21

On the other hand, however, a near zero value for the ratio of marginal utilities at this time can be rationalized. In Chapter 3 when we analyzed the federal equalization program, we discussed the impact of energy price changes and the equalization program had on net federal oil revenues. That is, we indicated in Chapter 3 that if the price of oil increased by $1 per barrel, or alternatively in this context, if $1 more output was generated, the additional revenues that would accrue to the federal government would be required, in a large part, to finance the additional provincial equalization payments thereby leaving the federal government with little net revenues. Consequently, one could envision a near zero value for $q_2$.
the ratio of marginal utilities in the federal utility function. 

(ii) The Implied Value of \( q_2^f \) -- The Co-operative Model

The pattern of implied or revealed values of \( q_2^f \) over time (summarized in Table 5.1) for the co-operative model (given our assumptions) can be rationalized quite easily. From Table 5.1 we see that first of all, \( q_2^f \) remains positive throughout and rises moderately between 1972 and 1974 and then jumps rather significantly between 1974 and the introduction of the NEP and then again, in the case of Canadian firms, after the introduction of the NEP. In the case of foreign-owned and controlled oil firms the value of \( q_2^f \) (for the federal government) declines (but is still positive) after the NEP is introduced.

It is possible that the moderate increase noted in the implied or revealed value of \( q_2^f \) by 1974 (relative to 1972) may simply reflect the desire of the federal government to increase oil production which could then be exported (recall Canada was a net exporter of oil in 1974) and generate additional oil revenues for the federal government (via the federal oil export tax which was introduced in 1974).

Similarly, the revealed pattern for \( q_2^f \) just prior to the introduction of the NEP may be easily explained with respect to Canada's trade position in oil. By 1980, as already noted, Canada was a net importer of oil and furthermore, the cost of these oil imports were being subsidized substantially by the federal government out of their general revenues. Therefore, the implied higher weight or value attached to domestic oil production in the federal government's utility function may be reflecting the potential, and the desire of the federal government, for oil import-substitution.
Finally, the revealed pattern for $q_2^f$ following the introduction of the NEP (increasing for Canadian-owned firms and decreasing, but remaining positive, for foreign-owned firms) reflects the sincerity of the federal government with respect to two of the announced objectives of the NEP:

i) increasing the degree of Canadian ownership in the oil industry (i.e., reflected by the higher marginal utility ratio for Canadian firms relative to foreign firms),

and

ii) security of supply -- reflected by the still positive value of $q_2^f$ for foreign-owned firms (i.e., the recognition by the federal government that at least a significant share of foreign-owned firms' oil production is still necessary if the supply of oil is to be maintained).

It should also be noted that the decline in the value of $q_2^f$ for foreign firms in the post-NEP period is also consistent with an increased desire by the federal government for extracting additional oil revenues from foreign firms (i.e., an increase in the marginal utility of federal oil revenues collected from foreign firms relative to the marginal utility of their oil production).

5.6.3 An Illustration of the Impact of an Unchanging Value for $q_2^f$
(The Nash Model)

In the preceding section we estimated (under the assumption that the actual tax and subsidy rates were optimal) the implied or revealed value for the federal government of $q_2^f$ -- the ratio of the marginal utility of oil output to the marginal utility of federal oil revenues and noted that it varied considerably over time. In our Nash model, for example, the value of $q_2^f$ for foreign oil firms' production essentially declined steadily over the 1972-81 period while alternatively, the value of $q_2^f$, while declining initially, rose after the introduction of the NEP in the case of Canadian oil firms' production.
In this section we wish to address the question -- what are the consequences of having $q_2^f$ vary? Or, put another way, what are the implications if the value of $q_2^f$ was to remain unchanged over the 1972-81 period? For illustrative purposes, we will examine these issues in the framework of our Nash model. In our Nash model the optimality condition was summarized by equation (10.5)* -- which is reproduced below.

\[(10.5) \quad (T_f^f + T_e^f) - (t_e^f + t_e^p) = -(q_2^f/p)(1-t_e^f - t_e^p)\]

From equation (10.5) we can see that if $q_2^f$ was to remain constant -- that is, if it was prevented from falling (rising), then the excess of the combined subsidy rates ($t_e^f + t_e^p$) will be kept at a higher (lower) level than it otherwise would be. Consequently, the observation that the federal government implicitly reduced the importance of oil production and increased (relatively) the importance of oil production and increased (relatively) the importance of oil revenues in their utility function (i.e., $q_2^f$ falling rather than remaining constant at, say, its 1972 value) implies a lower production level in the 1974-81 period occurred.

