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Oil Supply and Tax Incentives

THE WORLD ECONOMY now depends almost entirely on fossil fuels for its energy. Even according to the most optimistic assumption of the Atomic Energy Commission, fossil fuels, especially oil and natural gas, will be dominant sources of energy until well into the twenty-first century. The supplies and demands for energy are, however, intricately connected in terms of both fuels and locations, so that marginal changes in one part of the system elicit responses in other parts, especially affecting the United States, which is both the largest producer and the largest consumer. The stress on the system in 1973 and 1974 became apparent when world oil prices were raised sharply, intensifying interest in reducing U.S. dependence on foreign supplies. Events since then bear plain witness to this phenom-

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enon, as well as to the profound influence that governmental policies can have.[1]

On the supply side, a number of forces were at work. Nuclear power plants have not been delivered and installed on schedule, and those that have been installed have generally not had the anticipated reliability. Artificially low ceiling prices in the United States have induced shortages of reserves of natural gas and held down production.

Furthermore, environmental considerations have hampered the development of new sources of fossil fuels. They have curtailed the drilling program in the Santa Barbara Channel; delayed the construction of the trans-Alaska pipeline and the drilling on the Alaskan North Slope to estimate its oil and gas reserves; and clouded discussions of a Mackenzie Valley pipeline through Canada and delayed exploratory drilling in the Canadian Arctic.[2]

At the same time, challenges to the U.S. Bureau of Land Management postponed the sale of leases and thus delayed the discovery and development of new oil and gas reserves in the Gulf of Mexico, while the cut from 27.5 percent to 22 percent in the depletion allowance on oil and natural gas, in the Tax Reform Act of 1969, removed some part of the tax incentives for exploration, development, and production of domestic oil and gas.

All of these influences were complicated and reinforced by uncertainty. The deliberations of the Cabinet Task Force on Oil Import Control disturbed producers in the United States and left them uncertain about when and how the mandatory import control program would be relaxed; about the prospects for the state conservation regulations under which they were

1. A partial catalogue of the factors at work, many of them related to U.S. policy, also appears in the editors' introduction to Edward W. Erickson and Leonard Waverman (eds.), *The Energy Question: An International Failure of Policy*, Vol. 1, *The World* (Toronto: University of Toronto Press, 1974). Vol. 2 of *The Energy Question* focuses on North America. The papers in these volumes are the background against which energy problems are discussed here.

2. Our mention of a number of policies associated with environmental protection does not mean that we believe that they are a fundamental cause of the energy crisis (although we do not believe that all of them are necessarily optimal). Such policies have aggravated energy supply and demand adjustment processes in the United States, and, to the extent that U.S. problems are pivotal to the worldwide energy industry, have contributed to stress elsewhere as well. But they are at most second- or perhaps even third-order factors in the energy crisis. In our view, the nation can have enhanced environmental protection—at some cost—without drastic changes in either the level or rate of growth of real income.

accustomed to operating; and about the landed price, source, and volume of foreign oil against which they would have to compete. One result was the interruption in U.S. refinery construction at the very time when substantial new capacity should have been initiated.

Pressures came from the demand side, as well. Demand accelerated under the impact of automobile emission controls, which depress gasoline mileage. Restrictions on the production and use of coal, as well as the government's efforts to control end uses rather than rely on price rationing as a means of allocating short supplies of natural gas, spurred demand for low-sulfur fuel oils; but refining capacity, more and more pinched, was less and less able to meet the demand.

In some areas, demand and supply factors were inextricably entwined. Price controls in the United States distorted the normal economic incentives that determine the mix of refinery output, kept the price of crude oil below the market-clearing level, and finally evolved into a two-tier price system for "old" and "new" domestic crude oil with various categories of exemptions and incentives that affected production decisions.

Growth in the demand for electricity caused power companies to prolong the life of aging equipment, which is on average less dependable, to use older equipment more intensively than they would prefer, and to expand effective capacity with fuel-intensive internal combustion turbines.

The supplies and demands for coal, the fuel most readily substitutable for oil in some uses, were both affected by controls on power plant emissions, land reclamation standards, and mine safety laws.

Overlying these economic and policy matters, and interacting with them, were two significant psychological factors. One was the proclamation by alarmists marching to the beat of an imaginary drummer that the world was in imminent danger of running out of fossil fuels—this in face of new oil and gas strikes in Indonesia, China, Russia, Nigeria, South America, the North Sea, Australia, Alaska, Canada, and elsewhere. The other was the unaccustomed role of supplicant that the United States adopted in dealing with the oil merchants of the Persian Gulf.

In our opinion, the cumulative effects of these policies created the economic vulnerability conducive to the Arabs' use of the oil embargo as a political weapon; in that sense, it was a sequela, rather than a cause. But its demonstrated success changed the economics of policy planning—particularly with regard to the tradeoffs among security of supply and other policy objectives.

Project Independence and U.S. Supplies of Oil and Natural Gas

An evaluation of the costs and benefits associated with an undertaking such as Project Independence, which aims at total U.S. self-sufficiency in oil by 1980, is an exercise fraught with uncertainty.[3] In an admirable first approximation of the supply and demand balances involved, a study group at MIT acknowledge that all of their forecasts are necessarily imprecise.[4] The econometric models of supply and demand for fossil fuels are subject to error within the range of data upon which they were estimated, and the forecasts are well beyond the range of the price data.[5] The noneconometric estimates of availability and uses of fuels are not amenable to sensitivity analysis through parametric variation.[6] And the conjuncture within which

3. In the subsequent analysis and simulations, we consider only crude oil from conventional domestic sources, omitting exotic sources such as synthetic crude oil, oil shale, or tar sands.

4. The Policy Study Group of the M.I.T. Energy Laboratory, "Energy Self-Sufficiency: An Economic Evaluation," *Technology Review*, Vol. 76 (May 1974), pp. 23–58.

5. For example, there may be undeterminable biases in the econometric work on oil and natural gas supply done by Edward W. Erickson and Robert M. Spann, in "Supply Response in a Regulated Industry: The Case of Natural Gas," *Bell Journal of Economics and Management Science*, Vol. 2 (Spring 1971), pp. 94–121, and by Paul W. MacAvoy and Robert S. Pindyck, in "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage," *Bell Journal of Economics and Management Science*, Vol. 4 (Autumn 1973), pp. 454–98. These biases might arise because of the definitional basis of the discovery series used and because wellhead price regulation by the Federal Power Commission caused real natural-gas prices to stabilize or decrease during the 1960s. Erickson and Spann used a series that credits subsequent extensions and revisions to the year of discovery. The closer one is to the present in such a series the fewer the years of extensions and revisions. The result may be that later years' discoveries are arbitrarily smaller than earlier years' discoveries. As a consequence, in a period during which real prices are declining, the estimated elasticity of supply may be biased upward. This problem is not so severe for MacAvoy and Pindyck because they model extensions and revisions separately. But the real price of natural gas was relatively stable over the period covered by their estimations. Thus, the trend for the 1960s may be only random deviations around a point on the natural-gas supply curve.

6. For example, the National Petroleum Council supply cases define average "price" so as to provide an average after-tax rate of return on average book value. "Price" is a slack variable to relate after-tax net profit and net investment as measured by total balance sheet assets from year to year in order to generate industry income statements. The analysis is not incremental in the sense that incremental discoveries or production are some well-defined function of incremental investment. The NPC supply cases are designed to cover investment expenditures out of current revenues. Despite the other merits of the NPC supply cases, the result is that the original NPC study is not susceptible to sensitivity analysis. See National Petroleum Council, *U.S. Energy Outlook:*

market forces will operate is uncertain.[7] Quantitative analysis must be supplemented by qualitative judgments.[8]

Critical uncertainties revolve around the following aspects of the problem: (1) the price and security of oil in world markets and its landed cost in U.S. markets; (2) whether U.S. natural gas markets will be allowed to clear through deregulation of the wellhead price; (3) the effects of environmental regulation and technology upon the unit costs (and permissibility) of utilizing certain energy sources; (4) the extent to which new supplies of oil and gas from conventional sources in the United States can be economically exploited; (5) the tax treatment of income from oil and gas operations (and other extractive aspects of the energy industries) and the effect of alternative tax policies on supply and demand balances; and (6) the resolution of the antitrust complaint filed against eight major oil companies by the Federal Trade Commission.

In this paper, estimates are made of the long-run response of oil supply to price and tax incentives. As in previous such estimates in this industry, it is assumed that markets are typified by competition among sellers.[9] The Federal Trade Commission considers the tax treatment of income from oil and gas operations a crucial determinant of the competitiveness of the petroleum industry. The degree of competition and tax policy also figure in the economic and environmental regulation of the development of offshore oil and gas reserves. Thus, before considering the effect of reducing or eliminating existing tax incentives on future balances of the supply and demand for energy in the United States, we must examine the question of competition.

A Report of the National Petroleum Council's Committee on U.S. Energy Outlook (Washington: NPC, 1972), Chap. 4.

7. With regard to conjuncture, Alfred Marshall notes, " . . .'we understand [conjuncture to be] the sum total of the technical, economic, social and legal conditions; which . . . determine the demand for and supply of goods . . . ' " *Principles of Economics* (9th ed., Macmillan, 1961), Vol. 1, p. 125, note 1.

8. Many of the factors listed above may be regarded as elements that were held unchanged or included in the error term, for econometric estimations based on data from the 1950s and 1960s. Nevertheless, they form an important part of the data base. This means, however, that simulations based on estimations from this period must be treated circumspectly.

9. Those who have done econometric work on oil and gas supply (such as Paul MacAvoy, Franklin Fisher, and ourselves) are often also students of the economics of antitrust and industrial organization. Assumptions of competitiveness were not made without considerable thought.

Competition in the U.S. Petroleum Industry

The Federal Trade Commission advances a number of hypotheses with regard to competition at all stages of the U.S. petroleum industry, using data for the period 1951–71.[10] We deal here with the FTC hypotheses about the depletion allowance and vertical integration, cooperative rather than competitive behavior in gasoline marketing, and barriers to entry in refining.[11] This examination is important for at least two reasons. First, if the industry is in fact effectively competitive, the analytical and intellectual resources spent in the recent debate on the issue could better be allocated to more substantial issues of energy policy. Second, most simulations of energy balances under alternative policy scenarios (including those reported below) are based on econometric estimations that assume effective competition on the supply side of oil and gas markets.

THE DEPLETION ALLOWANCE

The FTC alleges that the depletion allowance is used by vertically integrated petroleum companies to "squeeze" independent refiners through manipulation of the price of crude oil.[12] The allegation relies on the logically inconsistent argument that an increase in the supply of crude oil induced by a depletion allowance results in a higher price for crude oil; but its venerated position in public policy debates makes it useful to address it in detail.[13]

10. See "Preliminary Federal Trade Commission Staff Report on Its Investigation of the Petroleum Industry," released as Senate Committee Print, *Investigation of the Petroleum Industry*, Printed for the Use of the Permanent Subcommittee on Investigations of the Committee on Government Operations, 93 Cong. 1 sess. (1973).

11. For additional discussion of competition in the U.S. petroleum industry, see the relevant papers in *The Energy Question*, Vol. 2.

12. See *Investigation of the Petroleum Industry*, pp. 17, 26, 29, 35, and Appendix B. Several members of the Brookings panel have wondered why we take the FTC allegations seriously, especially with regard to the depletion allowance. We feel compelled to take them seriously because the FTC takes them seriously. See FTC Docket 8934, In the Matter of Exxon Corporation et al., Complaint Counsel's Prediscovery Statement (July 18, 1973), pp. 93–95.

