BUSINESS REVIEW

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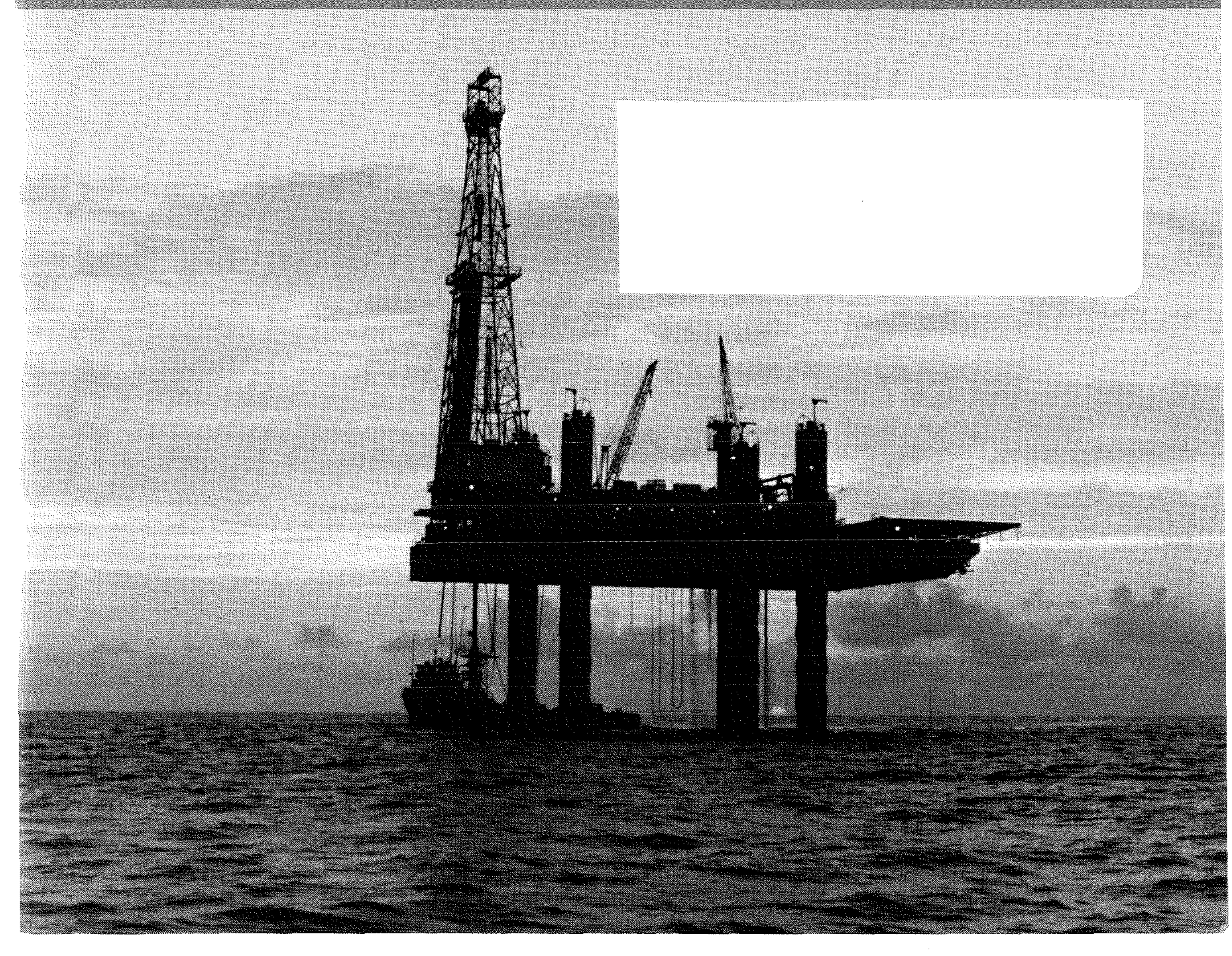
FEDERAL RESERVE BANK OF SAN FRANCISCO

WESTERN ENERGY AND GROWTH



Western Resources: Key to the Nation's Energy Future

Yvonne Levy

The United States is dedicated to a policy of independence from foreign sources of energy. Originally, the Administration envisioned Project Independence as a "crash" program to achieve the national goal of complete energy self-sufficiency by the end of the decade. Later, in recognition of the intolerable strains such a program would place on the environment and on the productive capacity of the economy, the Administration relaxed that goal to allow for a more leisurely target deadline of 1985. At that point, the nation would not be completely self-sufficient, but its oil imports would be sufficiently small—3 to 5 million barrels a day—that it would be invulnerable to disruption from oil embargoes or worldwide price increases.[1] To help achieve this goal, President Ford last January called for the nation to reduce its oil imports by 1 million b/d by the end of 1975 and by 2 million b/d by the end of 1977.

With that as background, this article will discuss the broad trends in demand and supply which have led to the nation's growing dependence on insecure and costly foreign sources of energy, the supply strategies and conditions required to move the nation toward the goal of energy independence, and the nonfinancial constraints likely to be encountered. The question of financial constraints on development—a major topic in itself—is not considered in this analysis. Our primary emphasis is on the prospects for increased energy development in the West, which because of the abundant and varied nature of its energy-resource base, is certain to play a major role in any national effort to increase domestic energy production.

The Energy Gap

The events of late 1973—the Arab embargo and the quadrupling of oil-import prices—focused attention on the dangers inherent in the nation's growing dependence on foreign sources of energy. But that situation had been developing for over two decades, because of a growing imbalance between domestic production and consumption of energy. U.S. energy consumption increased at an annual rate of about 3.5 percent between 1950 and 1965, and the rate accelerated to 4.5 percent over the 1965-73 period. (In 1974, however, consumption dropped by 2.2 percent to 73.1 quadrillion British Thermal units—BTU's—under the impact of rising energy prices, the economic slowdown and conservation efforts.)[2] Although energy use has grown even faster in other nations of the world, U.S. per capita consumption is still six times the world average (Chart 2).

Domestic energy production, on the other hand, has lagged far behind the growth of demand. Production grew at a 3-percent annual rate between 1950 and 1973, despite a steady decline in the present decade. In this recent period, crude-oil production dropped from a peak of 9.6 million b/d to 8.8 million b/d, while natural-gas production dipped slightly to 21.9 trillion cubic feet. Coal production, at 606 million tons last year, remains below the level of thirty years ago. Other energy sources were of minor importance. Nuclear power, although growing rapidly, supplied less than 2 percent of the nation's total energy requirements last year, while hydropower maintained its steady 4-percent share. Altogether, the U.S. produced domestically last year only 60.7 quadrillion BTU's of its total consumption of 73.1 quadrillion BTU's (Chart 1).

Role of foreign imports

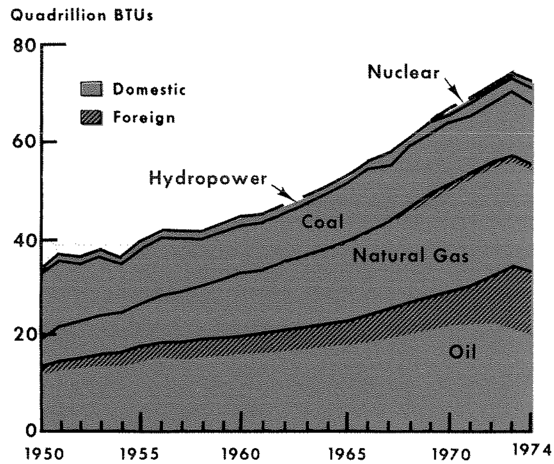
To fill the growing gap, the United States has come to rely increasingly upon foreign imports —primarily crude oil and refined petroleum products. Over the past decade, oil imports rose from 2.3 million b/d to 6.1 million b/d. Foreign nations now supply 36 percent of the nation's total petroleum consumption and 16 percent of its total energy consumption (Chart 3).

Canada and Venezuela are still our principal suppliers, but the Middle East has recently become a key supplier, especially since domestic production has levelled off. Prior to the embargo, U.S. imports of Middle East crude and refined petroleum products amounted to about 20 percent of total oil imports and 6 percent of total petroleum consumption, and imports of products refined from Arab crude were even more important. Thus, the decline in imports during the embargo was equivalent to 14 percent of total U.S. petroleum consumption.

The impact on the economy would probably be much more serious in the event of another embargo. The U.S. could be importing as much as 23 percent of its total energy requirements by 1985 if steps are not taken to increase domestic supplies and to slow the growth of demand. Moreover, its dependence could be much greater on Middle Eastern nations, which hold 60 percent of the world's oil reserves. Aside from its national-security implications, this dependence could have serious economic consequences in the form of possible disruptions in supply, inflationary pressures and balance-of-payment difficulties.