To illustrate to what extent this may occur, suppose that the value of $q_2^f$ was maintained throughout the 1974-81 period at its 1972 value (or pre-world "energy crisis" value). To derive this value we simply plug in the actual values of $T_f^f$, $T_e^f$, $t_e^f$ and $t_e^p$ in 1972 into (10.5) and solve for $q_2^f$ -- i.e., we assume the actual rates in 1972 are Nash optimal. Then taking this value of $q_2^f$ to be constant from 1974 to after the introduction of the NEP (i.e., for the 1974, 1980 (pre-NEP) and 1981 (immediate post-NEP) periods) we can derive either the potential (or predicted) values of the federal revenue tax OR the federal input subsidy rate that would restore the Nash equilibrium tax and subsidy rates. The results of this
exercise are displayed in Table 5.2 below.

If the ratio of marginal utilities did not change (i.e., if the federal government had retained the same implicit emphasis on oil production as they did (according to our model) in 1972, instead of increasing their relative focus on collecting oil revenues), then the federal government could have reduced their revenue tax rate to just under 17 per cent (instead of the prevailing 30 per cent) in 1974. Or, alternatively, at the same time, the federal government could have increased their input subsidy rate to 52.3 per cent (instead of the prevailing 40 per cent) to achieve the same results. These figures indicate rather remarkably, the high degree of tax revenue competition that prevailed in 1974. Or, instead, if the predicted changes in the revenue tax rate or input subsidy rate were combined with an appropriate elasticity measure (i.e., price elasticity in the case of the revenue tax rate and a factor demand elasticity and an output elasticity in the case of the input subsidy rate) we could infer what the costs for Canada, in terms of foregone oil output were in 1974 of not maintaining the same emphasis on oil production in the federal utility function as implied in 1972.

Similarly, by 1980 the potential federal revenue tax rate that would be required, if all other tax and subsidy rates remained in effect at this time and the ratio of marginal utilities (i.e., $q_2^e$) remained constant at its 1972 value, would be 22.2 per cent versus the actual value of 27 per cent -- which represents a much smaller differential than was noted for 1974. Alternatively, if the federal government wished to alter its input subsidy rate instead (and not their revenue tax rate) then the resulting subsidy rate required to conform to our pattern of optimality would be nearly 53 per cent (instead of 48 per cent).
TABLE 5.2 PREDICTED FEDERAL REVENUE TAX RATES OR INPUT SUBSIDY RATES FOR CONSTANT MARGINAL UTILITY RATIO -- NASH MODEL (a)

<table>
<thead>
<tr>
<th>Year</th>
<th>Actual Rate (%)</th>
<th>Predicted Rate (%)</th>
<th>Actual Rate (%)</th>
<th>Predicted Rate (%)</th>
<th>Actual Rate (%)</th>
<th>Predicted Rate (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1974</td>
<td>30.0</td>
<td>16.6</td>
<td>27.0</td>
<td>22.2</td>
<td>35.0(b)</td>
<td>35.2(b)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>35.0(c)</td>
<td>21.7(c)</td>
</tr>
<tr>
<td>1980</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>48.0</td>
<td>66.2(b)</td>
</tr>
<tr>
<td>OR</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>60.8(c)</td>
</tr>
<tr>
<td>1981</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Notes:
(a) $q_f$ is fixed at its 1972 value and $T^p$, $t_e^p$ and either $T^f$ or $t_e^f$ are held constant at their actual values in equation (10.5) for the time period considered.
(b) For a Canadian firm
(c) For a Foreign firm

Finally, if we look at the post-NEP potential values for the federal revenue tax rate (or input subsidy rate) for a Canadian firm we find that the actual rates in place conform almost exactly to the implied optimal rates in our (Nash) model. Consequently, it appears that, at least in the case of Canadian firms, by 1981, the federal government has increased the relative importance of oil production in their utility function to a level comparable to that which existed in 1972 (before the
emergence of the energy crisis). This result was also indicated earlier in our consideration of Table 5.1.