13. For its genesis, see, for example, Melvin G. de Chazeau and Alfred E. Kahn, *Integration and Competition in the Petroleum Industry* (Yale University Press, 1959), pp. 221–22. The basic proposition of the FTC argument was made repeatedly to the Cabinet Task Force on Oil Import Control. See Cabinet Task Force on Oil Import

The FTC argument starts with the fact that the depletion allowance allows crude-oil producers to deduct 22 percent of the value of their production from taxable income.[14] Does it pay a vertically integrated firm to set a high internal transfer price on crude oil to shift profits from refining to production, with its lower effective tax rate? The effect, according to the FTC, is to raise the price of crude oil and, by reducing the profitability of refining, to squeeze independent refiners out of the market.

Suppose that large, vertically integrated petroleum firms did attempt to behave in the fashion hypothesized by the FTC.[15] The internal transfer prices of crude oil would then exceed the costs (including a competitive return on capital) of producing crude oil, and new firms would be attracted to the industry. "Ratable-take provisions" prevent discrimination in purchasing crude by owners of gathering lines. A substantial body of evidence indicates that entry into the industry is relatively easy, even for small firms;[16] and, in fact, the number of crude-oil producers is quite large and fluctuates as economic conditions change.

Control, *The Oil Import Question*, A Report on the Relationship of Oil Imports to the National Security (1970), p. 80, note 25. We will try to put it to rest. But, as with all "free-lunch" arguments, it appears to have a life independent of facts or logic.

14. Prior to the Tax Reform Act of 1969, this percentage was 27.5 percent; the deduction cannot exceed 50 percent of net revenue. The crude-oil and natural-gas industries also enjoy the privilege of expensing intangible drilling costs.

15. The condition necessary for such a strategy to be successful is that each of the majors have a self-sufficiency ratio in excess of $(1 - \tau)/(1 - T - T\tau)$, where τ is the rate of percentage depletion and T is the corporate income tax rate. See Stephen L. McDonald, *Petroleum Conservation in the United States: An Economic Analysis* (Johns Hopkins Press for Resources for the Future, 1971), p. 192. If the values for τ and T are 22 percent and 48 percent, respectively, a firm would need a self-sufficiency ratio greater than 83 percent. Only two of the eight majors meet this condition; moreover, only four of the seventeen firms listed in Table II-5, p. 20, of the FTC report meet it. Thus, the possibility of intercompany compensation by means of side payments within the group of majors, or the top seventeen, is remote. Internal Revenue Service Regulation 1.613-3A requires that petroleum firms use arm's length prices or the "representative market or field price" as internal transfer prices for tax purposes. The effectiveness of this requirement depends upon IRS enforcement, and perhaps also upon private rulings by the IRS. Tax Analysts and Advocates, a public-interest tax-law firm, has recently won on appeal a suit requiring the IRS retrospectively to divulge private rulings; see *Tax Notes*, Vol. 2 (August 26, 1974), p. 3. Such private rulings will be published in *Tax Notes*, the weekly publication of Tax Analysts and Advocates.

16. See, for example, James W. McKie, "Market Structure and Uncertainty in Oil and Gas Exploration," *Quarterly Journal of Economics*, Vol. 74 (November 1960), pp. 543–71; Jesse W. Markham, "The Competitive Effects of Joint Bidding by Oil Companies for Offshore Oil Leases," in Jesse W. Markham and Gustav F. Papanek

The depletion allowance gave the majors at most 2.7 cents (now 2.2 cents) of tax benefit on their own production for every 10-cent increase in the internal transfer price. But every additional 10 cents paid to an independent producer for purchased crude oil gave them no benefit at all. At a simple average self-sufficiency ratio of slightly more than 50 percent—that is, where 50 percent of the oil processed is owned by the refiner—such a policy would be a net drain on profits.[17]

The problems raised by the FTC allegations are compounded by the discussion of the possibility of "passing on" supposedly higher crude-oil prices in the form of higher product prices. According to the FTC:

De Chazeau and Kahn developed a simple model to examine this relationship. They determined that a company with a self-sufficiency greater than 77 percent would benefit from a crude price increase even if this increase were not passed on in the price of products at all. If 50 percent of the price increase were passed on, a company with a degree of self-sufficiency in excess of 38.5 percent would benefit from a price increase . . . based on the 27½ percent depletion allowance. . . .

Using the identical model and substituting the present 22 percent depletion

(eds.), *Industrial Organization and Economic Development* (Houghton Mifflin, 1970); and Robert M. Spann and Edward W. Erickson, "Entry and Competition in Joint Ventures for Offshore Petroleum Exploration," available from the authors. Even price-leadership or dominant-firm oligopoly models presume that the dominant firm either can prevent entry or must include the responses of other firms to price-setting behavior in the calculus of costs and benefits. Moreover, strong evidence suggests that the majors, through joint ventures with smaller firms for lease bids on the outer continental shelf, have actually facilitated the entry of smaller firms into offshore explorations and production activity in the Gulf of Mexico. Such behavior would be strictly against the interests of the majors were they acting according to the FTC depletion-allowance hypothesis.

17. In this context, the self-sufficiency ratio is the fraction of a company's domestic refinery runs that are accounted for by its own domestic-crude production. The simple average self-sufficiency ratio, rather than an average self-sufficiency weighted by production or reserves, is the appropriate measure, because the variable of interest to any firm in terms of its own profitability is its own self-sufficiency ratio. Firms with low self-sufficiency ratios have supported the depletion allowance because in its absence they would have had to pay more for purchased crude oil. At given levels of prices, imports, and demand factors, the effect of the depletion allowance is to make more domestic crude oil available than would otherwise be the case. For the FTC hypothesis to hold, the major producers must then be willing to continue buying crude oil to support a given price, or support the price of crude oil by cutting production by an amount equal to the increased production of nonmajors and new entrants. This contradicts the original FTC argument because the only way the majors could produce the same level of refined product in such a situation is to buy crude oil from the independents. In either case the majors would be giving up their own production to subsidize that of nonmajors. Yet the original FTC contention was that the majors desired to shift profits from the refining segment of the industry to the production segment.

allowance only alters their conclusions slightly. If the price increase is not [sic] passed on, a company with a self-sufficiency in excess of 40.4 percent would benefit from a price increase.[18]

Over the period 1951–72, the real price of gasoline (excluding tax) fell by 25 percent and the ratio of the real price per gallon of gasoline to the real price per barrel of crude oil fell from 9.4 percent to 6.8 percent, a drop of 27.7 percent. The FTC depletion-allowance hypothesis appears neither to be internally logically consistent, nor to conform with the facts.[19] We will return below to the real effects of the depletion allowance.

Finally, the FTC arguments against the depletion allowance are out of touch with the literature.[20] The normal workings of the marketplace prevent the behavior they hypothesize. Most of the critics of the depletion allowance have argued for its repeal, not on the grounds that it increases the prices of crude oil, but on the grounds that it is a subsidy to the petroleum industry that imposes the usual misallocation.

Competitive Rather Than Cooperative Behavior

Perhaps the greatest puzzle with regard to the FTC allegation of cooperative rather than competitive behavior in the domestic petroleum in-

18. See *Investigation of the Petroleum Industry*, pp. 19, 20.

19. A rudimentary empirical test of the FTC hypothesis is to track the ratios of crude-oil stocks to crude-oil production, crude-oil stocks to refinery runs, refined-product stocks to refinery runs, refined-product stocks to total demand, and refined product to total domestic demand over the 1950s and 1960s. Although the refined-product stocks ratios rose during the 1950s, they declined during the 1960s, and the crude-oil stocks ratios declined over the entire period. Rather than demonstrating the inventory accumulation implicit in the FTC hypothesis about the depletion allowance, this pattern approximates the behavior one would expect from more efficient management of inventories in a geographically more closely connected national market. Saul Hymans has raised the perceptive point that since the depletion allowance did not change over the 1950–68 period, we should not expect to see major changes in these ratios. But the FTC hypothesis is that the depletion allowance has served to make crude-oil prices artificially high. In such a situation even if demand were shifting to the right over time, such price would induce inventory accumulation. Moreover, between 1950 and 1968, the real price of crude oil decreased. The depletion allowance and related special tax provisions represent a problem in the efficiency of resource allocation and a case study in the political power primarily of the nonintegrated firms, not of market power on the part of the majors.

20. See Stephen W. Millsaps, Robert M. Spann, and Edward W. Erickson, "Tax Incentives in the US Petroleum Industry," in *The Energy Question*, Vol. 2, pp. 99–122;

dustry is found in the demand conditions for gasoline. Gasoline is the most important refinery output, and its marketing is given special emphasis by the FTC. Real gasoline prices, including and excluding tax, generally decreased over the years 1951–72. The real price of gasoline, excluding tax, fell 25 percent from 26.1 cents to 19.5 cents per gallon over the period. Although nominal taxes increased from an average of 6.8 cents to 11.7 cents per gallon, the real price of gasoline, including tax, fell 6.1 cents per gallon, a decrease of more than 17 percent. For purposes of evaluating the competitive price performance of the gasoline market and the petroleum industry, gasoline prices excluding taxes are the relevant measure.[21] The real tax per gallon actually rose slightly over the 1951–72 period, so the price decline over this period in both the series may be attributable to competitively induced decreases in industry receipts per gallon.

Competitive behavior and performance in the domestic petroleum industry are also reflected in real refinery margins. Over the 1952–72 period, these fell by over 39 cents per barrel, or 31.7 percent.[22] The real price of crude oil, the principal noncapital refinery input, was roughly constant over this period. The overall profitability of the eight major refinery companies declined, but remained approximately equal to that for all manufacturing. At the same time, demand increased substantially. The behavior of refinery margins, long-run profit rates, and real gasoline prices in a period of expanding demand suggests how strong competition spurs the adoption of new technology. Since the majors now control the better part of refinery capacity, they were pivotal in this phenomenon.[23] If the real price of gasoline fell because the majors were aggressively expanding

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Spann, Erickson, and Millsaps, "Percentage Depletion and the Price and Output of Domestic Crude Oil," in *General Tax Reform*, Panel Discussions before the House Committee on Ways and Means, 93 Cong. 1 sess. (1973), Pt. 9, pp. 1309–28; and Erickson and Millsaps, "Taxes, Goals, and Efficiency," in *The Economics of Federal Subsidy Programs*, A Compendium of Papers submitted to the Joint Economic Committee, 92 Cong. 2 sess. (1972), Pt. 3, pp. 286–304.

21. For data on gasoline prices and taxes, see the American Petroleum Institute, *Petroleum Facts and Figures, 1971 Edition*, p. 468, and *National Petroleum News, Factbook Issue* (McGraw-Hill, May 1973), p. 101. The deflator is the consumer price index from the *Economic Report of the President, February 1974*, Table C-44, p. 300.

22. See *Investigation of the Petroleum Industry*, Table 10, p. 35, and *Economic Report of the President, February 1974*, Table C-49, p. 305.

