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An Evaluation of
The Exploration Tax Credit

by

Tax Evaluation Division

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The Tax Evaluation Division is a specialized analytic unit independent of line management within the Department of Finance that conducts follow-up studies of the effectiveness of specific tax measures. The studies undertaken by the Division are intended to stimulate public and parliamentary discussion and to promote improved understanding of tax measures in general.

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EXECUTIVE SUMMARY

I. INTRODUCTION

The federal government announced the Exploration Tax Credit (ETC) in October 1985 as part of the Frontier Energy Policy, designed to encourage oil and gas exploration in Canada's frontier lands. The credit became available on December 1, 1985 and expired under a sunset clause at the end of 1990.

When the measure was introduced, the government announced that the cost and effectiveness of the credit would be evaluated and the present study analyses its economic and fiscal impacts. It examines such issues as the extent of exploration directly attributable to the ETC, the cost of the ETC to the federal government in forgone tax revenue, the impact of the credit on petroleum discoveries, and the degree to which the ETC has accomplished its original objectives.

II. BACKGROUND

Soon after the present government took office in September 1984, it set out principles to make energy policy more market-oriented and flexible. The Western Accord, signed in March 1985 by the Government of Canada and the western provinces, phased out the National Energy Program (NEP). The phasing-out of the substantial subsidies to offshore exploration provided by the Petroleum Incentives Program (PIP), which was part of the NEP, together with low petroleum price expectations and unfavourable geological prospects, meant that only companies with sufficient cash-flow and a longer-term view would make substantial investments in high-cost, high-risk offshore exploration. Hence the industry and provincial governments urged adoption of a replacement incentive for offshore exploration. The federal government responded by bringing in the ETC to provide transitional assistance until the commencement of offshore production.

The ETC is earned at a rate of 25 per cent of qualifying Canadian Exploration Expense (CEE) in excess of $5 million on a well in Canada. The credit is targeted at high-cost offshore oil and gas operations, but not discriminate between owners or locations. In addition, it cannot be earned on expenditures earning other forms of government assistance.

To the extent that ETCs earned in a particular year cannot be used to offset that year's tax, the firm is allowed to carry the credit back to offset income tax paid in any of the three preceding years. Taxpayers unable to claim the credit fully may earn a cash refund of up to 40 per cent of the unclaimed amount. The amount of ETC that cannot be claimed or refunded can be carried forward to offset tax in any of the following ten years. ETC claims and refunds reduce the cumulative CEE pool in the same year.

Tax reform terminated ETC refunds for 1988 and later tax years for companies that are not small Canadian-controlled private corporations, and applied the annual investment tax credit limitation rules to the ETC. In addition, for 1988 and later tax years, ETC claims and refunds reduce the cumulative CEE pool in the following tax year.

When the ETC was announced, the government expected the net federal cost of the ETC after the termination of PIP to be of the order of $150 to $250 million per year. The projections were based on petroleum prices that were considerably higher than those that eventually prevailed, however, and thus overestimated future exploration activity. The total amount of ETC earned from December 1985 to December 1990 was roughly $233 million in 1990 dollars. More than 95 per cent was earned on exploration in the frontier areas. About 60 per cent, or $145 million, was claimed by, or refunded to, 30 corporations in the year the credits were earned, with the remainder being carried forward to offset future taxes.

III. MAIN FINDINGS

The study developed a model of an oil and gas firm to analyze the tax variables affecting private investment decisions pertaining to exploration for Canadian oil and gas. Comparing the marginal after-tax cost of exploration with and without the ETC, the results show that, if a firm were taxable, the marginal after-tax cost would fall by roughly 26 per cent with the ETC. For non-taxable firms, the incentive was much less.

The model was also used to compare the incentive effects of other fiscal instruments with those of the ETC. For example, super depletion, which previously provided assistance to high-cost offshore exploration during the period April 1977 to March 1980, was found to provide the greatest incentive to exploration. With a 38 per cent corporate income tax rate, the ETC rate would have to be increased from 25 per cent to roughly 41 per cent to provide the same exploration incentive at the margin.

The Canadian federal tax system, even without the ETC, tends to encourage exploration at the margin. When comparing offshore exploration incentives in Australia, Norway, the United Kingdom, and the United States, the Canadian system without the ETC provides the greatest exploration incentive, with the exception of certain cases in the United Kingdom and Norway where a company can share tax benefits between its producing and non-producing projects. Conversely, the United States system appears to discourage marginal exploration drilling in its continental shelf.

Even if the Canadian tax structure as it affects exploration is internationally competitive, the key issue is what incremental impact the ETC had on exploration by oil and gas firms in Canada. A firm of private consultants was contracted for the study to assess the incrementality of the ETC by surveying companies that had earned an ETC at least once.

The case study analysis estimated incremental effects of the ETC in two ways -- at the individual well level, and at the level of the total exploration budget for the firm. The results of the case studies show that all of the individual ETC-assisted wells would have been drilled in essentially the same form at about the same time without the ETC. Only in two of the wells surveyed were some investors influenced by the ETC. Had the ETC incentive been terminated at the time the decision to drill was made, the impact would have been at most a delay of drilling for several months. As to the effect on exploration budgets, two out of nine companies had institutional mechanisms that made the ETC have some incremental impact on their Canadian exploration budget. One company directed the incremental funds to seismic exploration in the Canada lands. The other company said the incremental impact was either in additional seismic work, or in the drilling of an additional exploratory well in conventional operations in the provincial lands. As a result, the overall incremental activity attributable to the ETC was estimated to be about 5 per cent of qualifying Canadian exploration expenses, i.e., $47 million in 1990 dollars.

This measure of incrementality was incorporated into an assessment of the true opportunity cost of the ETC to the federal government in forgone tax revenue. A tax revenue simulation model was developed to estimate federal corporate tax revenues under actual and no-ETC scenarios. The actual case assumes that the firm attempts to minimize corporate tax according to the observed earning of the ETC. The no-ETC tax simulations assume a 5 per cent reduction in qualifying Canadian exploration expenses from the actual case. The cost of the total forgone federal tax revenues resulting from the ETC is estimated to be about $146 million in present value.

The $146 million cost of the ETC to the federal government is much smaller than the present value of ETC earned by corporations of $233 million. The difference is due first to the fact that many of the oil and gas firms are not sufficiently taxable to take immediate and full advantage of the ETC -- only about 60 per cent of ETCs earned were either claimed by, or refunded to, corporations in the year in which the credits were earned. The cost of the unclaimed balance is less to the government because it must be carried forward to offset tax in future years, and its value is discounted accordingly. Second, the cost of providing the ETC is reduced by the fact that most oil and gas companies have an array of large, unamortized tax deduction and credit pools, so that the earning of ETC does not necessarily imply an increased ability on the part of these firms to reduce tax. Third, the reduction of the cumulative CEE pool by ETCs claimed and refunded increases tax payable, which further reduces the cost to the government.

Bringing together the report's findings, we estimate that the $146 million cost of the ETC would generate $47 million in incremental exploration activity. This implies that every dollar of incremental exploration expenditure requires $3.2 of federal tax incentives.

The analysis was next extended to consider the ETC's effect on undiscovered resources. This part of the study, undertaken by the Department of Energy, Mines and Resources, is detailed and consistent in the treatment of geology, engineering, associated costs, and the economic and fiscal environment relevant to the area under evaluation. It assesses the effect of the ETC on incremental natural gas resources in the Mackenzie Delta and Beaufort Sea region. The simulation results indicate that retention of the ETC would increase the commercially viable portion of undiscovered resources by 4.2 per cent.

Although the analysis applies directly to the undiscovered natural gas resources of the Mackenzie Delta-Beaufort Sea region, the study indicates that the results are indicative of the ETC's impact on exploration in all of Canada's frontier petroleum resource basins. In other words, the retention of the ETC would have only a modest impact on the amount of resources found. This conclusion is consistent with the impact of the ETC on exploration activity described in the case-study interviews with the industry.

IV. CONCLUSION

The study concludes that the ETC incentive provided little stimulus to exploration in the oil and gas industry and has had a correspondingly modest effect on the discovery of new resources, for primarily three major reasons.

First, exploration costs are a small percentage of overall costs in most offshore oil and gas projects. Tax incentives aimed solely at exploration may not influence the overall cost significantly, since exploration, development, production, refining, and distribution costs all enter the assessment of the net return from the long-term commitment of funds to a project.

Second, offshore oil and gas projects, at which the ETC is effectively targeted, are highly risky. Great uncertainty surrounds both the possibility and pool-size of a discovery. The significance of the impacts of tax incentives on financial returns is typically overwhelmed by uncertainties about the project itself.

Third, many companies are in fact non-taxable and only some are eligible for the ETC refund. Others factor incentives into their investment decisions only if those incentives are extremely generous, such as the PIP.

Although the ETC has had little effect on exploration in Canada, it was not introduced solely to encourage exploration. The ETC was also intended to smooth out over time the fiscal shock to the system from the phasing out of the PIP. The analysis indicates that the ETC served this purpose of providing temporary assistance to the industry, although not to the extent initially projected, since lower-than-expected oil prices depressed incentives to explore.

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Appendices

AN EVALUATION OF THE EXPLORATION TAX CREDIT*

I. INTRODUCTION

A. Background

The Exploration Tax Credit (ETC), a special investment tax credit contained in the Income Tax Act, was announced in October 1985, as part of the federal government's Frontier Energy Policy.[1] This policy introduced a broad range of measures in addition to the ETC, including a new federal frontier royalty scheme, a new land management regime, and reduced regulatory burden. All were intended to encourage exploration for energy resources and other development in Canada's frontier lands.[2]

The ETC became available on December 1, 1985, and contained a sunset clause terminating it on December 31, 1990. It was introduced not solely out of concern about exploration, but to provide transitional help to the oil and gas industry in light of the government's decision to phase out the National Energy Program (NEP) and one of its principal elements, the Petroleum Incentives Program (PIP).

Oil and gas companies earn the ETC at a rate of 25 per cent on qualifying Canadian Exploration Expense (CEE) above $5 million on a well in Canada. The credit is non-discriminatory toward ownership and location. It cannot be earned on well expenses eligible for payments under the federal PIP or the Alberta Petroleum Incentives Program (APIP). If firms are not able to fully claim the credit earned in a year, 40 per cent of the unclaimed balance may be refunded in cash. The ETC claimed or refunded reduces the net amount of CEE that can be added to the cumulative CEE pool for tax deduction, in the same way that general investment tax credits reduce capital cost allowances.

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*. This paper could not have been completed without the co-operation of the Department of Energy, Mines and Resources and Revenue Canada, which supplied the basic data for the evaluation. Valuable comments and suggestions were provided by members of the Business Income Tax Division, the Department's Advisory Committee on Tax Evaluation, the Department of Energy, Mines and Resources, and Professors Robin W. Boadway, John F. Helliwell, and Glenn P. Jenkins.

1. Government of Canada, Canada's Energy Frontier -- A Framework for Investment and Jobs, (Ottawa: Supply and Services Canada, 1985).

2. The frontier lands include the mainland territories (Yukon and Northwest Territories), the West Coast, the Mackenzie Delta and Beaufort Sea, the Arctic Islands, Hudson Bay, the Grand Banks and Labrador Sea, and the Eastern Arctic and Nova Scotia offshore areas.

The 1987 tax reform altered some ETC provisions. Refundability was terminated for 1988 and succeeding taxation years for those companies that are not small Canadian-controlled private corporations. The annual investment tax credit limitation rules were applied to the ETC. Any ETC claimed or refunded reduced the cumulative CEE pool in the following tax year to simplify the taxpayers' calculation of optimal CEE deduction and ETC claims.

When the ETC was announced, its net federal costs after PIP was terminated were expected to be $150 to $250 million a year, depending on the projected level of high-cost exploration.[3]

B. Objectives of the ETC Incentive

When the present government took office in September 1984, it set out principles for a new energy policy that would be more market-oriented and flexible. Later, it announced a series of modifications to existing energy policy.

On February 11, 1985, the Governments of Canada and Newfoundland signed the Atlantic Accord, establishing joint management of the oil and gas off the coasts of Newfoundland and Labrador by the Canada-Newfoundland Offshore Petroleum Board. The Accord provided for the same sharing of resource revenue from offshore petroleum-related activities between Canada and Newfoundland as existed between Canada and provinces in Western Canada producing hydrocarbons. Newfoundland is thus entitled to establish and collect revenues from offshore resources as if they were on land.

A month and a half later, on March 28, the federal government signed the Western Accord with the producing provinces of British Columbia, Alberta, and Saskatchewan to replace the NEP with a more market-responsive pricing system and profit-sensitive fiscal regime. The government deregulated oil prices on June 1, 1985, and removed or phased out several federal oil and gas taxes, including the Natural Gas and Gas Liquids Tax, the Incremental Oil Revenue Tax, the Canadian Ownership Special Charge, as well as the Petroleum Compensation Charge. Further, the Petroleum and Gas Revenue Tax (PGRT) would no longer apply to either production from new wells of oil, natural gas, and gas liquids, from April 1, 1985, or to incremental production from pools subject to an enhanced recovery scheme; and PGRT levied on production would be completely phased out by the end of 1988.

An important aspect of the Western Accord was a committment that the federal government would introduce no new

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3. Government of Canada, The Exploration Tax Credit, Department of Energy, Mines and Resources, Press Release, (October 30, 1985).

oil and gas legislation that was discriminatory, either in terms of ownership or location. In the spirit of of this commitment, the government announced that the PIP, which discriminated against foreign investment and location, would be terminated on March 31, 1986, with grandfathering provisions to the end of 1987 on wells drilled in the frontier lands.

Exploration in the frontier areas had begun to decline in 1985, and was expected to decline further because of steadily decreasing oil prices and the impending termination of PIP. Only companies with sufficient resources and a longer term view would have been willing and able to make substantial investments in high-cost, high-risk offshore exploration. Taken together, the elimination of the PIP, low price expectations, and geological prospects in the petroleum industry at that time increased the risk borne by private investors in exploration and development. As a result, the industry and provincial governments called for a replacement incentive to maintain reasonable levels of exploration. The response of the government was the introduction of the ETC, a non-discriminatory tax instrument designed to provide the industry with transitional assistance until the commencement of offshore production.

The ETC was expected to benefit mainly high-cost wells in Canada's offshore federal lands because high-cost exploration typically occurs in the off-shore areas, and also because of the $5 million threshold for earning ETC. Some exploration wells in the mainland territories and on the provincial lands were also expected to earn the credit.

To offer more balanced encouragement to oil and gas exploration in Canada's frontier areas, the federal government also introduced, in its Frontier Energy Policy, an Investment Royalty Credit (IRC). IRCs may be earned, at a 25-per-cent rate, on the first $5 million of eligible expenses on new exploration wells on frontier lands, and are therefore targetted at both low and high-cost wells. IRCs earned are used to offset federal royalties so, for non-producing wells, the value of the IRC must be discounted to take account of the delayed application of the royalty credit. Importantly, however, the ability of firms to transfer IRCs among projects can increase the credit's value.[4]

The new energy policy also abolished the controversial 25-per-cent Crown-share back-in, and the land-issue and bidding mechanism, discussed later.

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4. For many (offshore) projects, a relatively long lag exists between exploration and production, and thus between exploration and royalty payments. For this reason, IRCs earned on wells that are non-producing may be transferred and applied to offset federal royalties payable on producing projects, thus increasing the present value of the credit.

When the Minister of Energy, Mines and Resources announced the ETC as part of the Frontier Energy Statement, he said the new tax credit "will ensure that Canada's exploration fiscal regime remains internationally competitive". In addition, the Government of Canada expected the new measures to put high-cost exploration investments on a more equal footing with enhanced oil recovery, heavy oil, and oil sands projects in Western Canada, thus ensuring that frontier exploration and development would continue to contribute strongly to Canada's energy security.

C. Objectives and Scope of the Evaluation

When the ETC was introduced, the Minister of Energy, Mines and Resources directed the Petroleum Monitoring Agency to collect data on a timely basis "to enable the government to evaluate both the cost of the ETC and its effectiveness in meeting policy objectives". Since the incentive is scheduled to expire at the end of 1990, the industry urged the government in 1990 to consider whether it would continue the program.[5]

This study aims to evaluate the effectiveness of the credit. Its focus is two-fold:

- to evaluate the impact of the ETC on exploration activity in the Canadian petroleum industry; and
- to measure the impact of the ETC on federal tax revenues in order to assess the cost-effectiveness of the credit.

The paper is organized as follows:

Chapter II describes exploration activity in the oil and gas industry in the past 15 years and explores the major determinants of exploration. It pays special attention to the frontier areas since these are most affected by the ETC.

Chapter III spells out the important features of the ETC and changes under the 1987 tax reform. It presents the actual and expected amounts of ETCs earned, claimed, carried back and carried forward.

Chapter IV examines exploration investment decisions under the current fiscal regime. The after-tax cost and user cost of exploration are derived, allowing for an assessment of the ETC incentive to the private sector. The chapter compares

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5. The Canadian Petroleum Association made a submission before the February 1990 budget requesting that the government "address the continuation of the program in the budget of 1990. The sooner the petroleum industry is aware of the status of the ETC, the decision to drill or not will have one less uncertainty".

exploration incentives under the ETC with those under alternative incentive mechanisms. The chapter also compares the Canadian fiscal regime and incentives with those in other countries.

Chapter V considers the framework in which corporate decisions about major investment projects in the oil and gas industry are made. It investigates the extent to which exploration expenses are directly attributable to the ETC in the study period. It presents the findings of a case-study survey based on interviews by consultants with representatives of various companies in the industry.

Chapter VI analyzes the relationship between the ETC and other federal tax provisions such as the CEE deduction and earned depletion. It develops a simulation framework to analyze the effect of the ETC on federal tax revenues. This analysis, together with the findings on the incremental effect of the ETC on exploration activity discussed in Chapter V, allows us to compare ETC costs and benefits and thus assess the incremental tax cost of the ETC to the federal government.

Chapter VII assesses the impact of the ETC on undiscovered resources of oil and gas. The analysis uses a marginal analysis model for gas reserves developed by the Department of Energy, Mines and Resources.

Chapter VIII summarizes our results and draws conclusions about the effects of the ETC.

II. EXPLORATION ACTIVITIES IN THE CANADIAN OIL AND GAS INDUSTRY

This chapter describes the nature of exploration for mineral fuels in Canada and provides background information necessary for evaluating the ETC. It presents statistics on expenditure patterns and other aspects of the behaviour of the industry in the past 15 years.

The first section describes trends in the Canadian oil and gas industry from 1975 to 1989. The discussion includes factors affecting the pattern of exploration and development of mineral fuels and a summary of information on the leasing of land for exploration.

A. Trends in Exploration Activities

Because exploration can be viewed as long-term investment in the oil and gas industry, the proportion of overall investment devoted to it is of great interest. Table 2.1 compares total national spending on exploration in the petroleum industry with overall national investment from 1975 to 1989. In the first part of this period, exploration expenditures rose steadily to a peak in 1980 of 7.4 per cent of total investment, following the second OPEC oil price shock of 1979. By 1989, exploration had fallen to a share of only 2 per cent.

The introduction of the NEP at the end of 1980 and the recession of 1981-82 led to a drop in exploration spending. It rebounded in 1983, but fell again in 1986 as world oil prices dropped dramatically after a large increase in Saudi oil production. This coincided with the termination of the PIP and the deregulation of oil and gas in Canada. By contrast, except during the recession in the early 1980s, total investment in the economy increased throughout the period. The third column of Table 2.1 shows further that investment in the Canadian economy shifted toward the upstream petroleum industry from the mid-1970s to the mid-1980s, and then returned to the pre-mid-1970s level.

Trends in exploration spending in the petroleum industry followed different patterns in frontier and conventional lands. Table 2.2 shows that frontier exploration increased from 1975 to a peak in 1984. Conversely, exploration on provincial lands substantially diminished in 1981 and 1982 due to the recession. The continuation of strong exploration in the frontier area during the recession was partly due to the NEP and its PIP, which provided enormous incentives to the oil and gas companies to explore and develop, especially on the frontier.[6]

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6. Helliwell, J.F., M.E. MacGregor, R.N. McRae, and A. Plourde, Oil and Gas in Canada: The Effects of Domestic Policies and World Events, Canadian Tax Paper No. 83 (Toronto: Canadian Tax Foundation, 1989), p. 137.

After 1984, frontier exploration expenditures started to decline; they fell further in 1986 and 1987 when the PIP began to be phased out. They finally returned to the pre-1979 level by the end of the period. Conventional lands exploration expenditures followed a more stable pattern, peaking in 1980 and again in 1985, in line with swings in international oil prices. In sum, exploration in the conventional lands seems to follow general economic conditions and world oil prices. The size of incentive provided by governments seemed to be critical in the frontier areas, where the costs of exploration tend to be prohibitive.

Total exploration expenditure includes three major components: land acquisition and rental, geological and geophysical activity, and drilling. Only drilling is closely related to expenses that qualify for the ETC. Tables 2.3a and 2.3b separate exploration expenditures by type and region. They show that land acquisition and rental costs are much lower for frontier projects than for provincial exploration. But conventional lands often include well-established infrastructure that makes exploration, development and production much cheaper. Drilling costs account for most of the exploration expenditures in both areas, although they are much higher on the frontier. Much frontier drilling takes place offshore -- for example, in the Beaufort Sea and off the coast of Newfoundland -- where it is far more difficult and expensive than on land.[7]

Table 2.4 compares the completions of exploratory wells in the Canada lands and provincial lands. Drilling in both areas rose steadily from 1983 to 1985, then dropped slightly in 1986. The number of completed frontier wells dropped, however, by roughly four-fifths in 1987, while the number of conventional wells increased in both 1987 and 1988. Well completions declined in both areas in 1989, with frontier well completions falling to almost half their 1988 level.

The objective of exploration, of course, is to discover additional pools of recoverable oil and gas and to expand established reserves. The volume of established reserves of crude oil in conventional areas fell steadily over the study period, while the volume of frontier reserves increased gradually, except for a large increase in 1981 and a sharp reduction in 1984. These anomalies are explained in part by overly optimistic projections that were later adjusted.

Almost all frontier production was at Norman Wells in the Northwest Territories. Table 2.5 shows that frontier reserves of crude oil, as a share of all Canadian reserves, rose

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7. See, for example, The Coopers and Lybrand Consulting Group, Petroleum Incentive Program: Program Evaluation Study, a report prepared for the Department of Energy, Mines and Resources (November, 1985).

from about 1 per cent in the mid-1970s to more than 20 per cent in the late 1980s. Overall, the total established reserves of crude oil remained level from 1978 to 1989, fluctuating around 1 billion cubic metres.

Reserves of natural gas followed a different pattern illustrated in Table 2.6. Marketable natural gas reserves in conventional areas rose slowly to a peak in 1984, while frontier marketable natural gas reserves increased uniformly over the entire 15 years.[8]

Frontier reserves of crude oil and marketable natural gas thus assumed relatively greater importance, while the total established reserves of both remained quite stable.

B. Key Determinants of Exploration Expenditures

The key factors that influence the decision to invest in exploration for fossil fuels include geological prospects, prices of fuel in the international market, the fiscal regime faced by the industry, and the internal cash flow available to the companies. It is a complex decision process.

(a) Geology

Exploration activities depend heavily on geological prospects of potential resources existing in a particular area. Exploration activities related to the increments in established reserves of oil in the frontier lands exhibit relatively little drilling success over the interval from 1975 to 1985. According to internal assessments by the Department of Energy, Mines and Resources, the drilling results in frontier lands before the announcement of the ETC were less successful than hoped for. This tended to dampen exploration activity in the area.

Another important factor influencing exploration activity, related to the geological prospects of a potential resource, is the threshold volume of a field, defined loosely as the quantity of resource in the field required to justify its development, taking into account the costs of transporting the resource to market. The more remote an area, the higher are the transportation costs, in general, and the greater is the field's threshold volume. Threshold volume considerations are particulary important in the evaluation of frontier gas fields, since pipelines are typically needed to ship the gas to market.

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8. In both Table 2.5 and Table 2.6, additions are presented as gross additions after any retroactive adjustments. Initial estimates tend to overestimate or underestimate actual recoverable reserves. Corrections to the original figures are included in subsequent years. Therefore, it is possible for a negative value to appear in the additions column of both Table 2.5 and Table 2.6.

(b) Prices of Oil and Gas

International prices of crude oil are also a critical factor, perhaps the most critical, in decisions on exploration, development, and production. Table 2.7 shows that the world price of oil more than tripled from 1975 to 1981 after the second OPEC oil price shock. Oil prices then fluctuated slightly until 1986, when they dropped by one-third, and thereafter remained relatively stable except for a rise in 1987. The decline may be explained by competition from non-OPEC sources such as the North Sea, reduced discipline in the cartel, and restrained oil and gas consumption by both industry and the public.

Wellhead prices are the prices of most immediate interest to upstream operations. Until the mid-1980s, Western Canada wellhead prices were regulated under the National Energy Program, and thus cushioned from the volatile price movements in the global market. As a result, prices rose uniformly up to a peak in 1985. Deregulation under the Western Accord, coupled with the fall in world prices, brought a sharp drop in 1986 and another drop in 1988. Prices of natural gas at the plant gate followed a similar pattern.

(c) The Fiscal Regime

Taxes and incentives can strongly affect the behaviour of companies and the net revenues companies receive from their oil and gas operations. These effects depend not only on the financial and taxpaying status of the firm, but also on the tax rules, which have varied a great deal. In the past 15 years, a number of oil and gas tax regimes were introduced and removed, compounding uncertainty for companies in an already far from certain investment environment.[9]

In 1973, the Middle East War brought OPEC's first unilateral price increases, which caused not only a shock to the economy but raised questions about national security and energy supplies. The federal government responded with an interventionist energy policy. It introduced an Oil Import Compensation program in March 1974 to subsidize the price of imported oil down to domestic regulated wellhead prices. The Petroleum Administration Act of 1975 gave the federal government final authority to decide interprovincial crude oil and gas prices.[10] This pricing system directly regulated domestic crude

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9. See Helliwell, J.F., M.E. MacGregor, R.N. McRae and A. Plourde, "Oil and Gas Taxation," Osgoode Hall Law Journal, Vol. 26, No. 3 (Fall 1988).

10. Helliwell, J.F., M.E. MacGregor, R.N. McRae and A. Plourde, Oil and Gas in Canada: The Effects of Domestic Policies and World Events, Canadian Tax Paper No. 83 (Toronto: Canadian Tax Foundation, 1989).

oil prices, subsidized eastern Canadian imports, and controlled both the domestic price and the amount of hydrocarbon exports. Federal oil subsidies increased substantially as the level of imports rose, placing increasing pressure on the government's fiscal capacity.

To encourage greater exploration for oil and gas in Canada, the federal government replaced percentage depletion with a more generous depletion allowance system. The federal budget of November 1974 introduced earned depletion which allowed one-third of eligible expenditures to be written off, but the claim was limited to 25 per cent of resource profits as defined for earned depletion purposes. This allowance was later supplemented by "super depletion", introduced in March 1977, which allowed exploration expenditures above a threshold of $5 million to qualify for an allowance earned at a rate of 66 2/3 per cent. This was in addition to both earned depletion earned at the rate of 33 1/3 per cent, and the immediate 100 per cent write-off of those exploration expenses. The combined effect of super depletion, earned depletion and immediate write-off meant that fully 200 per cent of these expenses were deductible.

World oil prices began to rise in early 1979 with the second OPEC oil price shock. By 1980, they had doubled. This compounded the federal government's difficulty in subsidizing oil imports. It also allowed oil producers and oil-producing provinces to gain significant amounts of revenue, which intensified conflict between the federal government and the producing provinces. When the government attempted to initiate an energy price strategy moving domestic oil prices towards 85 per cent of world prices, and to levy a tax of 18 cents a gallon on transportation fuels, the budget was defeated in the House of Commons and the government lost the subsequent election.

The newly-elected federal government unveiled the NEP in October 1980.[11] The policy had several goals, including the control of domestic prices, increased Canadianization of the oil and gas industry, and the shifting of consumption from oil to natural gas. A number of new levies were introduced to further these objectives. The Petroleum Compensation Charge raised funds to help subsidize oil imports in the Maritimes and synthetic oil. Another levy, the Natural Gas and Gas Liquids Tax, was added to the price of all gas and gas liquids produced in Canada.

In addition, an 8-per-cent PGRT was levied on oil and natural gas production revenues net of operating costs. Subsequently, the federal government signed agreements in 1981 with the producing provinces for the implementation of the NEP, including a restructuring of the PGRT. The PGRT rate was increased to 16 per cent. The introduction of a 25-per-cent resource allowance, which included the PGRT in its base, meant

11. Department of Finance, The Budget (October 18, 1980).

that the effective rate of the PGRT was 12 per cent. This rate was reduced to 11 per cent, beginning June 1, 1982, and a $250,000 credit against the PGRT was offered to eliminate the PGRT burden for small producers.

The PIP was also introduced as part of the NEP to replace earned depletion allowances.[12] PIP was a system of cash grants to corporations; it varied between exploration and development, between regions and according to the degree of Canadian ownership of the individual firms.

The federal government introduced the Canadian Ownership Special Charge in May 1981 to finance its acquisition of the Canadian assets of Petrofina and encourage Canadianization of the industry. Moreover, the Crown was granted a retroactive right to acquire a 25-per-cent back-in interest in any Production Licence on the Canada lands.

