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John F. Helliwell

Mary E. MacGregor

Robert N. McRae

Andre Plourde

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OIL AND GAS TAXATION*

BY JOHN F. HELLIWELL,** MARY E. MACGREGOR,***
ROBERT N. McRAE**** AND ANDRÉ PLOURDE*****

I. INTRODUCTION

The oil and gas industry has never been far from the centre of attention whenever tax reform and tax changes have been under consideration. At the time of the Royal Commission on Taxation, the oil and gas industry was favourably treated under the federal income tax system, and the main thrust of the Royal Commission's proposals was to increase taxes in that industry towards the general levels applicable to the rest of the business sector. As a result, the oil and gas industry's arguments at that time took the form of defending the preferential treatment accorded to it. These arguments were fairly effective in the political arena, so that when oil and gas prices rose rapidly in the early 1970s, the federal government received little revenue from the industry. These problems were exacerbated by the costs of the federal subsidy to imported oil, and by the sharp increases in provincial royalty rates, both of which reduced net federal revenues from oil and natural gas.

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** Department of Economics, University of British Columbia.

*** Institute for Policy Analysis, University of Toronto.

**** Department of Economics, University of Calgary.

***** Department of Economics, University of Ottawa.

The subsequent series of federal tax changes in the 1970s and early 1980s altered the federal tax treatment of oil and gas revenues so markedly that industry arguments took the form of asking for a tax system in which oil and gas revenues were subject to the same tax regime that applied to other industries. In particular, the federal tax system was tilted against the extractive industries by the introduction, in 1974, of a concessionary lower rate of corporation income tax for manufacturing and processing profits. By the early 1980s, when the range and height of federal taxes on oil and gas production were at their greatest, the equal tax treatment fought by the industry in the aftermath of the Royal Commission would have looked attractive. By the end of 1986, almost all of the special federal taxes applicable to oil and gas revenues had been removed,¹ and the industry was asking for the reintroduction of a broadly based, earned depletion allowance as a means of helping firms hard hit by the 1985-86 fall of world oil prices.

The purpose of this paper is to recount the main elements of the pre-reform tax system, the Royal Commission proposals, and the several regimes that have been in place since Carter. We shall also attempt some quantitative assessment of alternative systems, including their effects on the distribution of risks and revenues among the industry, provincial governments, and the federal government.

In addition, we will examine the consequences of variations in oil and gas prices to the distribution of revenues and rents under the approach to taxation proposed by the Royal Commission, and a few alternatives. The ultimate objective here is to assess the political and economic robustness of these taxation systems to changes in world market conditions.

We shall also address a fundamental issue that was not even discussed in the Royal Commission *Report*: the extent to which changes in the tax system influence the ability of the oil and gas industry to evaluate investment projects. The past fifteen years have seen so many oil and gas tax regimes come and go that even

¹The major exceptions involve the treatment of offshore exploration, the resource allowance to "compensate" for the non-deductibility of royalties, and the ability of the consortium operating the Syncrude oil sands plant to deduct royalty payments for federal income tax purposes.

specialists lose track of what provisions were in place during which years. It has been suggested that these rapid and often unpredictable changes in tax regimes have caused needless political tensions, created an uncertain planning environment for oil and gas producers, and led to an inefficient concentration of resources in tax planning and in political activity aimed at changing the tax system.

In addition, we will examine the consequences of variations in oil and gas prices to the distribution of revenues and rents under the approach to taxation proposed by the Royal Commission, and a few alternatives. The ultimate objective here is to assess the political and economic robustness of these taxation systems² to changes in world market conditions.

II. THE ROYAL COMMISSION'S APPROACH

The Royal Commission's approach to resource taxation in general, and to the taxation of oil and gas in particular, was consistent with its approach to overall tax reform. Indeed, it is one of the strengths of any coherent and integrated approach to tax reform that its principles can be generally applied, without the need for a separate rationale and separate provisions for each industry, type of organization, and class of income. The Royal Commission's general approach to the taxation of income from business was to treat all industries and types of organization as equally as possible. Seen in this light, the main special provisions extended to resource industries prior to 1967 were percentage depletion,³ the three-year tax-free period for new mines, and the accelerated write-off of exploration and development expenditures. In volume four of the

²J.F. Helliwell *et al.*, *Oil and Gas in Canada: The Effects of Domestic Policies and World Events* (Toronto: Canadian Tax Foundation, 1988) contains a more complete description of the federal elements of the various tax systems that have been proposed or applied to oil and gas income and expenses since 1967.

³Under the provisions of percentage depletion, firms were automatically allowed to deduct a given percentage of oil and gas production profits (33 1/3 percent for operators and 25 percent for non-operators) when calculating taxable income.

Commission's *Report*, and in the related study by Bucovetsky,⁴ the pros and cons of these special provisions were considered at some length. The percentage depletion provision was originally designed to offset the non-deductibility of certain expenditures related to the acquisition of mineral properties. By the time the Commission was formed, all of the previously non-deductible expenses were fully deductible,⁵ so the remaining case for the depletion allowance was based on considerations of abnormally high risks entailing a higher cost of capital. The *Report* took the view that the possibilities for the spreading and diversification of risks were as great in the mining and petroleum industries as elsewhere in the economy, and that any tax-based disincentives to risk-taking should be addressed in a way that is equally applicable to all industries and types of organization. In particular, the Commission argued that if all gains were fully and equally taxable, and all losses fully and immediately deductible, "there would be little need for any special concessions to the mining and petroleum industries even if it was felt that they were characterized by greater risk than other industries."⁶ The main issues related to the depletion allowance, and to the treatment of exploration and development expenditures. The Commission went through the various arguments based on regional development, the existence of similar incentives in the United States, the special role of energy in economic development, and the encouragement of domestic ownership in the extractive industries, and concluded that

the need for special encouragement to mineral and petroleum exploration to compensate for a capital market bias against risky ventures is small, if it exists at all. We are also convinced that there are fiscal methods available that would be as efficient as, or more efficient than, tax concessions in encouraging exploration if this was deemed to be in the public interest.⁷

⁴Canada, Royal Commission on Taxation, *The Taxation of Mineral Extraction* by M.W. Bucovetsky, Study No. 8 (Ottawa: Queen's Printer, 1967).

⁵The most important of these were expenditures to acquire land and production rights, which became fully deductible from 10 April 1962.

⁶Canada, Royal Commission on Taxation, *Report*, vol. 4 (Ottawa: Queen's Printer, 1966) (Chair: K. LeM. Carter) at 309 [hereinafter *Report*].

⁷*Ibid.* at 327.

The Royal Commission's main proposals⁸ were that:

1. The depletion allowance should be withdrawn.
2. Exploration costs (including related depreciable assets) should have a separate capital cost allowance class with a write-off rate of 100 percent.
3. Development costs (including related depreciable assets) should be included with exploration costs for a transitional period of five to ten years and thereafter segregated in a separate class subject to write-off at 20 to 30 percent on a diminishing balance.
4. The cost of acquiring properties should have a separate capital cost class for each property, subject to a high transitional rate of depreciation, but thereafter be written off at 10 to 20 percent of the operating income from the property.
5. Losses on the sale of properties should be subject to the same provisions as in other industries, and gains should be fully taxable, also as in other industries.

III. THE *WHITE PAPER* AND BILL C-259⁹

In the four years between the release of the Royal Commission's *Report* in late 1966 and the introduction of Bill C-259 embodying tax reform in 1971, there were many changes made to the proposals. Responding to a combination of pressures from the extractive industries and the governments of resource-rich provinces, the Benson *White Paper*

recognized that the exploration for and development of mineral deposits continue to provide special benefits to Canada and to various provinces by creating or maintaining highly productive industry in areas other than those where rapid urban and industrial growth are already occurring.... Just as scientific research and development are believed to warrant some special public support, the government feels that exploration for and development of minerals still warrant some support

⁸*Ibid.* at 335-36.

⁹*Bill C-259, An Act to Amend the Income Tax Act, 3d Sess., 28th Parl., 1970-71.*

in a form more directly related to this activity than has been the case with past depletion.¹⁰ It is believed that support on a less-generous scale should suffice for this purpose.

The proposals contained in the *White Paper* can be summarized as follows:

1. To retain immediate deductibility for all exploration and development expenses against all income for those principally involved in resource extraction, and against resource income for others.
2. To retain full deductibility of the costs of acquiring mineral properties (subject to the same "principal business" tests as for exploration and development), but to treat gains from the sale of such properties as capital gains, and hence taxable, under the *White Paper's* general proposals for capital gains, at 50 percent of their actual value.
3. For operators, the 33 1/3 percent depletion allowance would be retained, but only if firms "earned" the rights to the allowance by capital expenditures of \$3 for every \$1 of depletion allowance claimed.
4. Percentage depletion for non-operators would be repealed.

In all major respects, the *White Paper* proposals treated oil and gas production revenues more generously than did those of the Royal Commission, but they too came under pressure from the extractive industries, especially before hearings held by Committees of the Senate and the House of Commons. In the course of hundreds of briefs and scores of meetings on tax reform, the Commons Finance Committee heard, once again, the arguments favouring special incentives for the extractive industries, and phrased their resulting dilemma as: "Is Canada prepared to suffer the possibility of a ... reduction in the growth and development of its natural resource industries in exchange for the longer term benefits of a more neutral and equitable tax system?"¹¹

¹⁰Hon. E.J. Benson, Minister of Finance, *Proposals for Tax Reform* (Ottawa: Queen's Printer, 1969) at 64.

¹¹Canada, House of Commons, Standing Committee on Finance, Trade and Economic Affairs, *Eighteenth Report Respecting the White Paper on Tax Reform* (Ottawa: Queen's Printer, 1970) at 74.