Chart 1

U.S. Energy Consumption by Source



From coal to oil and natural gas

Another crucial change in energy patterns has been the shift away from coal and toward oil and natural gas in the past two decades.[3] Coal still remains the dominant fuel for electric-power generation, an increasingly important energy user, but overall, coal now accounts for less than 20 percent of the nation's total energy requirements. Despite an upswing since 1959, coal production still has not regained the peak level reached in 1947. Coal's declining importance reflects its high sulphur content, as well as the convenience and comparative low cost of oil and gas.

Natural-gas consumption rose rapidly after World War II, as pipelines were built to transport gas from the producing regions of the Southwest to other areas of the nation. Between 1950 and 1970 natural-gas consumption rose almost four-fold—twice as fast as total energy consumption—but shortage of supplies then began to restrict consumption. Nonetheless, natural gas still accounts for 30 percent of total consumption.

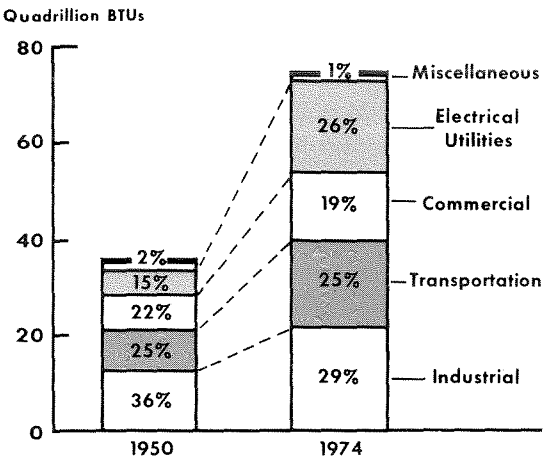
Since 1954, the Federal Power Commission has regulated wellhead prices of natural gas sold in interstate commerce. Under this regulation, the FPC has held natural-gas prices at artificially low levels, stimulating consumption but at the same time discouraging producers from trying to find new supplies. Since 1968 Americans have been consuming natural gas at about twice the rate of discovery. As a result, proven domestic reserves (including a major Alaska find) dropped from 293 trillion cubic feet in 1967 to 237 trillion cubic feet in 1974—equivalent to only 10 years' production at current rates.[4] Serious shortages have developed, despite a doubling of imports over the 1967-74 period to almost 5 percent of total gas consumption.

The environmental movement meanwhile has helped to boost the demand for natural gas. Natural gas is the cleanest-burning fossil fuel in that it is free of sulphur and particulate matter—in contrast to "dirty" coal, the traditional fuel of power-generating plants. To meet the Federal environmental requirements, an increasing number of power plants have had to switch to natural gas and, during the past few years, due to the gas shortage, to low-sulphur fuel oil.[5]

In this situation, petroleum has proven to be pivotal in balancing the nation's energy needs. Oil consumption increased at a 5-percent annual rate during the 1960-70 period, and then accelerated to a 6-percent rate between 1970 and 1973. In that period it grew faster than total energy demand, so that oil's share of total consumption rose to 46 percent in 1973. (During the 1974 crisis, of course, oil consumption declined.) Petroleum supplies nearly all of the nation's transportation fuel, 45 percent of household and commercial usage, almost 25 percent of industrial energy, and about 13 percent of electric utilities' requirements.

Chart 2

U.S. Energy Consumption by Sector



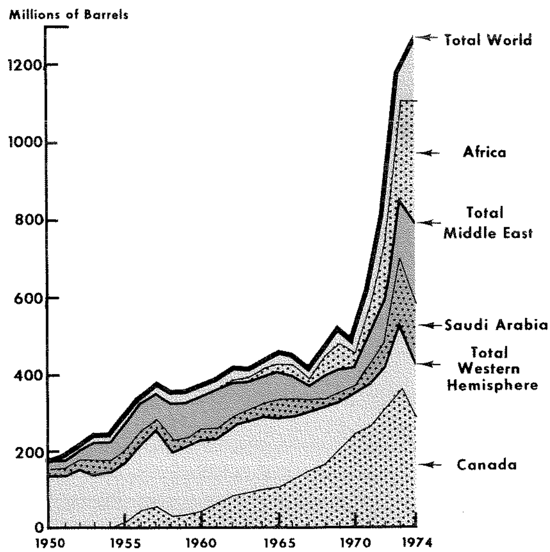
Domestic petroleum production has trended downward in the face of booming demand. This decline reflects an almost uninterrupted decade-long reduction in crude-oil reserves—except for 1970, when the Alaska bonanza added 9.4 billion barrels to the nation's reserves. Proven reserves at the end of 1974 amounted to 38.8 billion barrels—the equivalent of 12 years' supply at the current production rate. Higher prices recently have stimulated increased drilling, but reserves still fell during 1974.

Resources versus reserves

The recent decline in oil and gas production can be attributed not to a scarcity of resources, but rather to inadequate economic incentives and environmental restrictions. Here a distinction must be made between resources and reserves. The nation's petroleum resource base may be thought of as the total amount of oil and gas occurring in the rocks lying within its boundaries, including the continental shelf. Resources comprise all those materials that are potentially recoverable, including those in deposits as yet undiscovered. Reserves, on the other hand, comprise that portion of the resource base that has been identified, explored and delineated with a reasonable degree of certainty, and from which a usable commodity can be extracted under existing economic and technological conditions. The occurrence of oil and gas is finite, being governed by geology, but the rate at which oil and gas resources are discovered, developed and transferred to the category of reserves is determined primarily by economics, technology, and environmental and political considerations. Proven reserves represent the underground assets (inventory) in which the petroleum industry has made specific investments.

Development activity in the U.S. industry, measured by the number of exploratory wells drilled, declined sharply after 1956 simply because the financial rewards from domestic development did not compare favorably with more attractive opportunities abroad, especially

Chart 3
U.S. Crude Oil Imports



in the Persian Gulf area. In addition, domestic oil prices failed to rise as fast as costs or industrial prices in general. The price of crude almost doubled over the 1947-57 period but thereafter rose only moderately, from $3.09 per barrel in 1957 to $3.66 per barrel in 1973. In real terms, oil prices declined by 18 percent. Natural-gas prices rose rapidly until the early 60's, largely because gas had been drastically underpriced when it first came into use as a by-product of oil, but the price declined 6 percent in real terms during the following decade. Environmental controls meanwhile helped to raise domestic costs, and also to curtail drilling and refinery construction.

In August 1973, Phase IV price controls were removed from "new oil"—defined as that oil in excess of a property's production rate in the corresponding month of 1972—and from a portion of "old" oil production. In January 1974, controls were lifted for petroleum liquids produced from "stripper" wells, i.e., from properties where average production per well did not exceed 10 b/d during the preceding calendar year. Prices on the remaining production ("old" oil) have remained limited to $5.25 per barrel, while prices for "new" oil have ranged from $12 to $13 per barrel at wellhead, in line with the prices of foreign oils of comparable quality. If all controls are lifted in the wake of this summer's intense political maneuvering, the resultant price rise could result eventually in larger reserves and stimulate increased production.

Domestic Supply Prospects

The extent of dependence on oil imports will depend primarily on the world price of oil, which will in turn largely determine U.S. energy prices, and also upon Federal government policies to slow the growth of consumption and encourage production. In its *Project Independence Report,* the Federal Energy Administration (FEA) therefore examined consumption and production possibilities at two different price levels—$7 and $11 per barrel—and under two sets of assumptions: 1) Business-As-Usual, assuming a continuation of policies in effect prior to 1973 (except for those controlling prices) and 2) Accelerated Development, assuming changes in policies to further stimulate production, such as accelerated leasing of offshore lands on the Outer Continental Shelf, the opening up of Naval Petroleum Reserves for production, and increased Federal funding for energy research and development.[6]

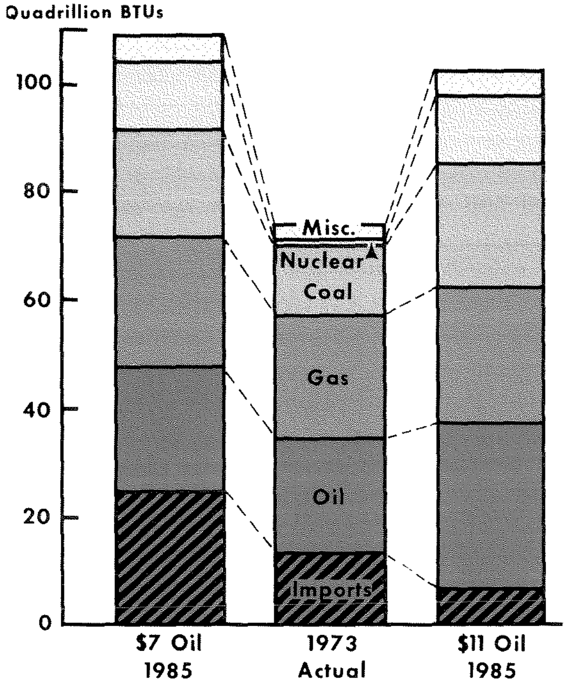
The FEA concluded that the long lead time involved in bringing new production on stream will forestall any increase in U.S. crude-oil production over the next few years, regardless of what the Federal government does to encourage production. Imports will thus rise in the absence of conservation strategies or direct limitation on imports. But by 1985, assuming Business-As-Usual conditions, U.S. production at a $7 price would rise about 5 percent above current levels to 8.9 million b/d. "Lower 48" production would fall almost by half, but this would be offset by increased production from Alaska and the Outer Continental Shelf. At an $11 price, however, domestic production would increase nearly 50 percent to 12.8 million b/d, mostly because of the more widespread use of secondary- and tertiary-recovery techniques (Chart 4).