In 1985, the Western Accord deregulated domestic oil prices over a period of one-and-a-half years and removed controls on short-term exports. Deregulation placed greater reliance on the market. The PIP was terminated in March 1986, but remained effective until 1987 because of grandfathering provisions. The Western Accord phased out the PGRT as well.

The Canadian Exploration and Development Incentive Program (CEDIP) was introduced in April 1987 to encourage exploration and development. It offered cash grants of one-third of up to $10 million a year in eligible expenditures, which included Canadian exploration and development expenses, net of related overhead expenses, plus abandonment and restoration costs on a well site if there was no commercial production. This grant did not discriminate between locations, but it could not be claimed on any expenses earning other incentives such as those available through the PIP, APIP, or ETC. The CEDIP rate was reduced to 25 per cent, for expenses incurred between September 30, 1988, and June 30, 1989, and was reduced once again, to a rate of one-sixth of eligible expenses, until its expiry on January 1, 1990. Moreover, the April 1989 budget announced that after April 27, 1989, the only expenses which would continue to qualify for CEDIP were those in respect of wells spudded and in progress on April 27, and those undertaken pursuant to legally binding commitments entered into prior to April 27.[13]

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12. The rate of 33 1/3 per cent at which eligible Canadian oil and gas exploration expenditures (all CEEs except those relating to mining) could be added to the earned depletion base was phased down, beginning in 1983. For 1985 and subsequent years, additions could no longer be made for these expenditures incurred in the Canada lands.

13. See Department of Finance, Budget Papers, (April 27, 1989), p17.

The Canadian Exploration Incentive Program (CEIP) provided grants equal to 30 per cent of the cost of mineral and oil and gas exploration financed with flow-through share arrangements, up to a maximum of $10 million a year. It started October 1, 1988, and ended February 20, 1990.

(d) Internal Cash Flow

The petroleum industry tends to finance exploration with the least possible use of borrowed funds. This is no doubt due in part to the risk and consequent high returns that would be demanded by creditors. Internal cash flow seems to be particularly important to finance upstream investments. This is especially true for exploration in the frontier areas, because of added difficulty and uncertainty in finding oil and gas, the longer period necessary to exploit reserves (for various technical and financial reasons), and the difficulty of predicting oil and gas prices far into the future.[14] Internal cash flow represents the amount of cash generated from the upstream activity that would be made available for financing the upstream investment.

Table 2.8 shows the relationship between total capital expenditures and internal cash flow in the upstream industry. In aggregate, exploration expenditures never exceeded internal cash flow, although total capital expenditures were sometimes greater than the amount of internally generated funds. The internally generated funds of companies surveyed by the PMA rose from $5.2 billion in 1981 to a peak of $9.5 billion in 1985. In 1986, this flow fell sharply to $5.3 billion, before fluctuating around $6 billion for the rest of the decade. This closely follows the pattern of aggregate exploration expenditures, which reached their peak in 1984 and 1985 at about $5 billion before dropping by roughly a third in 1986, and remaining at a level of about $3 billion for the rest of the decade.

C. Resource Management

The way governments manage the country's resources also influences exploration. The Canada Petroleum Resources Act (CPRA) sets out the rights and obligations of companies wishing to explore and exploit oil and gas resources in the Canada lands. Before February 1987, they were set out in the Canada Oil and Gas Act. Before March 1982, the Canada Oil and Gas Land Regulations governed these activities. Each province has its own legislation on the rights and obligations of companies to drill on, develop, and produce from provincial lands.

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14. See, for example, Department of Energy, Mines and Resources, "2020 Vision: Canada's Long Term Energy Outlook", a working paper prepared by the Economic and Financial Analysis Branch (January 1990).

(a) Canada Lands

To explore for and exploit oil and gas resources on the Canada lands, corporations make contractual arrangements with the government through various forms of leases, permits, agreements, or licences. Normally, companies obtain an Exploration Licence before exploration. This licence grants exclusive right to explore and drill for oil and gas on a particular parcel of land for a limited time.

If the discovery of oil or gas meets specific criteria, the holders may obtain a Significant Discovery Licence giving it indefinitely the exclusive right for exploration in the area. If the economics and technology enable commercial production, the company may obtain a Production Licence, as explained below.

Under federal legislation (CPRA), the Minister of Indian and Northern Affairs has responsibility for administering mineral rights in the Arctic lands and waters and the mainland territories (the Yukon and Northwest Territories), while the Minister of Energy, Mines and Resources is responsible for the east and west coast offshore areas, and Hudson Bay.

Exploration Licence

A parcel of land may be put up for bid at the initiative of the industry or the government. In either case, under the CPRA, the Government of Canada is required to call for bids on parcels of land. These bids are submitted to the Canada Oil and Gas Lands Administration, the Canada-Newfoundland Offshore Petroleum Board, or the Canada-Nova Scotia Offshore Oil and Gas Board.

A call for bids specifies the legal description of the parcel up for bid, the corresponding geological formations and substances, and other terms and conditions, including the duration of the exploration licence. Bid selection since introduction of the CPRA has normally been based on the amount of money the bidder commits to exploration on the parcel of land in the first period of the term. Exceptions occur where the old rules may still apply. For example, the term of an exploration licence negotiated before December 20, 1985, could be renegotiated only once for a further term not exceeding four years. This provision governed most exploration licences issued to the companies that earned ETCs from 1985 to 1990.

The exploration licence issued to the successful bidder confers the right to explore for petroleum, the exclusive right to drill and test for petroleum, and the exclusive right to develop for production.

The licence contains terms and conditions the holder must fulfil to keep these rights. According to the CPRA, the term shall not exceed nine years. Usually it ranges from six to nine years, although it may be extended in exceptional cases. The term is usually divided into two periods. By the end of the first, one or more wells must be drilled to a depth sufficient to evaluate a defined geological objective. In the second, the licensee normally pays annual rentals at a prescribed rate at the beginning of each year; these rentals are normally refundable up to allowable expenditures on the land.

Significant Discovery Licence

Before drilling a well, the successful bidder has to submit a drilling program to the Engineering Branch of COGLA or the relevant offshore Boards for approval. The program specifies the number of wells to be drilled, location, type of rigs to be used, intended drilling depth, contingency plans, environmental concerns, and other details.

A significant discovery means the first well on a geological feature that demonstrates by flow testing the existence of hydrocarbons and suggests their accumulation has potential for sustained production. After a significant discovery, the company may submit an application for a significant discovery licence. The application requests that the company be granted the oil and gas field on which the discovery was made. COGLA may or may not amend the declaration of significant discovery by increasing or decreasing the significant discovery area.

Where a significant discovery licence is issued, the holders have exclusive oil and gas rights to the field in perpetuity.

Production Licence

If a petroleum discovery justifies the investment of capital and effort to bring it to production, the company may apply for a declaration of commercial discovery. Upon approval, the company may then apply for a Production Licence. This licence confers:

- the right to explore for petroleum,
- the exclusive right to drill and test for petroleum,
- the exclusive right to develop in order to produce,
- the exclusive right to produce petroleum from those lands, and
- a title to the petroleum produced.

A production licence has a term of 25 years, although the term may be extended as long as petroleum continues to be produced commercially.

(b) Provincial Lands

Drilling a well on provincial lands involves many different sets of regulations, since each province has its own legislation on rights to the oil and gas it owns. Most exploration on the provincial lands is ineligible for the ETC, since it applies only to high-cost well drilling -- that is, more than $5 million a well. Alberta is used in the example below because it accounts for the most significant portion of exploration activities on the provincial lands.

If a company is interested in developing a "play" on a specific tract of the provincial crown lands, it will request that the land be "posted", either for itself or on behalf of a consortium. The Alberta Department of Energy regularly holds auctions on such posted land.[15] The highest bid is accepted and the lease is issued to the name of the successful bidder.

The registered owner has mineral rights to the licensed land and nominates an operator who will be responsible for developing it. The operator applies to the Energy Resources Conservation Board for a well licence. The Board may grant it subject to conditions and restrictions laid down in the Oil and Gas Conservation Act and Regulations.

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15. See, for example, Government of Alberta, "Alberta Oil and Gas Tenure", a paper prepared by Alberta Energy, Mineral Resources Division (1987).

Table 2.1

Exploration Expenditure in the Petroleum Industry and Total Investment, 1975-1989

Year	Exploration Expenditures in the Petroleum Industry ($M)	Total Investment ($M)	Ratio (%)
1975	901	38,216	2.36
1976	1,176	43,636	2.70
1977	1,998	46,597	4.29
1978	2,754	50,360	5.47
1979	3,796	58,355	6.51
1980	4,920	66,193	7.43
1981	4,330	79,604	5.44
1982	3,802	76,762	4.95
1983	4,635	73,519	6.30
1984	5,403	75,378	7.17
1985	5,721	90,504	6.32
1986	3.504	97,086	3.61
1987	3,047	109,162	2.79
1988	3,319	123,164	2.69
1989	2,759	136,862	2.02

Source: Canadian Petroleum Association, Statistical Handbook, Section IV; Statistics Canada, Private and Public Investment in Canada, Catalogue 61-206.

Table 2.2

Exploration Expenditure in the Petroleum Industry By Region, 1975-1989

Year	Canada Lands		Provincial Lands		Total	
	Amount ($M)	Percentage (%)	Amount ($M)	Percentage (%)	Amount ($M)	Percentage (%)
1975	348	38.6	553	61.3	901	100.0
1976	352	29.9	824	70.1	1,176	100.0
1977	380	19.0	1,618	81.0	1,998	100.0
1978	513	18.6	2,241	81.4	2,754	100.0
1979	637	16.8	3,159	83.2	3,796	100.0
1980	809	16.4	4,111	83.6	4,920	100.0
1981	1,213	28.0	3,117	72.0	4,330	100.0
1982	1,624	42.7	2,178	58.1	3,802	100.0
1983	2,244	48.4	2,391	51.6	4,635	100.0
1984	2,433	45.0	2,970	55.0	5,403	100.0
1985	2,117	37.0	3,604	63.0	5,721	100.0
1986	1,235	35.2	2,269	64.7	3,504	100.0
1987	414	13.6	2,633	86.4	3,047	100.0
1988	507	15.3	2,812	84.7	3,319	100.0
1989	416	15.1	2,343	84.9	2,759	100.0

Source: Canadian Petroleum Association, Statistical Handbook, Section IV.

Table 2.3a

Components of Exploration Expenditures on Canada Lands, 1975-1989

Year	Geological and Geophysical Expenditure		Land Acquisition and Rentals		Drilling Costs		Total Exploration Expeditures	
	Amount ($M)	Percentage (%)	Amount ($M)	Percentage (%)	Amount ($M)	Percentage (%)	Amount ($M)	Percentage (%)
1975	119.5	34.4	5.6	1.6	222.0	64.0	347.1	100.0
1976	97.0	27.7	4.7	1.3	248.7	71.0	350.4	100.0
1977	73.2	19.3	5.3	1.4	301.7	79.4	380.2	100.0
1978	61.2	11.9	8.3	1.6	443.6	86.5	513.1	100.0
1979	51.8	8.1	7.8	1.2	577.7	90.6	637.3	100.0
1980	99.3	12.3	9.8	1.2	700.0	86.5	809.1	100.0
1981	131.1	10.8	10.5	0.9	1,070.8	88.3	1,212.4	100.0
1982	162.6	10.2	4.7	0.3	1,425.9	89.5	1,593.2	100.0
1983	149.0	6.6	0.2	0.0	2,094.5	93.4	2,243.7	100.0
1984	194.6	8.0	3.5	0.1	2,235.0	91.9	2,433.1	100.0
1985	167.5	7.9	0.0	0.0	1,950.0	92.1	2,117.5	100.0
1986	97.8	7.9	3.8	0.3	1,134.2	91.8	1,235.8	100.0
1987	44.2	10.7	2.1	0.5	367.8	88.8	414.1	100.0
1988	79.7	15.7	2.5	0.5	425.2	83.8	507.4	100.0
1989	90.2	21.7	1.1	0.3	324.7	78.1	416.0	100.0

Source: Canadian Petroleum Association, Statistical Handbook, Section IV.

Table 2.3b

Components of Exploration Expenditures on Provincial Lands

Year	Geological and Geophysical Expenditure		Land Acquisition and Rentals		Drilling Costs		Total Exploration Expeditures	
	Amount ($M)	Percentage (%)	Amount ($M)	Percentage (%)	Amount ($M)	Percentage (%)	Amount ($M)	Percentage (%)
1975	115.6	20.9	250.9	45.3	187.3	33.8	553.8	100.0
1976	177.1	21.4	339.3	41.1	309.3	37.5	825.7	100.0
1977	280.2	17.3	854.8	52.9	482.3	29.8	1,617.3	100.0
1978	440.6	19.7	1,006.5	44.9	794.1	35.4	2,241.2	100.0
1979	466.1	14.8	1,430.2	45.3	1,262.6	40.0	3,158.9	100.0
1980	615.5	15.0	1,489.1	36.2	2,006.1	48.8	4,110.7	100.0
1981	455.2	14.6	861.8	27.6	1,800.7	57.8	3,117.7	100.0
1982	370.3	17.0	563.7	25.9	1,244.7	57.1	2,178.7	100.0
1983	460.2	19.2	759.6	31.8	1,171.4	49.0	2,391.2	100.0
1984	561.9	18.9	1,045.1	35.2	1,362.9	45.9	2,969.9	100.0
1985	612.6	17.0	1,329.5	36.9	1,661.5	46.1	3,603.6	100.0
1986	517.9	11.4	547.5	12.1	3,471.5	76.5	4,536.9	100.0
1987	491.7	18.7	1,001.3	38.0	1,139.4	43.3	2,632.4	100.0
1988	628.6	22.4	868.4	30.9	1,314.7	46.8	2,811.7	100.0
1989	544.3	23.2	737.7	31.5	1,060.9	45.3	2,342.9	100.0

Source: Canadian Petroleum Association, Statisitcal Handbook, Section IV.

Table 2.4

Exploratory Well Completions in Canada, 1983-1989

Year	Canada Lands	Provincial Lands	Total
1983	35	2,100	2,135
1984	42	2,767	2,809
1985	64	3,257	3,321
1986	57	2,008	2,065
1987	13	2,353	2,366
1988	14	2,963	2,977
1989	9	2,416	2,423

Source: Petroleum Monitoring Agency Canada, Canadian Petroleum Industry: Monitoring Report, 1984-1989, Table A 18.

Table 2.5

Established Reserves of Crude Oil, 1975-1989
(Thousands of Cubic Metres)

	Canada Lands				Provincial Lands				Total
Year	Opening Balance	Additions	Production	Closing Balance	Opening Balance	Additions	Production	Closing Balance	Closing Balance
1975	11,250	1	160	11,091	1,319,613	(6,044)	79,974	1,233,595	1,244,686
1976	11,091	(29)	142	10,920	1,233,595	9,303	72,894	1,170,004	1,180,924
1977	10,920	(21)	138	10,761	1,170,004	12,720	73,206	1,109,518	1,120,279
1978	10,761	(17)	146	10,598	1,109,518	42,280	72,338	1,079,460	1,090,058
1979	10,598	10,700	150	21,148	1,079,460	62,100	80,704	1,060,856	1,082,004
1980	21,148	22	161	21,009	1,060,856	(55,445)	75,192	930,219	951,228
1981	21,009	175,024	173	195,860	930,219	4,533	67,037	867,715	1,063,575
1982	195,860	(14)	173	195,673	867,715	22,978	65,233	825,460	1,021,133
1983	195,673	9,989	169	205,493	825,460	59,526	67,760	817,226	1,022,719
1984	205,493	(71,998)	175	133,320	817,226	72,154	73,677	815,703	949,023
1985	133,320	(19,900)	1,099	112,321	815,703	59,308	71,502	803,509	915,830
1986	112,321	64,651	1,528	175,444	803,509	33,209	67,751	768,967	944,411
1987	175,444	530	1,567	174,407	768,967	66,994	70,206	765,755	940,162
1988	174,407	50,100	1,803	222,704	765,755	59,433	72,744	752,444	975,148
1989	222,704	(7,088)	231	215,385	752,444	38,765	68,601	722,608	937,993

Source: Canadian Petroleum Association, Statistical Handbook, Section II and Section III.

Table 2.6
Established Reserves of Natural Gas, 1975-1989
(Millions of Cubic Metres)

	Canada Lands				Provincial Lands				Total
Year	Opening Balance	Additions	Production	Closing Balance	Opening Balance	Additions	Production	Closing Balance	Closing Balance
1975	161,242	168,220	750	328,712	1,670,224	99,370	70,791	1,698,803	2,027,515
1976	328,712	146,250	972	473,990	1,698,803	63,425	71,428	1,690,800	2,164,790
1977	473,990	26,985	630	500,345	1,690,800	114,411	74,714	1,730,497	2,230,842
1978	500,345	9,536	521	509,360	1,730,497	155,022	72,666	1,812,853	2,322,213
1979	509,360	89,119	526	597,953	1,812,853	162,737	77,486	1,898,104	2,496,057
1980	597,953	(17,801)	376	579,776	1,898,104	85,487	71,503	1,912,088	2,491,864
1981	579,776	(3,229)	292	576,255	1,912,088	145,286	70,656	1,986,718	2,562,973
1982	576,255	28,694	176	604,773	1,986,718	72,097	72,538	1,986,277	2,591,050
1983	604,773	518	163	605,128	1,986,277	90,186	68,996	2,007,467	2,612,595
1984	605,128	41,030	178	645,980	2,007,467	230,314	75,180	2,162,601	2,808,581
1985	645,980	30,279	207	676,052	2,162,601	28,145	82,875	2,107,871	2,783,923
1986	676,052	435	171	676,316	2,107,871	36,364	75,041	2,069,194	2,745,510
1987	676,316	(198)	166	675,952	2,069,194	29,170	81,533	2,016,831	2,692,783
1988	675,952	21,872	119	697,705	2,016,831	50,501	94,492	1,972,840	2,670,545
1989	697,705	18,491	109	716,087	1,972,840	145,456	101,934	2,016,362	2,732,449

Source: Canadian Petroleum Association, Statistical Handbook, Section II and Section III.

Table 2.7
Oil and Gas Prices, 1975-1988

Year	Crude Oil		Natural Gas
	Average World Price	Average Wellhead Price	Average Wellhead/ Plant Price
	(Cdn $/bbl.)	(Cdn $/bbl.)	(Cdn $/TCM)
1975	12.51	7.17	19.26
1976	12.77	8.35	31.31
1977	14.92	10.05	41.70
1978	16.07	12.03	48.36
1979	22.40	13.02	54.99
1980	37.06	15.41	75.48
1981	42.69	18.61	80.61
1982	41.30	25.91	87.8
1983	36.54	31.45	93.23
1984	38.30	33.11	96.79
1985	39.10	35.12	93.57
1986	22.83	18.10	73.47
1987	25.31	21.97	58.55
1988	19.93	16.06	52.78

Source: Canadian Petroleum Association, Statistical Handbook, Section VI.

Table 2.8

Capital Expenditures and Internal Cash Flow in the Upstream Petroleum Industry

(Millions of dollars)

Year	Capital Expenditures			Internal Cash Flow
	Exploration	Other	Total	
1981	3,800	3,049	6,837	5,251
1982	3,585	2,826	6,410	5,785
1983	4,280	2,506	6,786	7,298
1984	4,978	2,976	7,954	8,421
1985	4,909	4,348	9,257	9,479
1986	3,273	3,001	6,274	5,275
1987	2,701	2,792	5,493	6,787
1988	2,996	3,789	6,785	5,796
1989	2,442	2,966	5,408	6,432

Source: Petroleum Monitoring Agency Canada, Canadian Petroleum Industry: Monitoring Report, 1982-1989.

III. THE EXPLORATION TAX CREDIT

A. The ETC Provision

The ETC provision is contained in the Income Tax Credit sections of the Income Tax Act. Subsection 127(9) prescribes the rate of the ETC, and subsections 66.1(6)(a) and 127(11.1) define the base for computing it. The provision allows a tax credit of 25 per cent of a taxpayer's qualified CEE incurred on an oil or gas well within Canada.

ETCs may only be earned between December 1, 1985 and December 31, 1990. However, certain expenses incurred on a well after March 31, 1985, would be taken into account in determining qualifying CEEs for the ETC.

(a) Qualifying Canadian Exploration Expenses

To earn an ETC, qualifying CEEs must be expenses described in subsections 66.1(6)(a) of the Income Tax Act. The expenses are also spelled out in Regulation 4608 of the Income Tax Act. The qualifying expenses are well-specific, determined by the excess of the "specified expense" of a well for the taxation year over the "base amount" at the end of the year.

Specified expenses are CEEs incurred in drilling or completing an oil or gas well in Canada, in building a temporary access road to the well, and in preparing the site for the well. Since the expenses are well-specific, they exclude general exploration costs, such as property acquisition, and geological and geophysical expenditures. They also exclude Canadian exploration and development overhead expenses; interest, financing and borrowing costs; and expenditures that attract incentives under the PIP, APIP, CEDIP or CEIP. Eligible expenses are certified by the Department of Energy, Mines and Resources and then verified by Revenue Canada.

The base amount for a well at the end of a taxation year is the amount, if any, by which the $5 million threshold exceeds the specified expenses of prior years, as described in Regulation 4608(6). Any expenditures eligible for the PIP, APIP, or other similar government assistance during the above period are treated as non-qualifying expenses for the credit. In other words, these costs must be taken into account in offsetting the threshold amount.

The credit is well-specific. If a well must be abandoned because of geological or mechanical difficulties, and work on a replacement well is begun within a reasonable time and in proximity, it will be deemed to be the same well by Regulation 4608(9). The total threshold for the wells therefore remains at $5 million.

Where there is more than one participant in a well, ETCs earned must be calculated on a consolidated basis and allocated among the participants. The information must be detailed on a prescribed form signed by all participants and filed for tax purposes with Revenue Canada. In practice, a participant's share of the qualified CEE and the base amount per well are calculated separately in computing income tax.

Expenditures by a partnership or joint exploration corporation, or renounced under a flow-through share agreement, are all eligible for the ETC. CEEs allocated within a partnership are deemed to have been incurred by the partners at the time the partnership incurred them. Similarly, regulations 4608(10) and (11) establish that CEEs renounced by a joint exploration corporation or under a flow-through share arrangement are deemed to have been incurred by the investors at the time the CEEs were incurred.

Exploration expenses entitled to other forms of assistance such as the PIP or APIP, cannot be claimed as flow-through expenses for the ETC. Also, any expenses renounced under a flow-through share arrangement, or by a joint exploration corporation to a shareholder corporation, do not qualify as expenses eligible for the ETC for the corporation originally incurring them, since the credit is effectively transferred to these investors.

Only a principal business corporation may renounce resource expenses pursuant to a flow-through share agreement.[16]

(b) <u>Applying the ETC to Reduce Tax</u>

The ETC is used to reduce federal Part I income tax. ETCs are treated as a separate class of investment tax credits (ITCs). The rules establishing how they may be used to offset tax are detailed by Revenue Canada in Form T2038, Investment Tax Credit (Corporations). Total ITCs earned in a taxation year, including ETCs earned in that year, plus the unamortized balance of all ITCs carried forward from prior years, constitute the total tax credits available to reduce tax in the year. Subject to certain income-related limitations, discussed below, a taxpayer <u>may</u> claim the ITCs available to reduce income tax otherwise payable in that year and may carry-back any remaining available credits to offset tax in any of the three preceding tax years.

Investment tax credits that cannot create immediate tax reductions in the current or carry-back years may be used by some

16. A principal business corporation is a corporation whose principal business is exploring or drilling for, producing, refining or marketing petroleum or natural gas, or engaging in certain related activities.

corporations to obtain current-year cash refunds. Prior to the 1988 tax reform, all corporations could claim 40 per cent of excess ETC credits as a cash refund, where 'excess ETC credits' equals ETCs earned in the current year minus the amount of them used to offset the current or a previous year's tax. After tax reform,[17] this refundability was disallowed for all corporations except small Canadian-controlled private corporations (CCPCs).[18]

As with general ITCs, excess ETCs less any refund earned on those credits may be carried forward to offset tax in future years. ETCs and other ITCs earned may be carried forward up to 10 years.

For taxation years ending in and after 1988, an annual ITC limit is imposed on the amount of available ITCs that may be used to offset tax in any tax year. For a corporation, the limit is three-quarters of Part I tax. If the corporation is a CCPC throughout the year, the limit is increased to include 3 per cent of its small business income for the year. Thus, tax on income which has received the benefit of the small business deduction may be fully offset by available credits.

For unincorporated businesses and individuals, the annual limit is determined by the sum of $24,000 and three-quarters of tax in excess of $24,000.

For taxation years ending before 1988, annual ITC limits do not apply: ITC claims are restricted only by the amount of tax otherwise payable. For taxpayers whose taxation year straddles January 1, 1988, the annual ITC limit is prorated, allowing the taxpayer to claim available ITCs to fully offset the portion of Part I tax payable for the calendar year 1987, plus three-quarters of the portion otherwise payable for the calendar year 1988.

(c) The Direct Impact of the ETC on Income Tax

ETCs claimed or refunded reduce the amount (that is, the pool) of cumulative CEE available for deduction in the same way the general ITC reduces the available capital cost allowance pool.

Before 1988, an ETC claimed or refunded reduced the taxpayer's cumulative CEE pool in the same tax year. This meant that -- depending on the taxpayer's income for the year, other

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17. Department of Finance, Tax Reform 1987 - Income Tax Reform (June 18, 1987); Income Tax Act, Section 127.1 Refundable Investment Tax Credit.

18. A 'small' CCPC is a CCPC which, together with any corporations associated with it, has taxable income in the preceding year not exceeding $200,000.

available tax deduction pools, and status (principal business or non-principal business) -- the claiming or refunding of an ETC could affect the amount of CEE deductible in the same year.[19] Tax calculations could consequently become circular when the credit reduced the CEE claim in the same year in which the credit was claimed.

Effective January 1, 1988, ETCs could only be claimed or refunded to reduce the cumulative CEE pool in the following, not the current tax year.

B. Estimates of ETCs Earned and Claimed

As explained in Chapter II, an exploration licence is issued to the company that bids on a specific parcel of land and commits itself to spend the most on exploration. The successful bidder may drill alone or seek other investors to participate. In shared operations, the operator (or the principal company) and the other investors enter into an exploration agreement specifying the allocation of expenditures among the participants.

The operating company contracts and oversees the drilling of the well on behalf of the participants. It budgets projected expenses and obtains budget approval, using an Authority For Expenditures form showing the breakdown of the budgeted figures, expenses already incurred, and additional expenses to be incurred. It also shows the participants' shares of expenses and the amount of the cash call. After all the participants agree on the budget and sign the form, each sends its share of the cash call to the operator to finance the expenditures.

Periodically, usually monthly, the operator gives a statement of expenditures to all the participants; they use it to compute individual CEE pools for income tax purposes. The operator also updates the cumulative monthly well-specific exploration expenses that qualify for the ETC. This is part of the information necessary for the calculation of the ETC and is kept on file in case taxation officials need it for audit.

Since the ETC is well-specific, all participants in a shared operation enter into an allocation agreement on "threshold amounts" per taxpayer for that well in making ETC calculations. All the parties sign the agreement and file copies with Revenue Canada in the first taxation year in which they desire to establish the threshold amount for the particular oil or gas well.

In addition, since the ETC cannot be earned on well expenses eligible for payments under the PIP, APIP, CEDIP, or

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19. Revenue Canada, Income Tax Act - Investment Tax Credit, Interpretation Bulletin IT - 331R, (October 25, 1985).

CEIP, the total amount of ETC ultimately earned by the industry cannot be determined until all interested corporations have done their own calculations. The problem is further complicated where qualifying CEEs are renounced to other companies whose particular tax status will affect the amount of the ETC earned, claimed and refunded.

This study uses three primary data sources to analyze and estimate the exploration tax credits earned, claimed and refunded over the period 1985 to 1990:

(1) The Petroleum Monitoring Agency, for the period 1985 to 1988: Data collected and compiled by the agency presents detailed estimates of exploration expenditures and the associated ETC potentially earned by well and by participant.

(2) Revenue Canada, for the same period: Individual corporate tax returns provide ETC figures that are the actual observed amounts earned, claimed, and refunded by individual taxpayers.

(3) Petroleum company data released to the case study team: The information includes the qualifying CEEs incurred on all wells during the two-year period 1989-1990 and the percentage shares of the expenditures by various participants.

(a) <u>ETCs Earned</u>

When the ETC was introduced in October 1985, the Minister of Energy, Mines and Resources directed the Petroleum Monitoring Agency (PMA) to collect data so that the government could evaluate it. This data has been checked against Revenue Canada data on ETCs actually earned and claimed. Estimates from both sources are discussed below.

<u>PMA Data</u>

The PMA, established in 1980, is responsible for providing comprehensive and objective data on, and analysis of, the financial performance of the oil and gas industry in Canada. The PMA publishes semi-annual and annual reports, derived mainly from twice-yearly survey questionnaires. The survey sample includes about 125 oil and gas corporations. The coverage is extensive, accounting for roughly 90 per cent of the industry's upstream revenues and omitting only the smallest companies.

The PMA began to incorporate information on the ETC and associated capital expenditures in its 1986 questionnaires. In addition, operators of wells eligible to earn an ETC must submit to the PMA an additional schedule once a year for each well.[20] The schedule must include a list of participants in each well potentially qualifying for the credit, their shares of eligible exploration expenditures, and the amount of ETC earned.

