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INTRODUCTION

This essay is concerned with government policy as it impinges on the oil and gas resources of Alberta. By "policy" we refer to the framework of laws, regulations, fiscal devices, institutional arrangements and procedures that provide the environment within which Alberta's oil and gas industry discovers, develops, produces, transports and markets these important natural resources. Our interest is in the way that this whole complex of policy instruments and administrative procedures interact to influence the pace and pattern of oil and gas resource development in Alberta.

Our definition of "policy" is thus very broad, but it is typical of economists' usage of the word in describing public intervention in economic affairs, as exemplified in "tariff policy," "regional policy," and "fiscal policy," all of which refer to the total impact of government in particular areas. Accordingly, our approach is on the whole qualitative rather than quantitative. We do not attempt to measure the extent to which, say, the rate of production is affected by a certain regulation; instead, we try to indicate the general direction in which policy shapes the structure of the industry and affects the efficiency of resource development. Moreover, since some of these

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influences work in opposing directions, we cannot with certainty predict the general tendency of all policies taken together. Our work must therefore be regarded as a framework, open to revision and supplementation in the light of quantitative research into the tendencies regarded here as working hypotheses. So far, the unique circumstances of the oil and gas industry with respect to uncertainties, market patterns, and industrial structures have frustrated reliable quantitative analysis of many central questions, some of which we discuss below.

We confine our scope to "conventional" oil and gas resource management in Alberta. Our task would otherwise become unmanageable insofar as other energy sources on the frontier of development are subject to different regulations and raise quite separable problems, many of which are poorly understood. Our review of public policy affecting the development and use of these resources emphasizes the influence of Alberta's laws, regulations, and institutional arrangements rather than those of Canada, because we have found the complex implications of a multitude of relatively minor Alberta policies more in need of examination than the broader and more conspicuous federal taxation and regulatory instruments. Although we confine ourselves to stated law and regulations and to explicit procedures, we are aware that governments dealing with a concentrated industry can influence behavior also through what bankers call "moral suasion" and that conversely the industry can, by argument and threat, influence policy implementation. But we must leave to others the task of identifying and assessing such unstated policies and pressures.

Such an ambitious essay calls for some criteria to provide a basis for examining the consequences of policies. In language familiar to economists, we focus on the implications of policies for the *efficiency* of resource development and use and for the *distribution* of income and wealth that they bring about. Efficiency refers to the extent to which the net gains are maximized; distribution refers to the way in which the gains become distributed among producers, consumers, governments, and others. Thus a particular form of royalty, for example, may create business incentives to alter the rate of degree of its recovery of oil from a reservoir. This would be described as a less *efficient* outcome if the net gains to all parties were thereby reduced. Its *distributional* consequences would be observed in its effects on the various parties' respective incomes, especially the extent to which it diverts revenues from the producing firms to the government.

In principle, the criterion of efficiency offers an unambiguous basis for evaluation: whenever it is possible to increase the excess of values generated over the costs incurred, efficiency can be enhanced—regardless of who bears the benefits and costs or when they are realized (providing that they are all evaluated properly). The distribution criterion lacks this prescriptive clarity, however, because the superiority of one pattern of distribution of income and wealth, or of one amount of government revenue over another, does not emerge from objective economic analysis. We must therefore confine ourselves simply either to identifying the distributional (revenue) consequences of policies or to judging them only in the light of assumed distributional objectives.

A policy measure that enhances economic efficiency may, of course, have undesired distributional effects, or *vice versa*. Compromise among these effects, according to the weights placed on efficiency and distributional criteria, is the task of politicians. Indeed, there are obviously other criteria that politicians will sometimes use to appraise policies. For example, self-sufficiency in energy, regional employment and development, and strategic power in federal-provincial disputes have all influenced the design of energy policies in Alberta and Canada, and compromises have been sought among them. Nevertheless, our focus upon efficiency and distributional criteria seems to us to be both manageable and useful. The efficiency criterion is, in our view, central, not because it should be pursued ruthlessly, but because it provides the only means of evaluating measures aimed at distributional or other goals. Thus the benefits arising from these measures can at least be seen in the light of their efficiency costs—in the form of reduced benefits from the petroleum sector. Distributional effects warrant specific attention because they are obviously a primary purpose of much of the policy affecting the oil and gas industry.

The following two sections of this paper contain a very brief sketch of the institutional and economic environment of the oil and gas industry in Alberta. The next section describes the forms of rights and the procedures used in Alberta to alienate resources from the Crown to private parties for purposes of exploration and development. The subsequent section then evaluates this tenure structure from the points of view of efficiency and distribution. The paper then turns to the public regulation of oil and gas production, first with a description and then with an evaluation of the system of controls in use. The concluding section examines alternative arrangements in light of the shortcomings identified in current policies.

I. ALBERTA'S OIL AND GAS ECONOMY

After the Leduc discovery in 1947, Alberta became one of the major sources of oil and gas on the continent and the dominant producing area in Canada. In these three decades the oil and gas sector has risen to a correspondingly dominant position in the economy of Alberta.

Between 1970 and 1976 Alberta's oil production rose to the highest level in the province's history. It now accounts for about 80 percent of Canadian production of both oil and gas.[1] An extensive pipeline network carries these products to markets to the east, south, and west.[2] Thus although Alberta's production makes Canada statistically self-sufficient in oil and gas, differing patterns of foreign purchases and sales across the continent have resulted in the current exportation to the United States of nearly 50 percent of Alberta's oil and more than 33 percent of her gas. These export proportions have declined in the recent past and will continue to do so in the future. In recent years, consumption within the province has accounted for only 10 percent of the oil and 20 percent of the gas produced.

Most of the producing oil fields in the province yield natural gas as well. The remaining "proven" oil reserves of almost 6,000 mmbl in 1975 represent about 12 times the current annual rate of production, and the "proven" gas reserves of nearly 55 tcf, about 23 times current annual production.[3] In the last few years the rate of additions of new reserves has declined, as the most promising geological structures have evidently been more fully explored. Thus while Alberta's production is not likely to fall for at least a decade, the cost of finding new reserves, particularly of oil, is expected to rise

1. In 1975 Alberta produced 424.6 million barrels (mmbl.) of crude oil from conventional sources and 2.64 trillion cubic feet (tcf.) of natural gas. The corresponding figures for all provinces were 504.1 mmbl. and 3.16 tcf., [1975] STATISTICAL YEARBOOK (Can. Petroleum A., Calgary).

2. The main oil delivery systems are the Interprovincial Pipeline, which serves the other prairie provinces and Ontario, as well as the midwestern United States, and the Transmountain Pipeline, which leads westward to British Columbia and the northwestern United States. Gas is collected by the Alberta Gas Trunk Line Company for delivery to markets outside the Province in eastern Canada and eastern and midwestern United States by Trans-Canada Pipelines Limited, in California by the Alberta and Southern Gas Company Limited, and small amounts to British Columbia and the northwestern United States by Westcoast Transmission Company Limited.

3. ALBERTA DEPARTMENT MINES AND MINERALS ANNUAL REPORT 49 (1976). Proven reserves is a technical term which includes only those reserves which have been well defined through geological information. Potential or ultimate reserves are open to considerable speculation, but have recently been estimated at 440,000 mmbl. of crude oil (including tar sand products) and 100 tcf. of gas. ENERGY RESOURCES CONSERVATION BOARD, ALTA., RESERVES OF CRUDE OIL, GAS, NATURAL GAS LIQUIDS & SULPHUR, DECEMBER 1972, at 3-4 & 4-6 (1973).

and the province's dominance as Canada's supply source will decline, especially as the "frontier" reserves of natural gas in the Arctic and offshore regions are developed.[4]

The industry in Alberta is an extension of the international oil industry, which is dominated by a very few, very large integrated companies with operations in most countries having resources or significant markets. More than two hundred companies are active in exploration and production of oil and gas in the province, but only eight have fully-integrated Canadian operations, involving exploration, production, transportation, and marketing. The remainder are involved only in exploration and production and account for only a small fraction of total operations. The major shareholders of the eight large firms operating in Alberta are foreign, so that more than 60 percent of the equity interest in Canada's oil and gas producers and more than 90 percent of the entire industry are held by foreigners. Recently, firms wholly or partially government owned, such as Petro-Canada, Alberta Energy Company, Panarctic, and Syncrude Canada Ltd. have become visible members of the industry. The numerous smaller, nonintegrated companies show various ownership patterns ranging from wholly Canadian to wholly foreign. The oil and gas industry, which is conspicuously capital-intensive, has depended upon foreign capital to a greater extent than any other major industrial sector.

Rapid expansion of the oil and gas industry has had a profound impact on the economy of Alberta. The heavy capital spending on exploration, production, and pipeline equipment has stimulated the growth of complementary drilling, consulting, and supply industries. It has also heavily influenced regional patterns of development and urbanization within the province.

In addition, the industry has generated a major source of public revenue. In 1975 the province received $1,320.6 million (mostly in the form of royalties and other payments for resource rights), representing about 41 percent of all budgetary revenues, and more recent shifts in energy values and systems of public charges (discussed below) promise to increase these revenues to almost 50 percent. To this percentage, much higher than in other provinces, must be added

4. Output/reserve estimates have been produced by many agencies and applicants in the three years that this paper has been in preparation. A recent source is DEP'T ENERGY, MINES & RESOURCES, OIL & NATURAL GAS RESOURCES OF CANADA, 1976, Rep. EP 77/1 (1977). For our original calculations, *see* Helliwell, Pearse, Sanderson & Scott, *Where Does Canada's National Interest Lie?*, in THE MACKENZIE PIPELINE 197 (P. Pearse ed. 1974). For a technical discussion (and bibliography) of the prospects of further discoveries in Alberta, *see* Uhler, *Costs and Supply in Petroleum Exploration: The Case of Alberta*, 9 CAN. J. ECON. 72 (1976).

revenues from corporation income taxes and federal revenues from income and export taxes.[5]

II. GOVERNMENTAL JURISDICTION AND CONTROL

The Canadian constitution vests ownership of natural resources largely in the provinces, but legislative authority is divided: essential powers relating to the management and sale of oil and gas rest with Alberta, while the federal Parliament can exercise important controls over trade and commerce, interprovincial pipelines, and taxation.[6]

Apart from certain early alienations—notably to the Hudson's Bay Company and the Canadian Pacific Railway—both the federal and provincial governments have followed a policy of retaining public ownership of underground hydrocarbon resources while relying almost exclusively on the private sector for the conduct of exploration and production. Private freehold thus accounted for less than 12 percent of the total oil and gas acreage held in recent years (see Table 1), but its influence on government policy has been disproportion-

TABLE 1

Oil and Gas Tenures in Alberta, by Area
1971

Ownership	*Form of Tenure*[a]	*Acreage* *(Thousands)*	*(Per cent)*
Private	Freehold	11,204[b]	12.4
Crown–Federal	Permits	463	0.5
	Leases	706	0.8
Crown–Provincial	Reservations and permits	32,093	35.4
	Petroleum and natural gas leases	40,387	44.6
	Natural gas licenses	723	0.8
	Natural gas leases	5,025	5.5
Alberta Total		90,601	100.0

a. Excludes oil sand permits and leases, of which 4,329 acres were held under agreement with the province in 1971.
b. Of which 7,266 and 1,538 thousand acres were held by the CPR and HBC respectively.

Sources: Compiled by the authors from various sources, particularly ALBERTA DEPARTMENT OF MINES AND MINERALS, ANNUAL REPORT (for various years).

5. *See* the various estimates in NATURAL RESOURCE REVENUES: A TEST OF FE ERALISM 1-51 (A. Scott ed. 1976).

6. Crommelin, *Jurisdiction over Onshore Oil and Gas in Canada,* 10 U.B.C. L. REV. (1975).

ately strong. Some of the earliest discoveries in Alberta (including Leduc) were made where mineral rights were privately owned; in the southwest United States, where many of the regulatory measures adopted by Alberta originated, private ownership is much more prevalent. In any event, a better indication of the importance of the freehold sector is production, rather than acreage, as compiled in Table 2. Comparison shows that the relatively small freehold acreage (12 percent) is the source of a much larger fraction of oil and gas production (between 20 and 25 percent).

To reconcile the policy of retaining public title to natural resources with that of dependence on private enterprise for exploration and production, the province has devised a variety of tenure systems and regulatory devices, which are discussed below. The first step in public management of Crown resources is the allocation to private parties of exploration and production rights, which establishes the initial private interest and constrains future government action. These arrangements are governed by the Mines and Minerals Act and administered by the Department of Energy and Natural Resources. Regulation of the many aspects of oil and gas production is entrusted to the Energy Resources Conservation Board,[7] an agency financed roughly equally by a share of royalties and by subventions from the Alberta government. This important institution exercises the prov-

TABLE 2

Oil and Gas Tenures in Alberta, by Production
1976

Ownership	*Oil Production*		*Gas Production*	
	(Thousands of barrels per day)	*Per cent*	*(Billions of cubic feet per year)*	*Per cent*
Private and Crown–Federal[a]	209	20	526	25
Crown–Provincial	837	80	1,579	75
Alberta Total	1,046	100	2,105	100

a. Federal Crown lands, mostly Indian lands, are currently insignificant as producing areas.

Source: Private communications from Alberta Energy Resources Conservation Board.

7. This board was first established in 1938 as the Petroleum and Natural Gas Conservation Board, later renamed the Oil and Gas Conservation Board. In 1971 it was given its present name and its powers were extended to deal with coal, hydro and electric energy as well as oil and gas. Energy Resources Conservation Act, ALTA. STAT. 1971, ch. 30.

ince's extensive controls over drilling, extraction rates, prorationing of production and other activity under the Oil and Gas Conservation Act, and its authority extends over freehold as well as Crown revenues.