The FEA claims that, under Business-As-Usual assumptions, domestic natural-gas production by 1985 would rise 10 percent above the current level of 22.4 trillion cubic feet if the price is deregulated, but would fall by some 30 percent if the ceiling is retained. A base price of at least 80 cents per thousand cubic feet for newly discovered gas is considered necessary to elicit this 10-percent increase in output. The Federal Power Commission already has moved toward this price level by raising the ceiling price of "new" gas (gas from wells producing since January 1, 1973) in two steps to 50 cents last December. If all new gas were permitted to go to the 80-cent level, it would result in more than a doubling of the average wellhead price for "new" and "old" gas combined, or an increase of at least $5 billion in the annual cost to consumers. Complete deregulation, which would imply prices well above 80 cents, would probably bring forth little additional output, owing to the physical limits on potentially exploitable resources and the inapplicability of secondary and tertiary recovery techniques to gas production.

Under these circumstances, coal production might double by 1985 to about 1.1 billion tons, replacing both gas and oil in many industrial and electric-utility uses. Nuclear power meanwhile could increase its share of electric power generation from 7 percent to 30 percent. Other fuels and energy sources, such as geothermal and solar power, are likely to be of only marginal importance by 1985, even under the higher ($11) oil-price assumption.

The FEA study concludes that oil imports over the long-run will be inversely related to the level of oil prices—the higher the price, the lower the vulnerability. At an $11-per-barrel price, imports could be reduced from a current level of around 6 million b/d to 3.3 million b/d by 1985. This decline would result from a reduced demand for energy and increased production from sources that are economically feasible

Chart 4
Sources of U.S. Energy Supply
(Business-As-Usual Assumptions)



at higher prices. However, maintenance of an $11 price would require extremely large production cutbacks by OPEC nations. Thus, the world price might be pushed down to about $7 per barrel—a price which could lead to imports of over 12 million b/d by 1985.

Consequently, for the nation to reduce its imports to a target level of 3-to-5 million b/d by 1985, it would have to adopt a policy of accelerated development. This would include increased offshore leasing off the Atlantic and Pacific coasts, development of Naval Petroleum Reserves, and increased Federal support for nuclear-plant construction, shale oil and synthetic-fuel production. Under this strategy, domestic oil production could rise almost to 13 million b/d at a $7 price and to 17 million b/d at an $11 price.

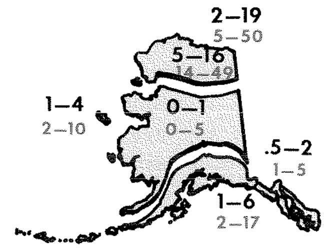
Technological and resource barriers

The ability to attain these levels of production will depend not only upon price but upon a wide range of other considerations as well. Indeed, recent estimates of the nation's resource base by the U.S. Geological Survey[7] indicate that undiscovered recoverable resources of oil and gas may be much smaller than the USGS had earlier suggested in its contribution to the *Project Independence Report.* (The adoption of more conservative estimating techniques accounts for the downward revision.) According to current estimates, undiscovered recoverable resources of oil and natural-gas liquids range between 61 billion and 149 billion barrels, and undiscovered recoverable natural-gas supplies range between 322 trillion and 655 trillion cubic feet. In both cases, the latest estimates are far below even the minimum levels estimated just a year ago. However, another 30 billion barrels of oil and 180 trillion cubic feet of gas may be recoverable from unexplored parts of known fields through the use of advanced-recovery technologies (Map 1).

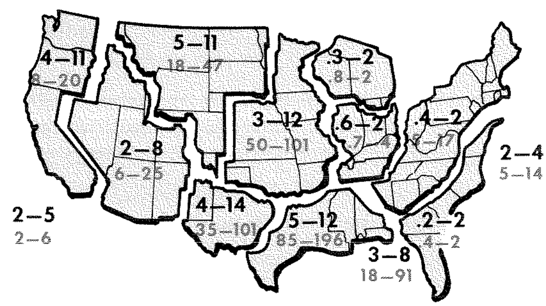
Aside from the question of how much is actually recoverable, the production and processing of energy materials could be constrained by inadequate manpower, materials, water and high-technology equipment — not to mention financial resources. For example, water is essential to almost every energy process. It is required to extract raw materials from the earth, process the materials into useful fuels, generate electricity from those fuels, and dispose of waste products in an environmentally acceptable manner. Yet in the rural regions of the West, where a substantial portion of the nation's total energy resources are located, there is not only a relative scarcity of water but also a prior call on roughly 90 percent of the available supply for agricul-

Map 1

Undiscovered Recoverable Resources of Oil and Gas*



Undiscovered Recoverable Oil 12—49 Billion Barrels
Undiscovered Recoverable Gas 29—132 Trillion Cu. Ft.



Undiscovered Recoverable Oil 36—81 Billion Barrels
Undiscovered Recoverable Gas 286—529 Trillion Cu. Ft.

*Estimated range at 95-5 percent probability levels. For example, in the case of the Pacific Coast region, the chance of having undiscovered recoverable resources of crude oil of at least 4 billion barrels is 95 out of 100; however, the chance of having 11 or more billion barrels is only 5 out of 100.

tural purposes. Meanwhile, recent shortages have dramatized the potential problems that could be faced in obtaining the drilling rigs, platforms, pipe and tubing, steam-turbine generators and other equipment required to meet targeted production levels.

Alaskan Oil and Gas

Alaska is certain to play the largest role in the current effort to increase domestic oil and gas production. Actually, the state has been an important factor in the industry for some years; in 1974 it produced 193,000 b/d of oil and 383,000 million cf/d of natural gas, with most of the output coming from the Kenai Peninsula/Cook Inlet area in the southern part of the state. By mid-1977, however, the Prudhoe Bay field on the North Slope should be producing 1.2 million b/d—and with full development of that and neighboring fields, the pipeline should be operating at its full capacity of 2.0 million b/d by the year 1980.

The pipeline project includes the 789-mile pipeline from Prudhoe Bay on the Arctic to Valdez on the Gulf of Alaska, and in addition, a road from the Yukon River to Prudhoe Bay, seven air fields, twelve pump stations, an ocean terminal and a number of offices and related service buildings. At this summer's peak, about 20,000 people were employed on the project. The overall cost, not including the cost of financing, is expected to top $6 billion—more than eight times the original estimate.

Tapping Prudhoe's resources

The Federal Power Commission is currently studying two pipeline proposals to transport North Slope gas to the lower 48 states. One company proposes a $6.7-billion project to deliver the gas to the U.S. West Coast via a combination pipeline and tanker system. An 809-mile underground pipeline would be built from Prudhoe Bay to Gravina Point, Alaska, where the gas would be liquefied for shipment by tanker to Point Conception, California. Alaskan gas would permit some West Texas supplies that are ordinarily piped to California to be shipped instead to Eastern and Midwestern markets. A second company proposes an $8.0-billion project that would deliver gas through a 2,600-mile pipeline from Alaska and Canadian Arctic areas down the Mackenzie River Valley of Canada to Idaho and Montana. Related lines would then carry the gas to California, the Midwest, the East Coast and Eastern Canada.

Midwestern Congressmen vigorously support the Mackenzie Valley project on the grounds that it would bring more gas to their energy-deficient region. Supporters of the trans-Alaska route argue, on the other hand, that the trans-Canada route would leave the U.S. vulnerable to a potential cutoff of gas supplied by Canada. They argue further that the trans-Canadian pipeline would adversely affect the U.S. balance of payments, by causing billions of U.S. dollars to be spent in Canada to hire Canadian workers and pay Canadian taxes. The trans-Canada route appears to have the most support at the present time; however, if Petroleum Reserve No. 4 and additional reserves are developed, both transmission systems eventually may be required to handle the increased supply.