In February, 1990, the PMA released its latest estimates of qualifying CEEs and the corresponding ETCs earned from 1985 to 1988.[21] To cover the entire period under evaluation, we obtained similar data directly from the operators of all ETC-qualifying wells drilled in 1989 and 1990. At the time of writing this report, in December 1990, there were only two high-cost wells being drilled that qualified for the ETC. According to COGLA, the Canada-Newfoundland Offshore Petroleum Board, the Canada-Nova Scotia Offshore Oil and Gas Board, and potential investors in the industry, no more high-cost well drilling was expected over the rest of the year.

The estimate for 1990 is much less than had been expected by government and industry. Gulf Canada Resources Ltd. abandoned plans to drill a $70 million exploration program in the Beaufort Sea after the Environmental Impact Review Board recommended that Gulf's application to undertake a three-year drilling program, beginning in the summer of 1990, be denied. Amoco Canada Petroleum Co. Ltd. scrapped a plan to drill in the Beaufort Sea because it could not find enough partners. As well, LASMO Canada Inc. and Nova Scotia Resource Ltd. postponed plans to drill two exploration wells in the Nova Scotia Offshore area because they could not find drilling rigs.

Incidentally, the wells and the participating companies mentioned above were used as the reference population from which the sample was drawn for the case studies discussed in Chapter V.

Tables 3.1 and 3.2 show the dispersion of exploration expenses for a total of 36 high-cost wells that qualified for the ETC over the entire period 1985 to 1990. Of the 36, seven were on provincial lands, a low percentage being expected since the ETC is designed to target only high cost wells in the frontier area. Of the seven, at least three had not been expected to exceed the $5 million threshold. Well expenses exceeded expected expenses because of unplanned considerations, including blow-outs and the need to re-enter the drill hole for unanticipated reasons. Usually, however, offshore wells are more expensive than onshore wells because of the high costs of deepwater drilling, the building of artificial islands, and the special types of rigs and equipment required. Table 3.2 shows that the Beaufort Sea had the highest average well cost, estimated to be

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20. Petroleum Monitoring Agency Canada, Petroleum Monitoring Survey Questionnaire, Schedule Xa.

21. Petroleum Monitoring Agency Canada, Exploration Tax Credits (February 7, 1990), Confidential.

about $49.6 million in 1990 dollars. Other average well costs, in descending order are: Newfoundland Offshore ($25.1 million), Nova Scotia Offshore ($18.8 million) and the provincial lands ($8.6 million).

Table 3.3 profiles aggregate CEEs on wells qualifying for the ETC, and gives the breakdown between CEEs that earn ETC and those that do not. Ineligible expenditures include those below the $5 million threshold and those qualifying for APIP, PIP, CEDIP or CEIP grants.[22] Total CEEs on these wells were roughly $7 million in 1985, as the ETC was in effect for only a short time that year. Aggregate CEEs then climbed from $97.6 million in 1986 to $364.3 million in 1988, falling to $249.1 million in 1989 and $26 million in 1990. CEEs ineligible for the ETC rose in proportion to the number of wells drilled because of the $5 million threshold. In 1987 and 1988, ineligible CEEs were greater than the threshold amount for each new well only by the amount of other government assistance received: PIP grants accounted for the difference in 1987, while CEDIP and CEIP grants accounted for the difference in 1988.

Total earned ETCs were roughly $.5 million in 1985, $20.7 million in 1986, $41.8 million in 1987, $70.7 million in 1988, $51.0 million in 1989, and $4.0 million in 1990.[23]

Table 3.4 presents the distribution of high-cost exploration wells by operator and region. Of the 36 wells that qualified for the ETC, 14 were in the Beaufort Sea. Nine of these were operated by Gulf Canada Resources Ltd. Of these, six were drilled on the 1984 Amauligak oil and gas discovery, which was the first major oil discovery in the Beaufort Sea. One of the six was an exploratory well; the other five were delineation wells. Esso Resources Ltd., a subsidiary company of Imperial Oil Ltd., was also a key player in the Beaufort Sea area, operating three wells.

In eastern Canada, 11 wells in the Newfoundland Offshore and four in the Nova Scotia Offshore qualified for the ETC. Of the 11, eight were in the Hibernia oil field and three elsewhere; of the Hibernia wells, three were on Petro-Canada's Terra Nova discovery and five on Husky/Bow Valley's Whiterose discovery. The drilling of three of these was farmed out to

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22. While certain CEEs may qualify for an ETC, they may also qualify for other forms of government assistance. A firm may elect to use CEE to earn a grant rather than an ETC if the rate of grant is higher.

23. Details on qualifying CEEs and ETCs earned by well and by corporation were obtained from Petroleum Monitoring Agency Canada, "Exploration Tax Credit: 1985-1988" (February 7, 1990), Confidential. For the years 1989 and 1990, this data was obtained from the operators of all ETC-earning wells.

Texaco Canada Enterprises Ltd., which was taken over in February, 1989, by Imperial Oil Ltd.

In the Nova Scotia Offshore, Mobil Oil Canada Ltd. operated one high-cost well on Mobil's Venture gas discovery on Sable Island; Petro-Canada operated two wells elsewhere.

The above discussion indicates that most operators concentrate their high-cost well drilling activities in one area. For example, Gulf Canada concentrated its efforts in the Beaufort Sea area, Husky Oil in Hibernia, Petro-Canada in Terra Nova and other eastern offshore areas, Mobil Oil on Sable Island, and Imperial Oil in both the Beaufort Sea and Hibernia areas.

Taxation Data

Taxation data for corporations that earned the ETC at least once during the period December, 1985, to December, 1988, were used to verify and supplement the information from the PMA.

From the tax returns of these corporations, we constructed detailed individual corporate tax files for the taxation years 1985 to 1988. Table 3.5 shows the aggregate amounts of annual ETCs earned, claimed in the current year or carried back to the previous three years, or refunded in cash and carried forward. The years here refer to the year in which the fiscal -- that is, the taxation -- year of the corporation ended.[24]

The Revenue Canada data presented in the first row of Table 3.5 show that earned ETCs totalled $19.3 million in 1986, $33.1 million in 1987, and $66.3 million in 1988. No ETC was earned in 1985.

The amount of ETCs actually earned in these three years, and the estimated ETCs earned in 1989 ($51 million) and 1990 ($4.0 million) totalled $190 million in constant 1990 dollars. Taking account of the opportunity cost of the public funds, the present value in 1990 dollars of ETCs earned over the entire period is $233 million.[25] These gross estimates are substantially smaller than the net federal costs forecast by the federal government when the credit was announced in October 1985, which ranged from $150 to $250 million a year.[26]

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24. The taxation year of most corporations in the petroleum industry coincides with their calendar year.

25. A 10 per cent real social opportunity cost of public funds is assumed. However, if a 7 per cent real is used, the present value of the earned ETCs would be $219 million.

26. Government of Canada, The Exploration Tax Credit, Press Release, (October 30, 1985).

The amounts of ETCs reported in corporate tax returns are generally smaller than the amounts reported by the PMA. The differences between the PMA and Revenue Canada data may occur because the PMA figures are based on estimates provided by operators, while Revenue Canada's are actual values earned and reported (and subject to audit) in tax returns by companies. Differences also appear in comparing the data by company, perhaps because of different periods used by operators and individual companies to refer to the same year for the allocation of CEEs. Further, since CEEs earning other government assistance do not qualify for the ETC, negligence in reporting types and amounts of assistance could lead to overestimates of ETCs earned.

(b) ETCs Claimed, Refunded, and Carried Forward

Earned ETCs do not mean tax savings to the individual companies or cost to the government until they are claimed or refunded. As discussed earlier, an ETC earned may be applied to offset federal tax in the year it was earned and unused amounts may be carried back three years to offset tax. Remaining current credits may be eligible for a refund. ETCs remaining after these claims or refunds may be carried forward for 10 years.

As reported in Table 3.5, $19.3 million of ETCs were actually earned by nine corporations in 1986, of which roughly 30 per cent was claimed in the same year. The claims were made by the four taxable corporations earning ETCs in that year. None of the ETCs earned were carried back to offset income taxes payable in previous years.[27] The other five corporations claimed a total of $5.4 million as cash refunds. The remaining $8.2 million was carried forward.

In 1987, 14 corporations, six of which were taxable, earned roughly $33 million in ETCs, ranging from $3,000 to $11.8 million, with a median of $410,000, and a mean of $2 million.[28] Of the $33 million, approximately $19 million or 58 per cent was claimed by the six taxable corporations to offset income tax in 1987, while $156,000 was carried back to offset income taxes paid in the previous years. ETC refunds amounted to $5.4 million, or about 40 per cent of the unclaimed credits.

In 1988, 14 corporations, four of which were taxable, earned $66.3 million in ETCs, double the amount in the previous year. The taxable firms earned $22.7 million, or roughly 34 per

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27. Since the corporations may claim credits from a variety of ITCs, there is no reason why they should first claim the ETC, because unclaimed ITCs may all be carried over to the next 10 years. For simplicity, Table 3.5 assumes that companies would claim the ETC before other ITCs.

28. One case showed a loss of $47,000 for the ETC. This was an adjustment to claims made in previous years.

cent of the total ETCs earned, but only $13.4 million of this was claimed to offset current year income tax. The low figure can be explained by the low percentage of corporations paying taxes that year and by the annual ITC limit.[29] The amount carried back was about $14.6 million, a figure much higher than in previous years. One corporation carried back more than $12 million to offset its 1985 tax, using its last opportunity to reduce tax in that year under the three-year carry-back rule. Only $7.9 million of the total $38.4 million unclaimed credit was claimed as a cash refund, reflecting the restrictions on refundability under tax reform. The remaining $30.5 million was carried forward.

Precise ETC claims, carrybacks, carryforwards and refunds were not known for 1989 and 1990, since the data on individual corporations were not available for these years. Estimates were made on the basis of the tax-history of each corporation over the preceding years in order to round out the study. A company not in a taxpaying position in the preceding years was assumed to carry forward the entire amount of the ETC currently earned, unless it was a small CCPC, for which a refund would be available. A company that paid taxes in previous years was assumed to claim immediately the full amount of ETCs earned in 1989 and 1990. The same assumption was made in estimating the federal tax cost of the ETC, as discussed in Chapter VI.

C. Summary

The total amount of ETCs earned from December 1985, to December 1990, is about $190 million, expressed in constant 1990 dollars. The credit was aimed at the drilling of high-cost wells; more than 95 per cent of it was earned from offshore exploration.

Of the $190 million, about 62 per cent, or $120 million, was claimed by 30 corporations as a credit or cash refund in the year in which the credits were earned. Remaining ETCs were carried forward and may be claimed in future years.

Clearly, the cost of the credit, before taking into account the opportunity cost of funds and the altered tax planning that might accompany the removal of the ETC (to be addressed in Chapter VI), was substantially less than the $150 to $250 million <u>a year</u> estimated by the government when the credit was announced.

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29. About three-quarters of the corporations examined in 1988 were not liable for taxes, compared with only half of them in the previous two years.

Table 3.1

Number of Exploration and Delineation Wells by Size of Drilling Cost, 1985-1990

	Size of Drilling Expenses (millions of 1990 dollars)												
Region	5-10	10-15	15-20	20-25	25-30	30-35	35-40	40-45	45-50	50-60	60-70	70+	Total
Provincial Lands	5	2											7
Canada Lands	2	6	7	3	0	2	1	1	0	1	2	4	29

Sources: Petroleum Monitoring Agency Canada, Exploration Tax Credit: 1985 - 1988, (1989); Canada Oil and Gas Lands Administration, annual reports, 1985 - 1989; and direct contact with the petroleum companies.

Table 3.2

Drilling Cost of Exploration and Delineation Wells, 1985-1990
(Thousands of 1990 dollars)

Region	No. of Wells (#)	Total Cost	Average Cost
Provincial Lands	7	$ 60,513	$ 8,645
Canada Lands			
Mackenzie Delta	1	8,000	8,000
Beaufort Sea	13	644,254	49,558
Nova Scotia Offshore	4	75,181	18,795
Newfoundland Offshore	11	275,767	25,070
Sub-total	29	1,003,203	34,593
Total	36	1,063,716	29,548

Sources: Petroleum Monitoring Agency Canada, Exploration Tax Credit: 1985-1988, (1989); Canada Oil and Gas Lands Administration, annual reports, 1985-1989; and direct contact with the petroleum companies.

Table 3.3

CEE and ETC Earned on Wells Qualifiying for ETCs, 1985-1990[1]

Location	1985	1986	1987	1988	1989	1990
Wells Drilled (#)						
Canada Lands	0	2	8	10	7	2
Provincial Lands	1	1	0	3	2	0
Total	1	3	8	13	9	2
	thousands of dollars					
Total CEE						
Canada Lands	0	87,884	227,901	339,868	235,610	26,000
Provincial Lands	6,968	9,738	0	24,402	13,450	0
Total	6,968	97,622	227,901	364,270	249,060	26,000
Ineligible Expenditures[2]						
Canada Lands	0	10,000	60,650	64,824	35,000	10,000
Provincial Lands	5,000	5,000	0	16,602	10,000	0
Total	5,000	15,000	60,650	81,426	45,000	10,000
CEE Earning ETC						
Canada Lands	0	77,884	167,251	275,044	200,610	16,000
Provincial Lands	1,968	4,738	0	7,800	3,450	0
Total	1,968	82,622	167,251	282,844	204,060	16,000
ETC Earned						
Canada Lands	0	19,471	41,813	68,761	50,152	4,000
Provincial Lands	492	1,185	0	1,950	863	0
Total	492	20,656	41,813	70,711	51,015	4,000

Source: Petroleum Monitoring Agency Canada, Exploration Tax Credit: 1985-1988, (1989).

Notes:

(1) Years refer to calendar year.

(2) Includes the $5 million threshold and the portion of expenditures used to attract PIP, APIP, CEIP & CEDIP incentives.

Table 3.4

Number of Exploration Wells by Operator and by Area, 1985-1990

	Operators	Canada Lands							Provincial Lands		
		Beaufort Sea		Newfoundland Offshore			Nova Scotia Offshore				
		Amauligak	Others	Hibernia: Whiterose	Hibernia: Terra Nova	Others	Sable Islands	Others	Alberta	British Columbia	Total
1	Amoco Canada Petroleum Company Ltd.		1								1
2	Chevron Canada Resources Ltd.					1					1
3	a) Esso Resources Canada Ltd.		3						1	1	5
	b) Texaco Canada Enterprises Ltd.			3							3
4	Gulf Canada Resources Ltd.	6	3								9
5	a) Husky Oil Operations Ltd.			2							2
	b) Canterra Energy Ltd.							1	1		2
6	a) Mobil Oil Canada Ltd.						1				1
	b) Canadian Superior Oil Ltd.								1		1
7	PanCanadian Petroleum Ltd.								1		1
8	Petro-Canada Inc.				3	2		2	1		8
9	Shell Canada Ltd.		1								1
10	Unocal Canada Limited	—	—	—	—	—	—	—	1	—	1
	Total	6	8	5	3	3	1	3	6	1	36

Sources: Petroleum Monitoring Agency Canada, Exploration Tax Credit: 1985-1988, (1989); Canada Oil and Gas Lands Administration, annual reports, 1985-1989; and direct contact with the petroleum companies.

Table 3.5

Exploration Tax Credits: 1985-1990
(Thousands of dollars)

Categories	1986	1987	1988	1989	1990
ETC Earned	19,345.90	33,055.18	66,320.78	51,015.00	4,000.00
ETC Claimed					
Current Year	5,750.96	19,009.02	13,377.08	32,987.00	4,000.00
Previous Years	0.00	156.23	14,564.52	0.00	0.00
Refunded	5,437.98	5,370.26	7,892.31	0.00	0.00
Total Claimed	11,188.94	24,535.51	35,833.91	32,987.00	4,.000.00
ETC Carried Over	8,156.96	8,519.67	30,486.87	18,028.00	0.00

Sources: Revenue Canada, corporate tax returns, 1986-1988.
Note: Data provided refer to the year in which the taxation year ended.

IV. INVESTMENT INCENTIVES IN THE OIL AND GAS INDUSTRY

A. The Basic Approach

This chapter isolates and analyzes the various relationships between tax variables affecting investment in Canadian oil and gas exploration and development. Sorting out which tax variables bear on the different types of oil and gas activity, and how, is difficult indeed, owing to the multitude of taxes affecting the sector and the dependence of one on another.

Insights can be gained, however, by integrating the financial and tax relationships into a model of a firm in the oil and gas industry, assuming that managers attempt to maximize the firm's market value through the choice of the optimal investment in each factor of production, and calculating the conditions that characterize the optimal hiring of each factor of production. The resulting marginal after-tax costs and user costs form the basis of comparison of the tax instruments considered below.[30]

Insight into how our tax system affects oil and gas industry behaviour is interesting on its own to clarify the mechanics of the tax rules, both in isolation and in conjunction with related tax policy. Knowing how taxes operate at the margin, meaning how they come into play when income or cost rises, is important in designing tax policy. Policy geared to encouraging exploration, for example, should reward the spending of marginal dollars and not confer windfall gains on shareholders on their exploration dollars already invested. Understanding how various tax rates apply at the margin is also important for the purposes of comparing the effect of one policy instrument with that of another under alternative rate settings of the different taxes.

An assessment of how and to what extent Canadian tax rates influence the profitability of investment at the margin is also relevant in judging the attractiveness, to corporations, of committing additional investment dollars to the Canadian oil and gas sector. The need for an international comparison of marginal effective tax rates is particularly strong in connection with large, multinational firms that drill offshore and are most often the beneficiaries of the ETC. The financial capital of these companies is highly mobile and can be expected to be directed to what they regard as the most profitable investment opportunity.

This chapter begins by outlining the model used to derive the conditions that characterize the decisions of oil and

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30. Similar approaches have been applied recently to other resource sectors. See R. Boadway, N. Bruce, K. McKenzie and J. Mintz, "Marginal Effective Tax Rates for Capital in the Canadian Mining Industry", Canadian Journal of Economics (February 1987).

gas companies to invest in labour, physical capital (machinery and buildings), property (land), and intangible development and exploration capital. Taxes, royalties and grants are treated by incorporating their effect on profit and the firm's market value.

While the model is used to derive the various optimizing conditions for the hiring of each factor of production, the analysis focuses on the exploration investment decision and the influence on it of the ETC. The model assumes that the firm is in a taxpaying position. Since this assumption is particularly tenuous for the oil and gas sector, the user cost results are generalized to the non-taxable case. The marginal effects of alternative incentive programs, such as federal grants and other tax instruments previously in place, are also briefly discussed. Lastly, the chapter considers corporate tax rules relating to exploration activity in the United States, the United Kingdom, Australia and Norway, and draws some international comparisons.

B. The Model[31]

The model assumes that the managers of an oil and gas firm, acting in the interest of their shareholders, choose the optimal amount of expenditure on each factor of production. The factors -- labour, physical capital, land, exploration capital, and development capital -- are employed to yield petroleum reserves. The optimal quantities of each of these factors -- that is, the quantities expected to maximize the stock market value of the firm -- are those that equate marginal benefits with marginal costs. In other words, each factor is employed in each period just up to the point where the after-tax benefit derived from it equals the after-tax cost of employing it.

Output is assumed to be determined by a production technology that combines the services derived from labour, land, and development expenditures with stocks of physical capital and discovered petroleum reserves. The stock of reserves discovered in each period is assumed to increase with the amount of exploration undertaken in that period, and to decrease with the cumulative amount of discoveries made in the field. This latter assumption is intended to capture the reality that petroleum is a depletable resource, unlike physical capital which is non-depletable. With this characterization, there is an implicit cost associated with a petroleum discovery in addition to the exploration expense incurred. As reserves are discovered and cumulative discoveries increase, future exploration activity is less productive; in other words, at each level of exploration expense in the future, marginal exploration dollars yield fewer discoveries because of the increased scarcity of the resource.

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31. The theoretical model is presented in Appendix A.

Taxes, royalties and grants are embedded in the model because the market value of the firm, which managers attempt to maximize, is measured by the present value of expected dividends to shareholders. The amount of funds that can be distributed to shareholders is reduced by corporate income taxes and royalties, and increased by credits and grants earned on exploration or development expenditures.

Corporate income taxes are determined by the product of the corporate income tax rate and the corresponding tax base, less ITCs. The corporate income tax base is measured as gross revenue less operating costs, the capital cost allowance, the resource allowance, the Canadian Oil and Gas Property Expense (COGPE) claim, the Canadian Development Expense (CDE) claim, the Canadian Exploration Expense (CEE) claim, and the Earned Depletion (ED) claim. Gross revenue is generated from the sale of discovered petroleum reserves. Operating costs are measured as labour costs. The capital cost allowance measurement is based on the assumption of a single homogeneous physical capital stock depreciated for tax purposes according to the declining-balance method. The resource allowance is determined by 25 per cent of gross revenue less operating costs and capital cost allowance. It is assumed that the firm cannot add to its ED base, but does have an unamortized ED pool from which it can draw. The ED claim is taken to be constrained by income and not by the size of the unamortized ED pool. Therefore, the ED deduction is determined by 25 per cent of resource profits for earned depletion purposes. This profits measure is determined by resource profits for resource allowance purposes, less the resource allowance claim, the COGPE claim, the CDE claim, and the CEE claim.

The COGPE claim is calculated as 10 per cent of the cumulative COGPE pool which evolves over time on a 10-per-cent declining-balance basis. Additions to this pool are determined by property expenses chosen to maximize the firm's market value. Similarly, the CDE claim is set at 30 per cent of the cumulative CDE pool, which evolves over time on a 30-per-cent declining-balance basis. Additions to this pool are determined by market value-maximizing development expenditures.

Two types of development expenditure are modelled. The first does not qualify for assistance; the second qualifies for grants such as those administered under the Canadian Exploration and Development Incentive Program (CEDIP). Grants are determined as a fraction of development expenditures of the second type. When measuring additions to the cumulative CDE pool, development expenses are measured net of grants earned on them.

The CEE claim in each period is determined by the CEE incurred net of government assistance. This reflects the fact that firms may write off 100 per cent of their CEE pool, and that this pool will have a zero balance at the end of each period when the maximum claim is taken.

Four types of exploration expense are modelled. The first does not qualify for assistance. The second qualifies for some form of federal grant, such as available under the CEDIP or PIP. The third consists of exploration costs that qualify for an IRC. The fourth consists of expenditures qualifying for the ETC. Each form of assistance is measured as a percentage of the corresponding nominal exploration expenditure. Grants and credits earned on exploration expenses reduce the net amount of exploration expense that can be claimed as CEE.[32]

Total federal grants are modelled as the sum of the grants earned on exploration and development expenditures. These are shown to increase the firm's stock market value and affect the optimal hiring of exploration and development capital.

Lastly, royalties are measured as a fraction of gross income. This corresponds to the federal 'pre-payout' royalty scheme and to the 'post-payout' scheme when 5 per cent of gross revenues is greater than 30 per cent of net revenues. The model can be easily amended to depict the alternative post-payout case.

C. <u>The Marginal After-tax and User Costs of Exploration Capital</u>

As derived in Appendix A, it is optimal for the firm to increase its exploration qualifying for the ETC up to the point where the expected before-tax marginal benefit derived from an additional dollar's worth of exploration:

$$pF_X(\cdot)J_{E4}(\cdot)+\int_t^{\infty} e^{-(r+J_{TX}(\cdot))(s-t)}\; pF_X(\cdot)J_{TX}(\cdot)J_{E4}(\cdot)\,ds \qquad (4.1)$$

just equals the user cost of that exploration capital:[33]

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32. Investment tax credits, such as the IRC and the ETC, reduce the cumulative CEE base in the year the credits are claimed (or refunded), except in 1988 and later tax years when the claims reduce the base in the following year. Since these credits are assumed to be fully claimed when earned and because of the continuous-time, rather than discrete-time, modelling technique, credits earned are treated to reduce the CEE claim immediately.

33. The user cost expression (4.2) assumes that the ED claim is restricted by resource profits for ED purposes. In the case where the ED claim is restricted by the size of the ED pool, implying that marginal CEE claims do not act to increase tax by reducing profits for ED purposes, and that increments in revenue and consequent increments in profits for ED purposes do not act to reduce tax, the user cost formula is given by (continued...)

$$\frac{(1 - \epsilon)\ (1 - u\ (1 - \Omega))}{(1 - u\ (1 - \Gamma)(1 - \Omega)\ - \gamma))}. \tag{4.2}$$

In these expressions, p measures the price of output; $F_X(\cdot)$ measures the increase in output resulting from a unit increase in newly discovered reserves; $J_{E4}(\cdot)$ measures the increase in discovered reserves resulting from a unit increase in exploration expenses qualifying for the ETC; $J_{TX}(\cdot)$ measures the reduction in discovered reserves for a particular level of exploration resulting from a unit increase in cumulative discoveries. The shareholder's real discount rate is r, the corporate income tax rate is u, and the royalty rate is γ. The resource allowance rate is Γ, and earned depletion rate is Ω. Lastly, the ETC rate is denoted by ϵ.

The expected before-tax marginal benefit derived from a dollar's worth of exploration consists of two components. The first is the value of additional output sales owing to the larger stock of discovered resources attributable to the increase in exploration activity.[34] The second component in equation (4.1), which is negative, measures the present discounted value of the reduced contributions of future exploration expenses to output that results from the effect of current exploration on cumulative discoveries. Recall that current exploration, by increasing current discoveries and therefore cumulative discoveries, reduces the amount of discoveries in the future for any given time path of exploration.[35]

The user cost of exploration capital, measuring the before-tax return that must be earned on a marginal dollar's worth of exploration expenditure for the after-tax marginal benefit to equal the after-tax marginal cost, can also be broken

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33.(...continued)
equation (4.2) with Ω set equal to zero. Similarly, in the case where the firm does not have an ED pool, the user cost formula is given by equation (4.2) with Ω set equal to zero.

34. Since the derivative $F_X(\cdot)$ measures the increase in output resulting from a unit increase in discovered reserves, and the derivative $J_{E4}(\cdot)$ gives the increase in discovered reserves that results from one additional dollar's worth of exploration expense, the product of the two measures the increase in output resulting from one additional dollar's worth of exploration.

35. Since a unit increase in discoveries yields a unit increase in cumulative discoveries, the product of $J_{TX}(\cdot)$ and $J_{E4}(\cdot)$ gives the decline in discoveries for a given level of exploration resulting from increased exploration as it affects cumulative discoveries.

down into two components. One component appears in the numerator of the user cost expression, and the other appears in the denominator.

The numerator of the user cost expression measures the marginal after-tax cost of one dollar's worth of exploration that qualifies for the ETC. This term, which we shall refer to as the marginal after-tax cost (MATC) term, is readily interpreted when expanded to give $(1-\epsilon-u(1-\epsilon)(1-\Omega))$. A dollar of exploration that qualifies for the ETC earns a credit of ϵ dollars. If claimed immediately, this credit reduces tax by ϵ dollars, reducing the net exploration cost to $(1-\epsilon)$ dollars. The exploration expense net of ETC, $(1-\epsilon)$, can then be deducted from the income tax base in the form of a CEE of $(1-\epsilon)$ dollars, which reduces tax payable by $u(1-\epsilon)$ dollars. Since the CEE claim reduces resource profits for earned depletion purposes by $(1-\epsilon)$ dollars, however, the ED claim decreases by $\Omega(1-\epsilon)$ dollars, which in turn increases tax payable by $u\Omega(1-\epsilon)$ dollars. The overall net cost of the one dollar of exploration expense that qualifies for the ETC is therefore given by $(1-\epsilon-u(1-\epsilon)+u\Omega(1-\epsilon))$ dollars.

The denominator of the user cost measures the amount of income received after the payment of tax and royalty when one dollar of gross revenue is earned. This expression is more readily interpreted when expanded to give $(1-u+u\Gamma+u\Omega(1-\Gamma)-\gamma)$. Aside from the resource allowance and earned depletion, a dollar of gross revenue, taxed at rate u, leaves $(1-u)$ dollars. Since gross revenue is included in the base of the resource allowance, one dollar of gross revenue increases the resource allowance by Γ dollars, which acts to reduce tax by $u\Gamma$ dollars. Moreover, since gross revenue increases the resource profits measure for earned depletion purposes by $(1-\Gamma)$ dollars, it follows that the earned depletion claim resulting from an additional one dollar's worth of gross revenue reduces tax by $u\Omega(1-\Gamma)$ dollars. The royalty reduces the net amount of income in the hands of the firm by γ dollars. Thus, it follows from the above that the overall return from a dollar of gross revenue is $(1-u(1-\Gamma)(1-\Omega)-\gamma)$ dollars.

The MATC expression shown above, giving the after-tax cost of a marginal dollar's worth of exploration qualifying for the ETC, or $(1-\epsilon)(1-u(1-\Omega))$, assumes that ETC earned and claimed reduces the cumulative CEE pool in the same tax year. While this is representative of tax years ending in and before 1987, any ETC claimed in tax years ending in or after 1988, decreases the cumulative CEE pool in the following tax year.