Although this paper is primarily concerned with provincial policy, federal policies and institutional arrangements relating to oil and gas also have an important impact on the development of resources in Alberta. Federal influence is exerted primarily through powers to tax and to regulate trade. By special provisions for the oil and gas industry in the federal income and corporation taxes the federal government has created incentives that have substantially stimulated exploration and development activity. Federal responsibilities for the regulation of interprovincial trade and commerce, as well as for external trade, mean that the federal government may control the marketing of all Alberta's oil and gas production not consumed within the province itself.

Statutory power to exercise federal jurisdiction on a broad range of energy issues has been given to the National Energy Board, established in 1959. In practice the Board, until the mid-1970's, confined itself to four main functions connected with oil and gas: licensing imports and exports of energy, regulating pipelines, managing the "national oil policy," and providing information and advice. Today's nine-man Board exercises broad advisory and research activities, ranging from estimating domestic demand and supplies of energy to surveillance of pipeline operations and tariffs. Following the 1958 and 1959 Borden Reports, and until the 1973 crisis in international oil supplies, the "national oil policy" was designed to promote production in Alberta by excluding foreign oil from that part of the Canadian market lying west of the Ottawa Valley, thus restricting lower-cost oil from Venezuela and the Middle East to the markets of Montreal and the Maritime Provinces. The international oil companies operating in Alberta, in return for this market protection, arranged access for western Canadian crude to the Detroit and midwestern markets of the United States. Escalation of foreign oil prices in the mid-1970's has eliminated the former price advantage of offshore imports, and this, coupled with apprehensions about the reliability of foreign supplies, led the federal government to extend the oil pipeline network to carry western crude to Montreal. Thus, since 1973, the national oil policy appears to have shifted somewhat from a concern for Alberta as a producing region to a concern for eastern consumers.

Before turning to the regulation of exploration and development of oil and gas—the main focus of this essay—three other areas of mixed federal and provincial control require brief explanation because of their important impact on resource development and use, i.e., transportation regulation, export control, pricing, and taxation.

Regulation of Transport

Both construction and operation of oil and gas pipelines are closely regulated. The National Energy Board must approve the construction of all pipelines that extend beyond the province, the tolls on oil lines, the prices charged by gas transmission (pipeline) utilities, and the export licenses for gas and oil. The granting and withholding of such approvals is the means by which some of the most critical oil and gas policy decisions are made.

Pipelines that do not extend beyond the province (excepting those that are entirely within the owner's property) are regulated by Alberta's Energy Resources Conservation Board under authority of the Pipe Line Act. The Board requires prospective constructors of such pipelines to obtain a permit that may be issued on whatever terms and conditions the Board sees fit. For the operation of a line the owner must obtain a license issued by the Superintendent of Pipelines.

The treatment and operation of oil pipelines differ importantly from those of gas lines. Oil pipelines are usually only carriers, charging a fee for transporting oil owned by others to refineries. The Energy Resources Conservation Board has the power to prevent a pipeline company from discriminating among producers by declaring it to be a common carrier,[8] but this power is rarely used because the prorationing of field production (see below) has effectively precluded discrimination on the basis of volume carried, and there have apparently been few attempts to do so. Applications for permits to construct oil lines are considered in light of the applicant's financial and technical capabilities, and competition among pipelines has been looked on favorably as a means of preventing excessive charges.[9] In contrast to gas lines, oil pipelines also compete, especially when volumes are low, with alternative forms of transport such as rail, trucks, and tankers.

The circumstances of gas pipelines differ between those that carry gas beyond Alberta and those that deliver gas for consumption within the province. Gas used within the province has so far been purchased from producers by gas utility companies who own and

8. Oil and Gas Conservation Act, ALTA. REV. STAT. 1970, ch. 267, § § 49, 56.

9. Olisa, *Government Control of Oil and Gas Pipelines in Alberta*, 5 ALTA. L. REV. 226 (1967).

operate their own transmission systems. Gas exported from the province is collected by Alberta Gas Trunk Line Company Ltd. and carried to various border points where it passes into the transmission systems of other companies. This company, incorporated in 1954 by special Act of the Alberta legislature, has an effective monopoly on removal of gas from the province, thus not only preventing any duplication of facilities but also reducing the area within which federal influence may be exerted.[10] It operates as a carrier only and has power to fix charges for transportation and other services performed; in practice, the company bases its charges on cost of service.[11] As in the case of oil lines, the Energy Resources Conservation Board has power to impose common carrier, common purchaser, and common processor orders on gas pipelines; in the few cases where this power has been exercised the main concern has been to ensure equitable treatment of competing producers on a common pool.[12]

Export Controls

Exports of oil and gas from Alberta are closely controlled by the Energy Resources Conservation Board, while exports from Canada are regulated also by the National Energy Board. Generally, these controls are aimed at ensuring adequate future supplies (for Alberta and Canada, respectively), appropriate pricing, and orderly resource development.

Until the early 1970's, the National Energy Board's responsibilities for oil and gas had been limited: it regulated gas exports and imports, and it controlled oil trade to the extent necessary to promote oil exports to the U.S. under the national oil policy. These powers and responsibilities have now been broadened. Today, either as regulator or as advisor to the federal government, the Board finds itself in charge both of interprovincial and international trade, both in oil and in gas.

The interprovincial powers are derived chiefly from its interprovincial pipeline regulatory responsibilities. International trade powers have been obtained by the extension of its previous gas-

10. Alberta Gas Trunk Line Company Act, ALTA. STAT. 1954, ch. 37 (as amended). Four of the fifteen directors of the company are appointed by the Lieutenant-Governor in Council and all must be Canadian citizens resident in Alberta. The monopoly is maintained by a condition in all permits for removal of gas outside the province to the effect that the permittee will use only the facilities of this company.

11. The company's charges may be reviewed by the Public Utilities Board upon application by an interested party or upon direction by the Lieutenant-Governor in Council. *Id.* § 30. The cost of service includes operating expenses, depreciation, income and other taxes and a rate of return on its depreciated capital in plant and working capital. ALBERTA GAS TRUNK LINE COMPANY LTD. ANNUAL REPORT 12 (1973).

12. Hebb, *Common Carrier, Common Purchase, and Common Processor Orders*, 7 ALTA. L. REV. 436 (1969).

export licensing activities to oil. This power, at the time of writing, is exercised directly by the federal cabinet, depending on recommendations and studies by the National Energy Board.

In order to remove gas from Alberta, producers are required to obtain a permit issued by the Energy Resources Conservation Board, subject to the approval of the Lieutenant-Governor in Council.[13] The Board usually conducts a hearing on an application for a permit and is concerned primarily with whether the permit would be in Alberta's public interests in light of the gas reserves in the province and those reserves' rate of growth. A permit may contain a wide variety of stipulations, specifying such conditions as the sources of the gas, the amounts and rates of removal from each source, the conditions under which removal may be interrupted and supplies diverted to provincial consumers, and the duration of the permit. In considering applications for permits the Board attempts to determine whether there are reserves in excess of the requirements of the province over the forthcoming 30 years. To do this, it estimates the present proved reserves and the trend in their growth and compares this with estimates of the province's requirements for 30 years plus the quantity already authorized for export under permits.[14] The

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13. This authority is provided to the Board by the Gas Resources Preservation Act, ALTA. REV. STAT. 1970, ch. 157 (as amended). By amendment in 1973 (ALTA. STAT. 1973, ch. 90) the application of the act was restricted to production from Crown leases, licenses or reservations. *Id.* § 2.1.

14. *See* OIL AND GAS CONSERVATION BOARD, ALTA., REPORT AND DECISION ON REVIEW OF POLICIES AND PROCEDURES FOR CONSIDERING APPLICATIONS UNDER THE GAS RESOURCES PRESERVATION ACT, Rep. 69-D (1969). The projected growth in reserves will not exceed the average rate over the previous ten years, and may be below that rate where a decline is apparent. The number of years over which growth is expected to continue is calculated with reference to the relation between ultimate and proved reserves. Provincial requirements are estimated following periodic public hearings on Alberta energy resources. *See, e.g.*, ENERGY RESOURCES CONSERVATION BOARD, ALTA., INTERIM REPORT ON ALBERTA'S REQUIREMENTS OF ENERGY AND ENERGY RESOURCES, Rep. 73-0 (1973) and app. thereto (Rep. 74-F, 1974).

Applicants for new permits are required to demonstrate both a "contractable surplus" and a "remaining surplus"—the former being an excess in the reserves available for delivery now or in the near future over the requirements to fulfill contracts within Alberta and approved exports; the latter being the quantity expected to be available in the future in excess of the projected needs of Alberta beyond existing contracts and within the thirty-year period.

Contractable requirements are the amounts needed to fulfill normal contracts with utilities and industries in Alberta and permitted export commitments; and contractable reserves are those available for delivery now or in the near future which are under contract or available for contract. Remaining requirements are the projected local needs during the later years of the thirty-year period plus the amounts needed to meet peak demands in the terminal year. Remaining and future reserves include those currently beyond economic reach, those where production has been deferred but can be expected within thirty years and those not yet discovered or developed but which the Board expects to be developed soon. The existence of a surplus is determined by comparing the reserves and requirements for each category. OIL AND GAS CONSERVATION BOARD, *supra*, at 2-3.

duration of permits usually matches the terms of the gas purchase contracts, up to a maximum of 25 years.

Pricing and Taxation

Interventions by the governments of both Alberta and Canada have for many years caused the prices of oil and gas produced in the province to diverge significantly from those that would have emerged under unimpeded market supply and demand and free trade. Regulation of the markets for Alberta's oil and gas outside the province and of exports to the United States, as well as U.S. price controls and regulation of imports, have profoundly affected the demand for the province's resources.

Similarly, the long history of special provisions in the federal taxation of oil and gas has made it impossible to dissociate Alberta's resource revenues from the changing structure of the federal corporate income tax. This is because the amounts bid for exploration and production rights in Alberta are essentially an estimate of the residual left to producers after expected federal taxes.

In the wake of the international oil crisis of 1973, the governments of both Canada and Alberta introduced radically new policies of price control and taxation that have strained relations between them and between Canada and the United States, and these policies have continued to evolve. Generally, Alberta has sought to take advantage of the escalation of world oil prices for resources removed from the province, while at the same time maintaining lower prices for provincial consumers, particularly of natural gas. The federal government, for its part, initially attempted to insulate Canada as a whole from the sharp rise in international prices and, at the same time, obtain a share in the increased value of resources exported. Since early 1975, Ottawa also appears to have added a further objective: price stability at a high level.[15]

Traditionally, the wellhead price of Alberta oil has been approximately equal to its price delivered to the major market area served also by competing sources, less the cost of transport to that market.[16] Until 1959, Sarnia, Ontario, was the market in which the prices of competing supplies were equalized, but the basing-point subsequently shifted south. After 1970, wellhead prices in Alberta,

15. For an official statement on the stability-level mix, *see* the policy statement, DEP'T ENERGY, MINES AND RESOURCES, AN ENERGY STRATEGY FOR CANADA: POLICIES FOR SELF-RELIANCE 147-48 (1974).

16. This basing-point system of pricing has been strengthened by the regulation of supply within Alberta through prorationing, because competition among alternative sources of supply within the province is thereby eliminated.

which had been quite stable for many years, began to increase as a result of strained U.S. supplies and the loosening of import quota restrictions.

By 1973 prices in Chicago, which had become the basing-point, rose sharply in response to the Middle East conflict. In September of that year, to insulate Canadian consumers from the escalation in international oil prices, the federal government imposed a "voluntary" freeze on wellhead oil prices in Canada, supported by an export tax on oil sold to the United States approximately equal to the difference between the U.S. price and the frozen price in Canada.[17] This export tax, initially set at $.40 per barrel, had, within 6 months, been stepped up to $6.40 as U.S. prices continued to rise. At this level, its revenues were earmarked both to subsidize consumers (in Quebec and the Atlantic provinces) of oil imported from Venezuela, Africa, and the Middle East and to establish "endowment funds" in the producing provinces.

The government of Alberta strenuously opposed both the export tax and the domestic price freeze. New arrangements have since been negotiated at a series of federal-provincial First Ministers conferences. These negotiations, responding to U.S. price fluctuations, have produced agreed increases in the wellhead price of oil with corresponding reductions in the export tax. The yield of the tax, which for a time was shared with the oil producing provinces, is now retained by the federal government but is not directly earmarked for, or linked to, to the subsidy on Eastern provinces' oil consumption.

Gas pricing policies have also undergone rapid revision in recent years. Alberta gas typically has been purchased by local or regional utilities under contracts with terms of twenty to twenty-five years and with base (or initial) prices subject to periodic "escalation" as costs change and pipelines are amortized. Many contracts also provide for renegotiation of price arrangements at specified times during their term, and some require the purchaser to meet any higher prices offered in a particular market.[18]

Competition among purchasers has not been a durable feature of gas marketing in Alberta, and the brief occurrences of competitive buying have been accompanied by sharp increases in prices that have

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17. The domestic price freeze was a voluntary agreement between producers and the federal government. The legislation imposing the tax was not passed by Parliament until January 1974, and was then made retroactive to October 1, 1973. Oil Export Tax Act, ALTA. STAT. 1974, ch. 52. Subsequent actions have been taken under the Petroleum Administration Act, ALTA. STAT. 1974-75, ch. 47.

