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*Note: This supplement is a reprint of articles that have appeared in the *Monthly Review* in November 1948, May 1949, and March and June 1950, with the exception of Part V and the starred sections, which represent added material.

Prepared by Wilfred Eldred, Economist, under the direction and review of officers of the Research Department.
In common with many other parts of the country, the Twelfth District has experienced more or less serious deficits of electric power during the past two years and has also found itself somewhat pinched for such industrial fuels as petroleum and natural gas. These shortages and the consequent necessity to impose restrictions on the use of electric power and gas, notably in California, have raised some question as to the adequacy of regional power and fuel supplies to sustain the industrial growth of the area. It is proposed to examine this general problem of the fuel and energy situation in the West in a series of articles in the Monthly Review. An attempt will be made to appraise the current position and probable future outlook for each of the three major sources of industrial energy available in the District—petroleum, natural gas, and electric power. Because public experience with power shortages has attracted more general attention, it will be advantageous to consider the electric power situation first.

### Changing conditions of fuel and energy supply in the West

Until comparatively recent years it was commonly taken for granted that the power and fuel resources of the West were practically inexhaustible. The existence of numerous undeveloped water power sites, in particular, has frequently been stressed as one among many arguments for the industrialization of the West. Although high-grade coal is lacking or is difficult of access in most states of the Twelfth District except Utah, the availability of large resources of petroleum and natural gas was confidently counted on to supplement hydro-electric sources of energy. Cheap power and fuel were definitely reckoned as among the permanent assets of the Western economy.

Since the war, however, a new situation has arisen and the aggregate demand for industrial energy and fuels threatens, at least temporarily, to outrun supply. The extremely rapid population growth of many District areas during and since the war, together with the general expansion and diversification of industry and the increasing mechanization of farm and factory operations, has caused a large per capita increase in energy requirements of all kinds. Following a brief recession at the end of the war, the demand for electric power in most parts of the District increased much more rapidly in 1946 and 1947 than the expansion of generating and transmission facilities. The phenomenal growth of demand for practically all types of petroleum products is placing a severe strain upon the petroleum industry of the West. It seems probable that the traditional export surplus of California's oil fields and refineries, which supply the bulk of the petroleum products used in the western states and which formerly shipped large quantities of crude and refined oils to eastern and foreign markets, may soon give way to a net import movement. Even the once apparently unlimited supplies of natural gas in California have proved inadequate in recent years to meet total demands and the state is already importing large quantities of this fuel from western Texas in order to conserve its own reserves as much as possible.

### Recent Power Shortages

Shrinking margins of generating capacity over load requirements characterized the electric utility industry in most parts of the District during almost the entire period from the last quarter of 1945 to the second quarter of 1948. This deterioration in the ability of the industry to meet its customers' needs was due in part to the unexpectedly rapid growth in demand for power following the reconversion of war industries and in part to the difficulties encountered in securing new electrical equipment from the manufacturers. Because of this situation, which was aggravated by extraordinary weather conditions during the past two seasons, some parts of the District experienced shortages of electric power which necessitated more or less drastic curtailments in service.

#### The California situation

In California some restriction of service to industrial customers supplied with "surplus" power at low rates became necessary in the summer of 1947. The 1946-47 season was marked by a serious deficiency in rainfall which resulted in low stream flow and generally reduced output of hydro-electric energy. Steam plants were called upon more heavily in 1947 and provided a much larger proportion than usual of the total energy output of the state. Even so, the total power supply proved inadequate and a group of chemical plants in the San Francisco Bay area, which were beneficiaries of low rates for power sold on an interruptible basis, were cut back for several months to about 50 percent of normal operation.

The power shortage of 1947 in central California continued into the first quarter of 1948 and was intensified by a second season of deficient rainfall, which also affected parts of Arizona and Nevada. Arizona, in fact, has experienced several successive years of water and power shortage. Up to about the middle of last March, the deficiency in seasonal precipitation over much of this area was almost the worst on record and resulted in serious damage to crops and pastures. Coming on top of the scanty supplies of 1947, the prolonged drought further reduced the effective generating capacity of many hydro-electric plants and threw a still heavier burden on steam plant operations. The demand for power for irrigation pumping reached levels in the early months of 1948 that are usually attained only during July or August. This abnormal irrigation demand was superimposed upon a steadily growing industrial and domestic load, the total effect of which carried the output of electric energy in California in the first three months of the year to a level nearly ten percent above that of the same period of 1947.

#### The 1948 curtailment program

Faced with these extraordinary increases in demand and hampered by lagging hydro-electric output, the principal electric utility concern in Northern California instituted a voluntary curtailment program in February among its customers and affiliated distributing companies. These measures proved ineffective, however, and were
superseded in March by orders of the California Public Utilities Commission designed to enforce a general 20 percent reduction in power consumption in the northern and central areas of the state. The use of electricity was drastically curtailed for most classes of users and for certain non-essential purposes was prohibited; the installation of new connections was also greatly restricted. Southern California, while affected by the drought and consequent reduction of hydro-electric energy, except from the Colorado River, had a larger margin of steam plant capacity and did not experience a general power shortage. Hence no compulsory restrictions were placed on power use in that area. By act of the legislature, statewide daylight saving time was adopted March 14 as a power conservation measure. This expedient was expected to save about 235 million kilowatt hours of energy, or roughly 9 percent of the estimated power deficiency during the remainder of the year.

Fortunately, a period of heavy precipitation set in late in March and continued for several weeks, substantially increasing the snow pack and the volume of water in storage reservoirs and also reducing the rate of irrigation pumping. Together with the timely installation of additional generating capacity in Northern California and the transfer of some 200,000 kilowatts of power from the southern part of the state, the ending of the drought permitted the lifting in April of the restrictions on power use which had been imposed a month earlier. Statewide daylight-saving was retained, however, as a safeguard against excessive drains on the still somewhat precarious power supply.

Reversing the trend of the first quarter of the year, total electric power consumption in California fell during the second quarter of 1948 to about the levels of the corresponding period of 1947. Beginning with July, however, new high records were again established. Both privately- and publicly-owned utility systems have energetically pushed the installation of new generating facilities, transmission lines, and transformer stations. In spite of continuing growth in total demand, peak loads have so far been taken care of, though with a scanty margin of reserve capacity. The situation has been under constant review by the industry Power Interchange Committee and by the Public Utilities Commission which have counselled the retention of daylight-saving time until the next major additions to the area's generating facilities are ready for operation, which is expected to be in December and January.1

The Pacific Northwest

While perhaps attracting less attention than the California experience, the Pacific Northwest is facing a probably more critical power problem than any comparable area in the West. This situation has arisen primarily from the rapid development of the electro-metallurgical industry in that region and from the large prospective demand on the power supply to be expected from the requirements for irrigation pumping as the huge acreage of the Columbia Basin project is gradually brought under cultivation. The demands of the defense industries during the next year or two will probably also put additional pressure on the power supplies of the area.

Growing concern is being voiced in the Pacific Northwest over the narrow margin of available power reserves over demand. In a statement issued in January 1948, spokesmen for the leading privately-owned electric utilities and city systems of the area pointed out that the power requirements of the Pacific Northwest already exceed the safe operating capacity of the generating facilities of the region. This statement emphasized the need for additional Federally-owned generating capacity if the future industrial development of the area is not to be retarded. In fact, plans for the establishment of new factories in the lower Columbia River basin have had to be dropped or indefinitely postponed because the available supply of firm electric power in that region is barely sufficient for the needs of already existing plants.

This situation in the Pacific Northwest was characterized by the tenth annual report of the Bonneville Power Authority, issued in December 1947, as “a far cry” from the conditions of ten years ago when the great dams on the Columbia River with their enormous electric power potential were regarded by many as “white elephants” for whose output no regional market could be developed. The problem at that time—one of finding markets—has given way to the problem of developing power output rapidly enough to keep up with the growth of demand. The temporary loss of heavy industrial power loads following shutdowns in the major war industries in the early post-war period was quickly made up as industry converted to a peacetime basis. The subsequent increase in demand from all sources—industrial, commercial, domestic, and rural—has absorbed the entire regional productive capacity of electric energy. Both the Bonneville Power Administration and the public and private utility managers agree that even if presently approved Federal power projects in the Pacific Northwest are completed as rapidly as is physically possible, the generating capacity of the region will not catch up with expected power requirements until at least 1954.

Postwar demand for electric power has, if possible, been even more insistent in the Pacific Northwest than in California, while the limitations upon expansion of generating capacity have operated more severely in that area. Few significant additions to generating facilities have, in fact, been made in recent years by the privately owned utility systems of the Northwest. Although the Bonneville Power Authority has added three large generators to its Grand Coulee plant, it had to relinquish in 1946 the two 75,000 kilowatt units which had been diverted in 1943 from the Shasta plant of the Central Valley Project. On balance, the total installed capacity in Washington, Oregon, and northern Idaho increased about 13 percent during the period from January 1946 to June 1948; nine-tenths of the net gain was accounted for by the installations at Grand Coulee, which has now been developed to one-half its ultimate capacity.

1 Daylight saving in California was officially ended December 31, 1948.
The aluminum industry and industrial power curtailment

The heavy draft on the power supplies of the Pacific Northwest made by the war-created metallurgical and chemical industries is probably not generally realized outside that region. The aluminum reduction plants, in particular, require huge quantities of electric energy, which the opportunity installation of the publicly owned facilities at Bonneville and Grand Coulee in the early war years fortunately made available. Except during the fiscal year 1945-46, when some of these plants were closed down, the aluminum industry has taken well over half the energy output of the entire Bonneville system and currently represents from one-quarter to one-third of the total power load of the aggregate utility system, public and private, in Oregon and Washington.

Due to its concentration in a small group of highly mechanized plants, which employ a relatively small labor force and hence present only a minor employment problem, the aluminum reduction industry of the Pacific Northwest offers a ready opportunity for the adjustment of industrial power use to seasonal fluctuations in total demand and output. Seasonal variations in demand are not so pronounced in the Pacific Northwest as in the California-Arizona-Nevada area, chiefly because of the lack of a heavy irrigation load in the summer months. Stream flow is also generally more uniform and dependable and much less use is made of auxiliary steam power. Fluctuations in total demand in the Pacific Northwest are associated primarily with the varying needs of domestic and commercial customers for lighting and heating. These users, generally speaking, pay the highest rates and must be served first. The large industrial users obtain a significant part of their total power requirements at very low rates for "surplus" power sold on interruptible schedules which permit their service to be cut to the extent necessary to assure a firm supply to the high rate users.

Both in 1947 and 1948 the Bonneville Power Administration has required the aluminum plants to reduce their power consumption during the hours of peak load in the winter months, when the maximum demand occurs. In 1947, unusually favorable weather conditions enabled the power agencies of the area to meet their energy requirements with a minimum of curtailment, though with a very narrow margin of reserve capacity. In 1948, in spite of increased generating capacity, the period of shortage has come earlier than usual; estimates of the extent of curtailment by the Bonneville Power Administration necessary to insure the maintenance of essential service run to approximately 150,000 kilowatts, or about 8 percent of the system’s peak capacity.

Generating Capacity vs. Demand

The electric power supply-demand situation in the Twelfth District is summarized in the following data reported by the Federal Power Commission. The table indicates the rated generating capacity of the electric power agencies of the area to meet their energy requirements at very low rates for "surplus" power sold on interruptible schedules which permit their service to be cut to the extent necessary to assure a firm supply to the high rate users.

<table>
<thead>
<tr>
<th>Power supply area</th>
<th>Installed capacity (kilowatts) June 30, 1948</th>
<th>Peak loads (kilowatts) Aug., 1948</th>
</tr>
</thead>
<tbody>
<tr>
<td>41—Utah, Southern Idaho, Eastern Oregon...</td>
<td>319,100</td>
<td>367,800</td>
</tr>
<tr>
<td>42 &amp; 44—Northern Idaho, Eastern &amp; Southern Washington, Northern Oregon</td>
<td>2,034,000</td>
<td>1,839,100</td>
</tr>
<tr>
<td>43—Northwestern Washington</td>
<td>882,400</td>
<td>839,200</td>
</tr>
<tr>
<td>45—Southern Oregon, Northern California</td>
<td>150,600</td>
<td>228,000</td>
</tr>
<tr>
<td><strong>Northwest</strong></td>
<td>3,146,100</td>
<td>3,274,100</td>
</tr>
<tr>
<td>46—Central California, Northwestern Nevada</td>
<td>1,808,900</td>
<td>2,137,500</td>
</tr>
<tr>
<td>47—Southern California, Eastern &amp; Southern Nevada, Western Arizona</td>
<td>2,922,600</td>
<td>2,263,500</td>
</tr>
<tr>
<td>48—Eastern Arizona</td>
<td>168,500</td>
<td>300,000</td>
</tr>
<tr>
<td><strong>Southwest</strong></td>
<td>4,900,000</td>
<td>4,701,000</td>
</tr>
<tr>
<td><strong>All District areas</strong></td>
<td>8,246,100</td>
<td>7,975,100</td>
</tr>
</tbody>
</table>


Electric Power Supply Areas—Twelfth District


The Commission also includes Montana in the Northwest region. The figures in the table, however, exclude Montana, which is not a Twelfth District State.

Lagging installations in early postwar period

The basic factors underlying recent shortages of electric power in the West are much the same as those oper-
ating generally throughout the country. Fundamental in the whole situation was the enforced suspension of all except the most necessary installations of generating equipment during the war. Only the projects considered vital to the national defense effort were sanctioned, while the facilities of the electrical equipment manufacturers were largely concentrated on supplying the needs of the armed forces, particularly the construction of generators for naval and merchant vessels. The West fared considerably better in this respect; however, than the country as a whole, for it was during this period that most of the generating capacity of the Columbia River projects and about one quarter of that at Boulder Canyon were installed. Largely as a result of these new facilities, the output of electric energy in the District more than doubled within the five years between 1939 and 1944, the peak year of the war. Nonetheless, wartime restrictions on construction of plant and equipment held back much of the expansion in generating and transmission facilities that would normally have occurred and some for which commitments had actually been made. The northern and central California areas were perhaps more affected by these delays and postponements than other parts of the District.

For the first two years following the end of the war relatively little progress could be made in most parts of the country, including the Twelfth District, in making up these war-induced delays in the installation of badly needed generating capacity. Material and manpower shortages, together with strikes in the plants of the electrical supply manufacturers, were chiefly responsible for delaying the delivery dates of new equipment. Because of the lagging delivery of new equipment, and the removal from the Grand Coulee power house of two large generators borrowed from the Shasta plant, there was an actual loss in total installed generating capacity in the District in 1946. A small increase occurred in 1947, amounting to about 330,000 kilowatts, or less than five percent, most of which was concentrated in the Columbia River and Southern California areas. Meanwhile the demand for power continued to grow at a phenomenal rate, especially since about mid-1946, and the margin of reserve capacity in most parts of the District was rapidly reduced. The aggregate peak load of power demand at the end of 1946 represented about 95 percent of rated plant capacity for the District as a whole and had increased to over 102 percent by the end of 1947. This overload completely wiped out any over-all margin of reserve capacity to insure against physical breakdowns in generating or transmission equipment, or other emergencies, such as the unusual demands arising from the 1948 drought in California and Arizona. Only through extensive interconnection and integration of facilities between various parts of the District was a more serious situation averted.

Within the District considerable differences have marked the various power supply areas with respect to available reserves and overloads. During the past year the Southern California-Nevada-Arizona area has enjoyed the widest margin between installed capacity and power loads, although here the reserve was none too large—around ten percent at the end of 1947. The Columbia River and Idaho-Utah areas rated next in order of reserve facilities, but by very narrow margins. At the other extreme, peak loads have exceeded rated generating capacity in the Central and Northern California, Southern Oregon, and Puget Sound areas and more recently in Eastern Arizona. The deficiency areas have become increasingly dependent upon other parts of the District and, to some extent, upon areas outside the District in meeting their power requirements.

**Outlook for the next few years**

Taking a somewhat longer view of the situation, the outlook for the next few years appears more promising, although it is admittedly difficult to anticipate the demand-supply situation very far in advance. Reliable forecasts of power requirements are not available for the District as a whole, although reasonably comprehensive estimates for the Pacific Northwest are prepared each year by the Bonneville Power Administration. On the supply side somewhat more definite, though still incomplete, data are available from the reports made by the utility systems to the Federal Power Commission indicating their scheduled additions to installed generating capacity for a period of three or four years in advance.

The most recently published official data on electric utility generating capacity in the Twelfth District, with scheduled additions for the years 1948-51, as reported by the Federal Power Commission, are summarized as follows:

<table>
<thead>
<tr>
<th></th>
<th>Twelfth District areas</th>
<th>United States</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installed capacity, June 30, 1948</td>
<td>8,246 (thousand kilowatts)</td>
<td>50,913 (thousand kilowatts)</td>
</tr>
<tr>
<td>Scheduled additions:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>July-Dec. 1948</td>
<td>529</td>
<td>3,044</td>
</tr>
<tr>
<td>1949</td>
<td>782</td>
<td>5,358</td>
</tr>
<tr>
<td>1950</td>
<td>915</td>
<td>4,474</td>
</tr>
<tr>
<td>1951</td>
<td>505</td>
<td>2,869</td>
</tr>
<tr>
<td>Total, July 1948-Dec. 1951</td>
<td>2,731</td>
<td>15,545</td>
</tr>
<tr>
<td>Indicated capacity, Dec. 31, 1951</td>
<td>10,977 (thousand kilowatts)</td>
<td>66,478 (thousand kilowatts)</td>
</tr>
<tr>
<td>Percent increase, 1948-1951</td>
<td>33.1</td>
<td>30.5</td>
</tr>
</tbody>
</table>

These forecasts, made prior to June 1948, somewhat underestimate the probable expansion of electric generating capacity to be expected in the District during the next few years, as not all plans are promptly reported. According to later information obtained from the San Francisco regional office of the Federal Power Commission, the above estimates may be raised by about 880,000 kilowatts, or roughly 25 percent, nearly nine-tenths of which is scheduled for 1950 and 1951. Among these additions are two more generators of 108,000 kilowatts each for the Grand Coulee plant to be installed in 1951, in addition to six included above for installation in 1949-50, thus leaving only one more unit needed to complete this power plant by 1952. Also included in this revised estimate is the installation of 225,000 kilowatts capacity at the new Davis Dam project of the United States Recla-

**Water Power vs. Fuel Plants**

As compared with most parts of the country, water power plays a relatively large part in the electric energy supply of the West. For the United States as a whole, from three-fourths to four-fifths of all electric power is fuel based, while in the Twelfth District the proportions are normally reversed. In 1946, in fact, hydro-electric plants supplied over 85 percent of the total District output. Except in California and Utah, fuel is scarce and relatively costly in most parts of the District. Climatic and topographic conditions over much of the region assure fairly dependable stream flow, at least when supplemented by dams and reservoirs, which in some locations provide extraordinary heads of falling water. Although distances from power sites to centers of industry and population are sometimes considerable, transmission losses are not usually excessive and water power has contributed notably to the generally low level of rates for electric energy prevailing in many parts of the District.

Until within recent years the role of fuel-based power in the West has largely been to supplement hydro-electric output by assuring firm supplies of energy at the seasons of heaviest demand, or in some cases at the period of relatively low stream flow and uncertain production by water-driven plants. In certain areas, more especially in the larger urban centers, steam plants are operated fairly continuously at somewhere near their full potential; in other areas they are chiefly in the nature of standby capacity, to be drawn upon principally at the low stage of the water power cycle. On the average, the heaviest use of fuel-operated plants in the District as a whole comes in the fall and early winter months, the lightest use in late winter and early spring. They provide the necessary element of flexibility which otherwise would be lacking in the power supply of the District.

**California and the Southwest**

Indications are beginning to multiply, however, that fuel-based energy is destined to play an increasingly important part in the electric power supplies of this region, especially in California. The better and more accessible water power sites for single purpose hydro-electric plants have mostly been put to use and the poorer or more distant sites will require relatively heavy capital investment to develop their possibilities and will also involve greater line losses in long distance transmission. On the other hand, it may be expected that a relatively large volume of hydro-electric power will continue to be developed, more or less as a by-product, in connection with multiple purpose projects for irrigation, municipal water supply, flood control, etc. A limited number of sites are available on the lower Colorado River where the development of hydro-electric energy is economically feasible and which are within practical transmission distance of power consuming centers. Recent estimates by the Federal Power Commission’s regional office at San Francisco indicate, for example, that five projects currently being considered for development by the Federal Government in California and two others on the Colorado River within economic transmission distance to southern California and Arizona markets, would provide an initial dependable capacity of some 1,600,000 to 1,700,000 kilowatts—an amount equal to about one-third of the existing installed capacity in the three-state area, California-Arizona-Nevada. Most of these projects are very large scale affairs, however, and require correspondingly large financial resources, which only the Federal Government is able to supply. Their development would also require considerable time.

Meanwhile the insistent demand for power is increasingly being supplied in the California-Arizona-Nevada area by steam plants. The proportion of the total electric energy produced from fuel by public utilities and industrial establishments in these three states for successive periods from 1930 to 1947 was as follows:

<table>
<thead>
<tr>
<th>Period</th>
<th>Proportion</th>
</tr>
</thead>
<tbody>
<tr>
<td>1930-34</td>
<td>23.9 percent</td>
</tr>
<tr>
<td>1935-39</td>
<td>13.7</td>
</tr>
<tr>
<td>1940-45</td>
<td>15.1</td>
</tr>
<tr>
<td>1946-47</td>
<td>33.3</td>
</tr>
</tbody>
</table>

In California, the proportion of fuel-based electric energy in 1947, a year of deficient water power, rose to over 42 percent of the total electric output. Of the new utility generating capacity scheduled for installation in the three-state area in the period 1948-1950, over 60 percent is to be served by fuel plants, less than 40 percent by hydro-driven plants; in Southern California the proportion for new fuel plants runs close to 75 percent. Informed opinion in the industry points to the probability that in California fuel-based electric energy will within a relatively short time come to exceed that from hydro-electric plants.

**The Pacific Northwest**

Fuel-based electric energy is much less important in the electric power supply of the Pacific Northwest than in other parts of the District. Over the period from 1930 to 1947 the proportion of the total electric power supply of Oregon and Washington produced by fuel plants has averaged only about 8 percent, declining from about 19 percent in 1930 to 2 percent in 1945. California oil and small quantities of Utah coal are used by steam plants in the Northwest, chiefly in the larger cities. The growing scarcity and rising costs of these fuels have added to the problems of local power supply during the past two seasons.

Well over half the total electric power supply of the Pacific Northwest has in recent years been produced by the hydro-electric generators of the Government-owned Columbia River system. The extensive program of further development of the Columbia River Basin to which the Federal Government is committed, together with the surplus power available from new large-scale irrigation projects in the area, promises to maintain a relatively high proportion of water power in the total energy supplies of the region. Presently approved plans
call for the construction of new dams and the installation of large generating capacities at various points along the Columbia, Willamette, and Snake Rivers and their tributary streams, and for doubling the present capacity of the Grand Coulee powerhouse to an ultimate capacity of nearly 2,000,000 kilowatts.

Following a long period of relative quiescence, some of the privately-owned utilities in the Pacific Northwest are now making commitments for enlargement of generating facilities. New installations are also projected by some of the municipal systems. With one relatively small exception, all of these call for further water power development rather than fuel-based plants.

Some idea of the future electric power requirements of the Northwest visualized by the public power agencies of the region may be had from the following estimates of the Bonneville Power Administration covering the period from 1946 to 1960. These figures are for the area including Oregon, Washington, Idaho, and Western Montana.

<table>
<thead>
<tr>
<th>Year</th>
<th>Total energy requirements</th>
<th>December peak</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(million kilowatt hours)</td>
<td>(thousands kilowatts)</td>
</tr>
<tr>
<td>1946</td>
<td>16,378</td>
<td>3,157</td>
</tr>
<tr>
<td>1947</td>
<td>19,988</td>
<td>3,544</td>
</tr>
<tr>
<td>1948</td>
<td>22,472</td>
<td>4,223</td>
</tr>
<tr>
<td>1949</td>
<td>25,106</td>
<td>4,628</td>
</tr>
<tr>
<td>1950</td>
<td>37,236</td>
<td>5,065</td>
</tr>
<tr>
<td>1955</td>
<td>45,622</td>
<td>8,015</td>
</tr>
<tr>
<td>1960</td>
<td>76,476</td>
<td>11,840</td>
</tr>
</tbody>
</table>


The problem of power costs

Whether water-based or fuel-based, the electric power supply of the future will probably be produced at higher unit costs than in the past. This is likely to necessitate the charging of higher rates for electric energy unless a policy of public subsidization is adopted. Certainly the continuation of the tendency to turn to fuel-based energy as the major future source of supply in the California-Arizona-Nevada area, which is the present outstanding trend in the privately-owned sector of the utility industry, implies higher costs, particularly as oil and natural gas become scarcer and more costly.

