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THE CONDENSATION OF GASOLINE FROM NATURAL GAS

BY

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THE CONDENSATION OF GASOLINE FROM NATURAL GAS.

By GEORGE A. BURRELL, FRANK M. SEIBERT, and G. G. OBERFELL.

INTRODUCTION.

The Bureau of Mines is conducting a series of investigations with the common aim of minimizing the losses that occur in the mining and treatment of mineral substances. The results of the investigations are being published in reports of the bureau. This report treats of a method of preventing some of the waste of the natural gas incidental to oil mining. This method, the condensation of gasoline from natural gas, offers to the oil operator and others a profitable means of utilizing some of the oil-well gas now being wasted. The most desired constituent of crude oil is obtained, the production of oil is not hindered, and the gas, after the extraction of gasoline, can be returned to the leased area to drive pumps or into pipe lines for uses to which natural gas is ordinarily put, usually with its fuel value lessened only in slight degree.

Publications already issued [a] briefly discuss the subject. In this report the work is treated in greater detail, and the results of many additional tests are shown.

GENERAL STATEMENT REGARDING WASTES OF NATURAL GAS.

Arnold and Clapp [b] classify as follows the various ways in which natural gas is wasted:

(*a*) In drilling and casing wells.
(*b*) From high-pressure wells.
(*c*) In oil production.
(*d*) Through lack of proper care of wells.
(*e*) In transportation.
(*f*) In utilization.
(*g*) Through improper plugging of wells.

This report concerns itself with method *c*, the waste incident to oil production.

A. B. Macbeth, chairman of a committee on conservation appointed by the Natural-Gas Association of America, presented at the annual

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[a] Allen, I. C., and Burrell, G. A., Liquefied products from natural gas; their properties and uses: Technical Paper 10, Bureau of Mines, 1912, 23 pp.; Burrell, G. A., and Seibert, F. M., The sampling and examination of mine gases and natural gas: Bull. 42, Bureau of Mines, 1913, 116 pp.

[b] Arnold, Ralph, and Clapp, F. G., Wastes in the production and utilization of natural gas and means for their prevention: Technical Paper 38, Bureau of Mines, 1913, 29 pp.

meeting of the association in Cleveland, Ohio, in May, 1913, a report [a] covering in brief different phases of the subject of the waste of natural gas. Following is an extract from that report, which defines the position of oil operators as regards waste in a new field:

Where oil and gas are found in the same field, it is the general practice to blow off the gas. In some fields where the rock pressure is low and the production of both oil and gas is small, some operators are able to produce and market both oil and gas from the same sand. In large operations no practicable way is found of obtaining the oil without wasting the gas, and this is the principal cause of the depletion of many gas fields, and is responsible for a greater waste of gas than all other causes put together. It is natural for the owners of a well to want to produce and sell the well's full production, whether oil or gas, in the shortest possible time, but it is impossible to market gas in the way oil is marketed, for gas can not be stored like oil. The committee saw no way of saving the gas from these wells without seriously affecting the oil production.

Arnold and Clapp,[b] Arnold and Garfias,[c] and Blatchley [d] also discuss various means of preventing the waste of natural gas. They briefly mention the production of gasoline from gas. Arnold and Clapp [e] state that at some wells the value of the recoverable gasoline in the gas is worth as much as 20 per cent of the oil produced,and that it is not extravagant to estimate the loss in gasoline, at 10 per cent of the oil produced, or, up to 1912, a clear loss of $4,000,000.

OCCURRENCE OF GAS AND OIL.

Gas may be found in a sand and separate from oil. It may be found in more than one sand separate from the oil, or the gas sand may be just above and in contact with the oil sand. A given sand may produce oil and gas in one place and in another part of a territory gas only.

Gas may come from the same sand as the oil itself. It is this manner of occurrence of gas and oil that the authors desire to emphasize, for under these conditions the gas is frequently mixed with enough of the gasoline constitutents of the oil to warrant the erection of a plant for the purpose of condensing the gasoline.

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[a] Report of committee on the conservation of natural gas: Proc. eighth ann. meet. Natural-Gas Assn. Am., vol. 6, 1913, p. 240.

[b] Arnold, Ralph, and Clapp, F. G., Wastes in the production and utilization of natural gas, and means for their prevention: Technical Paper 38, Bureau of Mines, 1913, 29 pp.

[c] Arnold, Ralph, and Garfias, V. R., The prevention of waste of oil and gas from flowing wells in California, with a discussion of special methods used by J. A. Pollard: Technical Paper 42, Bureau of Mines, 1913, 15 pp., 2 pls., 4 figs.

[d] Blatchley, R. S., Waste of oil and gas in the Mid-Continent fields: Technical Paper 45, Bureau of Mines, 1914, 57 pp.

[e] Arnold, Ralph, and Clapp, F. G., op. cit., p. 11.

The gas usually finds its way to the atmosphere through the space between the casing of the well and the tubing inserted for the removal of the oil. This gas is the so-called "casing-head gas." At the beginning of an oil flow when the flow is natural, a large quantity of gas escapes to the air through the same tubing as the oil. Where the gas finds its exit to the atmosphere apart from the oil at the casing head it is a simple matter to make pipe connections between the casing head and any desired point where the gas is to be utilized. This is frequently done when the supply of casing-head gas is sufficient to warrant its utilization, but frequently, when the supply exceeds the small demands of the lease, the excess is wasted.