18. ENERGY RESOURCES CONSERVATION BOARD, ALTA., FIELD PRICING OF GAS IN ALBERTA (1972).

otherwise been stable for long periods. Utilities within the province buy gas in the field, but they also acquire their own reserves from which they meet much of their requirements. Trans-Canada Pipelines Limited was the only purchaser of gas for removal from the province from 1955 to 1957 when Alberta and Southern Gas Co. Ltd. began contracting. But Alberta and Southern concentrated its purchases in the foothills and Trans-Canada in the plains region, so that the two companies rarely competed directly in the same field. This stability was upset in 1970 by the entry of Consolidated Natural Gas, seeking contracts for gas exports to the United States. However, the refusal of the National Energy Board to grant the necessary export permits (despite the willingness of the Energy Resources Conservation Board to allow removal of the gas from the province) terminated this intervention, leaving Trans-Canada alone as buyer. In 1972 another new competitor, Pan-Alberta Gas Ltd., began to purchase gas for export to the United States and quickly secured contracts for substantial volumes of supply by offering double the price being paid by traditional purchasers. Again the export proposal did not come to fruition, and Pan-Alberta now sells mainly in the Quebec market. Interestingly, the ownership of Pan-Alberta is shared by the Alberta Gas Trunk Line Company Limited and the new Alberta Energy Company, of which half the shares are owned by the provincial government.

After a thorough review of field pricing of gas in 1972, the Energy Resources Conservation Board found that the degree of competition was the most important determinant of price and that prevailing prices were well below "commodity value," i.e., the value of equivalent energy in competing forms (such as oil) in the markets served. Following the Board's recommendations, the provincial government took steps to secure higher prices for gas leaving the province, through amendments to the Arbitration Act, which governs the redetermination of gas prices paid to producers by pipelines. These prices are to be redetermined every two years with reference to commodity value, and escalation provisions have been strengthened.[19] Most contracts have since been renegotiated and prices substantially increased. More recently, prices have been fixed by agreement between the federal and provincial governments.[20]

19. Arbitration Amendment Act, ALTA. STAT. 1973, ch. 88.

20. Natural Gas Pricing Agreement Act, ALTA. STAT. 1975, 2d Sess., ch. 38. The Alberta government has also provided for direct price regulation by the provincial Minister for Energy and Natural Resources in Natural Gas Price Administration Act, ALTA. STAT. 1975, 2d Sess., ch. 70, but this "reserve power" has not been used while federal-provincial agreements have continued in force.

While the provincial government vigorously pursues a policy of maximum prices for gas removed from Alberta (presumably with an eye to royalty and tax revenues), it endeavors, at the same time, to maintain a lower price for consumers within the province (somewhat paralleling the federal government's effort to keep oil prices low for Eastern Canadians while taking revenue advantage of high export prices). Alberta's two-price system is implemented through rebates paid to vendors of gas for consumption within Alberta.[21] In addition, the Public Utilities Board has been empowered to fix the price of gas used or consumed in the province; this power has been exercised in the cases of propane and ethane.

Recent Institutional Innovations

A variety of new institutional arrangements have been devised by the federal and provincial governments in response to the rapid changes in the energy economy during the last couple of years. Both Alberta and Canada established Crown corporations—Alberta Energy Company and the Petroleum Corporation of Canada (Petro-Canada) respectively. However, the former is no longer a Crown corporation, and the latter does not have large conventional oil and gas operations in Alberta.

In addition, Alberta created in 1973 the Alberta Petroleum Marketing Commission with broad powers not only to intervene in the pricing and marketing of all oil produced from Crown leases in the province but also to accept and market the Crown royalty share of oil production.[22] This institution may have been destined for some reserve role in federal-provincial political and legal skirmishes over oil pricing in the event all Alberta oil is sold at prices agreed upon at federal-provincial conferences.

Alberta's control over gas pricing has also been compromised. The Natural Gas Price Administration Act, the Gas Resources Preservation Act and the untested powers of the Alberta Energy Company

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21. Natural Gas Rebates Act, ALTA. STAT. 1974, ch. 44. In certain circumstances rebates may be paid instead to purchasers or consumers. For a detailed description of these arrangements, which appeared after this paper was written, *see* Saville, *The New Regime in Natural Gas Pricing in Alberta,* 15 ALTA. L. REV. (Petroleum Law Supplement) 538 (1977).

22. Petroleum Marketing Act, ALTA. STAT. 1973, ch. 96. The Commission is a Crown Corporation consisting of three members appointed by the Lieutenant-Governor in Council. The Act provides also that the Lieutenant-Governor in Council may establish a plan for marketing all oil produced in Alberta, but these provisions have not been proclaimed. *Id.* § 24. There is some doubt about the constitutional validity of this legislation insofar as it purports to give the Commission powers over the price of oil destined for markets in other provinces and other countries. *See* Crommelin, *supra* note 6, pt. 1.

would appear to provide institutional means by which Alberta could set gas prices or withdraw exports. However, the federal government's direct setting of the export price and the federal-provincial agreement regarding the price of gas at the Toronto basing point leave Alberta with clear jurisdiction only over prices of gas consumed in Alberta. The wellhead price of gas therefore depends on where each well's gas will be consumed; in practice, much gas is priced at a weighted average of these three prices (less pipeline charges).

III. ALLOCATION OF RESOURCE RIGHTS

At the heart of the management system for public oil and gas resources in Alberta lies a mechanism for allocating private exploration and production rights. This mechanism was substantially modified as of July 1, 1976.[23] However, the provincial government has maintained its policy of avoiding direct involvement in resource development and of allowing private operators to acquire exploration and production rights over public resources in exchange for, initially, a commitment to carry out exploratory work, and later, a government share in the proceeds from discoveries. Curiously, perhaps, the efficacy of this basic approach to resource management has never been seriously questioned.

Preliminary Exploration

Very preliminary or "geophysical" exploration is controlled by a system of licensing administered by the Director of Minerals. These licenses convey a non-exclusive right to explore on almost all lands in the province including those subject to existing leases.[24] Anyone may apply for a license, which is renewable annually upon payment of the prescribed fee. Only relatively superficial exploration takes place under those licenses (which do not authorize the drilling of deep test wells), but they have important implications for the pattern of more intensive development.

Indeed, such exploratory work usually provides the basis for the licensee's selection of areas over which he applies for exclusive rights to drill exploratory wells and to apply for production leases. It is significant that, although the licensee is obliged to file reports on his exploratory operations, showing the location of all surveys, he need

23. ALTA. STAT. 1976 2nd Sess., ch. 33.

24. All operations are subject to the Geophysical Regulations, Alta. Reg. 26/59 (as amended). For operations on private land the consent of the owner or occupier is required. Permitted activities include seismic, gravimetric, magnetic, and geochemical operations, and other methods of investigating the subsurface.

not disclose the raw data derived from geophysical surveys.[25] These arrangements for preliminary exploration were not altered by the policy changes made in 1976.

Drilling and Production Arrangements Until 1976

Most exploration in the province has been carried out under exclusive rights linked to the ultimate acquisition of rights to production. The policy changes in 1976 have simplified considerably the allocation mechanism. However, it is necessary to review the complex mechanism that existed for 14 years prior to June 30, 1976, both for illustrative purposes and for the practical reason that all types of exploratory and production agreements made under the former system will be permitted to run their full terms. The influence of the old arrangements will therefore continue to be felt for some years. The following paragraphs review the full system as it existed until mid-1976; the modifications then introduced are noted later.

Exploration (drilling) rights. The traditional authorization to drill wells, and the first stage in obtaining resource rights, was the *petroleum and natural gas reservation* issued by the Director of Minerals over unexplored areas.[26] Each reservation required a fee of $250 and could not exceed 156 square miles, although there were no restrictions on the number held by an operator. Priorities among applicants for an area that had never been subject to a reservation, permit, or license were based upon the date of the application, but this method of allocation had been of little significance in recent years because there were few such areas left in the province.

A reservation could be kept in force beyond the initial four months up to a maximum of six and one-half years by conducting an exploration program approved by the Minister and by payment of the required fees (hence some issued prior to mid-1976 are still in force).[27] Upon termination of a reservation the holder is obliged to

25. Licensees must annually submit to the Board copies of all logs and surveys taken, but not seismic reflection data. The Director of Minerals also requires monthly reports on the location of surveys (but not the results). Mines and Minerals Act, ALTA. REV. STAT. 1970 (as amended) § 193.

26. Petroleum and Natural Gas Reservation Regulations, 1962, Alta. Reg. 251/62 (as amended).

27. The initial term of a reservation is four months with two renewals of four months each. There may be four further renewals of six months each upon satisfactory progress being made with exploration and upon payment of a fee of 10 cents per acre for each renewal. Under certain conditions that retard the progress of the exploration program, the Minister may grant further extensions of up to two years upon such conditions as he sees fit. Thereafter, where a well has been or is being drilled on lands in a reservation or group of reservations, six renewals of three months each may be obtained upon payment of fees that range from 10 cents per acre for the first renewal to 25 cents per acre for any renewal beyond the third.

file a report on his activities with the Minister, but, again, there is no requirement that geophysical data be disclosed.

Reservations convey exclusive rights to drill wells on the reserved lands together with the right to produce such oil and gas as may be found, but the oil and gas remain the property of the Crown. Entitlement to these resources is acquired only upon the granting of a lease.

Production rights and charges. The holder of the reservation has an exclusive right to apply for *petroleum and natural gas leases* over some, but not all, of the acreage of the lands contained in the reservation, and the Minister has normally granted these leases as long as the applicant fulfilled his obligations under the reservation. Holders of reservations may apply for leases whether they have made a discovery or not, but if a commercial discovery is made, the operator must apply for at least one lease over the lands containing the discovery well.

Restrictions on the size and selection of leases are crucially important in determining the final pattern of rights over reservoirs. The reservation holder can not apply for leases over more than 50 percent of the area in any township (36 square miles) included in the reservation. A lease cannot exceed eight or nine square miles[28] or be less than a quarter-section. They cannot be adjacent, so they typically form a checkerboard pattern or are separated by a corridor at least one mile wide. The portions of a reservation not selected by the reservation-holder for lease are surrendered and become *Crown reserves.*

A lease conveys the right to produce and sell the Crown's petroleum and natural gas in the lease area. The terms upon which a lease is obtained indicate a clear intention on the part of the Crown to retain the right to alter unilaterally the terms and conditions of the arrangement, so that there remains considerable flexibility in the financial and other conditions governing oil and gas production.[29]

Leases carry terms of 10 years. They impose no exploration or development requirements, but there are incentives to carry out such work, including provisions that a lease may be renewed beyond the initial term only over the area within the spacing units of producing wells and that drilling may be required after five years.[30]

28. The maximum size of a lease is nine sections if it is square or eight if rectangular (in which case the length may not exceed four miles).

29. For further details, *see* Thompson, *Sovereignty and Natural Resources: A Study of Canadian Petroleum Legislation,* 1 VAL. L. REV. 284 (1967), *reprinted in* 4 U.B.C. L. REV. 161 (1970).

30. Spacing units are described below. After the fifth year of granting a lease upon which there is no producing well the Minister may require the lessee to begin drilling within one year, failing which the lease may be cancelled. This discretion has never been exercised with

Payments to the Crown required under leases take the form of rentals and royalties set by legislation or order. The annual rental is $1 per acre, subject to certain adjustments downward. Royalty rates for both oil and gas were revised upward in 1974 in response to significant increases in wellhead prices.

The former rates for oil varied according to the rate of production from each well and averaged about 23 percent of the wellhead price per barrel. The revised schedule distinguishes between "old" and "new" oil according to the date (whether before or after March 31, 1974) of discovery of the pool or increase in reserves realized through enhanced recovery methods. The present complex rate formula has the effect of adding to the old schedule a supplementary royalty calculated upon the difference between the current price of crude oil and the price that was obtained before the dramatic increases in world prices in 1974 and thereafter.[31] For "old" oil this supplementary royalty approaches 80 percent of the original rate (making total royalty about 42 percent on average of wellhead price) while for "new" oil the supplementary royalty increases the previous rate by only 30 percent.

The revised gas royalties similarly distinguish between "old" and "new" reserves (established before and after January 1, 1974, respectively) and are calculated on a sliding scale that is based on selling price rather than production rate. The rate for "old" gas ranges from 22 percent when the wellhead price is 26 cents per thousand cubic feet or less to 42.7 percent at a price of $1.20. For "new" gas (discovered after December 31, 1973) the corresponding rates are 22 and 31.7 percent.[32]

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respect to individual leases. However, in the case of leases granted before 1962, which had an initial term of twenty-one years, drilling notices have been issued automatically to take effect at the end of the tenth year.

31. The present royalty formula is

$$R=S+kS\,\frac{(A-B)}{A}$$

where R=royalty payable, in barrels.

S=the number of barrels determined in accordance with the previous formula.

k=the royalty factor (presently 1,6096 for "old" oil, 0.596 for new oil).

A=the par price of crude oil for the month (presently $9.36).

B=the select price for crude oil for the month (presently $4.71).

The previous formula related royalty to monthly production (MP) as follows:

MP (barrels)	Royalty (barrels)
0-1200	$\left(\frac{MP}{120}+5\right)\frac{MP}{100}$
1200 plus	$180 + \frac{1}{4}(MP-1200)$

32. Natural Gas Royalty Regulations, Alta. Reg. 16/74 (as amended).

Special arrangements for "Block A." Over a large part of the province designated as Block A, the two-stage system of reservations and leases has not been used; instead, more generous arrangements were designed to stimulate waning interest in exploration. Here, operators first obtained a *permit,*[33] over an area of up to 36 square miles, which is more attractive than the reservation in two main respects. First, the fee paid by a permit holder is refunded in part when drilling begins.[34] Second, and more important, if the holder of a permit has drilled a well, he may apply for a lease of the oil and gas rights over all the permit lands without surrendering any as Crown reserves.