23. See *Investigation of the Petroleum Industry*, Table II-3, p. 18, and Table V-1, p. 33.

refining capacity and competing for incremental shares of the gasoline market, the cooperative-behavior hypothesis falls. If the majors were cooperatively restraining expansions of refining capacity and the real price of gasoline fell because of expansions of refining capacity by nonmajors, the hypothesis of barriers to entry falls. In our view of the evidence, the real price of gasoline, refinery margins, and long-run profit rates declined because *both* the FTC hypotheses—about barriers to entry and about cooperative behavior—are wide of the mark.[24]

Our conclusions with regard to effective competition apply to the domestic U.S. petroleum industry. The substantial market power now being exercised in the world petroleum market resides in the governments of the producing countries. In our opinion, functional divestiture of the major oil companies—however defined—would contribute little to curtailing the market power of producing countries, or to mitigating the inflationary and other effects of its exercise.[25] The domestic petroleum industry is effectively

24. The cooperative-conduct hypothesis of the FTC is not well defined. If the allegation is that "cooperative conduct" on the part of the majors leads to a monopoly solution for price and output in the gasoline market, this is contradicted by considerable econometric evidence that prices for gasoline have been in the inelastic region of both the short- and long-run demand functions. See J. Ramsey, R. Rasche, and B. Allen, "An Analysis of the Private and Commercial Demand for Gasoline," Department of Economics Working Paper (Michigan State University, 1973; processed); James C. Burrows and T. A. Domencich, *An Analysis of the United States Oil Import Quota* (Heath, 1970); H. S. Houthakker and Lester D. Taylor, *Consumer Demand in the United States, 1929–1970* (Harvard University Press, 1966); H. S. Houthakker and P. K. Verleger, "Dynamic Demand Analysis of Selected Energy Resources," Working Paper (Data Resources, Inc., 1973; processed); and Louis Phlips, "A Dynamic Version of the Linear Expenditure Model," *Review of Economics and Statistics*, Vol. 54 (November 1972), pp. 450–58. Additional evidence indicates the implausibility of the FTC argument. Because of the increase in per capita disposable income over the 1951–72 period and the increasing suburbanization of American society, it is likely that a systematic change took place in the structure of demand for gasoline—that it became gradually less responsive to price. This possibility is supported by the findings of Ramsey and his coworkers. When demand becomes more price inelastic, the optimum profit-maximizing response in a cooperative market is to raise real prices. But the actual record of real prices in the domestic gasoline market over the 1951–72 period was one of progressive decline. Franco Modigliani has pointed out that the elasticity-of-demand test, strictly interpreted, discriminates only between effective competition and complete monopolization. The question then becomes whether the number of gasoline refiners and marketers is sufficient to qualify the market as a large-numbers case. In our opinion, it does.

25. See, for example, M. A. Adelman, "The World Oil Market," in *The Energy Question*, Vol. 1, pp. 5–40, especially pp. 10–18, 34.

competitive and it is in this context that public policy and the supply response to changed economic incentives must be considered.[26] In this regard, the special tax provisions enjoyed by the industry are a critical factor. To these we now turn.

A Model of Supply

In addition to prices, environmental regulation, and other legal and technical considerations, special tax incentives influence the activity of the petroleum industry. These incentives include the immediate writeoff of dry-hole costs and of some capital expenditures through expensing of intangible drilling costs, and the percentage depletion allowance.[27] In order to estimate the effect of these special tax incentives upon the crude-oil reserves held by the industry, we develop a model of crude-oil reserves stocks. Our principal objective is to derive an estimating equation for the long-run equilibrium stock of crude-oil reserves that contains only observable values of variables that are exogenous to the firm in the current time period.

THE ESTIMATING EQUATION

The relationship used to describe the long-run equilibrium level of desired oil reserves is

$$R^* = A_0 Z_1^{\eta_1} Z_2^{\eta_2}, \ldots, Z_n^{\eta_n}, \qquad (1)$$

26. Our conclusion of effective competition in the private sector of the U.S. petroleum industry should not be construed as a belief that resource allocation in U.S. petroleum has been efficient. But the major inefficiencies of resource allocation result from failures in public policy or regulation. These have included wellhead ceiling prices for natural gas, the failure to unitize U.S. crude-oil reservoirs, market-demand prorationing, oil import controls, and special tax provisions. All but the first of these provide substantial benefits to the industry. In our opinion, the principal "credit" for implementing and maintaining these public policies resides with the independent producing sector and its role in state and national politics. This is not a pejorative comment: this sector has substantial interests that they have effectively protected. To make efficacious policy, policy analysts must understand the facts.

27. Percentage depletion is often used as a shorthand expression for the whole package of special tax provisions affecting the petroleum industry. Policymakers may

where

R^* = the long-run equilibrium level of desired oil reserves
Z_i = the prices, user costs, production restrictions, and other variables that determine R^*
η_i = parameters representing the elasticities of desired reserves with respect to its determinants.

The principal economic determinants of desired reserves are the expected price of oil, $\hat{P}$, and the "user cost" of oil reserves, C. User cost is a measure of the implicit price to the firm of capital embodied in oil reserves and is defined in its precise analytic form below. If, as in modern capital theory, desired reserves are constrained to be equally sensitive to changes in price and in user cost, the ratio of expected price to user cost, $\hat{P}/C$, would determine desired reserves.[28] In the empirical estimation of the model, we compare the constrained version with an unconstrained version in which the effects of price and user cost are estimated separately.

Domestic oil production was for years subject to production restrictions that limited the fraction of rated capacity at which wells could be operated. The typical measure of production restrictions for those states employing them is Texas shutdown days, K.[29] These production restrictions influence the desired level of oil reserves in at least two ways: they directly influence expectations about the price of oil; and they affect the value of reserves for

properly wish to distinguish between percentage depletion and expensing of intangibles; in fact we do so ourselves in the simulations presented below. The likelihood in the 1974 session of Congress for reform of the special provisions affecting the taxation of income from oil and gas production is not high. The proposed Oil and Gas Energy Tax Act of the House Ways and Means Committee is apparently stalled in the House Rules Committee. Some of the same language appears in the general tax reform bill of the Ways and Means Committee, but its enactment in the 1974 session of Congress is also unlikely.

28. Robert E. Hall and Dale W. Jorgenson, "Tax Policy and Investment Behavior," *American Economic Review*, Vol. 57 (June 1967), pp. 391–414.

29. The current terminology is "market-demand factor," or MDF. Shutdown days are simply equal to (1 − MDF) times 365 days. If the market-demand factor is 50 percent, a well that is not exempt from restriction is allowed to produce at half of its rated capacity. For a discussion of some of the intricacies of market-demand prorationing, see Edward W. Erickson, "Crude Oil Prices, Drilling Incentives and the Supply of New Discoveries," *Natural Resources Journal*, Vol. 10 (January 1970), pp. 27–52; and McDonald, *Petroleum Conservation in the United States*.

any given price and user cost by restricting the rate at which reserves can be pumped out and sold.

For any given assessment of demand, production restrictions should raise the expected price of oil. Since we have no well-established way of measuring the formation of expected prices, $\hat{P}_t$, we settle for assuming that they are determined by the current price, P_t, and current and lagged production restrictions, K_t and K_{t-1}:

$$\hat{P}_t = f(P_t, K_t, K_{t-1}). \tag{2}$$

Since interest rates are positive, production restrictions reduce the value of reserves for any given expected price by limiting the rate at which reserves can be converted into revenues from the sale of oil. Thus production restrictions enter into the calculation of desired reserves directly as well as through their influence on expected price. Because of these two effects, the direction of the net influence of production restrictions on desired reserves is uncertain.

User cost. The tax incentives that are of particular concern in the present policy debate on energy, and that are a main focus of this paper, enter the oil-supply picture through their effect on user cost. The definition of the user cost of oil reserves, C_t, is[30]

$$C_t = q_t \left[\frac{r(1 - T\gamma) + \delta(1 - T\gamma - T\nu)}{1 - T + T\tau} \right], \tag{3}$$

where

q_t = finding costs per barrel of additional reserves
r = the opportunity cost of committing funds to petroleum exploration, or the cost of capital
T = the corporate income tax rate
γ = the fraction of capital expenditure that can be expensed immediately
δ = the rate of depreciation of the capital stock or reserves

30. A rather lengthy proof of this formulation of user cost is available from the authors. For background on this relation, see Hall and Jorgenson, "Tax Policy and Investment Behavior"; Robert M. Coen, "Effects of Tax Policy on Investment in Manufacturing," in American Economic Association, *Papers and Proceedings of the Eightieth Annual Meeting, 1967* (*American Economic Review*, Vol. 58, May 1968), pp. 200–11; and J. C. Cox and A. W. Wright, "The Determinants of Investment in Petroleum Reserves and Their Implications for Public Policy," Working Paper (University of Massachusetts at Amherst, 1974; processed).

ν = the fraction of capital expenditure that is depreciable for tax purposes

τ = the rate of percentage depletion.[31]

Increases in user cost reduce the desired level of reserves. In turn, user cost is negatively related to the rate of percentage depletion and inversely related to γ, the fraction of capital expenditure that can be expensed immediately. For example, if expensing of intangible drilling costs were eliminated (while the depletion allowance was retained unchanged), γ would decrease and therefore ν, the fraction of capital expenditure that is depreciable for tax purposes, would increase; the net effect of decreasing γ, thereby increasing ν, is to increase C_t.[32]

The lack of adequate data on finding costs, q_t, complicates the measurement of user cost. Because of systematic variation in success ratios among PAD (Petroleum Administration for Defense) districts, average discovery sizes, average well depths, and costs per foot drilled, it is likely that average finding costs vary across PAD districts.[33] At the margin, however, net of locational and quality differentials, finding costs should be equal for all districts. In the estimations discussed below, district dummy variables, designated D_j, are used to pick up average cross-sectional variation.[34] The

31. For a more complete description of these data, see Spann, Erickson, and Millsaps, "Percentage Depletion."

32. The values for γ and ν do not sum to unity, however, because capital expenditure for oil development generally includes expensable, depreciable, and depletable items.

33. The PAD districts are defined roughly as follows: District 1 is Appalachia and the East Central Coast; District 2 is the midcontinental states; District 3 is the Gulf Coast and Southwest; District 4 is the Rocky Mountain area; and District 5 is the West Coast states and Alaska and Hawaii.

34. This approach differs from that used in the report prepared for the U.S. Treasury Department by CONSAD Research Corporation, "The Economic Factors Affecting the Level of Domestic Petroleum Reserves," Pt. 4 of *Tax Reform Studies and Proposals, U.S. Treasury Department*, Joint Publication of the House Committee on Ways and Means and the Senate Committee on Finance, 91 Cong. 1 sess. (1969). The CONSAD study used discovery-development costs per barrel of oil for 1947–63 from *Petroleum Outlook* for September 1964. This series has considerable yearly fluctuation, probably due to year-to-year changes in the success rate and average discovery sizes of the wells. In its estimation, CONSAD developed exponentially weighted moving averages of q_t to represent producers' expectations of the costs of finding new reserves. This technique smoothed the series somewhat (pp. 7.17–7.25). A linear regression of CONSAD q_t numbers on time yielded $q_t = 1.13 + 0.0106\ YEAR$ ($r^2 = 0.033$), where q_t is in dollars per barrel and $YEAR = 0$ for 1950 and 15 for 1965—that is, a rise of one cent

time-series problem is more difficult. There is no adequate time series on q_t, although it probably has been increasing.[35] We omit q_t from our estimation, in effect assuming it is constant over time. The logic of the relations among q_t, price, and the term in the brackets of the user-cost expression, equation (3)—designated [B]—is that price and q_t are positively related, while [B] and q_t are negatively related.[36] Omission of q_t from the estimations introduces an indeterminate set of biases in the estimated coefficients for price and tax incentives.[37] Embedded within our coefficients on price and user cost is a set of facts about finding and development costs. The assumption we make in the simulations reported below is that this set of facts is well behaved over time and continuous with respect to changes in economic incentives.

Actual reserves. It takes time to bring actual reserves, R_t, to the level of desired reserves. Actual reserve levels, R_t, are assumed to adjust to desired reserve levels, R_t^*, according to the following equation:

$$R_t/R_{t-1} = (R_t^*/R_{t-1})^\lambda;\ 0 < \lambda < 1. \tag{4}$$

per year. Quadratic regression equations were no better. The CONSAD results indicated that reserve holdings were insensitive to tax-induced changes in user costs. For a discussion of these results, see Erickson and Millsaps, "Taxes, Goals, and Efficiency," and Spann, Erickson, and Millsaps, "Percentage Depletion."