When a well is first drilled, the quantity of gas escaping with the oil from the tubing is frequently enormous, being 10,000,000 to 15,000,000 feet or more at times. This gas is wasted. The flow in time diminishes.

When gas comes with the oil in the flow pipe, the two are often separated by means of a gas trap. The oil, entering the top of a drum, settles to the bottom and is withdrawn, and the gas flows off at the top. Many of the plants in California utilize gas that flows with the oil for condensing gasoline. One gasoline plant in the Cushing field, Okla., also uses trap gas. A new type of trap for saving gas from gushers and separating the gasoline is described at the end of this report (p. 99).

Oil wells that have passed the flowing stage and are being pumped may still continue to give off much gas at the casing head. The quantity may vary from little or nothing at some wells to 500,000 cubic feet or more at others. When enough of the gas is available, it is used for pumping on the lease, the excess being wasted. A steam pumping engine of 50 horsepower requires about 25,000 cubic feet of gas for 10 hours' operation. From 12 to 15 cubic feet of natural gas is needed per horsepower-hour for gas engines that are used on leases for pumping oil wells. If there is not enough of the gas available for working pumps, it is all allowed to go to waste, or perhaps some is used for heating and lighting a few scattered houses on the lease.

The efficient utilization of the wasting casing-head gas ordinarily is a difficult problem. The many miles of pipe that would have to be laid to transport it from a field would usually be an unwarranted expense. However, some towns, among which may be mentioned Warren, Pa., and Sisterville, W. Va., are lighted and heated largely with casing-head gas.

In general, however, the oil man considers casing-head gas as waste gas and its escape necessary in oil-well operations, to permit the maximum flow of oil into the well from the surrounding strata.

Huntley[a] discusses the free escape of gas as one of the causes of the decline of oil fields, the action being somewhat as follows:

(1) Excessive refrigeration due to the free expansion of large quantities of gas forms waxy sediments in the productive stratum and in the tubing of the well. This sediment obstructs the passage of the oil from the sand.

(2) The gas in the immediate vicinity of the well dissipates itself in the initial flow, and the oil production therefore falls off, owing to a lessening of the expulsive force.

The rapid exhaustion of the gas in a certain part of the field may remove the only influence retarding the encroachment of water, which may, by a flanking movement, cut off a large section of the producing area; or water may exist in the lower part of the oil sand, being held in check only by the rock pressure of the gas. If each cubic foot of gas were retained to perform its work of expelling petroleum the pressure would help to retard the water for a considerable period, or until the maximum amount of oil could be recovered. Huntley[b] cites the Hogshooter pool in Oklahoma as an example of a producing gas district that was ruined by having its gas drained too rapidly. Wells were constantly drawn upon to their utmost capacity; hence as no pressure restrained the water under high pressure in the lower part of the productive formation the water flooded one well after another.

FACTORS AFFECTING FLOW OF GAS AND OIL IN DIFFERENT SECTIONS OF THE SAME FIELD OR IN NEIGHBORING WELLS.

The concern of the operator of a plant for making gasoline of natural gas covers all phases of the industry from the occurrence of gas and oil in the well to the final disposal of the gasoline. Hence, in the following pages, is given a brief summary of some of the views that are held regarding the factors that affect the occurrence of gas and oil underground. These views are fully discussed in reports of the United States Geological Survey.

The operator is frequently puzzled to know why wells in one part of a field are more productive than are others in the same field, or why adjoining wells or wells on the same lease, are so erratic as regards output. Another question that may occur to him is why a particular field is productive and an adjoining territory nonproductive. Many observations have shown that the strata yielding oil and gas are practically identical, the gas usually accumulating in the domes of the arches in the strata or in other elevated parts of the deposits. Gas almost invariably accompanies oil where conditions favor its accumulation, but oil is frequently found almost unaccom-

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[a] Huntley, L. G., Possible causes of the decline of oil wells and suggested methods of prolonging yield: Technical Paper 51, Bureau of Mines, 1913, pp. 6–7.

[b] Huntley, L. G., op. cit., p. 7.

panied by gas on account of the collection of the gas in the highest portions of the strata or because of its escape through imperfections of the covering layers. Brine almost universally accompanies the oil and gas.

In addition to possessing a porous structure for holding the oil or gaseous contents, the reservoir rock must be entirely covered with an impervious layer, the commonest and most perfect cover being a fine-grained shale, whose imperviousness and freedom from fracture enables the "sand" to retain the gas or oil. Gas, oil, and water are frequently found distributed according to their specific gravities, gas disengaging itself from the fluid and rising to the highest point in the beds, and water displacing the oil and finding a resting place as low down as possible. When oil and gas strata are comparatively little undisturbed, each well usually draws its supplies from a considerable area; indeed, the owners of wells in the United States are usually compelled to continue to raise oil, without regard to the conditions of market, to prevent its being obtained by neighboring leaseholders. On the other hand, faults and dislocations of strata may limit the area over which a single well draws its supplies, and so impede the free passage of the fluid that the pressure is small. It is now generally admitted that the pressures in wells are entirely due to accumulations of gaseous hydrocarbons, chiefly methane, which were formed with the liquid hydrocarbons and exist in a highly compressed condition and dissolved in the petroleum or accumulated in the beds immediately overlying the oil stratum. Where the gas has been allowed to escape freely, petroleum rarely flows from a well, and never, perhaps, unless left for a long time, rises to the surface unaided.