Special provisions for gas. Where a discovery of gas (as distinct from oil or a mixture of oil and gas) is made in a reservation or permit area, the operator may apply for a *natural gas license,* which conveys the right to drill gas wells into specified formations and to produce gas from them.[35] A licensee has the exclusive right to apply for leases in the license area, and the terms of these *natural gas leases* are less onerous than those of petroleum and natural gas leases.[36] Their maximum area varies with the depth of the productive formation and in some cases covers the entire field. Their terms are 21 years, renewable for further periods of the same duration as long as the area is capable of production.

If oil is discovered in any area covered by a natural gas license or lease, the holder is entitled to acquire a petroleum and natural gas lease covering the quarter-section in which the discovery was made, providing he surrenders an area three times that of the lease acquired.[37] Table 1 indicates that the holdings of natural gas leases are small relative to petroleum and natural gas leases.

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33. Petroleum and Natural Gas Permit Regulations, Alta. Reg. 250/62.

34. All permits carry a term of six months and the renewal provisions may vary slightly from those applicable to reservations. Permits may be renewed for three terms and two further extensions are allowed if drilling is in progress. The rental for each six-month period is 50 cents per acre and refunds of 30 cents, 20 cents or 10 cents per acre are made depending on whether the well is commenced during the first, second or third period, respectively.

35. Natural Gas License Regulations, 1962, Alta. Reg. 297/62 (as amended). The maximum area of a license is thirty square miles. These licenses carry terms of six months with provision for five six-month extensions upon payment of a fee of 5 cents per acre for each period.

36. The Minister may grant a natural gas lease only in specified circumstances, *i.e.*, if the natural gas is required in the operation of a natural gas utility, or if the area is required to complete the spacing units for a productive natural gas well, or if the area is required for a unit operation. Mines and Minerals Act, ALTA. REV. STAT. 1970 § 156.

37. The Mines and Minerals Act Upset § 156.

This system of natural gas licenses was designed to encourage development of gas reserves that would not take place under other tenure arrangements. It was introduced at a time when gas prices were extremely low and many discoveries were non-commercial.

Disposition of Crown reserves. Crown reserves—those areas that had been subject to reservation, permit, license, or lease but have since reverted to the Crown—were available for disposition on conditions prescribed by the Lieutenant-Governor in Council. Although the method used varied, depending upon the history of the acreage, it usually involved sale by "bonus" bids. Where oil had been discovered on a reservation area, the Department usually offered the Crown reserves for sale as *petroleum and natural gas leases.* In other cases different forms of tenure were offered. Where gas was discovered the offer was typically made in the form of *Crown reserve natural gas licenses,* which carried terms and conditions identical to ordinary *natural gas licenses.*[38] Where a reservation holder had "gone to lease" without having drilled a well, the Crown reserves were generally offered under a special form of title known as a *Crown reserve drilling reservation.* This special tenure required the holder to drill one or more wells following which he could apply for a lease for (usually) up to one-quarter of the area.[39] Finally, where a reservation holder had gone to lease, having drilled unsuccessfully, the Crown reserves were offered as *petroleum and natural gas reservations.* This last procedure has rarely been used.

Crown reserves were usually offered for sale in response to a request, although the Department sometimes initiated sales where there was a drainage of oil and gas from producing wells on adjoining areas. Typically, the original holder of the reservation requested the sale of the Crown reserves within a year after he had selected leases and surrendered the remaining reservation area, because within this period the information he had obtained from drilling remained confidential, giving him some advantage over competitors.

Sales of crown reserves were by sealed bids, following advertisement. The bids were in the form of a cash bonus payable in addition to the same schedule of rentals and royalties as apply elsewhere. There was considerable flexibility allowed in the design of bids, and sometimes "sliding" bids that rank the choices of the bidder for alternative groups of parcels were submitted. In practice, bids of less than $10 per acre were not accepted for a petroleum and natural gas

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38. Crown Reserve Natural Gas Regulations, 1962, Alta. Reg. 308/62.
39. Crown Reserve Natural Gas License Regulations, 1962, Alta. Reg. 284/62.

lease, and the Lieutenant Governor in Council could reject any bid at his discretion. The Department attempted to assess the acceptability of bids in light of the apparent competition among bidders and any available geological information, such as data about wells on nearby lands collected by the Energy Resources Conservation Board. But in areas where there had been little drilling the Department had scant basis for evaluating bids because the results of seismic surveys conducted by private operators were not disclosed to the Board.

New Tenure Arrangements Since 1976

The changes in tenure policy introduced in mid-1976 ended further issues of the several forms of exploration rights described above and substituted a single form of exploratory agreement—the *petroleum and natural gas license.*[40] This new tenure is to be used to convey all new rights to undertake exploratory drilling, in this role replacing petroleum and natural gas reservations, permits, drilling reservations, and the various natural gas licenses in the former system. The new licenses are obtained through sealed "bonus" bidding procedures like those described above,[41] usually in response to an operator's request that certain acreages be "posted" for sale. However, the Minister retains an important discretion to decline to post an area for sale, and thereby determine the rate at which licenses are made available to the industry.[42] Future sales are expected to be mainly from Crown reserves from older reservations and permits.

The holder of a petroleum and natural gas license not only obtains the right to drill wells for petroleum and natural gas and to produce the oil and gas discovered, but also "earns" the right to obtain a production lease, without which the operator has no right to the oil and gas he may produce. The term of the new license (during which drilling must take place) depends on which of three new areas it is located in: two years in the "plains" area, four in the "northern" area, and five in the "foothills" area. The differences between these terms presumably reflect interregional differences in drilling and exploration costs. The maximum area obtainable under a license

40., Mines and Minerals Act, ALTA. REV. STAT. 1970 ch. 238, § 125 (amended 1976), Petroleum and Natural Gas License Regulations, Alta. Reg. 169/76.

41. The Act and Regulations do not require sealed bonus bidding, merely "sale by public tender." Thus the opportunity exists for experimentation with bidding mechanisms, although in the past there has been a strong preference for cash bonus bidding.

42. It is interesting to note that the federal government plans to follow Alberta's lead in abolishing the "free entry" system of allocating exploration rights in northern and offshore regions, and to adopt a bidding system instead, Statement of Policy: Proposed Petroleum and Natural Gas Act and New Canada Oil and Gas Land Regulations (May 1976).

ranges from 29 sections in the plains area to 36 sections in the foothills.

An important characteristic of the new license is that it does not require the operator to relinquish half his acreage on going to lease; the checkerboard and its variants are no longer compulsory. The new rule, stripped of a number of technicalities, is simply that the greater the accumulated footage (depth) of drilling for oil and gas on the license area, the greater the percentage of its acreage the operator can retain.For example, in the plains area a license of 29 sections can be converted to a lease of 29 sections when the lease-earning footage amounts to at least 16,500 feet. In essence, the more generous arrangements that previously applied to Block A have been extended to the entire province.

As under the former system, a lease conveys the right to produce and sell the Crown's petroleum and natural gas, but the terms of new leases is five years in contrast to the previous 10 years. If, however, a proven oil or gas area within a lease is capable of commercial production, the lease can be renewed over the productive areas until the resources are depleted. However, from 1983 onwards, a further provision will operate to return unproductive formations (as distinct from areas) to the Crown. Leases will be renewed at the end of their terms only to the depth of the deepest productive formation; a vertical division of property rights will be superimposed upon the traditional areal division. Lands not converted from license to lease, unproductive lands under expired leases, and unproductive formations below renewed leases all revert to the Crown and thereby become available for posting for sale.

Both the new licenses and leases are subject to an annual rental of $1.00 per acre, although rental payments under a license are suspended from the date on which drilling begins. The royalty provisions described earlier also apply under the new tenures.

A final point of interest in the 1976 amendments is the strengthening of drilling requirements on longer-term leases issued under the previous legislation[43]—designed, no doubt, to encourage either accelerated exploration or relinquishment of areas covered by such leases.

Resource Revenues

Direct provincial revenues generated under these oil and gas rights are substantial, as Table 3 indicates. Rentals have increased gradually

43. Petroleum and Natural Gas Lease Regulations, Alta. Reg. 168/76 (as amended).

TABLE 3

Direct Provincial Revenue From Oil and Gas in Alberta

	1963[a]	1974[a]	1976[a]
Exploration	*(millions of dollars)*		
Sales: Petroleum and natural gas reservations	3.1	12.4	20.3
Crown reserve drilling reservations	10.9	22.2	23.0
Crown reserve natural gas licenses[c]	2.6	4.9	31.1
Permits (Block A)	b	11.2	8.2
Bonus from Alberta Energy Company for Suffield rights	–	–	14.0
Fees and Rentals:			
Petroleum and natural gas reservations	2.3	5.4	n.a.[d]
Crown reserve drilling reservations	.5	.7	
Crown reserve natural gas licenses	.0	.1	
Permits (Block A)	–[b]	3.7	
Total: Exploration	19.4	60.6	–
Production			
Sales: Petroleum and natural gas leases	1.8	30.8	44.2
Fees and Rentals:			
Petroleum and natural gas leases	24.0	39.5	52.7[d]
Natural gas leases	.7	1.5	
Royalties:			
Oil	51.1	302.1	975.4
Gas and gas products		70.0	519.1
Total: Production	77.6	443.9	–
Total: All Sources	97.0	504.5	1,688.0

a. Fiscal year ending March 31 of year indicated.
b. The permit system for Block A did not exist in 1962-3.
c. These tenures also convey rights to produce gas, but are included with other exploration rights here because their term is limited to only 3 years.
d. Recent official data show only total fees and rentals, for both production and exploration agreements. All these are included under production fees and rentals above.

Source: ALBERTA DEPARTMENT OF MINES AND MINERALS, ANNUAL REPORT (for various years).

over the years with the expansion of areas under tenure. They have, however, been a relatively stable source of revenue, while royalties and bonus returns from sales of Crown reserves have fluctuated with market conditions. But rental rates have not been revised for several years and their yield has accounted for a declining proportion of total oil and gas revenue. A relative decline in bonus revenue from sales of Crown reserves and growth of royalties as the predominant revenue source reflect Alberta's emergence as a developed petroleum province dominated today by production, rather than exploratory, activity.

IV. EVALUATION OF THE ALLOCATION SYSTEM

The complicated arrangements for conveying oil and gas rights from the Crown to private parties are even more complex in actual administration. This is chiefly because they not only convey titles but also link exploration rights and obligations to subsequent production activities. The regulation of these production activities is examined in the next section. However, to ease the problem of comprehending and evaluating the whole policy, we pause here to appraise certain features of the rights-allocation system separately from the eventual production and marketing arrangements.

This commentary reflects the two criteria identified at the outset: efficiency and distribution. Under the general heading of efficiency, we discuss the implications of allocation policies for (a) the timing of exploration and (b) the pattern of development. We turn then to distribution: (c) does the system recover for the Crown an appropriate share of the value—the so-called economic rents—of the resource? Finally, we explore an issue connected to both efficiency and distributive criteria, namely (d) whether the system rewards or deters risk-bearing.

a. *Implications for Distortion of Timing*

Just as any manufacturing enterprise's optimum rate of accumulating (or running down) inventories can be identified, so any petroleum exploration firm's optimum rate of accumulation of oil and gas inventories can be specified—at least theoretically.

The problem in both cases is avoiding the extra interest cost on outlays that are made too early while avoiding the losses arising when investment is too late to provide inventories when production plans call for them. In the case of reserves of oil and gas, the solution to the problem is to incur just that exploration expenditure in each period that will assure that the exploration costs of further reserves will be matched by their discounted, expected value in production. Discounting these expected values is necessary, of course, since the value of new reserves is not usually realized for some years, and in the meantime the value of the capital expended in finding them must be recognized. The question here is whether the arrangements for allocating oil and gas rights in Alberta cause the accumulation of reserves to proceed too fast or too slowly relative to this optimum rate.

Several features of the Alberta allocation system obviously promote rapid development. First, the allocation of exploratory permits and reservations over unexplored areas on a "first-come, first-served" basis created a strong incentive to acquire exploration rights as a matter of urgency, since failure to do so was likely to result in the loss of opportunities to competitors. This free-entry system stimulated the great "land plays" that marked the history of oil and gas exploration in Alberta. Second, once a reservation or petroleum and natural gas license was acquired, work requirements (to the extent that they were compelling) forced accelerated investment in exploration. The 1976 provisions linking area of lease entitlement to depth of drilling on the license area have the same tendency. Third, the provisions for renewal of leases beyond their first term and for drilling notices during their term, under both the old and the new systems, are likely to induce rapid investment in both exploration and development. Fourth, lease rentals at a fixed rate per acre provide financial incentives to hasten development and exploitation. Finally, certain special provisions in the federal income tax encourage such expenditures.

All these policies work in the same direction—to impel private exploration, development, and the accumulation of reserves at faster rates than would otherwise be observed. Our position is that this acceleration is undesirable—the slower rate of exploitation that would be observed in a private-enterprise environment without these policies would be closer to the economically efficient rate. (This position is based on the assumption that the alternative private environment would not only be competitive, but characterized by undivided private ownership of separate pools).[44] Although our conclusion about policy will be modified in section VI to take account of the uncertain bias of policy governing the rate of production, we feel justified in advancing this criticism: the combined effect of allocation policies is to force a rate of exploration that is too fast. This necessarily results either in excessive accumulation of reserves or in too-early development and production, the cost of which is an

44. Certain conditions could cause the rate chosen by unrestricted private enterprise to be slower than the social optimum: notably, monopoly control, consisting underestimation of demand on the part of private producers, and a private discount rate lower than the rate that would be chosen by the people (or government) of Alberta as a whole. None of these appears likely. Monopoly influences are notably weaker at the exploration and production stages than in transportation and refining. There is little evidence to suggest that governments have higher expectations of demand than producers. And it is generally believed that private investors employ higher discount rates than government.

unnecessarily large or early use of socially valuable labor and capital.[45]

The working of these policies should be distinguished from a further bias in the timing of exploration and development that is to result from the method of gas export regulation discussed earlier in section II. Two criticisms may be advanced in connection with the latter. First, requirements of demonstrating a surplus of proved reserves sufficient to meet both the committed export and domestic needs of Alberta for as long as thirty years into the future impose significant social cost in the form of unnecessarily early exploration and development activity and hence excessive inventory costs.[46] Second, little attempt is made to estimate trends in future prices; thus, no proper account is taken of either the price sensitivity of Alberta's "needs" or the relationship between the costs and benefits associated with meeting those "needs."[47] This export policy tends to aggravate earlier-than-optimal investment in natural gas resources. Even if these distortions were eliminated, however, the earlier criticisms of the allocation policies that lead to wastefully premature exploration and development would remain.