Continuing with the assumption that the firm is taxable, and can take its maximum CEE and ED claims and its maximum ITC claim, the marginal after-tax cost of one dollar's worth of exploration capital, purchased in a tax year ending in or after 1988, is given by the following:[36]

$$(1 - \epsilon - u(1 - \Omega)(1 - \frac{\epsilon}{(1 + \rho)})) \qquad (4.3)$$

where ρ is the shareholder's nominal discount rate. Ignoring the grinding of, and claim from, the CEE base, the claiming of the ETC in the year earned reduces the MATC to $(1-\epsilon)$ dollars. The extra dollar of exploration expense claimed in the current year acts to reduce the tax base by a dollar, but the resulting decline in the current ED claim by Ω dollars acts to increase the tax base by Ω dollars, so current taxes fall by $u(1-\Omega)$ dollars. With the CEE pool reduced by ϵ dollars in the following tax year and the CEE claim in that year reduced by ϵ dollars, the implicit future tax burden of the current ETC claim is $u\epsilon$ dollars, which has a present value in the current period of $u\epsilon/(1+\rho)$ dollars assuming a discrete time framework. Since a lower CEE claim in the following year means increased resource profits for earned depletion purposes in that year, and thus an increased ED claim of $\Omega\epsilon$ dollars, the total after-tax cost of a dollar's worth of qualifying exploration is $(1-\epsilon-u(1-\Omega)+(u\epsilon/(1+\rho))-(u\Omega\epsilon/(1+\rho)))$ dollars, which simplifies to the MATC expression given above.

Now consider the non-taxable case. Where the firm's income, when measured net of its tax deductions, losses, and credits other than the ETC, is not sufficiently large to permit the full claiming of the ETC earned in that period, the firm is allowed a 40-per-cent refund on the ETC currently earned that is not claimed to offset the current year's tax or a previous year's tax. The ETC refund reduces the cumulative CEE pool in the same manner as an ETC claim used to offset tax does. While the above refundability provision remains effective for small Canadian-Controlled Private Corporations (CCPCs), it was terminated for other corporations for tax years beginning in and after 1988.

Let β denote the ETC refund rate. Assume that the firm, which is non-taxable in the current tax year, becomes taxable in the following year. Ignoring momentarily the effect of the exploration expense on the cumulative CEE pool, the ETC and its refund provisions reduce the cost of a dollar's worth of qualifying exploration expenses to $(1-\beta\epsilon)$ dollars. Although the dollar of exploration expense results in a gross addition to the cumulative CEE pool of one dollar in the current year, the value

36. The formulae derived here implicitly assume that the tax year is a full calendar year. In the case where the firm files two or more tax returns in a single calendar year, the discounting would be less.

of the corresponding CEE claim and its impact on the ED claim must be discounted by one year, since the firm does not become taxable until the following year. The grinding of the cumulative CEE pool, attributable to the refund taken in the current year, occurs in the following year and affects the CEE claim and the ED claim in that year also. These considerations imply, in present-value terms, a tax savings of $(u(1-\Omega)/(1+\rho))(1-\beta\epsilon)$ dollars. Under the assumption that the excess ETC earned in the current year (that is, the amount of ETC earned in excess of the ETC refund) is claimed as a credit to offset tax in the following year, there is an additional tax saving of $(1-\beta)\epsilon/(1+\rho)$ dollars in present-value terms. At the same time, this effect grinds the cumulative CEE pool at a cost of $(1-\beta)\epsilon u(1-\Omega)/(1+\rho)^2$ dollars in present-value terms. Thus, the (present-value) marginal after-tax cost of a dollar expenditure in exploration qualifying for the ETC, in this case, is given by:

$$(1 - \beta\epsilon - \frac{u(1 - \Omega)}{(1 + \rho)}(1 - \beta\epsilon) - \frac{(1- \beta)\epsilon}{(1 + \rho)}(1 - \frac{u(1 - \Omega)}{(1 + \rho)})). \quad (4.4)$$

This MATC expression can be generalized. Where the firm is currently non-taxable, and thus cannot take its maximum CEE, ED and ITC claims in the current tax year, but can use this claim when it becomes taxable in, say, N years, and assuming that the ETC refundability provisions apply, the MATC expression is given by the following:

$$(1 - \beta\epsilon - \frac{u(1 - \Omega)}{(1 + \rho)^N}(1 - \beta\epsilon) - \frac{(1 - \beta)\epsilon}{(1 + \rho)^N}(1 - \frac{u(1 - \Omega)}{(1 + \rho)})) \quad (4.5)$$

Consider now the non-taxable cases where the ETC refundability provisions do not apply. These equations hold at the margin for non-taxable non-CCPCs for tax years beginning in or after 1988. Assuming again the firm becomes taxable in N years, and that the ED claim is limited by resource profits, the MATC expression is given by:

$$(1 - \frac{u(1 - \Omega)}{(1 + \rho)^N} - \frac{\epsilon}{(1 + \rho)^N}(1 - \frac{u(1 - \Omega)}{(1 + \rho)})). \quad (4.6)$$

The user cost expressions (4.2) to (4.6) assume that the ED claim is restricted by resource profits for ED purposes. The corresponding user cost expressions for the case where either the ED claim is restricted by the ED pool, or where the firm does not have an ED pool, are found by setting Ω equal to zero.

The impact of the ETC on the after-tax cost of exploration capital under the various assumptions about tax-paying status, the availability of ETC refunds, and whether ED claims are restricted by resource profits or the ED pool, can be clarified by a numerical example. Table 4.1 considers the case where ED claims are restricted by resource profits and Table 4.2 the case where the ED claims are constrained by the ED pool.[37]

As expected, in comparisons of the MATC of exploration capital with and without the ETC, but across otherwise identical categories, the MATC is smaller with the ETC.[38] In the currently taxable cases, for example, the MATC falls by roughly 26 per cent with the ETC, under both assumptions about the restriction on the ED deduction. When comparing corresponding categories between Tables 4.1 and 4.2, the MATC is considerably lower in Table 4.2. This follows from the fact that when the ED claim is restricted by the ED pool size, a larger CEE claim does not necessarily imply a lower ED claim, as it does in the alternative case.

As documented in Tables 4.1 and 4.2, the MATC of exploration is larger when the firm is non-taxable, and grows larger the longer it is before the firm becomes taxable. This result follows directly from the discounting of the tax benefits. Where the firm is non-taxable, the MATC is shown to be lower in each instance when the firm can earn a refund on its ETC earned. Figure 4.1 provides a graphical illustration of the effects of the ETC on the MATC of exploration under different assumptions of taxpaying status and refund availability.

D. Comparing the ETC with Other Incentives

Two special incentives provided in the past by the federal government, which also assisted oil and gas activity in the frontier, are the Petroleum Incentives Program, and the Frontier Exploration Allowance. These incentive mechanisms are described below and comparied with the ETC.[39]

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37. The table figures are based on the following parameter values: $\epsilon=\Omega=0.25$, $u=0.38$, $\rho=0.15$, $\beta=0.40$. Under income allocation rules, the income tax rate of 38 per cent is applicable to offshore oil and gas projects under federal jurisdiction.

38. The MATC formulas for the no-ETC cases can be derived from the corresponding formulas for the ETC cases, as provided in the text, by letting $\epsilon=0$.

39. A full description of the equations relevant to this section, along with a comparison of the ETC with other exploration incentives, is provided in Appendix B.

(a) The Petroleum Incentives Program

By far the most lucrative federal assistance to exploration activity in Canada during the 1980s came from the Petroleum Incentives Program (PIP). Although this program was terminated on March 31, 1986, grandfathering provisions allowed exploration expenses on wells drilled in the frontier lands to continue to qualify for PIP grants until December 31, 1987.

The PIP was discriminatory. The rate at which PIP grants could be earned varied by investment-type (development or exploration), location (provincial lands or Canada lands), and by the degree of Canadian ownership. If Canadian ownership was 65 per cent or more, and if the exploration expenditure was incurred in the Canada lands, the PIP grant rate over the period from 1981 to 1987 was 80 per cent.[40] With smaller degrees of Canadian ownership, the PIP rate varied between 25 and 65 per cent.

Unlike the ETC, whose value depends on the taxpaying position of the firm, a PIP grant represents 'cash in hand' to the firm. Once earned, it can be claimed without regard to the firm's taxable status. When earned at a rate above 25 per cent, a PIP grant would be preferred to the ETC, providing a greater exploration incentive. When earned at the lowest 25-per-cent rate, it would provide at least as much exploration stimulus as the ETC, and where the firm is non-taxpaying, PIP would be preferred again.[41]

(b) The Frontier Exploration Allowance (Super Depletion)

From April 1, 1977, to March 31, 1980, qualifying frontier exploration costs above $5 million on a single well

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40. By 1987, the degree of Canadian ownership required to obtain the 80 per cent PIP grant rate was increased to 75 per cent.

41. The comparisons with the ETC consider the PIP in isolation. When considering the design and incentive effects of the PIP, it is important to bear in mind the Crown-share back-in rules, in effect prior to the enactment of the Western Accord, which transferred to the federal government a 25-per-cent working interest in oil and gas discoveries. The Crown share was activated at the time corporations applied either for a production license or Special Renewal Permit, and meant that the government would assume 25-per-cent of the future income and costs of the project. If, prior to the time of the Crown share back-in, exploration expenses earned PIP grants at a 25-per-cent-rate, then the combined effect of the PIP grant and the Crown-share back-in would be to leave private (full cycle) project incentives unchanged from what they would be in the absence of these two forms of government intervention. Only PIP grant rates in exess of 25 per cent would act to encourage activity.

could earn a frontier exploration allowance, more commonly known as super depletion. Because of the $5 million threshold and the restriction of coverage to frontier lands, this tax deduction and the related incentive effects are obvious subjects for comparison with the ETC.[42]

Unlike earned depletion (ED) claims, super depletion (SD) claims were not restricted to a percentage of adjusted profits.[43] Moreover, the claims could be used to offset income from any source. The SD deduction was earned at a rate of 66 2/3 per cent on qualifying expenses. This incentive, together with the ED allowance, which permitted 33 1/3 per cent of qualifying exploration expenses to be added to the ED pool, meant that a dollar deduction could be obtained on a dollar of qualifying exploration expenses. This was in addition to the one-dollar CEE claim earned on those same expenses. These provisions together meant that a full two-dollar deduction could be earned on every dollar of qualifying exploration expense.

To compare the incentive effects of SD with those of the ETC, several possible combinations could be examined. The scenarios differ according to whether exploration expenses can be added to the ED pool at a rate of 33 1/3 per cent, as they could when SD was in effect. They also differ according to whether the ED claim is restricted by resource profits for earned depletion purposes or instead by the ED base. In the following examples, which all assume that CEE cannot be included in the ED base, as in the post-1984 period, it is assumed that the corporation has an unamortized ED pool to draw from. The examples also assume that the firm is in a taxable position. The non-taxable cases can be generalized from these.[44]

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42. Unlike super depletion, the ETC is not restricted to well costs in the frontier lands. But the $5 million threshold eligibility restriction effectively limits the scope of the ETC in most cases to the frontier regions.

43. Recall that an ED claim is restricted to the lesser of the cumulative ED pool measured prior to claim, and 25 per cent of resource profits for earned depletion purposes.

44. Incentive comparisons between SD and the ETC depend on the value of the corporate income tax rate assumed, since this rate affects the value of the SD deduction. Whether a pre-reform income tax rate (i.e., a rate that prevailed at the time of SD), or a post-reform rate should be used, depends on the assumed implementation period of the tax instrument. The comparisons presented here, which all use a 38 per-cent tax rate, consider SD as an alternative incentive mechanism to ETC during the post-reform period. The 38-per-cent rate would apply, under the income allocation rules, to projects in the frontier lands (earning income) if the percentage of (continued...)

Table 4.3 compares exploration investment incentives created by SD and the ETC. The table presents user costs for two cases.[45] Case I assumes that ED claims are limited by resource profits, while Case II assumes that they are restricted by the ED pool size.[46] The figures assume that CEE qualifies for inclusion in the ED pool.

Comparing the results of Cases I and II, the user cost is much less with the availability of SD than it is with the ETC, particularly when the ED claim is restricted by the ED pool. The Case II results in Table 4.3 make clear that, with the prescribed SD and ETC rates, SD offers more stimulus to exploration activity than does the ETC. The user cost of 0.36 with SD is considerably smaller than the user cost of 0.56 with the ETC.

Perhaps the most appropriate comparison of ETC and SD to be made is one that ignores earned depletion. It can be shown that for the ETC to provide the same incentive at the margin -- assuming a corporate income tax rate of 38 per cent -- the ETC rate would have to be increased from the existing 25 per cent to about 41 per cent.

E. An International Comparison of Exploration Capital Costs

This section compares the marginal after-tax cost and the user cost of exploration capital in several countries providing tax incentives for offshore exploration. The relevant tax provisions of each country and the implied marginal cost considerations can be summarized as follows.

a) Australia

Australia derives revenues from offshore petroleum production using both a corporate income tax and its Resource Rent Tax (RRT).[47] Exploration expenses and the RRT are both

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44. (...continued) the firm's income earned in that area equals the percentage of its wage and salary expense incurred there.

45. Unlike Tables 4.1 and 4.2, Table 4.3 is based on the assumption that CEE claims grind the cumulative CEE pool in the same tax year (as was the practice during the period in which SD was in place) rather than in the following tax year.

46. Table 4.3 is based on the following parameter values: $\epsilon=\Gamma=\Omega=0.25$, $u=0.38$, $\gamma=0.05$, $\upsilon=0.333$, $\sigma=0.666$.

47. The RRT applies to offshore projects for which production licences were issued after June 30, 1984. Royalties and (continued...)

fully deductible when deriving the corporate income tax base. The federal corporate income tax rate (u) declined to 39 per cent July 1, 1988, and the state income tax does not apply. The RRT, which is levied on a project basis, is applicable only after the project attains a given threshold rate of return.[48] Exploration costs are deductible from the base of the RRT, and the rate of RRT is 40 per cent.

Since the RRT applies only after a project has reached payout status,[49] the MATC of exploration differs pre-payout and post-payout. Over the pre-payout period, the MATC of exploration is $(1-u)$ dollars, since the expenditure is tax deductible. During the post-payout interval, the MATC is $(1-u(1-\Phi)-\Phi)$ dollars, where Φ denotes the 40 per cent RRT rate.[50]

Consider now the tax treatment of project revenue. During the pre-payout period, the net return from a dollar of gross revenue is $(1-u)$ dollars, since revenues are only subject to income tax. During the post-payout interval, where revenues are taxed by both the income tax and the RRT -- where the RRT is deductible for income tax purposes -- the after-tax return from a dollar of gross revenues is $(1-u(1-\Phi)-\Phi)$ dollars.

Based on the above considerations, the ratio of the MATC of exploration over the corresponding after-tax return, in

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47.(...continued)
excise duties are not levied on income from these projects, but are levied on other earlier offshore projects where the RRT does not apply.

48. This threshold rate of return is set at 15 per cent plus a (floating) long-term bond rate.

49. Consideration of the 'payout status' of a project, for the purpose of determining when special levies (i.e., those in addition to income tax) are to be imposed, is common among countries levying such charges. In general, during the 'pre-payout' period of a project, where cumulative costs exceed cumulative revenues, these special charges are not imposed -- they are imposed later, during the post-payout period, where cumulative revenues exceed cumulative costs.

50. This can be illustrated as follows. The RRT is given by $\Phi(X-E)$, where X denotes the RRT base, excluding exploration expenses denoted by E. The reduction in RRT resulting from a dollar increase in E is Φ dollars. Corporate income tax is given by $u(Y-E-\Phi(X-E))$, where Y denotes the corporate income tax base, excluding exploration expense and RRT deductions. The reduction in income tax resulting from a dollar increase in E is $u(1-\Phi)$ dollars. Thus, it follows that the MATC of E is $(1-u(1-\Phi)-\Phi)$ dollars.

both the pre-payout and post-payout periods, is identically one. This user cost, giving the pre-tax return that must be earned at the margin on one dollar's worth of exploration capital, reveals that the Australian system is neutral, neither discouraging nor encouraging exploration activity.[51]

b) Norway

The Norwegian government levies a corporate income tax as well as a Special Tax (ST) on offshore petroleum production.[52] The Norwegian corporate income tax rate is 50.8 per cent. The ST is **not** deductible for income tax purposes and is levied at a rate of 30 per cent once an oil and gas project reaches payout status. Exploration expenses are deductible in full when calculating the ST base and the income tax base. Also relevant are the generous 'ring-fencing' provisions which allow income and costs connected with all of the petroleum offshore activities of a company to be assessed together. Therefore, in the Norwegian case of offshore exploration, exploration costs from one field may be applied to offset revenue from other producing fields when establishing the base for the ST. The situation where there is a sharing of costs across projects is referred to below as the 'flow-through' case.

Over the pre-payout period of a project, where the ST does not apply and where the investing company is participating in only one field (called a 'stand-alone' project) the MATC of a dollar's worth of exploration is $(1-u)$ dollars. If, however, the company is participating in other projects, and is able to write-off exploration costs from the pre-payout project against the ST levied on the other projects, the MATC falls to $(1-u-\Psi)$ dollars. Similarly, in the situation where a project is in a post-payout status where the ST applies directly, the MATC of one dollar of exploration is $(1-u-\Psi)$ dollars.

Considering now the treatment of revenues, over the pre-payout period the net return from a dollar of gross revenue is $(1-u)$ dollars, since revenues are only subject to income tax. During the post-payout period, where revenues are taxed by both the income tax and the ST, the after-tax return from one dollar of gross revenue is $(1-u-\Psi)$ dollars.

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51. The tax treatment is 'neutral' in the sense that it leaves incentives unchanged from what would prevail in the no-tax situation. Clearly, with no taxes, funds would be invested only up to the point where the last dollar invested yielded a return of exactly a dollar (implying a user cost of one).

52. While Norway continues to impose royalties on some (older) projects, no royalties are levied if development plans have been approved after December, 1986.

Based on these considerations it follows that over the pre-payout period the user cost of exploration capital, given by the ratio of the MATC of exploration over the after-tax return, is one in the stand-alone case and 0.39 in the flow-through case. Therefore, the system is neutral in the first case while tending to encourage exploration in the latter. In the post-payout case, the user cost of exploration capital is one in all cases implying that the system is neutral, neither encouraging or discouraging marginal exploration activity.

c) United Kingdom

The United Kingdom levies a corporate income tax and a Petroleum Revenue Tax (PRT) on offshore petroleum income.[53] The corporate income tax rate is set at 35 per cent and both the PRT and 100 per cent of exploration expenses are deductible from the base. The PRT is a post-payout tax, levied on a profits measure when cumulative income is in excess of cumulative allowed costs. The rate of the PRT is 75 per cent. While the PRT is determined on a field by field basis, offshore exploration expense incurred in one offshore field may be used to offset PRT owing on another.

Under these rules, the marginal costs and benefits of offshore projects differ between the pre-payout and post-payout periods and differ depending on whether the company earns income from one project alone -- the so-called 'green field' case -- or from more than one project implying that exploration expenses can be allocated across fields -- the so called 'cross-field' case.

During the pre-payout period, the MATC of a dollar's worth of exploration is (1-u) dollars in the green field case, since the PRT does not apply. If, however, the firm has a PRT liability on one project and under the cross-field rules is able to offset this tax using exploration expenses transferred from a pre-payout project, the MATC of a dollar's worth of exploration in the pre-payout project is decreased to $(1-u(1-\xi)-\xi)$ dollars, where ξ is the PRT rate. During the post-payout interval, the MATC of one dollar's worth of exploration in each case is equal to $(1-u(1-\xi)-\xi)$ dollars.

Over the pre-payout period where the PRT does not apply, the after-tax return from one dollar of gross revenue is (1-u) dollars. During the post-payout period where revenues are taxed by both the income tax and the PRT, the return declines to $(1-u(1-\xi)-\xi)$ dollars, which reflects the fact that the PRT is deductible from income tax.

The implied user cost values are as follows. Over the pre-payout period, the user cost is one in the green-field case,

53. Offshore oil and gas fields receiving development approval after March 31, 1982, are exempt from royalty.

implying neutrality, and 0.25 in the cross-field case implying a tax stimulus to exploration activity. In the post-payout period, the user cost is one and thus the system neutral in each case.

d) United States

The U.S. government generates revenues from offshore oil and gas production by levying royalties and a corporate income tax. The most commonly applied royalty scheme levies a flat rate of 16.67 per cent on gross income.[54] These royalties, along with Intangible Drilling and Development Costs (IDDCs), which include exploration costs, are deductible from the income tax base[55], taxed at a basic rate of 34 per cent.

Independent producers can either immediately expense 100 per cent of their IDDCs, or capitalize the costs and write them off through depletion.[56] An integrated producer, however, can only immediately expense 70 per cent of its IDDCs and then amortize the remaining 30 per cent over a five-year period;[57] the oil and gas producers exploring offshore (in Outer Continental Shelf) are typically integrated producers. Using a 15-per-cent discount rate, the after-tax cost of one dollar of exploration expense is 0.69 dollars, as determined by (1-uZ) where u is the corporate income tax rate and Z denotes the present value of the associated tax deductions.[58] Since royalties are deductible from tax, the after-tax return from a dollar of gross revenue is 0.55

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54. While the flat-rate royalty scheme is the most common, there is also a 'sliding scale' royalty scheme, where the royalty rate varies between 16.67 per cent and 65 per cent. A third possible scheme is a net-profit-share royalty, typically levied at a rate of 50 per cent on profits.

55. Also deductible from the corporate tax base is the Windfall Profits Tax (WPT). Since the WPT is a tax, calculated per barrel of oil, on the excess of the removal (sale) price of the oil over an adjusted (for inflation) base price of a barrel of oil, the WPT can be regarded as invariant to increments in exploration expense. Therefore the after-tax cost of exploration can be regarded as invariant to the WPT.

56. Depletion deductions for the independent producers are determined as the greater of cost and percentage depletion.

57. The 'depletion' system in the U.S. is unlike the Canadian earned depletion system in more closely addressing the depletable nature of a resource. Depletable costs are recovered either through cost depletion or percentage depletion.

58. Z is determined by $0.7+((0.06)\Sigma(1/(1.15)^i)$ where the summation sign Σ ranges from i=1 to 5.

dollars, determined by $(1-u(1-\gamma)-\gamma)$ where γ is the flat royalty rate. The implied user cost is 1.25, meaning the U.S. system discourages exploration activity.

Tables 4.4 and 4.5 summarize the international comparisons described above, comparing both the MATCs and the associated user cost across countries. These are illustrated in Figures 4.2 and 4.3.

The MATC statistics, by themselves, do not provide a full picture of the effects of the tax systems because the MATC ignores the effect of the income tax rate on revenue, an aspect important to exploration incentives. While a high corporate tax rate implies lower exploration expenses after tax, the high rate also implies a reduced after-tax return from the investment. For example, while the MATC in Norway in the stand-alone case is low ($0.49) relative to the Canadian no-ETC case ($0.62), the overall exploration incentive offered by the Canadian federal system is greater. This is reflected by the lower user cost (0.81) compared to the Norwegian user cost (1.00).

These user cost statistics imply that the Canadian federal tax system **with and without the ETC** is internationally competitive when compared to the tax policies in Australia, the U.S., Norway, and the U.K.. Greater exploration incentives are, however, provided to firms with existing interests in the U.K. or Norway, where pre-payout cross-field and flow-through provisions apply.

It should be remembered that these MATC and user cost statistics for Canada ignore provincial taxes and royalties that may apply, so that care should be taken when making international comparisons. In particular, these comparisons focus on offshore projects alone, and, in the case of Canada, on offshore projects on federal lands where provincial tax and royalty schemes do not apply.

It should also be stressed that the above comparisons focus on tax factors alone, and ignore geological, cost and reserve differences among these countries.

TABLE 4.1

Comparison of Marginal After-Tax Costs of Exploration Capital With and Without ETC*

-- ED Claim is Constrained by Resource Profit
(dollars)

Taxable Status	Without ETC	With ETC	
Currently Taxable	0.72	0.53	
		With Refund	With No Refund
Currently Non-Taxable			
- Taxable in 1 yr	0.75	0.58	0.59
- Taxable in 5 yrs	0.86	0.62	0.66
- Taxable in 10 yrs	0.93	0.65	0.71

* Figures based on $1 exploration expense.

ED claim constrained by 25 per cent of resource profits for earned depletion purposes.

CEE claims assumed to grind cumulative CEE pool in following year.

TABLE 4.2

Comparison of Marginal After-Tax Costs of Exploration Capital With and Without ETC*

-- ED Claim is Constrained by ED Pool

(dollars)

Taxable Status	Without ETC	With ETC	
Currently Taxable	0.62	0.45	
Currently Non-Taxable		With Refund	With No Refund
- Taxable in 1 yr	0.67	0.52	0.52
- Taxable in 5 yrs	0.81	0.55	0.59
- Taxable in 10 yrs	0.91	0.58	0.63

* Figures based on $1 exploration expense.

ED claim constrained by size of cumulative ED pool.

CEE claims assumed to grind cumulative CEE pool in following year.

TABLE 4.3

Comparison of After-Tax Cost of Exploration Capital With ETC and SD*

(dollars)

		With SD	With ETC
Case I:	ED Claims are Constrained by Resource Profits	0.63	0.73
Case II:	ED Claims are Constrained by ED Pool	0.36	0.56

* Figures based on $1 exploration expense.

Figures assume a 38-per-cent corporate income tax rate.

Companies are assumed to be taxable.

Case I: ED claims are constrained by 25 per cent of resource profits for earned depletion purposes.

Case II: ED claims are constrained by the size of the ED pool. Additions to the ED pool are allowed at a rate of 33 1/3 per cent on qualifying CEE.

CEE claims assumed to grind cumulative CEE pool in the same year.

TABLE 4.4

An International Comparison of
Pre-Payout Marginal Exploration Capital
(dollars)

Countries	After-Tax Cost	User Cost
Canada*- With ETC	0.47	0.61
Canada*- No ETC	0.62	0.81
Australia	0.61	1.00
Norway - stand alone	0.49	1.00
Norway - flow-through	0.19	0.39
U.K. - green field	0.65	1.00
U.K. - cross field	0.16	0.25
U.S.	0.69	1.25

* Figures based on federal tax\royalty system alone.

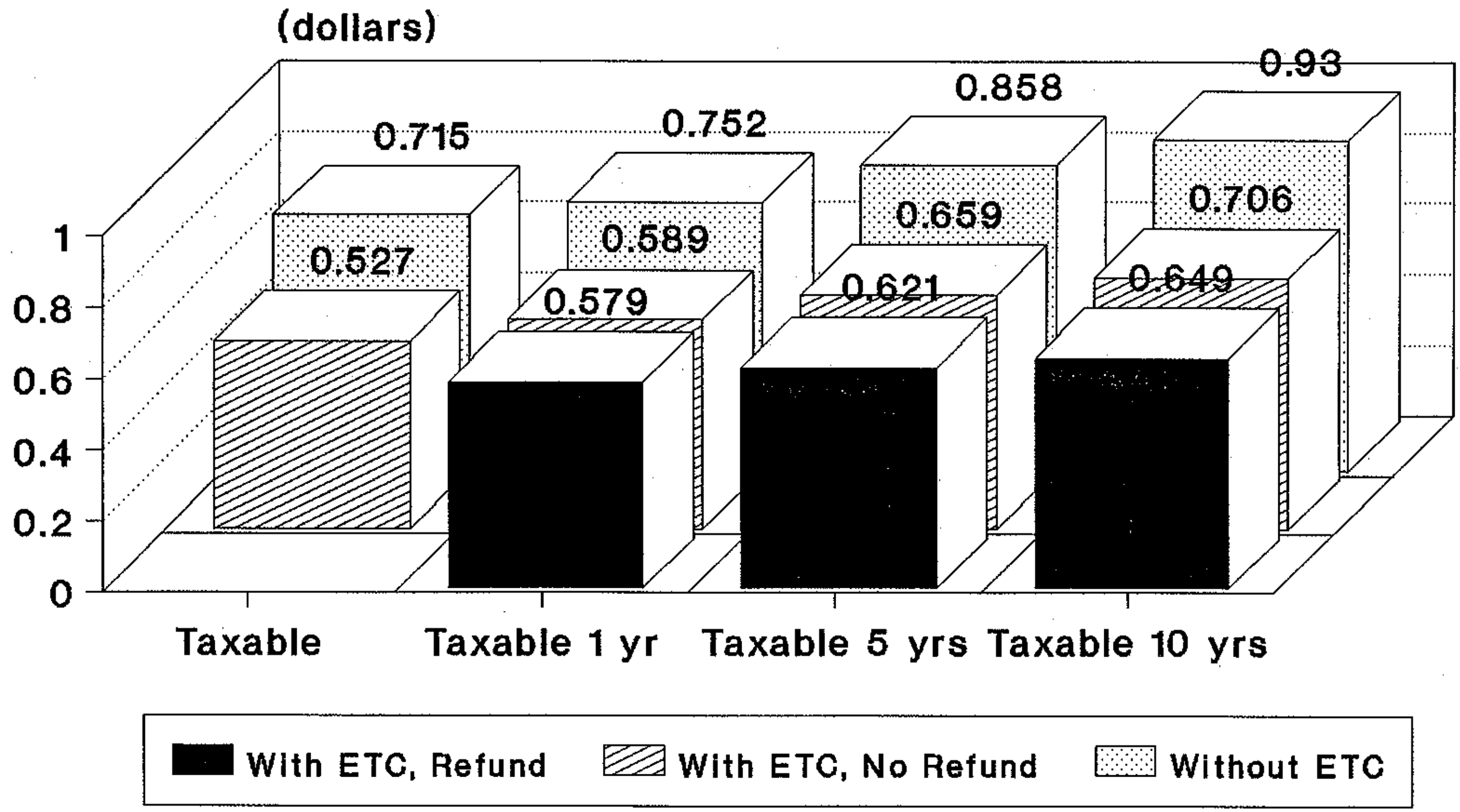
TABLE 4.5

An International Comparison of
Post-Payout Marginal Exploration Capital
(dollars)

Countries	After-Tax Cost	User Cost
Canada*- With ETC	0.47	0.61
Canada*- No ETC	0.62	0.81
Australia	0.61	1.00
Norway - stand alone	0.19	1.00
Norway - flow-through	0.19	1.00
U.K. - green-field	0.16	1.00
U.K. - cross-field	0.16	1.00
U.S.	0.69	1.25

* Figures based on federal tax\royalty system alone.