35. In his study of drilling costs, Franklin M. Fisher does find substantial depth-favoring technological change. See his *Supply and Costs in the U.S. Petroleum Industry: Two Econometric Studies* (Johns Hopkins Press for Resources for the Future, 1964), Pt. 2, and his "Technological Change and the Drilling Cost-Depth Relationship, 1960–6," in *The Energy Question*, Vol. 2, pp. 255–64. Since unit finding costs are inversely related to size, these observations are partially confirmed by the trend to smaller average discoveries at approximately constant real output prices. The Fisher findings indicate a substantial technological offset to any tendency toward increased finding costs. The best prospects are, however, drilled first. Gordon Kaufman and Krishna Challa of MIT have found in their investigations of sampling without replacement that average discovery size *within* a geologic play is a tight and strongly decreasing function of time (unpublished data). This does not mean that discoveries are insensitive to economic incentives. The economic decisions about which plays to drill and the rate at which to drill them must still be made. But it does suggest that, with some random variations, finding costs may be increasing over time.

36. For a discussion of the terms, see Spann, Erickson, and Millsaps, "Percentage Depletion," pp. 1318–19. However, for the purposes of the estimations reported below, we will continue to denote user cost as C_t.

37. To the extent that the direction of these biases can be inferred from simple correlations, the coefficient on price is probably biased downward and those on user cost and speed of adjustment upward.

The parameter λ is the adjustment coefficient. The larger λ is, the speedier is the rate of adjustment.[38]

Substituting equation (1) into (4), representing the Z_is by the determinants of desired reserves just discussed, and taking logarithms, leads to the following estimating equation containing only observable variables:[39]

$$(5) \quad \ln(R_{t,j}) = d_0 + d_1 \ln(P_{t,j}) + d_2 \ln(C_t) + d_3 \ln(K_{t,j}) + d_4 \ln(K_{t-1,j}) + d_5 D_j + d_6 \ln(R_{t-1,j}),$$

38. If reserves are insensitive to tax-induced changes in user cost, the speed with which the industry moves from actual to desired reserves is of little consequence. If, however, the relationship is more sensitive, knowledge of the adjustment speed becomes more important, especially to managers of energy planning. In their earlier work, CONSAD assumed a rapid adjustment—within one year. We prefer to estimate the adjustment speed, and our model allows us to do so. The CONSAD assumption is based on Almon's finding that capital investment in petroleum and coal showed the shortest lag of any standard industrial classification industry group, with over 95 percent of investment occurring within one year of authorization. Given Almon's basic assumptions that expenditures come entirely from previous appropriations, that no capital expenditure is made without an appropriation, and that appropriations are eventually spent, her finding concerning the expenditure-appropriation data for the petroleum industry is not surprising. To get an appropriation, geological exploration, lease acquisition, and the like must be completed. A positive change in economic incentives causes increased production out of existing reserves and drilling out of the inventory of existing prospects, as well as accumulation and drilling of new prospects. For a significant change in economic incentives, the latter component of the adjustment process probably dominates. Thus, although the time required to bring a well into production, once the decision to drill has been made and the project funded, is quite short—as little as two months in some cases—the conclusion that adjustments in reserves are largely accomplished within each year does not necessarily follow from Almon's results. Our kind of statistical estimation of the speed of adjustment, however, may not be completely satisfactory either, because the historical adjustment process was probably significantly affected by the rate of offshore leasing and by market-demand prorationing. These elements of the conjuncture have changed, and the estimated adjustment speed may be too low for current conditions. See Shirley Almon, "The Distributed Lag Between Capital Appropriations and Expenditures," *Econometrica*, Vol. 33 (January 1965), pp. 178–96.

39. The estimations are done directly in terms of current and lagged reserves. Intuitively, estimation in terms of first differences for reserves might seem appealing, but the model developed here is for the stock of reserves. For a model that deals with the flow of discoveries, see Robert M. Spann and Edward W. Erickson, "Joint Costs and Separability in Oil and Gas Exploration," in Milton F. Searl (ed.), *Energy Modeling: Art, Science, Practice* (Resources for the Future, 1973). There is a recursive relationship between production, discoveries, and reserves that allows the independent estimation of only two of the three.

A more detailed development of the model presented in the present paper is available from Edward W. Erickson.

where

R = proved oil reserves in thousands of barrels[40]
P = deflated average wellhead price of oil per barrel[41]
C = user cost of oil reserves[42]
K = Texas shutdown days, a measure of the severity of production restrictions[43]
t = a time subscript
j = a subscript denoting PAD district
D = a vector of district dummy variables.

The coefficients in the estimating equation, (5), are related to the parameters, η_i and λ in equations (1) and (4), as follows:

$$d_i = \eta_i\lambda \text{ for } i = 1, \ldots, 5$$
$$d_6 = 1 - \lambda.$$

Thus, the coefficients d_1 and d_2 in the estimating equation directly measure the short-run elasticity of oil reserves with respect to prices and user costs. The long-run elasticities of reserves with respect to prices and user costs are given by $d_1/(1 - d_6)$ and $d_2/(1 - d_6)$.

40. American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1970*, Vol. 25 (published jointly by AGA, API, CPA, 1971), Table III, p. 25, and Table III-2, p. 27.

41. American Petroleum Institute, *Petroleum Facts and Figures, 1971 Edition*, pp. 86, 87, and *Economic Report of the President, January 1973*, Table C-48.

42. The real interest rate in year t is computed by taking Moody's Aaa bond rate and subtracting out the expected rate of inflation defined by $w_0\dot{P}_t + w_1\dot{P}_{t-1} + w_2\dot{P}_{t-2}$, where $\dot{P}_{t-i}$ equals the rate of inflation (from the wholesale price index) in time $t - i$ and $w_0 = 0.480$, $w_1 = 0.327$, and $w_2 = 0.193$. The weights were derived by summing the first twelve, the second twelve, and the third twelve monthly digits as reported in William P. Yohe and Denis S. Karnosky, "Interest Rates and Price Level Changes, 1952–69," *Federal Reserve Bank of St. Louis Review*, Vol. 51 (December 1969), Table 2, p. 37. The weights were constrained to be in the same proportion as the sums computed above subject to the constraint $w_0 + w_1 + w_2 = 1$. The percentage depletion allowance equaled 0.275 for the period 1950–68. The values for γ, ν, and δ were taken from CONSAD Research Corportation, "Economic Factors," p. 7.19.

43. The data come from a letter to the authors from the Texas Railroad Commission, Austin, Texas.

EMPIRICAL ESTIMATES

The empirical estimates of the model seek answers to two questions. First, are long-run petroleum reserves sensitive to tax-induced changes in user costs? Second, what is the empirical relation, if any, between price and tax incentives? These questions are of interest for a number of reasons. In their evaluation of Project Independence, the MIT Energy Laboratory group concentrated on price incentives. But if, in the wake of the discussion of further reform of the tax treatment of income from oil operations, the provisions are changed, the domestic balance between oil and other fuels will change; and there will be expectations and perhaps realizations of similar changes for other fuels such as natural gas, coal, and uranium. These would be important to energy-policy planners, for they would alter the balance between domestic and foreign sources of energy over the transition period of Project Independence and, furthermore, affect its length.[44]

The unconstrained model. Unconstrained estimation of the model using pooled cross-sectional and time-series data from 1950–68 yielded the following:

$$
\begin{aligned}
\ln R_{t,j} = {} & \underset{(0.71076)}{1.41085} + \underset{(0.09003)}{0.10169} \ln P_{t,j} - \underset{(0.02802)}{0.06929} \ln C_t \\
& - \underset{(0.08308)}{0.06666} \ln K_{t,j} + \underset{(0.07663)}{0.07607} \ln K_{t-1,j} \\
& + \underset{(0.04025)}{0.90185} \ln R_{t-1,j} - \underset{(0.26896)}{0.48685} D_1 \\
& - \underset{(0.20352)}{0.12483} D_2 - \underset{(0.21048)}{0.151921} D_4 - \underset{(0.20132)}{0.095101} D_5.
\end{aligned} \tag{6}
$$

$R^2 = 0.9991$; standard error of estimate = 0.00238; degrees of freedom = 85.

44. An additional reason for concern with the first hypothesis involves the CONSAD finding that desired reserve holdings were insensitive to elimination of tax incentives. In contradiction to this, and also related to the second question discussed here, are the statements by some industry spokesmen that seem to imply that taxes have more influence than prices. For example, in a June 1973 statement prepared for presentation before the Senate Committee on Interior and Insular Affairs, Richard J. Gonzalez wrote: "Because of unusual risks and the long time lag, investments in petroleum involve much more uncertainty concerning prospective returns than most other businesses. For this reason, price alone is not an adequate incentive for investment of funds."

Here and in the following equations, the numbers in parentheses are standard errors.

The estimate of the price elasticity of the long-run equilibrium stock of reserves (found by dividing the price coefficient by one minus the coefficient on lagged reserves) is approximately unity and is consistent with estimates from other models.[45] A 10 percent increase in price results in approximately a 10 percent increase in discoveries, reserves, and production.[46]

The user-cost coefficient is negative and statistically significant. The estimate of the long-run user-cost elasticity of reserves (found by dividing the coefficient on user cost by one minus the coefficient on the lagged reserves variable) is -0.71. Thus, in the unconstrained estimation, a 10 percent increase in user cost results in approximately a 7 percent decrease in reserves.

The coefficients on production restrictions are unsatisfactory. The positive sign on lagged production restrictions and the negative sign on current restrictions have no obvious interpretation, and in any case, net out to a very small impact.[47]

45. See, for example, Spann and Erickson, "Joint Costs," in *Energy Modeling;* Erickson and Spann, "Supply Response"; and Edward W. Erickson, "Economic Incentives, Industrial Structure and the Supply of Crude Oil Discoveries in the U.S., 1946–1958/59" (Ph.D. dissertation, Vanderbilt University, 1968), in which the estimated long-run price elasticities of crude-oil production and discoveries are less than the estimate of the price elasticity of long-run equilibrium reserve stocks estimated here. This difference arises from the downward sloping value of the marginal product curve for reserves as capital stock.

46. In the future, the ratio of ultimate recovery to original oil-in-place may increase because of price incentives or technological change. A price-induced increase in the recovery rate would result in upward revisions of proved reserves. Charles Schultze has pointed out to us that the proportion of additions to annual reserves in recent years accounted for by "revisions" has grown steadily. The National Petroleum Council estimates that, within plus or minus 5 percent, revisions represent secondary reserve additions. At relatively constant real prices for crude oil, and with the cut in percentage depletion in 1969, this pattern of revisions appears to represent the benefits of technological change. A larger proportion of these reserve additions have recently been in older fields. This pattern may change under the new price regime; but further technological development, in response to economic incentives, is likely to raise feasible recovery rates. Our estimations implicitly include the expansion of secondary and tertiary reserves, although technological change is not explicitly modeled.

The NPC estimates are from *U.S. Energy Outlook: Oil and Gas Availability* (NPC, 1973), p. 188.

47. We must confess that this result may be the consequence of one ad hoc assumption we made—that the effects of production restrictions could be estimated using a two-parameter lag distribution. Although the lag structure for production restrictions

The estimate of the speed-of-adjustment parameter, λ, is approximately 0.10. (The coefficient on lagged reserves is $1 - \lambda$ and is approximately $+0.9$.) Thus, adjustment from actual to desired reserve levels proceeds relatively slowly: approximately 10 percent of the gap between the two is closed each year.[48] At this rate it would take about seven years to accomplish 50 percent of the total desired change. It must be remembered, however, that the rate of adjustment may be affected by factors such as the amount of offshore leasing, which has shifted in a manner that may have increased λ. In addition, the incentive to adjust may be affected by the magnitude of a price change, and recent changes have been well outside the range of past experience. Even if the prospective speed of adjustment for the stock of reserves were 50 percent faster than that indicated by our estimations, it would be relatively slow and a serious constraint upon policymakers with, say, five-year horizons.