). *Implications for Distorting the Pattern of Development*

If the exploration stage were perfectly efficient, a particular pattern would emerge in the allocation of inputs to specific wells and fields at any time. In this sub-section we point out three distorting elements in the allocation system that tend to prevent this efficient development pattern from emerging.

The first concerns information. Welfare economics demonstrates that an increase in social welfare results from the general diffusion of productive information and that losses result from secrecy. (Hence

45. The new controls asserted by the government of Alberta over initial allocations of xploration rights since 1976 give the government an opportunity to ensure an appropriate ite of exploration. This could be accomplished by careful regulation of the size and equency of license sales; once licenses are issued, the bias inherent in the tenure system romotes too-early exploration expenditures.

46. This burden of the thirty-year reserve requirement is mitigated somewhat insofar as it partly covered by undiscovered reserves ("trend gas").

It should be observed that a countervailing incentive may exist. To the extent that xploration produces information of value to other explorers on adjoining areas ("information spillovers"), the latter have an incentive to delay exploration. Exploration licenses may e large enough to minimize such spillovers, and restrictions on disclosure obviously impede iem. Nevertheless, as we point out later, the exploration industry does benefit from information about adjoining areas in bidding for rights.

47. We are grateful to Campbell Watkins for pointing out that the Alberta Gas Reserves reservation Act has public interest provisions that can substitute for price awareness.

economic analysts tend to favor the early release of private information about new drugs and processes, the publication of the contents of sealed packages, and the removal of "taxes on knowledge," such as excises on books and journals). However, this position meets resistance both from politicians and industry, because the right to keep discoveries confidential is used, instead of cash, to reward research and exploration.

The Alberta approach is a case in point: the actual provisions for disclosure of geological information obtained in the course of exploration permit the operator to keep much of his knowledge to himself for two years or more (thereafter, cores and logs from all wells are available in a publicly accessible core storage center). Even if this information would be useful to others, they may be forced to go without it, wait for it, or produce it again, especially if it is not known what information the first operator has. This policy tends to increase the aggregate social cost and to otherwise frustrate efficient development of reserves.

Second, while it is economically desirable to produce oil and gas from a well as long as the recovered value exceeds the operating costs, the royalty system discourages production from wells that cannot yield a current surplus at least equal to the royalty charge. The present royalties–being a proportion of the gross value of recovered resources without reference to the widely varying costs of development and production–encourage capping wells and pools at a stage when they still might generate an economic gain and create an incentive to concentrate on the more productive wells and pools at the expense of those near the margin of productivity. This distortion of the pattern of production is aggravated by the gross royalty's deterrent effect on investment in enhanced recovery systems for low-pressure pools. This additional disincentive, unimportant in the past, is likely to be increasingly costly in view of Alberta's inevitable decline as a conventional oil-producing region.[48]

Third, the optimum intensity of development of reservoirs may be impeded by the new royalty schedule that rewards drilling an excessive number of wells. It can do this by levying lower rates at lower levels of production per well, so that the spreading of production over more wells will result in reduced total royalty charges.[49]

48. These adverse incentives are mitigated to some extent in the case of oil by the royalty scale, which provides for reduced rates at lower production rates; and they could presumably be eliminated through the cabinet's discretion to reduce royalties whenever economic conditions require it.

49. This incentive to excessive drilling may be consequential only for wells with low production, because the marginal royalty rate increases only for well production up to 120(

Without extensive empirical analysis it is difficult to generalize about the seriousness of these distortions; they may never lead to misallocation of resources to (or away from) some fields, yet they may generate costly inefficiencies during the history of others. The two-year non-disclosure of private geological information probably has the greatest potential for social cost. It is true that a later exploratory enterprise can sometimes buy, directly or indirectly (as by takeover by merger), the findings of earlier enterprises, but it cannot do so if it does not know the information exists. And the cost of the indirect routes may be so high as to deter the purchase. In any case, even successful purchases of earlier data are socially costly compared with the theoretical ideal: free and immediate dissemination of knowledge. It may be argued that the right to withhold information may counter incentives that would otherwise exist to postpone exploration until data from drilling on adjoining areas becomes available (see foonote 46). However, any such tendency can more effectively be controlled by other regulations in the tenure system, such as drilling requirements.

The likelihood that the royalty system will deter or prevent some secondary-recovery investments also has the potential for imposing significant social cost. We understand, however, that a reform of the royalty system to increase its neutrality toward secondary recovery is being implemented.

c. *Implications for Recovery of Resource Rents by the Crown*

Direct government revenues from oil and gas are very large, as Table 3 indicates. But it is not certain that the Crown captures a large share of the total net value, or economic rent, in alienated oil and gas rights. In the first place, it is obvious that no system of charges can recover that part of the full potential rent that has been dissipated through inefficiencies of the kind suggested above. Just as important, it is apparent that there is no intention to capture the full resource rent from every operation. Instead, the "right" of holders of exploratory tenures to acquire production leases is clearly meant to become the prize for exploration, providing an incentive to explore by promising successful explorers a share of the rent from their discoveries. Whether this short circuiting of Crown revenues is the best way of stimulating the right amount of exploration activity is a question we consider further below.

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barrels per month, which is about half the capacity of the average Alberta well. Even then the incentive may not be strong because the savings in royalties would have to be sufficient to cover the cost of drilling and operating any "excess" wells.

At this stage, faced with the evidence that both inefficiencies and explicit policy bar the capture of all the rent, we confine ourselves to the lesser task of examining the capacities of the royalty, rental and bonus-bid system to capture whatever remaining fraction of resource values is desired. With respect to sales of Crown reserves, the provisions for competitive bidding and the effort made to appraise such bids suggest that the prevailing policy objective is to capture the full resource value.[50] Here exploration is substantially complete; there is no need to induce or reward discovery expenditures. Hence, if all geological information were available to all bidders, the highest bonus bid might indeed reflect the full current expected value of the resources net of expected future rentals, royalties, and recovery payments.[51]

This argument raises three important questions, however. The first is whether firms in the industry over-discount, and hence undervalue, expected returns from oil and gas discoveries. It must be recognized that imperfections in capital markets, combined with special tax provisions and loopholes, may lead potential bidders to discount future returns at a higher rate than would be employed in a perfect world where all public and private decisions were guided by the same rate of interest.

The second is the degree of competition. At best, there may be vigorous price competition among many potential buyers; at worst bidding may be impeded by monopolistic, oligopolistic, or slack rivalry among applicants. We are not in a position to generalize about the efficacy of competition for lease sales; indeed, this question seems to suffer from a dearth of research, in Alberta or anywhere else.[52] It must be recognized that joint venture arrangements frequently facilitate necessary collaboration. However, the obvious temptations for competitors to collude are balanced by stringent penalties on firms found to have rigged their bonus bids. It therefore seems likely that any inter-firm collusion that does take place is implicit, reflecting a joint recognition of neutral gain from low bidding, rather than explicit.

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50. Although reservation holders are required to surrender at least 50 per cent of th reservation areas as Crown reserves, it cannot be assumed (as it is sometimes alleged) tha competitive sales of the reserves will capture half of the overall economic rents of an resource location discovered. The reservation holder will obviously select what he believes t be the most valuable acreage (within the constraints of the selection controls), leavin inferior acreage to become Crown reserves.

51. This implies that, in discounting, the firms will behave similarly. They may in fac differ in their access to the capital market and in their aversion to risky investments.

52. For one analysis of the degree of competition, *see* Watkins, *Competitive Bidding an Alberta Petroleum Rents*, 23 J. INDUS. ECON. 301 (1975).

The third question refers again to the issue of disclosure of geological information. Alberta goes further than most private-enterprise jurisdictions in requiring reports at each stage, but not all findings need be reported nor are the reports demanded immediately. We have already argued that the withholding of information (or other goods and services, for that matter) that could costlessly be made available to individuals who value it is, *prima facie,* inefficient.

But confidentiality of information has implications, also, for the outcome of bonus bidding. It is asserted by many industry spokesmen that, paradoxically, the Crown can reap more revenue when some data are withheld, suggesting that aggregate bids from an unevenly-informed industry will exceed those from any industry that shares all its information. For example, it is possible that the highest bidders often bid more than the resources are worth (the full economic rent) and then fail, as their excessive bids lead to their demise. In this view, the stock of bidders consists of a flow of overly-optimistic, ill-advised, short-term participants. But this is unconvincing. Investigation shows that neither the general population of bidders, nor of operators, consists of such short-term entrants. Old-established firms do bid successfully and survive. Hence, in the long run, the Crown cannot hope to collect more than the full economic rent on its resources; if the non-disclosure policy had lead some firms to over-bid on particular plays, the industry as a whole cannot, play after play, over-bid on all. In general, the level of bids will lie below, not above, the resource rent. This argument does not imply that withholding information will always produce lower bids, but it does mean that they will not, in the long run, be higher.[53]

This digression leads to the differences in information available to various bidders. All geological information is useful to potential competitors, from superficial and geophysical findings to the discovery of a reservoir, but not all is equally easy to keep confidential. Whatever the rules about reporting, it is apparent that exploratory well findings are, in the inquisitive petroleum industry, very difficult to keep completely secret; whereas surface and aerial surveys, while less definite, can more easily be kept private, especially from smaller firms.

These differences are likely to bear on the workings of the new license system. Under this system petroleum and natural gas licenses are put up for bidding before exploratory wells have been drilled. Thus the bidders must often depend on completely private geophysi-

53. For an investigation of the distributive aspects of public and private information, the possibilities of over-investment in information and the implications of its appropriability, *see* Hirschleifer, *The Private and Social Value of Information and the Reward to Innovative Activity,* 61 AM. ECON. REV. 561 (1971).

cal information, perhaps obtained separately by each of them. This system therefore appears to make it difficult for newer or smaller entrants to make bids; it may tend to squeeze out such competition and, hence, if anything, to reduce opportunities for license sales to be dominated by gambling bids from small speculative operators.

Returning to the central issue—the incapability of bonus bids to capture full resource rents when information is withheld—it is necessary to consider the alternatives. Clearly, general disclosure, providing equal information to all potential bidders, is necessary to eliminate this impediment; in addition, the information must be reliable. The bonus-bidding system cannot be isolated from the general problem of encouraging exploration: who can best undertake it and who should pay for it?

If the Crown simply published all geological information, competitive lease sales could be expected to yield higher bonus bids, but since confidential information is now one of the rewards for private investment in exploration, this would have to be accompanied by downward adjustments in some other revenues. Firms that can obtain both a right to acquire leases and a monopoly on their exploratory findings are obviously willing to pay more initially, and to invest more, than if all information were disclosed. Hence the more disclosure required, the less rewarding exploration would be and the less would be undertaken, unless royalty rates were also lowered. In short, there would be greater access to less information, or Crown revenues would decline.

Alternatively, exploration could be undertaken at Crown expense directly: an approach frequently discussed but rarely tried.[54] The government might well decide to employ private firms to explore under contract with the Crown for payments in cash, with exploration firms in a position similar to that of highway contractors or defense firms offering, by way of tender, to provide public services. Not all exploration need be handled in this way, of course; for these purposes the expertise of the industry could be utilized and harnessed without supplanting it altogether. Thus there might emerge some mix of Crown-sponsored and industry-sponsored exploration,

54. Even in the Middle East, where there is certainly no dogmatic adherence to private enterprise, it is rarely proposed that governments should go directly into the drilling business. Instead, under the Middle East concession system (which is basically different from that in Alberta), Arab governments were eventually able to participate as partners with exploring firms from the outset, rather than later, claiming in bonus bidding or royalties a share of what was privately discovered. Thus the Arab states did obtain more information, and earlier. But because they were already partners, they were in a poor position to obtain independent information or to shop for competing bids.

with the Crown filling any deficiency in the discovery program resulting from the private explorers' knowledge that their information will be released on going to lease.

Such an approach has considerable appeal. By separating the exploration and production phases through Crown exploration, more (Crown-explored) properties would be offered for competitive sale, and full disclosure of exploratory information would ensure more effective bidding. It would also eliminate wasteful competition for rights to rediscover existing confidential information. Private explorers facing disclosure of their data would, of course, be willing to pay less to acquire properties or in royalties, and the Crown would bear some exploration costs more directly, but on balance these would almost certainly be more than compensated by increased competitive sales, more informed bidding, and more efficient exploratory effort, resulting in a net gain in public revenues.