Discrepancy in production may in some cases be attributed to local variations of the reservoir rock, but Arnold and Garfias [a] state that an abnormally low production of oil can be traced to one or more of the following causes: Inefficient management; improperly finished well; poor condition of casing; failure to perforate casing, or inadequate size and number of perforations; obstruction of the bore-hole by tools or fragments of débris; failure to exclude water, which sometimes results in the inrush of sand; effect of neighboring wells; and drawing on a secondary sand only. Some of these causes affect the yield of gas also. Arnold and Garfias [b] add that although at some wells conditions can not be remedied, and at others the expense incurred would not be compensated by the added production, nevertheless, in most instances, an intelligent study of the trouble and its sources will disclose some comparatively simple means of improving conditions so as to increase the total yield.

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[a] Arnold, Ralph, and Garfias, V. R., Methods of oil recovery in California: Technical Paper 70, Bureau of Mines, 1914, p. 9.

[b] Arnold, Ralph, and Garfias, V. R., idem.

EFFECT OF DRILLING NEIGHBORING WELLS.

Regarding underground connection between neighboring wells Huntley [a] has the following to say:

> The first well drilled in a group will tend to set up drainage channels and divert large quantities of oil from a considerable area. Subsequent wells come in as much smaller producers than the original well. Again, in loose unconsolidated sands, such as are found in the Caddo field in Louisiana, and in the famous Glenn pool, in Oklahoma, if a well stops pumping for a day, the surrounding wells extend their own channels, breaking down the drainage systems of the first well, to the extent that it is often difficult to again recover oil from the well that has stopped pumping. As a result the wells in the Glenn pool are pumped 24 hours a day, 365 days in a year. The condition of the sand in the Glenn pool was brought about somewhat artificially by the use of enormous quantities of nitroglycerin in shooting. The sand, originally coarse and porous, has probably been shattered throughout the entire producing area.
>
> In certain lenticular formations, described by the oil man as "spotty," of two wells drilled only 150 feet apart, one has been a large producer and the other a dry hole. This discrepancy may be due to drainage conditions or may be caused by an intervening hard spot in the oil sand. If it is caused by drainage conditions, the stopping of the producing well would probably cause the other to produce. Again, wells 1,000 to 2,000 feet apart are in places so closely connected underground that the muddy water used in drilling one well has been pumped out by another well a considerable distance away, not necessarily the well nearest to the one being drilled.

Huntley [b] further states that in a tight sand neighboring wells do not affect each other to the same degree as in a very porous stratum; that is, such pronounced drainage channels toward the wells first drilled are not formed.

EFFECT OF FORMATION OF WAXY SEDIMENT.

Most of the plants for making gasoline from natural gas draw the gas from old wells, many of which are very small producers of oil. Hence many of them have not received much attention as regards upkeep. One result of this inattention is the formation of waxy sediment or paraffin. Regarding the formation of this waxy sediment Huntley [c] comments as follows:

> Petroleum in the so-called paraffin-oil fuels consists of hydrocarbons of the paraffin series, which range from the heaviest oil to the lightest gas. The gaseous constituents of petroleum exist in what may be likened to solution, much like the gas of soda water, and as such expand and escape when the pressure is relieved by a well. The sudden expansion and volatilization of such light hydrocarbons has a refrigerating effect, like the expansion of ammonia gas in an ice machine, chilling the remainder of the liquid petroleum and causing the separation of the heaviest paraffin as a waxy sediment. * * * This, * * * along with water and fine rock sediments, clogs the pores of the sand and obstructs the passage of the oil into the well.

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[a] Huntley, L. G., Possible causes of the decline of oil wells and suggested methods of prolonging yield Technical Paper 51, Bureau of Mines, 1913, pp. 23-24.

[b] Huntley, L. G., op. cit., p. 22.

[c] Huntley, L. G., op. cit., p. 6.

HISTORY OF THE MAKING OF GASOLINE FROM NATURAL GAS.

That gasoline can be extracted from natural gas has long been known, ever since oil and gas have been noticed in some gas pipe lines, but the production of gasoline from natural gas has only within the past few years become of commercial consequence, owing principally to the ever-increasing demand for gasoline.

TWO SUCCESSFUL PLANTS IN 1904.

A. Fasenmeyer made gasoline from the gas of oil wells near Titusville, Pa., in the fall of 1904. His plant is almost within sight of the old Drake well. His first equipment was crude. The gas from the wells after passing through the gas pumps was cooled by means of a coil of pipe placed in a tank of water. The condensate produced was allowed to drip into a wooden barrel. The losses resulting from evaporation were large. The product when first collected had a gravity of 80° to 90° on the Baumé scale. His production the first year was approximately 4,000 gallons, for which he received 10 cents per gallon. Tompsett Bros., of Tidioute, Pa., claim to have preceded Fasenmeyer in the making of a commercial venture out of the process. They are operating successfully at the present time.