The constrained model. In the unrestricted estimates just presented, the coefficients on price and user cost are not precisely equal. On the hypothesis that an economic incentive is an economic incentive, alternative estimates can be made with the coefficients on price and user cost constrained to be equal. The efficiency of this restriction can be tested using the weak mean-

on reserves in past periods may be substantially more complicated, we felt that the data series was insufficient to estimate a more complex lag structure. In addition, as a result of such practices as calendar-day testing, actual production restrictions in recent years may not have been as onerous as nominal production restrictions appear to indicate. For a discussion of calendar-day testing, see Erickson, "Crude Oil Prices," pp. 44–49, and for a discussion of related aspects of the administration of production restrictions, see McDonald, *Petroleum Conservation in the United States.*

48. There is a distinction between the speed of adjustment of the reserves stock to the desired level of reserves and the speed of adjustment of the rate of discoveries to the desired rate of discoveries. The former will always be slower than the latter. Cumulative production and lagged reserves are positively related, and the inclusion of lagged reserves in a pooled time-series and cross-section estimation biases the coefficient on lagged reserves toward unity. This tendency is partially offset by the inclusion of PAD district dummies. Although they are individually insignificant, the district dummies all have the anticipated sign, and their inclusion or exclusion should be judged as a package. As such, they are significant. In addition, to the extent that the coefficient on lagged reserves is biased toward unity, the speed of adjustment is biased downward. Whether or not this is a desirable result depends upon the symmetry of policymakers' loss functions with respect to the date of attainment of target reserve levels.

square criterion.[49] The constrained estimate of the oil-stock reserves equation, again estimated with annual data for 1950–68, is

$$\begin{aligned}(7)\qquad \ln R_{t,j} = {} & \underset{(0.69507)}{1.36664} + \underset{(0.02621)}{0.07253}\,(\ln P_{t,j} - \ln C_t) \\ & - \underset{(0.07931)}{0.05874}\ln K_{t,j} + \underset{(0.07467)}{0.07083}\ln K_{t-1,j} \\ & + \underset{(0.03947)}{0.90414}\ln R_{t-1,j} - \underset{(0.24635)}{0.45129}D_1 \\ & - \underset{(0.19566)}{0.10710}D_2 - \underset{(0.20411)}{0.136021}D_4 - \underset{(0.19636)}{0.08167}D_5.\end{aligned}$$

$R^2 = 0.9990$; standard error of estimate $= 0.00236$; degrees of freedom $= 86$.

Judging on the basis of the mean-square criterion, one cannot reject the hypothesis that price and user cost enter the determination of reserves symmetrically.[50] The constrained equation, (7), does as well in tracking reserves over the sample period as the unconstrained equation, (6). Since symmetry has a theoretical appeal and the empirical estimates in no way refute it, equation (7) will be utilized in the projections offered below.

The constrained long-run elasticity of price and user cost are plus and minus 0.76, respectively, lying between the individually estimated elasticities from equation (6). Thus a 10 percent rise in price or decline in user costs leads, eventually, to a 7.6 percent rise in the supply of reserves. The estimated adjustment of reserves to their long-run desired level is slow, just as in the unconstrained equation. The speed-of-adjustment parameter, λ, is again 0.10, indicating it takes seven years to accomplish half the adjustment of reserves to their desired level. There is similarly little change in the other coefficient estimates. The estimated effect of production restrictions is again unsatisfactory, as it was in the unconstrained estimates. In the simulations that follow, however, we set production restrictions equal to

49. See Carlos Toro-Vizcarrondo and T. D. Wallace, "A Test of the Mean Square Error Criterion for Restrictions in Linear Regression," *Journal of the American Statistical Association*, Vol. 63 (June 1968), pp. 558–72; and T. D. Wallace, "Weaker Criteria and Tests for Linear Restrictions in Regression," *Econometrica*, Vol. 40 (July 1972), pp. 689–98.

50. The calculated noncentral F-statistic is 0.123 with degrees of freedom equal to 1 and 85. The noncentrality factor equals $m/2$, or $1/2$, since m equals the number of constraints.

Table 1. Actual and Predicted U.S. Oil Reserves, 1969–74[a]
Billions of barrels

Year	*Actual*	*Predicted*
1969	29.2	30.6
1970	28.9	30.3
1971	27.9	30.2
1972	26.2	30.0
1973	25.2	29.8
1974	...	30.6

Sources: Actual reserves are from American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1973*, Vol. 28 (published jointly by AGA, API, CPA, 1974), Table III, p. 25, and Table III-2, p. 27. Predicted reserves are derived from text equation (7).
a. Lower forty-eight states only.

zero so the estimated coefficients do not directly affect the 1975–85 predictions.

Table 1 illustrates the tracking record of equation (7) for 1969–73, the first five years after the end of the estimation period. The principal policy change that occurred in this period was the reduction of the depletion allowance from 27.5 to 22.0 percent in the Tax Reform Act of 1969. This change is reflected in the user-cost measure employed in the equation. On the other hand, a number of other events of this period may have influenced the development of reserves but could not be reflected in the model. These include the removal of restrictions on oil imports, the Alaskan discovery (whose reserves are not included in this model) followed by the extended uncertainty over building the oil pipeline, and the imposition of wage and price controls. All these increased the uncertainty of expectations in the oil industry;[51] and the controls created, in addition, some shortages of inputs for the discovery and development process. These factors may help explain the growing overprediction of reserves by the model shown in Table 1. Since the model is basically concerned with long-run equilibrium responses, we do not regard the prediction errors during this period of turmoil in the industry as particularly significant. Our main interest centers on comparisons of long-run reserves under alternative prices and tax incentives, which can be made even without considering short-run disturbances that cannot be accounted for in the model.

51. For a discussion of the importance of expectations, see Erickson and Spann, "Supply Response," p. 116, note 43.

Policy Simulations

This section reports the results of using equation (7) to project the supply of U.S. oil reserves (again, exclusive of those in Alaska) under alternative sets of tax policies relating to the oil industry and of future oil prices. Case A assumes the continuation of the depletion allowance at its current level, and expensing of intangibles; case B eliminates the first but maintains the second; case C drops the expensing of intangibles, but assumes a depletion allowance at the current 22 percent level; and case D eliminates both provisions.[52] The alternative prices are \$8.00, \$10.00, and \$12.00 per barrel in 1974 dollars in PAD District 3.[53] Alaska is omitted from the projections because it was not included in the data for the estimation of the coefficients upon which the projection simulations are based. The simulations for the four cases for the period 1975–85 are presented in Tables 2 through 5 and take off from the projected level of reserves for 1974 of 30.6 billion barrels, shown in Table 1.[54] The tax changes and price levels that are modeled in the tables are maintained from the beginning of 1975.

Under all sets of projections, reserves increase noticeably over the next decade as the effect of higher prices, at all the assumed prices, dominates even the rise in user cost induced by the elimination of all tax incentives assumed in Table 5. Under the most favorable conditions for expanding supply—the \$12 per barrel price and the maintenance of present tax incentives, shown in Table 2—reserves rise by roughly 55 percent between 1974

52. Elimination of percentage depletion is equivalent to setting the depletion term, τ, in the user-cost formulation equal to 0.032. The point at which all depletion is claimed as cost-based depletion would be that point at which the allowable deductions for cost and percentage depletion are equal. Based on an estimate that percentage depletion has allowed about 85.6 percent excess recovery of outlays over cost depletion (CONSAD, page 7.31), this breakeven point would occur when percentage depletion was 14.4 percent of the current rate. Eliminating expensing of intangibles decreased γ and increased ν. The total effect of eliminating both expensing of intangibles and percentage depletion is to increase user cost by 44.9 percent.

53. Prices for PAD Districts 1, 2, 4, and 5 are established by application of the relative price differential in 1968 between prices in PAD District 3 and the other four PAD districts.

54. Although the depletion allowance did not change over the period on which our estimations are based, it is possible to simulate the effects of changes in user cost induced by tax policy because there was substantial variation in user cost in our data due to changes in real interest rates and in the general corporate tax rate.

Table 2. Estimates of U.S. Domestic Crude-Oil Reserves When Percentage Depletion and Expensing of Intangibles Remain at 1974 Levels, by Alternative Prices, 1975–85

Billions of barrels

	Price per barrel		
Year	*$8.00*	*$10.00*	*$12.00*
1975	31.5	32.1	32.5
1976	32.4	33.5	34.3
1977	33.3	34.8	36.1
1978	34.1	36.0	37.7
1979	34.8	37.2	39.3
1980	35.4	38.3	40.8
1981	36.1	39.3	42.1
1982	36.6	40.3	43.4
1983	37.1	41.1	44.6
1984	37.6	41.9	45.7
1985	38.0	42.7	46.8

Sources: Simulations discussed in the text.

Table 3. Estimates of U.S. Domestic Crude-Oil Reserves with Elimination of Percentage Depletion, by Alternative Prices, 1975–85

Billions of barrels

	Price per barrel		
Year	*$8.00*	*$10.00*	*$12.00*
1975	31.2	31.7	32.1
1976	31.7	32.7	33.6
1977	32.3	33.7	35.0
1978	32.7	34.6	36.3
1979	33.2	35.5	37.5
1980	33.6	36.3	38.6
1981	34.0	37.0	39.7
1982	34.3	37.7	40.7
1983	34.6	38.3	41.6
1984	34.9	38.9	42.4
1985	35.1	39.4	43.2

Sources: Simulations discussed in the text.

Table 4. Estimates of U.S. Domestic Crude-Oil Reserves with Elimination of Expensing of Intangibles, by Alternative Prices, 1975–85

Billions of barrels

	Price per barrel		
Year	*$8.00*	*$10.00*	*$12.00*
1975	31.0	31.6	32.0
1976	31.5	32.5	33.3
1977	31.9	33.4	34.6
1978	32.3	34.2	35.8
1979	32.6	34.9	36.8
1980	32.9	35.6	37.9
1981	33.2	36.2	38.8
1982	33.5	36.8	39.7
1983	33.7	37.3	40.5
1984	33.9	37.8	41.3
1985	34.1	38.3	42.0

Sources: Simulations discussed in the text.

Table 5. Estimates of U.S. Domestic Crude-Oil Reserves with Elimination of Both Percentage Depletion and Expensing of Intangibles, by Alternative Prices, 1975–85

Billions of barrels

	Price per barrel		
Year	*$8.00*	*$10.00*	*$12.00*
1975	30.7	31.2	31.6
1976	30.8	31.8	32.6
1977	30.9	32.3	33.5
1978	31.0	32.8	34.4
1979	31.1	33.3	35.2
1980	31.2	33.7	35.9
1981	31.3	34.1	36.6
1982	31.4	34.4	37.2
1983	31.4	34.8	37.8
1984	31.5	35.1	38.3
1985	31.5	35.3	38.8

Sources: Simulations discussed in the text.