Unfortunately, this is not the case of foreign firms. The potential federal revenue tax rate which is necessary to be compatible with our notion of (Nash) optimality is significantly lower (only 21.7 per cent versus the actual rate of 35 per cent). On the other hand, if the federal government wanted to maintain Nash equilibrium rates and retain the implicit weighting of oil products in their utility function, but now alter their input subsidy rate, the federal government would have to increase their subsidy rate to foreign firms to the neighbourhood of 61 per cent.

The considerable disparity noted here regarding actual and implied optimal tax and subsidy rates for foreign firms again serves to demonstrate the much lower value attached by the federal government to oil production from foreign firms since the introduction of the NEP. The consequences of this (i.e., the efficiency loss to Canada), however, were duly noted in the preceding chapter.

5.6.4 An Illustration of the Costs of Non-Co-operative Behaviour

As a final application of our results suppose the federal and provincial governments during the 1974-81 period (post-NEP) were setting their tax and subsidy rates in a fashion that is consistent with our Nash assumption. Then, using the results of our analysis, the consequences or costs of the public sector not co-operatively setting the tax/subsidy rates may be derived. That is, the first finding of our model (that the combined tax effort is higher when tax rates are set in a Nash rather than co-operative setting) implies, during the 1974-81 period, Canada's oil production was lower than it otherwise might have been.
Unfortunately, the results of our illustration vary considerably with the choice of the model we employ (i.e., whether it be version II — where we assumed only one tax instrument per level of government, or version III — where there exists two tax instruments per level of government). We will consider the one tax instrument case first.

(i) An Illustration of the Costs of Non-Cooperative Behaviour — Model II

If we assume that both governments' utility functions are properly specified and their actual tax rates conform to the (Nash) optimality pattern, we can infer what the value of \( q_2^f \) (the ratio of marginal utilities) may be. Specifically, as we noted in model II the combined (Nash) tax effort of the federal and provincial governments was given to be:

\[
(16) \quad (T_{II}^f + T_{II}^p) = \frac{2\alpha - (q_2^f/P)}{1 + 2\alpha}
\]

where \( \alpha = -FF'/F' \), or given \( F(K_e) = K_e^\beta \), where \( \beta < 1 \) then \( \alpha = (1 - \beta)/\beta \). Rewriting (16) substituting for \( \alpha \), yields:

\[
(16.1) \quad (T_{II}^f + T_{II}^p)_{Nash} = \frac{2(1 - \beta) - \beta(q_2^f/P)}{2 - \beta}
\]

Therefore, plugging the actual values for \( T_f \) and \( T_p \) into (16.1) and employing various values for the output elasticity (\( \beta \)) we can solve for \( q_2^f \). Next, by plugging the value of \( q_2^f \) derived from our Nash model into the equilibrium co-operative expression, which can be represented as:

\[
(17) \quad (T_{II}^f + T_{II}^p)' = \frac{\alpha - (q_2^f/P)}{1 + \alpha} = 1 - \beta[1 + (q_2^f/P)]
\]

we can obtain estimates for the combined tax effort, for various values of the output elasticity, when tax rates are co-operatively set. (Note that by assuming \( q_2^f \) remains constant in going from (16.1) to (17) we are
assuming oil production remains as important in the federal utility function if we move to co-operatively set tax rates.

This exercise has been performed for three different time periods — 1974, 1980 (pre-NEP) and 1981 (immediate post-NEP). The results of this exercise, which are displayed in Table 5.3 below, are quite impressive. The gain to the domestic oil industry (via reduced tax liabilities) or alternatively, the implied additional oil production that could be generated as a result of co-operative behaviour is very significant. For example, if the output elasticity ($\beta$) is equal to 0.25, then in 1974, if the governments had co-operatively set their tax rates then the combined revenue tax rates could have been 42 per cent lower than their actual sum.