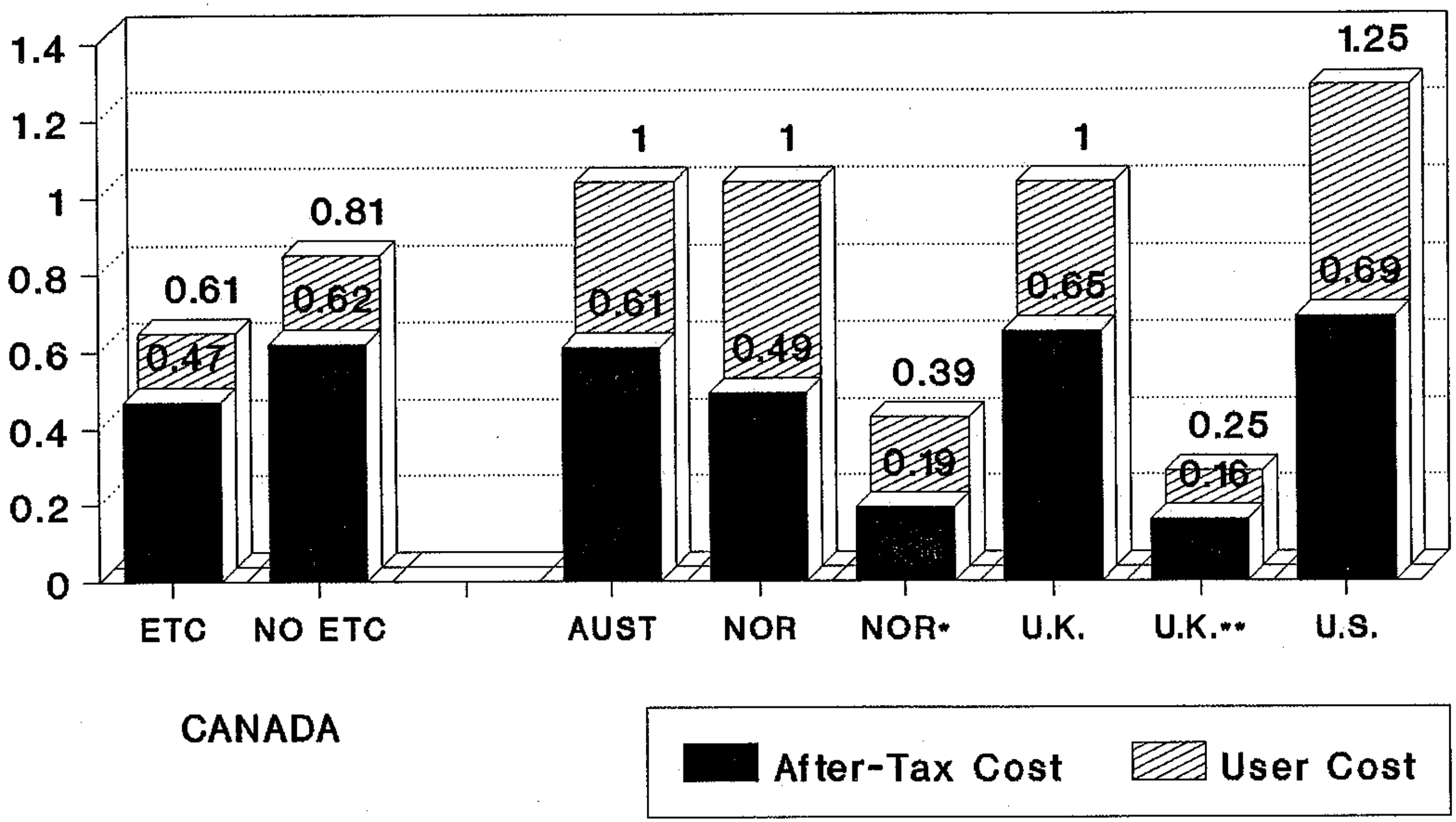
FIGURE 4.1
MATC OF EXPLORATION WITH AND WITHOUT THE ETC



-based on $1 gross exploration expense

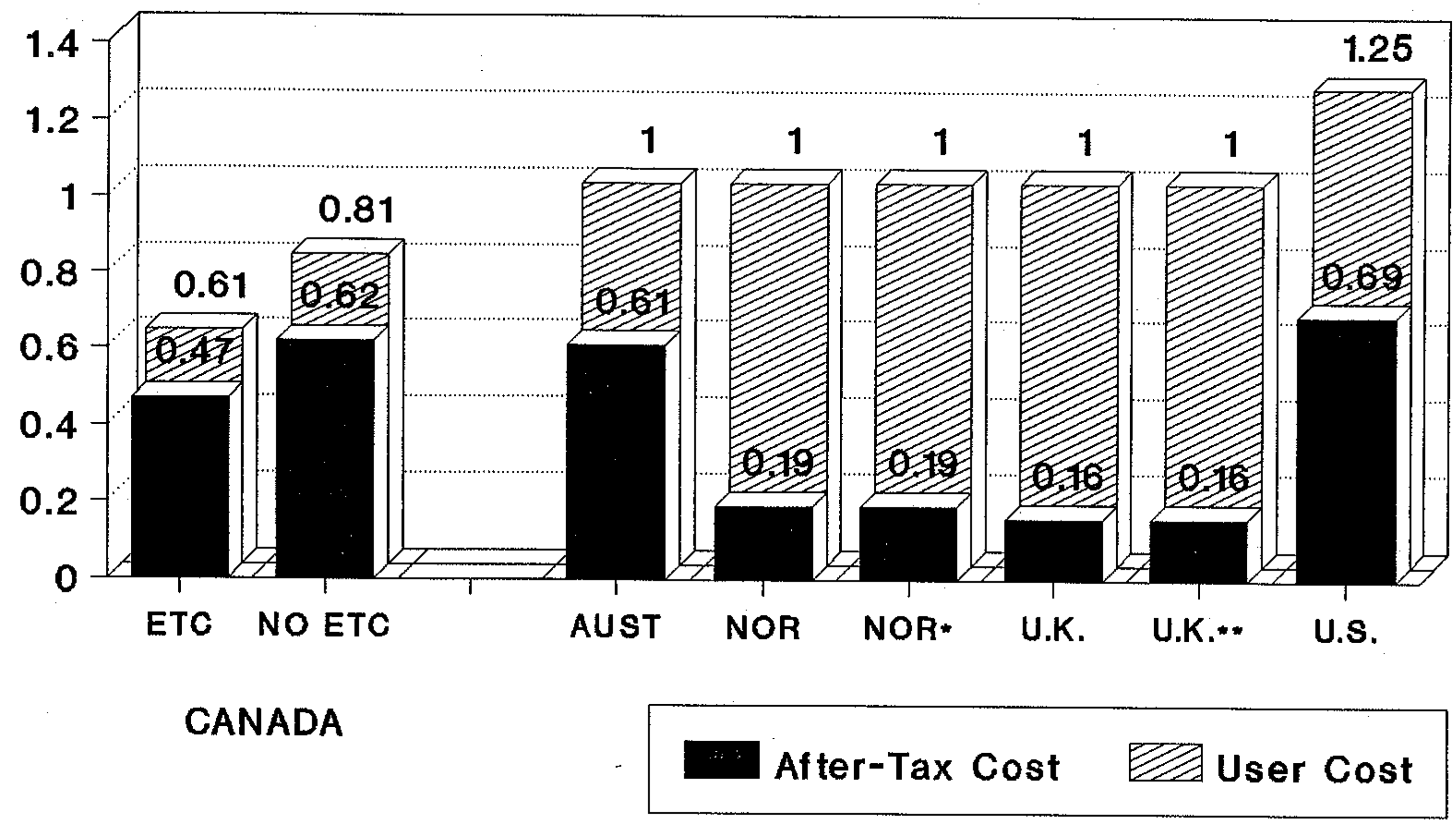
*ED claim restricted by resource profits

FIGURE 4.2
INTERNATIONAL COMPARISON OF PRE-PAYOUT MARGINAL EXPLORATION COSTS



-based on $1 exploration
* flow through case
** cross-field case

FIGURE 4.3
INTERNATIONAL COMPARISON OF POST-PAYOUT MARGINAL EXPLORATION COSTS



-based on $1 exploration
* flow through case
** cross-field case

V. INCREMENTAL EFFECTS OF THE ETC ON EXPLORATION ACTIVITY

Assessment of the ETC requires an estimate of the extent to which it affects oil and gas exploration. Although the formula for the user cost of exploration derived in the preceding chapter can be used to illustrate qualitatively how the credit influences exploration incentives, it cannot be used alone to measure the quantitative impact of the ETC on exploration.

In this chapter we wish to address and quantify the incremental effect of the credit on exploration expenditures in Canada. Exploration expenses qualifying for the ETC, reported in Chapter III, are not necessarily attributable to it. We want to know the percentage of qualifying CEEs directly attributable to the credit. That is, how would exploration expenditures in Canada have been different without the ETC?

A. The Analytical Approach

An econometric study was ruled out at the outset because of the serious difficulties in measuring, in a reliable way, the variables pertaining to the investment decision-making of the ETC-earning oil and gas firms in Canada.[59] Expected after-tax costs and revenues would be difficult to properly measure and align over time with the related exploration expenditures, owing to the frequent and extensive changes in federal and provincial taxation and lending arrangements with the industry and the consequent investor uncertainty.[60]

As an alternative, we decided on a professional survey of companies that earned ETCs over the study period to assess the extent to which exploration is directly attributable to the ETC. The consultant firm of Peat Marwick Stevenson & Kellogg conducted the case-study survey on behalf of the Department of Finance.[61]

The consultants used a detailed questionnaire in interviewing key managers in companies that earned ETCs to find out what, if any, incremental effect the credit had. Answers to the questions which related directly and peripherally to the ETC

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59. The sample would not necessarily have to be restricted to ETC-earning firms, since what is needed is an estimate of the elasticity of exploration expenditures with respect to the after-tax cost of exploration, in general, whether or not the ETC is a component of that cost.

60. See Pesaran, M. H., "An Econometric Analysis of Exploration and Extraction of Oil in the U. K. Continental Shelf", Economic Journal, Forthcoming.

61. Peat Marwick Stevenson & Kellog, "Exploration Tax Credit Study - Final Report", prepared for the Department of Finance, (November 1990), Confidential.

were judged for consistency and level of confidence. They were used in follow-up, independent financial analyses of the effects of the ETC on expected project returns. These interviews also sought insight into the process of establishing exploration budgets and allocating them among competing projects.

Conceptually, five basic cases are possible in connection with incremental effects of the ETC on an individual oil and gas project. In each case, incrementality is measured by comparing the actual project with the alternative which would have occurred in the absence of the tax credit, but with all other circumstances unchanged. The five cases are:

- In the absence of ETC, there is no investment in the ETC-earning project, or any other project involving exploration expenditures with the same objectives. The incremental impact of the ETC is the entire project and its outcome.

- The ETC project and the alternative are identical in every respect except that the ETC project is accelerated in time. In this case, the incremental impact of the ETC is the difference in the timing of the project.

- The ETC project and the alternative are identical except that the alternative project is outside of Canada. The incremental impact of the ETC is the diversion of the project to Canada.

- Because of the ETC, the investors choose the ETC project instead of an alternative that would have occurred at the same time with the same objectives. The incremental impact of the tax credit is the difference in activity between the two cases.

- The ETC has no incremental impact: the sponsor receives the tax credit but does not change his behaviour in any way.

The items in the list are not mutually exclusive, and the interviewers expected to find combinations of them.

Applying the incrementality concept in assessing the ETC impact is complex. The ETC may be incremental, not only at the individual project level, but also at the level of the overall exploration budget.

At the individual project level, the ETC could factor into internal rate of return calculations significantly, altering the prioritized ranking of candidate investment projects either in the period in question or beyond. The credit might well be incremental at the exploration budget level as well, since the petroleum industry tends to finance exploration activities primarily from its internally generated cash flow. Depending on the taxpaying position of the firm, the ETC may increase cash flow enough to allow the firm to undertake a greater number of projects without necessarily changing their ranking. The incremental projects are then the ones that can be funded by additional resources attributable to the ETC.

Assessing incremental effects of the ETC could raise additional complexities. For example, most projects that earn ETCs are multi-company projects so that the taxpaying status and financial position of more than one company will decide whether the ETC is relevant to a proposed investment project.[62]

Contingent drilling also raises problems. The drilling of a well is often contingent on the drilling of earlier wells. Delineation wells, for example, are drilled after the drilling of an original wildcat exploratory well. If the wildcat well is incremental with respect to the ETC, because the well would not have been drilled without ETC assistance, all of the delineation wells associated with it are also incremental. That is, neither the wildcat nor any of the delineation wells would have been drilled without the ETC. Similarly, if the original wildcat well is time-incremental -- drilled sooner than it would have been without the ETC -- the delineation wells may be time-incremental too.

The complexity of contingent drilling did not raise serious evaluation problems, for two reasons. First, while many of the wells studied were delineation wells contingent on the success of earlier wildcat wells, the ETC was not in effect when these wildcat wells were drilled.[63] Second, the case studies indicate that wildcat wells were drilled without regard to the ETC, so the influence of the ETC on decision-making related to delineation wells can be assessed independently of concern for related wildcat wells.

B. The Selected Case Studies

The ETC is earned well by well, several companies participate in drilling most wells, and most companies participate in drilling several wells. The complexity of these relationships requires a careful selection of subjects for case studies to cover all aspects of incrementality. In particular, case studies must be structured to explore the following issues:

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62. While it is true that each well has an operator who is generally the major force behind the investment decisions, the interests of each participating investor are clearly relevant.

63. See, Canada Oil and Gas Lands Administration, Annual Reports, 1985-89; and the Coopers and Lybrand Consulting Group, "Petroleum Incentive Program: Program Evaluation Study", paper prepared for the Department of Energy, Mines and Resources (November 1985).

- The ETC may generate incremental impacts, not only at the individual project level, but also at the level of overall exploration expenditures, including expenditures on contingent wells.

- Separate companies that cost-share a project may have different degrees of control over the decision to proceed.

The subjects of the case studies were organized in three categories to encompass the different circumstances:

- an individual well, with discussions with each of the companies participating in that well;
- an individual well, with discussions with the well's operator; and

- an individual company that participated in the drilling of more than one well.

The selected case studies were based on a population of 27 corporations that earned an ETC at least once on a total of 36 high-cost exploration wells drilled between December 1985 and December 1990. Wells operated by companies later acquired by others were excluded.[64]

The case-study types selected, and the associated wells and companies, are as follows:

- Type A: All qualifying ETC wells of a specific company. The selected companies are Esso Resources Canada Ltd. (operator of five ETC wells) and Mobil Oil Canada Ltd. (operator of one ETC well and investor in six others).

- Type B: All participating investors in an individual well. The selected wells are Amauligak O-86 and Terra-Nova C-09.

    - Amauligak O-86 involves Gulf Canada Resources Ltd. (operator), BP Petroleum Ltd., Husky Oil Operations Ltd., and Texaco Canada Enterprises Ltd.

    - Terra-Nova C-09 involves Petro-Canada Inc. (operator), Canterra Energy Ltd., ICG Resources Ltd., Trillium Exploration Corporation, and Parex (partnership).

- Type C: The operators of individual wells. The five wells and their operators are:

    - Amauligak F-24: Gulf Canada Resources Ltd.,

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64. Corporations that operated and invested in ETC-earning wells and were subsequently taken over were excluded because of difficulties in identifying their managers.

- Terra-Nova H-99: Petro-Canada Inc.,
- Whiterose E-09: Husky Oil Operations Ltd.,
- Immiugak A-06: Chevron Canada ResourcesLtd.,
- Sarcee Alberta: Unocal Canada Ltd.

- Type D: A company that was non-taxable during the period in which it invested in ETC-earning wells. Bow Valley Industries Ltd. was selected, after excluding companies that had been selected under Type A, B, or C.

- Type E: A company eligible for the credit but that did not earn a significant ETC. The company is Shell Canada Inc..

C. The Survey Results

The case study findings make clear that incrementality should be considered at two levels: the individual well, and the overall exploration budget.

- At the level of the individual well, the ETC may be incremental in influencing the expected economics of the project. The credit alters the relative attractiveness of the ETC-earning project, causing it to be undertaken, typically at the expense of some other project.

- At the level of the overall exploration budget, the ETC may provide additional cash flow to the company that could be used to expand this budget, and perhaps lead to additional exploration activities. On the other hand, the cash made available by the ETC may be used for corporate purposes other than exploration.

(a) Incrementality at the Individual Well Level

The case study shows very little incrementality attributable to the ETC at the project level. It strongly indicates that all of the individual ETC wells would have been drilled in essentially the same form at about the same time regardless of the ETC. In all the cases, these incrementality findings were judged to be held with a high level of confidence.

In the analysis of the 23 case study wells, the only indication of incrementality was found in two specific wells where investors may have been influenced by the ETC. These investors would probably not have participated without the ETC. From the perspective of the operator, however, these two wells were sufficiently attractive to have been drilled in any event. Had the ETC incentive been terminated when the investment was decided, drilling might have been delayed by several months, at the most, to find new investors.

The following reasons were found for zero incrementality of the ETC for the remaining wells:

First, exploration expenses may comprise only two to ten per cent of the total capital cost of an offshore project, with development expenses contributing much more to the overall project cost.[65] An incentive, like the ETC, targeted solely at exploration, and not offered at an excessively generous rate, would not be expected to affect overall project costs and therefore project decisions in a significant way.[66]

As one company indicated, "the magnitude of the ETC is within the error implicit in our estimates of exploration costs." As an example, if a company spends $20 million in CEE on a single well and $15 million qualifies for the ETC, the credit earned at 25 per cent is $3.75 million. This benefit is partially offset by the corresponding reduction in CEE (see Chapters IV and VI). The net benefit is $2.14 million assuming a marginal tax rate of 43 per cent. If $2.14 million is discounted to reflect a one-year delay in actually receiving the credit, the benefit of the ETC falls to $1.86 million using a 15 per-cent discount rate. The impact of the ETC is therefore less than 10 per cent of the $20 million capital cost, considered to be within rounding error. Where some of the CEE is grandfathered under PIP, the value of the ETC would be an even lower percentage of the costs.[67]

In another project, where development was not expected to occur within this decade, the ETC earned on four planned

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65. The contribution of exploration cost to total project capital cost depends on the specific project. Relevant considerations include the number of dry holes drilled, the size of the discovered resource pool, and whether the project is a stand-alone project.

66. In the financial project analysis provided in Appendix C, the net impact of the ETC is $23 million in net present value on a project where the net present value of the total capital costs is $2,681 million.

67. There was widespread agreement that the ETC rate was not sufficiently large to influence decisions on drilling wells. Most of the respondents claimed that for an incentive to influence the allocation of their expenditure budget, it would have to at least reduce the cost of a dollar's worth of exploration to 25 to 30 cents. Under the ETC, the after-tax cost of exploration is roughly 57 cents, as determined by $(1-\epsilon)(1-u)$, and assuming a tax rate (u) of 43 per cent. Companies noted that under PIP, oil and gas firms talked of costs as low as 15 to 20 cents per dollar of exploration, depending on the degree of Canadian ownership.

delineation wells (assuming the continuance of the program) was about five per cent of the discounted total cost of the project.

Second, the most important factors influencing exploration are the expected future prices of oil and gas, the probability of discovering deposits, and the probable size of potential reserves. These uncertain factors that underlie the real economics of the projects are the critical considerations. While the ETC can alter the after-tax cost of exploration, the companies indicate that the credit did not factor into project analyses significantly enough to shift emphasis away from oil price and geological and geophysical considerations.

Third, the majority of wells could not be regarded as incremental as they were delineation wells associated with highly attractive discoveries. In such projects, a significant discovery was found to be commercial; the expected returns from proceeding with it were high even without the ETC. The delineation wells associated with these discoveries would have been drilled regardless of the ETC.

Fourth, for three wells drilled in provincial lands, either in conventional or foothill (deep gas) areas in British Columbia or Alberta, drilling costs, which are typically much lower there than offshore, unexpectedly exceeded the $5 million threshold for ETC-eligibility. Unanticipated events, including blow-outs and the need to re-enter the drill hole for unexpected reasons, drove them higher than planned. These wells therefore cannot be considered incremental with respect to the ETC at the individual well level.

Fifth, the opportunity cost of drilling some wells was low, regardless of ETC benefits. Where a corporation owned or was committed to leasing a drilling rig that could not be otherwise employed during a particular drilling season -- implying that the implicit rental cost would be incurred regardless of whether the well was drilled -- the well would probably be drilled in any event, with or without the ETC. For several companies, commitments to drilling programs made the opportunity cost of drilling low.

Finally, certain corporations were not in a taxpaying position. This prevented them from deriving any gain from ETCs earned after 1987, since ETC refunds for firms other than small CCPCs were terminated under tax reform. These companies do not anticipate becoming taxable in the foreseeable future. The ETC would thus not be expected to have any impact.

Conceptually, there is no reason to expect that non-incrementality of the ETC with respect to individual wells can be attributed uniquely to one of these reasons. Several might apply to a single well.

(b) Incrementality at the Exploration Budget Level

ETCs provide cash flow to companies that are taxable in the year the credit is earned, are taxable in any of the three preceding tax years or are eligible for an ETC refund. Similarly, under the carry-forward rules, unutilized ETCs may provide cash flow in the future if the company later becomes taxable, although the present value of this benefit diminishes over time.

The survey intended to establish, if possible, the linkages between the incremental cash flow generated by the ETC and the expenditures it was allocated to. The issue is whether incremental cash flow from the ETC flows back into a frontier or conventional exploration budget, or into other investments.

The ETC can incrementally influence the exploration budget in two ways. First, a direct impact can result if a budget allocation mechanism channels ETC funds directly into the corporation's exploration budget. Second, an indirect effect can occur if ETC funds flow into some larger corporate pot for allocation. The incremental ETC dollars may or may not flow into the firm's Canadian frontier exploration budget in the second case, depending on the competing priorities of the corporate organization.

ETC funds can have a direct impact on a firm's exploration budget in two ways. In one case, additional cash generated by the ETC is simply added to the exploration budget, more or less dollar for dollar. Thus the exploration budget is increased by the additional cash flow the credit generates. It might be increased by the tax value of the ETC upon commitment to an ETC-qualifying project.

In the other direct impact case, projects are drawn down against the exploration budget on an after-tax, net-of-ETC basis. If an ETC project were substituted for a non-ETC project of similar capital cost when measured gross of the ETC, and if the allocation of the exploration budget to the ETC project were based on its cost net of the ETC, the existing exploration budget could be stretched further to cover additional projects. Here, the ETC affects not the size of the exploration budget but the ranking -- and possibly the number --of exploration projects that can be undertaken.[68]

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68. Clearly, both direct effects could occur simultaneously. Management may increase the amount of funds allocated to the exploration budget -- owing to additional cash flow from the ETC -- and may rank projects on an after-tax basis. In this situation, the ETC could increase the number of possible projects by both increasing the total amount of exploration funds, and reducing the after-tax cost of individual ETC-earning projects.

In the case of an indirect incremental effect, cash flow from the ETC is not earmarked for exploration, but is assigned to a larger budget for not only exploration, but other investments as well, perhaps including development and production. Whether the additional funds from the ETC imply a larger exploration budget will depend on the competing investment priorities of the company, and the method by which these investments are ranked.

The case study findings show that the ETC created a direct incremental impact on the Canadian exploration budget of two of the nine companies surveyed owing to their institutional budgeting frameworks. One company directed incremental cash flow to seismic exploration in the Canada lands. The other directed it to additional seismic work or additional exploration drilling in conventional operations in Alberta and British Columbia.

For various reasons, the study discovered no incremental effects on the exploration budgets of the other corporations. Seven of the nine firms budgeted exploration on the basis of gross capital costs: individual projects drew down the exploration budget on the basis of their pre-tax cost. All tax effects, including the ETC, were therefore not recognized in exploration budgeting.[69] In a number of case studies, ETC funds flowed back into a 'corporate pot' managed in a foreign-based office, where Canadian operations were only a small part of international operations. Some corporations clearly focused their incremental exploration budget on international operations outside North America. Many corporations view the offshore projects as strategic commitments that must be ventured into, regardless of tax incentives, to maintain market shares into the twenty-first century.

In sum, for most companies the exploration budget was determined without consideration of the ETC.

(c) Overall Incrementality

The case study concludes, with a high degree of confidence, that none of the case study wells, or other wells earning ETC that were excluded from the sample, were incremental. Although the evidence reveals that some individual investors were motivated by the ETC, accelerating their investments in a project by several months, this time-incrementality is not considered to

69. Where taxes are not treated in the calculation of project cash flow, it is possible that the rate used to discount project returns account for after-tax considerations, and thus are affected by the ETC. In the case where frontier well projects were evaluated on a pre-tax basis, this was irrelevant since the discount rate was mandated by owners outside of Canada who apply the same discount rate to evaluate all offshore projects in all countries.

be significant, and therefore is assumed to be nil when measuring the incremental impact of the ETC.

While the study shows no significant incrementality at the individual well level, two corporations were identified that had institutional mechanisms leading to some incremental impact of the ETC on their Canadian exploration budget. This implies that the ETC did generate an incremental impact on exploration expenditures, although not necessarily on ETC-earnings wells.

When the measure of capital budget incrementality is expanded to cover the total population of wells, incrementality attributable to the ETC is estimated to be roughly 5 per cent of qualifying Canadian exploration expenses, or roughly $47 million in 1990 present value. This finding was then checked using the following 'back-of-the-envelope' calculation.

As discussed in Chapter IV, the ETC reduces the after-tax cost of exploration by roughly 26 per cent, assuming that the firm is taxable. In the non-taxable cases, the ETC could have as little as a zero per cent change in the after-tax cost, depending on the availability of an ETC refund, and on if and when the firm becomes taxable. Accounting for these considerations by reducing the percentage change in cost by one-third, implying that the ETC reduces the average after-tax cost by 17.2 per cent, and applying the case study finding of a 5 per cent increase in exploration in response to the introduction of the ETC, the total elasticity of demand for exploration capital with respect to its after-tax price is calculated to be approximately -0.29.

This implied elasticity can be checked using the following relationship:[70]

$$\varsigma = -(1-\alpha_E)\sigma + \alpha_E\eta \qquad (5.1)$$

where ς is the total own-price elasticity of demand for exploration capital defined negatively, α_E is the share of exploration capital in the value-added of the petroleum sector assumed to be 10 per cent, σ is the elasticity of substitution between exploration capital and other productive factors, taken to be small at 0.10, and η denotes the total own price elasticity of demand of output, defined negatively. Estimates of η from the Department of Energy, Mines, and Resources, ranging from -0.15 to -0.20, imply that ς should range from -0.24 to -0.29. This check suggests that the case study results are fairly robust.

70. See R.G.D. Allen, Mathematical Analysis for Economists, (London: MacMillan and Co., Ltd., 1938), pp.372-374.

VI. THE IMPACT OF THE ETC ON FEDERAL TAX REVENUES

Assessment of the cost-effectiveness of the ETC requires, in addition to an estimate of the incremental effect of the credit on exploration, as derived in the previous chapter, an estimate of the cost of the ETC in terms of foregone tax revenue. In this chapter we discuss the calculation of the federal tax revenue cost, and derive an ETC cost-effectivenss measure.

A. A Conceptual Framework

The true cost of the ETC to the federal government cannot be assessed by simply aggregating ETC claims and refunds, as was done in Chapter III. Proper measurement must take into account the fact that taxpayers typically have an array of tax deduction, credit and loss pools to reduce tax, and that claims on any of them will depend to some extent on the claims made on the others. The cost to the government of a tax instrument such as the ETC therefore depends on the cost of other ITCs and, more generally, on other claims taken in the same and earlier tax years.

A proper measure of the cost of the ETC must take into account the foregone federal tax revenue resulting from the ETC. In other words, what is the opportunity cost to the federal government of the ETC? Or, what would federal tax revenues have been in the absence of the ETC, allowing for the possibility that corporations' claims from alternative tax deduction, credit, and loss pools would have been different in that case?

This question is answered by estimating what federal corporate income tax revenues would have been without the ETC incentive in place over the period since 1985.[71] The estimates allow for the possibility that claims from alternative tax pools would have been higher in the absence of the ETC, and incorporate the results of the case-study survey showing the extent to which oil and gas exploration activity would be reduced in the absence of this tax credit. The simulated corporate tax revenues derived for this 'no-ETC' case are compared with the actual amounts of tax revenue collected over this period to estimate the federal cost of the ETC.

To fully assess the cost to the government of the ETC, tax revenue estimates would have to be determined annually for each ETC-earning corporation, both with and without ETC, since the ETC started. Even if the ETC expired on schedule at the end of 1990, taxpaying behaviour after 1990 would still have to be considered because of the possibility of prolonged ETC effects on the various tax deduction, credit, and loss pools resulting from

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71. Although the ETC became available in December 1985, no ETC credits were earned or claimed by firms whose fiscal year ended before December 31, 1985.

changed claiming behaviour when no ETC is assumed. Tax revenue differences for each firm earning ETC could then be normalized and discounted back to 1990 to a cost measure.