This dilemma is the inevitable consequence of advantageous tax treatment for any industry or activity – that the removal of the special treatment must generally lead to, at least the possibility of, either short-term or long-lasting reductions in the pace of that activity. Indeed, one of the primary justifications for the equal tax treatment championed by the Royal Commission was the possibility that there would be some redistribution of employment and investment away from the tax-favoured sectors towards those activities with a higher pre-tax return and with the potential, hence, for making a greater overall contribution to economic well-being. The usual result, at each stage of a reform process, is for the original thrust and consistency of the reforms to be muted by attempts to regain or retain the advantages originally available to the favoured industries or activities. Thus it was predictable that the Commons Finance Committee accepted the *White Paper* modifications of the Royal Commission's proposals and even offered some further expansion of incentives. This Committee suggested that:

1. Some consideration be given to permitting tax-free transfer of mineral rights between corporations (even though the cost of these rights might have been written off previously against taxable income), subject to safeguards against abuse.
 2. The earned depletion base be broadened to include the cost of all mineral properties and expenditures on processing equipment.
- Tax reform finally appeared before the House of Commons as a whole when Bill C-259 was introduced on 18 June 1971.¹² With respect to petroleum revenues and expenditures, the Bill followed the *White Paper* fairly closely. The main elements were:
1. Earned depletion was adopted, with eligible expenditures broadened to include expansion of milling capacity for mining (including oil sands) but excluding depreciable property such as production equipment and natural gas plants.
 2. Percentage depletion was to remain in force until the end of 1976, with no reduction of the accumulation of eligible

¹²Hon. E.J. Benson, Minister of Finance, *Budget Speech* (Ottawa: Department of Finance, 18 June 1971).

expenditures for earned depletion, based on all expenditures incurred after 7 November 1969.

3. Exploration and development expenditures would both be written off at 100 percent against all income for companies meeting "principal business" tests. Other firms could write off these expenditures at 20 percent of the unclaimed balance against any income, or at 100 percent against their resource income.
4. The purchase and sale of oil and gas rights was to be left unchanged, treated as fully deductible expenses and fully taxable income.

By permitting full expensing of all exploration and development expenditures, by extending percentage depletion to the end of 1976, and by allowing all expenditures from 1969 to 1976 to accumulate for the use of post-1976 earned depletion, Bill C-259 left substantially intact the pre-reform system applicable to oil and natural gas revenues in the 1970s. The system put in place at that time was first subjected to major change as a consequence of the rapid rise of world oil prices in 1973-74.

IV. TAX CONSEQUENCES OF THE 1973-74 WORLD OIL PRICE INCREASES

Starting in 1974, the pace of change in energy taxation and regulation was so fast that only the main elements can be sketched in this paper.¹³ In September 1973, a month before the start of the Arab-Israeli war, the domestic crude oil price was frozen at \$3.80 per barrel. The National Energy Board then began to regulate the export price, and an export tax was levied on the difference between these two prices. When the domestic wellhead price was raised, by federal-provincial agreement, to \$6.50 per barrel in March 1974, an Oil Import Compensation Program was introduced to subsidize the difference between the actual and regulated prices for imported oil

¹³A full review of the chronology is available in A. Plourde, *Oil and Gas in Canada: A Chronology of Important Developments, 1941-1986*, PEAP Energy Study No. 86-5 (Toronto: Institute for Policy Analysis, University of Toronto, 1986). The main stages of the regulation and deregulation of Canadian crude oil prices and trade are described in M.E. MacGregor, *Regulating and Deregulating Canadian Crude Oil*, PEAP Energy Study No. 86-4 (Toronto: Institute for Policy Analysis, University of Toronto, 1986).

and products. During that fall and winter, there were also several increases in provincial taxes and royalties on both crude oil and natural gas. The federal budget of May 1974¹⁴ proposed a number of tax increases on oil and gas revenues. However, the minority Liberal government was defeated in a House of Commons vote on this budget. The ensuing general election returned the Liberals to power, this time in a majority position, and the November 1974 budget¹⁵ reintroduced, with some modifications, the main elements of the May proposals. As enacted, the main tax changes were:

1. Provincial royalties were disallowed as an expense under the federal corporation income tax. In return, an additional ten points of provincial abatement (for oil and gas profits only) was given on the new national income tax rate of 50 percent on oil and gas profits. Of this 50 percent, 20 percent was considered to be abated to the provinces, leaving the federal rate at 30 percent. The budget also proposed that the corporation income tax rate applicable to petroleum production profits be reduced to 28 percent in 1975, and to 25 percent in and after 1976.
2. Percentage depletion was to be replaced immediately by earned depletion.
3. Earned depletion was to be subject to an upper limit of 25 percent of production profits, rather than the 33 1/3 percent established by the June 1971 budget.
4. One hundred percent write-off was to be retained for exploration expenditures, with a rate of 30 percent to be used for development expenditures, for which the definition was broadened to include land expenditures.¹⁶

¹⁴Hon. J.N. Turner, Minister of Finance, *Budget Speech* (Ottawa: Department of Finance, 6 May 1974).

¹⁵Hon. J.N. Turner, Minister of Finance, *Budget Speech* (Ottawa: Department of Finance, 18 November 1974).

¹⁶This is similar to what was proposed by the Royal Commission, except that the Commission proposals would have a lower rate of write-off for land expenditures and would have linked that write-off to income from the property in question. In the May 1974 budget, a 30 percent write-off rate had been proposed for both exploration and development expenditures.

The main purpose of these substantial changes was said to be to prevent the erosion of the federal income tax base by the recent substantial increases in provincial royalties. In his budget speech of November 1974,¹⁷ the Minister of Finance explained the underlying reasoning as follows:

I acknowledge that royalties in respect of property rights have traditionally been deductible as a business expense. However, in tax reform we began the process of disallowing certain income tax royalties in the mineral field¹⁸ and substituting federal tax abatements. Today, it is evident that a royalty is no longer a royalty in the traditional meaning of the word. There have emerged various provincial charges that are thinly disguised income taxes.

Today provincial charges take many forms ... there are provincial charges that are determined by price, profit and volume.... In fact, there are so many kinds of provincial charges and claims that it would be virtually impossible to draft workable legislation which could distinguish between bona fide royalties, traditionally deductible, and other taxes and charges.

The federal budget of June 1975,¹⁹ which raised the regulated oil price to \$8 per barrel and established regulated pricing for natural gas sold in central Canada, also made further changes in the income tax arrangements for the taxation of oil and gas profits. The key changes made at this time were:

1. Effective from 1 January 1976, the general rate of corporation income tax was set at 46 percent, and the additional 15 percentage-point abatement for oil and gas profits was converted to a 25 percent resource allowance on production income net of operating expenditures and capital cost allowances.
2. An investment tax credit of 5 percent of eligible expenditures on tangible assets was introduced, applicable to oil and gas exploration and development activities, to be in effect between June 1975 and June 1977.

The net effect of these budget changes was to lower the rate of federal corporation income tax below the 30 percent established

¹⁷Turner, *supra*, note 15 at 13.

¹⁸The reference was to mining profits taxes, which under Bill C-259 were no longer to be deductible expenses for the federal corporation income tax.

¹⁹Hon. J.N. Turner, Minister of Finance, *Budget Speech* (Ottawa: Department of Finance, 23 June 1975).

in the previous budget. The reduction was especially great for firms making substantial investment expenditures.²⁰

The next federal budget, in June 1976,²¹ continued the new tradition of using the budget as the occasion for announcing increases in the regulated domestic prices of crude oil and natural gas, and made the following modifications to energy taxation:

1. To encourage energy conservation, the budget proposed a two-year write-off for certain energy-conserving capital expenditures incurred between budget night and 1980. In addition, the federal sales tax was removed on certain non-fossil-fuel energy generators, such as solar furnaces, heat pumps, and wind-powered generators.
2. For similar reasons, the budget proposed special excise taxes on high-energy-consuming motor vehicles and motor-vehicle air-conditioners.
3. Between June 1976 and June 1979, all taxpayers (and not just "principal business" taxpayers) were to be permitted to deduct 100 percent of exploration expenditures against any other income. This would come to be known as the "drilling funds" deduction.

In the next federal budget,²² the key energy-related measure was the introduction of "superdepletion", to apply for three years, until 31 March 1980. In addition to regular earned depletion, exploration expenditures above \$5 million per well could "earn" an additional depletion allowance of $66 \frac{2}{3}$ percent. The combination of depletion and superdepletion meant that well expenditures above \$5 million gave rise to a 200 percent write-off, comprising the 100 percent immediate exploration write-off, the $33 \frac{1}{3}$ percent earned depletion allowance, and the $66 \frac{2}{3}$ percent depletion allowance. The combination of depletion allowances of this size with the

²⁰The resource allowance is a reduction from taxable income rather than a tax credit. It differs from a change in the tax rate because its base is larger than the corporation income tax base, especially for firms making substantial exploration and development expenditures.

²¹Hon. D.S. Macdonald, Minister of Finance, *Budget Speech* (Ottawa: Department of Finance, 25 May 1976).

²²Hon. D.S. Macdonald, Minister of Finance, *Budget Speech* (Ottawa: Department of Finance, 31 March 1977).

provision of the May 1976 budget that permitted anyone to obtain the 100 percent exploration write-off meant that 200 percent of well costs could be written off against resource income, or 166 2/3 percent against any other income. The growth in the number of drilling funds subsequently made these write-offs available to many individual taxpayers with tax rates above 50 percent, creating a perverse form of negative taxation whereby a more costly well (to do the same job) could make the investor better off, since the value of the tax reductions exceeded the costs of the drilling. Under these circumstances, it was not surprising that frontier wells became more numerous and much more expensive.²³

The next two federal budgets²⁴ aimed to reduce the effective tax burden on marginal projects such as heavy oil upgrading, oil sands plants, and enhanced oil recovery.²⁵ In addition, the November 1978 budget not only extended the drilling funds deduction to the end of 1981, but it also indefinitely extended the availability of the investment tax credit. At the same time, the general rate of tax credit was raised from 5 percent to 7 percent with higher rates for designated regions, including Saskatchewan and the northern parts of Alberta and British Columbia.

²³"For example, as a result of the 200-per-cent deduction now available, a taxpayer subject to a combined federal and provincial marginal tax rate of 62 per cent receives tax benefits of \$124 for every \$100 invested in the frontier." Hon. J.S. Crosbie, Minister of Finance, *Supplementary Information [on the Budget]* (Ottawa: Department of Finance, 11 December 1979) at 69.