Table 6. Differences in U.S. Domestic Crude-Oil Reserves under Alternative Levels of Tax Incentives and of Prices, 1985
Billions of barrels

	Price per barrel		
Assumption about tax incentive	*$8.00*	*$10.00*	*$12.00*
(1) Maintenance of both depletion allowance and expensing	38.0	42.7	46.8
(2) Elimination of both incentives	31.5	35.3	38.8
(3) Absolute difference (1) − (2)	6.5	7.4	8.0
(4) Relative difference (3) ÷ (1) (in percent)[a]	17.2	17.2	17.2

Sources: Tables 2 and 5.
a. Percentages are calculated from unrounded data.

and 1985. The absolute effect of tax incentives is greater at higher prices. For a summary comparison, Table 6 presents the absolute and relative differences in 1985 reserves for the three assumed price levels for our two extreme cases.[55] At $10.00 per barrel, the difference between maintenance of the two most prominent tax incentives enjoyed by the domestic industry and their complete elimination is 7.4 billion barrels of reserves in 1985, or roughly a 17 percent reduction in reserves. At $12.00 per barrel, the difference is 8.0 billion barrels and also 17 percent.[56] If, as a very rough estimate,

55. These cases are extremes only with respect to the situations that we simulate. On the basis of our results, some observers might wish to increase tax incentives to the oil industry. Care must be taken in interpreting the simulations. For the status-quo case (Table 2), the $12 price is 50 percent higher than the $8 price. But this does not mean that 1985 reserves should be 50 percent larger in the $12 column than in the $8 column. In percentage terms, the $12 price represents slightly more than twice as large an increase over the 1973 real price as does the $8 price. The absolute magnitude of the increase in reserves over the status-quo predicted base reserves in 1974 (Table 1) is slightly more than twice as large at the $12 price as at the $8 price. This in turn means that the percentage increase in reserves is slightly more than twice as large as well.

56. The MIT analysis, "Energy Self-Sufficiency," found that 1980 market-clearing prices ranged between $9 and $13 per barrel of crude-oil equivalent depending upon which combination of supply and demand forecasts was used. The Erickson-Spann econometric supply forecasts for crude oil used in the MIT analysis were an extrapolation significantly beyond the range of the data upon which they were estimated (as are the simulations above), and contained a weak implicit assumption that the exploration, development, and production stages of the industry were fully adjusted to the new price level. They did not include the effects of the Tax Reform Act of 1969. We are not here criticizing the MIT analysis. We ourselves performed the basic simulations of the Erickson-Spann model that were an input to that analysis; and those simulations represented the estimates readily available at the time. The Erickson-Spann model of crude-

we assume that annual production is 10 percent of reserves, the elimination of all the incentives would reduce oil production by between ½ billion and 1 billion barrels per year in 1985 compared with its level with present incentives maintained.

While tax incentives thus have a substantial effect on estimated future reserves in the lower forty-eight states, their importance is much reduced when viewed against the total U.S. energy supply. It is not improbable that prospective reserves on the Alaskan North Slope are equal to the total reserves in the lower forty-eight states. At current and expected prices, these North Slope reserves probably would be developed and produced even if all tax incentives were eliminated.[57] Thus, the elimination of both percentage depletion and expensing of intangibles would make total U.S. crude-oil reserves in 1985 approximately 10 percent less than they would otherwise be. Since crude oil represents about 33 percent of total U.S. energy supply, dropping these tax incentives might make a 3 to 5 percent difference in the 1985 U.S. energy balance.[58]

Conclusions

Many factors have contributed to the recent stress on energy markets. They represent elements in the conjuncture of the energy industries. And, as they impinge on the industry, they create conditions that make forecasts of future supply and price quite uncertain, whether based on econometric models or on the judgment of informed observers relying on their own experience. Events of the last several years indicate how sensitive energy balances are to changes in these conditions. Acknowledging this, we believe it is nonetheless useful to examine some aspects of the oil-supply situation that are amenable to analysis.

Empirical tests are not consistent with the popular hypothesis that the

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oil discoveries was then the model most amenable to policy simulations and sensitivity analyses. But, compared to the MIT analysis, the results presented above suggest that if self-sufficiency is a policy goal it will have to be defined more flexibly, delayed longer, or achieved at higher cost.

57. See M. A. Adelman, Paul G. Bradley, and Charles A. Norman, *Alaskan Oil: Costs and Supply* (Praeger, 1971).

58. This figure is illustrative only. It cannot be calculated with precision, because of the problems associated with forecasting total energy demand and the fact that elimination of the tax subsidies for domestic crude oil might mean also dropping the corresponding subsidies for coal and natural gas. We have not modeled coal or natural gas.

U.S. petroleum industry is ineffectually competitive at every stage. At the producing stage, which is particularly relevant to the evaluation of Project Independence, higher prices raise both output and rents. In the long run, rents are a cost to the industry. For prospective offshore activity, these rents will on average be captured by society in the form of lease bonuses and royalties, because the industry is competitive. Any attempt to limit the generation of rents through price regulation is apt to impede market adjustment and create imbalances similar to those now chronic for natural gas. Focusing on the doubtful hypothesis that private monopoly power is the basic source of recent dislocations in energy markets is likely to delay and compound the formulation of energy policy.[59] But even acceptance of the proposition that the U.S. petroleum industry is effectively competitive does not assure that efficacious policies will be formulated and implemented. In this regard, agriculture is an instructive, if disheartening, example.

Over a significant period, existing onshore supplies of oil and gas will continue to be a major source of domestic supplies. Eliminating the special tax provisions that favor the petroleum industry would reduce the rents that will accrue because of higher domestic prices, and also increase the efficiency of resource allocation between oil and other industries. The drawback is that such a policy change would noticeably reduce the development of incremental oil supplies, particularly for investments aimed at increasing the fraction of ultimate recovery of oil in place from its historic ratio of 30 to 35 percent. Nevertheless, on balance, we believe that the special tax breaks should be eliminated. They impede the rational discussion of national energy policy, result in a misallocation of resources, and in any case are unlikely to be the important determinants of prospective offshore and Alaskan supplies.[60] In our view, their elimination would be worthwhile.

59. For a discussion of the role of OPEC in these events, see James T. Jensen, "International Oil-Shortage, Cartel or Emerging Resource Monopoly?" *Vanderbilt Journal of Transnational Law*, Vol. 7 (Spring 1974), pp. 335–81. Jensen's analysis should be compared to the papers on the world oil market in *The Energy Question*, Vol. 1, especially Pts. 1, 3.

60. We do not calculate the social cost of this misallocation because we do not have the values for the elasticity of demand and demand-shifter coefficients, including our own, to justify such an exercise. For a dollar estimate of the social costs of the 1971 tax subsidy package for the petroleum industry, see Spann, Erickson, and Millsaps, "Percentage Depletion." At higher prices, social costs would be larger. Nor do we model the contribution of percentage depletion and expensing of intangibles to self-sufficiency under Project Independence, because we do not have a definition of "the capacity for energy self-sufficiency." Futhermore, we do not know the future role of crude oil in the overall energy balance with other fuels.

As our estimations indicate, actual reserves adjust slowly to their desired level. This means that under any feasible definition and implementation of a policy of energy self-sufficiency, imported oil will have to be significant in U.S. energy balances for a decade or more, a period as long as, or longer than, the era of mandatory oil import quotas. The landed cost of foreign oil is apt to be subject to considerable variation during this period, making the development of an appropriate policy on oil imports especially important.[61] Such a policy must be set in the context of a cohesive and consistent overall national energy policy that will permit substantial flexibility of prices in energy markets.

61. For analysis of a proposal that relies on market incentives and private initiative to attempt to achieve maximum efficiency, flexibility, and planning focus, see Daniel H. Newlon and Norman V. Breckner, "The Oil Security System: An Oil Import Policy for the United States," Research Contribution 255 (Institute of Naval Studies, Center for Naval Analyses, January 1974; processed).

Comments and Discussion

Charles Schultze: Both of these papers have two parts. The first part of each deals with the competitive structure of the industry. The second parts are empirical, and I shall devote most of my comments to the empirical results. I will talk first about the paper by Erickson and his associates.

The U.S. definition of oil reserves is essentially a very conservative one. Reserves are the oil underlying wells already drilled. This isn't the precise definition; but, for all practical purposes, development has to be undertaken, and production wells have to be sunk, to "prove" reserves. As a consequence, Erickson is right to treat his reserves as a capital stock variable.

In Erickson's model, it takes a higher price to induce producers to hold more reserves—that is, a higher capital stock. He fits a lag model to this basic conceptual structure. But it seems to me that this procedure misses the point. Changes in production are principally due, not to variations in reserves with other factors held constant, but to scale movements in which the ratio of production to reserves is relatively unchanged. Variations in marginal costs must be explained basically by changes in the cost of finding and developing reserves.

Let me explain the process. A recovery ratio applied against discovered oil-in-place describes the proportion of that oil that can be extracted—that is, the proportion of oil-in-place that can be turned into proved reserves. The recovery ratio is then the relationship between the amount of oil ultimately developed as reserves and the amount of oil-in-place. It has been rising because of newer, more advanced techniques of recovery. In turn, a fraction of the stock of reserves is converted to production each year; currently, annual production is about 12 percent of reserves.

Most changes in reserves, and in production, come from a scale movement, in which the ratio of reserves to production is held constant. In the last fifteen years, the ratio of annual capacity production to reserves has stayed in a range of about 10.8 percent to a little over 12 percent. Erickson, in fact, interprets the results of his model as a scale movement when he says that (with a unitary price elasticity of reserves) "a 10 percent increase in price results in approximately a 10 percent increase in discoveries, reserves, and production." But the essential problem of a depletable resource is the cost of developing reserves. One might conceptualize oil production as coming from two industries: the first develops reserves, and the second produces oil from the reserves. The oil-producing industry can double output at a constant price if it can double reserves (and double other inputs) without having to pay a higher price for the new reserves. Only if the "reserve-producing" industry cannot develop reserves at a constant price, because of higher finding and development costs, will it have a rising supply curve. If this is true, the appropriate variable on the left-hand side of the estimating equation is discoveries (that is, annual gross additions to reserves), not the net stock of reserves. In fact, Erickson and Spann used such an approach in an earlier article.

As production takes place, existing reserves are depleted; maintaining production and the net stock of reserves requires continuing development of new reserves. If the depletion of original oil-in-place forces development of reserves from increasingly less favorable prospects, then the finding and developing costs of new reserves to replace depleted reserves will tend to rise. The shape of the supply curve for oil depends basically, then, on the extent to which the costs of developing new reserves rise as the cumulative volume of discoveries grows over time. Holding any given stock of reserves would cost more and more, because "replacement costs" steadily increase. If, as Erickson's equations imply, it costs more on average to hold a higher stock of reserves, then holding the same stock will also be subject to increasing costs as the ultimately depletable amount of original oil-in-place is discovered and developed.

Therefore, for the long run at least, a model cannot be consistent if it states that a higher stock of reserves will be held only in response to a higher price but that a constant level of stocks can be held (with a constant rate of annual depletion) without a rising supply price. The rising cost of developing reserves, which explains the rising supply price of higher stocks, will also raise the price for a constant level of stocks and production.

In summary, the basic question is the cost of developing new reserves. In terms of projecting the costs of Project Independence, I am not willing to accept the Erickson approach—fitting reserve stocks against price and user costs—because it omits finding and developing costs.

One other problem is the implication of Erickson's use of the prior period's reserve stock in a pooled time-series and cross-section model. The coefficient on that lagged variable may be distorted by major geological differences among regions: the District of Columbia does not have oil reserves as large as those in Texas. Even if the marginal costs were the same at the intensive margin, average costs will be quite different and will lead to different reserve development, depending on geology. Clearly, the best statistical "explanation" of why reserves in Region 1 and Region 2 differ in period t is the difference in those reserves in period $t - 1$. I suspect, in other words, that the lagged term picks up more than a lag. It picks up some geological differences, even though Erickson also uses regional dummies. I am not quite sure what interactions may be present in an equation that includes, along with regional dummies, a variable that itself is a good proxy for regional dummies; but I suspect a possible overestimation of the coefficient on the lagged term.