There remains, ultimately, the question of how much resource rent must, or should, be left to the industry. The petroleum industry's attitude toward participation in Alberta depends on the returns available there, relative to those obtainable elsewhere in the world net, of course, of all governmental levies. In the final analysis this issue turns on the desired degree of industry participation and investment in the province and whether the rewards are sufficiently attractive to maintain this level. Bonus bidding arrangements offer a flexible means of capturing the rents that the industry is prepared to pay. Beyond this, all that can be said here is that, in order to achieve its resource development objectives, Alberta's mixture of public charges must satisfy the expectations of a sophisticated, moody, and peripatetic industry.

d. *Risk-bearing and the Distribution of Rents*

The final issue in our evaluation of the tenure system requires consideration of factors that bear upon the choice among three basic types of rent-collecting devices: a lump-sum, front-end payment, like a bonus bid, which can be described as the price for a right to explore or develop; an annual rental or tax, for the right to hold a reservoir or access to it as inventory; and a levy such as a royalty, payable only on recovery, for the right to produce and sell the resource. These forms of Crown levies can be employed singly, but more often, as in Alberta, governments favor some mixture of them. Their choice is influenced by the uncertainty, heterogeneity, and exhaustibility of all mineral production; of these, the effects of uncertainty warrant special comment here.

If future events are certain, it is a simple algebraic problem to find equivalent sets of lump sums, annual payments, and output levies. Yet when uncertainty prevails, the use of these different types of charges can not only affect the division of returns between the Crown and the producer but also bias their behavior in varying ways so that the amount of rent to be divided is altered.[55] Which type, or combination of them, is to be preferred?

This question has many complicating aspects, only a couple of which we shall explore here. Apart from the issue of unequal information among the parties concerned, to which we have repeatedly referred, it relates to the problem of optimum strategies for buyers and sellers where their numbers are small and their information incomplete. These aspects of the uncertainty question extend into a great realm of unsettled questions in game-theory and information-theory.[56] Here, we shall simply assume that the rules of bidding behavior and disclosure are already given.

To analyze the problem, it is helpful to distinguish between two types of risk that affect behavior in the oil and gas industry. One is the uncertainty surrounding future variations in prices, costs, and output: risk-averse firms, and governments, can be expected to demand higher returns to the extent that they are forced to bear the burden of such uncertainty. The second is the uncertainty about isolated events, such as whether a particular drilling operation will strike oil or not; the implications of such all-or-nothing possibilities are clearly different for a one-operation firm than they are for a firm with many operations, the industry as a whole, or the government. Many of these risks can be spread, and hence reduced, when governments or operators have an interest in not one but many operations simultaneously. It is this to which we want to draw particular attention, since opportunities to share and spread risks reduce the need to design the system of Crown charges to cope with behavioral responses to risk-bearing.

55. For recent investigations of such policy-induced changes in producers' behavior, *see* Burness, *On the Taxation of Non-Replenishable Natural Resources*, 3 J. ENVT'L ECON. & MANAGEMENT 289 (1976), and Burness, Price Uncertainty and the Exhaustive Firm (1977) (mimeograph).

56. On the risk-and-uncertainty side of this question there is a very large literature. The distinction between risk and uncertainty itself, which seems to be experiencing a useful revival, stems from F. KNIGHT, RISK, UNCERTAINTY AND PROFIT (1921). Recent contributions by H. Leland and W. Mead are to be found expanded and referred to in MINERAL LEASING AS AN INSTRUMENT OF PUBLIC POLICY (M. Crommelin & A. Thompson eds. 1977). Another recent source is M. GAFFNEY, A REPORT ON THE STATE OF ALASKA AND OTHERS, OIL AND GAS LEASING POLICY: ALTERNATIVES FOR ALASKA IN 1977 (1977). The Gaffney volume includes both useful references to, and appendices by, Richard Norgaard, Robert Rooney and others.

For a government like Alberta's, the fate of a particular well is not of great moment. It knows that oil exists in the province, that new oil will be found, and that old wells will continue producing. Its main uncertainty is about the future stream of oil revenues from the present until commercial production ceases—whether it will rise or fall, whether it will be steady or volatile, and when the peaks and troughs will occur. The smaller the province, the more bothersome this uncertain variability would be. But this problem is not unlike that of any jurisdiction that depends upon a volatile revenue base; many agricultural and manufacturing communities are in a similar position.

The position of the operator is less obvious. In most studies of the oil and gas industry the isolated single operator is the archetype, proceeding through the successive stages of exploration, development, and production. All of his critical decisions, about when and where to drill, the amount and timing of reservoir investment, and the rate at which to produce are heavily influenced not only by his estimates of prices and costs but also by his expectations about taxes, royalties, and regulations.

The most familiar arguments about mineral and petroleum taxation center on the way governmental levies affect these decisions by altering the attractiveness of different courses of action for such firms. Heavy reliance on initial payments such as bonus bidding make operations more risky than dependence on rentals or royalties, since they require large outlays to obtain rights that will yield very uncertain returns, while rentals and royalties imply little or no payments unless and until returns are realized. Thus, it is argued, a system based on initial payments imposes all the risk on the operator, whereas rentals and royalties mean that the government assumes a large share of the risk. This leads to the conclusion that to encourage the development of the industry the government should avoid front-end payment systems in favor of risk-sharing devices. If, however, the government is more risk-averse than such operators, initial payments should be preferred.

These arguments, though over-simplified, serve to identify the circumstances and responses of the isolated operator and to remind governments of their choice of levies in accommodating the needs of small risk-averse enterprises. But our understanding of the actual circumstances of the government and industry in Alberta lead us to conclude that an entirely different approach is needed. As we have noted, the government of Alberta is not a single-propertied landlord afflicted with the kind of extreme uncertainty surrounding a particular well. Moreover, operators are rarely isolated entrepreneurs of the kind pictured above; they are typically either large companies involved in a vast range of operations or smaller firms financed by, or in partnership with, other large or small companies. Few enterprises are solely dependent on the outcome of a single well, or even a single play. In insurance language, the risks are spread far and wide among firms and regions.

If this is so, then neither the province nor the industry is as vulnerable to the form of payments for resources as the popular arguments suggest. Both consider the prospects of particular plays in the context of many converging streams of bids, rentals, and royalties from old and new reservoirs in many parts of the province. The level and variability of the stream of payments is a matter of concern to both, but the different risk-sharing implications of bonus bids, rentals, and royalties are not nearly as important as analysis of isolated operations would suggest.

A separate question is whether the government of Alberta is less risk-averse than the oil and gas industry. If it is, it can gain by shouldering more of the industry's uncertainty through less reliance on bonus bids and more on rentals and royalties; potential revenues should be greater, reflecting the industry's premium for reduced risk. Indeed, the new emphasis on royalties rather than bonus bids in Alberta's recent policy revisions suggests that the government may be prepared to bear more such risk than formerly. But this inference is tenuous; the province of Alberta may well be more vulnerable to variability in revenues and more averse to risk than most of the large oil companies. If the province is more risk-averse, it should enjoy a revenue advantage through greater dependence on initial bonus charges.[57]

In suggesting that the industry would be prepared to pay more, in the form of a risk premium to the Crown, under a payments system that shifts risk onto the government, two qualifications should be noted. One is the possibility of greater political risk attached to certain forms of levy. If firms believe that their future returns are less vulnerable to governmental encroachment under one system than another, they will be willing to pay more under that arrangement. To an outside observer, it is difficult to guess whether oil and gas companies feel safer from provincial and federal revenue authorities under bonuses, rentals, royalties, or taxes. It is worth noting, however, that Alberta's royalties are not fixed in contracts but are set out in legislation and government orders that can be, and have been, altered significantly.

57. However, if (as it is sometimes suggested) the large oil companies have abandoned exploration in Alberta to the independents, *and* those independents are less able to reduce risk by joint ventures and other means, *and* the independents are averse to risk, there may be an advantage for Alberta in relying more heavily on rentals and royalties.

The other point relates to the distortions in the pattern of development induced by the royalty system discussed earlier. The misallocation of development and production effort caused by the royalty system tends to reduce the amount of rent generated, probably substantially. Thus, while firms may be willing to offer a greater share of expected returns in royalties than in bonus bids, in recognition of the lower risk, the ultimate result of greater dependence on royalties is likely to erode the amount of rent to be shared.

To summarize this discussion, we can assert that, if there were no uncertainty, if the pattern of development and production were fixed, and if vigorous competition among producers prevailed, a bonus bidding system could be expected to yield approximately the same revenues to the Crown as well-designed systems based on royalties or annual rentals. If competition is lacking, bonus bids will be less capable of capturing resource rents. But uncertainty and the sensitivity of operations to operators' financial incentives favor bonus bidding over the other forms of payment. Bonus bids are capable of discriminating among sites of different values, avoiding the distortions and inefficiencies associated with simple royalty formulae and thereby allowing more potential rent to be realized. Competitive bonus sales also simplify the problem of ensuring that the industry is left with a satisfactory level of returns, leaving the rest for the Crown.

Thus, providing competition is vigorous, the best combination of resource levies for Alberta is likely to involve a large bonus-bidding component. As long as the government and participating firms are similarly risk-averse and are both able to pool and spread the risks attached to individual operations there appears to be little to be said in favor of heavy or unique dependence on royalties on grounds of risk-sharing or of conventional economic efficiency. If the province is more averse to risk than the industry, bids should offer additional revenue advantage. And if the political risk attached to royalties or rentals is perceived to be greater than that of bonus payments, bonuses will be capable of yielding yet higher revenues. However, because excessively optimistic or pessimistic expectations can lead to ruinous or give-away bonus bids, it would be imprudent, from the point of view of both incentives and revenues, to rely exclusively on this method.

V. REGULATION OF PRODUCTION

The fugacious character of the recoverable resources of oil and gas within a reservoir makes the production from the various wells more or less interdependent. Moreover, if withdrawal proceeds too quickly, the natural pressures within the reservoir become dissipated, resulting in higher costs of recovery or loss of resources.

The natural unit for development of oil and gas resources, to which one firm or agent can be "specific," is therefore the reservoir.[58] Given the unique geological characteristics of each reservoir, the costs of production, and prices attainable, there is an optimum number and distribution of wells, and rate of production from each, that will maximize the net present worth of the resources underground. A profit-maximizing enterprise could be expected to adopt this optimum pattern of development and production only if it controlled the entire reservoir.

But the arrangements for allocating private rights over Crown resources (described earlier) result in fragmentation of development and production rights within reservoirs and thus prevent this type of optimum planning. Instead, we find a multiplicity of firms holding licenses or leases scattered over the surface area, each firm having full rights to produce what it can capture from the common pool underground. From an early date, American conservationists criticized the resulting waste of oil and gas, measured in terms of reserves, that were never recoverable. But this common-property characteristic of the non-specific resource has less obvious yet perhaps more profound implications for the economic efficiency of hydrocarbon production. Since each operator has a strong incentive to increase his share of production by developing his wells quickly, before the opportunity is lost to competitors on adjoining properties, all operators together create excessive productive capacity and produce at too fast a rate. Such competition for the common resource tends inevitably to encourage too-early development and wasteful use of labor and capital and hence tends to erode the potential net value of the resource.

These perverse tendencies associated with common-property resource exploitation are initially the product of the alienation system, which calls for no "specific" correspondence between the natural management unit and the rights of producers. To this defect the courts have added the rule of capture, which gives a producer ultimate title to oil and gas only upon their reduction into his possession, irrespective of the title to the resources underground.[59] The

58. M. MUSKAT, PHYSICAL PROPERTIES OF OIL PRODUCTION 591, 858-62, 899 (1949); Craze, *Development Plan for Oil Reservoirs*, in PETROLEUM PRODUCTION HANDBOOK 33.4-33.20 (Frick & Taylor eds. 1962); and NATURAL RESOURCES: THE ECONOMICS OF CONSERVATION 161-65 (A. Scott ed., 2d ed. 1972).

59. For a discussion on the Canadian position, *see* MacIntyre, *The Development of Oil and Gas Ownership Theory in Canada*, 4 U.B.C. L. REV. 245 (1969), and the decision of the Privy Council in Borys v. Can. P.R. & Imperial Oil Ltd., [1953] 7 W.W.R. (n.s.) 546.

tendencies toward mineral waste have in turn led to close governmental regulation, not so much to moderate development as to control output.

Regulation of most aspects of oil and gas production in Alberta is entrusted to the Energy Resources Conservation Board, and one of the Board's primary objectives is to bring under control the "flush" rates of production that would otherwise prevail under common-property exploitation of pools—especially high rates that would cause dissipation of natural reservoir energy and therefore affect total recovery. The main devices used for this purpose are controls over well-spacing, limits on production rates, and so-called "prorationing to market demand."

Well spacing

The Board controls the drilling of all wells (for private and Crown oil and gas) through a system of well licenses. A license, which authorizes the drilling of a well, can be obtained only in respect of a "drilling spacing unit" of designated area. Operators with production rights over smaller areas must "pool" their rights with those of adjoining operators to form a drilling spacing unit before a well may be drilled; in the event that pooling by agreement proves impossible, the Board may exercise compulsory powers to achieve the result. The size of a drilling spacing unit for oil has increased over the years from 40 acres in 1950 to 160 acres in 1962, as the extent of over-drilling has been progressively recognized. A drilling spacing unit for gas covers 640 acres.[60]

Regulation of Production Rates

The Oil and Gas Conservation Act forbids the commission of "waste," which is defined in terms of loss of physical production from a pool.[61] In recognition of the fact that beyond a critical rate of production known as the "maximum efficient rate" (or MER) the total volume of oil that can ever be recovered is inversely related to the production rate, the Board places limits on the rate of production from pools, portions of pools, and individual wells. There is no universally applicable formula for determination of MER's. In each case data relating to reservoir fluids, rock formations, recovery processes, and performance history are required. (Until it is available, the Board applies provisional limits on production rates.)

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60. In special cases the Board may prescribe different areas: Oil and Gas Conservation Regulations, Alta. Reg. 151/71 (as amended).

61. *See* §§ 2, 138.

The information required by the Board, including test results and production history for each well, must be supplied by operators, and the Board is obliged to make this information public one year after the well is completed. This information is also used by the Board to supervise enhanced recovery schemes. Such measures, which typically include underground injection of water or gas to supplement natural pressures, may be required by the Board (with the approval of the Lieutenant-Governor in Council).