²⁴Hon. J. Chrétien, Minister of Finance, *The Budget* (Ottawa: Department of Finance, 10 April 1978); Hon. J. Chrétien, Minister of Finance, *Budget Speech* (Ottawa: Department of Finance, 16 November 1978).

²⁵In August 1978, the federal government introduced a refinery levy on all oil refined in Canada. This levy, often referred to as the 'Syncrude levy', was used to raise the funds necessary to extend the world price to the output of the Syncrude oil sands plant when it came on stream towards the end of August. In December 1974, the federal government had guaranteed the Syncrude participants that the plant would receive the world price for its output.

V. THE SECOND WORLD OIL PRICE SHOCK, 1979-80

In early 1979, world oil prices began to rise rapidly once again, starting another series of tense and difficult federal-provincial negotiations about energy prices and taxes. In December of that year, John Crosbie introduced the budget proposals of the new Progressive Conservative government.²⁶ In the absence of an agreed federal-provincial resolution of energy pricing and taxation issues, some aspects of the energy proposals were deliberately vague, such as the form of a proposed new tax intended to collect for the federal government "roughly half of the returns from oil and gas price increases that exceed \$2.00 per barrel and 30 cents per thousand cubic feet per year."²⁷ The proposed energy price strategy was to move Canadian prices for crude oil gradually towards 85 percent of the lesser of U.S. and international prices, and to let prices for natural gas rise in concert with oil prices.

To encourage conservation, the budget also proposed to replace the 7-cent per gallon excise tax on gasoline with a 25-cent per gallon tax on all transportation fuels, to be partially offset by an income-tested refundable energy tax credit in the personal income tax. In addition, the budget proposed to extend superdepletion at a much reduced rate (6 2/3 percent) to the end of 1980 and then to let it expire. The write-off rate for the purchase prices of Canadian oil and gas properties, which had been 30 percent, was to be reduced to 10 percent.²⁸ However, the minority Progressive Conservative government was defeated on the budget in the House of Commons, principally as a result of opposition to the excise tax on transportation fuels.

²⁶Hon. J.S. Crosbie, Minister of Finance, *Budget Speech* (Ottawa: Department of Finance, 11 December 1979).

²⁷*Ibid.* at 4.

²⁸This measure would be enacted in April 1980, by the new Liberal government. See Hon. A.J. MacEachen, Minister of Finance, *Notice of Ways and Means Motion Relating to Proposed Amendments to the Income Tax Act* (Ottawa: Department of Finance, 21 April 1980).

After an election campaign that was heavily oriented to energy issues, a majority Liberal government was elected, having made promises to have a "Made in Canada" oil price and to increase the Canadian ownership share of the petroleum industry. This platform achieved heavy electoral support in central Canada, but almost none in the western provinces. It was therefore not entirely surprising that the next federal budget,²⁹ presented jointly with the National Energy Program (NEP) on 28 October 1980, contained several controversial energy taxes. Not only had federal-provincial negotiations been unsuccessful, but world oil prices had continued to rise rapidly, while Canadian energy prices remained frozen.³⁰ One result of this was rapidly rising federal subsidy payments covering the expenditures made necessary by the Oil Import Compensation Program.

VI. THE NATIONAL ENERGY PROGRAM AND ITS AFTERMATH

One of the centrepieces of the NEP was a schedule of "Made in Canada" prices to be paid for different categories of crude oil, being lowest for conventional oil, higher for tertiary recovery oil, and highest for production from the oil sands.³¹ Domestic oil users would pay a "blended price" designed to cover the average costs of all domestic and imported oil used. This was to be achieved by the establishment of a Petroleum Compensation Charge (PCC), an expanded version of the Syncrude levy that would be designed to finance the amounts by which the costs of synthetic oil, imported oil, and tertiary recovery oil exceeded the cost of conventional oil.

²⁹Hon. A.J. MacEachen, Minister of Finance, *The Budget* (Ottawa: Department of Finance, 28 October 1980).

³⁰In late 1978, the federal government and the governments of the producing provinces agreed to cancel the increases in domestic oil and gas prices scheduled for 1 January 1979, and no subsequent agreement had been achieved.

³¹See Canada, Energy, Mines and Resources, *The National Energy Program 1980* (Ottawa: Supply & Services Canada, 1980). A more detailed analysis of these issues can be found in MacGregor, *supra*, note 13.

Canadian oil users would then pay the sum of the PCC and the regulated price of conventional oil. Aside from the PCC, itself a quasi-tax, the main tax and subsidy elements of the NEP were as follows:

1. A new Natural Gas and Gas Liquids Tax (NGGLT) was introduced, starting at \$0.30 per thousand cubic feet (mcf) and rising to \$0.75 per mcf by 1983. This tax was to be levied on all gas and gas liquids produced in Canada.
2. A new Petroleum and Gas Revenue Tax (PGRT) was introduced, at 8 percent of petroleum and natural gas revenues net of operating costs. This new tax was not to be deductible from the income base for the corporation income tax.
3. The NEP proposed to replace earned depletion allowances³² with a system of cash payments under the new Petroleum Incentive Program (these payments were usually known as PIP grants). These grants varied between exploration and development, varied between exploration regions, and were higher for firms with higher degrees of Canadian ownership. With the exception of exploration activities on the Canada Lands, no PIP grants were payable to firms with less than 50 percent Canadian ownership. The maximum rate payable on provincial lands was 33 percent for exploration by firms with more than 75 percent Canadian ownership. On the Canada Lands, the maximum rate payable was 80 percent for exploration by firms with more than 75 percent Canadian ownership. The PIP grants were not taxable, but they correspondingly reduced the expenditure that could be deducted from taxable income, used to earn depletion allowances, or eligible for the investment tax credit.³³
4. The revenues from the continuing federal oil export tax were to be shared equally with the producing provinces.

³²The main exceptions to this were exploration activities by corporations in frontier regions (now called "Canada Lands"), and in non-conventional sources, including tertiary oil projects and heavy oil upgraders. In these cases, earned depletion was to remain at 33 1/3 percent, with PIP grants also available. However, superdepletion had been allowed to expire on 1 April 1980, as scheduled in the March 1977 budget introducing this form of exploration incentive.

³³Some departures from these proposals emerged when the measures were enacted.

5. There were a number of features relating to the ownership and taxation of oil and gas rights in the Canada Lands. Most important were:
 - a) the retroactive right granted to the Crown to acquire a 25 percent back-in interest, at accumulated cost, on any production licence on the Canada Lands; and
 - b) the planned introduction of a separate profits-related royalty system (the Progressive Incremental Royalty, or PIR) for production on the Canada Lands.
6. The NEP also envisaged the imposition of a tax on oil products to be used to finance government acquisitions of producing companies. Such a levy, labelled the Canadian Ownership Special Charge (cosc), was introduced in May 1981 with the aim of covering the costs of Petro-Canada's acquisition of the Canadian assets of Petrofina. It was set at \$1.15 per barrel for oil products and \$0.15 per mcf for natural gas.

The reaction of the governments of the producing provinces to the NEP was strongly negative. Two days after the introduction of the NEP, the government of Alberta announced a series of phased cutbacks of allowed conventional oil production and halted the approval process for new oil sands plants. These measures, the provincial government stated, would remain in effect until the sharp differences in energy policy were resolved in a manner acceptable to Alberta.³⁴ The resulting stalemate lasted until 1 September 1981, when a memorandum of agreement on oil and gas pricing and taxation was signed by the Prime Minister of Canada and the Premier of Alberta.³⁵ Similar agreements were subsequently signed with British Columbia (on 24 September) and Saskatchewan (on 26 October). These three agreements were unusual for their detail and the degree of commitment by both levels of government, each of which agreed not to alter tax and royalty rates in any way that would reduce aggregate revenues flowing to the other level of government

³⁴For a quantitative analysis of the NEP and the Alberta response, see J.F. Helliwell & R.N. McRae, "The National Energy Conflict" (1981) 7 Can. Pub. Pol'y 15.

³⁵Canada, Energy, Mines and Resources, *Memorandum of Agreement between the Government of Canada and the Government of Alberta relating to Energy Pricing and Taxation* (1 September 1981) [unpublished].

or to the oil and gas producing industry. The agreements were intended to last five years, until 31 December 1986.

The main features of these agreements were:

1. The pattern of regulated oil and gas prices was to be linked more closely to world oil prices, with synthetic oil and "new" oil (that is, crude oil produced from pools discovered after 1980) getting the world price, while a price schedule limited to 75 percent of the cost of world oil would apply to "old" oil (that is, crude oil produced from pools discovered before 1981). These new prices were, on average, substantially higher than the NEP or pre-NEP prices for both producers and consumers.³⁶
2. The federal government agreed to drop the NGGLT on gas exports, but proposed to raise the rate of this tax to make the Toronto city-gate price of natural gas equal to 65 percent of the delivered price of crude oil with an equal heating value.
3. The PGRT, originally 8 percent, was to be raised to 16 percent, but a 25 percent resource allowance was introduced to reduce the effective rate of PGRT to 12 percent.
4. The federal government was to introduce a new Incremental Oil Revenue Tax (IORT) equal to 50 percent of the incremental revenues on old oil, where the incremental revenues were defined by the difference between the conventional prices established in the NEP and those in effect under the agreements. Provincial royalties were deductible for the purpose of IORT, which was treated as a substitute for federal and provincial corporation income taxes.
5. Within Alberta, the PIP was to be administered and paid for by the provincial government, but left in the federal charge elsewhere.

The net effect of the new taxes and higher prices was to increase revenues, relative to the NEP, for the producing industry and for both levels of governments. The new federal taxes envisaged by the agreements were part of the federal budget of 12 November

³⁶For example, the 1982 wellhead price for new oil, net of all taxes and royalties, was \$7.10 per barrel under the NEP and \$14.60 per barrel under the agreements. For a more detailed quantitative analysis of the agreements, see J.F. Helliwell & R.N. McRae, "Resolving the Energy Conflict: From the National Energy Program to the Energy Agreements" (1982) 8 *Can. Pub. Pol'y* 14.