Alaska presently has proven oil reserves of 10.1 billion barrels and gas reserves of 31.1 trillion cubic feet, or about 33 and 13 percent, respectively, of the nation's total reserves. Most of this fuel is contained in the Prudhoe Bay field, by far the largest hydrocarbon deposit in the Western hemisphere. But the state may also contain undiscovered oil resources of 12 to 49 billion barrels—roughly one-quarter of the U.S. total—and undiscovered natural gas resources of 29 to 132 trillion cubic feet—roughly one-tenth to one-quarter of the U.S. total.

On the basis of its earlier (and higher) estimates, the FEA's *Project Independence Report* suggested that Alaskan oil production could reach as much as 4.6 million b/d by 1985 at a $7 price, and as much as 5.3 million b/d at an $11 price. To develop that level of resources, massive new investment would be required—another 48-inch oil pipeline, both the trans-Alaska and Mackenzie Valley gas pipelines, processing facilities for both the North Slope and Outer Continental Shelf, and transportation and other facilities to support these basic systems. The required investments would be substantial even if the conservative USGS estimates of resources turn out to be correct.

Other onshore resources

Exploration and drilling activity already has accelerated on the North Slope, upper Cook Inlet basin and the little-explored Susitna basin. But if Alaska's onshore resources are to be fully exploited, a larger proportion of Federal and state lands will have to be opened for development. Only about 5 percent of the 231,887 square miles of onshore land with resource potential has been offered for lease to date. Alaska's Department of Natural Resources last November announced a schedule of oil-and-gas lease sales for the 1975-78 period. But there are some complicating factors; the Federal government recently contested state-ownership rights to the Lower Cook Inlet,[8] and other offshore areas near the coastline could also be embroiled in jurisdictional disputes.

The Alaska state government is anxious to hold more lease sales to ease its financial problems. With the state budget running at $500 million or more each year, and state revenues at only about $300 million, the government is fearful it will run out of funds before North Slope oil royalty money begins to flow into the state treasury in late 1977 or 1978. The $900 million which the state collected in bonus money for the 1969 lease of North Slope oil fields is now two-thirds spent.

As for Federal land, Congress is still debating whether Naval Petroleum Reserve No. 4 (North Slope) should be opened to oil drilling by private companies. The Navy is currently drilling several test wells and has retained a contractor to do some exploratory work, but some experts argue that the best way to develop the reserve would be to lease tracts within the reserve to private industry. It could take at least ten years to explore, develop and construct delivery systems from NPR-4, and the cost could be well over the $15 to $20 billion required for Prudhoe Bay. However, the 3,500-square-mile reserve is geologically similar to Prudhoe Bay, and similar economic benefits could flow from its development in coming decades.

Meanwhile, Congress recently passed legislation authorizing large-scale civilian oil production from the Elk Hills Naval Petroleum Reserve near Taft, California, for the creation of a national strategic stockpile. Only jurisdictional problems remain to be resolved before exploitation of this field is begun.

Offshore resources

Offshore drilling for oil and gas in the Federally owned Outer Continental Shelf offers the greatest potential for significantly increasing U.S. oil and gas production by 1985. But exploitation of these areas, including not only the already lucrative Gulf of Mexico but also the untapped waters off the Gulf of Alaska and the Atlantic Coast, will be circumscribed by environmental and other difficulties. Development of the Outer Continental Shelf was made possible by 1953 legislation authorizing the Federal Government to lease tracts lying more than three miles off the coast. Production in 1974, although below the 1971 peak, comprised 11 and 14 percent respectively of the nation's total output of oil and gas. This was in addition to the production from state-owned land within the three-mile limit.

Nonetheless, only about 10 million of the 80 million acres in the Outer Continental Shelf have been offered for lease since 1953. To help meet its Project Independence goals, the Administration in late 1974 announced an accelerated schedule of lease sales for the 1975-78 period. Sales in 1975 alone may not reach the total 10 million acres scheduled, but will be considerably higher than in prior years and will include frontier areas in the Gulf of Alaska and possibly the Atlantic. According to USGS estimates, the Gulf of Alaska may contain 1 to 6 billion barrels of oil and 2 to 17 trillion cubic feet of natural gas, and other promising areas include the Beaufort, Bering and Chukchi Seas and the Outer Bristol Basin.

The planned leasing of new offshore areas has generated heavy criticism from environmentalists. Indeed, the President's Council on Environmental Quality this spring warned of grave problems from drilling, especially in the Gulf of Alaska. The Council foresaw a high probability of oil spills and wrecked drilling operations because of severe storms, earthquakes and tidal waves, in an area where conditions are "more severe than the industry has yet experienced anywhere in the world." Many conservationists also forecast heavy damage to animal life, since the Gulf is rich in fish, birds and marine animals. Despite these objections, a sale of Gulf of Alaska leases may occur in December of this year. Action is even more likely here than off the Atlantic Coast, where intense concern about drilling has risen because of the highly populated nature of the region, and where the states and the Federal government are locked in a jurisdictional struggle over title to the continental shelf.

California Oil and Gas

In California, hopes for reversing a four-year decline in oil and gas production also rest upon the development of the Outer Continental Shelf. Onshore, the most prolific oil-producing province in the state—and in relation to size, probably in the world—is the relatively small, semiarid Los Angeles basin. But since this is a densely populated area with very high land values, the area available for oil development is greatly restricted.

The productivity of existing wells may be increased, however, through the use of advanced-recovery techniques that boost the amount that can be produced from each reservoir above what could be obtained by the use of natural forces alone. California firms have had some success with a technique known as water flooding, and spurred on by the high price of oil, they are now utilizing a tertiary-recovery process called steam flooding. With the help of these and even more advanced techniques, U.S. (and California) reserves might possibly double in size.

California's offshore areas have long been an important source of energy for the nation and of revenues for the state. The first offshore wells in the world were drilled in 1896 as an extension to Santa Barbara's Summerland oil field. By 1974, there were 23 oil or gas fields off California's coast, and their production accounted for 27 percent of California's total output.

Drilling for new oil and gas wells on state-owned tidelands virtually ceased after the 1969 blow-out in the (Federal) Don Cuadros field in the Santa Barbara Channel. That action caused the State Lands Commission to place a moratorium on drilling in state tidelands, and the ban remained in place for almost five years. Even now, approval for drilling is granted only on a lease-for-lease basis.

The U.S. Department of the Interior plans a lease auction this October of about 1.6 million acres on California's Outer Continental Shelf. This area, extending from three to sixty miles off the Southern California coast, is believed to contain as much as 5 billion barrels of crude oil and more than 6 trillion cubic feet of natural gas in formations extending as much as 5,000 feet beneath the sea. Oil industry officials claim that these riches can safely be tapped, since advanced offshore technology could minimize the danger of oil spills and other disasters. But environmentalists argue that the drilling will entail increased risk because of the depth of the formations, and will also lead to other environmentally harmful consequences, such as the construction of extensive transportation, refining and distribution facilities. The Department of Transportation apparently agrees that there are environmental dangers, as it recently announced that probably only half of the 1.6 million acres scheduled for leasing in October would actually be offered. State officials are critical of the present system of leases and royalties, which would return to the Federal government only about 15 percent of the oil's present value—about $21.6 billion over the 50 to 60 year life of the California fields. In their view, the Federal government should retain title to the oil and permit the companies to extract it for a fee, instead of selling leases and receiving production royalties.