No general system of production rate limitation applies to gas reservoirs. For these, the Board monitors production practices to ensure that ultimate recovery is not adversely affected and operators are subject to the general requirement to avoid waste.

Prorationing

Prorationing to market demand is a system of allocating the monthly demand for oil from Alberta among the province's producing wells and pools. The procedure is complex and has frequently been revised, but it consists of three main steps.[62] The first is the determination of the next month's demand for all Albertan oil, by type, from oil sources. This is done at monthly Board hearings where refining companies submit "nominations," or statements of their requirements for the ensuing month. The total of these nominations becomes the province's allowable production for that month. In these proceedings it is assumed that the wellhead price is to be maintained, and the Board does not ask for buyers' nominations at alternative prices.

The second step is to allocate this total allowable production among the oil-producing pools in the province, and this is done according to their reserves. Each pool's share of the total is equal to the proportion that its reserves bear to the total for all pools.[63] If any pool is incapable of producing its full share calculated in this manner, the excess is distributed among the others.

62. The first comprehensive prorationing plan was introduced in 1950 and was substantially revised in 1958. The present scheme was devised by the Board, after public hearings, in 1964, and following a transition period was fully implemented in 1969; *see* OIL AND GAS CONSERVATION BOARD, ALTA., REPORT AND DECISION ON REVIEW OF PLAN FOR PRO-RATION OF OIL TO MARKET DEMAND IN ALBERTA, Rep. 64-10 (1964). The plan applies to light and medium crude, the demand for heavy crude having usually exceeded productive capacity. Pools on "good production practice" are exempt from the plan (these are pools with low productive capacity).

63. For this purpose, reserves consist of "remaining reserves" plus "ultimate reserves." The former expression refers to the quantity of oil then remaining in the pool that is expected to be recoverable by the extraction methods currently employed in the pool. The latter refers to the total reserves expected to be recovered from the pool after completion of all exploration and production.

The third step is the division of each pool's allocation among its wells. In some cases all the wells are managed under a coordinated plan, called "unitization," and in these cases distribution follows the particular unitization plan (see below). Where there is no unitization agreement or enhanced recovery scheme operating in a pool, the distribution is based on the area (or production spacing unit) assigned to each well subject to a minimum allocation where applicable. In mixed cases, where only a segment of the pool is unitized or under enhanced recovery, the allocation to each well in that segment is increased by a recovery factor that takes account of the addition to reserves attributable to the unitization or enhanced recovery scheme.

The allocation of production that result from these procedures are subject to two adjustments. First, each well is assured a *minimum allowance,* related directly to its depth (which is the primary determinant of completion and operating costs).[64] If a well's calculated prorata production falls below its minimum allowance, the allocation is increased to that minimum level, and the shares of other wells are reduced accordingly. Minimum allowances are intended to permit operators of marginal wells to recoup operating costs together with the costs of completing the wells at a satisfactory return on completion costs in order to encourage operations in pools with low reserves per acre and to discourage abandonment of marginal wells.

Further inducement to exploratory and development drilling in pools with low reserves per acre is provided through an *incentive allowance* plan, adopted in 1972.[65] This has the effect of increasing the minimum allocation to wells in pools that have proratable reserves of less than 2,500 barrels per acre.

Unitization

Utilization refers to the process of merging the fragmented private oil and gas rights in a common pool so that the pool may be operated as a coordinated unit. Under these arrangements the several owners relinquish their separate management rights in favor of a share in the production from the pool as a whole. Unitization is entirely voluntary; although the Board is charged with the task of encouraging

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64. Board studies suggest that completion and operating costs are more or less continuous functions of well depth. The minimum allowance is fifteen barrels per day for depths up to 2400 feet, increasing exponentially with depth to sixty-five barrels per day at 15,000 feet.

65. ENERGY RESOURCES CONSERVATION BOARD, ALTA., REPORT AND DECISION ON THE APPLICATION OF THE INDEPENDENT PETROLEUM ASSOCIATION OF CANADA FOR A DISCOVERY ALLOWABLE, Rep. 72-B-OG (1972).

these arrangements, it offers no special incentives apart from those included in the prorationing system (where recovery factors are increased by unitization and enhanced recovery schemes). Legislation does provide for compulsory unitization, but this provision has never been proclaimed.[66] Currently, well over 60 percent of Alberta's oil is produced under unitized operations.

Operators in gas pools have much stronger incentive to unitize, partly because their need to invest in a gas processing plant often leads to an agreement to share costs in proportion to entitlements to production from the pool; this agreement in turn paves the way for a unit agreement. Additional incentive is provided by the usual gas marketing arrangements, where purchasers buy reserves and may take delivery of them over the life of the contract or of the pool; production may then vary substantially according to seasons and peak load requirements. Obviously such longrun arrangements cannot easily be accommodated without unitization. Nearly all gas pools are therefore unitized.

VI. EVALUATION OF PRODUCTION CONTROLS

Alberta's controls over the production of oil and gas are, in effect, legislative responses to problems created by the fragmentation of rights over reserves emerging from the tenure system. The procedures for allocating rights to produce Crown resources, coupled with the rule of capture applied to both Crown and private lands, create overwhelming incentives for wasteful development and production patterns that, in the absence of controls, would destroy much of the potential value of the natural resources.

The general implications of the system of allocating rights were examined in Part V. Here, accepting the need for some control system to remedy the operations of the resulting pattern of rights, we offer a critical commentary on the particular controls described in the preceeding section.[67] In general, we conclude that these are concerned too much with preventing physical waste of resources and with assuring each producer a share of the market and too little with the prevention of economic waste.

The regulation of well spacing mitigates the tendency, induced by rule of capture, toward excessive investment in production wells, but it is obviously only a very crude device. The spacing limit is arbitrary

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66. Oil and Gas Conservation Act, ALTA. REV. STAT. 1970, ch. 267, § § 87-95.

67. This evaluation has been much influenced by the recent publication of Watkins, *Conservation and Economic Efficiency: Alberta Oil Production*, 4 J. ENVT'L ECON. & MANAGEMENT 40 (1977).

insofar as it takes no account of the widely varying geophysical and economic characteristics of reservoirs that determine the appropriate development and production pattern for any pool. No uniform spacing requirement can ensure an efficient or least-cost number and distribution of wells over different reservoirs.

The present size of spacing units is obviously a compromise. In the early years of the industry, Alberta favored small leases and reservations (apparently in the belief that this would maximize revenue from sales of reserves), and this carried a commitment to small spacing units. In the 1960's wider spacing was adopted in growing official and business recognition of the economic waste associated with redundant drilling that if reduced would increase prospective resource rents and hence also public revenue. But the extent to which spacing units could be widened was politically constrained. It has been suggested that Alberta's spacing unit—always wider than those in the United States—was regarded as a somewhat extreme departure from established and safe technology. Holders of small acreages, some Crown-granted, could not easily be denied drilling rights simply because their neighbors had already drilled. Moreover, the new prorationing policy offered rewards for more wells, and firms were apprehensive that stringent spacing rules might deprive them of their shares in old reservoirs. In short, present spacing limits have been much influenced by historical rights, prorationing, and unitization formulae and are likely to lead to patterns and densities of wells that diverge substantially from the most efficient distribution for any reservoir.

In regulating production rates from whatever wells are permitted, the Board fixes MER's with a view toward ensuring maximum recovery of oil rather than generating the maximum value from the resources recovered. Thus it considers only physical magnitudes without reference to such matters as price trends or interest rates relevant to a determination of the rate that yields the greatest value.

In deciding when enhanced recovery is to be required, the Board considers the operator's potential return from such a scheme but ignores the effect of the Crown's interest in the form of royalty. Clearly, royalties may prevent enhancement even in cases where it is economically advantageous, consistent with the earlier conclusion that royalties can provide a substantial disincentive to enhanced recovery.[68]

68. Oil production attributable to increases in reserves resulting from enhanced recovery measures adopted since April 1, 1974 is defined as "new oil" for purposes of calculating royalty and thus is subject to lower rates. This reduces the disincentive somewhat but does not eliminate it.

The prorating system in use has had profound implications for the economic efficiency of oil production. The initial step of receiving monthly nominations at a posted price eliminates suppliers' competition and effectively fixes that price. As a result, a producer can obtain a larger share of the available market only by increasing his productive capacity—the incentive for over-drilling referred to earlier. Moreover, insulated from independent shifts in supply or demand for western oil that would otherwise cause price softening, the price of crude oil for years remained higher than the price that would result from a free market (a phenomenon familiar under the "supply management" policies of many agricultural products marketing boards).

The second and third steps in the prorationing procedure have the effect of distorting the pattern of operations in favor of high-cost production. The allocation of the monthly provincial production quota among pools according to their reserves is an arbitrary and somewhat costly procedure.[69] More important, because there is not a strong relation between a pool's reserves and its marginal production costs, the system brings about some production from high-cost reservoirs at the expense of low-cost reservoirs. Indeed, if each period's provincial production were taken from the least-cost sources, all producing at roughly equal marginal costs, some high-cost pools would probably not produce at all. Further bias toward high-cost production results from the minimum and incentive allowances that serve to allocate a greater share of output from marginal wells.

These distortions affect exploration activity as well. By assuring production from even high-cost sources, the risk of certain types of failure is eliminated from exploration, and insofar as the pricing arrangement maintains higher or more stable prices, this, too, serves to encourage more exploration than would otherwise take place.

The basic procedure for dividing a reservoir's production among wells on the basis of their assigned areas is to be regarded as a means of providing some degree of equity among producers. Assigned surface areas are, however, only a crude proxy for the proportions of reserves recoverable from those blocks, because these are much influenced by such highly variable factors as the volume of oil-bearing rock, porosity, and permeability.

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69. The specific formula used by the Board is also arbitrary. Insofar as the allocation among pools is based on their ultimate reserves, the pool's allocation tends to exceed its capacity as production declines during the later years of a pool's life. Insofar as it is based on remaining reserves, the allocation is reduced as reserves decline, thus extending indefinitely the life of the pool. The Board sought to compromise these effects by basing its formula on a combination of the two classes of reserves. ENERGY RESOURCES CONSERVATION BOARD, *supra* note 61, at 90, 111.

The prorationing system as a whole should be evaluated in terms of its basic objectives, which the legislation specifies as twofold: the prevention of waste of natural resources and the protection of each owner's share of production.[70] The prevention of physical waste is presumably the justification for the first two steps of the prorationing procedure. Without regulation, it is frequently alleged that physical waste will result from price instability in oil and gas markets because of the random nature of new discoveries. Occasional large new increments of supply threaten market stability and aggravate incentives toward too-rapid production, causing losses through dissipation of reservoir energy. To avoid such instability and waste (the argument runs) it is necessary to regulate price and to distribute the quantity demanded at that price among producing pools.[71]

But while the randomness of new discoveries (in both number and size) is well recognized, it does not follow that oil and gas production must, if unregulated, be attended by wide price fluctuations. In the first place, newly-discovered crude is not, and need not be, immediately offered on the market. Furthermore, the industry is well prepared to live with an unending sequence of expected but "random" new discoveries, each relatively minor in comparison with existing old reserves. A very large and low-cost new source may well cause producers to make a downward revision of their expectation of the path that oil prices will follow in the future. This will also induce them to offer oil today at lower prices. But these are desirable adjustments to an unexpected event. The price change might or might not be sharp, but it would not likely be unstable. A new source would temporarily displace, in the ordering of fields and pools, previously profitable fields. And, of course, such impacts are more likely in the early stages of a producing province, where markets are small in relation to new discoveries, than in later stages when production from existing fields is declining and any new additions are substitutes for enhanced recovery systems. Just as fluctuation in metal markets can seldom be ascribed to discovery of new ore bodies, oil prices are unlikely to fluctuate wildly in response to discoveries of new fields.

In short, it is not at all apparent that the prevention of waste of natural resources calls for regulation of either prices or province-wide

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70. Oil and Gas Conservation Act, ALTA. REV. STAT. 1970, ch. 267, § 5. The same two objectives underlie corresponding regulations in the United States. *See* E. ZIMMERMAN, CONSERVATION IN THE PRODUCTION OF PETROLEUM 24 (1957).

71. A variant of this argument is that oil production exhibits infinite economies of scale and is thus a natural monopoly. Hence regulation is necessary to prevent ruinous competition followed by monopolization of production. This theory has been effectively refuted by M. ADELMAN, THE WORLD PETROLEUM MARKET 13-34 (1972).

allowable output—the first two steps of Alberta's prorationing arrangements. The tendencies toward resource waste in the oil and gas industries seem to have been mistakenly blamed on market instability, whereas the province's fundamental problem arises from the application of the rule of capture applied where rights to a common pool are fragmented.

This basic cause of physical and economic waste can be said to be addressed by the prorationing policy only at the third level: the distribution of production among the wells within a pool. The common-property phenomenon, with its perverse incentives for excessive development and too-rapid exploitation, arises only in the context of the individual pool. Without regulations such as prorationing the rule of capture forces producers with shared access to a pool to ignore the usual economic criteria for optimum rates of production because they cannot safely maintain inventories underground even though the reservoir provides the most efficient storage capacity. Hence it is a rule of capture as it would otherwise apply in Alberta that provides the basic rationale for regulation, and for this purpose the required regulatory regime need apply only to the distribution of a pool's production among the wells in that pool.

Although the other explanations (criticized above) are common, it was undoubtedly the difficulties stemming from the rule of capture that led to adoption of prorationing in Alberta in 1950. In the wake of major discoveries enormous excess capacity had emerged. By that year it was estimated that there was excess production capacity of some 62,000 barrels per day in the Redwater field alone, representing 84 percent of the production rate in the whole province. Fragmented rights over pools quickly resulted in competitive drilling and production, and serious inequities arose as the major refining companies allocated their limited purchases to favored producers.[72] After a hearing, the Board adopted the first prorationing scheme.