1981,³⁷ and came into effect on 1 January 1982. However, world oil prices had stopped rising, so that the agreement prices, which were limited by world oil prices, soon fell below the "Made in Canada" prices envisaged by the NEP. Thus the new taxes, the IORT, NGGLT, and PGRT produced much less revenue than originally forecast. In response to the stagnant world oil prices, the Alberta government lowered royalty rates in April 1982, and the federal government released an "update" to the NEP³⁸ a few months later.

The overall intent of the Alberta changes was to increase industry cash flows by \$5 billion in the 1982-86 period covered by the 1981 agreements, while the NEP update changes were expected to add \$2 billion to industry cash flows during the same period. These two sets of changes were expected to offset slightly more than fully the effects on the producing industry of the drop in actual and expected oil prices between September 1981 and June 1982.³⁹

The main tax changes announced in the NEP update were:

1. The suspension of the IORT from 1 June 1982 to 1 June 1983. This suspension was subsequently renewed until the tax was removed entirely. Thus, the IORT was only in effect for the first half of 1982.⁴⁰
2. A reduction in the effective rate of PGRT from 12 to 11 percent for a one-year period starting 1 June 1982.
3. The effective rate of PGRT for oil sands production was reduced to 8 percent for a two-year period ending 31 December 1984.
4. A credit of \$250,000 per year against PGRT payments was granted to all producers with the aim of eliminating the tax entirely for the smallest producers.

³⁷Hon. A.J. MacEachen, Minister of Finance, *Budget Speech* (Ottawa: Department of Finance, 12 November 1981).

³⁸Canada, Energy, Mines and Resources, *The National Energy Program: Update 1982* (Ottawa: Supply & Services Canada, 1982).

³⁹These calculations are reported in J.F. Helliwell, M.E. MacGregor & A. Plourde, "The National Energy Program Meets Falling World Oil Prices" (1983) 9 *Can. Pub. Pol'y* 284.

⁴⁰The IORT was levied on the production of the Suncor oil sands plant for a longer period.

The April 1983 budget⁴¹ renewed the IORT suspension for another year and proposed to change the PGRT for tertiary oil recovery projects so as to eliminate liabilities under the tax until all capital costs from the projects were recovered. The indefinite continuation of the COSC was also announced in this budget.

In the November 1984 *Economic and Fiscal Statement*,⁴² the lower rate of PGRT for oil sands production was extended, and there was an increase in the small producers' credit against the PGRT. In addition, it was announced that the narrowing gap between Canadian and world oil prices had lessened the justification for subsidy programmes designed to cut oil use by conservation or substitution, and that such subsidies would be phased out or consolidated. The *Statement* also foreshadowed changes designed to reduce and simplify the extent of energy taxation and regulation, including the system of PIP grants.

VII. THE WESTERN ACCORD AND THE CURRENT TAX SYSTEM

By the time the *Western Accord*⁴³ was signed in March 1985 by the governments of Canada, Alberta, British Columbia, and Saskatchewan, Canadian energy prices were at or close to world levels, and the various special taxes and charges introduced as part of the NEP were producing little revenue, with the exception of the PGRT. Under the *Western Accord*, PIP grants and the PGRT were both to be phased out, the IORT and the NGGLT were to be withdrawn

⁴¹Hon. M. Lalonde, Minister of Finance, *Budget Speech* (Ottawa: Department of Finance, 19 April 1983).

⁴²Hon. M.H. Wilson, Minister of Finance, *Economic and Fiscal Statement* (Ottawa: Department of Finance, 8 November 1984).

⁴³Canada, *The Western Accord – an agreement between the Governments of Canada, Alberta, Saskatchewan and British Columbia on oil and gas pricing and taxation* (28 March 1985) [unpublished].

immediately, and deregulation was promised for both crude oil and natural gas.⁴⁴

It was envisaged, and has been the case, that deregulation would proceed faster and further for crude oil than for natural gas. Moving to world prices for crude oil and oil products meant that the PCC, the oil export tax and the Oil Import Compensation Program were all redundant, and were accordingly dismantled.⁴⁵ The tight links between domestic and international oil prices, effected by permitting almost unrestricted exports and imports of crude oil and products, meant that the post-*Accord* reductions in world oil prices drove down taxes and energy cash flows alike, and created substantial pressure for accelerated removal of the PGRT. The immediate elimination of the PGRT was announced, outside the normal budget process, in September 1986, to be effective 1 October.⁴⁶

By early 1987, the principal remaining special features of oil and gas taxation were:⁴⁷

1. The immediate write-off of exploration expenditures, a 30 percent write-off for development expenditures, and a 10 percent write-off for land expenditures. All of these features are similar to the proposals made by the Royal Commission.

⁴⁴Shortly after the *Western Accord* was signed, the government of Alberta announced a reduction in oil and gas royalty rates. See Alberta, "Statement by Premier Lougheed and Energy Minister Zaozirny on Oil and Gas Incentives" (24 June 1985) [unpublished].

⁴⁵For a quantitative examination of the potential impact of the Western Accord and related developments, see J.F. Helliwell *et al.*, "The Western Accord and Lower World Oil Prices" (1986) 12 *Can. Pub. Pol'y* 341.

⁴⁶Shortly afterwards, the government of Alberta announced a reduction in oil and gas royalty rates. See Alberta, "Oil and Gas Activity Incentives" (29 October 1986) [unpublished].

⁴⁷After the empirical work in this paper was completed, the federal government announced a new oil and gas exploration incentives program. Basically, this program is intended to provide grants for one-third of the exploration costs incurred anywhere in Canada, up to an annual maximum of \$10 million per firm. At the same time, the government extended tax advantages to the oil and gas industry by allowing certain of its activities to be financed through the issue of flow-through shares. (Such advantages had previously been made available to the mining industry.) See, for example, K. Cox & C. Waddell, "Ottawa gift to energy firms to cost \$350 million a year" *The [Toronto] Globe and Mail* (26 March 1987) A1-A2.

2. Royalties paid to provincial governments are non-deductible for purposes of the federal corporation income tax. This non-deductibility is intended to be offset by the (federal) resource allowance, which reduces resource income by 25 percent. The offset is more or less than complete, depending on whether royalty rates are less or more than 25 percent of production income.⁴⁸ Hence, this special feature amounts to a federal subsidy to oil and gas extraction whenever the provincial royalty rates are below 25 percent.
3. The rate of corporation income tax is higher for oil and gas extraction than for manufacturing and processing (including the operation of gas processing plants).
4. Flow-through shares receive special tax treatment, and can be used by the oil and gas, and mining industries to finance some of their activities. In addition, the federal oil and gas development incentive is to be in effect until the end of 1989.

Aside from these issues of unequal treatment of industries, which are likely to be addressed to some extent in the federal government's 1987 tax reform proposals, there is the possibly more important issue of the instability, over time, of the Canadian system of taxation of production revenues from oil and gas. There have been very large and rapid swings in the rates and structure of taxation, ranging from subsidies exceeding 100 percent of costs in the high-flying days of superdepletion, to marginal tax rates reaching 100 percent during some of the federal-provincial struggles for larger shares of revenues when oil prices were rising rapidly in the aftermath of the 1973-74 and 1979-80 world oil price shocks.

How can the consequences of the changes be assessed? In principle, it is likely that a rapidly changing system would act to increase investor uncertainty and thus reduce the attractiveness of oil and gas investments. However, it is also possible that the changes in the level and structure of oil and gas taxation have served to make actual net-of-tax revenues less variable and more predictable than they would have been in the absence of these changes. This latter outcome is perhaps less likely in recent Canadian history, when the major changes have been triggered by competition for revenue

⁴⁸The details of the resource allowance are described in Helliwell *et al.*, *supra*, note 2.

shares more than by any intent to stabilize net industry returns. Some rough empirical judgments about this issue can be made by comparing the rates of return and their variability under the historical regime of fast-changing rules with those that would have obtained under several alternative and more stable tax regimes.

VIII. EVALUATION OF ALTERNATIVE OIL AND GAS TAXATION SYSTEMS

In this Part, we use results from alternative simulations of the MACE model of the Canadian economy⁴⁹ to compare the consequences of five main policy regimes during the 1974–1990 period:

1. The historical pattern of changing tax structures and rates with the historical pricing policies ("historical prices and taxation policies" or "HISTORY" in the text, tables, and figures).
2. The historical pattern of changing tax structures and rates with unregulated crude oil and natural gas prices ("deregulation" or "DEREG").
3. The tax system and royalty rates that were in place before oil prices and royalty rates started to rise in 1973–74 ("the pre-reform system" or "PREREF").
4. The royalty rates that were in place before 1973, coupled with the income tax system recommended by the Royal Commission on Taxation ("the Royal Commission proposals" or "COMMIS").
5. The current tax regime, which has somewhat higher royalty rates than in the early 1970s. Royalties are non-deductible for federal income tax purposes, but there is a resource allowance ("the current system" or "CURRENT").

In all cases, we make the assessments using the historical pattern of *world* oil prices; and in all cases except the historical one (HISTORY), we assume that *Canadian* oil and natural gas prices were unregulated and therefore rose and fell in concert with the movements in world prices. Even in our analysis of the historical

⁴⁹The version of the MACE model used in this paper is described in J.F. Helliwell *et al.*, "Supply oriented Macroeconomics: The MACE model of Canada," 4 *Econ. Modelling* 318.

system, we compare the historical results with what they would have been had domestic energy prices been unregulated (DEREG). This helps to show the relative importance of price regulation and tax changes in determining the changing size and distribution of energy revenues.

The main point of our assessment is to see to what extent the historical pattern of complex energy taxes and regulations sheltered Canadian energy users and producers from changes in world markets and to assess the extent to which the distribution of energy revenues, energy industry activity, and energy demand would have been different under any of the alternative systems under review.