Higher cost power in this region will mean a narrowing of the differential in power costs currently enjoyed by certain western industries as compared with similar industries in other parts of the country. This is not likely, however, to involve any marked competitive handicap, since in the great majority of instances power costs play a relatively small part in the total cost of production of western industries. Probably only in such cases as the electro-metallurgical and electro-chemical industries is the availability of large blocks of power at very low rates a vital factor in determining plant location. The dependence of the aluminum industry of the Pacific Northwest on the cheap power of the Columbia River is a case in point. Even here, however, in spite of the elaborate expansion program already authorized in that area, prospective power supplies are limited. It is significant in this connection that in planning for new plant expansion to meet anticipated future demands, one of the leading aluminum producers in the Northwest will construct its next plant in Texas, using natural gas to generate the necessary electric power, rather than wait for additional hydro-power in the Columbia River area.

Addendum, November 1950

General improvement in the power outlook

The electric power situation in most parts of the Twelfth District has greatly improved over the past two years, and the outlook for adequate supplies of power for normal requirements is generally much more reassuring than was the case two years ago. While complaints of shortages have been persistent in the Pacific Northwest, the over-all demand-supply position is today in much better balance than in 1948. No serious power deficiency has occurred in any part of the District since that year, nor has any drastic curtailment of service been necessary for any class of consumers except those served on an interruptible basis.

The relatively favorable experience of the past two years, compared with the previous critical situation, was due in part to better weather conditions, with improved water supplies for hydro plants and diminished requirements for such uses as off-season irrigation pumping. In large measure, however, it was the result of the energetic pushing of new power plant construction and the installation of much additional generating equipment, both steam and hydro. This additional capacity has enabled the electric utilities to keep even with, and in large areas to keep ahead of, the growing demand for power. The business recession of early 1949 seems to have had little adverse effect upon power demands in this District.

While the marked diversity of conditions in the various parts of the District make it difficult to generalize about the power situation as a whole, a few such generalizations are in order. Among the more important developments of the past two years are the following: (1) an over-all expansion in generating capacity of about 26 percent, compared with a growth in aggregate peak loads of around 18 percent; (2) a marked trend in California to the installation of steam power plants, notably by the privately-owned utilities; (3) continuance of the drift toward public ownership in the Pacific Northwest, taking the form of a constantly larger share of Federally-owned capacity and the absorption of existing privately-owned utilities by municipal and other local public agencies; (4) a cessation of the long downtrend in power rates and the beginning, at least in California, of an upward trend.

The race between demand and supply

Demand for electric energy has continued to expand at an impressive rate in practically all parts of the Twelfth District during the past two years. Continued rapid population growth, increased industrialization, larger irrigation requirements, the housing boom, and widening household use of electricity in a multitude of applications
associated with rising standards of living, are the obvious explanations.

The supply of electric power in most parts of the District other than the Pacific Northwest has more than kept pace, however, with the growth of demand. Large new installations at central power stations, provision of additional transmission lines, and more complete integration of operations among the various power houses over wide geographical areas have enabled the utilities generally to take care of the rapidly increasing and broadening demand for electric energy without incurring critical shortages.

The margin of generating capacity over normal power requirements has been considerably widened in most parts of the District during the past two years. The situation is much more favorable in some areas, however, than in others, with the Southwestern group of states enjoying the largest margin of reserve and the Northwestern region still being hard pressed to make ends meet. It must be remembered, too, that figures for installed capacity do not tell the whole story as to actual output. In areas like the Pacific Northwest for example, which depend primarily on water power, increases in total installed capacity mean little except when interpreted in terms of water conditions, which vary from year to year. The factors determining power output, in such cases, involve both machines and water supply. In a year of deficient water supply the power situation may deteriorate even though nominal capacity of generators may show an increase. Most of the new capacity installed during the past two years in the Pacific Northwest has been at Grand Coulee Dam, but it has not greatly increased the power output because the previously existing generating units at that site were already utilizing practically all the water available. Additional upstream storage is necessary to provide enough water to operate the additional machines installed. Meanwhile, demand for power continues to grow and in the event of an adverse water year the Northwest would be faced with a serious power shortage.

The relatively more favorable position as to reserve capacity existing in other areas, notably in Northern and Central California, reflects the energetic construction policy followed during the postwar period by the leading utility company in that area, and the completion of the Federal installations at Shasta Dam. Considerable expansion of generating facilities has also taken place in the Southern California-Colorado River area where the public companies, municipal governments, and Federal agencies are actively pushing new construction.

Increasing trend to fuel-based plants in California

A notable feature of recent and current power expansion programs in California is the high proportion of new plant capacity based on fuel rather than water power. As already pointed out, the relative importance of steam plants in the power supply of California has been increasing rapidly since the war. Over 42 percent of the energy produced by all electric utility plants within the state in 1947 was generated in steam plants; the proportion rose in 1949 to 47 percent. Even including the production of Arizona and Nevada, steam plants in 1949 accounted for close to 40 percent of the total power output of the three states.

The aggregate of new steam plant capacity installed in California since the war or planned for completion in 1951 reaches the impressive total of 1,950,000 kilowatts, about equal to the ultimate planned capacity of the giant hydro-electric powerhouse at Grand Coulee. Capacity of these steam plant installations exceeds that of the new hydro plants installed in California during the same period by more than three to one. Recent announcements by leading utility companies indicate the continuance of a large volume of steam plant construction in 1952 and 1953. This strong trend to fuel based plants rests in part on the growing scarcity and high development cost of water power sites and in part on increasing efficiency of steam generation in units of large size, where high pressures and temperatures can be effectively utilized. Such considerations as flexibility of location with reference to load centers and transmission lines, and saving of time in

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**TWELFTH DISTRICT ELECTRIC UTILITY GENERATING CAPACITY AND PEAK LOADS**

![Graph showing electric utility generating capacity and peak loads](image)

1 Data as of year-end for 1946 and 1947, quarter-end for 1948 on. Latest figure plotted is for June. Monthly data. Last figure plotted is for August.

Note: This chart is plotted on a semi-logarithmic scale on which equal vertical distances represent equal percent changes rather than equal absolute amounts.

Source: Federal Power Commission, Electric Utility System Loads; Entries for December 1950 and December 1951 are based on utility estimates.

Comment: Chart: There is an apparent inconsistency in the relation of peak loads to installed capacity in Region VII (the Pacific Northwest) depicted on the above chart, with loads exceeding "capacity" for periods ranging from four to eight months at a time. This inconsistency is due to the fact that capacity figures are given in terms of "name plate" rating of the individual dynamos, while in point of fact the actual working capacity of these generators usually runs 10 percent or more above rated capacity. Even making allowance for this excess working capacity, it is evident that the reserve margin in the Pacific Northwest in recent years has been practically at the vanishing point, and local power supplies have had to be supplemented by imports from Montana, California, and British Columbia.
procuring sites, planning, and construction, also play a part.

These big new steam plants are not intended to be used primarily as stand-by facilities, supplementary to the hydro plants, but rather as base-load plants, to be operated on a regular day-in, day-out basis. Although total unit cost of production of electric energy will be somewhat higher in steam plants than in some of the recent hydro plants, they will play an important part in assuring abundant supplies of firm power at all seasons.

**Tight power situation in the Pacific Northwest**

Complaints of power shortages have become more or less chronic in the Pacific Northwest, where there has been a tendency to depend largely upon the Federal Government for the provision of additional power supplies. For a considerable period, relatively little construction of new generating facilities was made in some important areas of this region by non-Federal agencies, in spite of rapidly growing demands for power. Most of the utilities of the area, both privately and municipally owned, depend upon the Federal system for an important part of their power supplies and have followed the policy of letting Congress provide the necessary funds for new generating facilities. The growing movement towards setting up local public utility districts to acquire the plants of existing utility concerns has put a damper on private utility initiative in the Northwest, especially in Washington. More recently, however, some of the municipal systems, such as those in Seattle and Tacoma, have embarked upon programs of expansion and are currently making large investments in additional generating capacity.

According to data assembled by the Bonneville Power Administration, the proportion of the entire utility generating capacity of the Pacific Northwest in Federal ownership has increased from less than 2 percent in 1935 to nearly one-half the total at the present time. On the basis of existing plans or actual commitments, this proportion will rise to about two-thirds of the total by 1958. Including municipal and other local public agencies, the share of the total power supply of the region in public contrasted with private ownership is already around 64 percent of the total and by 1958 will rise to about 80 percent.

**Lack of stand-by capacity**

The problem of adequate power supplies to take care of peak requirements is complicated in the Pacific Northwest by the relatively small volume of steam plant capacity in the area. In contrast with the situation in the country as a whole, where steam and internal combustion plants represent close to three-fourths of the total installed capacity of all electric utility plants, the proportion of such non-hydro capacity in Oregon and Washington has declined from 33 percent of the total in 1932 to less than 12 percent at the present time and appears likely to shrink still further. Normally, in areas dependent basically on hydro sources, it is necessary to provide a substantial reserve of steam plant capacity to take care of peak loads or to handle emergencies. The limited steam capacity in the Northwest and the apparent unwillingness to enlarge it make the area peculiarly susceptible to seasonal power shortages arising from deficient stream flow and emphasize the necessity of operating the power resources of the area as a unified pool. The utility managements of the area are keenly alive to this situation and have worked out arrangements for interchange of power, both among themselves and with the Federal system, so as to insure the most efficient over-all use of physical resources in meeting the constantly varying power demands of the region. Even with the utmost endeavor to integrate facilities, however, it has been necessary in the state of Washington to put some limitation on the addition of new industrial loads and on the use of electricity in space heating.\(^1\)

**Some consequences of remote control**

Because of the large size of its generating units and its extensive transmission lines, the Federal power system in the Northwest is able to deliver power to the distributing utilities at wholesale rates as low as 2 mills per kilowatt hour. This is far below what it would cost most of the utilities to produce electric power individually in their smaller power houses. Hence the privately-owned utilities in particular have tended to buy Federal power to meet their growing requirements rather than produce it themselves. Consequently, much of the new private utility investment in this area in recent years has gone into distribution facilities rather than into generating equipment. On the other hand, dependence upon Congress to maintain the scheduled rate of construction of new dams and provide the necessary additional generators and high voltage transmission lines exposes the area to uncertainties and delay over and above those normally associated with purely commercial undertakings. Policy controversies can easily involve one or another of the far-flung Federal power projects and throw the orderly development of the whole integrated system out of gear. This is part of the price which must be paid for local benefits provided from national funds.

Another consequence of making Federal authority rather than local initiative responsible for the development of Northwestern power resources is the surrender of a large measure of control over marketing policies in the disposal of available energy. Almost of necessity the Federal system has had to give priority to national defense considerations and other public objectives. This means, for example, long time contracts with the electrometallurgical industries, such as aluminum production, which require enormous quantities of low cost power in order to exist at all. Another large fraction of the Federal power output is earmarked for pumping water for the

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\(^1\) The Pacific Northwest, as here defined, is substantially the Columbia Basin, including Idaho and Western Montana. See Bonneville Power Administration, *Advance Program*, 1930.

1,000,000 acre Columbia Basin irrigation project. An overriding directive of the basic Bonneville Act is that preference in the sale of power be given to public agencies, such as municipalities, cooperatives, and public utility districts.

All this tends to limit rather drastically the supply of power available for sale to miscellaneous users and has operated to tie the hands of the various public utility managements of the area in building additional loads on their various systems and in bidding for new industries. Many potential industrial customers have had to be turned away. It is in this sense that a power shortage may be said to exist in the Northwest. Such a large proportion of all the eggs is in one basket—the defense industries—that relatively little is left over to be divided up among all other claimants, existing and potential.

**Trend to higher costs and rates**

In common with all other types of construction, the extensive postwar expansion of electric power facilities has incurred higher costs than most of the earlier installations. There is every prospect that these higher construction costs, as well as advancing costs of operation and maintenance, will be relatively permanent and will probably be reflected in basic rates and charges. Already in California the leading electric utility company has been granted an increase of about 6 percent in its general rate schedules. This increase marks the first reversal in a steady downtrend in average rates for this company extending over a period of nearly 30 years.

In the Pacific Northwest, the Bonneville Power Administration, which is the marketing agency for the Federal power system in the area, reviews its basic rates every five years. This was last done in December, 1949. The decision reached at that time was to maintain the existing wholesale rate of $17.50 per kilowatt year for another five years. This rate is equivalent to 2 mills per kilowatt hour. However, a note of warning was sounded that, because of higher costs of construction and operation already evident or anticipated, it might become necessary to increase the basic rate after 1954. On the basis of present cost forecasts and assumed allocations of cost between power and other purposes, it was indicated that an average wholesale rate of about $22.50 per kilowatt year would probably be adequate to meet the financial requirements of the existing and authorized projects of the Columbia River power system. This rate is equivalent to slightly more than 2.5 mills per kilowatt hour.

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**PART II. NATURAL GAS**

**Recent Growth in Use of Natural Gas in United States**

One of the outstanding developments of recent years in the fuel and energy supply of the United States has been the rapid growth in the use of natural gas, for both domestic and industrial purposes. The total consumption of natural gas for all uses increased over five-fold between 1920 and 1947 and close to twelve-fold over the period since 1906. At the earlier date natural gas supplied around 3 percent of the nation's total energy requirements; by 1947 it accounted for some 15 to 16 percent, or roughly four times the contribution of hydro-electric power. Even more impressive has been the growth in long-distance transmission of natural gas by pipe line. The interstate movement of natural gas increased from about 150 billion cubic feet in 1921 to over 1,100 billion in 1946—a seven-fold expansion in 25 years. Comparable data are not yet available for more recent years, but the rapid construction of additional pipe line facilities since 1946 indicates a corresponding increase in the transmission of natural gas to distant points of consumption.

This remarkable growth in the utilization of natural gas was made possible by the discovery of large new gas fields, particularly during the period between 1916 and 1940. These discoveries occurred chiefly in the southwestern states—Kansas, Oklahoma, Louisiana and Texas—and in California. Most of them were made in connection with the search for oil and their development has largely been associated with oil production, though some important "dry" gas fields were also discovered during that period. Coincident with these increasing gas supplies came important technological improvements in the materials, design, construction, and operation of pipe line and pumping facilities. High pressure transmission had been used as early as 1891 to bring gas 120 miles into Chicago from natural gas fields in Indiana, but it was not until about 1926 that really long distance transmission and marketing of natural gas became feasible. The first 1,000-mile pipe line was put into operation in 1930; subsequent development has been rapid, especially since the war. By 1948 the total mileage of natural gas pipe lines in the United States, including gathering, transmission, and distribution facilities, had reached the impressive figure of 250,000 miles, of which over 60,000 miles was in transmission lines.

New lines currently under construction or authorized, and pending applications before the regulatory authorities for additional facilities, will add substantially to the existing mileage which already exceeds the total mileage of railroad lines in the United States and is far in excess of the oil pipe line mileage. According to the records of the Federal Power Commission, the gross plant investment of all natural gas pipe line companies reporting to the Commission exceeded $2 billion at the end of 1945. By the end of 1949 the mileage of natural gas mains in the United States had increased to 281,480, distributed as follows: Field and gathering, 36,800 miles; transmission, 98,270 miles; distribution, 152,350. See American Gas Association, *Gas Facts*, 1949.
tween that date and April 1, 1948 the Commission had authorized the construction of new transmission lines from six natural gas producing states in the Southwest estimated to cost $577 million, while applications were still pending for additional pipe line facilities from that area involving an estimated outlay of $800 million.

Principal uses of natural gas; local utilization bulks large

Notwithstanding this rapid and continuous development of long distance transmission lines, more than two-thirds of all the natural gas produced in the United States is still consumed in the six chief producing states—Texas, Louisiana, California, Oklahoma, West Virginia, and Kansas. These six states produced 87 percent and consumed 68 percent of the total marketed production of about 4 trillion cubic feet of natural gas in 1945. A very considerable fraction of the entire marketed output is, in fact, consumed within or close to the same field where it is produced. The operation of the oil and gas fields themselves accounts for close to a quarter of the total marketed production, with Texas alone representing nearly half the entire field use of natural gas. Here is included usage for oil and gas well drilling and pumping, and the operation of natural gasoline extraction plants and the other facilities connected directly with oil or gas production.

Field use; gas reinjection

Field use of natural gas has frequently been lavish, not to say wasteful, in some of the surplus producing areas, especially in the Southwest and formerly in California also. An important factor where such waste has occurred has been the lack of readily available markets with consequent low field prices for “wet” gas, i.e., natural gas produced in association with oil, although this situation has improved. There has also been in recent years a definite tendency toward conservation of oil-well gas, by its reinjection after processing for liquid content, into the underground reservoir in order to maintain the pressure necessary to secure the maximum efficient recovery from the oil structure. Extravagant use of gas has also occurred in some of the dry gas fields and conservation regulations have been necessary in order to curb such wasteful use and to enforce the use of more efficient operating practices.

Carbon black

Large quantities of natural gas are used as raw material, especially in Texas and Louisiana, in the local manufacture of carbon black and in other chemical industries, which are conducted almost entirely within or very close to the producing fields. These industries are based upon the extremely low prices at which this essential raw material can be obtained close to the source of supply. Aside from oil- and gas-field operations, the carbon black industry is the most important single industrial user of natural gas in the United States and accounts for some 10 to 12 percent of the total yearly marketed production. About 75 percent of this product is used by the rubber industry, especially in the manufacture of tires, and most of the remainder is exported, as nearly the entire world supply of carbon black is produced in this country.

Petroleum refining

Petroleum refineries rank third among the industrial users of natural gas in the United States; this use is largely concentrated in the five leading oil producing states, and accounts for some 8 or 9 percent of the entire marketed production of natural gas. The use of natural gas as refinery fuel increased very rapidly during the war when it was necessary to conserve fuel oil for military use. Since the war, with the development of petroleum “cracking” and chemical-refining techniques as distinguished from simpler distillation methods, refinery fuel requirements have increased substantially. These requirements are being met in part, however, by the increasing availability of refinery by-product gases and residual oils; and natural gas enters into the picture only to the extent that its price to the refineries is competitive with other fuels.

Natural Gas in the West

The fuel situation in the West differs in important respects from that in most other sections of the country. Coal is largely unavailable or is excessively costly in the more populous states—those on the Pacific Coast—though it is mined in most of the Rocky Mountain states where it finds important uses in local industry and as locomotive fuel. Important resources of petroleum are known to exist only in California, Wyoming, New Mexico, Colorado, and Montana. California refined oil production supplies the major requirements of practically all the states of the Twelfth District, though refining operations have recently been started in Utah, based on crude oil piped in from the Rangely field in Colorado. Natural gas has until recently been discovered or developed on a large scale in the West only in California and New Mexico, although scattered fields of local importance occur in Wyoming, Montana, and Colorado.

Of the seven states of the Twelfth District, only California, Arizona, and Utah are listed by the Bureau of Mines as among the 33 natural gas consuming states. Together they account for approximately 14 or 15 percent of the total United States consumption of natural gas; including the four Rocky Mountain states outside the District, the figure for the seven Western States mentioned is raised to about 18 or 19 percent of the national total. Other areas in the West have been too remote from potential sources of supply to warrant the heavy investment required to construct the necessary transmission facilities. Indications are appearing, however, that this situation may be rapidly changed as new exploratory and developmental work is pushed in the Rocky Mountain area, extending from New Mexico to Alberta. It seems probable that adequate reserves may soon be proved up in this region which will permit the transmission of natural gas to areas, such as the Pacific Northwest, that have not hitherto had access to this fuel.
Demand for gas in California

In California, natural gas has for many years played a leading role in the fuel economy of the state. The rapid growth of population and industry incident to and following the war, however, has multiplied the demand for gas, especially by domestic users, beyond the capacity of local resources to supply. With the gradual depletion of existing older fields, the lack of sizable new discoveries, and the increasing practice of reinjection to effect greater recovery of oil, there has even been a tendency for the availability of natural gas in California to decline. It is with considerable concern, therefore, that industrialists and the public utilities have realized during the past few years that the local supplies of natural gas are no longer adequate to their needs. It has become necessary to seek additional sources of supply from distant areas and to make very large outlays for transmission facilities, with resulting substantial increases in unit costs and higher rates for service.

A considerable variety of problems are involved in making this transition from a local and self-sufficient fuel base to one more closely integrated with the national fuel economy. Moreover, it is far from certain whether the alleviation of California’s fuel problems expected to result from the importation of out-of-state supplies of natural gas will prove to be more than temporary. Rather, a continuing search for additional fuel resources is indicated as an inevitable consequence of the probable future growth of the state’s population and industry.

Development of natural gas in California

California was relatively late in the discovery and utilization of its natural gas supplies but it has gone further than almost any other state or region in the development and general use of this resource. There was little or no investment in the natural gas business in California until about 1908, when the industry may be said really to have started. At the present time the total investment in the industry is around $500 million with annual revenues exceeding $170 million. Some 26,000 miles of pipe line serve approximately 2,500,000 customers.

California has, in fact, long had more natural gas consumers than any other state. Unlike the situation in Texas and some of the other surplus gas areas, where natural gas serves as a raw material for important chemical industries, its use in California is confined almost entirely to fuel and heating purposes.

Because of its great convenience, natural gas is used for domestic heating in Southern California practically to the exclusion of other types of fuel, and its use for space heating is equally general in other parts of the state wherever mains make it available. According to the housing census of 1940, 70 percent of all heated dwelling units in California used gas. It is the almost universal fuel for water heating and by far the most important fuel for cooking in all urban areas in the state. Industrial use of natural gas is also widespread, especially in the cement, glass, and ceramics industries and in other applications involving heat treatment, such as food processing and metal fabrication, as well as for boiler fuel in electric power generation and in a wide variety of other industries. Most small industrial and commercial plants are not equipped to use other types of fuel. Its relative cheapness as compared with other fuels has stimulated its general use and both industry and domestic consumers have come to depend on its economy and ready availability.

Oil well gas

The first pipe line deliveries of natural gas to the Los Angeles area were made in 1913 from the Buena Vista Hills in the southern San Joaquin Valley, about 150 miles distant; it was not until 1929 that service to the San Francisco Bay area was begun, following the development of the Kettleman Hills oilfields, also in the San Joaquin Valley. Before natural gas became available, the cities of California used manufactured gas, made from crude oil. The really rapid development of the natural gas business in the state came during the 1920’s and was based upon the rapid expansion of the California oil industry during that decade. Oil-well gas or wet gas (commonly called casing-head gas) occurs in association with oil and is necessarily produced along with the oil as it is the major source of energy in bringing the oil to the surface. Huge quantities of such wet gas were produced in the late 1920’s in connection with oil field operations in the Los Angeles Basin and the San Joaquin Valley, quantities so great in fact that adequate outlets could not quickly be provided and much gas was wasted. This wastage reached a peak around 1929 estimated at nearly one-third of the annual output, and led to the enactment by the State Legislature of a gas conservation act de-
signed to prevent excessive waste of natural gas in connection with oil production.

The gas utility companies were quick to take advantage of these large supplies of cheap natural gas made available in oil field operations and entered into contracts with the oil producers for their surplus gas output. Transmission lines were laid connecting the oil and gas fields with consuming centers. In a short time natural gas almost completely displaced manufactured gas in California; for nearly 20 years natural gas has constituted about 99 percent of the total utility gas sales in the state.

**Importance of dry gas**

The supply of oil-well or wet gas was supplemented, particularly in the decade of the 1930's, by the discovery of extensive dry gas fields, chiefly in the northern and central areas of California. The largest of these was the highly productive Rio Vista field in the lower Sacramento Valley, some 40 miles northeast of San Francisco. Discovered in 1936, this field is rated as one of the half dozen most important natural gas fields in the United States. Its rapid development was hastened by the war, when in 1942 an important pipe line bringing oil-well gas from the Kettleman Hills area in the San Joaquin Valley to San Francisco Bay was temporarily converted into an oil line. The heavy fuel requirements of war industries and military installations were an added stimulus to increased gas production, particularly in view of the need to conserve oil for military use.

Dry gas occurs independently of oil deposits; as contrasted with oil-well gas, it has the important advantage of flexibility of output and can be produced in varying quantities to meet fluctuations in demand, whereas the production of oil-well gas is relatively inflexible and is geared more or less to the rate of oil output. The production of dry gas in California has expanded at an extremely rapid pace during and since the war. Representing less than 4 percent of the total natural gas production of the state between 1935 and 1938, dry gas has in recent years accounted for more than a third of the entire state output. It represents an even larger fraction of the quantity available to the gas utilities for general distribution, exceeding 50 percent of the total in recent years. This is due to the extensive field use of oil-well gas in drilling, pumping, natural gas liquids recovery, and other field operations. Substantially less than two-thirds of the net output of oil-well gas in California in recent years has been made available by the producers and pipe line companies for general public distribution. A much larger fraction of the dry gas output is delivered to the gas companies for resale and utility use.

The two major sections of the state present almost exactly opposite conditions with respect to their relative dependence upon oil-well gas and dry gas. Dry gas has in recent years accounted for some 75 to 80 percent of the total natural gas disposed of by the utilities in Northern California, while in Southern California well over 90 percent of the total is oil-well gas. In the latter area dry gas is relied upon chiefly as a means of meeting the peak demands of consumers during the winter months when seasonal requirements are at the maximum.

**The place of natural gas in the western fuel supply**

In terms of total energy requirements for all purposes, petroleum and natural gas together account for more than nine-tenths of the fuel supplies of the five Far Western states and nearly 97 percent of California’s requirements, as contrasted with about 50 percent for the country as a whole. The relative contribution of natural gas to total energy requirements in these areas is about 22 percent, 29 percent, and 14 percent, respectively.