As these ventures proved a commercial success attention was turned to the designing of better plant equipment. Gas and oil operators in other oil fields in the United States proceeded to install gasoline plants.

EARLY METHODS.

At first common gas pumps, with pressures not exceeding 50 pounds per square inch, were used. Condensation was effected by running a pipe through the earth to the gasoline receivers. Mr. William Richards, of Warren, Pa., claims to have been the first to install high-pressure compressors. His first experiments, made in 1905, were with pressures of 400 pounds per square inch. Later he came to the conclusion that a pressure of 250 pounds per square inch was sufficient to make gasoline that was about right for shipping. Mr. Richards's plant was located at Mayburg, Pa.

In the first plants for making gasoline from natural gas the cooling system consisted in general of a series of pipes. In some plants the

LATER IMPROVEMENTS.

The next step in the industry was to pass the gases from collecting tanks from the single-stage compressor through a higher-stage compressor. The gases were again cooled. In this manner a second and more volatile product was obtained, which was mixed with the product from the first-stage compressor. This mixture was again "weathered" and then marketed. F. P. Peterson, while connected with a gas-engine company in Grove City, Pa., claims to be the first to use the two-stage compressor method. As producers realized the great waste involved in this process, another improvement was introduced, as follows:

The condensate produced from both stages of compression and cooling, which had a gravity of 80° to 100° B., was mixed with refinery napthas until the specific gravity had been lowered to 60° to 76° B. By this means there was obtained a product that evaporated more slowly than did the condensate. The process of blending is more fully discussed elsewhere in this report.

The waste gases, after the gasoline had been extracted, were in part used for plant operation, and, in some plants, the remainder was returned to gas mains which supplied towns with gas for lighting and manufacturing purposes. In most plants the waste gases were allowed to escape into the atmosphere. At present much information is at hand as the result of the experimental work done, so that plants are now installed to meet particular requirements. The advisability of employing single or double stage compressors, the pressures to be used, the method of handling and disposing of the condensate, and the disposition of the waste gases are all considered.

PATENTS ISSUED.

Chute [a] gives the various patents that have been taken out covering the condensation of the hydrocarbons in natural gas, as follows:

In 1866 Johnson received patent No. 54910 which clearly discloses the art of rendering liquid the vapors that rise with or are forced up with petroleum.

In the Heinzerling patent of 1897, No. 575714, which expired January 28, 1914, there is shown an air-compressor or gas-comcooled by the residual gas, which is in the meantime expanded in the second cylinder, thus aiding the compression. The expansion produces cold gas which afterwards, circulating through the last condensers, cools the compressed gas to a point stated to be between −25° and −40° C. (−13° to −40° F.). The first water cooling is stated to refrigerate the gas to 10° C. (50° F.).

Among the earlier unexpired patents is No. 668197 of 1901, issued to Seceur, which claims a process of liquefying methane from natural gas.

In 1907 patent No. 867505 was granted to Dennis Hastings and W. Brink. It discloses that natural gas, after having been artificially compressed, is brought into contact with water which serves to cool the gas; later water or oil is atomized to intermingle with the gas to cool it. The claims are for an arrangement of apparatus.

In 1909, John L. Gray obtained patent No. 993976, for certain apparatus for obtaining gasoline from the casing-head gas. The claims are for an organization of apparatus for separating, first, any engine or cylinder oil from the gas by means of the ordinary steam trap or oil trap used on steam lines, a condenser with another oil trap beyond, and a relief valve which is an ordinary steam safety valve. There is also a pot steam trap to separate the condensed gasoline from the gas, and a receiving tank.

Chute[a] states that in the processes now in successful use the essential steps have been covered by expired patents.

Patents covering the separation of the light paraffin hydrocarbons in natural gas are described in the appendix at the end of this report.

PRODUCTION OF GASOLINE FROM NATURAL GAS IN THE EASTERN PART OF THE UNITED STATES.

In the Appalachian oil fields the utilization of casing-head gas for making gasoline is more extensive than in the Mid-Continent or California fields. The industry had its commercial inception in Pennsylvania and West Virginia. East of the Mississippi River the approximate number of plants in commercial operation was about 253 in July, 1913. The plants were distributed among the various States about as follows: New York, 1; Pennsylvania, 100; West Virginia, 100; Ohio, 47; Illinois, 5. The industry in these States is firmly established, and new plants are being built even in places where many thought that installations would not be placed.

THE GASOLINE INDUSTRY IN WEST VIRGINIA.

The industry of making gasoline from natural gas has made fairly rapid progress in West Virginia in the past few years. In that State gasoline was first made from natural gas in 1905. There were

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[a] Chute, H. O., op. cit., p. 148.

in July, 1913, about 100 plants in the State. The production from 10 plants exceeded 500 gallons per day and from 5 exceeded 1,000 gallons per day. The production of the remaining plants ranged from a few gallons up to 500 gallons per day. The number of wells connected to each plant varies from 1 or 2 up to 100, with an average of about 15 to 20. Of the total number of oil wells in the State, about 1,500 are utilized for gasoline production. The production is confined almost exclusively to 12 counties—Brooke, Calhoun, Hancock, Harrison, Marion, Marshall, Pleasant, Richie, Tyler, Wetzel, Wirt, and Wood. The total production for 1913 was 7,662,493 gallons.[a] Hill[b] states that in 1912 there was produced 5,318,136 gallons.