It has since been suggested that all three steps in the procedure are necessary to maintain "equity among pools."[73] In our opinion, this implies a somewhat unusual view of equity insofar as competitive producers are not generally presumed to be entitled, as of right, to a share of a market. In any event, the first two steps of the prorationing procedure are not relevant to the statutory intention to "afford each owner the opportunity of obtaining his share of the production of oil or gas from any pool."[74] Neither the specification of price nor

72. G. Watkins, Pro-ration and the Economics of Oil Reservoir Development, Province of Alberta, Canada (1971) (unpublished Ph.D. thesis, University of Leeds).
73. ENERGY RESOURCES CONSERVATION BOARD, *supra* note 61, at 20.
74. Oil and Gas Conservation Act, ALTA. REV. STAT. 1970, ch. 267, § 5.

the allocation of the demand at that price among pools alleviates problems created by the rule of capture. Only the third step—the allocation of the pools' allowables among the wells—modifies the rule and constrains its excesses. Total abolition of the rule of capture could also have been accomplished through the Board's power to require unitization, but the Board does not appear ever to have seriously considered undertaking the daunting task of getting neighbors to agree on shares.

During the energy crisis, the rapid growth in demand for Alberta's oil almost overtook the excess capacity that provided the traditional justification of prorationing. In 1973 the Board found that only four percent (25 of 655) of the pools subject to prorationing were operating at less than their assigned maximum rates, but these few pools, still producing at their prorated levels, nevertheless accounted for some 45 percent of the province's total production.[75]

Unitization has long been recognized in Alberta as the best means of serving the objectives of conservation.[76] The technical advantages it offers are obvious. "Under unit operation, freedom to locate wells in conformance with the structural characteristics of the reservoirs and to utilize fully the reservoir-drive mechanism will permit more efficient recovery with fewer wells."[77] Through unitization, excessive investment in wells can be avoided, and production from pools may be efficiently distributed among wells and through time.[78] As noted earlier, unitization, by internalizing all the benefits from such measures, also avoids the blunting of incentives for enhanced recovery as reservoir energy declines. In short, unitization abrogates—or at least circumvents—the rule of capture. It thus removes the necessity for the final step in the prorationing procedures—the distribution of pool production among wells. Indeed, it eliminates the need for uniform or arbitrary well-spacing controls and external determination of production rates as well.

The obstacle to unitization is the reconciliation of the interests of numerous producers on a pool that result from the system of allo-

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75. ENERGY RESOURCES CONSERVATION BOARD, ALTA., CONSERVATION IN ALBERTA 1973, at 18 (1974).

76. The 1940 Royal Commission on Alberta's oil industry reported, firstly, ". . . that the ideal Conservation is attained only under unit operation, and secondly, that in the absence of unitization, the compromise measure of Conservation and Pro-ration law must be accepted." Harrison, *Regulation of Oil Well Spacing,* 8 ALTA. L. REV. 368 (1970).

77. INTERSTATE OIL COMPACT COMMISSION, A STUDY OF CONSERVATION OF OIL AND GAS IN THE UNITED STATES 57 (1964).

78. Watkins, *supra* note 66 estimates that the 1950 and 1957 spacing and proration regulation systems in Alberta, if applied to 183 reservoirs, would impose excess costs of between $271 and $643 million over a unitization or concession system.

cating rights. The cost and difficulty of reaching voluntary agreement are often very substantial. An alternative to dependence upon voluntary arrangements is compulsory unitization, and the costs attending the search for and negotiation of potential accords among producers would undoubtedly be reduced if Alberta's legislation for compulsory unitization were proclaimed and enforced. This would greatly increase incentives for producers to bargain through to voluntary agreement, and the remaining compulsory agreements would ensure efficient development and production programs throughout the province.

The reluctance to invoke compulsory unitization appears to stem from an unwillingness to interfere with private-property rights, but insofar as the alternative of prorationing was chosen out of respect for the sanctity of private rights, it is by no means clear that the best choice was made even on this individualistic ground. Quite apart from the generally higher private and public returns that can be generated through more efficient unitized development, unitization offers means of determining producers' shares of production that must be considered much less arbitrary than when they are based on the area of their surface rights.

Finally, it must be emphasized that the root cause of much of the production inefficiency is not simply the rule of capture but this rule in combination with fragmented rights in pools. The degree of fragmentation is attributable in no small measure to the requirement that 50 percent of reservation acreages be relinquished upon conversion to lease. The new system of exploration licenses adopted in 1976, by allowing retention of most if not all of the acreage upon conversion to lease, should mitigate this problem. Thus the new arrangements may lead to increasing resort to unitization, which in turn would weaken traditional arguments for well spacing, production rate limits, and prorationing.

CONCLUDING COMMENT

In this section we do not presume to summarize all points made in our previous evaluation sections. Many of those points stand by themselves and are frequently an extension of standard analyses in the literature on the oil and gas industry. For this reason we offer here no further commentary about prorationing, spacing, and other means of regulating production. But because the economic literature in Canada often neglects these extremely important controls and the inefficiency they may engender, we wish to stress that our decision not to dwell on them further does not reflect a feeling that they are unimportant. Indeed, the possibility that certain types of heavy oil will again be in excess supply (given export restrictions and high world prices) reminds us that Alberta's potentially costly prorationing system deserves vigilant attention. In this concluding overview, however, we wish to direct attention from the multitude of decisions and interventions that govern oil and gas production today to the permanent problems of exploration, discovery, incentive, and investment.

The feature that distinguishes oil and gas (together with many other minerals) from most other government-owned resources is the lack of information initially available regarding location, quality, and quantity of deposits. Such information is costly and can be obtained only through the process of exploration. Should exploration be performed by private enterprise or by the government itself? If private enterprise is "employed," what form should its remuneration take—ordinary cash payments or entitlement to produce and sell any oil and gas discovered?

Alberta has consistently chosen to resolve these problems by linking the exploration and production stages, by encouraging private enterprises to perform the necessary exploration in exchange for entitlement to private production rights. The result is an arrangement whereby the government contributes the undiscovered resources, the private sector provides exploratory labor and capital, and the parties share in the proceeds of each success through a system of public levies. The problems inherent in this arrangement have been identified already. The complicated system of exploration and production rights leads to inefficiency on the one hand and fails to achieve a satisfactory distribution of benefits between government and private enterprise on the other.

Some of the problems we have discussed relate specifically to the form in which the Crown attempts to recoup its share of resource rents, and some summary of these arguments is warranted. We have argued that royalties of the kind currently employed in Alberta tend to seriously distort the pattern of resource development and impede realization of full resource values. Moreover, we have discounted the conventional argument that such means of collecting revenues are advantageous insofar as they allow isolated operators to share the risk of their ventures with the government on grounds that such enterprises are the exception rather than the rule. Other shortcomings of royalties may lie in relatively higher risk aversion on the part of the government and in their susceptability to revision, but their most serious disadvantage is undoubtedly the economic inefficiencies in exploration, development, and production they induce and the costly controls needed to mitigate these distortions.

Alternative forms of royalty are, of course, possible. Instead of ad valorem rates applied to production, fixed charges, in dollars per unit produced, could be assessed, as is often the case for mineral and timber royalties. However, such levies raise the same efficiency problems as gross percentage royalties, since both cause the private and social marginal costs of production to diverge; these therefore warrant no additional attention here.

A royalty based on the net, rather than the gross, value of production is much more attractive in this respect. If oil royalties were determined as, for example, the new Alberta coal royalty or the well-known stumpage charges for timber in some jurisdictions,[79] operators would be charged per barrel a share of the difference between price and the cost of finding, developing, and producing the oil from each well. This difference, or net value, could be calculated with reference to either estimated (*ex ante*) or actual (*ex post*) prices and costs.

An *ex post* net royalty would, if all costs were properly recognized, eliminate distortions in the pattern of exploration and development and the bias against marginal resources inherent in gross royalties. Indeed, the federal government has recently proposed such an approach for oil and gas royalties in northern and offshore regions.[80] Such royalties present certain special problems, however. Obviously they imply considerably greater monitoring and administrative costs than gross royalties. Moreover, because the charge varies with the actual performance of the operator, they blunt incentives for efficiency to a degree that depends on the marginal rate charged. This may be significant, because, with all costs deducted, marginal rates would have to be high to enable the government to capture adequate revenues.[81]

79. For a detailed discussion of forest tenures and the types of Crown levies applied to timber resources (especially in British Columbia), *see* ROYAL COMMISSION ON FOREST RESOURCES: TIMBER RIGHTS AND FOREST POLICY IN BRITISH COLUMBIA, Rep. (Peter H. Pearse comm'r 1976), and TASK FORCE ON CROWN TIMBER DISPOSAL, TIMBER APPRAISAL: POLICIES AND PROCEDURES FOR EVALUATING CROWN TIMBER IN BRITISH COLUMBIA (P. Pearse *et al.* 1974).

80. The proposed "Petroleum Incremental Royalty" would amount to 40 percent of production revenues after deduction of all current costs, an allowance for capital costs, a basic royalty of 10 per cent of this gross wellhead value of production, a provision for income tax and a return of 25 per cent on depreciated investment. Statement of Policy, *supra* note 42.

81. Thus the federal government's proposed "Petroleum Incremental Royalty" is only 40 per cent, despite generous allowances for costs; but higher rates would likely encourage "gold plating" expenditures that provide private gain through reduced taxation without contributing any net social product.

An *ex ante* royalty would avoid these particular difficulties. Corresponding to familiar stumpage assessments on timber, the charge (in dollars per barrel or in the form of a percent of wellhead value) could be determined in advance on the basis of estimated prices and costs for individual operations. The burden of administration would be shifted from adjusting the charge on each operation according to its actual financial performance to the compilation of reliable cost and price statistics for use in estimating net values in new operations. Being fixed in advance, this form would preserve all incentives to maintain efficient operations, regardless of the share of net value it appropriates, because the operator would fully benefit from any improvements in performance.

A singular advantage of the *ex post* over the *ex ante* approach is that it automatically responds to the declining profitability of wells as they approach exhaustion. An *ex ante* net royalty, unless it is subject to adjustments downward as extraction progresses, would not eliminate incentives to abandon wells as costs of recovery rise, although the impact of this distortion may be questionable in practice. Any levy on output can, of course, incorporate sliding-scale adjustments in response to substantial changes in prices during the term of a property right.

Earlier in this paper we argued that reliance on competitive initial charges, like bonus bids, held strong advantages on grounds of both efficiency and distribution. Provided that competition is maintained, and expectations are fairly accurate, this method assures that the Crown collects the resource rents remaining after producers allow for their required returns; it takes account of quality differences of different properties; and since they do not affect costs at the margin of production, they do not impede efficient recovery patterns. We have also noted certain difficulties with heavy dependence on bonus bids as the rent-collecting mechanism: competition may be slack; bidders may employ excessively high discount rates in estimating the present worth of future revenues, perhaps because of imperfections in capital markets; and some operators, at least, may be more risk-averse than the government. These qualifications do not appear to us to be compelling; however, most can be dealt with by more careful attention to reserve prices.

It is worth noting that, if the front-end loading aspect of bonus bidding is considered disadvantageous for reasons such as its imposition of risk or high discount rates attributable to faulty capital markets, bidding might alternatively take the form of offers to pay a sum annually, like a rental, or a price for each unit of resource recovered. The latter would amount to a competitively determined *ex ante* net royalty of the kind described above. All these forms combine certain advantages while avoiding the worst distortions associated with fixed percentage gross royalties.

The more fundamental issue, however, is the policy of linking exploration and production activities under the system of resource rights, a matter which, as we have said, cannot be divorced from the payments system. We have already argued that separation of these functions, through more direct governmental involvement in exploration, warrants more sympathetic consideration. This approach has a number of attractions. The information acquired by the government would permit evaluation of resources before production rights were issued to private operators, presumably using a system of competitive bidding, so that the government could be satisfied that it was obtaining an adequate price. Production rights could be issued in respect of whole reservoirs, thereby avoiding the problems attributable to fragmentation of interests in pools and removing the necessity for detailed regulation of production practices (including the market demand prorationing scheme and the system of maximum efficient rates of production). The new tenure system goes some way in this direction by altering the relinquishment procedure upon conversion to lease, but lack of information at the time of sale of exploration rights will continue to result in some fragmentation.

The obvious disadvantage in separating exploration from production through governmental involvement in the former is the financial cost that would be incurred by the government in exploration. Whether these costs would be greater or less than those that would be incurred under private exploration is uncertain. But in any event the Alberta government is likely to be more concerned about whether governmental exploration would enable it to gain sufficiently greater revenue to fully offset the exploration cost. Again, the answer is elusive.

However, several considerations suggest the net gain might be positive. First, removal of the inefficiencies in linked exploration and fragmentation of productive rights offers considerable scope for increasing realized resource values and hence also government revenues. Second, it is at least arguable that the provincial government is in a better position to reduce risk by pooling than are the smaller private operators who conduct most of the exploration in Alberta today. If these private operators are averse to risk and if this aversion leads them to subtract a considerable risk premium from their payments for resource rights, the government could provide the necessary information to reduce their risk at a cost less than this premium. Third, it is also plausible that possession of increased resource information before rights are allocated would allow the government to take greater account of such factors as environmental quality which have a bearing on the social benefits derived from resource use. It can hardly be said that these considerations conclude the issue in favor of government exploration, but we do suggest that they provide grounds for questioning the continued adherence to the present system of resource management in Alberta.