Western Coal

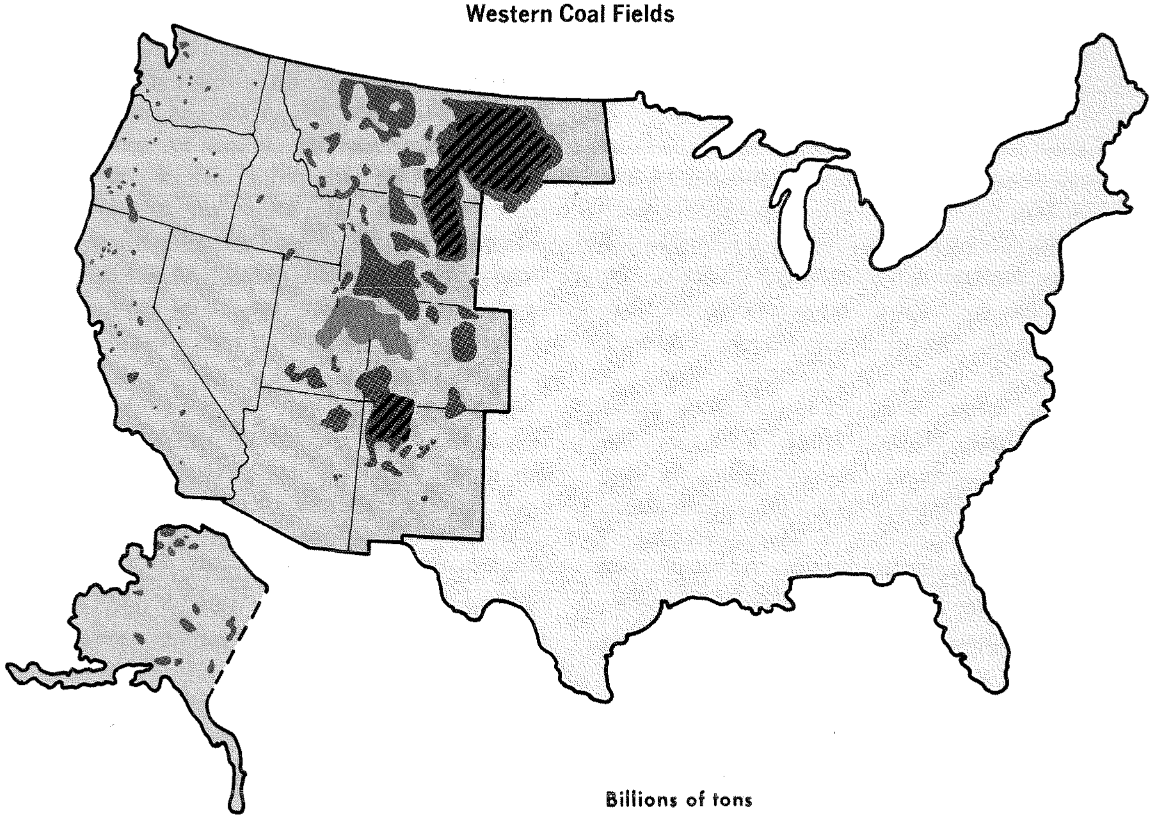
The U.S. is the Persian Gulf of coal with more than one-fifth of the world's reserves locked up in its crust, and coal accordingly is counted on to play a major role in reducing the nation's dependence on uncertain Middle Eastern sources of oil. According to FEA estimates, coal production could reach 1.1 billion tons per year by 1985—almost double the present level—even without any help from higher coal prices. Nearly all of the industry's production will be consumed in the generation of electricity and in steel making. The West is expected to supply most of the increase because Western coal is a clean low-sulphur product which is capable of being mined by low-cost surface-mining techniques (Map 2).

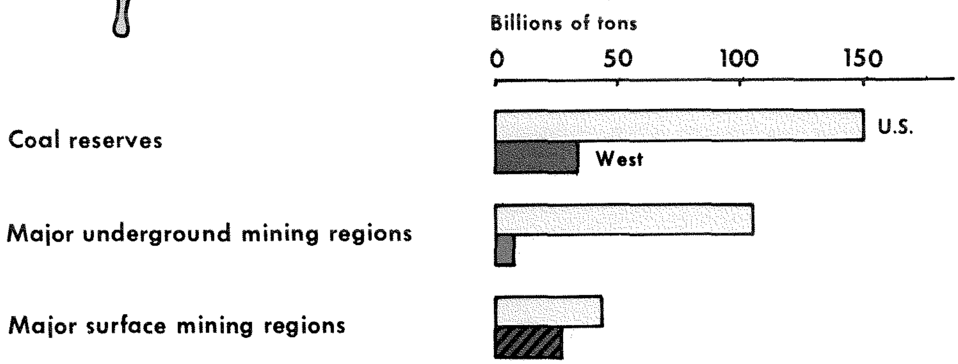
The nation's total coal resources have been conservatively estimated at about 3.2 trillion tons, about half of which has been mapped.[9] These resources, measured in terms of heat content, amount to about three-quarters of the nation's ultimately recoverable fossil fuels. Only about 150 billion tons are recoverable under current technological and economic conditions—but even this amount would provide over two centuries' supply at current consumption rates.

The Western states contain one-fifth of these enormous recoverable reserves of coal. Utah has almost 7 billion tons of reserves, mineable through underground techniques, while the states of Montana, Wyoming, New Mexico and North Dakota contain about 26 billion tons of strippable reserves. These Western reserves comprise four-fifths of the nation's low-sulphur deposits and more than one-half of the total reserves mineable through surface methods. Until recent years, the West's subbituminous deposits occasioned little interest, because they have a lower BTU content than Eastern coal and are expensively far from Eastern markets. But utilities, faced with new clear-air legislation, are now buying substantial amounts of this coal because of its very low sulphur content. Western coal production thus has grown phenomenally in the last few years, although the region still accounts for only 10 percent of total U.S. production.

Map 2

Western Coal Fields





Problems of surface mining

Surface mining—the dominant mode of production in the West—has a number of advantages over underground mining. Productivity in underground mines dropped 29 percent between 1969 and 1973, under the impact of labor troubles and (particularly) new safety legislation, and output and costs were affected commensurately. In this situation, the industry has turned increasingly to surface mining, which now accounts for one-half of the nation's total output, compared with less than one-third in 1960. Strip mining requires less manpower and capital than underground mining, and is also safer and more productive—but it can also be environmentally disastrous.

Strip mining involves removing the earth cover, or "overburden" from a seam of coal lying relatively near the surface, then scooping up the fuel and carrying it away. In the process, streams can be diverted or fouled with poisonous minerals, drainage patterns upset and huge mountains of rubble created. In the arid West, where strip mining is in its infancy, surface vegetation may not grow back for years or even decades. In the meantime the land is vulnerable to constant erosion by wind and water, and becomes unsightly and worthless for agriculture or recreational purposes.

Congress recently sustained a Presidential veto on a bill that would have established stringent Federal controls on strip mining, far more restrictive than state standards presently in effect. In a sense, the legislators were expressing a preference for energy independence over the goal of environmental protection. The legislation would have required all companies engaged in strip mining to protect water sources from pollution and to return strip-mined lands to whatever condition they were in prior to mining. To pay for land reclamation, a tax would have been imposed on each ton of coal mined.

The bill's supporters argued that coal-company profits would be more than sufficient to cover reclamation costs, in view of the sharp upsurge in coal prices generated by the oil crisis. Their arguments failed, however, in the face of industry claims that reclamation requirements would not only reduce output severely but would also raise costs as much as $5 to $6 a ton, giving consumers much higher electricity bills. Another major consideration in the veto was the argument that urgently needed coal development could be stymied by certain provisions of the bill, permitting ordinary citizens as well as surface owners to file suit against mining firms.

Despite this defeat, environmentalists are continuing to press for restrictions on strip mining. In Wyoming, environmental groups have won a temporary injunction against further strip mining in the Powder River Basin. The state of Montana has joined a farmers' and ranchers' lawsuit against the U.S. Bureau of Reclamation for giving away valuable water rights to coal developers.

Problems of water availability

Indeed, problems of water availability—particularly in the Missouri and Upper Colorado River Basins—are likely to pose even more of a stumbling block to coal development than environmental pressures.[10] Water requirements are especially heavy for the reclamation of land, the transportation of coal through slurry lines, the conversion of coal to synthetic gas, and the cooling of thermal-electric plants. Even now, water demands for revegetation pose serious problems, particularly in the Four Corners area of Arizona, New Mexico, Utah and Colorado.

Most of the coal produced at Western mines moves by train, or train-barge-train combinations to major consumers. However, these systems may not be able to handle the greatly increased coal flows expected in the future. Industry planners thus are proposing slurry pipelines, a low-cost subsurface system for transporting pulverized coal with water to power-plant sites. Slurry pipelines have been used for many years in the East, and a 273-mile line also extends from the Black Mesa coal mine in northeastern Arizona to the Mohave power plant in southern Nevada.[11] One proposed 1,000-mile pipeline would carry 25 million tons of coal a year from a site near Gillette, Wyoming to White Bluffs, Arkansas. At $750 million, this line would be both the longest and the most expensive slurry line ever constructed. But environmentalists claim that the project would require 15,000 acre-feet of water a year—enough to supply a city of 10,000 people. Indeed, it would deplete much of the large underground reservoir that lies beneath the near-barren plains of Montana, Wyoming and the Dakotas.

Water availability could also prove to be a stumbling block in the construction of the coal-gasification and coal-liquefaction plants which are expected to help expand the nation's energy supply in the 1980's.[12] The first plant to be constructed in the U.S. using the new Lurgi gasification process—a plant located near Farmington, New Mexico—already is running behind schedule because of a conflict over water. This plant would require more than 10,000 acre-feet per year for providing the necessary hydrogen for the gasification process. But the Navajo Indians in this area claim that the water requirements of this plant would place an extra burden on Colorado River supplies which have already been overallocated by the state of New Mexico. Coal liquefaction, which is at an earlier stage of development, promises to be an even heavier user of water than coal gasification. A typical plant producing 100,000 b/d of oil could require 20,000 acre-feet of water a year.