Tyler and Pleasant Counties produce about 75 per cent of the total quantity of gasoline produced in the State. In Tyler County are five productive oil sands. The gas utilized for gasoline production accompanies the oil in the Big Injun sand. In Pleasant County the gas utilized is chiefly from oil wells tapping sands in the Berea grit. This sand lies below the Big Injun. The wells from which the natural gas is derived in these fields are from a few years to 20 years old, some of the first wells drilled still producing vapors of the heavy hydrocarbons. The highest pressures utilized for making gasoline in West Virginia are about 150 pounds per square inch, none being over 250 pounds. Two plants at Follansbee, W. Va., use the pressure last mentioned.

Of about 14,000 producing oil wells in the State approximately 1,500 are utilized for gasoline production. Day[c] gives 13,014 as the number of producing oil wells in the State at the end of the year 1911. This was an increase of 279 wells over the year 1910. At the present time the authors estimate that there are 14,000 wells in the State. This estimate is based only on what seems to be a reasonable increase in two years' time over the production for 1911 as given by the Geological Survey. The rate of increase in production for the two years 1912 and 1913 is greater than during the preceding two years largely because the price of petroleum increased decidedly for a time.

THE INDUSTRY IN PENNSYLVANIA.

The industry in Pennsylvania during 1912 and 1913 has made rapid progress. At the close of 1913 there were nearly 100 plants in successful operation. The industry is confined almost entirely to the counties of Butler, Forest, McKean, and Warren.

Most of the plants are rather small, few producing 500 gallons per day. The average plant produces only about 200 gallons per day. The number of wells used for making gasoline is 1,100 or 1,200.

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[a] Hill, B., Natural gas: Mineral Resources U. S. for 1913, U. S. Geol. Survey, 1914, p. 1481.
[b] Hill, B., Natural gas: Mineral Resources U. S. for 1911, U. S. Geol. Survey, 1912, p. 348.
[c] Day, D. T., Petroleum: Mineral Resources U. S. for 1911, U. S. Geol. Survey, 1912, p. 351.

There were in 1913 about 56,000 producing oil wells in the State. Day[a] gives 52,545 as the total number of producing wells in the State for 1911. The increase for the year 1912 was 1,645 wells and for 1913 was 2,065 wells.

The output of gasoline for the year 1913 was 3,680,096 gallons.[b] The production for 1912 was 2,041,109 gallons.[c] The drawback to development in the northern counties lies in the lack of satisfactory transportation facilities. Most of the gasoline is hauled in tank wagons to the refineries where it is blended with naphtha. Some producers are forced to haul their product as far as 15 miles in tanks. When better facilities shall have been provided for transportation, thereby cutting down considerably the cost of production, there will be a wider expansion in these oil fields. Less than 2 per cent of the producing oil wells are utilized for the production of gasoline, as against 10 per cent in West Virginia.

The gases available in the Bradford County and the Warren County fields are from the third oil sand. The gases from most of the wells issue under a few pounds pressure. A small area around Tidioute, Pa., produces a gas consisting almost entirely of the vapors of the liquid hydrocarbons. These vapors are drawn out under a reduced pressure of 20 inches (12 pounds) of mercury. In no other field, to the authors' knowledge, are such "wet" gases encountered. The vapors after passing the vacuum pumps are simply cooled by means of running water. They are not compressed.

THE INDUSTRY IN CALIFORNIA.

PRODUCTION IN 1912.

Hill[d] states that the gasoline produced in California in 1913 was 3,460,747 gallons, valued at $405,186.

Gilmore[e] specifies the following production for California:

Company and field.	Gallons per day.
Puente Oil Co., Puente field	450
Pacific Gasoline Co., Brea Canyon, two plants	4, 000
Union Oil Co., Santa Maria field	1, 000
Standard Oil Co., Newhall field	450
American Gasoline Co., Santa Maria field	1, 400
Purity Gasoline Co., Santa Maria field, two plants	1, 700
Pinel Dome, Santa Maria field, two plants	3, 500
Frank Hall, Santa Maria field	500
Olinda Gasoline Co., Olinda field	1, 000
Hurley-Smith-Collins Co., Oleo field	2, 500
A. F. Gilmore, Salt Lake field	450
Total	16, 950

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[a] Day, D. T., Petroleum: Mineral Resources U. S. for 1911, U. S. Geol. Survey, 1912, p. 351.

[b] Hill B., Natural gas: Mineral Resources U. S. for 1913, U. S. Geol. Survey, 1914, p. 1480.

[c] Hill, B., loc cit.

[d] Hill, B., loc. cit.

[e] Gilmore Frank, Gasoline in California: Oil and Gas Jour., vol. 12, Oct. 9, 1913, p. 30.

NOTEWORTHY INTEREST IN THE INDUSTRY.

Gilmore[a] says further, regarding the gasoline industry in California.