From the standpoint of strictly industrial use, as distinct from transportation requirements, natural gas is much more important in the fuel economy of California than the above comparison would indicate. In the nature of things, gas is not competitive with other fuels as a transportation fuel, whether by land, air, or water, where-

![Table 1—Industrial Use of Natural Gas in California and of Fuel Oil in Pacific Coast Territory, 1936-49](image-url)

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1 Pacific Coast Territory includes California, Oregon, Washington, Arizona, and Nevada. All grades of fuel oil are included: heavy fuel oil, Diesel engine fuel and other light fuel oils.

2 Approximate. Basis 1 barrel oil equals 6,000 cubic feet natural gas.

3 Smelters, mines, and manufacturing establishments.

as this use accounts for the major part of the consumption of petroleum and its derivatives. In strictly industrial applications, however, natural gas has long been the principal fuel used in California. In fact, the total energy requirements supplied by natural gas in this state in strictly industrial uses exceed the equivalent heat units supplied by fuel oil in comparable utilisations in the entire five westernmost states.¹

The relevant facts are indicated in Table 1. In each of the 12 years shown the industrial use of natural gas in California was materially larger than that of fuel oil in the entire western area, although the use of oil has increased more rapidly than that of gas in recent years of limited gas availability. The greater part of the relative gain in oil consumption in recent years was in the public utility and general miscellaneous classifications.

**Demand and Supply Problems**

The over-all demand-supply situation in recent years with respect to natural gas in California is indicated in Table 2. This table covers the period 1936-1947 and presents a breakdown of the major uses of natural gas in comparison with the available supplies. These supplies are net, excluding gas used in pressure maintenance operations and shrinkage due to the recovery of natural gas liquids. The use of gas for fuel in oil company operations has averaged close to one-third of the available supply throughout the 12-year period. An outstanding feature has been the steady and continuous increase in domestic and commercial use as compared with industrial use. The ratio of about 3 to 1 in industrial as against domestic and commercial use in 1936 had shifted to around 3 to 2 by 1946-47. Field waste and other loss, while not negligible, have tended to decline relative to total usage.

**Factors limiting supply**

Few important discoveries of new oil or gas fields have been made in California in recent years in spite of marked activity in exploration and drilling. Mean-

Table 2—Utilization of Natural Gas in California, 1936-49

<table>
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<tr>
<th>Year</th>
<th>Total current production</th>
<th>Total industrial use</th>
<th>Oil company use</th>
<th>Electric power</th>
<th>Other industrial</th>
<th>Domestic and commercial use</th>
<th>Unaccounted for</th>
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<td>96</td>
<td>61</td>
<td>66</td>
<td>112</td>
<td>251</td>
</tr>
</tbody>
</table>

¹ Net withdrawals from formation and underground storage.
² Field fuel, drilling fuel, and gasoline plant fuel.
³ Refinery and pump station fuel.
⁴ Includes gas companies' own use.
⁵ Including 3.5 billion cubic feet from Texas pipeline.

Sources: Federal Power Commission and California Public Utilities Commission, previous citations.

¹ American Gas Association, Proved Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas, December 31, 1948.
of such gas is to exert pressure in forcing the oil to the well bore and raising it to the surface. Under certain conditions the recovery of oil can be greatly increased and its unit cost reduced by reinjecting gas into the oil structure. After serving as a pressure agent the gas may again be recovered, but only after a period of years.

The practice of gas injection for pressure maintenance has increased very rapidly in California oil fields, especially since the war, and in recent years the quantity so used has amounted to nearly one-third as much as the total volume of natural gas sold by the gas utility companies of the state to their customers. It seems probable that the quantity of injection gas will continue to increase for some years. This will further reduce the amount available for public distribution and general use, at least until recoveries begin to offset new injections.

Substantial quantities of wet gas are processed by the oil companies for the extraction of natural gasoline and other liquids. Together with increasing field use for other purposes and growing requirements for pressure maintenance projects, the net effect has been to limit rather severely the amount of oil-well gas available for delivery to the utility companies, particularly in Southern California which depends almost exclusively upon gas from the oil fields.

**Characteristics of demand**

The general public market for natural gas has numerous facets and their interrelations are extremely complex with respect to relative access to supplies, availability of other fuels, rates, and character of service. Three broad classes of public utility sales can be distinguished—residential, commercial, and industrial. The first two are commonly considered together, as their characteristics are somewhat similar, although commercial users generally pay lower rates per unit of service in consideration of their greater average use. Most industrial customers pay still lower rates, again, in part, because of relatively large average usage, but more importantly in many cases because of special conditions applicable to their contracts which limit the availability of service at times of peak demand. The circumstances giving rise to these special arrangements and some of the problems ensuing therefrom have been of particular importance in California.

Residential and commercial usage of natural gas in the United States as a whole has represented from one-third to two-fifths of the total physical volume of sales of such gas by utility companies in recent years, with a definite trend toward an increasing fraction of the total. Such usage accounted for approximately two-thirds of the entire gas revenues of the utility companies of the United States in the three years 1946 to 1948. In California, the relative importance of residential and commercial usage in the sales and revenues of the natural gas utility companies is much greater than in the country as a whole. In the three-year period, 1945-47, residential and commercial use averaged about 57 percent of natural gas sales by California utilities as compared with about 36 percent by the utilities of the entire country. The revenues from such sales ranged between 72 and 82 percent of total natural gas utility revenues in California in the same years as against 64 to 67 percent in the country as a whole.

**Changing use and rate patterns**

For the country as a whole, both physical volume and utility revenues from domestic and commercial sales are becoming a larger fraction of their respective totals. In California, in contrast, domestic and commercial customers are taking an increasing proportion of total utility gas sales, but the industrial consumers are paying a larger fraction of the total cost. Drastic increases in charges to industrial users of natural gas have been levied in California during the past two or three years, while rates to residential users have been substantially reduced over a considerable period of years; rates to commercial customers have, at least until recently, also generally tended to move down.

A somewhat similar tendency in the relative behavior of rates for the several classes of natural gas service is apparent in the country as a whole. Over-all average revenues per unit of sale have been moving upward, at least since 1945, with the largest relative increases in the rates to industrial users. Rates for commercial customers have also increased somewhat, while the average charge for residential service has declined. Rate adjustments have been more gradual and relatively more moderate, however, in the United States as a whole than in California, particularly advances in rates to industrial users. Between 1945 and 1948 the average revenue from utility sales of natural gas to residential and commercial customers declined from 60 cents to a little over 58 cents per M.c.f. in the United States as a whole, and from about 57 cents to about 54 cents per M.c.f. in California. During the same period average revenues from sales to industrial customers increased from about 17 cents to 19 cents per M.c.f. in the country as a whole, but from about 15.5 cents to over 31 cents per M.c.f. in California.1

**Seasonal fluctuations**

Extreme seasonal variation is the outstanding characteristic of the domestic demand for gas; from this fundamental fact flow important economic consequences for the gas utility industry. The general service sales of California gas utility companies, representing chiefly the requirements of residential consumers, average nearly two and one-half times higher during the winter months, when demand is at its peak, than during the slack summer season. The variation between individual peak days of the year and the daily average for the year is, of course, even more extreme. This marked imbalance is due primarily to the heavy space heating requirements of domestic consumers: according to the records of the California Public Utilities Commission, over 54 percent

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1 American Gas Association; California Public Utilities Commission.
2 Based on data for the years 1939-42, for which monthly records are available. See Railroad Commission of the State of California: Report on the Utilization of Natural Gas, Case No. 4591, Special Study No. S-218, Tables 3, 4, 5.
of the total volume of all residential and commercial gas sales in the state was for space heating in 1945, a year of somewhat below average temperature.¹

An important means of helping to adjust gas supplies to fluctuating seasonal requirements is through the provision of underground storage facilities close to consuming centers. This is done on a relatively large scale in Southern California where natural underground storage reservoirs are locally available in partially depleted dry gas fields. Surplus gas supplied by the oil companies during the summer months is injected, after compression, into the underground structures and is thus available to help meet the peak demands of customers during the winter period. The use of these underground storage facilities has played an important part in recent years in the operations of the leading gas utilities in Southern California.

The problem of diversifying loads

The gas distributing utilities must be prepared with ample supplies and adequate delivery facilities to meet the inevitable peaks of demand, whenever they occur. If they had no other customers than the “firm load” of the residential and commercial service, their position would be one of extreme imbalance, with a large part of their facilities working far below capacity much of the time, resulting in much higher unit operating costs. In order to equalize their rate of operation as nearly as possible throughout the year, gas companies everywhere endeavor to secure a more diversified load by building up their summer volume. A common practice is to make contracts with industrial users for the sale of comparatively large blocks of gas at specially low rates. The usual consideration for these low rates is that the service is subject to curtailment at times when the supply of gas or line facilities are not adequate to meet the demands of all customers. In consideration of the higher rates paid by residential and most commercial customers for “firm” service, they are entitled to priority of service at all times. Gas sold to industrial users at low rates under these curtable arrangements is available only after the needs of firm customers have been met. Hence this class of sales is commonly called “surplus” or “interruptible” service.

Interruptible service contracts

These interruptible service arrangements were originally entered into by California public utilities at a time when there was a large surplus of natural gas available from oil field operations, much of which was being blown to the air. The pipe line and gas companies at that time also had an excess of physical facilities beyond the off-peak requirements of their regular customers and could take on additional customers with very little extra investment in transmission or service facilities. These conditions have now almost completely changed. Waste gas has practically disappeared in most California oil fields and there has long been no substantial volume of surplus gas in that sense. In fact, increasing drafts have been made on the reserves of dry gas in order to supply service to interruptible industrial customers, particularly in Northern California, where surplus gas sales have continued to increase.

Very large quantities of natural gas have been disposed of under the interruptible schedules. For a considerable time, in fact, such surplus gas represented the major part of all utility gas sales in California. This condition persisted in the northern part of the state up to about the beginning of the war. In recent years surplus gas has constituted about 40 percent of gas utility sales in Northern California, and about 33 percent in the state as a whole.

Industrial use of surplus gas

A wide variety of California industries depend on natural gas, either entirely or for a substantial part of their fuel requirements. About one-half of the total number of industrial customers of the state are now served under firm schedules, at relatively high rates, for all their fuel needs where the inherent advantages of gas make its use technologically necessary. Such firm industrial use, however, has accounted in recent years for only about 5

---


<table>
<thead>
<tr>
<th>Industry classification</th>
<th>Number of customers¹</th>
<th>Annual sales (million c. ft.)</th>
<th>Percent of total</th>
<th>Average usage per customer (million c. ft.)</th>
<th>Average revenue (cents per M.c.f.)</th>
<th>Revenue from sales (in thousands)</th>
<th>Seasonal factor ² (percent)</th>
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<td>All other industries</td>
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<td>32.1</td>
<td>13.1</td>
<td>12,773</td>
<td>77.2</td>
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¹ Monthly average.
² Ratio average monthly volume to volume in month of highest use.

percent of the total volume of utility gas sales. By far the more important industrial consumption of natural gas is represented by such crude or bulk uses as boiler fuel, heating kilns and furnaces, etc. These users are served under the surplus or interruptible schedules. Table 3 summarizes the results of a detailed study by the California Public Utilities Commission of surplus gas sales by all gas companies in the state in 1940. The first dozen industry classifications, including about 1100 customers, for which the data can be segregated accounted for about 70 percent of the total volume of surplus sales and for a somewhat smaller proportion of the dollar revenues; some 1,900 other customers, scattered through miscellaneous industry classifications, made up the remainder of the surplus group.

Curtailment of service to industrial users

The extremely rapid growth of California urban population in recent years, with its consequent stimulus to demand for residential and commercial gas service, has intensified the problems of the gas utilities in meeting their peak load requirements. It has become necessary to restrict the service to interruptible users with increasing stringency, particularly in Southern California, where gas availability has been lowest and the requirements of residential customers greatest. Curtailment of deliveries to industrial customers became a regular practice in Southern California and in 1946 reached a figure of 51 percent of total demand (curtailment plus actual use) of all curtailable users other than electric power companies; substantial curtailment was necessary in every month of that year. Even in Northern California, where dry gas fields permit somewhat greater flexibility of supply, curtailment of service has become increasingly important in recent years.

One consequence of these restrictions upon industrial deliveries has been an increasing tendency by industrial users to whom an assured supply of gas is essential at all times to switch from interruptible schedules to the intermediate class of firm schedules, paying considerably higher rates to secure greater continuity of service. This trend has been especially pronounced in Southern California, where the number of customers served under "firm industrial" schedules increased approximately 50 percent between 1944 and 1947. Firm industrial sales accounted for close to one-quarter of all industrial sales of Southern California gas utilities in 1946. A similar tendency was evident in Northern California during the war years but has slackened off since. Firm gas in large quantities is not available to all comers, however, because of the basic limitations upon supply and the necessity to protect the requirements of general service customers. Usually only those customers who cannot install standby facilities for alternative fuels are eligible to service under the firm industrial schedules.

Another and much more important consequence of restrictions upon the supply of industrial gas, which of course reflect the exceedingly tight over-all gas supply position in California, has been to stimulate the search for additional sources of natural gas. The vital importance of conserving the state's natural gas reserves so as to make them available for future needs and the necessity to supplement these limited resources by securing gas from outside sources have been a constant preoccupation of the California Public Utilities Commission for a number of years. As far back as 1941 the Commission initiated a comprehensive investigation into the whole problem of the adequacy of natural gas supplies in California and the related questions of reasonableness of rates and fairness of the curtailments imposed under interruptible contracts. By keeping these questions constantly in the foreground the Commission has rendered a useful public service and has emphasized the need of supplementing California's reserves of natural gas by developing additional supplies from outside sources.

Importation of Natural Gas Into California

Southern California

The inadequacy of existing and potential local supplies of natural gas to meet the growing requirements of their customers has long been a matter of concern to the California gas utilities. After an intensive study of California gas reserves in 1943, a group of leading Southern California utility companies decided that it would be necessary to seek additional sources of supply outside the state, not only to provide for their expanding local market potential but even to keep up with the increase in firm demand. Arrangements were accordingly made by these companies in 1945 for the purchase under a 30-year contract of large volumes of natural gas from Texas and New Mexico to be supplied by an independent pipe line company. This company undertook to secure the necessary gas supplies from the Hugoton and Panhandle fields in Texas and the Permian Basin area in western Texas and southeastern New Mexico, and also to construct and operate transmission facilities to a point near Blythe, California, at the Arizona border. From that point of delivery the associated utility companies would provide their own pipe line and compressing facilities for transmission of the gas to a convenient distribution center in the Los Angeles industrial area.

After appropriate hearings before the Federal Power Commission and the California Public Utilities Commission, authorization was secured in 1946 for the construction of the necessary facilities, including approximately 1,200 miles of large diameter pipe line. In authorizing this project, the Federal Power Commission called attention to the fact that large quantities of oil-well gas in the Permian Basin were currently being wasted for lack of a market and indicated that the plan for utilization of this gas was an important factor in warranting approval of the venture. The Commission also pointed out that there are inherent difficulties in obtaining a long and continuing supply of surplus gas from oil fields and endorsed the position of the California utilities in insist-
ing that the Permian Basin oil-well gas be backed up by the dedication of dry gas reserves in the Panhandle-Hugoton area, containing the two largest natural gas fields in the United States.

The first deliveries of gas over the new system were made in October 1947; the rate of delivery was progressively increased to 305 million cubic feet per day early in 1949, which is the full nominal capacity of the line. Subsequent contracts between the Southern California companies and the supplying company call for the construction of additional pipe line facilities and have raised the total volume of contemplated deliveries to a rate of approximately 400 million cubic feet per day beginning in October 1951. This quantity may be compared with the 510 million cubic feet per day actually available in 1947 to the three major Southern California gas distributing companies from California sources.

**Northern California**

Arrangements were also made in 1947 between the Southern California companies and the leading gas utility company of Northern California to share for a five-year period extending into 1953 the additional supply of gas made available by deliveries from out of the state. This Northern California utility in 1947 also contracted independently for the purchase of large quantities of natural gas to be supplied by the same pipe line company currently serving the southern companies. Under the terms of these contracts, gas is to be delivered at Topock, Arizona, a point near Needles, California, by a large new pipe line from the San Juan Basin which embraces parts of New Mexico, Colorado, and Utah, and from the Permian Basin area of Texas and New Mexico.

From the delivery point at the California-Arizona border, the utility company plans to build a 500-mile, 34-inch pipe line to a connection with its existing system near San Jose, California. This transmission line, together with the necessary compressing stations, is estimated to cost around $63 million. An important feature of this segment of extra-large diameter pipe line (the largest yet designed anywhere), which is to be operated under very high pressure at the delivery end of the transmission system, is that it will permit the accumulation of a substantial volume of "line pack" or temporary storage. This will greatly ease the problem of accommodating the normal fluctuations of demand experienced within any 24-hour period. This line pack can be provided at a fraction of the cost of conventional surface storage units. The final 214-mile 30-inch line of the Southern California companies, for example, is designed to provide line pack storage equivalent to about one-sixth of its rated delivery capacity.

Authorizations for the construction of the new transmission lines to serve Northern California were secured early in 1949 and construction work has recently begun. The purchase contracts contemplate the delivery of gas at the rate of 150 million cubic feet per day during 1951, 300 million in 1952, and, at the utility company's option, 400 million between mid-1953 and mid-1954, reaching a final maximum of 500 million by July 1956, if the additional gas is available and the pipe line company can finance the necessary transmission facilities on reasonable terms. The agreement is to extend for 25 years from the date gas is first delivered but the supplying company is not committed to deliver gas in excess of 300 million cubic feet per day for more than 15 years. The above quantities compare with average daily receipts of approximately 600 million cubic feet by all Northern California gas utility companies during the years 1944-47.

It is significant that the two Southern California utilities, the supplying pipe line company, and the leading Northern California gas utility company have recently formed an agreement to make a common pool of the gas dedicated to the California contracts if a shortage should develop and the supply company not be able to make deliveries in full according to the terms of its agreements. This pooling arrangement is intended to provide for the proration of available supplies of gas between the Northern and Southern California utilities on an equitable basis.

**Supply outlook for the next few years**

These bold programs for augmenting California's gas supplies might be thought to have quieted all concern as to the future fuel outlook for California industries. This is far from being the case, however, and spokesmen for industry are still concerned as to both the availability of gas and its cost. It is true that the substantial deliveries of gas initiated in 1947-48 have temporarily eased the supply situation in Southern California and have permitted a marked increase in the volume of deliveries to industrial consumers served on an interruptible basis. The major gas utilities serving the Los Angeles area increased their interruptible industrial sales from an average of around 87 million cubic feet per day in 1946, which was the low year since the war, to about 145 million in 1948, or approximately the level of the peak war years, 1943-44. The demand for such service was, of course, greatly in excess of the quantity available during most of this period, as was pointed out earlier in the discussion of curtailment.

Forecasts by the utility companies of expected increases in demand for gas during the next four or five years indicate a rather tight balance of supply and demand, even allowing for generous estimates of the volume of out-of-state gas deliverable. The supply of California oil-well gas available to the utility companies appears rather certain to decline in the absence of important new oil field discoveries. The decline in local supplies appears likely to exceed the probable increase in deliveries of out-of-state gas, with an indicated net deficiency ranging from about 5 percent of total demand in 1949 to around 18 percent in 1953. Because of the prior claims of customers

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1 Prospectus, Pacific Lighting Corporation, Preferred Stock, April 19, 1949.
served under firm schedules, these shortages will have to be assessed against the interruptible customers. This might result in cutting gas deliveries to this group by amounts increasing to as high as 35 percent of their total average demand in the year 1953. These estimates are based on daily requirements averaged throughout the year. Because of the great seasonal variability in residential requirements, which make up the bulk of firm demand, the deficit in supplies available for interruptible customers at periods of peak demand is certain to be much greater than indicated by daily averages. Hence continuing heavy curtailments of service to interruptible industrial customers appear inevitable.

A complicating factor is the somewhat uncertain status of gas use by the electric utility companies in relation to use by other industrial customers. In some cases, where utility companies supply both gas and electricity, the electric power plants of these utilities technically have priority over all other interruptible customers in the use of gas. If such priority should continue to be resorted to on a large scale, considerable curtailment to industrial users could scarcely be avoided.

The consumption of gas for the generation of electric power by public utility companies in California averaged about 110 million cubic feet per day in 1947 and was close to 170 million in 1948, or approximately nine-tenths the consumption of fuel oil for electric generation in the latter year on an equivalent heat unit basis. These were years of unusually high steam generation of electric power because of the shortage of hydroelectric energy at a time of exceptionally high demand due to drought conditions. There was also a shortage of fuel oil in the fall of 1948, caused by a refinery strike which resulted in a sharp increase in the use of gas for steam electric generation. There is no reassurance, however, that such conditions may not recur, and there is a steady trend in the electric power industry toward relatively large investment in steam plants as compared with hydro plants, indicating correspondingly increased fuel requirements.

An Era of Higher Fuel Costs

California industry geared itself to the use of gas fuel largely as a consequence of the very low prices at which surplus natural gas was disposed of by the oil producers, and in turn by the public utilities, during the flush period of oil production in the late 1920's. The gas utilities adopted an aggressive marketing policy and made attractive rates to industrial users of surplus gas. The resulting saving in fuel costs as compared with oil was so great that the cost of converting fuel equipment to the use of gas could frequently be written off within a very short period. The average price paid by the utilities for gas purchased directly from the producers in the field fluctuated from 1935 to 1945 within a narrow range around 7 to 8 cents per M.c.f., reaching the low point in 1940 and gradually moving up thereafter.

Gas rates and oil prices

Gas companies in California own virtually no gas-producing wells. They have procured their supply of gas either directly from producers in the fields, who are usually oil companies, or from pipe line companies which make delivery at points close to consuming centers. In the past, in theory at least, prices paid for gas by the utilities have been largely based on the price of oil. Most of the purchase contracts with the gas producers contained fuel oil clauses which linked the price of gas with the posted price of fuel oil at the refineries. The rates charged by the utilities for surplus gas sold under the interruptible schedules are also more or less closely linked to oil prices. These schedules contain "escalator" clauses, similar in general purport to those used in the contracts between the utilities and the gas producers, which provide for automatic revisions of rates according to changes in the posted price of fuel oil. The escalations contained in the interruptible schedules, however, are usually about double the rates of those contained in the gas purchase contracts.

For a considerable time during the 1930's, however, the actual price of fuel oil was depressed below its posted price at the refineries and surplus gas rates were reduced correspondingly. Once established on a low basis, they tended to resist upward revision and a substantial differential has persisted between the cost of the two competitive fuels available to industrial users. This differential was widened during the war, when the OPA froze the price of natural gas from producers to the utilities but permitted increases in the price of fuel oil in 1943 and early 1946.

Fuel oil prices rose sharply after the war, reaching their peak late in 1948. The posted price of heavy fuel oil, tank-car basis, f.o.b. Richmond, advanced from $1.35 per barrel in August 1946 to $2.40 per barrel in November 1948, dropping again between January and April 1949 to $1.85. Corresponding changes occurred in the prices paid by the utilities to the gas producers and in the rates charged under the interruptible schedules. The average cost of natural gas purchased by the leading Northern California gas utility company increased from about 8.6 cents per M.c.f. in 1944 and 1945 to nearly 11 cents in 1946 and to about 15.4 cents in 1948. Rates for gas charged industrial users also increased very rapidly; successive advances in the interruptible service rates between 1946 and the end of 1948 more than doubled the average level of charges for such service as compared with the situation in 1944-45. Some reduction in these rates occurred in the early months of 1949, however, reflecting the lower level of oil prices.

1 The priority of electric power plants over other interruptible customers in the use of gas was relinquished by the leading Northern California gas utility company in 1949 except in emergencies or when necessary to prevent interruption or impairment of electric service. Southern California gas utilities have for a long time accorded equal treatment to electric utilities and other interruptible customers.

2 See California Railroad Commission, Case No. 4591, Special Study No. S-258, pp. 41-47.

3 Federal Power Commission, Docket G-1092, Exhibit No. 163.
Divergent trends in domestic and industrial rates

The general over-all relationship of rates for the principal classes of gas utility service in California in recent years is indicated by the following comparison of average unit revenues to the utilities from their sales of natural gas in the years indicated. While unit revenues from general service sales have tended downward, charges for both firm industrial and surplus interruptible service have moved upward, the latter sharply so.

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<th>Year</th>
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<th>Firm Industrial</th>
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<td>28</td>
<td>14</td>
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<tr>
<td>1943</td>
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<td>1946</td>
<td>55.5</td>
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<td>1947</td>
<td>56</td>
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</tr>
<tr>
<td>1948</td>
<td>55</td>
<td>36</td>
<td>33</td>
</tr>
</tbody>
</table>

Source: California Public Utilities Commission.

Certain limiting provisions established by the California Public Utilities Commission have had the effect of setting what amounts to a ceiling on possible increases in the rates for interruptible surplus service, and during the past year or more these rates have generally been close to these ceiling levels. It continues to be true, however, at least in Northern California, that the relative cost of gas fuel to industrial users served on an interruptible basis remains below the cost of equivalent fuel oil, although the differential is not so large as in the period from 1943 to 1946.