In turning to the paper by Davidson and his associates, I want again to talk initially about the empirical results and their theoretical basis. The interesting part hinges on the estimate of the elasticity of supply. While several hypothetical estimates are given, the authors cite 1.6 as the value corresponding to the empirical findings. I want to consider that estimate because it is critical to the whole price-quantity projection.

Davidson and his associates apply an ingenious technique which uses the rent share to estimate supply elasticity. They assume a constant-elasticity production function, in which nature is the fixed factor and all other inputs are the variable factor. Then if one calculates the rent share, α, appropriately (amortizing those kinds of rents that are paid in advance) $(1 - \alpha)/\alpha$ is the supply elasticity.

In the first place, even if the elasticity of supply is correct, the equation has no lag. It is a timeless function. The authors could just as well put their 1980 results into 1974. Let me illustrate what is implied by their estimate of 1980 supply. With a price elasticity of supply of 1.6 and a demand elasticity of 0.5, they project domestic production of 16.9 million barrels a day in 1980. (I assume that Alaska is included in this total, so they are really projecting 14.9 MMB/d, or 5.4 billion barrels a year, for the rest of the country. If Alaska is excluded, it makes my point even stronger.) At a production-reserves ratio of 13 percent, which allows for an increase from the current ratio of 12 percent, this projection implies that, between now and 1980, the United States will have developed a stock of 41.8 billion barrels of reserves, as compared with 25 billion to 26 billion at the end of 1973. In order to get this kind of development in net reserves, allowing for the fact that reserves converted into production must be replaced and allowing for just a little lag, annual gross additions to reserves must rise from 2.1 billion in 1973 to about 9 billion a year by 1979.

In order to expand reserves that much at a time when drilling depths are increasing, total drilling must expand even faster. Annual drilling may have to quintuple to achieve the Davidson results by 1980. Quite apart from the basic theoretical structure of the model, therefore, it is critical to inspect the lags before projecting results to any given year. Their result may be possible, but it depends on a massive increase in the rate of annual additions to reserves in a very short time.

In my view, Davidson's paper shares a basic problem with Erickson's in assuming that oil is like wheat. The ultimate stock of oil-in-place is treated like land. When more variable factors are applied, marginal cost rises, and generates rent. But this does not seem to me a fruitful concept for modeling depletable resources. It assumes, for example, that output could be continued at the same level at constant cost, unaffected by depletion of resources. In a depletable-resource industry, the same factors that imply a higher supply price for a higher output would also imply rising costs for a constant output unless they were offset by something like improved technology.

If the various discoverable oil prospects are of roughly equal quality, then long-run marginal costs would be constant. There would be no diminishing-return rents, although there might be scarcity rent if a sharp upturn in costs is expected at some future date. If, on the other hand, the quality of resources in place yet to be discovered is not uniform and geological science provides some advance knowledge of quality, then the long-run marginal costs of discovering resources will be rising. This rise may be offset by improved technology, or may be interrupted by surprises, like the opening of production offshore or in Alaska. Even with such offsets, it remains improper to treat a depletable resource like oil as a renewable resource like wheat.

Let me move on to the next point. To get the elasticity estimate, Davidson and his associates use statistics for the federal outer continental shelf since, as they say, the largest growth in U.S. production will come from there. Now the outer shelf accounts for about one-eighth of oil and condensate production. They calculate the rent share of the value of output of offshore oil, take $(1 - \alpha)/\alpha$, and get their supply elasticity. But offshore oil fields yield a differential rent; and that is inconsistent with the assumption of a homogeneous fixed factor that underlies the rent-share method of estimating elasticity. Using their techniques, annualizing the lease bonuses, and spreading them over time, I calculated the rent share for onshore oil. I find a smaller rent share, and therefore a *higher* elasticity—2.4 compared with their 1.6. I suggest that that is an absurd result. The elasticity must, in fact, be a good deal higher for offshore than for onshore oil. Even accepting the rent-share technique, I see a major problem in trying to use it on data from a particular segment of the oil industry, particularly when that segment happens to be very flush and generates high differential rents.

Let me discuss briefly the problems with any econometric approach to estimating the cost of Project Independence and the future supply price of domestic oil production. Recent important developments have affected the supply price of domestic oil resources in opposite directions. First, the development of primary reserves—that is, reserves recoverable with natural-drive techniques—has been declining sharply, and costs have been rising. According to my estimates, primary reserves declined from about 25 billion barrels in 1959 to 19 billion in 1970, and to 15 billion in 1973. Discoveries of primary reserves fell from an average of about 1.7 billion a year in 1959–62 to about 600 million in 1973.

I estimate that the cost of developing a barrel of primary reserves has increased from about 88 cents to \$1.68 from 1959–62 through 1972. Using a 10 percent after-tax rate of return, that raw cost of developing a barrel of reserves translates into a rise from \$1.76 a barrel to \$3.36 a barrel in the cost of producing oil at a fixed (11½ percent) decline rate. Given a declining real price of oil, primary-reserve development fell very sharply. The rise in cost would have been even larger had not Texas and Louisiana eliminated the restrictions on production based on the market-demand factor. That action allowed annual production to rise from an average of 8 percent of reserves to 12 percent of reserves. At a 10 percent after-tax discount rate, the ability to recover oil faster was worth about 80 cents a barrel. So the rising cost has been partly offset by the removal of market-demand factors.

Second, there has been a huge growth of secondary production, which applies water-flood techniques to old fields, thereby increasing reserves and production. The marginal cost (at a 10 percent rate of return) of developing secondary reserves from existing wells has been only 40 to 55 cents a barrel, plus 15 cents a barrel because secondary costs are higher than primary costs. So a fairly substantial decline in development of new primary reserves was partly offset by the rise in secondary recovery. Unitization has also decreased the cost of developing and operating wells, and the opening up of offshore leases has provided new territories for development. A host of factors has affected costs. Some of these are temporary, some are not, but all are very difficult to pick up in any reduced-form econometric model.

One final point. There is an alternative explanation of the large decline in primary reserves, which fits in, somewhat, with the thesis of Davidson and his associates. Suppose I find a very large new field of oil. My geologist tells me there is a 99 percent chance that it contains a lot of oil. But, as I noted earlier, only as the property is developed by sinking production wells will reserves be generated.

Over the past ten years annual expenditures in constant dollars for exploring for new fields have been roughly constant. But the amount of development drilling—that is, developing the oil-in-place—has gone down steadily. Let me offer a hypothesis. Exploring for oil in the kind of situation prevailing during the last fifteen years is an overhead cost. A certain amount of money each year goes into exploration, depending on the price and all the other factors. But firms may or may not undertake the major expense of development—that is, drilling development wells for oil already discovered. The apparent rising costs and the reduction in output may result, not from withholding production from existing wells, but from failure to develop the oil already discovered by exploratory drilling. But since the oil hasn't been developed, it isn't counted in the reserve statistics.

Finally, Davidson and his associates make much of the point that, starting after 1970, statistics on offshore oil show a sharp increase in the number of shut-in wells. This is their major indication of speculative withholding. Now, it turns out that in December 1970, offshore producers went from state regulation in allowables to federal regulation, which allowed more production per well. Between 1970 and 1973, the number of wells decreased by 30 percent, but production rose by 7 percent. Production per well went up by almost 40 percent. My interpretation of that is straightforward. Because of the nature of state allowables, it paid to drill marginal wells, but the same amount of oil was obtainable out of a smaller number of wells under the federal allowable schedule. It may be that producers in the last five or six years have been finding oil that they have not developed. And that may be a much more pervasive kind of speculative withholding than shut-in wells.

Robert E. Hall: I shall discuss mainly the paper by Davidson and his associates. It begins with a critique of free markets, and argues that the market cannot be trusted to do anything right on oil. It builds a pretty strong case for some kind of government intervention, possibly including price controls. I find that argument unconvincing.

The efficient market solution can be derived only from a very complicated intertemporal model, with lots of special assumptions, including the operation of forward markets. Clearly, not all of those assumptions are met; Davidson reasons, therefore, that all of the conclusions that follow are wrong.

Of course, the conclusions could be right even though the assumptions and the argument are wrong. Efficiency really depends, not on the detailed assumptions, but on the economic principle that no opportunity for profit remains permanently unexploited. Davidson's paper offers no diagnosis of a failure of this economic principle, and hence makes no case, as far as I can see, that a free market does not perform reasonably well. There is a lot of slippage in its performance, but not enough to justify reliance on price controls. I see a plain element of perversity in controls as they have been, and are now, administered with regard to U.S. petroleum.

According to the study by William Nordhaus (*BPEA*, 3:1973), the efficient competitive price of petroleum should be less than \$2 a barrel. In fact, the price is at least quadruple that. If the free market is doing its job, how can the price be so far above the Nordhaus prescription?

The first reason is monopoly, which is excluded in the Nordhaus diagnosis. What we have is a monopoly or some kind of highly effective cartel, operating with a competitive fringe. This means that the monopolist sees as his demand function the difference between the market demand function and the competitive supply function. The existence of a competitive fringe in petroleum is demonstrated in the Erickson paper. There is no significant barrier to entry in this business, and hence production will rise up to the point where the competitors' marginal cost equals price. The problem is that monopolists control such a large share of the market, especially through the multinational companies, that the price is still much higher than their marginal cost. The major U.S. companies control about 50 percent of U.S. petroleum, and that portion may be part of the monopoly supply that is set against the demand function that OPEC and the majors face. As a result, the monopolists can drive the prices way up, even though the competitive fringe raises its supply up to the point at which its marginal cost equals price. Despite some competition, monopoly is able to quadruple the price compared with what Nordhaus estimates it should be.

It follows that the nation needs to do something about monopoly in the oil business. I endorse that part of Davidson's policy prescription—to put as much oil as possible under diversified ownership and, in particular, to keep as much as possible out of the existing cartel.

I am very skeptical about the alleged effect of speculation that Davidson and his associates stress so much. I strongly doubt that, in a competitive market, a speculative bubble could develop and no one would foresee its eventually bursting. I see no evidence to support the claim that even competitive suppliers are now withholding output because they believe the price is going to rise further. I believe that the competitive suppliers are now riding up a very steep short-run marginal cost schedule. They are producing at marginal costs equal to the high price, and there is no speculative element in that. I can't accept the whole business about speculation with a capital "S"; I have never found it a convincing part of Keynes, and I find it a no more convincing part of Davidson.

The authors propose to solve this problem with price controls even if the market is made competitive. They offer the ingenious suggestion that speculation can be broken by imposing price ceilings that rise less rapidly than the interest rate. But then speculation against the removal of price controls becomes the real danger. People cannot conceivably be convinced that price controls will last forever. Hence, controls will always generate speculation against the probability that, because of shortages, they will break down and be eliminated.

The amazing conclusion of this study is that Project Independence will bring oil prices down close to their pre-embargo levels. As Davidson recognizes, that conclusion is in complete conflict with the study at MIT that I have been involved in, which estimates that Project Independence will result in oil prices of about $12.

As he points out, part of this difference is that we at MIT treated 1973 as a point of long-run equilibrium. That assumption on our part seems quite clearly wrong. But I doubt that much of the discrepancy can be explained by taking 1971 as a more plausible point of long-run equilibrium. It would take a lot of work to identify the elements on both the supply and demand sides that account for the large discrepancies between the findings of this study and of previous studies.

The elasticity estimates themselves do not seem to explain the difference. Like Charles Schultze, I am uneasy about the notion of a fairly simple static supply function for petroleum. There is very high substitutability between the supply of petroleum today and the supply a year from now; the intertemporal cross-elasticity must be at least 10, and might be as high as 50. A one-year supply elasticity is not the relevant number for this analysis. Much more thought is needed to develop an intertemporal supply function that takes into account the very high cross-elasticity.