> In the manufacture of this much-needed commodity [gasoline] more interest has been shown during the past year than in oil. Many experiments have been made and every theory brought forth and worked upon to bring out the greatest percentage possible in extracting the motor fuel from crude oil and gas. Refrigerating and freezing processes have worked overtime and enthusiastic estimates of the possibilities likely to be attained have been published, leading to the belief that the very air around an oil well would be converted into liquid, but from general observations made in the field most of these experiments are still in their incipiency. It has been demonstrated that low-gravity oil and its gas do not contain proportions of gasoline equal to those of the higher grade, and every effort to bring out and increase the percentage has been a failure. It is contended that the gas found in the Olinda field and worked out through the refrigerating process contains a larger percentage than could be given by the compressor method. This is a matter of theory alone. The "plant" so far has not proved its efficiency over the latter method and has fallen far short of expectations. They are making about 1,000 gallons per day. The same results and possibly better would have been obtained with the compressor system. They claim, however, that if the results are no larger the running expenses are considerably less.
>
> In the Santa Maria field, where the gravity of the oil runs above 30° B., gasoline of the best gravity is manufactured from casing-head gas. The field is noted for its large amount of escaping gas, and during the past two years a number of plants have been installed. Each of these up to the present time has shown an increase rather than a decrease in output, and what is more the operation of these "plants" has shown a tendency to increase the amount of production in the wells from which the gas is taken, the result of the vacuum caused in draining out the gas.
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> **MARKETING THE PRODUCT.**
>
> Nearly all of the production of casing-head gasoline is marketed in southern California. The coast towns, such as Santa Barbara, Santa Maria, and Ventura, get a liberal supply from the Santa Maria field. The Pinel-Dome people ship their product here and market from tank wagons; the Purity gasoline is shipped to a distributing station here and is marketed in the city and through adjoining towns and cities. The Union Oil Co. markets the product of the Pacific Co. and its own.
>
> Investigations made prove that where the gravity is not lowered below 62° or 64° B. there is no perceptible difference between this article and that manufactured from crude oil. Wherever an inferior grade is placed on the market it is in every instance the result of reducing below the commercial grade by the application of too large a percentage of distillate, and this may happen to all grades. This is frequently the result of low prices being advertised, and until methods are adopted that will call for an inspector and impose a penalty for selling anything below a given specific gravity these dishonest methods will probably continue. These adulterations are brought about by the retailers, and not by the manufacturers, it is claimed.

Regarding immediate future developments Mr. Gilmore, in a letter to the authors, states that "the Union Oil Co. expected to extract with a new installation about 8,000 gallons per day from 8,000,000 cubic feet of gas, and a new plant owned by A. F. Gilmore is expected to add another 1,000 gallons per day, making a total of 25,450 gallons per day "

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[a] Gilmore, Frank, Gasoline in California: Oil and Gas Jour., vol. 12, Oct. 9, 1913, p. 30.

DISTRIBUTION OF PLANTS.

Laney [a] writes as follows regarding the production of gasoline in California.

> The coast-range mountains divide the State into two great groups known as the coast fields and the interior or valley fields. In the former group are the Santa Maria Ventura, Newhall, Salt Lake, and Fullerton-Whittier, while the Coalinga, Lost Hills, McKittrick, Kern River, Sunset, and Midway fields comprise the latter group. The valley fields have but one gasoline plant and that inoperative, while every field in the former group has one or more plants either in the course of construction or having been in actual operation for a year or more. And this in spite of the fact that production of both gas and oil in the valley fields is many times greater than that from the fields to the west of the mountains. That not all the gas is suitable for gasoline production is true, but it will undoubtedly be found when a thorough examination is made of these gases that the volume carrying considerable gasoline costituents is as great if not greater than in all the rest of the State taken together. The total number of gasoline plants in these fields is, at the present writing, 16, having a capacity in excess of 24,000,000 cubic feet of gas and producing upwards of 25,000 gallons of this valuable commodity daily.

METHODS EMPLOYED.

> In general the methods employed in recovering the condensible fraction from the gases in these fields are similar to those used elsewhere in the country, the variations being due to differences in local conditions. A great deal of the gas worked is obtained from flowing wells in combination with the oil and is separated in gas traps, being lead-line rather than casing-head gas. Naturally this gas is often far from clean, and in some cases leaves the trap at high temperatures (100° to 120° F.—38° to 49° C.), and it has been found necessary to use some form of precooling to lower the temperature before leading the gas to the machine, and in many cases scrubbers have been employed in order to remove the heavier distillates and any foreign matter that might work harm to the compressor cylinders and valves.
>
> The pressures used run generally from 210 to 250 pounds per square inch, with the exception of one plant using an ammonia refrigerating system where the product is obtained at 40 pounds pressure. There is one plant using three-stage compression; the majority use two-stage, but since their final pressures are 250 pounds the only apparent advantage of this variation is that they get one more cut in their product, and this advantage disappears when, as is done in most cases, the different cuts are all run into one stock tank and allowed to blend.
>
> The problem of final cooling of the compressed gas has been approached in a variety of ways, chief among which are, first, by allowing the compressed gas to expand through a controlling valve or an orifice around the pipe containing the incoming compressed gas; second, by means of an ammonia refrigerating plant, auxiliary to the main plant; and third, by expanding the compressed gas through a power cylinder and using the power thus made available for any one of a variety of purposes around the plant, such as redistributing the residue gas over the lease, assisting in the operation of the main compressor or operating another low-pressure compressor cylinder in parallel with that of the main machine. This third method seems to be by far the most practical, where low temperatures are desirable, for not only can as low or lower temperatures be obtained by this method as by either of the other methods, but a part of the power expended in the main engines in compressing the gas is here recovered and put to some useful purpose. The principal difficulties so far encoun-