### Table 5.3 Percentage Differences in Combined Tax Effort

**Co-operative Behaviour Versus Nash Behaviour (Model II)**

<table>
<thead>
<tr>
<th>Output Elasticity</th>
<th>1974 (%)</th>
<th>1980 (pre-NEP) (%)</th>
<th>1981 (post-NEP) (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\beta = 1/4$</td>
<td>-42.2</td>
<td>-38.6</td>
<td>-25.4</td>
</tr>
<tr>
<td>$\beta = 1/2$</td>
<td>-28.2</td>
<td>-25.8</td>
<td>-17.0</td>
</tr>
<tr>
<td>$\beta = 3/4$</td>
<td>-14.1</td>
<td>-12.9</td>
<td>-8.5</td>
</tr>
</tbody>
</table>

In addition, the results in Table 5.3 indicate that the costs of non-co-operative behaviour appear to be highest in the period immediately following the quadrupling of world oil prices (i.e., 1974). That is, with each successive time period the potential or predicted percentage
change in combined tax rates, although still substantial, is lower than the previous period's estimate of the costs of non-cooperative behaviour.

(ii) An Illustration of the Costs of Non-Cooperative Behaviour - Model III

The results of this exercise, however, are dramatically different when we estimate the costs of non-cooperative taxing behaviour in our Model III version (i.e., two tax instruments per level of government). The reason for this dramatic reversal is, as we noted earlier, the implied values of $q_2^f$ (the ratio of federal marginal utilities) in our Nash version of Model III were negative in the 1974, 1980 (pre-NEP), and the 1981 period (immediate post-NEP period for foreign firms oil production). Consequently, with a negative value of $q_2^f$, plugged into the co-operative equilibrium expression (rather than a positive value), and treating all other tax instruments ($T^p_1$, $T^p_2$ and $T^f_1$) as constants, the optimal value of $T^f_2$ will increase. That is, the combined revenue tax rates will now increase when we employ a co-operative behavioural assumption rather than decrease (when $q_2^f$ is assumed to be positive).

As a result, our estimates of the consequences of non-cooperative behaviour (see Table 5.4) in model III (given negative estimates for $q_2^f$) indicate that the combined revenue tax rates are lower than they would otherwise be (i.e., than if rates were co-operatively set). For example, in the 1974 period, the combined revenue tax rates would be almost 45 percent higher under co-operative behaviour than they were (under assumed non-cooperative (Nash) behaviour).

Clearly then, the consequences of non-cooperative behaviour critically depends on the sign of $q_2^f$. If it is indeed negative, as suggested in Model III, then co-operatively set tax rates result in higher combined
revenue tax rates and hence, lower total oil production.

| TABLE 5.4 PERCENTAGE DIFFERENCES IN COMBINED REVENUE TAX RATES |
| CO-OPERATIVE MODEL VERSUS NASH MODEL (MODEL III) |
| % |
| 1974 | + 44.8 |
| 1980 (pre-NEP) | + 41.1 |
| 1981 (post-NEP) |
| - Canadian firm | + 23.9 |
| - Foreign firm | + 42.1 |

That is, if we accept that the two levels of government set their tax/subsidy rates in a manner that is consistent with our Nash behavioural assumption and further that the actual rates in effect in the 1974, 1980 and 1981 periods were Nash optimal (i.e., implying $q_2^f$ is negative) then the conclusion is that if the federal and provincial governments had instead co-operatively set their tax rates, Canada's oil production during this period would have been significantly lower than it actually was.

On the other hand, if $q_2^f$ is positive (i.e., the federal marginal utility of oil production is positive) then co-operation on the part of both levels of government in setting their tax rates will generate a lower combined tax effort and consequently, a higher total production level.
FOOTNOTES TO CHAPTER 5

1. The subsidy awarded to the domestic oil industry is the value of tax savings from incurring certain qualifying capital expenditures (e.g., exploration or development expenditures). For further details concerning these writeoffs see Chapter 2.