A. *Historical Prices and Taxation Policies (HISTORY)*

The pattern of regulated prices and tax changes that evolved during the 1970s and early 1980s was in large part a response to a rapidly changing world oil market. Regulated domestic prices insulated both Canadian consumers and producers from the full impact of changes in world oil prices. Despite this insulation, Canadian energy prices, in general, still rose more rapidly than the overall price level in the economy. Domestic requirements for crude oil generally declined while the demand for natural gas increased. Real investment in the energy industry more than doubled between 1974 and 1985,⁵⁰ and net government energy revenues, particularly those from the upstream oil and gas industry, increased steadily.

Although part of the rise in government revenues is due to increases in the wellhead prices of crude oil and natural gas, a large part is attributable to increases in provincial royalty rates and the introduction by the federal government of special industry taxes or tax provisions when world oil prices were rising rapidly. The average wellhead price of crude oil, for example, increased sixfold between 1974 and 1985, while the after-tax prices received by producers for

⁵⁰For a more detailed discussion of investment trends in the Canadian oil and gas industry during this period, see M.E. MacGregor & A. Plourde, *Investment Trends and Changing Policies in the Canadian Oil and Gas Industry*, PEAP Energy Study No. 86-4 (Toronto: Institute for Policy Analysis, University of Toronto, 1987).

new oil increased by a factor of five. As Figure 1 shows,⁵¹ rates of return for the industry increased from around 10 percent in 1974 to a maximum of just over 14 percent in 1980. Rates of return increased sharply in the early 1980s with the introduction of world-equivalent pricing on new oil production, but this was more than offset by the decreased rate of return on natural gas production. The combined rate of return fell sharply in 1986 with the drop in world oil prices from around u.s. \$27 per barrel in 1985 to u.s. \$15 per barrel in 1986. We have assumed that the recovery apparent in world oil prices at the beginning of 1987 will be sustained,⁵² and this accounts for the gradual recovery in the overall rates of return to around 8 percent, which is still below the levels prevailing during the 1970s.

Rates of Return for Oil, Gas and Combined under HISTORY
(percent)

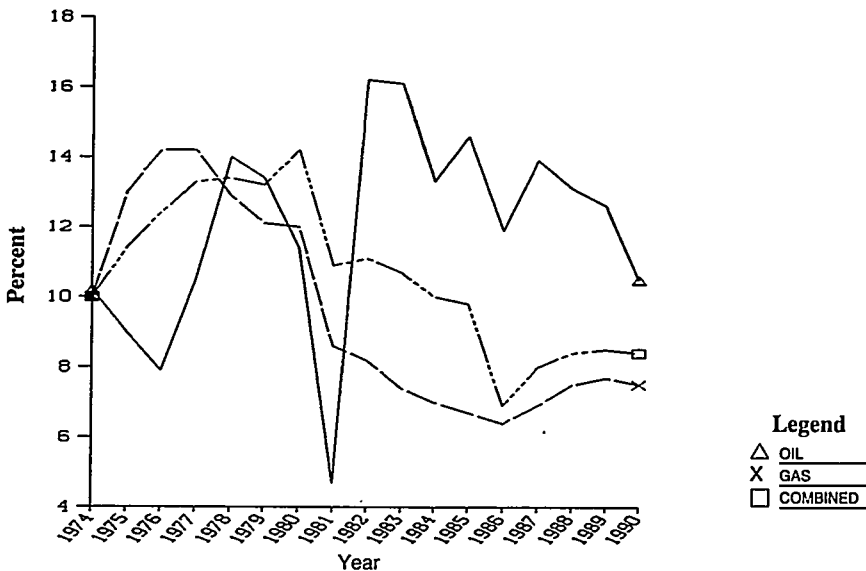


Figure 1

⁵¹Note that "Oil" excludes oil sands production, while "Combined" includes it.

⁵²In our projection period, we assume that 1987 world oil prices will average U.S. \$18 per barrel and that they will grow at the U.S. rate of inflation thereafter. We also assume that domestic natural gas prices will be equal to 85 percent of the btu-parity oil price starting in 1987.

Figure 2 provides an indication of how the net economic benefits from Canadian crude oil and natural gas production are distributed among producers, consumers, and governments, under historical pricing and taxation policies. These annual flows have been converted to 1971 dollars in order to facilitate year-to-year (and later, case-to-case) comparisons.⁵³ As is evident from Figure 2, consumers and the provincial governments tended to reap most of the economic benefit from oil and natural gas production during the 1970s. The federal government received the least benefit, partly because of the subsidy payments to crude oil importers. Consumer rents fell sharply after 1980 (and federal rents rose) as domestic prices approached world levels and consumers began to bear the costs of the subsidy programme. Rents to the federal government also rose during the early 1980s with the introduction of a number of special taxes on the industry.

B. *Deregulation (DEREG)*

In our deregulation case, we assume that all domestically produced oil receives the equivalent of the world price and that the delivered price of natural gas in eastern Canada is equal to 85 percent of the btu-equivalent, delivered oil price. While our oil price assumptions are not controversial, our assumptions about natural gas prices under deregulation are of a more heroic nature. Given the highly regulated nature of the natural gas market, the past swings from expected shortfalls to large surpluses, and the uncertainty about the impact of deregulation in the future, our assumptions about what deregulation would have meant in past

⁵³Economic rents to consumers ("CONS" in the figures) are the compensated consumer surpluses accruing between domestic and world prices. Producer rents ("PROD") are equal to wellhead revenues net of operating costs, all taxes and royalties, land payments, economic depreciation, and an after-tax charge on unamortized capital. Rents to provincial governments ("PROV") are equal to revenues from income taxes, royalties, land payments, and the equity interest in Syncrude net of incentive payments, royalty abatements, and a real tax opportunity cost of about 1 percent of invested capital. Rents to the federal government ("FED") are defined as the sum of income and other taxes on the oil and gas industry, consumer taxes on oil and natural gas, less subsidy and incentive payments and a real tax opportunity cost of about 2 percent of invested capital.

should be viewed mainly as illustrative of how a market-sensitive pricing system might have functioned.

Flow Rents from Oil and Gas under HISTORY
(billions of 1971 dollars)

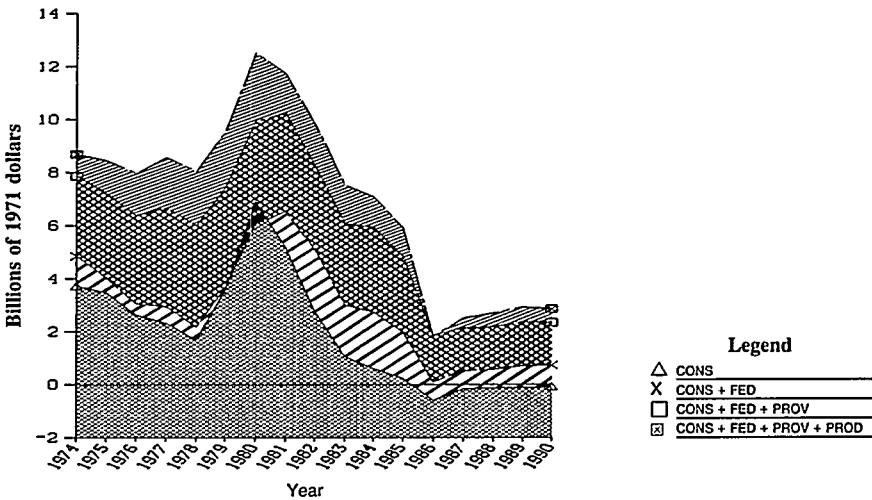


Figure 2

In this case we assume that, except for prices, everything would have remained the same as in our historical base case. By assuming that taxes, royalty rates, export volumes, and other policies are unchanged, we can separate the effects of historical pricing policies from the many changes in taxes and royalties that accompanied price regulation. This will later allow us to compare the effects of the historical pattern of tax changes with several more stable regimes in order to assess how they contributed to or subtracted from the stability of industry revenues and investment.

The most obvious outcome of our deregulated pricing system is the higher prices producers would have received for both oil and natural gas during the 1970s and the first half of the 1980s. Average wellhead prices for crude oil would have been anywhere from 6 to 114 percent higher, while natural gas prices would have been from 12 to 128 percent higher.⁵⁴

In our model, changes in oil and natural gas investment are driven by changes in the ratio of the after-tax price to the after-tax costs of finding, developing, and producing new reserves. As is evident from Figures 3 and 4, the increases in producer prices outweigh the increases in producer-borne costs under deregulation; so that oil and gas investment, discoveries, and, indeed, the ultimate stock of recoverable reserves all would have been much higher. Real energy investment would have been around 4.2 percent higher on average between 1974 and 1985, although after 1981, when new oil began receiving the world-equivalent price, the differences are small.⁵⁵

Although higher wellhead prices result in increased investment and productive capacity for both oil and natural gas, production levels tend to be lower because of the effects of the higher prices on consumer demand for oil and natural gas. Overall energy prices to consumers are up by 19 percent on average over the 1974 to 1985 period, and at the peak of world prices in 1980, they are 45 percent higher than under historical prices and policies. Canadian crude oil requirements are down an average of 5 percent (reducing oil imports by nearly 20 percent), and the demand for natural gas is down an average of 22 percent.

For many of the years under consideration, consumers are clearly worse off in our deregulation case. What of producers and governments? Revenues to both increase as a result of deregulation,

⁵⁴The differences in oil prices are strictly a function of how far domestic prices were below world levels and the resulting differences in the exchange rate. Natural gas prices, however, are a function of both changes in the btu-parity pricing rule and higher oil prices. Lower btu-parity pricing rules were in effect prior to 1976 and after 1980, when the NEP and 1981 agreements lowered the btu-parity ratio from 85 to 65 percent.

⁵⁵Energy-sector investment is actually somewhat lower after 1981 under deregulation, since the method used to calculate the world-equivalent price under the administered pricing system tended to overestimate market values.

but have net economic rents also increased? Figure 5 shows the changes in flow rents to producers, consumers, and the federal and provincial governments. Obviously, deregulation results in a shift in the net economic benefits from oil and gas consumers to producers and governments.