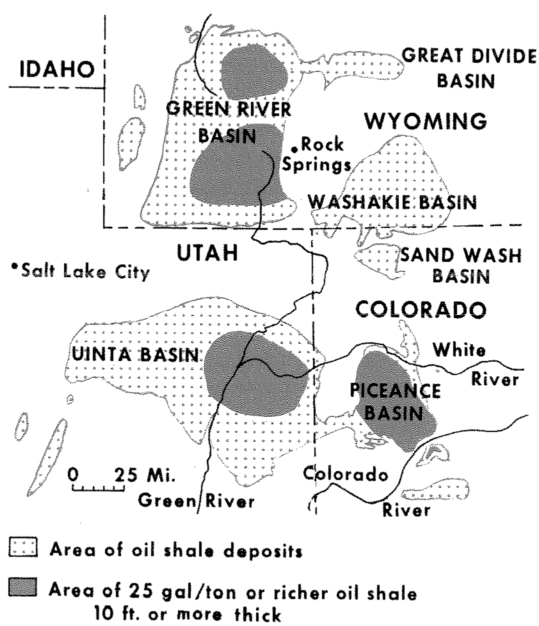
Many Rocky Mountain officials and private citizens are also adverse to large-scale coal development because it could change the essentially rural character of their communities. Unbridled growth could occur as thousands of new residents stream into the area to enter the surface-mining and gasification industries, and the result could be the usual urban problems of pollution, congestion and higher taxes. Achieving the right balance between economic growth and environmental quality will require careful planning in regard to land use and water use.

Western Shale Oil

The large oil-bearing shale deposits in the Green River Formation of Colorado, Wyoming and Utah could produce as much as one million b/d of oil by 1985 if oil prices remain close to $11 per barrel and if water and environmental constraints can be overcome. On the other hand, if the world oil price drops to $7 per barrel and if water remains a problem, production could be limited to 250,000 b/d (Map 3).[13]

Oil shale is a laminated marlstone rock which contains a solid tarlike organic material called kerogen, formed from the remains of animals and plants which settled as deposits on the floors of freshwater lakes millions of years ago. The Green River deposits may contain some 1,800 billion barrels of oil—more than four times the amount of crude oil discovered to date in the United States. However, only about 130 billion barrels—6 percent of the total—are worthwhile exploiting at the $7 to $11 price of oil. These are the deposits which are found in seams 30 or more feet thick and which contain more than

Map 3
Western Oil Shale Deposits



30 gallons of oil per ton of rock.[14] Pilot-plant studies have shown the feasibility of recovering shale oil (kerogen) from the mined rock and converting it to a synthetic crude low in nitrogen. With the technology established, a full-scale production plant is scheduled to be in operation in the late 1970's.

However, the availability of water could be a severely limiting factor to oil-shale development. Water is needed to cool the hot kerogen vapors from the retort or kiln, and even more to dispose of the dry spent shale after it has been crushed and roasted, especially when compacting and stabilizing the disposal pile. By some estimates, shale mining and processing would require almost three barrels of water for each barrel of oil produced. (For two shale tracts in Utah and two in Colorado already leased by the Federal government, 111,000 acre-feet of water may be required annually for shale production.) Upper Colorado River water supplies may be able to support production of one million b/d at the maximum, but a larger industry would require transfer of water rights from agriculture and other users.

Disposal problems

Disposal of spent shale poses an immense problem. Producing one million b/d of synthetic crude oil, while not large in terms of the nation's overall energy needs, would require the mining of over 500 million tons of rock per year. This amount is almost equal to the entire 1974 production of the U.S. coal-mining industry. The disposal problem is complicated by the fact that heated shale expands to as much as half again its original volume. The spent shale and its highly alkaline runoff require special disposal arrangements that boost costs substantially. In addition, special air-pollution control equipment is needed to control the emissions created in the production of synthetic crude from kerogen.

The same criticisms that apply to the surface mining of coal are equally applicable to the mining of oil shale. Also, underground mining would be more feasible than surface mining in Colorado's Piceance Basin, where a substantial rock cover overlays the shale. But this method would present the usual disposal problem and would also result in the loss of 50 to 60 percent of the resource because of the shale pillars left inside the mine for roof support.

Because of the limitations of surface processing, considerable research is underway to develop methods for extracting the kerogen in situ, that is, underground. Cavities would be mined inside the shale layers by traditional mining techniques; the shale would be crushed by explosives and heated to product oil, which would then be pumped above ground. In-situ extraction would require much less water than surface extraction, would create fewer environmental problems, and would cost less than other methods because of the reduced need for mining and aboveground equipment. Following a 1973 pilot test, experimentation is continuing on this promising approach.

Uranium

Up until recently, Federal government sources had estimated that U.S. nuclear-generating capacity would grow from 7 to 30 percent of the nation's total electrical-generating capacity by 1985. In view of the industry's many difficulties, this estimate appears to be high but still attainable. The industry's strong prospects are based upon its ability to replace oil and gas in electrical generation, freeing those scarce fuels for other uses to which they are uniquely suited, i.e., as petrochemical feedstocks and household and transportation fuels. Growth of any significance for nuclear power would require an enormous increase in uranium mine and milling capacity, as well as an accelerated program of exploration to add to present reserves in New Mexico, Wyoming, Colorado and Utah.

Nuclear growth

After thirty years of checkered history, nuclear powerplants are finally becoming a major factor in the nation's power picture. By the end of this year, about 60 thermal (fission) reactors will be in operation with an electrical generating capacity of 43,000 megawatts—and a decade from now, the number may grow to 213 reactors with a rated capacity of 208,000 megawatts.[15] These 213 plants will need more than 30,000 tons of uranium oxide (U_3O_8) annually—more than double the present capacity of the U.S. uranium mining industry. In addition, each new plant will require about 500 tons of U_3O_8 for its initial fuel load.[16]

The industry's planned growth actually has been scaled down considerably in recent years. In the last half of 1974 alone, construction was deferred on 94 plants and 14 plants were cancelled completely. These cutbacks were caused in part by the utilities' present financial difficulties and their anticipation of a slowdown in the growth of future electrical demand.

The slowdown in nuclear growth may also reflect the lengthy delays encountered in licensing and construction of nuclear plants, which may take as much as eight years' time. Each construction application must include a safety-analysis report and an environmental-impact statement, and these reports must be reviewed by authorities such as the Energy Research and Development Administration and publicized at open hearings. Moreover, construction is often delayed by necessary design changes and adherence to strict quality control.

Resources and enrichment capacity

According to ERDA estimates, proven reserves of uranium oxide range between 200,000 tons at a cost of $8 per pound to 420,000 tons at $15 per pound—and at the latter price, another 1.5 billion tons of undiscovered resources may also become available.[17] The vast bulk of the reserves are found in New Mexico and Wyoming.

On the basis of presently scheduled growth in nuclear generating capacity, the nation may need a cumulative total of 325,000 tons of uranium oxide by 1985.[18] Prices have recently risen sharply above the prior level of $6.50 per pound, an increase which should help to generate the supply necessary to meet that demand.

Another essential factor in nuclear-power growth will be the development of adequate enrichment capacity, capable of separating the fissionable U^{235} isotope from nonfissionable material to provide a more potent mixture of the element. Present enrichment services, which supply all of the foreign and domestic commercial demand, are provided by the Government-owned, privately operated plants at Oak Ridge, Tennessee; Portsmouth, Ohio and Paducah, Kentucky. The capacity of these plants is now being expanded by 60 percent to meet the needs of the generating plants already in operation or in the planning stage, but 8 to 10 additional enrichment plants may be required to meet nuclear generating needs by the turn of the century. In this situation, the Administration has recently proposed legislation to support the creation of a private-sector uranium enrichment industry.

Environmental and other problems

The exploitation of uranium resources creates the same type of problems associated with other Rocky Mountain energy resources, plus some unique problems of its own. Mine production is split about evenly between underground and open-pit mines. The latter involves the removal of vegetative cover and the creation of overburden and waste rock, which reduces the suitability of the area for wildlife, grazing and outdoor recreation. Underground mining meanwhile involves substantial accumulation of waste rock in dump areas. In addition, milling produces considerable amounts of low-level radioactive tailing, which are unsuitable for use as fill material where human exposure might result.