Cost of imported gas

The extremely heavy investment required to obtain large quantities of out-of-state gas results necessarily in high costs and high prices for such supplies. The Southern California utilities contracted to pay approximately 14 cents per M.c.f. for the initial 305 million cubic feet per day delivered at the California border, in addition to which they must incur the costs of transportation some 200 miles farther by an expensive high pressure transmission line before the gas is available to their principal markets. The cost of the Northern California utility’s share in the first installments of this out-of-state gas delivered in the San Joaquin Valley is close to 20 cents per M.c.f. Under its own more ambitious program with the supply company, current estimates by this utility place the total cost of imported gas to be delivered at the San Francisco Bay Area at around 24 to 25 cents per M.c.f.

Higher domestic and commercial rates impending

Under the impact of these higher costs, present and prospective, some of the California gas distributing companies have recently taken steps to secure increases in their rates for natural gas service. Applications are currently pending before the Public Utilities Commission from at least three gas utility companies seeking rate increases.

Note on Natural Gas Situation in Utah—1949

Another instance of growing pains, though on a smaller scale, is illustrated by the current situation in the Salt Lake City Area where local demand for natural gas has temporarily outrun supply. The requirements of this locality and its neighboring cities have been supplied from a number of different fields located in Utah, Colorado and Wyoming. Deliveries from an additional source of supply, the partially developed Church Buttes field, near Granger in western Wyoming, late in 1948 permitted the serving of industrial customers during the winter months who would otherwise have had their service curtailed. Rapidly increasing demand from domestic and commercial customers, however, arising both from new residential construction and from extensive conversions to gas from other fuels, especially for domestic heating, reached a point early in 1949 beyond the capacity of the regional gas utility to supply. It became necessary in March to discontinue taking on new customers for space heating and in April the Utah Public Service Commission forbade the connecting of new customers for any use of natural gas whatsoever after July 1 of this year.

Addendum, November 1950

No striking changes have occurred in the California natural gas situation during the past year. Demand for gas, after moderating among some classes of consumers, has turned up again and has now reached the highest levels yet recorded. The supply position has become much easier, due to gas imports from Texas which have permitted some reduction in the drain on California reserves. Average costs of gas to the distributing companies have continued to increase and the Public Utilities Commission...
has sanctioned advances in rates charged to consumers. Further advances appear probable in order to defray the costs of imported gas, which will supply a growing part of the state’s total requirements.

Nationally, the industry continues in a state of rapid expansion, with natural gas making increasing inroads upon the fuel markets of the eastern and midwestern states. Pipe line construction continues at a high rate and additional lines are constantly being projected. The backlog of applications pending before the Federal Power Commission for authority to construct new gas transmission lines has remained close to 15,000 miles for the past two years. The interstate transportation of natural gas is now absorbing close to one-third of the entire marketed production, and promises to increase further as demand still outruns supply. Sales of natural gas for domestic use have nearly doubled since the end of the war. Over seven million customers were reported to have heated their homes with gas in the 1949-50 season, over half of them in California, Texas, Ohio, and Pennsylvania.

Significance of Texas gas in California supplies

Natural gas from Texas and New Mexico first came “on the line” in California in October, 1947. Initial deliveries were small and amounted to less than one percent of the total gas used in California in that year, including oil company use. Increasing deliveries during the next two years brought the Texas contribution up to 10 percent of total California gas utilization in 1948 and to nearly 15 percent in 1949. From the standpoint of the gas utility companies, however, the importance of the Texas supply was somewhat greater, amounting to about 18 percent of all natural gas available to the utilities for distribution in 1949. For the group of companies serving the Southern California area, Texas gas is even more important and provided nearly one-third of their total supplies in 1949 and upwards of 40 percent in the first half of 1950.1 Because of the flexibility of “line pack” in the high pressure large diameter Texas supply line, this pipe line is now performing an important function in adjusting the gas receipts of Southern California to daily and hourly fluctuations in demand, a function analogous to that performed in Northern California by the dry gas fields.2

The new Texas supplies have more than taken up the slack in the output of California oil and gas fields during the past two years. They have made possible both an overall increase in gas consumption in the state and the conservation for future use of California gas resources. They have also eased temporarily the problem of serving interruptible loads of industrial customers in the Los Angeles area. Somewhat similar consequences may be expected to follow from the recent completion of the initial line bringing Texas and New Mexico gas to Northern California. These out-of-state supplies will undoubtedly play an important part in conserving the limited California natural gas reserves for some time to come. How long that time will be, and whether the total supply will suffice to meet the potential demand for gas, including both residential and industrial demand, remains to be seen. The answers to these questions will depend on the adequacy of natural gas reserves at distant points of supply and competition for their use, upon the rate of growth of California population and industries, and upon the price of competing fuels for industrial use.

Problems of curtailment persist

Notwithstanding larger over-all gas supplies, the problem of making ends meet in matching peak load requirements and total supply still continues and probably will indefinitely. This is due basically to the extreme seasonal variation in the demand for gas for domestic consumption, particularly for heating purposes. High domestic demand in the winter months makes it necessary to curtail deliveries to interruptible industrial consumers at that season.1

Data are not available to permit exact measurement of the trend in curtailment of gas service to interruptible customers in California. Evidence submitted in rate applications to the Public Utilities Commission, however, indicates that in Southern California the volume of curtailments to such customers other than electric utilities has fallen from a peak of around 32 billion cubic feet in 1946 to less than half that quantity in 1949. In the former year curtailments actually exceeded sales to this group of users, while in 1948 and 1949 they represented only about one-third the volume of deliveries. In Northern California, the problem of curtailment is much less serious, and restriction of service since the early war years has been considerably less severe than in Southern California. However, a marked increase of curtailment has occurred in the past two or three years. While curtailment data are not available for the period since 1947, it is significant that total industrial sales of gas by the leading Northern California utility declined between 1947 and 1949 by approximately 15 percent. This was due in major part to increased curtailment.2

As previously pointed out,3 the use of underground storage facilities has played an important part in Southern California in helping the utility companies meet seasonal variations in demand for gas. Increases currently being made in the capacity of these facilities and further projected increases may reduce to some extent the severity of curtailment to interruptible customers, unless offset by continued population growth.

California gas rate increases

Rising costs of operation and the higher capital costs involved in bringing Texas gas to California users have forced the gas utility companies of the state to seek increases in rates. Nearly all the important gas distributing companies have come before the Public Utilities Commis-

2 Same, p. 21; see pp. 12, 16, and 17 above.
3 See page 15.
5 See page 15.
sion during the past two years to secure legal sanction for such increases. While introducing no new principles, the decisions of the regulatory commission in passing upon these applications are noteworthy as illustrating the variety and complexity of the problems involved. Almost uniformly the pleas of the utilities for increased gas revenues have been granted, though not in the full amounts requested and seldom in the form sought in the original applications.

Factors making for higher costs

The first important case to come before the Commission was that of the leading utility in Northern California. This company sought an increase in revenues of approximately $9.6 million, $7.5 million of which it proposed to levy on general service customers—essentially residential and commercial users—and about $2 million on industrial customers served on an interruptible basis. The principal reasons adduced by the company for the proposed rate increase were:

1. Substantially increased cost of local gas supplies, due to decline in availability of natural gas from California oil and gas fields, and upward price adjustments in gas purchase contracts.

2. Large capital expenditures necessary to assure continuity of gas supply, including provision of storage facilities and initial outlays on the large diameter pipe line to bring Texas gas into the company’s distribution system.

3. Materially higher maintenance costs and general increases in payrolls.

4. Reduced rate of earnings and consequent need for added revenues to restore an adequate return on investment and thus maintain sound credit and ability to obtain on favorable terms the capital funds necessary to carry forward its large construction program.

On the basis of evidence submitted, the Commission estimated that the company would realize a rate of return in 1949 of about 5.3 percent on its allowable rate base under its then existing rate schedules, whereas a rate of 5.9 percent should be allowed, as against 6.5 percent requested by the company. Because of the need to finance its large construction program, the company’s debt had risen to approximately 57 percent of its capital structure. The Commission stated: "It is clear that the company is faced with the problem of reducing its debt ratio and of obtaining additional sums in substantial amounts from the issue of stock rather than bonds."  

The Commission had little difficulty in reaching the conclusion that the public interest required that existing rates be increased in order to maintain the company’s earnings at a level sufficient to enable it to service its outstanding securities and those necessary to finance a reasonable expansion program. To give effect to its findings, the Commission granted the company an increase in rates averaging about 6 percent, designed to provide the utility with additional net revenues of about $4 million. Most of this was made applicable to the general service classification, with a sharp percentage increase in the rates for “interdepartmental” sales, chiefly gas used in company steam plant generation of electric power and commercial heat.

Little change was made in basic rates to industrial users: firm industrial rates were reduced slightly; the separate schedules for interruptible and surplus customers were consolidated and simplified, with a resulting small net increase in total estimated revenues from the group as a whole. The gearing of interruptible rates to changes in the price of fuel oil was continued, as the Commission felt that such a tie-in, properly safeguarded as to upper and lower limits, served a useful purpose in stimulating interruptible use and thus improving the over-all system load factor, with resulting economies that react to the benefit of all customers.

Industrial sales and revenues down, 1949-1950

The new rates became effective in November 1949 and had little effect upon the company’s gas revenues for that year. Slight increases in average unit revenues were realized in 1949 as compared with 1948 in sales to residential and commercial customers, with resulting gains in dollar revenues as consumption increased in both these categories. These gains were more than offset, however, by diminished industrial consumption with a sharp reduction in dollar revenues which resulted in major part from increased curtailment of deliveries to customers on an interruptible service basis. Industrial revenues were further reduced in 1949 by downward adjustments of rates under the interruptible schedules as a result of successive reductions in the price of fuel oil, to which these schedules are geared.

Operating results in 1950 remained disappointing, largely due to the continued low level of fuel oil prices to which the interruptible gas schedules are adjusted. Meanwhile large outlays continued on the natural gas transmission line from the Arizona border to the San Francisco Bay area, which is expected to be in operation by the end of the current year. The investment in this project represents a substantial addition to the company’s rate base, without bringing a corresponding addition to its earning capacity. With other operating costs rising and higher Federal and local taxes indicated, the earnings prospect under existing rate schedules forecasts a rate of return on property investment considerably below the rate found necessary by the Commission’s decision of a year ago.

Additional rate increases pending

Faced with this outlook, the company has applied to the Public Utilities Commission for further substantial increases in gas rates designed to produce approximately $18 million in gross revenues on an annual basis, or about
half that amount after taxes. If granted, these increases would require an average advance in gas rates of approximately 24 percent. In support of its claims for needed additional revenues, the company stresses sharply increased cost of natural gas purchased from California producers, continuing large capital investments in transmission and distributing facilities, including the 500-mile “super-inch” pipe line, higher operating costs, and large increases in property and income taxes. This application is currently pending before the Public Utilities Commission.

Southern California rate increases

All the principal gas distributing utilities in Southern California have applied for commission approval of gas rate adjustments during the past year or two, and some increase has generally been allowed. Claims for increased rates were based on reasons substantially similar to those already discussed above. The southern companies have incurred somewhat lower costs in equipping themselves to handle out-of-state gas, because their connecting lines with the Texas supplies delivered at the Arizona-California border are much shorter than the line extending to Northern California. On the other hand, due to rapid population growth and abnormal volume of housing construction in the Los Angeles area, it has become necessary for the distributing companies to make very large capital outlays in enlarging their mains and in renovating their distributing facilities generally.

The largest gas utility in the Southern California area in October 1949 proposed rates which, if granted, would have resulted in an increase in its gross revenues estimated at about $16.7 million, or sufficient to produce a net return of about 6.25 percent on the company’s estimated rate base. By an interim order issued in January 1950, the Commission authorized the adoption of emergency rates, effective February 1, estimated to produce an increase in gross revenue on an annual basis of about $5.7 million at the 1949 level of business. This represented an average rate increase of about 8 percent. In its final decision, issued in August 1950, the Commission found that the revenues yielded by these interim rates were adequate for the utility’s needs and allowed a permanent over-all dollar increase of approximately the same amount but made various changes in the several rate schedules. Rates for general service—domestic and commercial customers—were raised about 11 percent; firm industrial rates were reduced moderately and interruptible rates increased slightly. As in Northern California, rates to interruptible customers were linked by an escalator arrangement to the price of fuel oil, but with a ceiling fixed at a comparatively low figure.

The Commission pointed out that its decision took no account of any effect on cost of purchased gas that might result from an application then pending with the Federal Power Commission filed by the supplier of Texas gas to the Southern California companies seeking approval of a proposed 12 percent increase in the wholesale price of gas. This increase became effective October 1, 1950, subject to the Federal Power Commission’s review. If finally approved, it would add approximately $2 million to the cost of out-of-state gas used in Southern California and would probably be the basis for an additional rate advance by the gas distributing companies.

Canadian natural gas and the Pacific Northwest

An important development of the year was the removal of one of the obstacles to the importation of natural gas from Canada into the Pacific Northwest. Exploration of Canadian oil resources during the past few years, particularly in Alberta, has raised hopes that supplies of associated natural gas might prove adequate to support the construction of a pipe line to carry gas to the cities of British Columbia, Washington, and Oregon. Three rival groups, each proposing a different route, have promoted plans for the construction and financing of such a line. These plans had been delayed, however, by the action of the Alberta provincial government in August 1949, barring exports of gas from the province until an official survey had determined the adequacy of the reserves to provide for domestic needs as well as exports. Such a survey has now been made and a recent official report has confirmed that the supply of gas is ample both for Canadian use and export.

Following the publication of this report, one of the promoting groups has filed application with the Federal Power Commission for authorization to construct a transmission line to serve the Pacific Northwest and British Columbia markets. Hearings before the Canadian authorities to secure export permission are reported currently in progress. Meanwhile, an ambitious project has been launched for connecting the Northwest with the extensive gas reserves of the Texas Gulf Coast fields. Application was filed with the Federal Power Commission last June by Texas interests for authority to construct a large diameter pipe line nearly 2,200 miles long to serve the Pacific Northwest and intermediate markets in Utah and Idaho, with a possible tie-in at the international border with one of the projected Alberta lines.

These developments indicate the potential early start on actual construction of pipe line facilities. On the other hand, the current tense international situation and the probable over-riding requirements of the national defense program for steel and other construction materials may cause the indefinite postponement of these plans. Until these uncertainties are resolved, the whole situation remains unsettled.

1 Dominion of Canada, Department of Mines and Technical Surveys.
Oil is a peculiarly American industry. While only about 40 percent of the world's known oil resources are located in the United States, this country has for many years produced upward of 60 percent of the total world supply of crude petroleum. Petroleum technology developed earlier and has made greater progress here than almost anywhere else, both in the application of basic geological principles to oil discovery, and in methods of production, transport, and refining. It is no accident, therefore, that the United States occupies a dominant position in the world's oil industry or that American organizational skill and technical efficiency have played a leading part in developing the petroleum resources of so many other countries.

Growing importance of petroleum in the total energy supply

It has often been pointed out that the dynamic factors in the American fuel situation over the past 30 years have been petroleum and natural gas, while coal has remained the static element. During the period from about 1890 to 1918, production of coal in the United States expanded fairly rapidly, particularly bituminous coal, which finds its largest use in industrial applications. Since 1918, coal output has fluctuated considerably from year to year, but, except during the war, increased only slightly over the levels attained 30 years earlier. The production of petroleum and natural gas, on the other hand, has grown enormously. Petroleum output has been multiplied five-fold and natural gas output seven-fold since 1918. These two fuels have supplied a steadily larger share of the nation's energy requirements, rising from about 10 percent of the total mineral fuel and water power consumption of the United States in the years 1901-10 to well over 50 percent in 1949.

Because of the relatively scanty deposits of high grade coal in the West, petroleum and natural gas are much more important in the economy of this region than in the country as a whole. Estimates of petroleum economists indicate that in recent years oil and natural gas have accounted for close to 90 percent of the total energy supplied by mineral fuel and water power in the Pacific Coast states, some 60 to 70 percent being contributed by liquid petroleum.

Since the early part of this century petroleum has sustained the basic industrial development of California by providing abundant and relatively cheap supplies of fuel in the form of oil and its associated natural gas. Petroleum products from California have also contributed importantly to the economy of neighboring areas, including British Columbia, Alaska, and Hawaii, as well as the Pacific Coast and intermountain states. Motor fuel for automobiles, trucks, and tractors throughout this whole region, and aviation fuel as well, have been supplied predominantly by California refineries, often with substantial surpluses for shipment to the Atlantic Coast and export markets. The industrial growth of the Los Angeles area in particular was greatly stimulated by local supplies of cheap oil and natural gas. Industries in which the cost of fuel is an important item were enabled to locate successfully in the western region and maintain themselves against competitors located in areas where fuel costs were higher. Such by-products of oil refining as asphalt and road oils have facilitated highway construction and maintenance throughout the West. Oil has also supplied a convenient and economic fuel for domestic and commercial heating in many western areas beyond the reach of natural gas supplies. In a very real sense it may be said that much of the Pacific Coast region is essentially an oil- and gas-based economy.

The problem of future supplies

Concern is expressed from time to time, however, as to the adequacy of Western petroleum resources to meet the expanding needs of the rapidly growing regional population and its industries. Except during the two war periods, 1915-20 and 1942-45, the production of crude oil and refined petroleum products in the Pacific Coast area has generally exceeded local requirements by a fairly wide margin, leaving a substantial surplus for accumulation of stocks and for export. The great increase of population and industry incident to and following World War II has considerably changed this situation. Local demand, especially for gasoline and the other more highly refined products, now tends to absorb a constantly larger fraction of the total output as compared with the prewar situation. Also in the background lurks the possibility of suddenly expanded demands resulting from military emergency, complicated by potential enemy threats to waterborne supplies for certain parts of the area.

Petroleum is a non-replaceable resource, and it is becoming increasingly difficult and costly to find. In spite of intensive exploratory efforts and heavy financial outlays in recent years, relatively few oil fields of substantial importance have been discovered in the Pacific Coast and intermountain areas since the mid-thirties. The decline in new discoveries up to about 1948, together with the narrowing margin between current production and local consumption, tended to give some support to those who took a dim view of the outlook for continued abundant and cheap petroleum supplies in this region. On the other hand, the lack of sensational new discoveries was offset to a considerable degree by the finding of numerous smaller fields and by the extension of older fields, both in area and depth. The discovery in 1948 of a large new field in the Cuyama Valley in Central California, with consequent stimulus to exploration generally, coming at a time when current production has been outrunning market demand, has given comfort to those who are more optimistic as to the adequacy of Western oil resources.

The present article cannot explore this basic problem in detail but will be limited to a factual account of the

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1 Joe S. Bain, "War and Postwar Developments in the Southern California Petroleum Industry," The Haynes Foundation, Los Angeles, California, 1944.
petroleum demand and supply situation in this area as it has developed over the years, together with some comments on certain factors which seem pertinent in appraising the future outlook.

**Western Petroleum Supply and Demand, 1900-45**

Although crude petroleum has been discovered in widely scattered locations in the United States, it is produced in important quantities in only about 20 states, with six of these accounting for nearly seven-eighths of the total output in recent years. In the Twelfth District important oil resources have been discovered and developed only in California. That state has accounted in recent years for between one-sixth and one-fifth of the total United States output of both crude oil and refined products. The relative position of California in comparison with other important crude producing areas at various times since 1920 is shown by the following statement which indicates the percentage of total crude output produced in each area.

<table>
<thead>
<tr>
<th>Year</th>
<th>Midcontinent-Gulf region (7 states)</th>
<th>California</th>
<th>Eastern region (8 states)</th>
<th>Rocky Mountain region (3 states)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1920</td>
<td>63</td>
<td>23</td>
<td>10</td>
<td>4</td>
</tr>
<tr>
<td>1929</td>
<td>63</td>
<td>29</td>
<td>5</td>
<td>3</td>
</tr>
<tr>
<td>1941</td>
<td>67</td>
<td>16</td>
<td>14</td>
<td>3</td>
</tr>
<tr>
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</tr>
<tr>
<td>1949</td>
<td>71</td>
<td>18</td>
<td>7</td>
<td>4</td>
</tr>
</tbody>
</table>

Commercially successful oil production in California began as early as 1875 but remained relatively unimportant until about the year 1900. Development of the industry from that time on was very rapid, first in the San Joaquin Valley and later in the Los Angeles and southern coastal areas. By 1903 California had become the nation's leading oil producer and generally maintained that position until 1926, when output in the mid-continent and Texas fields shot ahead. As late as 1936, however, California had produced more crude oil than any other state; aggregate output to the end of 1949 totalled about 8.3 billion barrels—somewhat over one-fifth of the nation's entire crude oil production since 1859.

Since about 1914 California oil production has supplied the basic petroleum requirements of the Pacific Coast region, and in addition has regularly provided a substantial surplus for shipment to Hawaii, British Columbia, and Alaska, to trans-Pacific areas, and in some years to the Atlantic Coast. The volume of outside shipments was relatively small before World War I but averaged close to 12 million barrels per year from 1914 to 1922 when the equivalent of about one-eighth of all crude oil produced in California was shipped out, largely in the form of fuel oil. Most of the California crude production before 1920 came from the San Joaquin Valley, much of which was of heavy grade yielding relatively little gasoline and other light distillates, but a high proportion of residual or heavy fuel oil. Some of this heavy crude was not even run through refineries, but was used directly as fuel or mixed with residual fuel oil and marketed in that form.

**Great increase in production, shipments, and stocks in the 1920's**

With the discovery of large new fields in the Los Angeles basin in the early 1920's, notably at Santa Fe Springs, Huntington Beach, and Long Beach, there came a great increase in crude oil production, much beyond the capacity of local or regional markets. The average annual output of California crude oil more than doubled during the decade 1921-30 as compared with the period 1911-20. Whereas during the earlier period annual output ranged between 85 million and 105 million barrels, production jumped in 1923 to 264 million and in 1929 reached a peak of 293 million barrels when deeper zones were tapped in the Santa Fe Springs and Long Beach fields. Over the whole decade 1921-30, California crude oil output averaged about 218 million barrels per year as against 96 million barrels in the decade 1911-20.

Ships of all petroleum products to points outside the Pacific Coast area, which had gradually climbed to a peak of 16 million barrels in 1922, shot up suddenly to 90 million barrels in 1923 when the flood of new production came in. More than 60 million barrels of crude oil were shipped out in that year, some 52 million barrels to the Atlantic Coast alone. Outside shipments of all petroleum products during the years 1923-30 averaged over 84 million barrels a year, equivalent to about one-third of total California crude oil production during that period.

The output of the new fields in the Los Angeles area was of much higher average gravity—light crudes as contrasted with the heavy San Joaquin Valley crudes of

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1. These states, in order of production in 1949 are Texas, California, Louisiana, Oklahoma, Kansas, and Illinois. Source: U.S. Bureau of Mines.
2. Defined by the U.S. Bureau of Mines as California, Oregon, Washington, Arizona, and Nevada. This term will be used throughout as meaning the states specified.
the earlier period. Hence a higher proportion of gasoline and other light distillates could be obtained. This was reflected in the rapid increase in gasoline production, which was stepped up from around 12 million barrels in 1920 and 1921 to 42 million barrels in 1925 and to over 92 million barrels in 1929, a level not again approached until the war years. These quantities were greatly in excess of local market requirements; the gasoline surplus found its outlet chiefly on the Atlantic Coast. Total gasoline shipments jumped from less than a million barrels in 1920, a year of actual gasoline shortage in California, to 16 million barrels in 1925 and to an all-time peak of 44 million barrels in 1929. This quantity exceeded the total consumption of gasoline within the entire Pacific Coast area and represented nearly one-half of the year's petroleum shipments of all kinds. Fuel oil shipments reached their maximum in 1927, at approximately 43 million barrels. Shipments of kerosene, a product not specially favored by California refineries and relatively little used in the Pacific Coast region, attained their peak in 1928, at 6 million barrels.

Notwithstanding the large volume of outside shipments and the continuous growth of regional demand for petroleum products, California oil production expanded so rapidly during the 1920's that huge storage stocks were built up, particularly of heavy crude and residual fuels. Total crude and residual inventories increased from less than 40 million barrels at the end of 1921 to over 150 million barrels by the end of 1929, of which more than two-thirds consisted of low gravity crude and heavy residual oil. Gasoline-bearing crude, which had never been in excess supply until the high gravity discoveries of the early 1920's, accounted for around 40 million barrels of all crude stocks at the end of the decade. Total producers' inventories of all petroleum products reached a peak early in 1930 in excess of 188 million barrels, a figure never since approached.

**Slowing down of activity in the 1930's**

Much less hectic conditions marked the California oil industry during the 1930's and development was more orderly than during the feverish activity of the preceding decade. This slowing down was in part a consequence of the general economic depression and in part a specific reaction from the condition of flooded oil markets and unstable prices of the prior period. Production of crude oil declined sharply from the 1929 peak and remained at a considerably lower level as the previous chronic over-production was brought under fairly effective control. A considerable number of producing wells were shut in, while output of others was curtailed. Total annual output in 1931-35 averaged about 185 million barrels, rising in 1936-40 to around 230 million.