Ratio of After-tax Prices to After-tax Costs – Oil

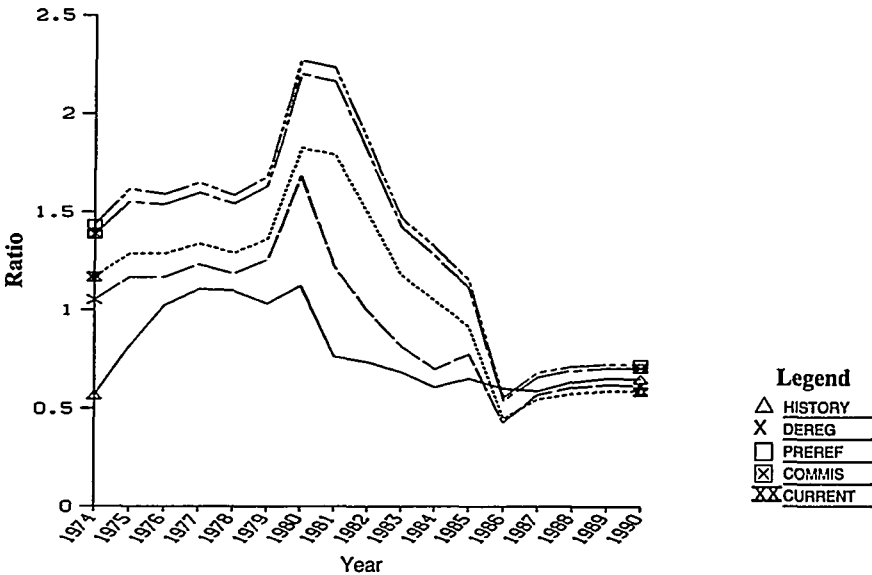


Figure 3

The overall impact of deregulation on real GNP is negative, despite the boost given to energy-sector investment and the positive impact on government balances (see Table 1). Deregulation results in strong increases in the economy-wide inflation rate during the two OPEC price shocks of 1973–74 and 1979–80, although the price level gradually returns to base-case levels following the shocks. The increase in the cost of a factor of production (that is, energy), however, reduces output in the non-energy sector. Higher domestic prices also reduce the competitiveness of Canadian output in both export and domestic markets, so that the overall current account deteriorates despite the improvement in the energy trade balance.

Table 1
 Macroeconomic Impact of Deregulation DEREG
 (percentage change from HISTORY)¹

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1990
Real GNP	-0.64	-0.87	-1.00	-1.21	-1.11	-0.72	-0.26	-1.02	-2.39	-3.29	-3.80	-2.26	-1.54
GNP Price Deflator	4.60	5.19	3.48	1.85	0.03	1.72	7.22	9.01	7.41	3.78	0.85	-1.18	2.00
Exchange Rate (Cdn\$/U.S.\$)	0.41	0.35	0.34	0.17	-0.02	0.39	1.10	1.48	0.93	0.51	0.37	-0.28	0.99
Real Energy Investment	7.39	3.72	2.01	2.32	2.12	8.14	21.64	11.10	-1.80	-1.83	-1.52	-0.81	0.08
All-Government Balance ²	1.09	1.04	0.19	0.14	0.20	2.65	7.70	5.81	1.17	-1.12	-2.17	0.51	-1.73

¹ In DEREG all domestic oil is assumed to be priced at world-equivalent levels. Domestic natural gas is assumed to be priced at 85% of the equivalent oil price, on a delivered basis.

² These results are level differences between DEREG and HISTORY; units are billions of dollars.

Now that we have briefly discussed the likely implications of the regulated pricing system that was in place prior to the *Western Accord* of 1985, we turn to an examination of the effects of the tax changes that were made over the years. We compare the historical pattern of tax changes to three more stable alternatives, assuming the same deregulated pricing system in all four cases.⁵⁶

C. *The Pre-Reform System (PREREF)*

This alternative is, essentially, the system that was in place before tax reform was introduced in 1971, which we refer to as the pre-reform system. Non-tangible exploration and development expenditures and land acquisition costs are all fully deductible in the year in which they are incurred. Provincial royalties are equal to 16 $\frac{2}{3}$ percent on all production, and are fully deductible for the purposes of both federal and provincial income taxes. In addition, resource profits are subject to a 33 $\frac{1}{3}$ percent depletion allowance, a provision that effectively reduces the effective corporate income tax rates by one-third. Since we are interested primarily in the effects of specific oil and gas measures, we have maintained the historical pattern of corporate tax changes that are not specific to the oil and gas sector (that is, the investment tax credit, the half-year capital cost allowance, and general corporation income tax rates).⁵⁷ None of the special industry taxes introduced later in the NEP or the 1981 agreements are in effect.

The combination of percentage depletion and lower, fully deductible provincial royalties results in extremely large increases in the after-tax prices received by producers. After-tax prices for new production come close to doubling for both oil and natural gas under the pre-reform system, compared with deregulation alone. Removing the PGRT substantially increases the after-tax producer prices in the early 1980s: after-tax prices increase by around 14 percent during

⁵⁶In the following three sections, impacts will thus be measured as deviations from the results obtained under our deregulation case.

⁵⁷The exception here is in 1974 and 1975, when the federal corporation income tax rate for oil and gas was changed to that prevailing in the rest of the corporate sector.

the period when the PGRT is in effect, as compared with just under 70 percent prior to the introduction of the PGRT.

The 1980-dollar values of capital and operating costs also show increases of 25 to 30 percent, however, moderating the impact of the rise in after-tax prices. Increasing the volume of discoveries increases the costs of finding new reserves, since, in our model, the marginal costs of new reserves increase with cumulative discoveries because of depletion effects. The other, and perhaps more important, factor in the increase in the after-tax costs is the fact that the value of the investment tax deductions is reduced under this set of policies. The provisions for depletion are no longer tied to the level of investment. Rather, percentage depletion merely reduces the effective tax rate. The lower statutory tax rate also reduces the value of tax write-offs in general. Despite the increases in after-tax costs in this case, the ratio of after-tax prices to costs shows a substantial increase compared with deregulation alone, especially during the early years (see Figures 3 and 4). Real energy investment is increased by almost 12 percent, between 1974 and 1985, as a result of the increases in oil and gas investment.

Not surprisingly, net government revenues from oil and gas are down compared with deregulation alone, although for the most part the increase brought about by the higher prices under deregulation still means that net government revenues are higher than in the historical pricing and taxation case. The pre-reform taxation system, basically, effects a transfer of rents from both levels of government to producers (Figure 6). The provincial governments tend to lose the most with oil, and the federal government tends to lose more with natural gas.⁵⁸ Consumer rents are almost unaffected, compared with deregulation alone, but increase slightly after 1980 with the removal of the Canadian Ownership Special Charge.

After 1985, however, producers tend to do worse under the pre-reform system than under deregulation alone, while provincial governments do better. Under the pre-reform system, producers invest more than they would have under the historical tax system (even with deregulated prices), so that when world oil prices fall in

⁵⁸This is because average royalty rates tended to be higher for oil than natural gas under historical policies.

1986, they are holding greater stocks of reserves and face a higher opportunity cost of doing so. The provincial governments, on the other hand, benefit from higher income tax revenues, owing to the elimination of the royalty tax credit (which was increased in 1985) and to generally higher production levels. Higher after-tax prices for producers also result in higher land payments under the pre-reform system.⁵⁹ In addition, royalty revenues are lower under the pre-reform system than under deregulation, but after 1984 the differences become less pronounced. This is because the deregulation case incorporates the effects of the 1985 and 1986 reductions in provincial royalty rates, so that by the end of the simulation period these rates are much closer to the constant royalty rates prevailing in the pre-reform system.

Ratio of After-tax Prices to After-tax Costs – Gas

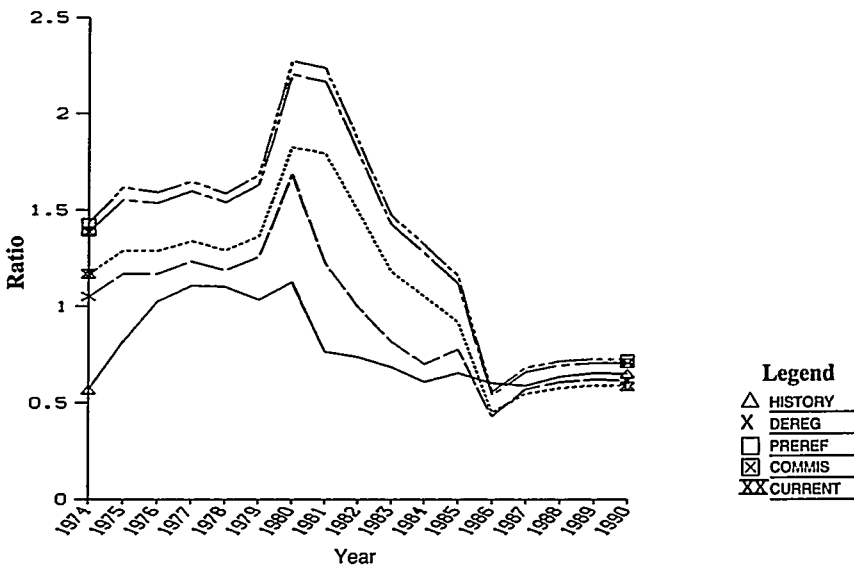


Figure 4

⁵⁹ In the flow rent equations, land payments are written off as reserves are produced, and unit land costs are expressed as the unamortized stock of land payments per unit of current production. Since land payments increase proportionately more than production in the pre-reform case, the unamortized stock of land payments per unit of current production is much larger.