Nuclear-power plants, unlike fossil-fuel plants, do not produce particulates and sulphur oxides, and hence do not generate severe air-pollution problems. However, they do generate waste heat and radioactive emissions and wastes, and thus must be strictly controlled to protect against disastrous health consequences. Because of these dangers and the potential for nuclear accidents and theft, the Federal government has tightened standards guiding the construction and operation of nuclear plants, but many doubts still persist about the adequacy of these safeguards.

The proposed breeder reactor would create less thermal pollution and would be a more efficient user of uranium than the conventional light-water nuclear power plant. Its greater efficiency is based on its projected ability to utilize more than 50 percent of the uranium input in the production process, in contrast to the 0.3 percent utilized in the present light-water reactor technology. But it would also produce more plutonium—a poisonous and explosive material—and thus would present even greater safety hazards than the present type of reactor. The Federal government has been financing the operation of a 450-megawatt demonstration reactor in Tennessee, but spending on this project has recently been curtailed because of cost and safety factors, eliminating the possibility of bringing the breeder into commercial operation within the next decade.

Hydro, Geothermal and Solar Energy

Hydro, geothermal and solar resources may contribute very little to the nation's energy requirements by 1985, although geothermal and solar could become important energy sources by the year 2000, now that the Federal government is directing a large-scale research-and-development effort towards their development. Hydroelectric power production has almost doubled since 1950. But despite the huge dams built on the Columbia and the Colorado, and despite the utilization of the Niagara River and the far-flung Tennessee Valley system, hydro now supplies less than 4 percent of the nation's total energy requirements.

Moreover, hydropower's market share could slip still further by 1985. Only about one-third of the nation's hydroelectric potential has been harnessed, but most of the good sites for dam construction have already been developed. As a result, most of the growth in capacity will come from the expansion of existing installations, for the purpose of supplementing the output of large fossil-fueled and nuclear-steam-electric generating units. The Pacific Northwest, for example, is beginning to shift from almost complete reliance on hydroelectric generation to a mixed system of both hydroelectric and thermal-electric generation. Under present plans, more than 10,000 megawatts of new capacity will come on line in the Pacific Northwest between 1978 and 1985. But only about 3,700 mw of that total will be hydroelectric generating capacity; the rest will be made up of 3,700 mw of nuclear capacity and 1,700 mw of coal-fired power.[19]

Geothermal potential

The West has vast potential geothermal resources, consisting of a whole spectrum of heat sources stored within the earth. The West contains about 1.83 million acres of land with known geothermal resources, and another 99 million acres with "prospective value" for geothermal steam .[20]

Yet, despite this vast potential, there is only one commercial geothermal powerplant in the nation, at The Geysers, California. Completed in 1960, the plant has an annual generating capacity of 502,000 kilowatts, with capacity scheduled to reach 900,000 kilowatts by 1978 and an ultimate level of 2 million kilowatts by around 1990. The fields at The Geysers are dry steam, the easiest type of geothermal energy to develop—but unfortunately also the rarest.

Other more abundant and widely distributed forms, such as hot brines and dry rocks, present difficult problems. Power generation from hot brines creates serious pollution and environmental problems, and in addition requires a great technological effort. For example, the briny water (and steam) produced by exploratory wells in California's Imperial Valley is highly corrosive, containing as much as 25-percent dissolved minerals compared to 3-percent in seawater. Continuous removal of water from reservoirs also can lead to subsidence, as has occurred at some Mexican sites. Also, the technology for extracting heat from dry rocks is even less advanced than for other sources. Finally, the large-scale use of geothermal energy would require increased leasing of Federal lands, which make up more than one-half of the West's total geothermal resource acreage.

Solar energy potential

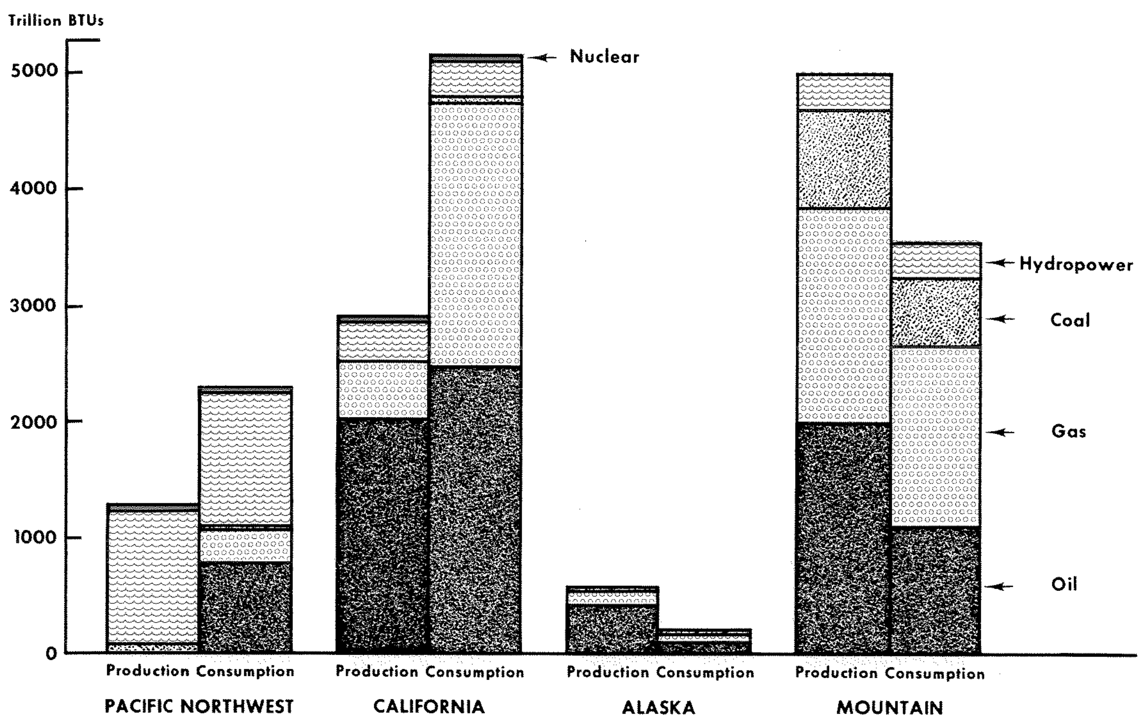
Solar radiation is the world's most abundant renewable energy resource. Its practical application is obstructed, however, by numerous engineering and economic roadblocks. The general trend in energy engineering is toward ever higher temperatures and energy densities, limited only by the capabilities of the confining materials. But solar is a diffuse and intermittent form of energy that must be collected over large areas with bulky and complicated equipment. Fortunately for the West, some of the highest intensity solar regions are located in New Mexico, Arizona, Nevada and California.

Heating and cooling of buildings with solar energy is now possible on a small scale. There are now about 175 solar-heated homes in the United States, completed or under construction. The typical system uses rooftop collectors to gather the sun's energy. The heat from the collector is transferred to a liquid—often water—that is circulated through the building or else stored in some fashion.

Harnessing solar heat to generate electricity is a more difficult challenge. Some engineers believe that small generating units located near the point of consumption provide the best way of utilizing such an inherently diffuse resource; others propose the use of large, centralized solar-thermal plants with present-day turbines; still others favor photovoltaic conversion, the solar-cell system which powered this nation's space probes. But even with lavish Governmental subsidies, it may be decades before solar energy accounts for any appreciable portion of the nation's energy needs.

Chart 5

Western Energy Patterns



The West—Producer and Consumer

The nation is becoming increasingly reliant on Western coal resources. Western production of coal more than doubled between 1970 and 1974, rising from 5 to 10 percent of the national total. This shift reflects the stringent pollution controls imposed on electric utilities and their growing preference for low-sulphur Western coal, produced especially in the Mountain states.

Crude-oil production in the West has trended downward during the past four years, dropping to slightly less than one-quarter of the national total. California, the nation's third largest producer, experienced a greater-than-national 13-percent decline. Oil-and-gas drilling activity practically ceased on state-owned offshore lands after the 1969 Santa Barbara blowout, first because of a state ban and later (after the moratorium was lifted) by environmentalists' protests. Leasing of Outer Continenal Shelf acreage by the Federal government has been affected by similar problems; for instance, a scheduled 1.6-million acre sale off the Southern California coast has recently met with strong opposition. California's difficulties with offshore drilling are only part of the problem, however, since production has fallen in other states as well.

Natural-gas production in the West has followed a roughly similar pattern, since it is often found in association with petroleum. Between 1970 and 1974, gas production dropped from 2.4 to 2.3 trillion cubic feet, or from 11 to 10 percent of total U.S. production. The West has come to depend heavily on imports from other states and nations, because it produces far less gas than it consumes.