2. The Petroleum Incentive Payments program introduced a new regime of input subsidies differentiated by the degree of Canadian ownership. Canadian owned and controlled firms (i.e., firms that are at least 75 per cent Canadian owned and controlled) now qualify for larger input subsidies than a foreign owned firm producing the same type of oil in the same region of the country. In other words, the larger subsidy rates afforded Canadian owned and controlled firms are not related to differences in the costs of production but rather simply, the nationality of the owners.

3. It should be kept in mind, however, that despite the fact that this oil is assumed to be produced in the province of Alberta, both the federal and Alberta governments offer tax-based input subsidies and collect a share of the total production revenues.

4. The assumption of no market failures implies that tax and subsidy rates are imposed by each level of government for reasons other than attempting to correct market distortions (i.e., in our model tax and subsidy rates are imposed in order to maximize a government's utility function (only) as discussed below).

5. However, there is an alternative way of envisioning the federal revenue tax. From the producers point of view the fact that the domestic price of oil is kept below world levels can be viewed as essentially taxing potential revenues. In fact, in the case of oil exports this is exactly the situation. Any oil exported from Canada is sold at the world price of oil. The producer, however, only receives the domestic price of oil. The difference (the federal oil export charge) then can be thought of as a federal revenue tax and generates oil revenues for the federal government. This unfortunately is not the case for domestic sales of oil. The "tax" imposed on the oil industry (by receiving less than the world price for their oil) does not represent actual revenues for the federal government.

6. It can be shown algebraically that the federal tax indifference curves have the curvature shown in Figure 5.2 in what will be the relevant region (lying below the federal Nash reaction curve, RCF). That is, (1.1.3) can be rewritten as:

\[
\left(1.1.4\right) \quad \frac{dT^f}{dT^P} = \frac{T^f}{\alpha \left(1-T^P\right) - (1+\alpha)T^f}
\]

Differentiating (1.1.4) we obtain:
\[
(1.1.5) \quad \frac{d^2[\frac{dT_f}{dP}]}{dT^2} \bigg|_{Uf} = \frac{d[T_f]}{dP} - T_f(\alpha - (1+\alpha) \frac{dT_f}{dT}) \\
(D)^2
\]

where \( D \) is the denominator of (1.1.4). Then since we have shown that below the federal government's reaction curve, \( (\frac{dT_f}{dP})|_{Uf} \neq 0 \)

then (1.1.5) is positive, and the federal government's tax indifference curves are convex as demonstrated in Figure 5.2. Note, similar results could also be derived with respect to the provincial government's tax indifference curves (displayed in Figure 5.3 below).

7. The provincial government's optimal tax rate given our assumption of Nash-type behaviour, is derived by solving the identical programming problem as in the simple model (since we are retaining the assumption that the province maximizes a utility function with provincial oil-related revenues as its only argument). Therefore, the equation of their reaction curve in this Nash model will be unchanged.

8. Solving for \( T_{II}^P \) from the equations of \( R_{p} \) and \( R_{II}^f \) yields;
\[
T_{II}^P = \left[ \frac{\alpha}{1+2\alpha} \right] + \left[ \frac{\alpha(q_2/P)}{1+2\alpha} \right]
\]

whereas, previously we found, \( T_{I}^P = \left[ \frac{\alpha}{1+2\alpha} \right] = T_{II}^f \).

9. Similarly, solving for \( T_{II}^f \) from the equations of \( R_{p} \) and \( R_{II}^f \) yields;
\[
T_{II}^f = \left[ \frac{\alpha}{1+2\alpha} \right] - \left[ \frac{(1+\alpha)(q_2^f/P)}{1+2\alpha} \right]
\]

whereas, previously we found, \( T_{I}^f = \frac{\alpha}{1+2\alpha} \).

10. From footnotes 8 and 9 we can see that;
\[
(T_{I}^f + T_{II}^P) = \left[ \frac{2 \alpha}{1+2\alpha} \right]
\]

and 
\[
(T_{II}^f + T_{II}^P) = \left[ \frac{2\alpha - (q_2^f/P)}{1+2\alpha} \right].
\]

Therefore, \( (T_{II}^P + T_{II}^f) \) is greater than \( (T_{II}^P + T_{II}^f) \). The difference being
\[
= \frac{(q_2^f/P)}{(1+2\alpha)}.
\]
11. See footnote 10 above.