Such a procedure would require information on tax-claiming behaviour beyond the present time. Owing to this lack of data, the next best strategy would be to measure revenue differences in the actual case and the no-ETC case up to and including 1990, and also measure any differences between the cases in the 1990 closing balances of the various tax pools, since these imply different abilities to reduce tax over the post-1990 period. With some assumptions about the taxpaying status of each firm over the post-1990 period and, in particular, their time-profiles of tax-pool use, the present value of revenue differences beyond 1990, implied by any differences in the 1990 closing balances of tax pools, could be estimated. This estimate, when added to the present value of the revenue differences measured between the actual case and no-ETC case for tax years before and including 1990, would give a good approximation of the present value of the cost of the ETC.

At the time of writing, Revenue Canada had not transcribed tax return data for tax years ending in 1989 and 1990 into machine-readable form. Therefore, a modified version of the above methodology was employed. Operators of ETC-earning wells made available information on the amount of ETC earned by well and by corporation in 1989 and 1990. Estimates of the cost of the ETC were based on this and individual corporate tax return data for tax years 1986, 1987 and 1988.

Tax revenue differences between the actual and no-ETC cases were estimated for each ETC-earning firm for tax years ending in 1986, 1987, and 1988. In those cases where a firm had filed more than once in a tax year, the revenue differences were estimated for each short taxation period. All tax revenue estimates were normalized to constant 1990 dollars and discounted forward to 1990; the real discount rate used was 10 per cent.[72]

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72. The 10-per-cent real social discount rate, estimated by Jenkins, was endorsed by the Treasury Board. See G.P. Jenkins, "The Measurement of Rates of Return and Taxation from Private Capital in Canada", in <u>Benefit-Cost and Policy Analysis</u>, 1972, ed. W.A. Niskanen et al. (Chicago: Aldine Publishing Co., 1973); "Capital in Canada: Its Social and Private Performance, 1965-74", Discussion Paper No. 98 (Ottawa: Economic Council of Canada, October 1977); and "The Public Sector Discount Rate for Canada: Some Further Observations", <u>Canadian Public Policy</u>, Vol. 7, No. 3 (summer 1981). Also see Treasury Board's <u>Benefit-Cost Analysis Guide</u> (Ottawa: Minister of Supply and Services Canada, 1982). The 10-per-cent real figure has been challenged by Burgess, who has estimated it at 7 per cent (continued...)

Differences between the closing balances of tax deduction and credit and loss pools in the two cases at the end of the last tax year in 1988 were recorded. Then the present value in 1990 of tax revenue differences implied by differences in the closing balances of the tax pools in 1988 was estimated under various assumptions about the time-profile of tax pool use. The 1989 and 1990 ETC data by well and by corporation were also used to estimate the federal revenue cost of the ETCs earned in those years; this was done by analyzing the impact that the ETCs would have had on the CEE and investment tax credit pools of the firms earning ETC. Applying the same assumptions about the time-profile of tax pool use noted above, the present value of the cost implications of the ETC earned in 1989 and 1990 was estimated. These results were then aggregated with the estimates of the present-value cost of ETCs earned in 1986, 1987, and 1988, to provide an estimate of the total cost of the ETC.

B. The Data Set

Since the objective of the tax revenue simulation was to estimate federal corporate tax revenues in the absence of the ETC, only firms earning ETC in one or more years were considered. Each corporation was included in the sample in the first year it earned an ETC and retained regardless of whether it continued to. For example, a firm that earned an ETC only once, say in 1986, would be retained in the 1987 and 1988 sample, and its corporate tax revenues estimated for those two years. This was necessary because the size of the pools of tax deductions, tax credits, and tax losses from which the firm could draw to reduce its tax in those subsequent years might be different in the simulated no-ETC case as a result of a different tax-reducing strategy in 1986.

The removal of the ETC does not necessarily imply greater tax revenues, owing to the availability to many of the ETC-earning firms in this period of often large pools of unused credits, deductions, and losses. In the absence of the ETC, the corporations could have had greater recourse to them.

Because many tax claims might be affected by removal of the ETC, the simulated closing balances of the various tax pools in one tax year were used to measure their opening balances the next year. An in-house tax simulation model was developed to do this since Revenue Canada's cannot.

72.(...continued)
(see D.F. Burgess, "The Social Discount Rate for Canada: Theory and Evidence", Canadian Public Policy, Vol. 7, No. 3 (summer 1981). The 3-per-cent difference is considered to be significant and both Jenkins and Burgess agree that the difference can only be resolved through more empirical analysis. In the evaluation, we footnote the results with a 7 per cent discount rate.

C. The Tax Revenue Simulation Model

The model was developed to estimate federal Part I corporate tax revenues under two scenarios.

The first, the actual-case estimate, assumes that the firm attempts to minimize Part I tax, with the observed earning of the ETC. The only difference from the actual tax return, if any, results from the assumption that firms take their maximum allowable claims from the available tax-deduction, credit, and loss pools: everything else, including real behaviour, is assumed to be unchanged.[73] The tax revenue estimates are used to verify if firms do in fact reduce tax in this manner, and to check the proper functioning of the simulation program.

In the second scenario, the no-ETC scenario, revenue estimates are derived under the assumption that the ETC does not exist. They are based on the reduction of exploration that would occur without the ETC, as shown by the case-study survey. In the normal situation, the reduction lies somewhere between two extremes. In the non-incremental case, where a firm's real economic behaviour is unaltered by the absence of the ETC, the only impact of the ETC is on the financial side, affecting the firm's tax status. Conversely, in the fully incremental case, where CEEs qualifying for the ETC are attributable fully to the credit, both real and financial behaviour are influenced by the ETC.

The no-ETC simulation results, based on the survey findings discussed in Chapter V, assume that the incremental effect of the ETC is measured by taking 5 per cent of qualifying Canadian exploration expenses; the simulation results therefore tend towards those of the non-incremental case. These no-ETC estimates assume a small decline in CEEs, allowing for implied differences in a firm's tax claiming behaviour expected to arise under the no-ETC assumption.

(a) Modelling Direct Impacts of No ETC

The most obvious impact of eliminating the ETC is a reduction in ITCs otherwise earned and thus available to reduce

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73. In all cases except one, the observed claims from the COGPE and CDE pools were the maximum possible. Since the net additions to these pools in the no-ETC case are assumed to be unchanged from the actual case, the simulated maximum claims from these pools in each case except one were the same as the actual maximum claims. Principal business corporations are required by law to take their maximum CEE deductions.

tax. If a firm spends $100 on CEEs qualifying for the ETC[74] and the ETC rate is 25 per cent, the firm earns a $25 ETC in that year. This credit would be added to its pool of ITCs and be available to reduce its tax liability in either the current tax year or perhaps a previous or future year, or some combination. Without the ETC, the available ITC pool would be smaller by $25, all other things equal.

Whether the reduction in the available pool of ITCs implies greater tax revenues in the current year depends on the amount of federal tax payable by the firm, measured before claiming the credit,[75] and also on whether the firm attempts to fully use this pool to reduce its tax.

If tax payable measured just before the claiming of the ITC is zero, implying that an ITC could not be claimed to reduce tax in that year, the non-availability of the ETC clearly does not affect the amount of tax payable in that tax year.[76] However, because of the carry-back, carry-forward and refund provisions of ITCs,[77] the removal of the ETC may affect net tax revenues collected in the same year and over time.

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74. Recall that CEE qualifying for the ETC is a well-specific amount in excess of a cumulative threshold of $5 million. If, in a specific tax year, the threshold amount of $5 million has already been incurred in previous tax years, the well-specific CEE qualifying for the ETC in that year is the total CEE incurred on the well in the year. If however the threshold amount is achieved in the current tax year, the well-specific CEE qualifying for the ETC is the CEE incurred in that year less $5 million. Where the well costs are incurred by more than one taxpayer, the qualifying CEE is divided among them according to an agreement filed with Revenue Canada.

75. The amount of tax that ITCs can offset is restricted by the fact that there is a mandatory structured sequence in which the various tax deductions, losses, and credits claims available to the firm can be used. When calculating federal Part I tax payable for tax years ending in 1986 or 1987, the ITC is the second last claim that can be made, the very last being the employment tax credit. For tax years ending in and after 1988, the amount of tax that can be reduced by the ITC is determined by the amount of tax payable after all claims including the employment tax credit.

76. Corporations are not allowed to claim investment tax credits to create non-capital losses.

77. As discussed elsewhere in this paper, tax reform curtailed the refundability of investment tax credits.

When an ETC is earned but cannot be claimed because no current tax liability exists, a firm is allowed to carry the tax credit back to offset income taxes paid in any of the three preceding tax years. In addition, any ETC earned in a period that cannot be applied to reduce tax in that year or carried back to reduce tax in a previous year may earn a 40 per cent refund.[78] The ETCs earned in the current year that are not applied to reduce current or previous year's tax, or to earn a refund, can be carried forward to offset tax in any of the following ten tax years.[79]

Alternatively, the non-availability of the ETC will increase taxes if tax payable measured just before the claiming of the credit is positive, so that an ITC could be used to reduce current year's tax.[80] Non-availability of the ETC will not influence tax, however, if the size of the available ITC pool, less the ETC, exceeds the amount of tax that can be reduced by the credit.[81] Also, the non-availability of the ETC may not

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78. Small CCPCs earn investment tax credit refunds equal to 40 per cent of their "excess" credits (the excess of credits currently earned over that amount claimed to offset current or previous year's tax). This rule applies to ETCs earned, and to (general) investment tax credits earned as well. For tax years beginning before 1988, non-CCPCs earned refunds at a 20 per cent rate on their "excess" general investment tax credits, and at a 40 per cent on their "excess" ETCs; refundability for all tax credits was terminated for all corporations other than small CCPCs for tax years beginning after 1987.

79. Investment tax credits, including the ETC, cannot be carried forward and then subsequently carried back to offset tax in a given year if the credits were available in that year to reduce that year's tax.

80. This is true only if the size of the ITC pool constrains the claim. As an example, consider the situation where a firm has $100 in tax payable prior to its ITC claim. Assume that in case A the size of the ITC pool is $1000 with the ETC and $990 without, while in case B the ITC pool size is $75 with the ETC and $65 without. Since, for tax years ending before 1988, the maximum ITC claim is $100 (decreased to $75, under the Annual Investment Tax Credit Rules, for tax years ending after 1988), non-availability of the ETC can only affect the firm's current year tax in case B.

81. For tax years ending before 1988, available tax credits can be claimed to reduce up to the full amount of tax payable. However, for tax years ending in or after 1988, the amount of investment tax credit (including the ETC) that can be used to offset current year tax is limited to the lesser of (continued...)

imply increased tax if ITC claims are not set to their maximum level as determined by the amount of tax otherwise payable and the size of the ITC pool, and if, as in the previous case, the size of the ITC pool was not the binding constraint on the chosen ITC claim.

In these latter two cases where the non-availability of the ETC does not directly affect tax, as in the no-tax case, the partial refundability of the ETC implies that the inability to claim ETC in a given tax year will affect the net tax revenues collected in that year. Also, because of the carry-forward provision of the ITC, the inability to claim ETC, by influencing the closing balance of the investment tax credit pool in that year, will affect the opening balance of the pool in the following tax year, which in turn affects the net federal taxpaying position of the firm subsequently.

Eliminating the ETC also causes an adjustment to the firm's cumulative CEE account. When an ETC earned either currently or in a previous tax year is claimed to reduce current-year tax, or is carried back to offset a previous year's tax, or is used to generate an ETC refund, the taxpayer's cumulative CEE pool must be reduced by the amount of assistance received. This 'grinding' of the cumulative CEE pool means decreased CEE deductions in either the current or subsequent tax years, which tends to increase tax. For tax years ending before 1988, the claiming or refunding of ETC grinds the cumulative CEE pool in the same tax year, while for tax years ending in or after 1988, ETC assistance in a tax year decreases the cumulative CEE pool in the following year. The overall net effect of utilizing ETC is, however, to reduce tax because a dollar credit or refund more than offsets the increase in tax resulting from a dollar decline in tax deductions.[82]

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81. (...continued)
1) the total available pool of investment tax credits (including current amounts earned, and any carry-forward or carry-back amounts available in the year) and 2) the Annual Investment Tax Credit Limitation. For non-CCPCs whose tax year ends after 1987, investment tax credit claims cannot exceed three-quarters of taxes otherwise payable. For corporate tax years ending in 1988 which include any days in the 1987 calendar year, there is a prorated annual limitation for non-CCPCs, consisting of the number of days in the tax year before 1988 plus three-quarters of the number of days in the tax year after 1988, all divided by the number of days in the tax year and multiplied by taxes otherwise payable.

82. While ETC refunds are earned at a 40 per cent rate on "excess" ETC credits, a one dollar ETC refund reduces the cumulative CEE pool by exactly one dollar.

When simulating tax payable for a firm in a tax year ending in either calendar 1986 or 1987, the firm's cumulative CEE pool in that year is adjusted upwards by the actual total amount of ETC assistance received by the firm in that year. This is done because the observed net addition to the pool is an amount measured net of the ETC assistance actually received by the firm in that year, due to the grinding of the cumulative CEE pool by this assistance, as mentioned above. Without the ETC, the net additions to the cumulative CEE pool in the non-incremental case would be greater than the actual net addition by this amount of ETC assistance.

For tax returns having a fiscal period ending in 1988, this adjustment is not required because the net adjustment to the pool is not measured net of ETC claims or refunds that are taken in that tax year. In this case, the cumulative CEE pool is reduced by that amount in the following tax year.

In the non-incremental case, where exploration expenditures are assumed to be unchanged as a result of the elimination of the ETC, the only required adjustment to net additions to the cumulative CEE pool are those just described that relate to the grinding of this pool by the amount of ETC assistance claimed. In the fully incremental case and in the case-study-based incremental case, where exploration expenses respond to the elimination of the ETC, observed net additions to the cumulative CEE pool have to be adjusted upward by the actual total amount of ETC assistance received, and downward by the reduction in CEE undertaken in the year resulting from the elimination of the ETC.

When calculating actual and no-ETC revenue estimates, it is presumed that firms take the maximum claim in each tax year.[83] The maximum is calculated as the lesser of the balance of the CEE pool measured before claim, and the amount of income in the tax year measured before the earned depletion claim and after the claim for dividends received from taxable Canadian corporations and foreign affiliates.

In the simulations, the cumulative CEE pool before claim is the simulated opening balance of the pool[84] plus the simulated net addition to the pool. Simulated income for the year is the sum of actual non-resource income, regarded as invariant to the presence of the ETC, and simulated resource

83. By law, the CEE deduction is not optional, if firms are principal business corporations.

84. When considering the first tax year of a firm in the data set, the actual opening balance of the CEE pool is taken as the opening balance in the simulated case. In the following tax years, the simulated opening balance is the simulated closing balance of the previous tax year.

income. Simulated resource income differs from actual resource income by the amount that simulated claims taken before the CEE deduction differ from the corresponding actual claims. These simulated deductions, including the COGPE, CDE, and CEDE, that sometimes differ from actual, are discussed below.

The removal of the ETC will not affect a firm's CEE claim and hence its tax payable if the firm's actual net income and simulated net income are both zero before the computation of the CEE claim. In this case, the maximum CEE claim is zero.[85] While current year's tax is unaffected, the net addition to the CEE pool will be different, between the actual and no-ETC cases, if the firm obtains ETC assistance in the actual case, implying a difference in the cumulative CEE pool between the two cases.[86] This difference implies differences in ability to reduce tax in future years.

On the other hand, if actual net income measured before the CEE deduction is positive and a CEE deduction is actually taken, whereas in the no-ETC case net income is estimated to be zero, clearly the actual and simulated CEE deductions will be different, which could imply differences in that year's Part I tax payable. Final Part I tax will be the same, however, if subsequent tax deductions and tax credits reduce taxable income to zero in both the actual and no-ETC claims.

The same logic applies if net income before the CEE claim is positive in the simulated case and zero in the actual. Indeed, even if this net income measure is positive in both cases, the final tax payable may be no different because of differences in the same tax year in tax claims other than the CEE claim.

In short, the net final impact on tax of removing the ETC from the cumulative CEE pool depends largely on the actual profitability of the firm, and the differences in the size of other tax pools and claims from them in the actual and the simulated cases.

(b) <u>Modelling Indirect Impacts of No ETC</u>

Aside from the effect that the elimination of the ETC has on the investment tax credit pool and CEE pool of the ETC-earning firms, which may not change tax, the removal of the ETC may also be judged to have indirect tax impacts by influencing

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85. This follows because firms are not allowed to create non-capital losses by claiming CEE.

86. The available cumulative CEE pools will also be different to the extent that the opening balances are different because of changes in net additions or claiming in prior tax years.

claims on other resource expense pools and on the pool of accumulated non-capital losses.

The simulation model calculates in each tax year, for both the actual and no-ETC scenarios, maximum claims from the COGPE, CDE, CEDE and ED tax-deduction pools. It also derives the maximum claim from the taxpayer's pool of non-capital losses. Description of the mechanics and inter-dependencies of these maximum claim calculations follows. The maximum claim from the CEE pool and the investment tax credit pool are also calculated for each case, as outlined in the preceding section.

The maximum COGPE claim is determined as 10 per cent of the available cumulative COGPE pool. This pool is calculated as the opening balance of the pool plus net additions to the pool in the tax year. When considering the first tax return filed in the post-1985 period by a firm in the sample, the simulated opening balance of the pool was set equal to the actual observed opening balance. For subsequent tax returns, the simulated opening balance was set equal to the simulated closing balance of the COGPE pool for the previous tax year, determined by the prior year's tax simulation.[87] The simulated net additions to the cumulative COGPE pool in each case were set equal to the actual observed net additions. Finally, the closing balance of the pool was determined by subtracting the simulated maximum claim from the simulated available balance measured before claim.[88]

If a company had a short taxation year (less than 51 weeks) and the fiscal period started after June 5, 1987, the COGPE claim was prorated. That is, the maximum COGPE claim was

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87. If a discrete adjustment to the actual cumulative COGPE pool between tax years was observed creating a discrepancy between the actual closing balance in one tax year and the actual opening balance in the following tax year, the simulated opening balance of the pool was adjusted accordingly. That is, the simulated opening balance of the pool in tax year (t) was set equal to the observed opening balance in year (t), plus any discrepancies between the simulated and actual closing balances of the pool in the previous tax year (t-1). These observed discrete adjustments to the pool could arise, for example, if the firm merged with another that also had a positive balance in its cumulative COGPE pool.

88. If the net addition to the pool is negative (which could arise from the disposition of property) and exceeds in absolute value the opening balance of the pool, implying that the balance of this pool measured before claim is negative, the absolute value of this negative amount is added to the cumulative CDE pool in the same year and the closing balance of the cumulative COGPE pool is set at zero.

determined by multiplying the maximum claim by the number of days in the year divided by 365.

The maximum CDE claim is calculated as 30 per cent of the available cumulative CDE pool, equal to the pool's opening balance plus the net additions to the pool. As with the other tax pools, the simulated opening balance of the cumulative CDE pool was set equal to the actual observed opening balance when considering the first tax return filed in the sample period by the firm. For subsequent tax returns, it was set equal to the simulated closing balance of the previous tax year.[89] The net additions to the pool in the actual and no-ETC cases were not assumed to differ. The closing balance of this pool is determined by subtracting the simulated CDE claim from the simulated balance of the cumulative CDE pool before claim.[90]

As with the COGPE claim, if a company had a short taxation year and the fiscal period started after June 5, 1987, the CDE claim was prorated.

By setting the COGPE and CDE claims as percentages of the available balance of their pools, particularly regardless of the firm's income, either claim could generate a non-capital loss. This procedure can be distinguished from the CEE deduction, which is limited to the taxpayer's income, as discussed below.

Now consider the CEDE deduction. While CEDEs could only arise from January 1, 1972 to May 7, 1974, implying that taxpayers could not create additions to this expenditure pool over the sample period, some did have unamortized balances of their CEDE pool during this period.

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89. As with the cumulative COGPE pool, when the closing balance of the cumulative CDE pool in year (t) did not match the opening balance in year (t+1) in the actual case, the simulated opening balance of the pool in year (t+1) was set equal to the observed opening balance in year (t+1) plus any measured discrepancy between the simulated and actual closing balances in year (t).

90. If the net addition to the cumulative CDE pool is negative and exceeds in absolute value the opening balance of the pool, which implies that the balance before claim is negative, the absolute value of this negative amount is added to income before the computation of resource profits for earned depletion purposes, and the closing balance of the cumulative CDE pool is set to zero. The net addition to the cumulative CDE pool could be negative, for example, where no CDE was incurred but the firm received a grant for previous CDE that draws down the cumulative CDE pool.

The income constraint that could limit the simulated CEDE deduction had to be determined, since principal business corporations may deduct CEDEs to the extent of their income from all sources (resource income as well as non-resource income),[91] and CEDE deductions can only be claimed after the COGPE and CDE deductions. Simulated income before the CEDE claim was set equal to actual income before the actual CEDE claim, less differences between the simulated and actual claims from each of the COGPE and the CDE pools.[92] The simulated maximum CEDE claim is determined as the lesser of simulated income before the CEDE claim, and the simulated balance of the CEDE account before claim. The closing balance is determined by subtracting the simulated CEDE claim from the balance.

The maximum ED claim is set at the lesser of 25 per cent of resource profits for earned depletion purposes, and the available ED pool before claim. Resource profits for earned depletion purposes are determined after the COGPE, CDE, CEDE, and CEE deductions, and therefore will vary between the actual and the no-ETC case to the extent that these deductions taken before ED differ between the two.

Before 1985, one-third of Canadian oil and gas exploration expenses before government assistance were added to the earned depletion pool. Since all taxpayers were restricted during the sample period from adding CEE to their ED pool, the simulated net additions to the ED pool are set equal to the actual net additions, if any.

Observed resource profits used for earned depletion determine simulated resource profits for earned depletion, adjusting for differences in the COGPE, CDE, CEDE and CEE claims between the actual and no-ETC cases, since by law these claims must precede the ED claim.

Non-capital loss claims that reduce the amount of net income to become taxable are the last to consider. The simulated net income before the non-capital loss claim is positive, implying that the firm is taxable and that a non-capital loss claim could be taken, the maximum non-capital loss claim is

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91. The CEDE deduction, like the COGPE and CDE deductions, are not mandatory deductions, unlike the CEE deduction which is mandatory for principal business corporations.

92. The actual value of income measured before the actual CEDE claim is estimated by subtracting the actual resource allowance claim, interest expenses for resource activities, resource royalties, and COGPE and CDE claims, from the observed value of resource profits before the resource allowance. Non-resource income, if any, is added to determine the level of income limiting the observed CEDE claim.

determined as the lesser of the simulated amount of net income measured before the non-capital loss claim and the simulated balance of the non-capital loss pool as measured before claim. Simulated net income before the claim differs from actual net income before claim to the extent that the preceding claims -- the COGPE, CDE, CEDE, CEE and ED claims -- differ between the no-ETC and actual cases.

If the firm is taxable, the simulated balance of the non-capital loss pool available to reduce tax is given by the simulated opening balance of the pool. This balance is given by the pool's simulated closing balance in the preceding tax year. Where simulated net income measured before the non-capital loss claim is negative, it is added to the opening balance of the pool. This determines the simulated opening balance of the pool in the following year.

D. The Simulation Results

The tax revenue simulation results can be summarized as follows. In the 1986, 1987 and 1988 tax years, federal Part I tax revenues are estimated for the actual and no-ETC cases to assess the ETC impact on them. Revenue impact estimates of ETCs earned in 1989 and 1990 are derived in a more direct fashion, since tax return data are not available for those tax years.

For the 1986 and 1987 tax years, we estimate for each firm a Part I tax 'F' estimate (PITF), defined as final Part I tax 'M' (PITM) less ITC credit carry-backs (ITCNCB) and refunds (ITCNR). PITM measures the minimized value of final Part I tax payable as measured after the claiming of ITCs to offset the current year's tax. While carry-backs are used to offset a previous year's tax, they reduce federal revenues in the year claimed, so no discounting of ITCNCB is required when subtracting ITCNB from PITM to obtain PITF.

For each corporation, PITF is estimated for both the actual (PITF(1)) and the no-ETC case (PITF(2)), and then their difference (PITF(2)-PITF(1)) is measured to determine if PITF is greater without the ETC. These differences are summed across corporations, with a positive or negative value indicating larger or smaller federal Part I tax revenues in the no-ETC case, taking into account ITC carry-backs and refunds.

The (PITF(2)-PITF(1)) differences in 1986 and 1987 are then converted to constant 1990 dollars and adjusted to account for the opportunity cost of funds; this gives for these tax years present value of the opportunity cost of the ETC in 1990 dollars, ignoring the implications of the ETC on the closing balances of the tax pools in 1987, which are carried through to 1988 and treated there, as discussed below.

Similarly, when analyzing the 1988 tax year simulations, PITF is estimated for each corporation for the actual and no-ETC cases; then the difference (PITF(2)-PITF(1)) is measured and aggregated across firms. Since the simulation model allows for the claims from the COGPE, CDE, CEDE, and ED tax pools to differ between the actual and no-ETC cases, in addition to allowing for the additions to, and claims from, the non-capital-loss, CEE and ITC pools to differ between the two cases, not all of the impact of the ETC removal is captured in PITF differences. Part of the effect of removing the ETC is embedded in differences in the 1988 closing balances of these tax pools.

This revenue implication was taken into account by first measuring the differences in the closing balances of each of these tax pools between the actual and no-ETC cases, which we can indicate by $(TPCL(1)_i-TPCL(2)_i)$ where $TPCL_i$ is the closing balance of the tax pool (i). For each tax pool a positive or negative value implies a greater or lesser ability to reduce future tax in the actual case. Differences in the tax deduction pools were multiplied by u(1+s), where u is the corporate income tax rate (38 per cent) and s the surtax rate (3 per cent), to convert the measure into one consistent with the impact on taxes payable. The results were added across tax deduction pools, then added to the difference in the investment tax credit pool. This was done corporation-by-corporation.

The revenue implications of these differences in tax-pool balances depend on when the pools can be used, which in turn depends on the taxpaying status of the firm. We assumed firms taxable in 1988[93] would remain taxable in 1989, and that differences in pools would be realized as claims in that year. The tax-revenue effects were then converted to 1990 present value terms. We assumed arbitrarily that firms non-taxable in 1988 would not become taxable until 1993. Again the implied revenue effects in 1993 were converted to 1990 values. The actual and no-ETC values were then aggregated.

For 1989 and 1990, where individual corporate tax returns were not available but figures on ETC earned by corporation were, we took into account the impact of the earned credits on revenues with the same assumptions as above about taxpaying status. That is, if a firm was taxable in 1988, we assumed that it would fully use ETCs earned in 1989 to offset tax in 1989, and that they would, in turn, grind its CEE pool in the following tax year and affect CEE claims and taxes payable in 1990. Hence, in the no-ETC case, the firm's ITC claim would be lower and its taxes higher in 1989 by the amount of ETC earned in 1989, and its CEE claim would be higher and its taxes lower in 1990, due to the absence of ETC grinding of its CEE base. This same principle was used to estimate the revenue implications of ETC earned in 1990, where once again it was assumed that a firm that was taxable in 1988 would remain taxable in 1990. These tax

93. Almost all the same firms that were taxable or non-taxable in 1988 were taxable or non-taxable in 1986 and 1987.

revenue implications were calculated in 1990 dollar present value terms.

Similarly, if a firm was non-taxable in 1988, we assumed that it would remain non-taxable in 1989 and 1990, and that ETCs earned in those years could not be used to reduce tax until 1993. The firms that were non-taxable in 1988 were all non-CCPCs. Thus none were assumed to be eligible for an ETC refund. The no-ETC revenue estimates assumed that the ITC claims in 1993 by the non-taxpaying firms would be lower and thus taxes greater in 1993 by the amount of ETC earned in 1989 and 1990, and took into account the implications of credit differences on the CEE claims in the following tax year. All tax revenue implications were again calculated in 1990 dollar present value terms.

The results in Tables 6.1 and 6.2 show that the aggregate amount of ETC earned over the period 1986 to 1990, ignoring the necessary adjustments for inflation and the opportunity cost of funds, is roughly $174 million, or about $190 million in constatn 1990 dollars. When accounting for the real rate of return that could be earned on the funds used elsewhere, the corresponding present value is roughly $233 million using a real discount rate of 10 per cent.

The net cost of the ETC, estimated by the tax simulation model to be approximately $146 million,[94] is far less. The reasons for this finding can be summarized, as follows. One important explaining factor is that many of the oil and gas firms are not sufficiently taxable to take immediate and full advantage of the ETC -- only roughly 60 per cent of ETCs earned were either claimed by, or refunded to, corporations in the year in which the credits were earned. The cost of the unclaimed balance is less to the government because it must be carried forward to offset tax in future years, and its value is discounted accordingly. Second, the cost of providing the ETC is reduced by the fact that most oil and gas companies have an array of large, unamortized deduction and credit pools, so that the earning of ETC does not necessarily imply an increased ability on the part of these firms to reduce tax. Third, the "grinding" of the CEE pool by the ETCs claimed and refunded for income tax pouposes increases tax payble and further reduces the cost to the government. Figure 6.1 gives a graphic illustration of the estimated ETC-cost differences.

Finally, based on the finding that $146 million of federal tax dollars would generate approximately $47 million in incremental exploration activity (as discussed in the previous chapter), a measure of the cost-effectiveness of the ETC can be

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94. When using a 7-per-cent discount rate, the aggregate 1990 present value of ETCs earned is roughly $219 million, and the corresponding opportunity cost measure is roughly $142 million.

derived. These figures imply that every dollar of incremental exploration expenditure requires $3.20 of federal tax incentives.