California presently depends on out-of-state sources for more than 57 percent of its energy requirements. It gets about 78 percent of its natural gas from the Southwestern states and Canada, plus about 18 percent of its oil from the Mountain states, Alaska and foreign sources. In addition, it imports some of its electricity from coal-fired plants in the Southwest and hydroelectric plants in the Pacific Northwest. Altogether, more than 24 percent of its total energy needs are supplied by uncertain foreign sources, and Canadian natural-gas supplies may become even more uncertain as that nation acts to meet its own internal requirements.

The Pacific Northwest contains hydroelectric and coal resources, but it is in a precarious position with regard to its future supplies of oil and natural gas. Its oil supplies are imported from Canada, Alaska, California and various other foreign countries, while its natural-gas supplies come principally from Canada and to a lesser extent from the Mountain states. With 40 percent of the nation's total developed hydroelectric capacity, the Northwest is now able to satisfy all of its own electrical requirements from hydro-power and to have some left over for export. But in the future, it will become increasingly dependent on coal and nuclear power for its electricity (Chart 5).

FOOTNOTES

1. Federal Energy Administration, *Project Independence Report* (Washington, D.C.: U.S. Government Printing Office, November 1974). The background material utilized in the preparation of the final report appears in thirty-one Task Force Reports and Transcripts of Public Hearings, published by FEA and listed in Appendix AVIII of the *Project Independence Report,* page 335.

2. By "energy" consumption or use, we refer to combined resource inputs (coal, oil, natural gas, hydro and nuclear electricity) expressed in a common calorific measure (Btu's), irrespective of whether such resources are ultimately utilized in the forms of fuels and power or as raw materials (e.g. in the chemical industry). For hydro and nuclear, the Btu equivalent of the electricity generated is computed on the basis of primary energy inputs at fossil-fueled generating stations at prevailing rates of efficiency. In practice, about 95 percent of energy resource inputs go to fuels and power use. A Btu—the common standard of measurement to which all forms of fuels and power sources can be converted—is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. The approximate Btu equivalents of common fuels and power sources are as follows:

		Btu
Crude oil, 1 barrel	=	5,800,000
Natural gas, 1 cubic foot	=	1,032
Coal, 1 ton	=	25,000,000
Nuclear power, 1 kilowatt-hour	=	10,660
Hydropower, 1 kilowatt-hour	=	10,389

Energy production and consumption statistics for the

years 1950 to 1974 in original units of measurement and Btu equivalents are from the following publications: Walter G. Dupree, Jr. and James A. West, *United States Energy Through the Year 2000* (Washington, D.C.: U.S. Department of the Interior, December 1972), Appendix B. U. S. Department of the Interior, Bureau of Mines, "Energy Use in 1974" (and in 1975), *News Release,* March 13, 1974 and April 3, 1975. These data, as well as state production figures for individual fossil fuels, are also published on an annual basis by the Bureau of Mines in its *Minerals Yearbook.*

3. For a detailed discussion of historical energy consumption and supply patterns see, Hans H. Landsberg and Sam H. Schurr, *Energy in The United States, Sources, Uses and Policy Issues,* A Resources for The Future Study (New York: Random House, 1968), pp. 9-63. Joel Darmstadter, "Energy Consumption: Trends and Patterns," *Energy, Economic Growth, and The Environment,* ed. by Sam H. Schurr (Baltimore: The Johns Hopkins University Press), pp. 155-189. Ford Foundation Energy Policy Project, *Exploring Energy Choices,* A Preliminary Report (Washington, D.C.: The Ford Foundation, 1974), pp. 1-9.

4. Reserves of crude oil and natural gas are from: American Gas Association, American Petroleum Institute, 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, 1974.* Detailed statistics on the physical and financial operations of the natural gas and petroleum industries, including exploration and drilling, may be found in the following: American Gas Association, *Gas Facts, A Statistical Record of the Gas Utility Industry,* published annually; American Petroleum Institute, *Petroleum Facts and Figures,* published biennially.

5. The shortage of that fuel in turn, led the Federal Energy Administration, in late June of 1975, to order 25 utilities to switch back to coal at 74 power plants throughout the nation. At the same time, the FEA directed 41 companies building new fossil-fuel power plants to make certain that the plants have coal-burning capacity. Plants receiving the orders were required to submit plans to the Environmental Protection Agency which could then order the installation of additional pollution control equipment if necessary.

6. The $7 and $11 world oil prices refer to prices in constant 1973 dollars. The supply response at $7 and $11 world oil prices presumably also assumes that both "old" and "new" oil produced in the United States sells at that price. A number of national energy forecasts have been published in recent years. Most of these relied on extrapolations of past behavior of energy markets or judgmental factors, however, and did not take explicit account of the response of energy demand and supply to price changes. For two of the most notable of these "judgmental" forecasts see: National Petroleum Council, *U.S. Energy Outlook,* A Report of the National Petroleum Council's Committee on U.S. Energy Outlook (Washington, D.C.: National Petroleum Council, December 1972). Ford Foundation Energy Policy Project, *A Time To Choose America's Energy Future* (Cambridge: Ballinger Publishing Company, 1974). For the most notable econometric forecast aside from the *Project Independence Report* see: M. I. T. Energy Laboratory Policy Study Group, *Energy Self-Sufficiency, An Economic Evaluation* (Washington, D.C.: American Enterprise Institute for Public Policy Research, November 1974). M. I. T. researchers, in forecasting to the year 1980, found domestic supplies to be generally more responsive to higher prices than the FEA.

7. Betty M. Miller, et. al., *Geological Estimates of Undiscovered Recoverable Oil and Gas Resources of the United States,* Geological Survey Circular 725 (Washington, D.C.: U.S. Department of the Interior, Geological Survey, 1975). All oil and natural gas resource estimates used in this article were taken from this Circular. Contrary to previous estimates which utilized prior data on hand, these estimates were made by carefully evaluating a large amount of new geological and geophysical information gathered on more than 100 different provinces by over 70 specialists within the Survey and by applying a variety of resource appraisal techniques to each potential petroleum province. Due to the thoroughness of this process and the elimination of highly speculative resources lying outside the 5 percent probability range, these figures are much smaller than earlier estimates by the Survey.

8. The Supreme Court upheld the Federal Government claims to leasing rights to lands beneath lower Cook Inlet on the basis that the property in question is part of the "high seas" and not the kind of "inland waters" over which states were granted title under the 1953 Submerged Lands Act. See, "Land Off Alaska Belongs to U.S., Top Court Rules," *Wall Street Journal,* June 24, 1975, page 2.

9. Paul Averitt, *Coal Resources of the United States, January 1, 1967,* Geological Survey Bulletin 1275 (Washington, D.C.: U.S. Department of the Interior, Geological Survey, 1969). Also, National Petroleum Council, Committee on U.S. Energy Outlook, *U.S. Energy Outlook: Coal Availability* (Washington, D.C.: National Petroleum Council, 1973).

10. George H. Davis and Leonard A. Wood, *Water Demands For Expanding Energy Development,* Geological Survey Circular 703 (Washington, D.C.: U.S. Department of the Interior, Geological Survey, 1974). National Petroleum Council, *U.S. Energy Outlook: Water Availability* (Washington, D.C.: National Petroleum Council, 1973).

11. For a discussion of coal transportation problems and synthetic fuel technologies see, National Academy of Engineering, Task Force on Energy, *U.S. Energy Prospects: An Engineering Viewpoint* (Washington, D.C.: National Academy of Engineering, 1974), pp. 36-48.

12. K. C. Vyas and W. W. Bodle, "Coal and Oil-Shale Conversion Looks Better," *Oil and Gas Journal,* Vol. 73, Number 12 (March 24, 1975), pp. 45-54.

13. Federal Energy Administration, *Project Independence Report,* page 132.

14. National Petroleum Council, *U.S. Energy Outlook,* page 208.

15. Federal Energy Administration, National Energy Information Center, "Nuclear Power," *Monthly Energy Review* (April, 1975), page 5.

16. Douglas M. Johnson, "Uranium Fuel Prices," *The Conference Board Record,* XII, Number 1 (January, 1976), page 52.

17. Energy Research and Development Administration, *Statistical Data of the Uranium Industry* (Grand Junction: Grand Junction Office, January 1, 1975).

18. Federal Energy Administration, *Project Independence Report,* page 113. Data adjusted for changes in scheduled capacity.

19. Pacific Northwest River Basins Commission, Power Planning Committee, *Review of Power Planning in the Pacific Northwest, Calendar Year 1973* (Vancouver: Pacific Northwest River Basins Commission, 1974), page 3.

20. L. H. Godwin, et. al., *Classification of Public Lands Valuable for Geothermal Resources,* Geological Survey Circular 647 (Washington, D.C.: U.S. Department of the Interior, Geological Survey, 1971).