Except for the large Wilmington field, few outstanding new oil discoveries were made in California during this period, a situation in marked contrast with that in Texas where enormous new fields were being opened up. The rapidly expanding Texas output tended to depress prices and to limit the market outlet for California oil in the Atlantic area. Shipments to points outside the Pacific Coast region declined to around 66 million barrels per year for the period 1931-40, as compared with an average of some 84 million barrels during the eight years ending in 1930. Japan became a heavy buyer of California oil during this decade, however, and took especially large quantities of crude and fuel oil in the years 1935 to 1939. Meanwhile regional population and industry were growing and the domestic market for the higher grade products, especially motor fuel, became increasingly important. The burden of unwieldy inventories with which the decade began was appreciably reduced, being about one-fourth less at the end of the decade.

**The war and California's petroleum resources**

World War II put a severe strain on the productive capacity of the California oil industry; it also took a huge bite out of the area's raw material resources. The geographical position of California with respect to the Pacific war area made this region a logical center for the supply of military fuel and motor oil requirements of all kinds, while the rapid growth of defense industries throughout the Pacific Coast region and the extra burden on railroads and shipping caused by the war gave an enormous impetus to the demand for fuel oils. These several forces combined to stimulate the production of crude oil in California to a rate previously unknown and required the operation of refineries and oil transport facilities at capacity levels.

Fortunately, large accumulated stocks were available to draw upon during the early war years. In spite of the general reduction in inventories during the preceding decade, very substantial stocks, especially of crude and heavy fuel oil, remained on hand at the date of Pearl Harbor. Approximately 142 million barrels of petroleum and oil products were held by Pacific Coast oil companies at December 1, 1941, of which about 63 million barrels were heavy crude or residual fuel oil and about 55 million barrels were gasoline-bearing crude or gasoline. These stocks were worked down, at first gradually and then more rapidly, under the impact of growing military and industrial requirements to a level of around 75 million barrels by mid-1945, with the bulk of the reduction falling in the heavy classifications.

War demands concentrated at first on fuel oil, reflecting enlarged transportation and naval activity, but with the progressive increase in air warfare in the Pacific area, requirements for gasoline also shot upward. Demand for heavy fuel oil, which had averaged around 250,000 barrels per day in the period 1936-40, reached a peak of nearly 600,000 barrels per day early in 1945; gasoline consumption over the same time increased from around 210,000 to about 400,000 barrels per day. To meet these huge requirements crude oil production was raised from a pre-war level of around 630,000 barrels per day to a peak of

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1 The Wilmington field in the Los Angeles basin was brought in in 1936 and since 1938 has consistently been the state's leading crude oil producer, with a cumulative output to date of approximately 500 million barrels.
about 942,000 barrels in May 1945. Supplementary supplies of both crude and refined oil were obtained by rail from Texas and Rocky Mountain producing areas. Considerable additional refinery capacity was installed, notably for the production of aviation gasoline and other special war needs, including constituents for the manufacture of synthetic rubber.

**Difficulty of obtaining increased output**

The great increase in California crude oil output required to meet the war demand was obtained chiefly by stepping up production from existing wells, a considerable number of which, especially in the San Joaquin Valley, had been shut in during the curtailment program of the 1930’s, and in part by drilling new wells, largely in already proven fields. In spite of material and equipment shortages, nearly 6,000 new producing oil wells were completed during the five years 1941-45, as compared with about 4,600 in the preceding five-year period.

Among the new wells drilled were some 300 in the Elk Hills Naval Reserve, where an extensive area had been proved at an earlier date but not developed. An intensive drilling campaign succeeded in raising the total output of the Elk Hills field, including wells privately owned as well as those in the Naval Reserve, from a daily average of about 13,000 barrels in early 1943 to a peak figure of 65,000 barrels per day in July 1945. Following the war, the Naval Reserve wells were promptly shut in and the field’s production was cut back to about the 1943 level.

**Decline in output per well**

Generally speaking, the results of the war-time drilling in producing additional oil were none too reassuring. The new wells were less productive, on the average, than those completed in the prewar years. While the number of active producing wells increased between the end of 1940 and mid-1945 by nearly 50 percent—from about 15,000 to around 22,500—the average output per well declined by roughly 10 percent between the period 1936-40 and the five war years, 1941-45. In fact, the total output of all the fields in the Los Angeles basin was actually less during the latter period than in the preceding five years, in spite of the large contribution from the recently developed Wilmington field. The entire increased output of the state’s oil fields during the war came from the San Joaquin and Coastal districts, each of which had sufficient reserve capacity to permit the necessary expansion in output.

The forced draft under which the industry operated during the war, while abundantly justified from the standpoint of its vital contribution to national defense, was inevitably at the expense of basic raw material resources. It is true that exploratory and drilling effort more than offset the drafts made for war purposes, with the result that the industry’s proved reserves were actually higher at the war’s end than at its beginning. None the less, many fields were operated during the war at rates above their maximum efficient rates, with consequent acceleration of their eventual depletion and with probable loss of otherwise recoverable oil.

**Readjustments in the Postwar Period**

The previous section has outlined briefly some of the main developments in the Pacific Coast petroleum situation up to 1945. New conditions have arisen since the war and the oil industry is in process of adjusting itself to the changed situation. Shifts in demand occur so rapidly, however, that any far-reaching plans for the future must be flexible and subject to more or less drastic revision.

Even within the brief period since the end of the war the Pacific Coast petroleum situation has experienced a pronounced cycle. Following a condition of temporary easing in demand and reduction of output in 1945-46 came the business boom of 1947-48 which stimulated the industry to another high pitch of activity. Something approaching an actual shortage of fuel oils and heating oils appeared in 1947 for almost the first time in some parts of the area. Industrial demand for heavy fuel oil again became an important factor, stimulated by increasing shortages in California natural gas supplies available for industrial use. Public utility consumption of fuel oil set a new record in the Pacific Coast states in 1947 as abnormally low rainfall cut down the generation of hydro-electric power and put an extra load on steam plants. Gasoline demand grew apace as population continued its rapid growth, and new cars and trucks began to appear in appreciable numbers. More lubricating oil was wanted; even the demand for kerosene spurted.

Under this combination of pressures the industry experienced in 1948 its banner year. Prices of major refined products advanced sharply, in the case of heavy fuel oil to the highest levels in more than 20 years. Exploration and drilling activity were intensified, and in spite of strikes among refinery operatives late in the year new records were established in both crude oil production and refinery output. Some disturbing factors began to appear, however, which pointed to impending changes in the de-
mand outlook. One of these was a prolonged waterfront strike which caused a sharp drop in deliveries of bunker oil in the second half of the year. The railroads were also turning increasingly from heavy fuel oil to Diesel oil, while deliveries of natural gas from the newly completed Texas pipe line restricted further expansion of the industrial fuel oil market. Partly in consequence of these factors, but also reflecting the increased rates of output, aggregate inventories were built up by the end of 1948 to levels approximately half-way between those existing at the dates of Pearl Harbor and V-J Day, with the bulk of the increase coming in heavy fuel oil and crude petroleum.

Rapid shifts in industry outlook

Expanding civilian demand for gasoline, Diesel oil, and light heating oils—the latter stimulated by unusually cold weather—carried the industry into new high ground early in 1949, but demand for heavy fuel oil still dragged while its production continued to increase. In spite of sharp price cuts both in fuel oil and in low gravity crude, inventories kept on accumulating. The end of 1949 found the industry with approximately 10 percent of its producing wells shut in and crude oil production back to a level of around 870,000 barrels per day as compared with about 950,000 barrels per day twelve months earlier.

The extent of the change in the industry’s outlook between 1947 and 1949 may be indicated by a single comparison. While as recently as 1947 leaders in the industry were actively discussing plans for the construction of a pipe line to bring Texas oil to California, before the end of 1949 large tanker shipments of heavy fuel oil and of light distillates were being made to the Atlantic Coast—probably at unremunerative prices—in order to relieve the pressure of burdensome inventories.

Discounting short-run changes in the supply and demand situation, the basic contrast between prewar and postwar conditions is the more or less inevitable transformation of the regional economy from a position of substantial oil surplus to one more nearly approaching balance between supply and demand, with some indication that a condition of local oil deficit may not be very far distant if the search for new oil is permitted to lag. It has already been pointed out that regional petroleum consumption accounted for about two-thirds of all California crude oil production in the period 1926-30. By 1946-49 domestic demand had grown to the point where it absorbed nearly nine-tenths of the total output. The basic explanation, of course, is the continued large population growth and industrial expansion of the area. These developments, together with rapidly increasing per capita consumption of many petroleum products, have generated a total volume of demand which tends to take an ever larger fraction of the available supply.

Complex and variable nature of demand for oil

While the demand for petroleum products in the aggregate has grown more rapidly than the aggregate local supply, the composition of the over-all demand has changed very markedly and continues to change. Pronounced shifts have occurred in the character and volume of demand for individual petroleum products, reflecting new types of use, changes in industrial processes, and basic technological developments. It is the impact of these changes in demand which is causing or at least accentuating some of the current difficulties within the industry and which emphasizes the necessity for continued flexibility and adaptation of industry processes to meet the new situation.

Crude petroleum is not a simple or uniform substance, but is rather a general term for a highly complex mixture of what the chemist calls hydrocarbons, including liquids, gases, and solids. No two types of crude petroleum are precisely alike; the various types of crude vary greatly in their chemical and physical characteristics. Hence they yield the several component products of the distillation process in quite different proportions, depending upon their specific composition. They also differ greatly in their relative ease of treatment by the techniques of the refining process.

Similarly the demand for petroleum is not homogeneous, but is a composite of demand for a wide variety of products, the chief of which are gasoline, fuel and heating oils of various grades, kerosene, and lubricants. These are all “joint products” of simple distillation and are obtained in varying proportions from practically all types of crude petroleum. The miscellaneous end-products of the more complex refining processes extend to literally hundreds of items. The proportions in which the major refined products can be obtained from a given grade of crude oil are not rigidly fixed but can be varied somewhat according to market requirements, as refining processes are sufficiently flexible to permit more or less variation in the yield of the several products. The ultimate limiting factor is, of course, the specific characteristics of the crude oil available to the refinery, although the various “cracking” processes—stages in refining procedure following simple distillation—permit an important additional recovery of the more volatile and hence more valuable products from those of lower grade.

The Pacific Coast market for refined products

Almost nine-tenths of the total domestic demand for refined petroleum products in the Pacific Coast region is normally for motor fuel—gasoline and Diesel oil—and the various types of fuel oils, including heating oil. The proportions in which these several major products are wanted in the regional market have changed very greatly over the past 25 years. Heavy fuel oil was long the dominant product in a quantitative sense, yielding first place to gasoline only as recently as 1948. In 1923 regional consumption of heavy fuel oil was around 250,000 barrels per day, or more than two-thirds of all refined products consumed in the whole area, while in 1949 the daily average consumption of 288,000 barrels represented only about one-third of the total domestic demand. Gasoline consumption of less than 50,000 barrels per day in 1923
was less than one-eighth of the total regional market for refined products at that time. By 1949, with an average daily consumption of 332,000 barrels, gasoline had become the leading product in terms of volume—a position it had long held in terms of value—and accounted for nearly 40 percent of the total quantity of refined products sold in the domestic market.

Other fuel oils, including Diesel engine fuel and heating oils, which represented less than 2 percent of all sales in the regional market in 1923, had increased to nearly one-seventh of the total physical volume in 1949, with an average daily consumption of 115,000 barrels. Taking the demand for all refined products together, the domestic market in the Pacific Coast area grew from about 365,000 barrels per day in 1923 to about 848,000 in 1949. During the war, of course, demand soared much higher and reached an annual peak in 1945, at 976,000 barrels per day, of which military consumption, about equally divided between gasoline and other products, represented nearly one-third.

**Fuel oils overweight western refinery output**

As compared with other principal refining areas of the United States, the output of Pacific Coast refineries runs to a much higher proportion of residual fuel oil and a somewhat lower proportion of gasoline than elsewhere. This has been due in part to the special characteristics of California crudes, in part to the fact that a ready local market existed for heavy fuel oil at prices relatively higher than in other sections of the country. Kerosene and lubricants also represent much smaller fractions of total refinery output in the West, while the production of Diesel fuel and light heating oils, and of asphalt and road oils, is relatively larger than in other areas. Because of the preponderance of low gravity crudes in California, that state is the leading producer of heavy fuel oil. This condition has played an important part in the development of the industry in this region and has given rise to some of its distinctive problems.

In the United States as a whole the output of all fuel oils, including light fuels such as heating oil and Diesel oil, exceeded that of gasoline up to about the year 1929. Since that time gasoline production, except during the war years, has surpassed the output of all fuel oils combined and in most years has accounted for around 44 percent of the total refinery output of the United States, as compared with around 27 percent for residual fuel oil and from 10 to 14 percent for light fuel oils. This shift reflected the increased demand for motor fuels, resulting from the great expansion in use of automobiles, trucks, and tractors. It was made possible by constant improvements in refining technology, such as wider use of the cracking process, and by the increasing availability of higher grades of crude oil.

In California, the use of the more advanced type of cracking techniques—as represented by the catalytic process—has not been as general as in other parts of the country. Hence the shift toward higher recoveries of gasoline and other light distillates has lagged somewhat behind the national trend. In the early twenties, gasoline production in California represented only about 20 percent of total refinery output, as against a national figure of at least 30 percent. In each case the relative importance of gasoline in the total reached its approximate peak in the early thirties and except during the war has remained fairly constant. As compared with the national yield of around 44 percent, however, gasoline production in California has seldom exceeded around 37 or 38 percent of total refinery output, while heavy fuel oil production has generally run close to 40 percent. Including the light fuel distillates (heating and Diesel oils), fuel oil production in California has continued to represent approximately half the total output of all refined products.

**Shifting demands for fuel oils in the West**

Beginning in 1924 the United States Bureau of Mines has made an annual survey of fuel oil distribution in the five western states known as District 5, including California, Washington, Oregon, Arizona, and Nevada. Sales of fuel oil by the reporting companies are classified by principal type of use or ultimate market, e.g., railroads, ships, utilities, industries; since 1936 aggregate sales are broken down to show the various types or grades of fuel going to each major use. These data show that demand from railroads and vessels has long constituted the backbone of the market for fuel oils in this area; their requirements usually represented well over half the total—taking all types of oil together—until the postwar period when their proportion fell below 40 percent.

The second largest group of fuel oil users in the West is the mining, smelting, and manufacturing industries,
whose aggregate consumption has represented 10 to 20 percent of total sales. Sales of heating oils show the most consistent gain and have risen from about 4 percent of the total in the mid-twenties to nearly 18 percent in the years 1946 to 1949. The electric utilities are sometimes important consumers of heavy fuel oil, particularly when shortages in hydro-electric power necessitate increased steam generation. The gas utilities also utilize heavy fuel oil in the manufacture of artificial gas in areas such as the Pacific Northwest which lack natural gas or cheap coal. During the postwar years the gas and electric utilities have accounted for nearly 11 percent of total fuel oil sales in District 5. The oil companies themselves consume about 5 percent of all fuel oil used in the domestic market. The remainder of the total domestic demand, varying from 7 to 15 percent in different years, is represented by such miscellaneous uses as trucks, tractors, dredges, road oils, orchard heating and spraying, and by the requirements of the national defense forces.

The special problem of heavy fuel oil—handicap or challenge?

A significant clue to the problems and prospects of the Western petroleum industry is to be found in the important place of heavy fuel oil in relation to total refinery output in this region, and in the marked shifts in market demand for this product as compared with the relative stability and more constant growth in demand for gasoline and light oils. While the trend in regional consumption of these latter products has long been consistently and strongly upward, except for the temporary recession in 1946 which marked the transition from war to peace, demand for heavy fuel oil has not increased correspondingly and in recent years, as already indicated, has actually declined. This condition has created a major problem for the industry.

Consumption of heavy fuel oil in this region reached its peak in 1945 with total domestic deliveries in that year of about 170 million barrels, 49 million barrels of which were for military use and 121 million for civilian use. By 1949 domestic deliveries had fallen to about 105 million barrels; military demand shrank 75 percent—from 49 to 12 million barrels, while civilian consumption fell off from 121 million to 93 million barrels, a decline of around 23 percent. The principal factor accounting for the drop of about 28 million barrels in civilian demand was a 25 million barrel reduction in railroad use—from 47 million barrels in 1945 to about 22 million barrels in 1949—the lowest figure since 1935. A decline in maritime demand from 31 million barrels in 1945 to about 17 million barrels in 1949 was offset, however, by an increase from 34 to 48 million barrels in combined use by industries, utilities, and oil companies. The latter figure was the highest, except for that of 1947, yet recorded.

The heavy shrinkage in railroad consumption is perhaps the most serious aspect of the fuel oil situation in this region, and most of this promises to be permanent. The railroads have been continuously losing freight traffic to highway truck transport and are rapidly replacing their steam motive power by Diesel-electric locomotives. The net efficiency of the Diesel engine is so much greater than that of the steam locomotive that one gallon of Diesel engine fuel does the work of nearly 5 gallons of heavy fuel oil used in generating steam. Hence the increased use of more expensive Diesel fuel by the railroads is far over-balanced by their reduced buying of heavy fuel oil.

Competitive fuels forecast further market limitation

Any considerable extension of local Pacific Coast markets, either for heavy fuel oil for industrial consumption or for the intermediate oils used for space heating, appears likely to be limited by the increasing availability of natural gas. Substantial imports of oil-well gas from Texas and New Mexico are already being made into California, and present contracts call for a considerable increase in these supplies within the next few years. Plans for the importation of natural gas from Alberta into British Columbia and the Pacific Northwest also seem due to be realized in the not distant future. Such imports might result in some loss of markets in those areas for California fuel oils. Continuing large imports of foreign oil into Atlantic and Gulf coastal areas, particularly of crude petroleum from Venezuela, which runs to a high proportion of heavy fuel oil, would also tend to restrict the profitable shipment of California residual oil to the East Coast market, an area which it does not ordinarily serve.

Little comfort from the California crude oil producers’ standpoint can be derived from the trend of demand for heavy fuel oil in recent years. Under the impact of sharply falling fuel oil prices in 1949, drastic adjustments were made in posted prices for California crudes which marked down those grades yielding relatively little gasoline and light distillates, while offering better prices for higher gravity crudes. These adjustments forced a large reduction of output from fields producing lower grade crude. The large integrated companies controlling considerable oil field acreage have also curtailed their own output of the heavier grades of crude. Unless these trends are reversed and some significant and permanent increase occurs in the market demand for heavy fuel oils—a contingency which currently appears remote—the outlook for utilization of the heavier grades of low gravity California crude reserves seems increasingly discouraging.

Upgrading or dumping?

While the story of demand has thus been one of diminishing consumption, with little indication of probable improvement, no corresponding reduction has occurred in refinery output of heavy fuel oil, which of necessity must be produced, by current refining methods, in the normal process of distillation of crude oil in order to obtain gasoline and other "fractions" which are in greater demand. In spite of constant improvements in refinery techniques and the development of cracking processes to derive a larger proportion of gasoline and other light distillates from each barrel of crude, the average yield of residual

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oil in California refineries is still relatively high—not far short of 40 percent of crude input in recent years.

The consequence has been a build-up in stocks of heavy fuel oil, including cracking stocks, from a postwar low of about 16 million barrels in March 1947 to 50 million barrels in September 1949. During the ensuing six months no less than 120 tankship cargoes of heavy fuel oil were dispatched by Pacific Coast refiners to the Atlantic Coast, or an aggregate movement of some 12 million barrels—more than at any time since 1934. While these shipments were no doubt stimulated in part by the bituminous coal shortage during the winter of 1949-50, they were probably motivated chiefly by the desire to reduce burdensome inventories. According to trade reports they were made for the most part at unremunerative prices. They can hardly be regarded as providing a permanent solution to the persistence of excess residual stocks arising to some degree, at least, from the relative backwardness of current refinery practice.

New refinery procedures imperative

The problem of dealing with the continuing over-supply of heavy fuel oil has become essentially an engineering and capital investment problem rather than one of retrieving lost markets. This calls for the installation of technological processes for increasing still further the percentage yield of gasoline and distillates and for the conversion of surplus residual oil into salable products. Some procedure more effective than mere dumping at unremunerative prices will have to be found for disposing of excess residual materials.

Only a few of the larger integrated companies in this area have begun to attack the problem from this angle, which is the only way that seems to promise a really constructive and permanent solution. One company has invested heavily in coking facilities designed to secure the maximum possible extraction of higher grade derivatives from residual oil, leaving solid coke as a final end product for which there is a ready though limited market. Others are planning a general revamping of their existing refinery equipment and techniques in order to “dig deeper into the barrel” and secure more high grade products and less of residual materials. The very heavy capital investment required is probably the basic reason why more California refiners have hesitated to embark upon such costly programs, to which the pressure of events is now apparently forcing them. An important collateral benefit from this general type of approach is its probable contribution to petroleum conservation through limiting the withdrawal of crude oil from underground reserves to quantities more nearly in line with demonstrated economic demand.

The Trend of Reserves

The term “reserves” as applied to the petroleum industry is a somewhat flexible one and its use has not been entirely understood or even consistent. It refers primarily to oil resources that have been proved by adequate drilling, although some allowance is also given to undrilled reserves where conditions give reasonable basis for sound estimates. By proved reserves is meant that fraction of the total discovered crude oil supply now known to exist below ground that can be recovered by present producing methods and under current economic conditions. This recoverable proportion is often surprisingly low for individual fields; it probably averages considerably under 50 percent of the original underground oil supplies. Improvements in current production practices, such, for example, as unitization and pressure maintenance of an entire field, could greatly increase the estimated recoverable volume of reserves and the total ultimate recovery, even without additional new discoveries.

More complete recovery of the oil in underground structures can sometimes be effected by what are known as secondary recovery methods. As the initial energy present in the form of natural gas—which is responsible for driving the oil to the well bore—is gradually exhausted, the flow of oil declines and eventually ceases. This may result in leaving a large quantity of oil in the sand and rock structures which cannot be recovered by ordinary methods and hence is permanently lost. Under certain appropriate conditions, however, the underground pressure can be maintained or restored by means of gas or water injection. Such secondary methods have been adopted in an increasing number of fields in the United States and have made some progress in California in recent years. They have made possible the recovery of large additional quantities of oil that would otherwise be left in the ground.

Discoveries vs. extensions and revisions

The industry committees who are responsible for making the annual estimates of crude oil reserves are careful to point out that newly discovered oil fields are seldom fully developed, i.e., proved, for several years following the original discovery. Hence the quantity of additional oil estimated as proved through new discoveries in any one year is comparatively small. On the other hand, the volume of oil in already existing reserves in older fields can be more precisely estimated and revised year by year as more wells are drilled and more information becomes available. Hence the quantity of oil credited to reserves in any one year by the extension of existing fields and the revision of previous estimates is comparatively large. To a certain extent, therefore, the significance of new discoveries is likely to be understated, at least in the initial stages, as the original or first-year estimates of additional oil brought in by such discoveries necessarily represent but a part and often only a small part of the reserves that may ultimately be assigned to these same fields in succeeding years.

This contrast may be illustrated by taking the data on new oil blocked out for any representative period. During the 13 years 1937 to 1949, for example, the total new oil added to the proved reserves of the United States averaged close to 2.4 billion barrels per year. Of this quantity slightly more than 19 percent, on the average, was repre-
sented in any one year by the discovery of new fields or new pools within the year, while nearly 81 percent was represented by the revision of previous estimates or the extension of previously discovered fields. In California, during the same period, the proportion of new oil represented by original discoveries was only 15 percent, by subsequent revisions and extensions 85 percent.

**Other misconceptions concerning reserves**

It should also be noted, as the estimating committees point out, that only incorrect and misleading conclusions as to the probable life of existing reserves and their rate of depletion can be obtained by dividing the estimated volume of reserves by the current or projected annual rate of production. The physical factors of the underground reservoirs control the rate at which oil can be obtained from any particular pool and the oil in existing reserves can be recovered only over a period of many years and at gradually declining annual rates. Hence current estimates of proved reserves can give no reliable basis for measuring the rate at which these reserves can be “produced” in actual practice.

In point of fact, the estimated crude oil reserves of the United States have shown a practically continuous growth over a long period of time, despite the great increase in annual rate of production. During the 31-year period from 1918 to 1949 there were only six years in which annual output exceeded the total of new oil found by first-year discoveries and by the extension and revision of reserves found in previous years. Total crude oil output during this period aggregated nearly 34.3 billion barrels, an average of over 1 billion barrels a year; but new discoveries, extensions, and revisions aggregated nearly 53 billion barrels, an average of 1.7 billion barrels a year. For every barrel of oil produced, on the average over this 31-year period, more than one and a half new barrels were found. Total proved reserves increased from 6.2 billion barrels in 1918 to over 24.6 billion at the end of 1949. In short, discoveries of new oil reserves have more than kept pace with production withdrawals.

**Growth in reserves relatively smaller in California than in United States as a whole**

The California record since 1918 runs in much the same general terms, although there were more years in which current production exceeded replacement of oil in reserves—13 years out of 31, as against six for the country as a whole. Total new oil found in California between 1918 and 1949 amounted to 8.8 billion barrels as against total output of 7.2 billion barrels, while proved reserves rose from 2.2 billion barrels to 3.82 billion. The net increase in reserves over the whole period from 1918 to 1949 was relatively much less in California, however, than in the country as a whole, only about 72 percent, as against a nearly three-fold rate of increase for the United States. The great bulk of the increase in California’s reserves came before 1930, since which time a small net decline occurred until 1948, when the trend turned sharply upward and continued into 1949. As a consequence of the high postwar rate of exploratory and development effort culminating in those years, a much larger net addition was made to California reserves in 1948 than in any of the preceding 20 years.