12. That is, the sum of the co-operative tax rates without output in the federal utility function (Model I) was shown to be;

\[ \frac{\alpha}{1 + \alpha} \]

Similarly, we have found the combined tax rates when oil production is present in the federal utility function to be;

\[ \frac{\alpha - (q_2^f / P)}{1 + \alpha} \]

Therefore, the reduction in combined tax effort in a co-operative model attributed to the inclusion of oil output in the federal utility function is given by;

\[ \frac{(q_2^f / P)}{(1 + \alpha)} \]

13. Note since we are introducing an input subsidy we are retaining our assumption that the federal government maximizes a utility function containing oil production and federal oil-related revenues as the two arguments. On the other hand, the provincial utility function contains provincial oil-related revenues only.

14. The simplifying assumption that the production function employed is a Cobb-Douglas production function of the form,

\[ Q = F(K_e) = K_e^\beta \]

where \( \beta < 1 \) was utilized in the process to derive equation (10).

15. Unless of course, \( q_2^f = 0 \).

16. This will be true provided the value of \( q_2^f \) is positive. If the ratio of marginal utilities were negative (i.e., the federal government received disutility from increased oil production) then the analysis of equation (15) which follows below will be reversed.

17. That is, if \( q_2^f \) is relatively large then \( (t_P^D - T_f)/(t_e^D - t_e^f) \) is likely to be negative and since we have assumed \( (t_e^D - t_e^f) \) is negative, it follows \( T_P^D \) must exceed \( T_f^D \).

18. Specifically, in the two dimensional model we analyzed earlier we saw that a linear mapping of optimal co-operative tax rates existed. In our multi-dimensional model, therefore, it follows that the optimal tax parameters resembles a plane in our sub-spaces so various combinations of \( T_f^D, T_P^D, t_f^D \) and \( t_e^D \) will be consistent with our co-operative equilibrium.

19. Except in the case of oil exports where the oil is sold at world prices but the domestic producer earns only the domestic price for his output -- the difference, the oil export tax -- goes to the federal government.
20. For example, including labour services in the provincial utility function is analogous to including oil production in the federal utility function, so the results should be comparable.

21. In fact, since the cost of financing the oil price subsidies are excluded from our definition of net federal oil revenues, this may explain a negative value for \( q_2^f \). With a more comprehensive model specifically including the oil price subsidies (i.e., which would necessitate modelling the consumption of oil), this unusual result (\( q_2^f < 0 \)) may disappear. Alternatively, it may simply be that the Nash behavioural assumption is inappropriate. That is, in the pre-NEP period it may very well be that the two levels of government are in fact, co-operatively setting their tax rates so \( q_2^f \) is really positive (see Column 2 of Table 5.1).

22. Taking this argument one step further, since the federal government stood to gain very little additional oil revenues from increased oil production (excluding the influence of the oil price subsidies), yet the provincial governments did, if we argued that the federal government's utility was adversely affected by the provincial government's level of utility, then it is possible that the value of \( q_2^f \) for the federal government at this time was negative.

23. That is, rewriting equation (15) as:

\[
T_f = \frac{P(1-t_e^f)}{(1-2t_e^P)} - \frac{(t_e^P - t_e^f)}{(1-2t_e^P)} - \frac{(q_2^f/P)(1-t_e^f-t_e^P)}{(1-2t_e^P)}
\]

then we can see that as \( q_2^f \) tends to go negative, \( T_f \) tends to increase.
CONCLUSION

The thesis attempted to examine some of the implications of the policy initiatives taken by both the federal and the oil-producing provincial levels of government in Canada since the quadrupling of world oil prices in 1973-74 and up to the introduction of the National Energy Program (October 1980).