I have a few comments on the paper by Erickson and his associates. I concur in their conclusions about the competitiveness of the oil market. In particular, I agree that special tax provisions do not have very much to do with the competitiveness of the industry; in fact, I am surprised that the notion that they do is so hard to dispel. Also, I find their estimate of a supply elasticity a little below unity more acceptable than the estimate Davidson uses.

But percentage depletion presents a problem. I thought the reason that some of the international oil companies were willing to give up percentage depletion is that, after deduction of the royalty payments they make to foreign governments, nothing is left over to be taxed. Apparently, oil companies are very successful in assigning their costs to their foreign operations. Hence, the added benefits of percentage depletion may be small; even without that provision, they might still pay essentially no taxes. I doubt that the treatment of depletion in the formula for the user cost of reserves takes appropriate account of this fact.

Paul Davidson: Let me start with a response to Charles Schultze's question. He sees a problem in applying a Marshallian analysis to oil production over time. He argues, in essence, that maintaining a constant production flow and replacing reserves tend to shift the long-run supply curve up over time, contrary to our model. It seems to me, however, that Schultze presented some good reasons why supply was shifting down over time, such as the introduction of secondary recovery, unitization, and offshore drilling.

In part, this is an answer to Hall's question about our differences with the MIT study. That study may have suggested that supply was shifting up over time. Historically, I find very little evidence of a major shift in either direction, certainly not over a decade. In the absence of such evidence, I think it is fair to argue that the supply curve is pretty stable.

The search for reserves does not have to yield diminishing returns. The oil industry does not necessarily develop the least-cost oil reservoirs first. The company may take leases to block competitors from getting to these reservoirs, and then just sit on them as long as they can. Ultimately, they have to decide to drill somewhere, and then they may arbitrarily drill on Block A and not on Block B, even though the anticipated costs of finding might be just as low on Block B. So I don't think that the marginal cost of finding reserves is going to go up very rapidly, although I would concede rising costs if we were considering a period of a century, rather than a decade.

Schultze suggested that the large number of shut-in wells developed suddenly when federal prorationing replaced state prorationing. But why should that in itself cause producers to shut down wells? Offshore wells are efficient, and are not offset wells. The amount brought up in one well affects neither recovery nor the marginal efficiency of another well. Producers could have brought up twice as much oil once they were free of state controls. They didn't. They shut in those wells, and held up the price of oil in the absence of state regulation. In terms of the bottleneck question, it is important to recognize that these shut-in wells are already available for production. It merely requires someone to turn them on. They could produce significant quantities without any delay for exploration or development.

Let me turn to the important question of reserves. I know that some companies have two sets of reserve statistics—one that is reported to the industry and a higher one that is used for internal planning. This assertion is very hard to prove about oil reserves, because the producers are not required to file reports with a public agency.

One of the benefits of natural-gas regulation, however, is that the producers are required to file reports and hence the assertion of underreporting of reserves can be documented. In testimony before the Senate Subcommittee on Integrated Oil Operations (December 13, 1973), FPC economist David Schwartz provided substantial evidence of underreporting of reserves by many gas producers. In one of many examples he cited, one company reported that, as of June 30, 1973, it had zero uncommitted proved reserves in a particular offshore area. A few days later the company entered into an interstate contract to sell natural gas from that property and therefore applied for certification with the FPC. On July 5, five days after reporting zero uncommitted reserves, the company's application for certification estimated the proved reserves to be 3 billion cubic feet per year for the next twenty years.

This is just one of many documented instances that suggest that the statistic on proved reserves is a very unreliable indicator of natural-gas reserves. The problem may be as bad for petroleum, but that cannot be demonstrated because the data are collected by the industry. On the other hand, production statistics—particularly for offshore oil, where the government is the owner—are reasonably accurate.

Let me respond to a few of Hall's comments. I cannot accept his conclusion that profit opportunity brings about efficiency in oil, because I believe monopolies prevent that result. There are differences between a joint monopoly and pure competition. The existence of a brand-name premium in gasoline until a few months ago suggests that even the retail market is not purely competitive. Certainly at the wellhead there are serious departures from pure competition despite the ability of firms to enter as strippers. The scope of the competitive fringe can be overestimated.

As for price controls, if they are announced as temporary and are administered by people with no faith in them, they clearly will encourage user costs. But price controls can work if people are convinced that they are permanent. And I think they can be convinced of that if the government is clever and has regulators who believe in regulation.

I agree with Hall that the cross-elasticity of supply between alternative years is high. That implies that user cost can be fantastically high in this situation. Hence, in order to have stable production flows, some policy must be devised to convince producers that they cannot profit because of user cost.

Laurence H. Falk: I would like to comment on Charles Schultze's assumption of a constant ratio of reserves to production. I see no reason at all why the ratio should be constant. According to the U.S. Geological Survey, producible U.S. reserves (prior to the recent price rises) may be as high as

500 billion barrels. Compare that with the 36 billion barrels of proved reserves currently reported by the companies. Proved reserves can be altered very suddenly, thus changing the reserves-to-production ratio.

We don't know where big oil deposits are located. Before the Ghawar field in Saudi Arabia was discovered, no reserves existed there, and no structure there was identified by geologists as a particularly good prospect. That discovery suddenly increased world reserves by more than twice existing proved U.S. reserves. As this suggests, the reserves-to-production ratio can change dramatically with new discoveries. And the ratio will always appear lower than it actually is because of underreporting.

Edward W. Erickson: I want to support some of the price estimates made by Paul Davidson and then qualify that support substantially. I participated in an effort to predict average bonus bids for three offshore lease sales, two in 1972 and one in 1973. It turned out that the assumption that the bidding firms expected to get \$5 a barrel for oil and \$0.65 per thousand cubic feet for natural gas yielded amazingly accurate forecasts. On the equimarginal principle, this suggests that the marginal cost of developing onshore oil reserves in 1972 and 1973 was about \$5 a barrel, quite close to the number Davidson calculates.

I submit, however, that the price was appropriate for 1972 or 1973, rather than for 1980, and for offshore oil, rather than for all domestic oil. The domestic supply curve is drifting up and to the left, because the United States is a relatively old petroleum province. Companies have drilled the least-cost prospects first, and the exhaustion of the inventory of prospects is only partially offset by technological change. Many small technological changes are occurring now but none is as cost-saving as the invention of the rotary drill, and they are not sufficient to offset the drilling up of the available prospects. Conditional on OPEC cartel prices at current levels, this process will make the 1980 market-clearing price much more than the \$5 a barrel appropriate to the conditions existing in 1972 and early 1973.

The key issue for 1980 production is the rate of offshore leasing. Lease sales amounted to 1.7 million acres in the first ten months of 1974, a sharp increase over 1973, and may rise as high as 10 million acres by 1980. That would provide some relatively low-cost reserves. But even offshore development runs into diminishing marginal returns, because the companies deplete the best prospects first. They are moving into a margin of deeper-water and higher-cost development. Furthermore, since offshore wells now produce only about 12 percent of domestic oil and condensate, their cost cannot substantially diminish the overall domestic cost.

I would be much more confident about relying on the market to generate the best possible outcome than on some price-control scheme. I submit the natural-gas case as evidence in that regard.

General Discussion

There was a lively discussion concerning the market power of the major U.S. oil companies. Edward Erickson argued that industry concentration ratios were small and that because there were about twenty large companies in the industry, they would find it hard to exercise effective market control. The historically observed problems of resource misallocation in the domestic petroleum industry have been due more to TIPRO (Texas Independent Producers and Royalty Owners) than to the major U.S. oil companies. Paul Davidson would not agree that the existence of twenty promiinent firms precluded effective cartel action, arguing that even a large cartel can stick together if the firms have common objectives. On the international oil scene, Erickson and Arnold Packer thought the power of the major companies was small in comparison with the power of the OPEC cartel. Michael Wachter argued that historically, if not currently, the major firms and OPEC have been acting in coordination and that the United States helps sustain the international cartel by dealing with OPEC through the oil majors.

James Tobin questioned the theoretical basis for Davidson's contention that a conglomerate energy company will suppress an alternative energy source to protect the value of its oil reserves, or the value of OPEC oil reserves in which it has a concession. A conglomerate will introduce a new technology or new source when its marginal full cost is lower than the marginal variable cost of its existing operations. It will continue to operate its old sources so long as their marginal variable costs can be reduced, by partial curtailment of their operations, to the level of the marginal costs of the new operations. These are the same conditions under which a new technology would be introduced under perfect competition. The competition and conglomerate cases differ only if the two technologies are mutually exclusive. Marina Whitman and Davidson thought that while this analysis might apply if the new technology were already in existence, the conglomerate might not be willing to make as large an investment as a competitor to develop an alternative energy source that would diminish the value of the conglomerate's oil reserves.

Tobin began an extended discussion by asking Davidson to clarify his definition of "zero user cost." He and other participants objected to Davidson's excluding from the price of oil under "zero user cost" the diminishing marginal-returns rents associated with an exhaustible resource. As a result of this exclusion, the price of oil for Davidson is only the marginal factor cost plus a monopoly markup. By that definition, Christopher Sims said, "zero user cost" may not be a desirable goal, because it would exhaust reserves prematurely. Davidson argued that oil may be exhaustible over a very long time horizon, like 200 years; but over normal time horizons, oil should not be modeled in the aggregate as exhaustible. He noted that even the sun will burn out eventually, but that doesn't mean we should analyze sunlight as an exhaustible resource. And, to support his view that future reserves were so uncertain that they should not be modeled as exhaustible, he referred to a Bureau of Mines report of a geological formation under South Carolina that might be as productive as the oil reservoirs of Saudi Arabia.

Saul Hymans was unwilling to accept Erickson's user-cost formula without some test of the sensitivity of the regression to alterations in the formula. He said complex user-cost expressions are frequently inserted in regressions without any knowledge of whether the estimation succeeds because of, or in spite of, the form of the expression. Hymans also argued that, in a proper model of supply, current production and the discovery rate of new oil would be jointly determined.

Sims and Robert Spann were not so ready as Davidson to dismiss speculation by oil producers as socially undesirable. When producers act upon the information that prices are going to change, they tend to even out the long-term path of prices. Spann said that the recent energy crunch might have been alleviated if producers had had incentives to speculate against the possibility of an Arab oil shutoff. If they could have counted on prices being allowed to rise freely, Americans would have stockpiled oil to sell at high embargo prices, increasing the supply of oil and diminishing the price. Arthur Okun thought Spann's scenario was academic because no one foresaw a cessation of oil imports before the embargo. Franco Modigliani agreed with Davidson that a speculative bubble could persist for a long time and could generate false market signals.

The failure of U.S. supply to respond thus far to higher prices was discussed. Erickson argued that the weak supply response was a market failure arising from price controls, including the present control of prices for "old" oil. Okun noted that there is now an incentive not to increase production on an oil property if production will not exceed 100 percent of its 1972 production level, the condition that would free the price on further production increments as well as on matching quantities of old oil. Charles Schultze suggested that stripper wells are now being drilled because their free price makes them more profitable, even though they are more costly and less productive. Producers also appear to be speculating against removal of price controls: drilling is up 40 percent, but production is down 6 or 7 percent.

R. J. Gordon questioned whether Davidson's production forecasts for 1980 could possibly be achieved even if his prescription for policy were followed, in view of the massive investment that would be required. Whitman wanted to know what environment would be necessary to achieve self-sufficiency at Davidson's prices by 1980. Would the price of foreign oil matter and would the United States have to pledge price supports for domestic oil? Whitman and Packer were concerned that we be prepared for the eventuality of someday producing ten-dollar oil rather than importing five- or even two-dollar oil in a future with self-sufficiency achieved and the OPEC cartel broken.