TABLE 6.1

AGGREGATE ETC EARNED
($,000)

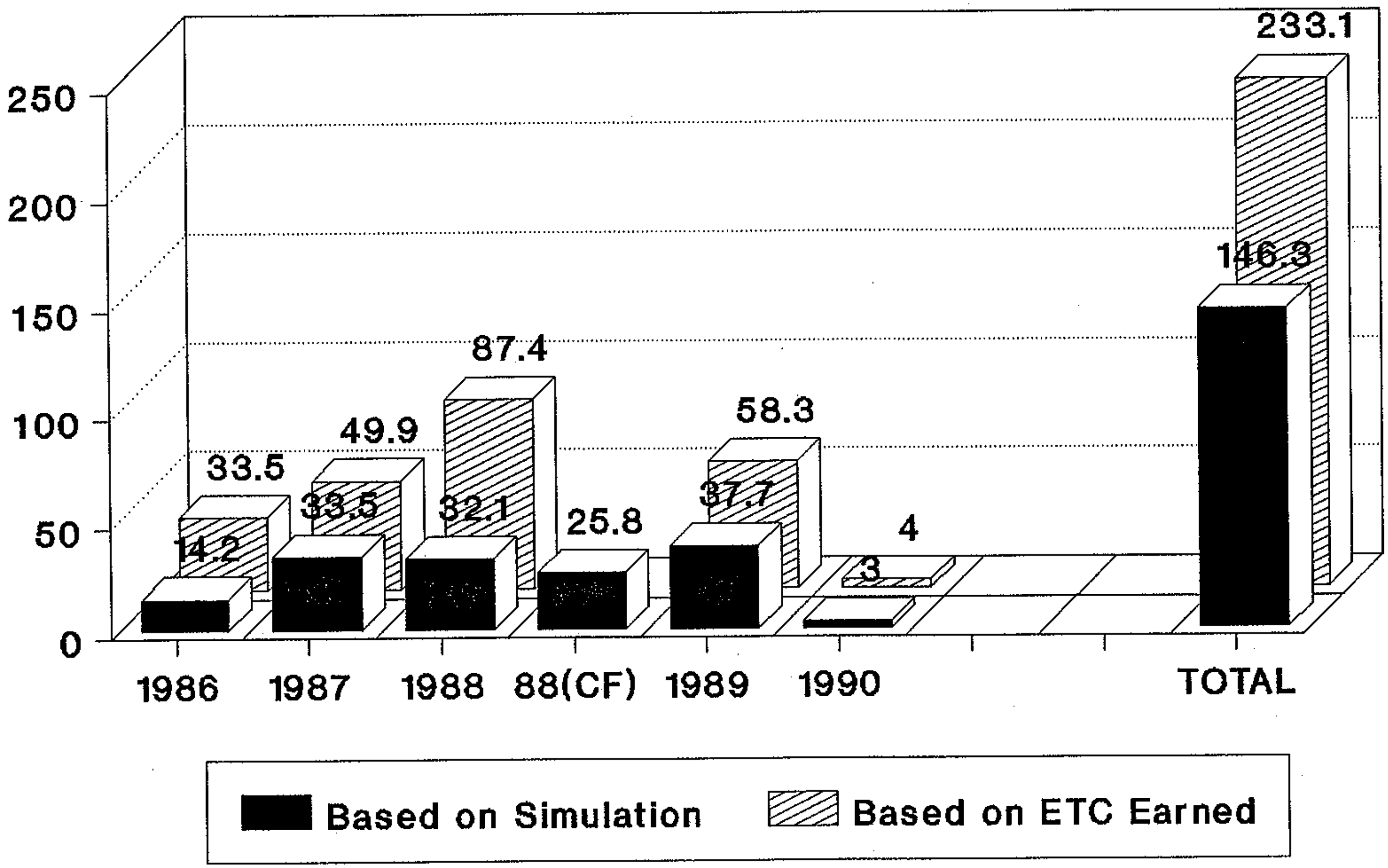
Current Dollars	
1986	19,346
1987	33,055
1988	66,321
1989	51,015
1990	4,000
Total	173,737
Constant 1990 Dollars	189,581
Present Value at 1990 Dollars	
• Discounted at 10% Rate Real	233,074
• Discounted at 7% Rate Real	219,303

TABLE 6.2

The Impact of the ETC on
Federal Tax Revenues
($,000)

	PV at 7% Discount Rate	PV at 10% Discount Rate
1986	14,019	14,178
1987	30,841	33,509
1988	57,281	57,881
1989	37,263	37,770
1990	2,973	3,001
TOTAL	142,377	146,338

FIGURE 6.1
FEDERAL COST OF ETC
(PV 1990 millions $)



-10% discount rate used

VII. THE IMPACT OF THE ETC ON PETROLEUM DISCOVERIES

The case studies, discussed in Chapter V, found that well operators did not perceive the ETC as having a significant incremental impact on wildcat or delineation wells drilled over the period under evaluation. While the studies detected a minor response, since some investors in two wells indicated that they probably would have pulled out had the ETC been terminated at the time the decision to drill was made, the delay in drilling would have been at most several months. However, the findings indicate that the ETC did contribute incrementally to the overall Canadian exploration budget in the petroleum industry. The results imply that the total incremental exploration attributable to the ETC is about 5 per cent of qualifying Canadian exploration expenses. This finding suggests that the tax credit may not have a significant impact on discoveries of oil and gas resources.

Our analysis could be usefully extended to determine the effect of the ETC on petroleum discoveries, since it is hoped that incentives for exploration ultimately increase oil and gas findings, and thus serve to determine the size of this resource potential.[95] An independent assessment of this effect was carried out by the Energy Sector of the Department of Energy, Mines and Resources.[96] This chapter summarizes the findings of that study on the long-run effect of the ETC on petroleum discoveries.

A. Methodology

The analysis seeks to determine the long-run impact of the ETC on the commercially viable portion of undiscovered resource potential in Canada; in other words, the analysis assesses the difference that the ETC would have, over the long run, on the amount of petroleum that private investors would expect could be profitably explored, discovered and produced from frontier oil and gas operations. The discounted cash flow results are sensitive to assumptions of expected exploration success and resource price, other factors affecting revenues and costs, and the investors' after-tax required rate of return.

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95. An interesting cost-effectiveness measure of the ETC would be one comparing the federal revenue cost of the ETC and the additional potential petroleum discoveries stemming from it. This comparison could not be made because the Department of Energy, Mines and Resources simulated the impact of the ETC on incremental gas resources alone, and did not investigate the effect on incremental oil resources.

96. Department of Energy, Mines and Resources, "Exploration Tax Credit Review", paper prepared by Economic and Fiscal Analysis Branch, (July 18, 1990), Confidential.

The approach is multi-disciplinary,[97] establishing a consistent treatment of the geology, engineering, the associated costs, and the economic and fiscal environment. The Institute of Sedimentary and Petroleum Geology -- a division of the Geological Survey of Canada, Department of Energy, Mines and Resources (EMR) -- undertook the analysis of the ETC on resource potential using a probalistic methodology. The analysis is very detailed, giving close attention to each stage of investment activity to establish an appropriate basis for assessment. Exploration, development, and production requirements are carefully identified to correctly reflect resource pool size, location, depth, and so on.

The analysis focuses on a geological play in order to supply a homogenous basis for the resource assessment. It considers individually a number of 'plays' in a particular region in question. A 'play' is a family of pools (reservoirs) with common geological characteristics. Significant cost variations typically exist among different plays, with costs associated with the exploration, development, and production from each particular play depending on the geological and geophysical characteristics of its resource base, the technology required for drilling and production, and the reserve size. Much of this data was supplied by the Canada Oil and Gas Lands Administration which took into account the likely development practices and production forecasts for existing discoveries in the areas.

Consistent with the long-term view of the economic and fiscal environment, the model assumes the existence of processing facilities and a gas pipeline to Western Canada. The engineering and costing model estimates the requirements for the development and production of new discoveries.

The methodology for the resource analysis uses a marginal analysis model. For each individual play, the marginally commercial pool size is determined, where the marginal pool is defined as the smallest pool expected to yield the investors required rate of return. The marginal pool is determined through an iterative process, where iterations on different pool sizes continue until the discounted cash flow rate-of-return calculated for the pool is within 0.5 per cent of the target rate. When this pool size is found, it is defined as marginal for the particular play, under the assumed economic and fiscal environment.

Pools larger than the marginal size are regarded as commercially profitable, while smaller pools are assumed to be unprofitable. The play's profitable potential is defined as the

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97. Detailed description of the analysis can be found in Geological Survey of Canada, Conventional Oil Resources of Western Canada, Part II: Economic Analysis (Ottawa: Minister of Supply and Services Canada, 1987).

sum of all pools in the play that are at least as large as the play's marginal pool.

Repeating this procedure for each play, and then aggregating the results over all plays gives an estimate of the total profitable undiscovered resource potential for the basin. Extending this estimate for all frontier regions in Canada gives an economy-wide estimate.

Different sets of assumptions in the model result in different marginal pool sizes for each play. Factors affecting the cost of extracting and developing resources, and changes in fiscal regimes and price variations in inputs, all influence marginal pool sizes. Revenue considerations also matter. An increase in the resource price will increase the net present value of discounted cash flow to the private sector, which, for any particular minimum acceptable rate of return, will lower the marginal pool sizes, increasing undiscovered resource potential.

Calculating the total commercially profitable resource potential for the ETC case, and for the no-ETC case, and taking the difference yields an estimate of the impact of the ETC on commercially profitable resource potential in Canada.

B. Key Assumptions

The impact of the ETC on incremental natural gas resources is assessed in the Mackenzie Delta and Beaufort Sea region by measuring the difference in resource potential between the ETC case and the no-ETC case. Resource potential is measured both in terms of number of pools and volume. In the no-ETC case, the long-term economic conditions and fiscal parameters are taken to be the same as the system with the ETC. All costs and revenues are measured in 1988 dollars.

A gas price of $3 per mcf (1,000 cubic feet) at the plant gate is assumed. This reflects a $4-per-mcf Alberta-U.S. border price, minus a $1-per-mcf toll. Gas prices and all other expenditures are assumed constant in real terms.

An exploration success ratio of 1:7 is applied to estimate the expenditures incurred to find an economic discovery. The ratio assumes one economic discovery per seven exploratory wells, reflecting the experience in the area and taking into account the economic environment. This ratio is appropriate over the price range of $2 to $4 per mcf. All pools are assumed to be located 25 km from gas processing facilities in the calculation of transportation costs.

The analysis is full-cycle, including costs associated with the drilling of dry and abandoned exploratory wells, and the costs of development wells, and considers the production of a gas pool over its profitable life beginning at the time a decision to drill is taken. The analysis focuses on the 10 gas plays in the

Mackenzie Delta-Beaufort Sea area of current interest to the industry.[98]

The real expected after-tax rate-of-return for marginal commercial profitability for a full cycle investment project is taken to be 15 per cent.

C. Simulation Results

With a gas price of $3 per mcf at the plant outlet, it is estimated that retention of the ETC would increase the commercially attractive prospects from 20 to 23 pools of natural gas in the Mackenzie Delta-Beaufort Sea, or the commercially viable portion of undiscovered resources by 4.2 per cent. The results suggest that retention of the ETC would likely have only a modest positive effect on new discoveries of gas resources.[99]

To place the effect of the ETC in perspective, the analysis also considers the impact of a gas price change on the undiscovered resource potential. The simulations indicate that an increase in the price of gas from $3 per mcf to $4 per mcf would increase the commercially profitable potential by roughly 35 per cent. Conversely, a decline in the gas price of $1 per mcf is estimated to reduce the number of potential pools by half, which corresponds to roughly 25 per cent of the commercial portion of the undiscovered resource potential.

A simulation was also performed to illustrate the importance of exploration success on the results. Simulations using a technical exploration success ratio of 1:3, rather than 1:7, show that the profitable resource potential would increase by more than 45 per cent.

D. Summary

The ETC was found to have a moderate impact on the commercially viable quantity of undiscovered natural gas reserves in the Mackenzie Delta-Beaufort Sea region. The increment in reserve potential represents roughly 4.2 per cent of total

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98. A total of 20 gas-bearing exploration plays were recently assessed by the Geological Survey of Canada, Department of Energy, Mines and Resources.

99. Assessing the real economic costs and benefits of the ETC to the country as a whole is a complicated exercise. The real cost of the ETC can be measured by the deadweight loss of raising the additional federal tax revenues of $146 million plus the proportion of the above federal revenues not used in the incremental exploration but paid out to foreigners. The benefits would be the present value of both excess profits received by the producers and additional tax revenues resulting from exploration and production.

commercially viable potential. The influence of other factors, such as the price of gas, is shown to be far more important than the availability of the ETC.

Although the analysis is only directly applicable to undiscovered natural gas resources of the Delta-Beaufort region, the study suggests that the results are generally indicative of the ETC's impact on exploration in all of Canada's frontier petroleum resource basins.

It may be concluded that the removal of the ETC would have a moderate impact on the amount of resources ultimately found. This appears to be consistent with the view expressed in the case study interviews with industry representatives that the impact of the ETC on exploration is small.

VIII. SUMMARY AND CONCLUSIONS

This paper has evaluated the economic and fiscal impacts in Canada of the exploration tax credit. It has examined such issues as the extent of exploration directly attributable to the ETC, the cost of the ETC to the federal government in forgone tax revenue, the impact of the credit on findings in undiscovered resources, and the degree to which the ETC has accomplished its original objectives.

The federal government announced the ETC in October 1985 as part of the Frontier Energy Policy, designed to encourage high-cost oil and gas exploration activity in Canada. The incentive provided firms with a 25-per-cent tax credit to be earned on their qualifying Canadian exploration expenses incurred on a well costing more than $5 million. Since most high-cost exploration activity occurs on the frontier, the ETC mainly benefited wells in the Canada lands. A companion incentive, the Investment Royalty Credit, offsetting federal royalties otherwise payable, may be earned at a rate of 25 per-cent on the first $5 million in costs of new exploration wells on frontier lands. This credit essentially allows production from lower cost wells to enjoy a royalty free period of up to $1.25 million per well. The combination of the ETC and IRC incentives was expected to provide a balanced encouragement to oil and gas exploration in all frontier areas of Canada.

Soon after the present government took office in September 1984, it set out principles under which energy policies would be more market-oriented and flexible. The Western Accord, signed in March 1985 by the Government of Canada and the western provinces, phased out the National Energy Program and set an agenda for the gradual elimination of the Petroleum Incentives Program. This significantly increased the cost and risk to private investors of exploration and development. Owing to low petroleum price expectations and geological prospects, decision makers felt that only companies with sufficient resources and a longer-term view would make substantial investments in high-cost, high-risk offshore exploration. Hence the industry and provincial governments urged a replacement incentive. The federal government responded with the ETC to provide transitional assistance until offshore production started.

This paper first examined actual expenditure patterns and other behavioral aspects of the oil and gas industry over the past 15 years. Exploration in the conventional lands in this period seems to follow general economic conditions and prices of oil and gas. In the frontier areas, where exploration costs tend to be prohibitive, the enormous incentives provided by governments, such as those administered through the PIP, were regarded as extremely important. By contrast, it is questionable whether the ETC has provided enough incentive to encourage offshore drilling.

Total ETCs earned from December 1985 to December 1990 is about $190 million in constant 1990 dollars. More than 95 per cent was earned on frontier exploration. About 62 per cent, or $120 million, was claimed as credit or cash refund by some 30 corporations in the same year the credits were earned. The remainder was carried forward. The $190 million, which is not the true cost to the government of the ETC, is substantially less than the $150 to $250 million per year forecast by the government when the credit was announced. The overestimate can be mainly attributed to the unexpected but significant and sustained drop of oil prices in 1986, which depressed exploration activity and thus the base for the ETC.

A theoretical model of an oil and gas firm was developed to analyze the tax variables affecting private investment decisions on exploration for, and development of, Canadian oil and gas resources, assuming that the managers of the firm attempt to maximize the firm's market value by choosing the optimal investment in each factor of production. Comparing the marginal after-tax cost of exploration with and without the ETC, we found that, if the firm were taxable, the marginal after-tax cost would fall by roughly 26 per cent with the ETC.

The model was also used to compare the incentive effects of super depletion and other fiscal instruments with those of the ETC. Although several possible cases can apply, depending on the tax deductions available to the firm and its taxpaying status, it is clear that super depletion provides the most incentive to exploration at the observed prescribed rates. For the ETC to provide the same investment incentive at the margin, the ETC rate would have to be increased from the existing 25 per cent to about 41 per cent.

Compared with offshore exploration incentives in Australia, Norway, the United Kingdom and the United States, the Canadian federal fiscal system, both with and without the ETC, is internationally competitive. However, the analysis indicates that greater fiscal incentives are given to companies with existing interests in the U.K. or Norway. Conversely, the U.S. system appears to discourage marginal exploration drilling in its continental shelf.

Although the Canadian tax structure targetted at exploration is internationally competitive, one key issue relevant to the ETC is whether the assistance provided by it has any incremental impact on exploration by oil and gas firms in Canada. A private consultant firm, contracted for the study, assessed the incrementality of the ETC by surveying companies that had earned an ETC at least once.

The case studies find that incrementality should be thought of at the individual well level and at the level of the total exploration budget. The case-study results show that all of the individual ETC-assisted wells would have been drilled in essentially the same form at about the same time without the ETC. For only two of the wells surveyed were certain investors motivated by the ETC. Had the ETC incentive been terminated at the time the decision to drill was made, the impact would have been at most a delay of drilling for several months. As to the effect on exploration budgets, two out of nine companies had institutional mechanisms that gave the ETC some incremental impact on their Canadian exploration budget. One company directed the incremental funds to seismic exploration in the Canada lands. The other company said the incremental impact was either in additional seismic work, or in the drilling of an additional exploratory well in conventional operations in the provincial lands. The overall incremental activity attributable to the ETC was estimated to be about 5 per cent of qualifying Canadian exploration expenses.

The study incorporated the incrementality estimate into an assessment of the opportunity cost of the ETC to the federal government in forgone tax revenue, which also depends on the cost of other investment tax credits and all other claims in the same period and earlier and later tax years. A tax revenue simulation model was developed to estimate federal corporate tax revenues under actual and no-ETC scenarios, allowing for tax claiming behavior to adjust in the no-ETC case. The actual case assumes that the firm attempts to minimize Part I tax according to the observed earning of the ETC. Tax calculations in the no-ETC case rely on the case-study results showing the degree to which exploration activity is reduced as a result of the absence of the ETC. In particular, the no-ETC revenue simulations assume a 5 per cent reduction in qualifying Canadian exploration expenses from the actual case. The cost of the total forgone federal tax revenues resulting from the ETC is estimated to be about $146 million in present value, which is much smaller than the aggregate ETC claims and refunds taken by ETC-earning corporations. This $146 million of federal tax dollars would generate $47 million in incremental exploration activity. This implies that every dollar of incremental exploration expenditure requires $3.2 of federal tax incentives.

The analysis of the ETC was extended to consider its effect on petroleum discoveries, since incentives for exploration are ultimately intended to increase the findings of oil and gas, as well as to determine the size of resources in the frontier area. The study, undertaken by the Department of Energy, Mines and Resources, is detailed and consistent in the treatment of geology, engineering, associated costs, and the economic and fiscal environment relevant to the area under evaluation. It assesses the ETC effect on incremental natural gas resources in the Mackenzie Delta and Beaufort Sea region. The simulation results indicate that retention of the ETC would only increase the commercially viable portion of undiscovered resources by 4.2 per cent.

Although the analysis applies directly to the undiscovered natural gas resources of the Mackenzie Delta-Beaufort Sea region, the results are indicative of the ETC's impact on exploration in all of Canada's frontier petroleum resource basins. The removal of the ETC would therefore have a modest impact on the amount of resources ultimately found. This conclusion is consistent with the impact of the ETC on exploration activity described in the case-study interviews with the industry.

In conclusion, the ETC incentive has provided little stimulus to exploration activity in the oil and gas industry. Its retention is likely to have only a modest effect on new discoveries of oil and gas resources, for the following reasons.

First, exploration costs are a small percentage of overall costs in most offshore oil and gas projects. Tax incentives aimed solely at exploration may not influence the overall cost significantly, since exploration, development, production, refining, and distribution costs all enter the assessment of the net return from the long-term commitment of funds to a project.

Second, offshore oil and gas projects, at which the ETC is effectively targeted, are highly risky. Great uncertainty surrounds both the possibility and pool-size of a discovery. The significance of tax-incentive impacts on financial returns is typically overwhelmed by uncertainties about the project itself.

Third, many companies appear to decide on the size of the exploration budget without regard to taxes. Either foreign corporate head offices, where tax treatment are often ignored, determine the budget, or the companies budget exploration on a gross (before-tax) basis. If the exploration budget is fixed, the ETC could at most effect a different ranking of projects competing for funds in the exploration department, without increasing the total amount of funds committed to exploration. The evidence suggests that the ETC incentive is too small to do this. Only an extremely generous incentive, such as the PIP, might be expected to persuade these corporations to alter investment patterns.

Although the ETC has had little effect, it was not introduced solely out of concern about exploration in Canada. Providing assistance to accompany the phasing out of the PIP was a main objective. The ETC was intended to smooth out over time the fiscal shock to the system and help minimize the industry's uncertainty about the government's fiscal commitment.

Our analysis indicates that the ETC has served its purpose of providing temporary assistance to the industry, although not to the extent as initially projected, since lower-than-expected oil prices depressed the incentives to explore. To effectively promote exploration, the credit would have to be offered at a much higher rate, implying not only greater market distortion but possibly high cost to the government. Further, continuation of the credit may only provide windfall gains to the industry, since many companies view these offshore projects as strategic commitments that must be undertaken in any event to maintain their market shares in the twenty-first century.

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APPENDIX A

A MODEL OF CANADIAN OIL AND GAS INVESTMENT INCENTIVES

A.1 The Underlying Assumptions

The following model, which is based on the assumption that the managers of a representative oil and gas corporation in Canada attempt to maximize the corporation's market value, is used to derive the marginal conditions that characterize optimal expenditures in exploration capital, development capital, physical capital, and real property (land). While the focus of this study is on the effect of the Exploration Tax Credit on exploration activity undertaken by the firm, other tax instruments that bear on the optimal hiring of various other factors of production are considered as well.

The market value of the firm, which the managers attempt to maximize through their production decisions, can be expressed as the expected present discounted value of future dividends distributed to the shareholders. Assuming that the firm is totally equity financed,[100] the identity equating sources of funds with uses of funds is given by:

$$REV=OPC+COGPE+CDE+CEE+INV+DIV+T \tag{A.1}$$

where REV denotes gross revenues from the production of oil and gas, OPC denotes operating costs (wages and salaries), COGPE denotes Canadian Oil and Gas Property Expenses incurred, CDE denotes Canadian Development Expenses incurred, while CEE denotes Canadian Exploration Expenses incurred. INV denotes investment in physical capital, DIV denotes the (aggregate) amount of dividends distributed to shareholders and lastly, T denotes net taxes. Net taxes are determined by:[101]

$$T=CIT+R-G \tag{A.2}$$

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100. While debt finance could be included in the model, it is ignored here for simplicity. When included, the rate used to discount future income streams is a weighted average of the flow costs of debt and equity finance rather than simply the flow cost of equity finance (the shareholder's required rate of return).

101. The use of the term 'net taxes' is somewhat of a misnomer, since, strictly speaking, royalties are not taxes. The term T might be called the 'net take' of the government, measuring taxes plus royalties, net of government assistance in the form of grants.

where CIT denotes corporate income tax paid, R denotes federal royalties paid,[102] and G denotes federal grants received.

Corporate income tax is determined by the product of the tax rate and the base, less the investment tax credit:

$$CIT=u \cdot TB-ITC \tag{A.3}$$

where u denotes the corporate income tax rate, TB denotes the corresponding tax base, and ITC denotes all investment tax credits claimed. The tax base is determined by:

$$TB=REV-OPC-CCA-RA-COGPEC-CDEC-CEEC-EDC \tag{A.4}$$

where CCA denotes the capital cost allowance claimed, RA denotes the Resource Allowance claimed, COGPEC denotes Canadian Oil and Gas Expenses claimed, CDEC denotes Canadian Development Expenses claimed, CEEC denotes Canadian Exploration Expenses claimed, and EDC denotes Earned Depletion claimed. The Resource Allowance claimed is determined as a fraction of resource profits for resource allowance purposes:

$$RA=\Gamma(REV-OPC-CCA) \tag{A.5}$$

where Γ is the resource allowance rate (0.25). Similarly, the Earned Depletion claim EDC is determined as a fraction of resource profits for earned depletion purposes:

$$EDC=\Omega(REV-OPC-CCA-RA-COGPEC-CDEC-CEEC) \tag{A.6}$$

where Ω is the earned depletion rate (0.25). It is assumed here that the income limitation on the earned depletion claim, given by 25 per cent of resource profits for earned depletion purposes, rather than the size of the earned depletion pool, is the binding constraint on the earned depletion claim.

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102. The four major producing provinces, Alberta, British Columbia, Saskatchewan and Manitoba, all levy royalties in respect of oil and gas produced from their provincial Crown lands. The federal government levies royalties in respect of oil and gas production from federal Crown lands, including the frontier lands under federal jurisdiction. Since this study is primarily concerned with exploration in the frontier lands, only federal royalties are considered.

The aggregate investment tax credit claim can be written as the sum of three components, as follows:

$$ITC=ITCG+IRC+ETC \tag{A.7}$$

where IRC denotes the Investment Royalty Credit claim, ETC denotes the Exploration Tax Credit claim, and ITCG denotes a "general" investment tax credit claim on all tangible (i.e., physical) capital.

Federal royalties, which are assumed to be determined as a fraction γ of gross revenues, can be written as follows:[103]

$$R=\gamma REV. \tag{A.8}$$

Equations (A.2) through to (A.8) together imply that federal net taxes can be written as:

$$\begin{aligned}T=&(u(1-\Gamma)(1-\Omega)+\gamma)REV\\ &-u(1-\Gamma)(1-\Omega)(OPC+CCA)\\ &-u(1-\Omega)(COGPEC+CDEC+CEEC)\\ &-ITCG-IRC-ETC-G.\end{aligned} \tag{A.9}$$

Substituting this expression into equation (A.1) and solving for aggregate dividends yields:

$$\begin{aligned}DIV=&(1-u(1-\Gamma)(1-\Omega)-\gamma)REV\\ &-(1-u(1-\Gamma)(1-\Omega))OPC\\ &+u(1-\Gamma)(1-\Omega)CCA\end{aligned}$$

(cont'd)

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103. Federal royalties are not always determined as a fraction of gross revenues. Federal royalties (authorized under Bill C-92, the Canada Petroleum Resources Act) are 1 per cent of gross revenues during the 'pre-payout' period; then they are increased to 5 per cent of gross revenues, in increments of 1 per cent every 18 production months. When the project reaches 'payout' status (which, loosely speaking, occurs when cumulative gross revenues first equal cumulative costs), the royalty is set equal to the greater of 5 per cent of gross revenues and 30 per cent of net revenues.

$$-COGPE+u(1-\Omega)COGPEC$$

$$-CDE+u(1-\Omega)CDEC$$

$$-CEE+u(1-\Omega)CEEC$$

$$-INV+ITCG+IRC+ETC+G. \qquad (A.10)$$

The firm's maximum capital cost allowance, which is assumed to be determined in accordance with the declining-balance depreciation method, is calculated as a fraction α of the undepreciated capital stock for tax purposes K, whose value at time (t) is given by:[104]

$$\hat{K}_t=\int_o^t e^{-\alpha(t-s)}(1-\varsigma)QI\ ds \qquad (A.11)$$

where ς denotes the investment tax credit rate, I denotes the flow of gross investment in physical capital, and Q is the corresponding price index.

As with all of the tax claims considered below, it is assumed that the firm is sufficiently profitable to ensure that it can claim its maximum allowed tax deductions and credits.[105] Thus, the capital cost allowance claim is assumed to be its maximum allowed claim, as given by αK.

Differentiating equation (A.11) with respect to time[106] yields the following equation of motion for K:

$$\dot{\hat{K}}_t=(1-\varsigma_t)Q_tI_t-\alpha\hat{K}_t. \qquad (A.12)$$

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104. Time subscripts are generally ignored in the appendix, unless required for clarity.

105. The conditions governing optimal exploration investment, development investment, physical capital investment, and real property investment, which are derived below, can be amended to reflect the non-taxable case. The marginal condition for optimal exploration investment in the non-taxable case is discussed in the text.

106. A dot above a variable indicates its time derivative.

This equation of motion of the capital stock for tax purposes can be distinguished from the equation of motion for the actual physical capital stock K which evolves according to:

$$\dot{K}_t=I_t-\delta K_t \tag{A.13}$$

where δ denotes the true physical rate of depreciation.