**Changes in Flow Rents from Oil and Gas under DEREG
(Level differences from HISTORY in billions of 1971 dollars)**

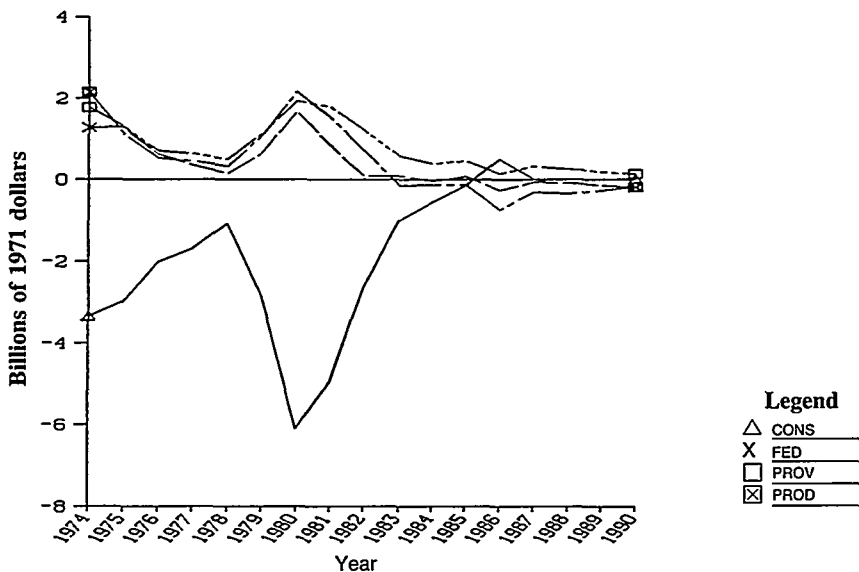


Figure 5

**Changes in Flow Rents from Oil and Gas under PREREF
(Level differences from DEREG in billions of 1971 dollars)**

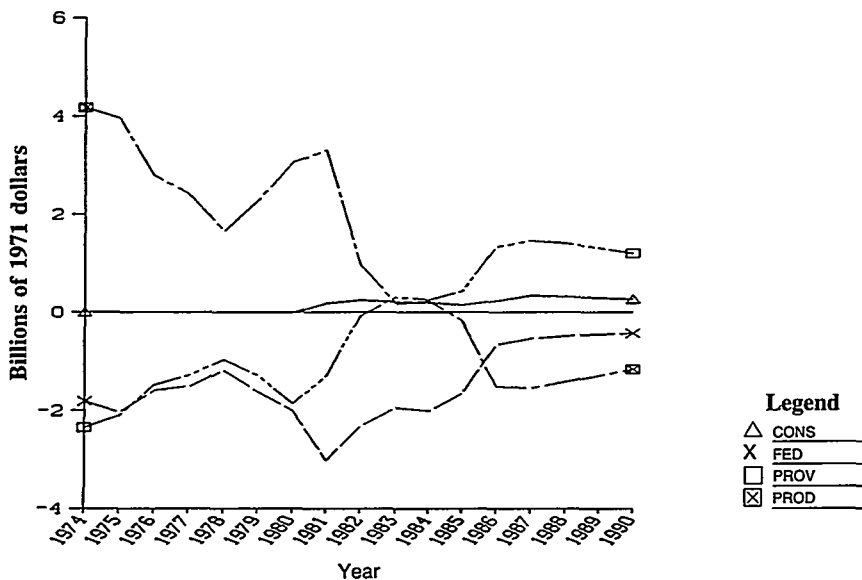


Figure 6

Table 2
 Macroeconomic Impact of Alternative Taxation Systems
 (percentage change from DEREG)¹

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1990
<i>Real GNP</i>													
PREREF	0.34	0.53	0.62	0.58	0.54	0.58	1.06	1.80	1.60	0.52	-0.89	-1.50	-1.09
COMMIS	0.28	0.43	0.52	0.49	0.47	0.50	0.92	1.72	1.60	0.61	-0.70	-1.34	-0.92
CURRENT	-0.24	-0.30	-0.31	-0.36	-0.30	-0.10	0.23	1.37	1.70	1.09	0.08	-0.82	-0.21
<i>GNP Price Deflator</i>													
PREREF	0.10	0.30	0.63	0.93	1.15	1.36	1.73	2.53	3.25	3.91	3.98	3.46	0.54
COMMIS	0.09	0.25	0.52	0.77	0.97	1.16	1.49	2.21	2.88	3.53	3.64	3.19	0.25
CURRENT	1.69	1.65	1.42	0.95	0.57	0.28	0.22	0.63	1.26	2.15	2.55	2.38	-1.37
<i>Exchange Rate</i>													
PREREF	-0.04	0.06	0.13	0.16	0.21	0.35	0.54	0.77	1.09	1.06	1.14	0.88	0.44
COMMIS	0.0	0.05	0.10	0.13	0.17	0.28	0.45	0.64	0.99	0.96	1.01	0.81	0.31
CURRENT	0.06	0.06	0.14	0.07	0.06	0.09	0.12	0.08	0.45	0.52	0.55	0.41	-1.09
<i>Real Energy Investment</i>													
PREREF	6.44	6.05	7.34	7.61	8.66	10.96	15.66	22.80	17.93	14.09	15.12	10.29	3.40
COMMIS	5.26	4.97	6.29	6.54	7.56	9.46	13.58	21.17	16.66	13.04	13.89	9.01	2.86
CURRENT	0.90	0.98	1.56	1.53	1.95	2.44	3.65	13.64	10.88	8.30	8.94	4.15	0.35
<i>All-Government Balance²</i>													
PREREF	-0.38	-0.14	-0.07	-0.16	-0.38	-0.13	-0.14	-0.95	-3.70	-6.53	-9.61	-10.81	-1.12
COMMIS	0.05	0.04	0.05	-0.15	-0.40	-0.26	-0.29	-1.07	-3.18	-6.01	-8.64	-9.57	0.32
CURRENT	0.69	0.38	0.43	0.48	0.63	1.30	1.95	1.80	0.52	-2.12	-4.70	-6.04	3.26

¹ The base in these cases is DEREG, the actual pattern of tax and royalty changes with world pricing for oil and 85% bru-parity pricing for natural gas.

² These results are level differences; units are billions of dollars.

The strong increases in energy-sector investment under the pre-reform system result in significant increases in real GNP when compared with deregulation alone (see Table 2), increases that for the most part, however, are not enough to offset the negative impact of deregulation. The energy-sector investment boom also increases the inflation rate in the economy, which eventually reduces Canadian exports and has a negative impact on the overall trade balance. Since higher activity levels in the economy also increase the demand for oil and natural gas, the deterioration in the non-energy trade balance is not offset by lower oil imports, as it was in the previous case.

D. *The Royal Commission Proposals (COMMIS)*

In this simulation, we assume that the system proposed by the Royal Commission would have been implemented by 1974. Provincial royalties are still $16 \frac{2}{3}$ percent on all production and fully deductible for income tax purposes, but depletion has been eliminated completely (earned or percentage), non-tangible development expenditures are written off at 30 percent per year instead of 100 percent, and land costs are written off at 10 percent.⁶⁰ In the spirit of the Royal Commission's efforts to design a neutral tax system, we have also set the investment tax credit rate at zero. The impact of this is moderated by the fact that it applies only to tangible investment expenditures, and these make up about 40 percent of total investment for natural gas and about 20 percent for oil.

As is immediately evident from Figures 2 and 3, the Royal Commission proposals have a smaller impact on the ratio of after-tax prices to after-tax costs than the pre-reform system has. Here the increases in after-tax producer prices are only about one-half those of PREREF, because of the loss of percentage depletion. After-tax costs for new production are greater than in the deregulation case, but less than under the pre-reform system. The loss of the investment tax credit and the earned depletion allowance reduces the write-off and credits available to producers but, on the other hand,

⁶⁰Note that exploration expenditures are still expensable.

the higher statutory tax rates enhance the value of the write-offs that do exist. The latter is the main reason why the after-tax costs are lower under the Royal Commission proposals than under the pre-reform system. Increases in real energy-sector investment average 10.6 percent during the 1974 to 1985 period, compared with 12 percent in the previous case, and the positive impact on real GNP is only about 80 percent of what it was with the pre-reform system, which is not enough to offset the negative impact of deregulation (Table 2).

Prior to 1986, the flow rents to both oil and gas producers increase with the Royal Commission proposals (Figure 7), but by much less than in the previous case. This time producer rents increase mainly at the expense of the provincial governments, since rents to the federal government increase slightly on crude oil and remain more or less the same for natural gas. After 1985, flow rents to producers decrease while rents to the provincial governments increase relative to deregulation alone. However, the changes are not as large as in the pre-reform case, since the impact of the Royal Commission proposals on investment and land payments is smaller.

Changes in Flow Rents from Oil and Gas under COMMIS
(Level differences from DEREG in billions of 1971 dollars)

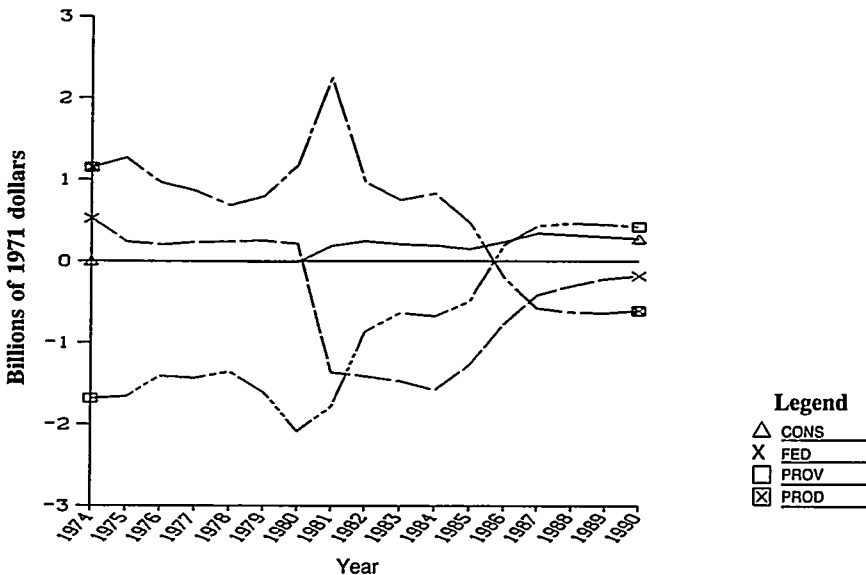
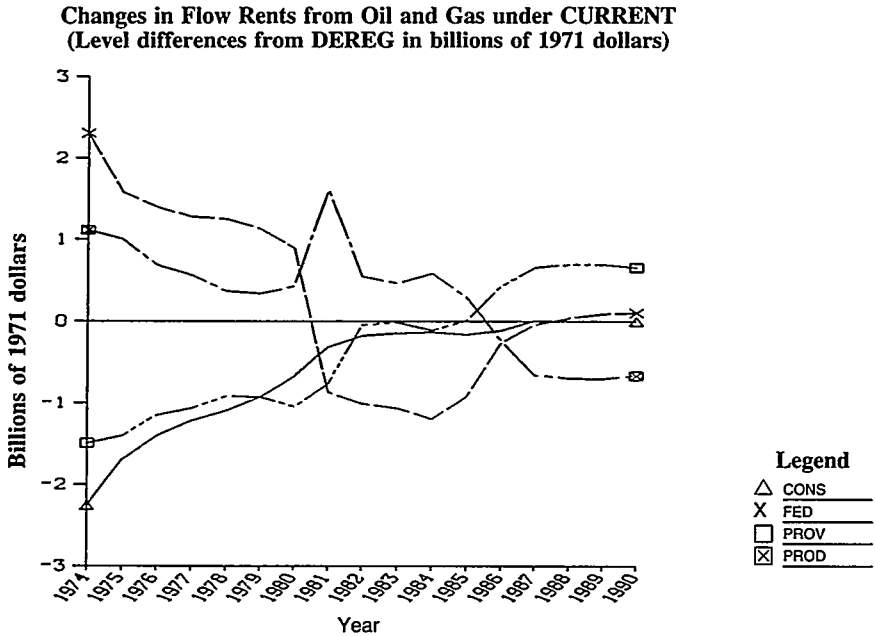