In part, the thesis focussed attention on the funding inequity associated with the prevailing equalization program (brought about by the inherent revenue-sharing as defined by the pre-NEP tax regime) and as well, proposed an alternative system of equalization. This alternative program was labelled a two-tier system in that the second tier took the form of an interprovincial revenue-sharing pool focussing on revenues under sole provincial control (e.g., natural resource revenues). The funding of the first tier, on the other hand, remained the financial responsibility of the federal government, thereby preserving (at least in part) a long-standing tradition in Canada for the federal government to assume financial responsibility for equalization payments. Our analysis concluded that a two-tier proposal which combines the dual principles of "co-operative federalism" and "ability to pay" has a great deal of merit.

The thesis also represented a concerted attempt to disentangle the complex tax legislation as it applies to the domestic oil industry and to analyze the distortions introduced by the tax system as to: the choices among alternative inputs in the production of domestic oil (e.g., exploration capital versus development capital); and the profitability of different types of oil production (e.g., conventional (old and new), secondary, tertiary, non-conventional and frontier oil).
This exercise was performed employing as our model of an efficient tax system a regime characterized by a pure-profits tax. As well, this analysis was performed for both the pre-NEP tax regime and the post-NEP tax regime. Our results indicated that the NEP tends to discourage less costly (and possibly more secure) sources of oil (e.g., conventional and secondary oil). Consequently, by so doing, the NEP may make Canada more susceptible to decreases in the world price of oil.

In addition, the thesis presented a highly simplified but suggestive assessment of the effects of the distortions on total resource rents (i.e., net government revenues plus industry profits). Our results indicated that in the vast majority of cases the NEP tends to increase (relative to the pre-NEP tax regime) the efficiency loss to the Canadian economy.

Finally, the results of our analysis of the "optimal" tax regime indicated that the combined net tax effort will be lower when the federal and oil-producing provincial governments co-operatively set their tax rates. Furthermore, the net combined tax effort will be lower when the federal government includes a proxy for oil self-sufficiency in its utility function (e.g., total domestic oil production). Armed with these theoretical propositions the thesis then attempted (under the assumption that the actual tax and subsidy rates applied to old conventional oil production conform to the optimality pattern generated in our model) to illustrate: the revealed, or implied, policy preferences of the federal government (i.e., the implied relative weight attached to the oil self-sufficiency proxy in the federal government's utility function); the implications in terms of potential output tax rates or input subsidy rates of not maintaining a constant relative importance of the oil self-sufficiency proxy in the federal utility function; and finally, the costs
in terms of potential output tax rates of assumed non-cooperative taxing behaviour on the part of both levels of government.

The results of these exercises indicated that the implied relative importance of the proxy for oil self-sufficiency (relative to federal oil revenues) has varied considerably over time. In fact, in the non-cooperative (i.e., Nash) model our results indicated the federal government would be receiving disutility from our oil self-sufficiency proxy (i.e., increased domestic oil production) for the 1974 to 1980 period and even after the introduction of the NEP in the case of foreign-owned firms' oil production.

Consequently, the implications are profound for the net combined tax effort of the two levels of government, and subsequently for total oil production, if the federal government increases (relatively) the importance of gathering additional federal oil revenues rather than maintaining a constant marginal utility ratio. In fact, the results of our analysis appear to suggest that at least in part, we have come full-circle with respect to the implied value of post-NEP oil production. That is, our results indicate an almost identical value attached to the oil production argument in the federal utility function for Canadian firms' post-NEP production as was implied in 1972 (before the quadrupling of world oil prices). This however, was not the case for foreign-owned firms' post-NEP production.

In conclusion, although the thesis does provide some significant advances in terms of our understanding of some of the implications of Canadian oil tax policies, it also suggests a set of topics for future research. Included in this list would be an update and incorporation of the recent Alberta/Ottawa energy agreements of September 1981 into our
analysis to determine whether the efficiency effects of the new agreements are, or are not, consistent with the NEP's efficiency effects. As well, future research could be directed toward attempting to determine the intertemporal distortive effects on the time paths of exploration and development capital inputs, and subsequently, of various types of oil production, as a result of introducing a new tax regime (e.g., the NEP or even the Alberta/Ottawa energy agreements). This would obviously require the extension of this analysis to an explicitly dynamic framework.
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