Important new fields discovered in the Cuyama Valley in 1948 were under intensive development in 1949, and, while not yet fully proved, are expected to add substantially to the oil resources of the state, particularly in high gravity crudes. These discoveries have given additional impetus to renewed exploration in other areas not previously tested by modern methods. As a rule, periods of relatively high prices for oil are marked by a stepping up in the rate of exploration and development. The postwar period supplies an excellent illustration of this principle, with high incentive prices stimulating the search for new oil and resulting in this case, at least, in large additions to reserves. Exploratory efforts since the war have been greatly aided by the increased availability of materials and manpower, as contrasted with conditions prevailing during the war when frozen prices and shortages of essential materials restricted discovery efforts.
Necessity to stimulate discovery effort

It seems to be the general practice in the petroleum industry to keep proved reserves at a level about 10 to 15 times the current annual rate of production in order to assure the necessary margin of safety. When reserves, relative to production, drop toward a 10 to 1 backlog, discovery efforts are speeded up; when reserves approach a 15 to 1 supply, geological and exploration activity slackens somewhat. By this standard, the California backlog of reserves in recent years has been none too high. Except during the depression years of the early thirties, the ratio of annual output to existing reserves has been steadily creeping up, with the result that since about 1943 proved reserves have averaged less than 11 times the current rate of withdrawal.

The production of oil 10 or 20 years hence must come in substantial measure from fields that have not yet been discovered. Hence the adequacy of future supply depends on a continuing and persistant discovery effort. This, in turn, depends on price levels for crude oil which will provide the incentive to risk the large expenditures necessary in modern drilling, and on public policies which encourage the sound development of the industry. A momentary production surplus, such as exists at present, should not, therefore, be allowed to slow down discovery effort even temporarily, since there is no current over-supply of undrilled locations and proved reserves are only about 11 times current production.

Conservation and Control

An important factor, both in the maintenance of adequate crude oil reserves and in the basic conservation of petroleum resources, is the exercise of a reasonable degree of restraint on the rate of production or withdrawal of oil from the underground reservoirs, especially in newly developed fields. It is physically possible, within fairly wide limits, to produce or "flow" the oil from any particular field either rapidly or slowly—on the one hand by drilling additional wells and operating them at flush rates; on the other by curtailment or shut-in of existing wells. It may make an appreciable difference, however, both in the total ultimate recovery of oil and in the life of the field, which method is used, as excessively high rates of output in the early stages make it more difficult and costly—in extreme cases impossible—to obtain the maximum recovery of the oil remaining underground.

Wasteful practices in California oil production

In the early days of unrestricted rates of flow in practically all oil-producing areas, as illustrated by the experience of the 1920's in Southern California, many oil fields were prematurely depleted, at least in part, to the permanent detriment of the potential ultimate recovery. This followed from the excessive reduction in underground pressures through exhaustion of the natural gas produced along with the oil. With the growth of basic geological knowledge, however, sound engineering practice has increasingly emphasized retarding the initial flow of oil to what is known as the optimum, or maximum efficient rate, i.e., the rate which will most probably result in the largest eventual recovery of oil and gas from the particular field. It is argued that retarded rates of flow for new fields not only make for more economical and efficient operation, but that through contributing to over-all stability of output such restraint tends to promote greater market stability and thus to assure more equal opportunity for all producers and all fields to participate in the total current market demand. By preventing excessive fluctuations in output the premature abandonment of marginal wells is avoided, with consequent saving of oil which might otherwise be permanently lost.

Even as recently as 1949 a flagrant example of uneconomic and wasteful oil production occurred in California—the over-rapid exploitation of the newly discovered Placerita Canyon field. Within a few months of its original discovery this relatively small field, estimated to contain 60 million barrels of oil, was rapidly drilled by competitive "town-lot" methods, encouraged in part by a recent court decision which held invalid a California statute designed to limit the close spacing of oil wells in order to restrain precisely this type of wasteful competition. The result at Placerita was a brief period of flush production followed by a quick decline in rate of output due to the premature reduction of the underground pressures which might otherwise have prolonged the productive life of the new field indefinitely. Coming at the particular time it did, when crude oil markets were already surfeited and thousands of wells were being shut in, this new flood of oil contributed to further price unsettlement and general market instability. More important, however, is the consideration that only about 25 percent of the oil contained in this formation, according to industry estimates, is expected to be ultimately recovered, to say nothing of the large wastage of natural gas blown to the air.

Voluntary vs. compulsory conservation

This episode, which may be duplicated on a larger scale in the future unless some form of control is imposed, gives point to the proposals currently being advanced in the industry to secure legislation for the more effective conservation of oil in California. Among the important oil producing states, California and Wyoming stand practically alone in not having conservation laws. Voluntary conservation has been practiced more or less consistently in California for the past 20 years through the activities of a joint agency supported by a substantial majority of the producers. This organization is purely advisory in function, however, and has no authority to issue orders or to impose sanctions on anyone; the individual operators are free to accept or decline its recommendations as they see fit. The basic efforts of this agency, known as the Conservation Committee of the California Oil Producers, are directed to securing the maximum efficient rates of production in the relatively small number of flush fields which produce upwards of half the total crude oil output of the state. An attempt is made, however, to secure com-
pliance with recommended rates of production by the operators in each field or pool, and the total scheduled output is apportioned among the individual producers on the basis of engineering estimates which take account of all the pertinent physical operating conditions involved. Although these voluntary efforts have not been uniformly successful in preventing wasteful practices, a considerable body of opinion in the California petroleum industry apparently prefers this type of conservation to the more formal procedures established under the laws of many other states.¹

Nevertheless, there appears to be a growing disposition in the industry to favor some form of compulsory conservation similar in scope to the measures which have been adopted elsewhere. These laws, some of which date back more than 20 years, usually provide for regulation of spacing, drilling, and operation of wells so as to prevent waste; cooperative development of fields for the protection of individual interests and unitized operation of pools in connection with pressure maintenance projects to increase ultimate recovery; limitation of output of oil and gas to reasonable market requirements and allocation of the restricted output among pools and individual producers on an equitable basis. Administration is usually lodged in some form of state commission clothed with adequate power to compel compliance with its orders, but subject to appropriate court review. The vital features of regulation are the authority to establish the total current allowable volume of production, usually after public hearings to determine existing and prospective market demand, and the pro-rata allocation of the allowable output among the various producers.

This type of public regulation and control, though not universally popular among all producers, seems to be reasonably acceptable to the industry. While limitation of output might theoretically be subject to abuse, there is no evidence that deliberate restriction of supply designed to hold prices at unduly high levels has ever been authorized by any of the state commissions. On the whole, the existing state conservation laws appear to have worked reasonably well in practice and to have safeguarded the public interest by checking the over-rapid development of new fields and reducing wasteful operating practices. In so doing they have contributed to the maintenance of more stable conditions in the industry and to the basic conservation of oil and gas resources. They have thus tended to encourage the search for new oil and the maintenance of adequate reserves.

Addendum, November 1950

From the standpoint of fuel supply and demand, the western oil industry during the current year has witnessed a striking reversal from the situation that marked 1949. During most of that year the industry was struggling with top-heavy inventories, lagging demand, and falling prices for fuel oil and crude petroleum. Price instability even extended into the market for gasoline, with sporadic price cutting in various localities. In 1950 inventories have been cut, demand has improved, and prices have strengthened. With these developments have come recent increases in output of both crude oil and refined products, the latter having reached new high levels.

Inventory position improved

The response of the industry to the conditions prevailing in 1949 took two major forms. First, a sharp curtailment was made in crude oil production from the high levels of output attained in 1948 and early 1949. The reduction was effected primarily by the shutting in of approximately 3,000 producing wells, concentrated largely in the fields producing low gravity crudes. The total shut-in capacity was estimated in industry circles at close to 100,000 barrels per day. Second, a large reduction was made in heavy fuel oil stocks by shipments to the Atlantic Coast, where a shortage of bituminous coal had created an extensive but not especially profitable market. These shipments began on a considerable scale toward the end of the third quarter of 1949 and continued at a heavy rate for more than a year. They have taken well over 20 million barrels of residual fuel oil out of the Pacific area, the largest quantity shipped out in any twelve months since the early 1930's.

These measures brought a striking change in the industry’s inventory position. Following a 33 percent expansion during the 12 months ending September 30, 1949, total stocks of the Pacific Coast petroleum industry, including both crude oil and refined products, declined from 134 million barrels at that date to about 97 million barrels a year later. Residual fuel oil stocks, with a reduction of 26 million barrels, accounted for more than two-thirds of the total decrease, and crude oil stocks for another 5 million barrels. The net result of these developments was a marked easing of downward price pressures and a definite improvement in the industry’s market position.

Expanding demand

Meanwhile demand for practically all petroleum products began to pick up as the recession of 1949 faded into the background, and general business recovery became more pronounced. Demand for fuel oils was particularly responsive to improved business conditions; the growth in demand for gasoline seems to be geared primarily to the steady increase in the number of motor vehicles in use and is apparently little affected by fluctuations in general business activity. A notable feature of the fuel oil market in this area during the current year has been the reversal in the downward trend, previously noted, in railroad and steamship use of heavy fuel oils.¹ Larger demand from these sources was especially marked following the outbreak of the Korean crisis, when railroad and marine activity was considerably stepped up. These in-

¹See page 29.
creased transportation loads have caused the restoration to service of oil-burning steam locomotives and the expansion of military and merchant shipping in the Pacific area, with resulting larger requirements for fuel oil. Military requirements for aviation fuel and motor gasoline have also brought more business to petroleum refiners.

**Price increases and enlarged production**

The greatly improved inventory and demand situation encouraged a series of upward revisions in prices of heavy fuel oil and low gravity crudes which had been so drastically reduced in 1949. These increases began in June and in the case of crude oil have wiped out from one-third to one-half of the previous price reductions. As a consequence of better prices for heavy oils, most of the shut-in wells have been reopened and have accounted for much of the substantial increase in production during the last few months which has recently reached a level only slightly below the records established in 1948-49 subsequent to the refinery strike. Output of refined products set new high records in August and September and according to trade reports is still running at nearly the same rate.

The contrasting winds and currents that have marked the western oil situation during the past two years supply another example of the industry's technical and economic flexibility. They also give basis for confidence that the industry will be able to meet successfully the problems posed by the existing tense national defense situation. Military needs for specialized types of fuels are currently being met without imposing any serious drain on civilian supplies, either in quantity or quality. Whether more drastic restraints on civilian consumption may be necessary will depend, of course, on the magnitude of military requirements and their incidence with respect to particular types of products.

**Investment in the future**

One of the factors which tends to inspire confidence in the petroleum industry's capacity to keep abreast of and even ahead of its problems is the large investment the industry makes in fundamental research. Compared with most other industries, the proportion of its total investment dollar which the petroleum industry devotes to basic research is relatively high. That such research pays good dividends in improving product quality, in perfecting new products, in advancing techniques and processes, in cutting costs, in finding and exploiting new uses, is one of the commonplacest of the industry's daily experience. This essentially experimental point of view and willingness to venture resources in the search for constant improvement augurs well for the industry's continued progress and stability.

The long run outlook for continued abundance of petroleum fuels and lubricants at reasonable prices has certainly not deteriorated in this area over the past year. The relatively high rate of current drilling activity, stimulated by improved crude and product prices, is certain to result in appreciable increments to petroleum and natural gas reserves, and most of this will be harvested over a considerable period of time. Additions to petroleum reserves continue to exceed current rates of production and consumption. None the less, old projects are being revived and new plans laid to bring crude oil by pipe line into one part or another of the Pacific area from such distant sources of supply as Texas and Alberta. Whether such plans are soundly conceived only time will tell. Their economic feasibility will depend basically upon relative costs and prices and upon the progress of technology. The time may not be distant when it will prove to be good engineering and good business to supplement this area's petroleum resources by such drafts upon the surplus stores of other regions.

**PART IV. COAL**

**Previous** articles in this series have dealt with electric power, natural gas, and petroleum as sources of industrial energy in the western states. Each of these energy sources has experienced a continuous and relatively rapid expansion in use during the past 30 years, although a shift has occurred in the postwar period from some types of fuel oil in industrial and transport applications to certain other fuels. In contrast, the production and utilization of coal in the western area has been relatively stagnant over the period since the twenties and its importance in the whole energy situation has declined steadily.

**Declining importance of coal**

This shift away from coal as a basic source of industrial energy has been due essentially to the increasing availability, relative economy, and greater convenience in use of other fuels in most parts of the West. Grades of coal which might be competitive with such other sources of energy are limited in their geographical occurrence in the West to certain districts in Utah, Wyoming, Colorado, Montana, and New Mexico. These coals must incur relatively high transport costs over considerable distances to reach the industrial centers of the more densely populated areas. A rail haul of a few hundred miles may easily double the mine price of coal, and distances in the West are relatively great. Oil, on the other hand, moves more cheaply, due to the economy of transport by pipe line or tanker, and regional differences in the price of oil are comparatively small. Gasoline and fuel oil may be transported very considerable distances by pipe line or tanker at relatively small cost. Hence oil, and natural gas where available, have become the preferred types of fuel over large areas in the West while coal has fallen behind.

Increasing use is also being made of purchased electric energy for general industrial purposes at the expense of fuels consumed within the individual plant. Hydroelectric power has supplied the great bulk of such pur-
purchased energy, especially in the Pacific Coast states. The installation of extensive public power projects, such as the Colorado River, Shasta, and Columbia River developments, together with only less spectacular units constructed by privately owned companies, has made available a large pool of public utility power in this area. Purchased electric energy has become relatively more important, and plant-generated power less important, than in most other parts of the country.

**Coal not a major industrial fuel in the West**

Because of this growing importance of other sources of energy, coal no longer rates as an important industrial fuel over extensive parts of the western region. Its market has tended to become increasingly a local one and its utilization is largely restricted to such uses as the smelting of iron and other ores, chiefly in the form of coke, where for technological reasons no other fuel can be substituted; as locomotive fuel—though at a rapidly diminishing rate in recent years; for electric power generation in areas adjacent to coal mines; and for domestic heating in districts where other types of fuel are not readily available. Its general industrial use in the West is usually limited to applications where large amounts of heat or process steam are necessary, as in cement kilns, brick and tile works, local beet sugar refineries, pulp and paper plants, and similar uses. Aside from utilization in the form of coke for blast furnace operation at a California steel mill constructed during the recent war and at one or two tidewater smelters, there is little or no large scale industrial use of coal anywhere in the Pacific Coast states. Even in areas of formerly considerable production, such as Colorado, coal has been waging an apparently losing battle as oil and natural gas make increasing inroads upon its markets.

**The Trend of Production**

Production of coal in the western states is limited to a relatively small number of districts in the Rocky Mountain states, which have accounted for roughly 90 percent of total western production, and to a few localities in the state of Washington. California and Oregon lack significant deposits of coal, although small quantities of lignite were produced from the Mt. Diablo district near San Francisco Bay over the period from 1861 to about 1906. The early industries of California depended upon imported coal and coastal shipments from Washington and the Atlantic seaboard until the discovery and successful utilization of oil toward the end of the last century supplied the basis for a new type of fuel economy. Receipts of coal at San Francisco reached their maximum in 1900 at a volume slightly over 1,600,000 tons, declining by 1916 to about 240,000 tons, and by 1929 to less than 20,000 tons.

**Utah, Colorado, and Wyoming major producing states**

Commercial coal production in the West got its first big impetus from the coming of the transcontinental railroads, for whom convenient access to supplies of local fuel was an essential. Some of the most productive mines were first developed and are still controlled by the transcontinental carriers. Coal mining on the line of the Union Pacific began at Rock Springs in southern Wyoming in 1869. Output of Wyoming mines reached 105,000 tons in 1870 and exceeded 500,000 tons annually by 1880. Railroad building in Colorado in the seventies spurred the demand for coal in that state; Colorado took the lead in 1881 with an output of 707,000 tons and maintained its position continuously until 1941, with a maximum output of some 12 million tons in 1917 and 1918. Colorado coal has supplied the fuel base for an important local iron and steel industry and was also distributed in considerable volume to other states. Wyoming again held first place in production from 1942 to 1947, with an average output during those years of close to 9 million tons. The bulk of Wyoming’s output has regularly been used as railroad fuel, with most of the remainder being shipped to out-of-state markets.

Development in Utah was more gradual until the decade of the nineties, when extensive coking plants were established in the Castlegate and Sunnyside districts to supply the smelters of the Salt Lake Valley and more distant markets. Coal output expanded rapidly until about 1920 but lagged thereafter until the war years when it received a big stimulus from the establishment of blast furnaces in connection with new integrated steel plants in Utah and California. Utah displaced Colorado as the second largest coal producer among the western states in 1946, and again in 1947 with an output of 7.4 million tons, and took first place in 1948. In that year output dropped, however, to 6.8 million tons, and declined again in 1949 to 5.9 million tons, still the top figure among the western states. Utah coal in recent years has probably been the most widely distributed of all the coals produced in the West.

The above three states have accounted for over sevenths of the total reported coal production in the western
states. The remainder has come in nearly equal proportions from Montana, Washington, and New Mexico. The record in these states has also been one of fluctuating output, reaching in each instance a record production of about 4 million tons in 1918, followed by steady decline in Washington and New Mexico; Montana, which has some large open strip mines, exceeded its earlier record during the recent war. Postwar output has been relatively low in all three states.

Western states produce 5 to 6 percent of national total

Total reported output of the six leading western states up to the end of 1949 was about 1,453 million tons, or a little under 6 percent of the total United States production of bituminous coal to that time. Production in each of these six states in 1948 and 1949 and their total output to the end of 1949 were as follows:

<table>
<thead>
<tr>
<th></th>
<th>1948 output</th>
<th>1949 output</th>
<th>Total output to end of 1949 (million tons)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Colorado</td>
<td>5,631</td>
<td>4,540</td>
<td>471.0</td>
</tr>
<tr>
<td>Wyoming</td>
<td>6,412</td>
<td>5,372</td>
<td>365.1</td>
</tr>
<tr>
<td>Montana</td>
<td>2,898</td>
<td>2,750</td>
<td>157.3</td>
</tr>
<tr>
<td>Washington</td>
<td>1,229</td>
<td>895</td>
<td>142.4</td>
</tr>
<tr>
<td>New Mexico</td>
<td>1,364</td>
<td>980</td>
<td>121.4</td>
</tr>
<tr>
<td>Total six states</td>
<td>24,338</td>
<td>20,621</td>
<td>1,453.7</td>
</tr>
</tbody>
</table>

Percent of United States total bituminous 4.06 4.74 5.84

Large coal resources in the West

In surveying the coal resources of the West one is impressed by the striking contrast between the enormous potential energy reserve contained in western coal deposits and the relatively small degree of development or current utilization of these resources. This discrepancy arises only in part from the fact that the western coal deposits are predominantly of lower rank and are not suitable for industrial use under present economic conditions and with present technological methods. Huge deposits of good bituminous coal exist in the Rocky Mountain area suitable for most industrial uses. Many of these deposits can be mined by advanced technological methods and lend themselves to a high degree of mechanization. The difficulty lies primarily in the fact that they are relatively distant from centers of population and industry, and hence must overcome a heavy transportation handicap, and in the further fact that competing sources of energy, particularly fuel oil and to some extent natural gas, are available over much of the western region at prices and costs which coal cannot meet.

Types of western coals

Coals are of many different types, which vary greatly in quality from lignite or brown coal at the lower extreme, through the intermediate or bituminous types, to anthracite or “hard” coal at the upper end of the range. Most of the coal output of Colorado and Utah is high grade bituminous, although considerable quantities of subbituminous are produced for local use. Over half the production of Wyoming is also of bituminous rank; northern Wyoming produces chiefly subbituminous coal. The largest part of Montana’s output is subbituminous, with some low rank bituminous and a small quantity of lignite. Washington production in recent years has averaged about 75 percent bituminous and 25 percent subbituminous coal.

The best coking coals are found in the Appalachian region, although coals suitable for making good grades of metallurgical coke occur in the Trinidad-Raton field of Colorado-New Mexico, in the Castlegate and Sunnyside fields of Utah, and in western Washington. To improve coking efficiency in the smelting of iron ore in Utah and California blast furnaces, the high volatile Utah coals are supplemented with about 10 percent of special coking coals from Arkansas and Oklahoma, brought in at high freight costs.

Owing to their high moisture content as mined, the western subbituminous coals and lignites give off moisture rapidly when exposed to the air and the coal “slacks” into small pieces. This slack coal cannot be stored for any length of time in the open air or shipped safely in open cars because of its tendency to spontaneous ignition. This characteristic, together with the low heating value of these coals, limits their use to local markets within short distances of their point of origin.

Western Coal Consumption

Any satisfactory accounting for the coal consumption of any particular area of the United States is extremely difficult due to lack of detailed information on a regional basis. For the United States as a whole, the estimated distribution of bituminous coal among domestic consumers in 1937 and in the past three years was reported as follows:

<table>
<thead>
<tr>
<th></th>
<th>1937</th>
<th>1947</th>
<th>1948</th>
<th>1949</th>
</tr>
</thead>
<tbody>
<tr>
<td>Railroads (Class I)</td>
<td>20.4</td>
<td>20.0</td>
<td>18.1</td>
<td>15.3</td>
</tr>
<tr>
<td>Coke</td>
<td>17.2</td>
<td>20.2</td>
<td>18.8</td>
<td>20.5</td>
</tr>
<tr>
<td>Electric power utilities</td>
<td>9.9</td>
<td>15.8</td>
<td>18.3</td>
<td>18.1</td>
</tr>
<tr>
<td>Other industrial</td>
<td>24.0</td>
<td>26.8</td>
<td>27.6</td>
<td>25.8</td>
</tr>
<tr>
<td>Retail deliveries</td>
<td>18.5</td>
<td>20.2</td>
<td>17.2</td>
<td>20.3</td>
</tr>
<tr>
<td>Total of classes shown</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0</td>
</tr>
</tbody>
</table>

No comparable breakdown is available for the coal consumed in the western states. Reliable data for the

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1 For an excellent recent discussion of western coals, see V. F. Parry, “Production, Classification, and Utilization of Western United States Coals,” Economic Geology, Vol. 41, No. 6, September 1949.

region can be had on a regular annual basis only for electric utility use and for exports. These two together amount to a very minor part of the total produced, e.g., about 1.6 million tons in 1947, less than 6 percent of the 27.6 million tons produced in the western states in that year. Data on industrial use can be obtained at irregular intervals from the Census of Manufactures. For 1947, Census reports indicate manufacturing consumption of coal in the western states at about 5.9 million tons, or 21.4 percent of total production. These several items amount to about 7.5 million tons, leaving some 20 million tons to be accounted for by railroad consumption, shipments to outside points, and domestic and miscellaneous use.

Manufacturing use of fuels and electric energy

The figures in the accompanying table confirm the fact that coal and coke play a much smaller part in western industry than in American manufacturing as a whole while each of the other sources of energy and power is of relatively greater importance in the West than in the remainder of the country. Some wide differences mark the various states, however, as well as the two major groups of states within the western region. The relatively high proportion of total fuel costs represented by coal and coke in the mountain states is accounted for by the large quantities of coke used in blast furnace operations by the iron and steel industries of Colorado and Utah, whose fuel requirements overshadow those of the other industries of those states.

Among individual states, purchased electric energy represented over half the total fuel and power bill in manufacturing plants in Montana and reached nearly as high a ratio in Oregon and Washington. In these states the unit cost of electric energy used in manufacturing in 1947 was well below half the average cost for the United States as a whole. Over two-fifths of the aggregate cost of purchased electric energy used by Oregon and Washington industries in 1947 was accounted for by the primary metal producers, meaning substantially the aluminum reduction plants which used a large fraction of the Bonneville energy supply obtained at very favorable rates. Use of purchased electricity was also significantly above the national average in 1947 in California and Arizona in spite of the power shortage in that year.

Because of the extensive use of natural gas by California industries, outlays on gas fuel accounted for over one-third of the total fuel and energy costs of all manufacturing establishments in that state in 1947. The ratio for use of gas was even higher for Wyoming and New Mexico, where gas reserves are relatively abundant, and was topped only by Texas and the adjoining gas-producing states. Although Washington produces coal and imports even more, at high cost, from the Rocky Mountain area, coal and coke represented only one-tenth of the total fuel and energy bill of its manufacturing industries in 1947. Both Washington and Oregon rated high in outlays on fuel oil, proportionately higher than California, their major source of supply. The high figure for "other fuels" in Washington and Oregon (14-17 percent of the total) is probably accounted for largely by purchased wood and "hogged" fuel.

Use of coal for coke

The quantity of coal consumed directly as fuel in manufacturing establishments in the 11 western states in 1947 was reported by the Census as 2,350,000 tons, at a cost of $14.5 million. An additional 3,556,000 tons were used for the production of coke in Utah, Colorado, and California, chiefly for use in iron blast furnace operations. The quantity of coke used in manufacturing in the 11 states was reported at 2,360,000 tons, with a cost of $32.4 million. In total, then, an aggregate quantity of about 5,900,000 tons of coal was used either directly or in the form of coke, at a cost of approximately $47 million. This usage was equivalent to about 21 percent of the reported mine production of coal in the western states in 1947. A relatively small part of the coal and coke consumed came from states outside the West.