Figure 7



E. The Current System (CURRENT)

In many respects, the current taxation system is remarkably similar to the one proposed by the Royal Commission: No depletion allowance, earned or otherwise;⁶¹ land expenditures written off at 10 percent, non-tangible development expenditures at 30 percent, expenditures at 100 percent. The main differences between the current system and the preceding simulation are that, here, provincial royalties are somewhat higher⁶² and not deductible for the purposes of federal income tax. In place of royalty deductibility, there is a federal resource allowance equal to 25 percent of resource income. We have also included the increases in the federal excise tax that accompanied the implementation of the *Western Accord*.

⁶¹In the flow rent equations, land payments are written off as reserves are produced, and unit land costs are expressed as the unamortized stock of land payments per unit of current production. Since land payments increase proportionately more than production in the pre-reform case, the unamortized stock of land payments per unit of current production is much larger.

⁶²Note that exploration expenditures are still expensible.

If the current royalty and taxation system had been in effect in 1974, after-tax prices to producers would have been larger than under the deregulated system with the historical tax policies, but by somewhat less than under the Royal Commission proposals because of higher and non-deductible provincial royalties. Increases in after-tax costs would have been somewhat larger than under the Royal Commission proposals, because the resource allowance reduces the tax rate applicable to oil and gas income and therefore reduces the value of the tax write-offs. The increases in real energy-sector investment, therefore, are more moderate than in either of the previous two systems, as are the positive impacts on real GNP (see Table 2). As Figure 8 suggests, the current policies would have increased rents flowing to producers during the initial part of the simulation, mainly because of the lower royalty rates in effect. After 1985, royalty rates are roughly the same in this simulation and the deregulation case, but production levels are higher (particularly for oil) and result in an increase in provincial royalty revenues. This is sufficient to ensure that provincial rents increase slightly more after 1986 under the current system than under the Royal Commission proposals, even though the impact on investment and land payments is somewhat lower. Rents to the federal government would also have increased, because of the elimination of earned depletion and the earlier introduction of the excise tax on motive fuels, a move that substantially reduces consumer rents and also increases the inflation rate in the economy during the early period.

IX. TAXATION AND RISK-SHARING

The final issue that we shall address is the extent to which instability in the tax system contributed to instability in the operating environment for the industry. Table 3 shows the average rates of return for conventional crude oil, natural gas, and the two combined, over the 1974 to 1985 period and the 1974 to 1990 period, along with the standard deviations for each period. The historical pattern of prices and policies consistently gives the lowest average after-tax rate of return, while the pre-reform system gives the highest. The Royal Commission proposals and the current system tend to yield similar results.

One of the more interesting features of these results is that the stable taxation policies tend to provide the most variable rates of return for the industry. This is particularly true for the pre-reform system. Part of the increase in variability is due to the higher variability in returns when the full impact of the changes in world oil prices flows through to the producers. The pre-reform system, which had the lowest marginal tax rates and provided the largest pass-through of changes in world prices, gave the highest investment responses and the most variable rates of return. It also yielded the lowest rates of return in the period after 1983 (this is even more true of the post-1985 period) when world oil prices began to fall. The other systems, which slowed down the investment responses during the boom time of 1979-81, yield higher rates of return after the slump in 1986. The historical pattern of prices and taxes had the lowest level of investment, and therefore the highest rate of return following the price collapse in 1986.

Table 3
Average Rates of Return Under Alternative
Taxation and Pricing Systems

	HISTORY	DEREG	PREREF	COMMIS	CURRENT
OIL¹					
1974-85	11.8 (3.5)	15.7 (5.0)	21.8 (5.2)	18.3 (3.1)	17.9 (2.9)
1974-90	12.0 (3.0)	14.5 (4.5)	18.1 (7.3)	15.8 (4.7)	15.6 (4.4)
GAS					
1974-85	10.5 (2.9)	12.0 (4.1)	15.7 (9.1)	12.6 (4.7)	12.6 (4.6)
1974-90	9.5 (2.8)	10.3 (4.4)	12.1 (9.4)	10.4 (5.3)	10.3 (5.3)
OIL AND GAS²					
1974-85	11.7 (1.5)	13.4 (3.0)	17.8 (7.5)	14.8 (3.9)	14.8 (3.8)
1974-90	10.6 (2.2)	11.5 (3.9)	14.0 (8.7)	12.3 (5.2)	12.2 (5.2)

Note: Numbers in brackets are standard deviations.

¹ Excludes oil sands plants.

² Includes oil sands plants.

This result does not mean that a constantly changing tax policy provides the most certain environment for investment planning, but it does illustrate that investor uncertainties about future tax policies may in part offset the uncertainties caused by the variability of future prices for oil and gas. This will be so if the general pattern of the changes is to raise tax rates when prices are high and to lower them when prices are low. In our model, investors are assumed to respond directly to current after-tax prices and costs when making their current investment decisions. This is no doubt oversimplified, as wise investment planners are not likely to alter their plans as drastically as suggested by this in response to what may be temporary changes in prices and tax rates. However, it is probably true, as indicated by, among other things, the big cycles in the bid prices paid for drilling rights sold at auction, that the cycles of optimism and pessimism about net returns exaggerate the effects that current prices will in fact have on the present value of revenues from oil and gas wells with production lives extending thirty or more years into the future.⁶³

Changing tax policies impose another cost that is difficult to quantify: if tax policies are thought to be subject to change under political pressure, then it becomes rational for industries to invest substantial resources in political efforts designed to improve the position of their own industry or activity in relation to other industries and activities. From the point of view of the system as a whole, however, the political volatility of the tax system imposes a real cost — since the efforts of each taxpayer group to increase its own benefits require real resources — and offers the prospect of a tax system that has substantial non-neutralities that lower the efficiency with which the nation's resources are allocated among alternative industries and activities.

Our results do seem to show that the taxation system, as it evolved in response to changing external conditions, increasing the

⁶³The short horizon for expectations and, hence, the over-response to current policies, events, and market conditions, may be due in part to similar behaviour on the part of institutional investors. Evidence on the myopia of share-market expectations may be found in R.J. Shiller, "Do Stock Prices Move Too Much to be Justified by Subsequent Changes in Dividends?" (1981) 71 *Am. Econ. Rev.* 421; S. Nickell & S. Wadwani, *Myopia, the 'Dividend Puzzle' and Share Prices*, Discussion Paper 155 (London, Eng.: Centre for Economic Policy Research, 1987).

tax burden in the boom times and backing off when times got rough, served to dampen the investment swings that are perhaps the inevitable consequence of a highly volatile world market. There is also no doubt that without the collapse in world prices in 1986, the historical policies that retarded investment would not have looked nearly as attractive as they do today.

One of the secondary benefits of the equal tax treatment proposed by the Royal Commission was that if it were generally applied then it would affect the ground rules for political activity designed to change the tax system. In particular, if everyone recognized that such a tax system provided general advantages, and was generally acceptable to all, then political activity designed to introduce special provisions favouring a particular activity or industry would have less likelihood of success and would be less likely to be undertaken.

Our results, and the history of oil and gas taxation in Canada, show that there is another important element to this issue that comes to the fore when an industry operates in an environment of uncertain and highly variable prices. In these circumstances, a tax system, to be politically viable, must produce a distribution of revenues that is perceived to be fair, not just on average across a thirty-year horizon, but for a much shorter period. In Canada, as in most countries, the oil and gas taxation systems that were designed and applied in an environment of oil at less than u.s. \$3 per barrel were not sustainable with oil at u.s. \$30 per barrel, while the systems brought in with oil at u.s. \$30 per barrel generally required many changes when oil prices dropped to u.s. \$10 or u.s. \$15 per barrel.

In a federal structure of government with resource ownership in the hands of the provinces, it is probably more efficient if the federal tax structure is kept as nearly equal as possible between industries, with the political viability and return-stabilizing features of the tax and royalty system being designed and implemented by the provincial governments, in the case of resources located in lands under provincial jurisdiction. If the resulting inter-regional variations in tax and activity levels pose political and efficiency problems, as they have done almost continuously in the Canadian context, then the remedy is probably better found in more robust systems for general fiscal equalization, and not by industry-specific tax provisions. These issues lay largely beyond the concerns of the Royal Commis-

sion on Taxation in its studies twenty years ago, but they have been brought to the fore by the subsequent large and unpredicted changes in the prices of oil and gas and are likely to require attention in any future reforms of oil and gas taxation.