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[a] The production of natural gasoline in California. The Bessemer Monthly, December, 1913, p. 1.

tered in dealing with the extremely low temperature obtained in this expanding cylinder, frequently as low as −50° to −60° F. (−46° to −51° C.), have been those of lubrication and obstruction due to congealed moisture. The former can usually be overcome by using a good grade of low-temperature oil and by exercising care in so feeding this oil to the cylinder and valves that it is applied directly to the surfaces in contact. The problem of removing all moisture from the gas before allowing it to enter the expanding cylinder is not, in all cases, so simple as would appear, for in spite of the fact that the temperature of this gas before expansion is several degrees below the freezing point of water, a certain amount of moisture sometimes persists in spite of all efforts to trap it out and later freezes either in the expanding cylinder or, as is more frequently the case, in the double cooling coils, necessitating the application of heat from time to time to thaw them in order that the operation may continue. To eliminate the possibility of shutdowns from this cause it has been found necessary in some cases to install double coils in duplicate, so that one half may be shut down for thawing without seriously disturbing the operation of the plant. A little warm high-pressure gas led to these coils has proved a very simple and convenient means of removing this accumulation of frost.

DETAILS OF EQUIPMENT.

With lower temperatures has come a recognition of the value and importance of thorough insulation of all piping through which this low-temperature gas is handled. This insulation is usually accomplished by boxing the coils and packing with dry sawdust, while all other piping is covered with a good grade of molded cork insulation. The finer details of construction and operation such as this were neglected during the earlier attempts at the recovery of gasoline, but their importance is now being fully recognized, and in the most up-to-date plants all condensing equipment following the water-cooling coils is housed and the piping carefully insulated.

The value of automatic traps, for handling the gasoline from the accumulators as fast as it is condensed, in order to eliminate as far as possible the solution of compressed gas in the product, is rapidly being appreciated, and at many plants the vapor tensions and evaporation losses have been materially reduced by the adoption of these simple devices.

IMPORTANCE OF WATER SUPPLY.

Another obstacle that the California operators have had to overcome is the difficulty of obtaining water in sufficient quantities and of such temperature as is necessary for cooling purposes. Water must be carefully conserved, for most of it is brought from some outside source and water bills form no small item in the operating expenses of a plant. This conservation has been accomplished by using the same water over and over again, pumping it through cooling towers and reducing its temperature by evaporation before leading it again over the cooling coils and through cylinder jackets. Only enough new water is added from time to time to make up for evaporation losses and those due to unavoidable leaks.

SPECIFIC GRAVITY AND PRICE OF PRODUCT.

The gravity of the product obtained varies greatly, running as low in some cases as 67° B., while in others it varies between 85° and 90° B., this gravity being the blend of all the cuts from any one plant.

The price obtained for the unblended product ran in the neighborhood of 10 cents at the plant, but some of the larger operators are doing their own blending, and marketing a resulting product at 62° B. that brings them from 15 to 17 cents, thus realizing the maximum return from the production of their plants.

THE INDUSTRY IN THE MID-CONTINENT FIELD.

DETAILS OF PRODUCTION.

In the Mid-Continent field the first plant was installed in 1909 by D. W. Franchot at Kiefer, Okla. At the close of the year 1911 there were 7 plants in operation, making about 2,000 gallons of gasoline daily. In June, 1913, there were 23 plants. Table 1, following, shows the location of some of the plants in the Mid-Continent field on June 1, 1913, the quantity of gas used, the number of wells used, the number of compressor units, the reduced pressure to which gas is subjected when drawn from the wells, the compression to which the gas is subjected in the compressors, the quantity of gasoline produced, the gravity of condensate in the accumulator tank, the purpose for which the condensate is used, the value of the plant, and the quantity of the gasoline sold. Complete returns were not obtained.

TABLE 1.—*Details of production of gasoline from natural gas in the Mid-Continent field in June, 1913.*