Almost nine-tenths of the total manufacturing consumption of coal and coke in 1947 was accounted for by the four states, Utah, Colorado, California, and Washington. The quantities reported for each of the 11 western states were as follows:

<table>
<thead>
<tr>
<th>State</th>
<th>Coal and coke</th>
<th>Fuel oil</th>
<th>Gas</th>
<th>Other fuels</th>
<th>Electric power</th>
</tr>
</thead>
<tbody>
<tr>
<td>United States</td>
<td>$3,331.5</td>
<td>$1,741</td>
<td>$11.5</td>
<td>$2.7</td>
<td>$28.6</td>
</tr>
<tr>
<td>11 Western States</td>
<td>$3,145</td>
<td>$1,917</td>
<td>$17.4</td>
<td>$21.0</td>
<td>$6.6</td>
</tr>
<tr>
<td>Pacific States</td>
<td>$1,754</td>
<td>$8.2</td>
<td>$20.6</td>
<td>$23.0</td>
<td>$7.0</td>
</tr>
<tr>
<td>California</td>
<td>$1,174</td>
<td>$7.4</td>
<td>$17.9</td>
<td>$33.7</td>
<td>$3.8</td>
</tr>
<tr>
<td>Washington</td>
<td>$1,900</td>
<td>$10.8</td>
<td>$26.9</td>
<td>$8</td>
<td>$13.7</td>
</tr>
<tr>
<td>Oregon</td>
<td>$1,950</td>
<td>$7.1</td>
<td>$24.7</td>
<td>$2.1</td>
<td>$17.1</td>
</tr>
<tr>
<td>Mountain States</td>
<td>$681</td>
<td>$47.9</td>
<td>$9.3</td>
<td>$16.0</td>
<td>$4.6</td>
</tr>
<tr>
<td>Utah</td>
<td>$20.0</td>
<td>$68.0</td>
<td>$2.5</td>
<td>$15.3</td>
<td>$5.6</td>
</tr>
<tr>
<td>Idaho</td>
<td>$6.4</td>
<td>$42.3</td>
<td>$21.3</td>
<td>.9</td>
<td>$2.7</td>
</tr>
<tr>
<td>Arizona</td>
<td>$5.7</td>
<td>$4.2</td>
<td>$22.5</td>
<td>$32.9</td>
<td>$5.5</td>
</tr>
<tr>
<td>Nevada</td>
<td>$2.5</td>
<td>$18.6</td>
<td>$30.1</td>
<td>.4</td>
<td>$1.5</td>
</tr>
<tr>
<td>Colorado</td>
<td>$21.3</td>
<td>$61.6</td>
<td>$8.4</td>
<td>$14.3</td>
<td>$1.6</td>
</tr>
<tr>
<td>Montana</td>
<td>$8.7</td>
<td>$24.0</td>
<td>$5.4</td>
<td>$16.3</td>
<td>$5.1</td>
</tr>
<tr>
<td>Wyoming</td>
<td>$2.1</td>
<td>$18.0</td>
<td>$8.5</td>
<td>$35.0</td>
<td>$3.4</td>
</tr>
<tr>
<td>New Mexico</td>
<td>$1.5</td>
<td>$2.7</td>
<td>$8.4</td>
<td>$44.9</td>
<td>$13.0</td>
</tr>
</tbody>
</table>

Cost of Fuels and Electric Energy Consumed in Manufacturing, 1947


As compared with the situation in 1929, manufacturing plants in the West apparently increased their total consumption of coal by about 700,000 tons, or some 14 percent. This gain was more than accounted for, however, by considerably larger use in coke making, chiefly...
in the new integrated steel plants erected during the war in Utah and California. Coke for iron and steel operations in the western states absorbed roughly 2 million more tons of coal in 1947 than in 1929, while other manufacturing operations used about 1.3 million tons less. Use of coal as fuel in these other industries declined in all the states except Utah, Idaho, and Oregon; substantial decreases occurred in Colorado, Washington, Arizona, and Montana.

**Railroads major users of coal**

Demand for coal as locomotive fuel was the original base on which much early western coal mining development was founded. In many cases the railroads were themselves among the first to engage in coal mining on any considerable scale and their operations have played a large part in the total activity of the industry. The proportion of "captive" mines is considerably higher in the West than in the country at large; this is particularly the case in Wyoming, Montana, and Washington, where the railroads are the principal owners of such captive mines. Due to the relatively slight industrial development of much of the western region, and the peculiar operating conditions of western railroads—involving long distances and heavy grades, railroad fuel requirements have represented a considerably larger fraction of the total market for coal in the West than in most other parts of the country.

In the country as a whole, railroad use of coal has until quite recent years been the largest single constituent of the total demand, ranging between 20 and 25 percent of the entire domestic consumption of bituminous coal. Following a peak of about 135 million tons in 1920, consumption by Class I railroads tended generally downward until the extraordinary requirements of the war period carried it up to 132 million tons in 1944. Since then railroad demand has declined continuously. By 1948 purchases of Class I railroads had fallen below 95 million tons, representing about 18 percent of total bituminous consumption in that year. Preliminary reports for 1949 indicate a further precipitous shrinkage to 68 million tons, scarcely half the 1944 volume, and only about 15 percent of total bituminous consumption.

**Causes of decline in railroad use of coal**

Several factors have combined to reduce consumption of coal by the railroads. One of these is the steadily improving efficiency in utilization of coal in railroad operations. The number of pounds of coal required, on the average, to perform a given unit of output in railroad freight service was reduced nearly 35 percent between 1920 and 1948; in passenger train service the reduction was about 15 percent. This improved fuel efficiency has been a persistent and long continued influence affecting railroad demand for coal. More recently it has been powerfully reinforced by two new factors—the sharp reduction in total railroad freight tonnage and passenger volume since the war, and the constantly accelerating rate of replacement of steam locomotives by Diesel-electric motive power.

The first of these forces will undoubtedly prove to be temporary, at least with respect to freight traffic. The downward trend in freight tonnage was relatively moderate until 1949 when it dropped to a level 23 percent under that of 1944. Some recovery in total freight volume is to be expected, although it may be a number of years until the war records are surpassed. But rising traffic volume will benefit the coal producers little if the railroads continue to replace their coal burning locomotives with Diesel power. The superior economy of the Diesel engine in railway operations is now so well established, however, that still further reductions in all types of steam motive power may confidently be expected.

**Railroads use larger share of western than of national output**

Adequate data are not available to permit a satisfactory regional analysis of railroad coal consumption comparable with the national trends discussed above. Scattered information on the distribution of coal produced in individual states has been published from time to time by the Bureau of Mines which permits some approximate estimates of railroad demand in the more important coal producing states of the West. The best of these are for the years 1944-46, when fairly complete data were released on shipments of bituminous coal to selected classes of users in all the states.¹ These data show that reported shipments of railroad fuel from mines in the six leading western states accounted for approximately 42 to 46 percent of the aggregate bituminous output in those states for the years in question. Fully comparable data are not available for any other year, but reports on individual states centering around the year 1929 permit a rough estimate for that year which yields a ratio of railroad fuel to

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¹ Bureau of Mines, Bituminous Coal Distribution, M.M.S. 1289, 1444, 1592.
total production in the six states of about 37 percent. It is probably safe to say that in the prewar years consumption of coal by the railroads represented somewhere between 35 and 40 percent of the total output of the western states, a ratio roughly double that for the country as a whole. In the postwar period the railroad market for coal in the West has probably been shrinking as rapidly as in most other parts of the country.

**Use of coal by electric utilities**

As compared with most other regions of the United States, coal plays a relatively minor part in the production of electric power for public use in the western states. Only in the southwestern region, where cheap natural gas is available, is less use made of coal in electric power generation. In only two years during the past decade has the consumption of coal by electric public utilities in all the western states exceeded a million tons. Most of this was concentrated in Colorado and Utah; these two states together with Wyoming and New Mexico have accounted for practically the entire consumption in recent years.

The availability of hydro-electric energy over much of the region and of oil or natural gas at lower costs explains, of course, the relatively small use made of coal for electric power generation in the West. Small quantities of coal are used in the manufacture of artificial gas by the public utilities in some of the cities of the Pacific Northwest, but even here by far the greater part of the raw material is oil.

**Coal and California electric utilities**

Most of the larger steam power plants installed by the leading California electric public utilities since the war have been designed so as to permit the use of coal as fuel alternatively with oil or gas. In part this policy was adopted as a precautionary measure against the possibility of a shortage of oil in case of war. In part it was motivated by economic considerations. During the early postwar years natural gas was in relatively short supply in California and the petroleum industry was also having difficulty in keeping up with the rapidly growing demand for its products, including heavy fuel oil. The price of residual fuel oil had been held by OPA regulations at about $1.15 per barrel f.o.b. Richmond over the three years from April 1, 1943 to March 20, 1946. From that date successive advances carried this grade of oil to $2.30 per barrel by the end of 1948. Comparison of the relative costs of Utah coal and California fuel oil as sources of energy at that time indicated that in spite of these advances, oil still had a net advantage over coal—taking into account the special costs incident to each—of roughly 18 percent, even if domestic freight rates on coal could be secured equally as low as prevailing export rates.

Prices of coal and of oil followed sharply divergent trends after 1948. While the mine price of coal has continued to rise, the price of fuel oil in California was reduced nearly 50 percent between January and September of 1949, and the previous substantial cost advantage possessed by oil has been considerably widened. This divergence in the price movements of the two fuels seems likely to persist for an appreciable time; all indications point to a continuing surplus of residual fuel oil in California with relatively low prices, while recurrent strikes and sharp wage increases for coal miners have pushed up the mine price of coal to a point where much of the demand has been choked off and coal mines are being forced out of business.

With the rapid extension of pipe line facilities for long distance transmission of natural gas, chiefly from Texas and the adjacent states, this source of energy is being made increasingly available to many areas for industrial use. The California electric utilities and those in a few other western states are in position to benefit from this relatively cheap fuel and are using more of it. The greater availability and relatively assured supply of oil and natural gas, compared with the uncertainties attending coal production, as evidenced by the recent history of work stoppages in that industry, seem definitely to exclude coal from consideration as a probable source of energy to such large scale consumers as the electric utilities of the Pacific Coast for many years to come.

The prudent course, however, is to be prepared for any emergency that may arise in the supply of other fuels and also to be in position to turn to the regular use of coal if the time arrives, as it may within a few decades, when the price of coal and the conditions as to its regular supply relative to other fuels make this procedure advisable. It was with this possibility in mind that the new steam power plants in California were designed to permit the use of coal. Even some recent Texas electric utility plants have been designed with a view to ultimate conversion to coal should natural gas no longer be available for use as boiler fuel.
High transport costs limit use of coal in western region

The significance of high transport costs as a limiting factor in the more widespread utilization of coal in the western region has already been pointed out. While the West is not unique in this respect, its position, because of the distances involved, is probably an extreme example of the handicap imposed by transportation costs. For the country as a whole, the average freight charge per ton on all bituminous coal hauled by Class I steam railroads during the period 1928 to 1936 was considerably greater in each year than the average sale price of coal at the mine.1 In the more heavily industrialized parts of the country, where the average haul from mine to factory is relatively short, this transport cost is not so serious a burden, although it has in many cases probably reinforced the tendency to shift from coal to other fuels. In the West, however, where the distance from the coal fields of the Rocky Mountain states to the industrial centers of the Pacific Coast approximates 1000 miles, the freight cost imposes a substantial extra burden on fuel costs.

Costs of transporting coal and fuel oil to Pacific Northwest

An illustration of the adverse effect of high transport cost for coal, relative to oil fuel, is found in the freight rate on coal from Utah to Puget Sound points compared with the cost of shipping oil to the same destinations from California. In 1947 the rail rate of $5.70 per ton on lump coal from Hiawatha, Utah to Seattle, when added to the cost of coal at the mine, more than doubled the Seattle cost over the mine price. At the same time the cost of shipping heavy fuel oil from Los Angeles to Seattle by tanker, a roughly comparable distance, was only 25 cents per barrel, which increased the delivered price at Seattle over California prices by less than one-seventh. This difference in relative transport costs changed a 25 percent unit cost advantage on a B.T.U. basis held by coal at point of origin over oil at point of origin to a net disadvantage at destination of over 40 percent.

Fuel Problems of the Pacific Northwest

Among the several geographical sub-regions in the western states, the Pacific Northwest is probably at the greatest relative disadvantage from a fuel standpoint. Local production of oil and natural gas is non-existent in the Northwest and surplus wood fuel is rapidly disappearing in the districts adjacent to the urban centers. Although possessing a great variety of coals, ranging from lignite to anthracite, Washington’s coal production has long been on the downgrade and the area has become increasingly dependent on supplies from outside sources, chiefly Utah and Wyoming. The shrinking demand for coal because of the rapid dieselization of railroad motive power makes the existence of many coal mining enterprises in the Rocky Mountain area increasingly precarious and creates uncertainty as to the continuity of supplies from this source for regions like the Pacific Northwest. Located at the end of long supply lines for oil and out-of-state coal, the region would be exposed to the risk of having its supplies of these essential fuels curtailed in the event of shortage or emergency. In such event, considerable difficulty might be experienced in stepping up production from the local coal mines sufficiently to provide for essential requirements.

High costs of coal production

Coal mining in Washington is relatively costly. The best of the accessible and most easily mined beds are found in the bituminous deposits of the Roslyn field, east of the Cascades. This field has been worked for many years and while much of the most accessible coal has been removed, the field is still far from exhausted. However, it is probable that further production in this area will be increasingly expensive as less accessible beds are resorted to. Large reserves of low rank subbituminous coal occur in southwestern Washington, but this coal is little better than lignite, having a high moisture content and slacking badly on mining. The remaining coal deposits of the state, in the area between Puget Sound and the Cascades, are handicapped by excessively high costs of mining and preparation for market. The coal bearing rocks in this region were badly faulted and broken in the process of mountain building and in many places are deeply covered with glacial drift. The result is that mining is exceedingly difficult and expensive and the coal is often mixed with shale and sandstone which necessitates additional costs for removal and washing. These conditions have made extensive mechanization impossible in most mines in this region and result in low output per man and high costs of production. The average daily output in Washington coal mines in 1948, for example, was 4.13 tons per man, as compared with 6.72 tons in Utah, 7.83 tons in Wyoming, and 6.26 tons for the bituminous mines of the country as a whole. The average cost at the mine of all bituminous coal produced in Washington runs considerably higher than in any other western state and until 1946, when some of the least efficient mines were closed, regularly exceeded the average for the country as a whole by over 60 percent.

Increasing importance of oil and electric power

The cumulative effect of these several influences affecting the fuel and energy supply in the Pacific Northwest has been to reduce the relative importance of coal in the total situation, while that of oil and hydro-electric energy has greatly increased. Studies made by the State College of Washington show that oil supplied about 50 percent of that state’s total estimated energy consumption in 1939 and 59 percent in 1948; the share of coal dropped during the same period from 41 percent of the total to 23 percent; the remainder was supplied chiefly by hydro-

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1 See Minerals Yearbook, 1937, pp. 790 and 803.
The use of oil nearly tripled and electric energy output gained almost five-fold during these nine years. While there was a net increase of about 25 percent in total coal consumption, a sharp falling off occurred in production and use of Washington coal. These estimates are for over-all fuel consumption and include domestic as well as industrial use; domestic use of coal probably represents at least one-third of the total consumption. It is notable that even during the war years, but to a greater degree since, more out-of-state coal has been shipped to retail yards than to industrial consumers. Outside coal has largely supplanted local coal in domestic usage.

What evidence is available indicates that the same general tendencies are at work in the other northwestern states—large increases in consumption of oil and hydroelectric energy, with little change in over-all consumption of coal. Oil is a competitive fuel, while electric energy is largely an additional factor in the situation, finding its chief industrial use in the electro-metallurgical industries which have developed in the Columbia River Basin. Even at the high prices for oil prevailing in 1947 and 1948, the delivered cost in the Pacific Northwest of fuel oil of the type required by large industrial users was below that of Utah coal on a comparable calorific basis. Sharply reduced prices resulting from glutted fuel oil markets in 1949 widened the margin.

**Proposed gasification of coal in Washington**

Because of the high cost of mining the better coals in Washington and the high delivered cost of coal from Utah and Wyoming, efforts are currently being made to find a satisfactory way to utilize the extensive sub-bituminous deposits of southwestern Washington. These coals are relatively easy to mine but have a low calorific value and poor storing characteristics. To offset these disadvantages, it is proposed to gasify these coals in large plants near the mines and to pipe the gas to consuming centers. The Washington Legislature in 1949 authorized the establishment of a pilot plant to investigate the feasibility of such a project, but made the expenditure of state funds contingent on securing additional amounts from other sources on a cooperative basis. Such cooperative action has so far not been forthcoming and the project is still in abeyance. Meanwhile, the prospect of obtaining natural gas from out-of-state sources has become a distinct possibility and has dimmed the outlook for coal gasification research.

**Possible importation of Canadian natural gas**

Rapid exploration and development of Canadian oil resources during the past two years, particularly in Alberta, give fairly reasonable assurance that an adequate and dependable supply of natural gas from this region may become available to the Pacific Northwest in the not distant future. As to how soon this new fuel resource can be developed and at what cost, it is still too early to predict, since legal and political questions as well as economic considerations are involved. Several different groups are currently reported to be actively promoting plans for the financing and construction of pipe lines to connect the Canadian gas reserves with north Pacific Coast markets. Should these plans be carried to early fruition, it seems likely that the competitive position of coal in this area will be still further impaired.

**Outlook for the Future**

So long as petroleum and natural gas remain in relatively abundant supply, there appears to be little prospect of any significant increase in the use of coal as an industrial fuel in the West. If and when these other sources of energy become scarce and high priced, coal may supply a larger part of industry's fuel requirements, either directly or in the form of gas or liquids derived by synthetic methods. It seems most probable, however, that before this latter stage is reached the oil industry will be utilizing the extensive shale deposits of the Rocky Mountain area for the synthetic production of fuel oil. The total estimated volume of recoverable oil from shale exceeds the currently proved petroleum reserves of the United States in the ratio of about 8 to 1. In comparison with all these, the nation's coal and lignite reserves, nearly half of which are in the 11 western states, are enormously greater. The ultimate destiny of the West's coal resources will probably be, therefore, to serve as the major source of mineral energy in the remote future when petroleum, gas, and shale resources have been exhausted.

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**WESTERN POWER AND FUEL OUTLOOK—V. SYNTHETIC FUELS**

The rapid growth in fuel consumption in the United States over the past three decades was based almost entirely on liquid fuels—petroleum products—and natural gas, rather than on solid fuels. On a per capita basis, according to U. S. Bureau of Mines figures, coal consumption in the United States has dropped in the past 30 years from 6 tons to 4 1/2 tons annually, while consumption of petroleum has increased from 4 1/2 barrels per capita to over 14 barrels, and that of natural gas from 7,500 cubic feet to 35,000 cubic feet. In view of the fact that solid fuel resources, including coal, lignite, and oil shale, constitute over 95 percent of the nation's known reserves of mineral fuel and are adequate for centuries of use, while the more limited petroleum and natural gas supplies are likely to be exhausted at a much earlier period, it is argued that the security of the nation's liquid fuel position would
be improved if the oil supply could be based increasingly upon solid fuels. This would mean the establishment of a synthetic fuel industry designed to produce liquid fuels from coal and oil shales, of which large quantities are available in many parts of the country, including extensive areas in the Rocky Mountain states.1

**Divergent policy views**

There appears to be little question that coal and oil shale will supplement or eventually even replace crude petroleum as major raw material sources for motor fuels and heating oils. Considerable difference of opinion, however, exists as to when this development will probably occur and what policies government and industry should follow in the meantime. One group of observers is impressed by the probability of an early decline in the production of oil in the United States and fears a disastrous shortage of petroleum products in the event of another large-scale war. This group maintains that the expanding use of petroleum products in this country will soon out-run any possible increase in production from domestic sources and urges the early establishment of a synthetic liquid fuels industry, backed if necessary by government subsidy in the form of long term loans, or possibly taking the form of outright public ownership.

The more conservative group, represented chiefly by elements in the oil industry, holds that the demand for petroleum products is unlikely to continue increasing at anywhere near so high a rate as during the past two or three decades, and that there is no danger of a serious liquid fuel shortage within the foreseeable future. This group opposes the policy of a government-supported synthetic fuel industry and maintains that the role of government should be limited to basic research and pilot plant studies designed to improve synthetic technology, which is still in a relatively early stage of development, or at most to the operation of demonstration plants designed to provide engineering and cost data.

Spokesmen for the oil industry represent that when the time comes that domestic and easily accessible foreign supplies of petroleum are no longer adequate to the nation’s requirements, the oil industry will itself provide the necessary fuel supplies by synthetic methods. Several important units in the industry have invested much time and money in synthetic fuel research, and a number have operated experimental pilot plants. Some of these are working on the synthesis of coal, some on oil shale, still others on the conversion of natural gas to liquid products. Up to the present time, however, no synthetic process has succeeded in producing liquid fuels from solid materials at costs competitive with the products of petroleum refining. The outlook for early development of competitive liquid fuels from cheap natural gas appears much more promising, however, and synthetic products from this source may well be the first significant addition to petroleum liquids.

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**Some uncertainties affecting the liquid fuel outlook**

If and when the time comes that a substantial part of the nation’s liquid fuel supply is derived from solid materials, it is probable that an important synthetic fuel industry will arise in the West. The location of large shale beds and enormous deposits of low-rank coal and lignite in this region, together with the probability that demand for liquid fuels will expand faster than new petroleum discoveries, points to such a development. How early this evolution may be expected is, of course, problematical. The whole situation is bound up with political as well as economic considerations and involves both international and domestic factors.

The availability of dependable supplies of petroleum from foreign sources, except perhaps from Canada where large-scale exploration and development are under way, is highly problematical in the present condition of international relations. Threats to such supplies, whether from potential military action or from arbitrary government procedures, would probably hasten the development of a domestic synthetic fuel industry in the West. Working in the opposite direction are such possibilities as (1) offshore discoveries of large petroleum resources along the California coast, the development of which is currently involved in controversy over Federal versus state ownership of the tidelands; (2) further rapid increases in the oil reserves of Texas and the Rocky Mountain states; and (3) development of offshore pools along the Gulf Coast. Pipeline transportation of crude oil or refined products to Pacific Coast markets might be economically feasible from some of these sources. In fact, one such development has occurred within the past two or three years: petroleum from the Rangely field in Colorado is currently piped to refineries in Utah and the resulting products piped to markets as far distant as central Washington.

Fundamentally, of course, the existing spread between the cost of petroleum products and that of synthetic fuel can be expected to narrow, as the search for new oil becomes more expensive because of the exhaustion of the more favorable locations for wildcatting and the necessity of deeper drilling, while the technology of synthetic production will become more firmly established and costs reduced with the progress of research and accumulated experience. As costs approach a more competitive range, a gradual shift of some parts of the liquid fuel market to synthetics may be expected, probably under the sponsorship of the oil industry itself which is not likely to limit its raw materials to petroleum if other sources offer a profitable opportunity to supply the market.

**A conservation aspect**

An argument sometimes raised against the production of synthetic fuels from natural gas or coal is the large loss in heat value involved. Under present methods, approximately half the energy content of both natural gas and coal is lost in the synthetic conversion of these mate-
mials to liquid fuels. It is argued that natural gas especially is too good a fuel in its own right to be used as a material for synthetic fuel production. The same argument applies to coals of coking quality. These materials are said to be better used in their "natural" state, while oil shale serves no useful purpose as such, and its conversion to synthetic fuel, by relieving the pressure on limited resources of petroleum, would be in the interest of basic conservation.

**Resources Available for Synthetic Fuel Production**

Large quantities of raw materials exist in the United States which might under appropriate conditions supply the basis for an extensive synthetic fuel industry. Among them are not only natural gas, coal, and oil shales, but tar sands and various agricultural wastes. It must be remembered, however, that mere physical existence does not always imply economic availability. Costs of development and exploitation of such potential resources must be related to the prices of the products obtained, and this in turn is limited by the prices of competing products obtained by conventional methods—e.g., gasoline and other products from crude petroleum. Nor does the physical existence of potential raw materials for synthetic fuel production necessarily indicate the feasibility of quickly supplementing existing supplies of liquid fuels in an emergency by products derived from such sources, even if cost could be neglected. The limiting factors of time and available manpower and equipment must always be borne in mind, in addition to the limitations imposed by the existing state of technology.

In view of these considerations, it is perhaps unnecessary to attempt too precise an estimate of the potential resources that might serve as raw materials for synthetic fuel production. Data on mineral reserves are seldom completely satisfactory, as they are usually subject to considerable revision, and estimates for some materials are much more up to date than for others. In the case of both coal and oil shale, wide differences in quality and suitability to synthetic processes mark the various deposits. Some deposits are rich and easily accessible, others so poor or difficult of access that it may never pay to work them. In general, however, it is safe to say that current estimates of coal and oil shale resources may be regarded as fairly solid, in contrast with the wide differences of opinion, even among the experts, as to the probable total resources of petroleum and natural gas, discovered and undiscovered.