The Canadian Oil and Gas Property Expense (COGPE) claim, which is given by:

$$COGPEC_t=\phi^A \cdot CCOGPE_t \tag{A.14}$$

is determined as a fraction ϕ^A of CCOGPE, the cumulative COGPE pool. The stock of this pool, which is built up when the firm incurs COGPEs, and decreases on a declining-balance basis at rate ϕ^A as claims are made, is measured by:

$$CCOGPE_t=\int_o^t e^{-\phi^A(t-s)}\ COGPE\ ds. \tag{A.15}$$

It follows that the equation of motion for this stock is given by the following:

$$CC\dot{O}GPE_t=COGPE_t-\phi^A CCOGPE_t. \tag{A.16}$$

Similarly, the Canadian Development Expense (CDE) claim, which can be written as

$$CDEC_t=\phi^D \cdot CCDE_t \tag{A.17}$$

is determined as a fraction ϕ^D of the cumulative CDE pool (CCDE) which increases with CDEs and decreases on a declining-balance basis at rate ϕ^D as claims are made on that pool. The cumulative CDE pool is measured by:

$$CCDE_t=\int_0^t e^{-\phi^D(t-s)}\ (CDE_1+(1-g^D)CDE_2)ds. \tag{A.18}$$

Two types of development expenses are considered here and captured in the preceding equation. CDEs that do not qualify for government assistance[107] are measured by CDE_1, while those CDEs that qualify for federal grants are measured by CDE_2.[108] The fraction g^D denotes the rate at which these grants are earned on qualifying development expenditures.

Differentiating equation (A.18) with respect to time yields the following equation of motion for the CCDE pool:

$$C\dot{CDE}_t=CDE_{1t}+(1-g^D)CDE_{2t}-\phi^D CCDE_t. \tag{A.19}$$

Similarily, Canadian Exploration Expenses (CEEs) are disaggregated in the model into those expenditures CEE_1 that do not qualify for government assistance and those that do, as follows:

$$CEE_t=\sum_{i=1}^{4} CEE_{it}. \tag{A.20}$$

CEEs qualifying for grants[109] are measured by CEE_2. Those expenditures which qualify for the Investment Royalty Credit (IRC) are measured by CEE_3. Lastly, those CEEs qualifying for the Exploration Tax Credit (ETC) are measured by CEE_4.

Implicit in these expression is the fact that each of these forms of government assistance are mutually exclusive meaning that one dollar of exploration expense which qualifies for one type of assistance cannot qualify for the others.

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107. While it can be said that the CDE deduction is a form of government assistance, since it reduces tax by reducing the tax base, the term 'government assistance' is used in the literature in reference to tax credits and grants.

108. Grants for which these CDEs may qualify are, for example, those administered through the Petroleum Incentives Program (PIP), or those administered through the Canadian Exploration and Development Incentive Program (CEDIP).

109. These grants include those offered through the Canadian Exploration Incentive Program (CEIP), or the CEDIP or PIP.

Under the assumption that the firm is sufficiently profitable to claim its maximum CEE claim, as determined by 100 per cent of the available pool, it follows that the CEE claim in each period equals the CEE earned in the same period. Therefore, the CEE claim can be measured by:

$$CEEC_t = CEE_{1t} + (1-g^E)CEE_{2t} + (1-\theta)CEE_{3t} + (1-\epsilon)CEE_{4t}. \qquad (A.21)$$

This equation reflects the fact that the CEE pool is reduced by all forms of government assistance received in respect of CEE. The pool is reduced by grants earned on CEE as measured by $g^E CEE_2$, where g^E is the rate at which grants are earned on qualifying CEE.[110] The CEE pool is also reduced by tax credits earned in respect of CEE. The pool is reduced by IRCs earned on CEE as measured by θCEE_3, where θ is the rate at which the IRC is earned on qualifying CEE, and by ETCs earned, ϵCEE_4, where ϵ is the rate at which ETC is earned on CEE_4.

Letting Y denote output and L denote labour, and letting P and W denote the corresponding price indexes, and recalling that the CCA claim equals αK and substituting equations (A.14), (A.17), (A.20) and (A.21) into (A.10), gives the following dividend expression:

$$\begin{aligned}
DIV = {} & (1-u(1-\Gamma)(1-\Omega)-\gamma)PY \\
& -(1-u(1-\Gamma)(1-\Omega))WL \\
& +u(1-\Gamma)(1-\Omega)\alpha\hat{K} \\
& -COGPE+u(1-\Omega)\phi^A CCOGPE \\
& -CDE_1-(1-g^D)CDE_2+u(1-\Omega)\phi^D CCDE \\
& -(1-u(1-\Omega))CEE_1 \\
& -(1-g^E)(1-u(1-\Omega))CEE_2 \\
& -(1-\theta)(1-u(1-\Omega))CEE_3 \\
& -(1-\epsilon)(1-u(1-\Omega))CEE_4 \\
& -(1-\varsigma)QI. \qquad (A.22)
\end{aligned}$$

110. Since grants are also earned on qualifying CDE, total grants are measured by $G_t = g^d CDE_{2t} + g^E CEE_{2t}$.

The output of extracted petroleum reserves is assumed to be produced according to the following production function:

$$Y_t=F(L_t,K_t,A_t,D_t,X_t) \tag{A.23}$$

where L is the flow of labour services, K denotes the physical capital stock employed, A denotes the flow of land services, and D denotes the real flow of development capital. Lastly, X is the stock of discovered petroleum which results from the real flow of exploration capital denoted by E. Nominal flows of land services at time (t) and development and exploration investment at (t) are related to their corresponding real magnitudes, expressed in time (o) dollars, according to $COGPE_t=e^{\pi t}A_t$, $CDE_t=e^{\pi t}D_t$, and $CEE_t=e^{\pi t}E_t$, where π denotes the general rate of inflation.

The amount of discovered petroleum in a given period is assumed to be determined by the following function:

$$X_t=J(E_t,TX_t) \tag{A.24}$$

where TX denotes the total cumulated amount of discovered petroleum reserves as of date t, as measured by:

$$TX_t=\int_0^t X_s \, ds. \tag{A.25}$$

It is assumed here that, while exploration expenses E result in increased discoveries ($J_E>0$), discovered reserves at time t decrease as TX_t increases ($J_{TX}<0$) for any given level of E_t. This is meant to capture the depletable nature of the resource. It follows from the preceding equation that the equation of motion for the stock TX is given by:

$$\dot{TX}_t=J(E_t,TX_t)=X_t. \tag{A.26}$$

A.2 The Problem of the Firm

The problem of the firm can now be stated as follows. The managers attempt to maximize the market value of equity V measured as the discounted value of the shareholder's expected future dividend stream:

$$V_o=\int_o^{\infty} e^{-\rho t} DIV_t \ dt. \qquad (A.27)$$

The risk associated with the uncertain future dividend flow is assumed to be captured in the nominal discount rate ρ and DIV_t implicitly represents shareholders' expectation at time (o) of that flow at time (t).

Substituting into this expression the definition of dividends, as measured by (A.22), and using the functional form for output (A.23) and discovered reserves (A.24) and the equations of motion for stocks TX, K, K, CCOGPE and CCDE, given by equations (A.26), (A.12), (A.13), (A.16) and (A.19), the firm's problem can be stated as:

$$\begin{aligned}
\max_{\{L,I,A,D,E\}} \quad V_o=\int_o^{\infty} e^{-\rho t} [\ & (1-u(1-\Gamma)(1-\Omega)-\gamma)PF(L,K,A,D,X) \\
& -(1-u(1-\Gamma)(1-\Omega))WL \\
& +u(1-\Gamma)(1-\Omega)\alpha\hat{K} \\
& -(1-\varsigma)QI \\
& -COGPE+u(1-\Omega)\phi^A CCOGPE \\
& -CDE_1-(1-g^D)CDE_2+u(1-\Omega)\phi^D CCDE \\
& -(1-u(1-\Omega))CEE_1 \\
& -(1-g^E)(1-u(1-\Omega))CEE_2 \\
& -(1-\theta)(1-u(1-\Omega))CEE_3 \\
& -(1-\epsilon)(1-u(1-\Omega))CEE_4 \ ]dt
\end{aligned}$$

subject to

$$\begin{aligned}
& 1) \ X_t=J(E_t,TX_t) \\
& 2) \ \dot{TX}_t=J(E_t,TX_t) \\
& 3) \ \dot{\hat{K}}_t=I_t-\alpha\hat{K}_t \\
& 4) \ \dot{K}_t=I_t-\delta K_t \\
& 5) \ \dot{CCOGPE}_t=COGPE_t-\phi^A CCOGPE_t \\
& 6) \ \dot{CCDE}_t=CDE_{1t}+(1-g^D)CDE_{2t}-\phi^D CCDE_t.
\end{aligned} \qquad (A.28)$$

This problem can be simplified by incorporating the equations of motion for K, CCOPGE and CCDE into the maximand of the problem (thus eliminating their costate variables).

Considering first the equation of motion for the capital stock for tax purposes $\hat{K}$, it can be shown that:

$$\int_0^\infty e^{-\rho t} u(1-\Gamma)(1-\Omega)\alpha\hat{K}\ dt = \int_0^\infty e^{-\rho t} ZqI\ dt \qquad (A.29)$$

where Z, measuring the present value of the future stream of capital cost allowance tax savings resulting from a dollar's worth of investment, is given by:

$$Z=\frac{u(1-\Gamma)(1-\Omega)\alpha(1-\varsigma)}{\rho+\alpha}\ . \qquad (A.30)$$

Considering next the equation of motion for CCOPGE, it can be shown that:

$$\int_0^\infty e^{-\rho t} u(1-\Omega)\phi^A CCOGPE\ dt = \int_0^\infty e^{-\rho t} v^A COGPE\ dt \qquad (A.31)$$

where v^A, measuring the present value of the tax savings associated with the future stream of COGPE deductions that result from an additional dollar's worth of expenditure in land property, is given by:

$$v^A=\frac{u(1-\Omega)\phi^A}{\rho+\phi^A}\ . \qquad (A.32)$$

Lastly, considering the equation of motion for CCDE, it can be shown that:

$$\int_0^\infty e^{-\rho t} u(1-\Omega)\phi^D CCDE\ dt$$

$$= \int_0^\infty e^{-\rho t} v_1^D CDE_1\ dt + \int_0^\infty e^{-\rho t} v_2^D CDE_2\ dt \qquad (A.33)$$

where v_1^D, measuring the present value of the tax savings attributable to the future stream of CDE deductions resulting from an additional dollar's worth of development investment that is non-qualifying for government grants, is given by:

$$v_1^D = \frac{u(1-\Omega)\phi^D}{\rho+\phi^D} \tag{A.34}$$

and where v_2^D, measuring the present value of the tax savings attributable to the future stream of CDE deductions resulting from an additional dollar's worth of development investment that qualifies for grants, is given by:

$$v_2^D = (1-g^D)v_1^D \ . \tag{A.35}$$

Let r denote the real required rate of return $\rho-\pi$, and let p_t, w_t and q_t measure the indexes P_t, W_t, and Q_t expressed in time (o) dollars. Furthermore, recall that $COGPE_t=e^{\pi t}A_t$, and let $CDE_{it}=e^{\pi t}D_{it}$ for i=1,2 and $CEE_{it}=e^{\pi t}E_{it}$ for i=1 to 4. Using this notation, and equations (A.29) to (A.35), the problem of the firm given by equation set (A.28) can be equivalently stated as follows:

$$\begin{aligned}\max_{\{L,I,A,D,E\}} \quad V_o = \int_o^\infty e^{-rt}[\ & (1-u(1-\Gamma)(1-\Omega)-\gamma)pF(L,K,A,D,J(E,TX)) \\ & -(1-u(1-\Gamma)(1-\Omega))wL \\ & -(1-\varsigma-Z)qI \\ & -(1-v^A)A \\ & -(1-v_1^D)D_1-(1-v_2^D)D_2 \\ & -(1-u(1-\Omega))E_1 \\ & -(1-g^E)(1-u(1-\Omega))E_2 \\ & -(1-\theta)(1-u(1-\Omega))E_3 \\ & -(1-\epsilon)(1-u(1-\Omega))E_4\ ]\ dt\end{aligned}$$

subject to

$$\begin{aligned}&1)\ \dot{K}_t=I_t-\delta K_t \\ &2)\ \dot{TX}_t=J(E_t,TX_t)\ .\end{aligned} \tag{A.36}$$

The firm's control variables are L, I, A, D and E. The problem can be solved using the following (current value) Hamiltonian H:

$$\begin{aligned} H=&(1-u(1-\Gamma)(1-\Omega)-\gamma)pF(L,K,A,D,J(E,TX)) \\ &-(1-u(1-\Gamma)(1-\Omega))wL-(1-\varsigma-Z)qI-(1-v^A)A \\ &-(1-v_1^D)D_1-(1-v_2^D)D_2 \\ &-(1-u(1-\Omega))E_1-(1-g^E)(1-u(1-\Omega))E_2 \\ &-(1-\theta)(1-u(1-\Omega))E_3-(1-\epsilon)(1-u(1-\Omega))E_4 \\ &+\lambda(I-\delta K)+\Psi(J(E,TX)) \quad . \end{aligned} \tag{A.37}$$

The first-order conditions characterizing the optimal investments in each factor of production (the optimal controls to the problem) can be written as follows:[111]

$$\begin{aligned} &(L): && (1-u(1-\Gamma)(1-\Omega)-\gamma)pF_L(\cdot)-(1-u(1-\Gamma)(1-\Omega))w=0 \\ &(I): && -(1-\varsigma-Z)q+\lambda=0 \\ &(K): && (1-u(1-\Gamma)(1-\Omega)-\gamma)pF_K(\cdot)-\delta\lambda=r\lambda-\dot{\lambda} \\ &(A): && (1-u(1-\Gamma)(1-\Omega)-\gamma)pF_A(\cdot)-(1-v^A)=0 \\ &(D_1): && (1-u(1-\Gamma)(1-\Omega)-\gamma)pF_D(\cdot)-(1-v_1^D)=0 \\ &(D_2): && (1-u(1-\Gamma)(1-\Omega)-\gamma)pF_D(\cdot)-(1-v_2^D)=0 \\ &(E_1): && (1-u(1-\Gamma)(1-\Omega)-\gamma)pF_X(\cdot)J_E(\cdot)-(1-u(1-\Omega))+\Psi J_E(\cdot)=0 \\ &(E_2): && (1-u(1-\Gamma)(1-\Omega)-\gamma)pF_X(\cdot)J_E(\cdot)-(1-g^E)(1-u(1-\Omega))+\Psi J_E(\cdot)=0 \\ &(E_3): && (1-u(1-\Gamma)(1-\Omega)-\gamma)pF_X(\cdot)J_E(\cdot)-(1-\theta)(1-u(1-\Omega))+\Psi J_E(\cdot)=0 \\ &(E_4): && (1-u(1-\Gamma)(1-\Omega)-\gamma)pF_X(\cdot)J_E(\cdot)-(1-\epsilon)(1-u(1-\Omega))+\Psi J_E(\cdot)=0 \\ &(TX): && (1-u(1-\Gamma)(1-\Omega)-\gamma)pF_X(\cdot)J_{TX}(\cdot)+ J_{TX}(\cdot)=r\Psi-\dot{\Psi} \end{aligned} \tag{A.38}$$

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111. In addition to these conditions are the equations of motion for the stocks K and TX as given by equations (A.8) and (A.9), and the transversality conditions that the corresponding costate variables λ and Ψ reach a finite value in infinite time.

The first-order conditions for optimal labour L and land services A can be expressed as follows:

$$\frac{pF_L(\cdot)}{w} = \frac{(1-u(1-\Gamma)(1-\Omega))}{(1-u(1-\Gamma)(1-\Omega)-\gamma)} \tag{A.39}$$

$$pF_A(\cdot) = \frac{(1-v^A)}{(1-u(1-\Gamma)(1-\Omega)-\gamma)} \; . \tag{A.40}$$

With constant prices and tax rates, λ is constant. Using this fact, and combining the first-order condition for I with the first-order (adjoint) condition for K yields the user cost expression for physical capital:

$$\frac{pF_K(\cdot)}{q} = \frac{(r+\delta)(1-\varsigma-Z)}{(1-u(1-\Gamma)(1-\Omega)-\gamma)} \; . \tag{A.41}$$

The first-order conditions for D_1 and D_2 can be solved for the following user cost expressions for these two types of development capital:

$$pF_{D1}(\cdot) = \frac{(1-v_1^D)}{(1-u(1-\Gamma)(1-\Omega)-\gamma)} \tag{A.42}$$

$$pF_{D2}(\cdot) = \frac{(1-v_2^D)}{(1-u(1-\Gamma)(1-\Omega)-\gamma)} \; . \tag{A.43}$$

From the first-order (adjoint) condition for TX, the shadow value of an additional unit of discovered reserves Ψ evolves over time according to the following:

$$\dot{\Psi}=(r+J_{TX}(\cdot))\Psi-(1-u(1-\Gamma)(1-\Omega)-\gamma)pF_X(\cdot)J_{TX}(\cdot). \tag{A.44}$$

Using the transversality condition that Ψ reaches a finite value in infinite time, Ψ can be solved for as follows:

$$\Psi_t = \int_t^\infty e^{-(r+J_{TX}(\cdot))(s-t)} \; (1-u(1-\Gamma)(1-\Omega)-\gamma) pF_X(\cdot) J_{TX}(\cdot) \; ds. \tag{A.46}$$

Combining this solution with the first-order conditions for E_1, E_2, E_3 and E_4 gives the following solutions characterizing optimal investment in each type of exploration expense:

$$pF_X(\cdot)J_{E1}(\cdot) + \int_t^\infty e^{-(r+J_{TX}(\cdot))(s-t)} \; pF_X(\cdot)J_{TX}(\cdot)J_{E1}(\cdot)ds$$

$$= \frac{(1-u(1-\Omega))}{(1-u(1-\Gamma)(1-\Omega)-\gamma)} \tag{A.47}$$

$$pF_X(\cdot)J_{E2}(\cdot) + \int_t^\infty e^{-(r+J_{TX}(\cdot))(s-t)} \; pF_X(\cdot)J_{TX}(\cdot)J_{E2}(\cdot)ds$$

$$= \frac{(1-g^E)(1-u(1-\Omega))}{(1-u(1-\Gamma)(1-\Omega)-\gamma)} \tag{A.48}$$

$$pF_X(\cdot)J_{E3}(\cdot) + \int_t^\infty e^{-(r+J_{TX}(\cdot))(s-t)} \; pF_X(\cdot)J_{TX}(\cdot)J_{E3}(\cdot)ds$$

$$= \frac{(1-\theta)(1-u(1-\Omega))}{(1-u(1-\Gamma)(1-\Omega)-\gamma)} \tag{A.49}$$

$$pF_X(\cdot)J_{E4}(\cdot) + \int_t^\infty e^{-(r+J_{TX}(\cdot))(s-t)} \; pF_X(\cdot)J_{TX}(\cdot)J_{E4}(\cdot)ds$$

$$= \frac{(1-\epsilon)(1-u(1-\Omega))}{(1-u(1-\Gamma)(1-\Omega)-\gamma)} \; . \tag{A.50}$$

APPENDIX B

COMPARISONS OF ALTERNATIVE EXPLORATION INCENTIVES

B.1 The Investment Royalty Credit

Remember that ETCs are earned when qualifying exploration expenditures on a well are above a $5 million threshold. Before the corporation's cumulative qualifying CEE reaches the threshold, the exploration dollars spent cannot earn ETC. The first $5 million of qualifying CEE incurred on the well are, however, eligible to earn an Investment Royalty Credit (IRC) in all frontier areas of Canada.

As the name implies, the IRC is applied to offset federal royalties. One important property of this credit is that an IRC earned on a well in the frontier lands must be applied to reduce any royalties payable by the taxpayer on any other project under the jurisdiction of the Canadian Petroleum Resources Act. Therefore, IRCs earned on a project that has not yet produced any revenue and, therefore, has not generated federal royalties payable on that revenue to be offset by the IRCs, could still be of immediate value if they could be applied to offset royalties payable on another project.

The user cost expression for exploration expenditures qualifying for the IRC, representative of the situation where IRCs earned can be used in the same year to offset royalties payable (on the project in question if royalties are currently payable on that project, or on some other project on which royalties are payable), is given by the following:[112]

$$\frac{(1 - \theta)(1 - u(1 - \Omega))}{(1 - u(1 - \Gamma)(1 - \Omega) - \gamma)}. \qquad \text{(B.1)}$$

This equation differs from the user cost expression for the ETC by replacing the ETC rate (ϵ) with the IRC rate (θ).

Since the ETC and IRC rates are 25 per cent, it follows that the same incentive is offered to qualifying well expenditures below and above the $5 million threshold, because both face the same cost. This is true at least in the case where the firm is taxpaying, can claim fully and immediately the ETC,

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112. This expression, along with the others presented in this appendix, is derived in Appendix A. This user cost formula is representative of the case where a dollar of IRC claimed reduces the cumulative CEE pool in the same year, implying a CEE claim in that year of $(1-\theta)$ dollars. The formula for the case where the cumulative CEE pool is reduced in the next year is analogous to that for the ETC.

and has royalties payable so that IRCs earned can be fully and immediately applied.

Other possibilities are likely to arise. In the event that the firm is never taxable, making the 40-per-cent refund the only possible benefit the firm could derive from the ETC, the IRC incentive would be preferred, provided the IRC could be fully applied to offset royalties currently payable. In that case, the IRC would also be preferred if the firm remained non-taxable for several years, since the present value of ETC claims would be less than the value of the IRC. When an ETC refund was not available, as in the case of non-CCPCs after 1987, the IRC would provide a greater incentive if it could be applied to offset royalty payments.

If, however, royalties were not currently payable, the relative incentive at the margin of the IRC would not necessarily be greater in each of the cases considered, but would depend on the time profiles of the taxpaying and royalty-paying position of the firm.

B.2 The Canadian Exploration and Development Incentive Program

The Canadian Exploration and Development Incentive Program (CEDIP), introduced April 1, 1987, and terminated December 31, 1989, provided cash grants equal to 33 1/3 per cent of eligible expenditures, including CEEs as well as CDEs (net of Canadian exploration and development overhead expenses). These grants were subject to limitation: eligible expenditures were restricted to $10 million a year per company.

CEDIP grants could be earned on exploration costs anywhere in Canada, including federal offshore lands, provided the expenses were not also eligible for ED,[113] other federal grants, the IRC, or the ETC.[114] The rate at which a CEDIP grant could be earned on exploration expenditures was reduced to 25 per cent on September 30, 1988, and to 16 2/3 per cent on June 30, 1989, where it remained until the termination of the program.

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113. Only CEEs measured net of government assistance (such as ETCs, IRCs, CEDIP grants) could be added to the ED base. After 1984, no oil and gas exploration expenses (except those in respect of qualified tertiary oil recovery projects) could be added to the earned depletion base.

114. The mutually exclusive principle that one dollar of expense can only be eligible for one type of special assistance is generally held across all forms of government assistance.

Assuming that expenses eligible for CEDIP grants are below the annual $10 million limitation in a tax year,[115] the user cost of qualifying exploration capital can be shown to equal the following:

$$\frac{(1 - g^E)(1 - u(1 - \Omega))}{(1 - u(1 - \Gamma)(1 - \Omega) - \gamma)}. \tag{B.2}$$

This user cost expression reflects the fact that one dollar's worth of CEE that earns a CEDIP grant increases the cumulative CEE pool by $(1-g^E)$ dollars, where g^E is the rate of grant on a nominal dollar of qualifying CEE. This provides a tax saving of $u(1-g^E)(1-\Omega)$ dollars, taking into account the impact on the earned depletion claim.[116] This tax saving is in addition to the direct effect of the grant, which reduces the cost of the qualifying exploration to $(1-g^E)$ dollars.

During the first phase of CEDIP, when the rate g^E was 33 1/3 per cent, a CEDIP grant would have been strictly preferred to an ETC regardless of the corporation's taxable status. This is because the grants were effectively 'cash in hand', unlike the ETC and the IRC, whose values depend on the taxpaying (ETC) or royalty-paying (IRC) position of the firm. Therefore, even when the CEDIP rate was reduced to 25 per cent, it was still as powerful an incentive as the ETC and IRC, assuming the firm was in a taxpaying or royalty-paying position, and would be strictly preferred to the ETC and IRC if the firm was not in a taxpaying or royalty-paying position. When the CEDIP rate g^E was reduced to 16 2/3 per cent, the relative attractiveness of the various instruments would depend on the time profile of the taxpaying and royalty-paying position of the firm.

B.3 The Canadian Exploration Incentive Program

The Canadian Exploration Incentive Program (CEIP), which was in effect from October 1, 1988, to February 19, 1990, provided grants of 30 per cent of a firm's eligible exploration expenditures incurred under a flow-through share agreement with its shareholders. Eligible exploration expenses were capped to $10 million a year. A corporation granted CEIP assistance had the choice of retaining the grants, or flowing them through to investors.

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115. This ensures that a CEDIP grant is earned on the marginal dollar of qualifying exploration expense. If the $10 million threshold is surpassed, the CEDIP rate does not impinge on the marginal investment decision.

116. This assumes that income, and not the size of the earned depletion pool, acts as the binding constraint on the earned depletion claim.

Two possible scenarios could be encountered. In one case, a firm undertakes exploration and flows out both the CEIP grant, earned at 30 per cent, and the corresponding CEE, net of the CEIP assistance, to the flow-through share investor. In the case where, for example, one dollar of exploration is undertaken, the flow-through share investor -- typically another corporation -- receives the $0.30 grant to be included in its income, as well as $0.70 to be included in its CEE pool.

In the alternative case, the firm undertaking the exploration flows out the CEE, net of the CEIP assistance, and retains the CEIP grant. The typical financing procedure can be explained by considering the case where the issuing corporation spends a dollar on exploration. This company retains the $0.30 grant, and flows out the net CEE earned, of $0.70, to the share investor. The $0.30 grant is then reinvested into exploration, earning a $0.09 CEIP grant, and the net CEE of $0.21 is flowed out to the share investor. Repeating this cycle can result in one full dollar being flowed out to the share investor.

In both of these cases, the flow-through share value depends on the amount of assistance transferred to the investor, the investor's marginal income tax rate, and its taxable status. The price paid for flow-through shares -- and thus the after-tax cost of exploration to the issuing corporation -- depends on not only these factors, but also the degree of arbitrage between the issuing firm and the investor over this value. For this reason, incentive comparisons with the ETC vary case-by-case.

B.4 The Petroleum Incentives Program[117]

Like the other grants described above, a PIP grant represents cash in hand to the firm. Once earned, it can be claimed without regard to taxpaying or royalty-paying status. PIP grant rates varied between 25 and 80 per cent, depending on the investment-type, location, and degree of Canadian ownership. The user cost of exploration capital, under the aternative grant rates, is found by assigning the rate to g^E in equation (B.2).

B.5 The Frontier Exploration Allowance (Super Depletion)[118]

In the situation where super depletion is available, and the ED claim is restricted by resource profits for earned depletion purposes, the user cost of qualifying exploration expenses is given by the following:

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117. The provisions and incentive effects of the Petroleum Incentives Program are described in section (IV.D) of this Report.

118. The provisions and incentive effects of Super Depletion are described in section (IV.D) of this Report.

$$\frac{(1 - u(1 - \Omega + \sigma))}{(1 - u(1 - \Gamma)(1 - \Omega) - \gamma)} \tag{B.3}$$

where σ is the SD rate of 66 2/3 per cent. This formula holds whether or not additions can be made to the ED pool because of the assumption that resource profits, not the size of the ED pool, limits the ED claim.[119]

In the alternative situation where the ED claim is restricted by the size of the ED pool, the formula depends on whether exploration expenses qualify for inclusion in the ED pool. In the case where the expenses do qualify, the user cost is given by:

$$\frac{(1 - u(1 + \upsilon + \sigma))}{(1 - u(1 - \Gamma) - \gamma)} \tag{B.4a}$$

where υ denotes the 33 1/3 per cent inclusion rate. Since the fractions υ and σ add up to 1, this formula can be written as:

$$\frac{(1 - 2u)}{(1 - u\ (1 - \Gamma)\ - \gamma))} \tag{B.4b}$$

indicating that two dollars of qualifying exploration expense can be written off for every dollar expense incurred.

In the alternative situation where the ED claim is restricted by the size of the ED pool, and exploration costs do not qualify for inclusion in the ED pool, but do earn SD, the user cost formula is given by:

$$\frac{(1 - u(1 + \sigma))}{(1 - u(1 - \Gamma) - \gamma)}. \tag{B.5}$$

119. The formula is a steady-state condition that assumes ED claims will continue to be restricted by resource profits for earned depletion purposes in the future, and not by the size of the ED pool. If the claim were to become restricted at a later date by the ED pool, an additional term would be required in the numerator (the after-tax cost measure) to take into account the present value of the future ED tax deduction attributable to the current increase in the ED base.

For the purpose of comparing SD and ETC incentives, it should first be remembered that the user cost formula given by equation (4.2) in the text is representative of the case where the ED claim is constrained by resource profits for ED purposes. This is true for both the case where exploration expenses can be added to the ED pool, and the case where they cannot; the reason corresponds to that given above for SD.

In the case where the ED claim is restricted by the ED pool, there are two possible user cost expressions for the ETC case. If the firm cannot make additions to the ED pool, the user cost is given by:[120]

$$\frac{(1 - \epsilon)(1 - u)}{(1 - u(1 - \Gamma) - \gamma)}. \tag{B.6}$$

Alternatively, if the ED claim is restricted by the available size of the ED pool but exploration expenditures do qualify for inclusion in the ED pool, the user cost is given by:

$$\frac{(1 - \epsilon)(1 - u(1 + \upsilon))}{(1 - u(1 - \Gamma) - \gamma)}. \tag{B.7}$$

This equation reflects the fact that the CEE additions to the ED pool must be measured net of ETC earned on that amount.

120. This formula is also representative of the case where the firm does not have an unamortized ED pool, and thus cannot take any ED claim.