On any sound basis of estimation, the solid fuel resources of the United States—coal, lignite, and shales—vastly exceed the presently known and proved reserves of petroleum and natural gas. A reasonably current official estimate ranks the various components of the nation's recoverable mineral fuel reserves at January 1, 1948 as follows, in terms of equivalent units of bituminous coal.1

<table>
<thead>
<tr>
<th>Material</th>
<th>Billion tons</th>
<th>Percent of total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anthracite and bituminous coal</td>
<td>710</td>
<td>54.3</td>
</tr>
<tr>
<td>Subbituminous coal and lignite</td>
<td>541</td>
<td>41.3</td>
</tr>
<tr>
<td>Oil from shale</td>
<td>46</td>
<td>3.6</td>
</tr>
<tr>
<td>Petroleum (proved reserves)</td>
<td>6</td>
<td>0.4</td>
</tr>
<tr>
<td>Natural gas (proved reserves)</td>
<td>6</td>
<td>0.4</td>
</tr>
<tr>
<td>Total</td>
<td>1309</td>
<td>100.0</td>
</tr>
</tbody>
</table>

and is not likely in any case to be increased, as the estimate of reserves is largely based on geological observation rather than actual drilling. The figure given for oil from shale has since been considerably enlarged as a result of recent exploration in the western states. Proved reserves of petroleum and natural gas will probably continue to increase with the progress of exploration and discovery, until offset by new current production. Making due allowance for these various discrepancies, the nation's ultimate resources in liquid and gaseous fuels are relatively small in comparison with the enormous deposits of coal and shale still awaiting development.

**Oil from natural gas**

Among the various materials available for use in synthetic fuel production, natural gas will probably be the first to be exploited on a commercial basis in this country. The natural gas hydrocarbon-synthesis has been thoroughly developed by experimental pilot plant operation and yields a gasoline of good quality with a relatively high octane rating.2 This technique is based on the original Fischer-Tropsch process, first developed in Germany.2 A large commercial plant, financed jointly by the Reconstruction Finance Corporation and a group of oil and gas companies, has recently been constructed at Brownsville, Texas, designed to produce about 7,000 barrels per day of gasoline and other products. The results of this operation will be available to a number of interested oil and gas companies; the volume of synthetic output could be expanded fairly rapidly in areas having a large surplus of natural gas, although it has been suggested that if many such plants were established the resulting output of chemical by-products might be so large as to break the market.

Reserves of natural gas have increased very rapidly in recent years with the discovery of additional oil fields in Texas and adjoining states. Proved reserves at the end of 1949 were estimated at 180 trillion cubic feet, or about 30 times the annual rate of production. Estimates by petroleum technologists indicate a probable rate of new discoveries that will yield a surplus over current consumption sufficient to permit the production from natural gas of about 500,000 barrels per day of synthetic products—roughly one-tenth the rate of production of all petroleum products in recent years.

**Oil from shale**

Oil shale is found in Alaska and 20 American states, but the shales of the vast Green River formation in the Rocky Mountains are by far the richest and most exten-

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2 Synthetic production of liquid fuels from dry natural gas is not to be confused with the comparatively simple process of extracting natural gasoline from casing-head or oil-well gas, which has long been employed as a regular practice in oil-field operations. See pages 10 and 14.

3 See page 43.
sive. Shale beds up to 500 feet thick occur in this forma-
tion, which covers some 2,600 square miles in western
Colorado and the adjacent areas of Utah and Wyoming.
Sampling of these beds indicates the existence of shales
containing a probable minimum of some 340 billion bar-
rels of shale oil in this one region, which compares with
existing proved reserves of petroleum and natural gas
liquids for the whole United States of around 28 billion
barrels at the end of 1949.

The main resources of the Green River shale formation
are contained in an area of about 1,000 square miles in
western Colorado, where the oil content averages about
15 gallons per ton of shale. This would indicate a total of
about 300 billion barrels in this area alone. The lower
segment of these beds, ranging from 70 to 94 feet thick
and known as the Mahogany Ledge, contains the richest
shales, which average about 30 gallons per ton. Allowing
for a necessary loss of about 25 percent in mining—using
the pillar system to support the overburden—this one
ledge is estimated to be capable of yielding about 100 bil-
lion barrels of shale oil. An extensive Naval oil reserve
has been set aside from the public lands in this area, and
a number of large oil companies, as well as private indi-
viduals, have also patented large holdings of these shale
lands.

Shale oil does not occur as such but is obtained from a
solid organic hydrocarbon called kerogen, which is dis-
persed throughout the shale rock. When the crushed shale
is heated to moderate temperatures in a retort, this sub-
stance is converted into a vapor which on condensing
forms crude shale oil. This product is definitely not petro-
leum but a black viscous liquid of low gravity which must
be refined in order to be of use for any purpose except
boiler fuel or simple heating.

Experimentation is currently under way with various
types of shale retorting processes, including a continuous
type retort, developed by a leading California oil com-
pany. This retort generates its own heat by burning the
carbon remaining in the shale residue, thus making the
plant self-supporting. It also requires no cooling water,
an important consideration in the semi-arid region of
Colorado.

Its high viscosity makes crude shale oil difficult to
transport by pipeline. Hence it will be necessary to give
it a preliminary treatment called vis-breaking in order to
reduce the pour point sufficiently to permit pipeline ship-
ment to refining centers; complete refining on any exten-
sive scale at points adjacent to the shale deposits would
probably be impracticable because of limited water
supplies.

The refining of shale oil presents numerous technical
problems not inherent in crude petroleum. One of these
is its high sulphur and nitrogen content, the latter of
which makes the application of normal catalytic refining
techniques impractical; another is its low hydrogen con-
tent, which affects its burning characteristics and also the
products that are obtainable. The answer to these prob-
lems appears to be treatment by a high pressure hydro-
genation process which, while expensive, would remove
the sulphur and nitrogen compounds and yield a good
cracking stock that can be successfully refined with
standard equipment and processes.

Western coals for synthetic fuel

As already indicated, the coal and lignite resources of
the United States far outrank all other sources of mineral
fuels combined, and are likely to constitute the nation’s
basic source of mechanical energy long after petroleum,
natural gas, and shale resources have been depleted. The
enormous reserves of coal and lignite in the western
states will undoubtedly provide the basis for an important
synthetic fuel industry when and if existing cost and price
relationships of petroleum products and synthetic fuels
have been reversed. It was pointed out in the discussion
of western coal supplies on page 36 that about two-fifths
of the entire estimated coal and lignite reserves of the
United States are located in eight western states. Addi-
tion of the extensive lignite deposits of North Dakota
would bring the aggregate western potential to over half
the national total.

Probably the major part of these western resources
could be more effectively used in synthetic form than
directly as fuel in their natural state. The relatively low
grade of most of the subbituminous and lignite deposits
appears to rule them out of consideration for any exten-
sive utilization in the predictable future as fuel for direct
generation of energy. The limited heating value and poor
storing and shipping quality of these low grade deposits
put them at a present competitive handicap compared
with most other fuels unless they can be used in close
proximity to the producing mines, as for example in the
generation of electric power which can be economically
tied in with integrated transmission systems. Proposals
of this sort have been suggested as a means of utilizing
the subbituminous deposits of southwestern Washington
in order to supplement available power supplies based on
hydro-electric sources.\footnote{L. A. Conradi, \textit{The Chemical Utilization of the Subbituminous Coals of Wash-
ington}, Report No. 6, Engineering Experiment Station, University of
Washington, 1936.}

Although inferior in heating value by present combus-
tion methods, the western subbituminous coals and lig-
nites are probably as well adapted to some of the synthetic
processes as the high rank bituminous coals of the Appa-
lachian region. Converted to gaseous or liquid form, they
may some day play an important role in industry; at
present they constitute an immense reserve of potential
energy.

Synthetic fuels from coal

Coal possesses a technical advantage over other raw
materials for synthetic fuel production in that it can serve
as a basis for both gaseous and liquid fuels. Gas made by
charring coal into coke in a closed retort was used for
illuminating purposes over a century ago. A marked im-
provement in making coal gas occurred in 1873 when it
was discovered that gas having a much higher heating
value could be obtained by blasting incandescent coke with steam. The resulting "water gas," now usually enriched with carburetted fuel oil or mixed with natural gas, is the basis of most manufactured gas used in American cities today. Prices of manufactured gas are generally not competitive with the present low prices of natural gas, and long distance transmission lines are leading to the rapid displacement of manufactured gas by natural gas in important consuming markets. It is entirely possible, however, that progress in synthetic technology may check this trend and lead to a revival of the manufactured gas industry on a large scale in areas having abundant coal supplies.

**Liquid Fuel Processes**

Two distinct methods have been developed for the synthetic conversion of coal to liquid fuel—the hydrogenation process and the gas or hydrocarbon-synthesis process. Both of these techniques were first worked out in Germany, but in both cases American engineers have made considerable advances over German methods, partly in simplification of mechanical equipment, partly in basic procedures.

The coal hydrogenation process was discovered in 1913 when F. Bergius, a German chemist, found that coal can be converted to oil if treated with hydrogen under high pressure. Much development work was required, however, to perfect practical methods of performing the reaction continuously, and it was not until 1926 that the first commercial plant was put into operation at Leuna in central Germany. Products comparable with those of petroleum were made from lignite, bituminous coal, and coal tar. Twelve hydrogenation plants were built in Germany to utilize these and other materials, including shale oil. These plants, having a total capacity of about 90,000 barrels per day, supplied most of the German aviation gasoline used during World War II as well as considerable quantities of motor gasoline, Diesel fuels, other fuel oils, and lubricants. A coal hydrogenation plant has been successfully operated in England since 1935. In the United States the hydrogenation principle has been used by the oil industry for the past 20 years to remove impurities and improve the quality of its products.

The groundwork for the hydrocarbon-synthesis, or so-called Fischer-Tropsch process, was laid in 1923. It consisted in the catalytic conversion of water gas into a product rich in hydrocarbons from which gasoline, Diesel fuel, and lubricants could be obtained. The great advantage of this process over hydrogenation lies in the relatively low pressures used, with a corresponding reduction in costs. The first commercial plant employing the Fischer-Tropsch process began operations in 1933. A total of 10 such plants were built in Germany; these plants supplied an important part of the gasoline and other fuels required during the war.

As between these two basic techniques for producing liquid fuels from coal, opinion in the oil industry apparently tends to favor the gas synthesis process, as offering the greater promise from the standpoint of costs, although the product range from this process is relatively limited. Advocates of the hydrogenation technique emphasize its greater flexibility, which permits products ranging from fuel oil to aviation gasoline.

While these two basic processes are frequently regarded as competitors, their complementary use in the synthesis of coal has certain definite advantages. Combining the use of both processes in a single plant not only makes possible the more complete utilization of raw material and maximum recovery of products, but also permits numerous economies in operation not feasible with either process alone, resulting in substantial savings in costs.1

**Low-Temperature Carbonization of Coal**

Numerous other processes for utilizing coal to obtain synthetic products have been the subject of experimentation both in this country and abroad.2 Among them are various processes for the "low-temperature" carbonization of coal to produce tar and smokeless solid fuel. Some of these have been successfully developed on a commercial scale in Germany and England, where a ready market for the solid fuel is available, and where the cost of petroleum products makes it economically feasible to utilize coal tar advantageously for synthetic fuel production and other purposes. A number of low-temperature coal carbonization ventures were launched in the United States some 20 to 30 years ago, but none of them was successful from the standpoint of efficient or economic recovery of oil, although one plant in Pittsburgh has successfully produced and marketed a smokeless solid fuel based on coal of coking quality, and is also finding an increasing demand for the by-product tar.

Considerable controversy has raged over the economic feasibility of low-temperature coal carbonization under American conditions. While such a process may ultimately find an appropriate place in the total economy of coal utilization, the drift of opinion among American chemists and oil technologists appears to be definitely toward exploring the possibilities inherent in the complete conversion of coal to liquid or gaseous form by the hydrogenation or gas synthesis processes.

**Synthetic Fuel Program of the Bureau of Mines**

World War II made large drafts on the nation's oil resources, and by restricting the supply of manpower and equipment hampered the industry's discovery efforts. Exploration and discovery lagged and relatively small additions were made to proved reserves. In 1943, petroleum reserves actually declined. Impressed by the apparent need to stimulate the development of alternative sources of liquid fuel, Congress enacted in April 1944 Public Law 290, which launched the Federal Government upon a synthetic fuel research and development program.

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2 An excellent discussion of various processes that have been used for converting coal to other usable products may be found in Conradi, previously cited, page 44.

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The Synthetic Liquid Fuels Act authorized the appropriation of $30 million for a five-year program of investigation and research. In addition to conducting laboratory and pilot plant work, the Bureau of Mines was directed to construct and operate demonstration plants to produce synthetic liquid fuels from coal, oil shales, and other materials. Such plants were to be of sufficient size to provide reliable cost and engineering data useful in the design and operation of commercial plants. Amendments adopted in 1948 and 1950 extended the life of the Act until 1952 and 1955, respectively, and authorized additional appropriations of $57.6 million, or a total of $87.6 million from the beginning.

Following the passage of the Act in 1944, the Office of Synthetic Liquid Fuels was set up in the Bureau of Mines and investigation begun for the selection of sites for research laboratories and demonstration plants for the various synthetic processes. Technical experts were sent to Germany to secure detailed information on the methods which had made possible the production of nearly 100,000 barrels a day of synthetic fuels at the peak of the German war effort in 1944. Design work was started on demonstration plants for each of the two principal oil-from-coal processes and for a shale-oil plant and refinery in Colorado. Research laboratories and pilot plants for the study of coal synthesis were established in Pennsylvania and West Virginia, and an oil shale experiment station was set up at Laramie, Wyoming. Extensive research work has been conducted at all these locations and considerable progress made in the development of basic synthetic processes. A research laboratory was also recently put in operation at Grand Forks, North Dakota, for the investigation of synthetic techniques and other problems connected with the utilization of lignite.

**Coal-to-oil syntheses**

Two coal-to-oil demonstration plants were constructed at Louisiana, Missouri, near St. Louis, and placed in operation in 1949. These plants employ two basically different processes for converting coal to liquid fuels: (1) the direct hydrogenation or Bergius process, and (2) the gas synthesis or modified Fischer-Tropsch process.

The hydrogenation plant, which represents a cost of about $10 million, is of 200-300 barrels per day capacity and employs pressures up to 10,000 pounds per square inch. Two major operations are involved in the hydrogenation process: (1) the liquid phase, which accomplishes liquefaction of the coal and the (2) vapor phase, which converts the liquid coal to gasoline, Diesel fuel, and various by-products. Numerous improvements over European practice were included in the design of the hydrogenation plant, which makes extensive use of automatic controls and devices for saving heat and securing greater thermal efficiency. The plant is being used for the processing of various types of coal, coal tars, and lignites and for testing the products. Shale oil is also said to be a potential raw material for this process which may prove to be the most practical method for recovering the oil in this material.

The gas synthesis plant, constructed at a cost of about $5 million, has a daily capacity of approximately 80-100 barrels of liquid products, principally gasoline, Diesel fuel, and heavy oil, with some propane. The operation consists of two principal stages: (1) the gasification of finely pulverized coal by its admixture with oxygen and superheated steam; (2) the conversion of the resulting gas, after purification, to liquid form by the basic hydrogenation process. Then follows product recovery by more or less conventional refining processes. The gas-synthesis plant also embodies extensive improvements over the German engineering procedures, notably in the considerably larger size and efficiency of the converting units.

**Oil from shale**

Substantial progress has also been made in the shale oil investigation. A site near Rifle, in northwestern Colorado, was selected as the location for the shale demonstration plants, as this area contains the richest and most extensive oil shale deposits in the United States. A highly mechanized mine or “underground quarry” was opened in the Mahogany Ledge, near the top of a plateau about 9,000 feet above sea level and roughly half a mile above the site of the demonstration plants, where the shale rock is crushed, retorted and refined.

Nearly 1½ tons of shale rock are required to produce one barrel of crude shale oil on the basis of an average content of 30 gallons per ton. Hence the cost of oil from shale will depend largely on the efficiency and economy of the mining operation. Highly successful results have been secured by the Bureau of Mines in the operation of the underground quarry, where an output of 148 tons per man-day for underground labor was attained in test runs extending over a three to four week period. Direct mining costs were brought below 30 cents per ton.1 These figures compare with an average output per man-day in bituminous coal mining in the United States in recent years of about 5½ tons in underground mines and between 15 and 16 tons in strip mines.

These mining results appear to justify the estimate of the Bureau that a regular commercial operation providing enough shale rock to supply an oil plant of 10,000 barrels per day capacity could attain a unit cost of mining, crushing, and conveying shale to the retort stock pile, of about 59 cents per ton. Compared with this low raw material cost, the average value, f.o.b. mine, of all bituminous coal produced in the United States in 1949 was close to $5 per ton.

In addition to operating a batch-process retorting plant at Rifle, the Bureau has shipped considerable quantities of shale (and shale oil also) to pilot plants operated by various oil companies and to other cooperating research organizations. A small refining unit has also been constructed in order to test the various methods of treating shale oil. While much work remains to be done, both by the Bureau and by private industry, to solve the technical and economic problems connected with recovering shale.

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oil and converting it into usable products, considerable progress has already been made. Results so far attained indicate that shale oil products may some day compete on an economic basis with the products of crude petroleum. This development is likely to be hastened by continuing technological progress in the treatment of shale and by the steadily increasing cost of discovering and developing new oil fields.

Underground gasification of coal

The Bureau of Mines is also conducting research and experimentation in the underground gasification of coal. Gas produced by burning unmined coal is a potential source of fuel for electric power generation and other industrial uses and may prove to be a practical method for utilizing coal veins too difficult or costly to mine. This procedure has been suggested, for example, as the most promising means of utilizing some of the badly faulted coal seams of western Washington, as well as the large subbituminous deposits in that area which are too low in grade to justify mining under present conditions of costs and markets, but which might supply a cheap gas for local industrial use.1

Underground gasification is also advocated by many persons who deplore the large economic wastes involved in conventional methods of mining and using coal. Costly processes are necessary in mining much of the coal produced from underground pits, lifting it to the surface, preparing it for use, and hauling it long distances to market, to say nothing of the inefficient methods of many users. It is urged that important savings could be realized if coal were burned in place underground and the resulting gas transported to consuming markets by pipeline.

In cooperation with private industry, the Bureau of Mines has made field-scale experiments in the Birmingham district of Alabama, designed to develop practical methods of recovering product gas from the controlled burning of coal in place. Successful results have been reported by the Russians in the underground gasification of coal in the Donets Basin, where investigation has been under way since 1933. More recently similar experiments have been launched in a number of other countries. The investigations of the Bureau of Mines are still in the early stages and considerable work remains to be done in order to secure complete combustion of the coal and recovery of the resulting gas. One of the principal problems is the low heating value of the gas resulting from dilution by the nitrogen present in the air used to supply the oxygen necessary for combustion. Use of oxygen instead of air as a combustion agent might avoid the troublesome nitrogen compounds and improve the heating value of the gas. Oxygen has been an expensive raw material but recent cost reductions resulting from mass production methods may make its use feasible in underground gasification.

Survey for location of synthetic plants

In conjunction with the Bureau of Mines, the Army Corps of Engineers is conducting a nation-wide survey to determine the general areas where necessary requirements can be met for the successful operation of synthetic fuel plants on a commercial scale. This involves not only the availability of raw material supplies at reasonable cost, but also adequate water supply, power and transportation facilities, etc. The objective is to catalogue the most promising locations for quickly setting up a large number of plants should an emergency make such a course necessary.

The importance of ample water supplies in synthetic fuel production is frequently overlooked. Especially large quantities of water are required in the coal hydrogenation process, where the tonnage of water necessary to supply the essential hydrogen is equal to or greater than the tonnage of coal consumed. This presents no problem, of course, in the Appalachian and mid-western coal regions where water supplies are ample but where the coals are generally of high rank and are advantageously used directly as fuel or for the manufacture of coke. In the western states, however, which have abundant supplies of low rank coal and lignite suitable for synthetic fuel production, water is scarce and might well be a limiting factor in establishing coal-to-oil plants.

Costs of Producing Synthetic Liquid Fuels

Satisfactory comparison of the relative costs of producing liquid fuels by the various synthetic processes, or comparison of synthetic costs with those of petroleum products made by conventional methods, is difficult because the synthetic techniques are still at a relatively early stage of development. Until these techniques have become more firmly established, cost estimates must be largely theoretical. A number of cost projections for synthetic products, consisting chiefly of engineering estimates based on pilot plant operations, have been published during the past few years, and more exact data may be expected to become available as a result of further experience gained at the Bureau of Mines demonstration plants and elsewhere.3

In brief, these estimates seem to indicate that liquid fuels can be produced from natural gas at considerably lower costs than from oil shale or coal. This is due both to the relatively low field price of natural gas in the surplus producing areas of the Southwest and to its lower processing costs as compared with coal or shale. In fact, it is probable that high octane gasoline can be produced synthetically from low-priced natural gas at a unit cost actually below that of gasoline made from some grades of crude petroleum, if only direct costs — raw materials and processing — are considered. The higher capital charges for depreciation and interest necessitated by the comparatively large plant investment required in the synthetic process would more than offset the advantage in direct costs, however. Hence it is unlikely that synthetic liquid fuels made from natural gas will be able to compete against petroleum products except in judiciously

1 L. A. Conradi, reference cited.

3 Most of the analysis of comparative costs contained in this section is based on a paper by George Roberts and Paul R. Schultz, “Production of Liquid Fuels from Coal and Oil Shale,” which appeared in The Oil and Gas Journal, September 15, 1945.
selected areas determined primarily by cheapness of locally produced raw material.

Even larger investments per unit of output would be required in processing facilities for the production of liquid fuels from oil shale and coal than from natural gas. This would involve correspondingly higher capital charges to cover depreciation and interest cost. The addition of these high investment charges to direct costs would result in total production costs for gasoline from coal or shale considerably above those for either the natural gas synthesis or for producing gasoline from even the least satisfactory grades of crude petroleum currently being used.

As between shale and coal, direct costs would probably not differ greatly, but the total operating investment— and capital charges—required for converting coal to liquid products would apparently run considerably higher than for shale. A recent estimate by the Bureau of Mines of the investment required for a coal hydrogenation plant to produce a daily output of 30,000 barrels per day of liquid products ranges from $243 million to $258 million, depending on the type of coal used. This would be equivalent to about $8,000 per barrel of daily capacity for overall production, or about $11,400 per barrel for gasoline alone.1

The Bureau has also estimated the investment cost of a 10,000 barrel shale oil installation, including mining and crude oil production as well as refining facilities, at $41 million. This would be equivalent to about $4,700 per barrel of daily capacity of finished products (8,840 barrels).2

Because of the remote location of the principal shale beds relative to eastern consuming markets, transport costs for moving shale oil to refining centers would probably limit its outlet for a considerable time to the western part of the United States. Synthetic fuel produced from Rocky Mountain coal would also incur a heavy transportation handicap over coals available in the eastern areas. These conditions seem to suggest a regional division of market areas that could be economically served by synthetic fuels based on shale and coal resources, respectively. Oil from shale apparently offers better economic possibilities for the future requirements of the Pacific Coast region than oil from coal.3

Abandonment of synthetic projects by private industry

It is perhaps significant that two of the apparently most promising projects for synthetic fuel production under private commercial auspices have been dropped within the past year or two. One of these was for natural gas synthesis, the other for coal gasification.

The natural gas project was planned by a large integrated midwestern oil company and was to be based on the dry gas reserves of the extensive Hugoton field in Kansas. In addition to a daily output of 6,000 to 7,000 barrels of gasoline, it was also planned to recover a wide variety of chemical by-products. Following several years of intensive laboratory research and careful analysis of comparative costs of synthetic and other fuels, the undertaking had reached the stage of actual construction when the whole plan was suddenly dropped. No reasons for abandoning the project have been disclosed, although it is suggested in industry circles that falling prices for petroleum products in 1948-49 may have been a factor in this decision.

The great expansion in recent years of pipe line facilities for long distance transmission of natural gas and its rapidly increasing use as domestic and industrial fuel have brought a significant increase in field prices in most natural gas producing areas. Should this trend continue, the economic feasibility of using gas as raw material for synthetic fuel will probably be still further limited.

The coal gasification project was a joint venture by a coal company and an eastern oil company, both leaders in their respective industries. A pilot plant near Pittsburgh was operated on an experimental basis for about a year and succeeded in developing a new method for converting coal into gas, either for use as such or as material for production of liquid fuel. The cost of obtaining synthetic gasoline by this process, however, was considerably higher than that of regular petroleum gasoline. Worsening labor relations and irregular production in the coal industry, in contrast with the improved outlook as to petroleum and natural gas supplies, were cited as a factor which made prospects for conversion of coal to liquid fuel much less attractive than when the project was first launched. Need for further basic research in alternative synthetic processes was also emphasized as a necessary preliminary to investment on a commercial scale.

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2 Bureau of Mines, R. I. 4652, Oil from Oil Shale, February 1950. An oil industry opinion rates these estimates as too low and places the capital investment required for producing gasoline from bituminous coal, for example, at close to $16,000 per barrel of daily capacity. See "When Do We Need a Synthetic Fuel Industry?"—a paper presented by A. L. Solliday, Executive Vice President, Stanolind Oil and Gas Company, at a meeting of the Petroleum Branch, American Institute of Mining and Metallurgical Engineers, San Antonio, Texas, October 6, 1949.