Location of plant.	Number of plant.	Quantity of gas used.	Number of wells connected to plant.	Number of compression units comprising plant.	Reduced pressure to which gas is subjected.	Compression to which gas is subjected.	Gravity of gasoline in accumulator.	Purpose for which gasoline is used.	Value of plant equipment.	Quantity of gasoline sold per month.
		Cubic feet per 24 hours.			*Inches of mercury.*	*Pounds per square inch.*	*°B.*			*Gallons.*
Cushing, Okla...	1	250,000	5	1	....	40 to 300	86	Gasoline gas.	....	....
Alluweo, Okla...	2	375,000	260	2	....	Up to 300	89	Blending.	$30,000	33,000
Coalton, Okla...	3	125,000	38	1	0 to 20	Up to 350	....	...do.....	....	8,000
Kiefer, Okla., Glenn pool.	4	300,000	......	1	0 to 20	Up to 300	....	...do.....	17,000	....
Do........	5	800,000	......	4	0 to 15	25 to 50 and 275 to 350	76 to 98	...do.....	24,000	50,000
Delaware, Okla .	6	250,000	......	1	....	50 to 250	100	...do.....	40,000	45,000
Kiefer, Okla.....	7	40,000	10	......	....	30 to 40 and 300	80	...do.....	6,000	4,000
Near Muskogee, Okla.	8	40,000	5	1	16	50 to 55 and 250 to 300	100	...do.....	11,000	3,000
Do........	9	70,000	......	1	25	40 and 250	88	...do.....	5,500	4,500
Near Kiefer, Okla., Glenn pool, No. 1 plant.	10	250,000	36	1	0 to 20	30 to 40 and 175 to 300	98	...do.....	11,000	3,700
Near Muskogee, Okla., plant No. 6.	11	200,000	11	1	0 to 20	30 to 40 and 175 to 300	94	...do.....	10,000	19,000
Near Kiefer, Okla., Glenn pool.	12	150,000	9	1	....	30 and 250	87	...do.....	12,000	18,000
Near Kiefer, Okla.	13	170,000	......	1	....	30 and 300	78	...do.....	10,000	10,000

QUANTITY AND VALUE OF CONDENSATE.

These plants, with others in Oklahoma not listed in the foregoing table, produced about 350,000 gallons of natural-gas condensate during April. The value of the condensate is estimated at $35,000, about 500 wells being utilized. At the close of May, 1913, there were in Oklahoma 25,612 producing oil wells, making about 4,000,000 barrels of oil, worth $3,520,000, at 88 cents a barrel, the price then prevailing. If the average percentage of gasoline obtainable from Oklahoma crude oil by refining is estimated to be 14, then 23,520,000 gallons of gasoline could be produced, which, at the rate of 15 cents per gallon, would be worth $3,528,000.

Gas from about 2 per cent of the total oil wells was used for making gasoline. The gasoline made from casing-head gas was probably less than 1 per cent of the gasoline produced at the refinery.

At the end of the year 1913 there were 40 plants in operation in Oklahoma. The value of gasoline produced in 1913 was $577,944.[a]

FUTURE OF THE INDUSTRY IN OKLAHOMA.

It has been stated that about 25,000 producing wells were in operation on the last day of May, 1913, and that 500 were used for gasoline production. It is not to be inferred that all of these wells will contain gas of sufficient volume or proper character to produce gasoline.

Probably less than one-third of the total number of wells will be available, owing to the reasons following. These reasons also apply of course to other localities in the United States.

(1) Insufficient gas yield.

(2) Unfavorable location of wells with reference to transportation of finished product.

(3) Poor quality of gas.

On the other hand, gas from many wells that have not been utilized as yet will produce gasoline in paying quantities. Many wells that do not produce gas of proper character now will do so in the future as the wells grow older. This statement is substantiated by the experience of many operators in the Appalachian fields. There the old wells are producing gas that is the richest in gasoline vapors. The final maximum yield per 1,000 cubic feet of gas will be reached when the minimum pressure is reached in the oil well. The gasoline yield should then become practically constant.

The Muskogee, Okmulgee, Cushing, and Cleveland oil fields in Oklahoma possess many wells that are promising. The outlook for large producing wells in the north of the State is not so promising. Seemingly there is not enough gas in many territories to warrant the installation of gasoline plants. There are, however, many favorable locations, and to date those plants that have been developed in the northern region are profitable notwithstanding the small size and great number of wells connected.

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[a] Hill, B., Natural gas: Mineral Resources U. S. for 1913: U. S. Geol. Survey, 1914, p. 1481.

DEVELOPMENT OF INDUSTRY IN FOREIGN COUNTRIES.

Development of the industry in foreign countries has been slow. The authors have knowledge of one plant at Payta, Peru, installed by Americans. The plant handles 60,000 cubic feet of gas per day. Another small plant in the Galicia oil fields, Austria-Hungary, handled 20,000 cubic feet of gas per day.

TOTAL GASOLINE PRODUCTION IN THE UNITED STATES.

PRODUCTION IN 1911 AND 1912.

The following table, covering gasoline production in the United States for 1911 and 1912, is taken from data compiled by Hill:[a]

The production of gasoline from natural gas in 1911 and 1912 in the United States.

State.	Number of operators.		Number of plants in operation.		Production.	
	1911	1912	1911	1912	1911	1912
					Gallons.	*Gallons.*
West Virginia	47	66	72	97	3,660,165	5,318,136
Pennsylvania	43	69	50	83	1,467,043	2,041,109
Ohio	26	25	39	43	1,678,985	1,718,719
Oklahoma	8	11	8	13	388,058	1,575,644
California	8	7	7	7	231,588	1,040,695
Illinois		4		4		386,876
Colorado		2		2		
New York		1		1		
Kentucky	......	(b)	......	(b)	....	....
Total	132	185	176	250	7,425,839	12,081,179

PRODUCTION IN 1913.

The data following show the production of gasoline from natural gas for the year 1913. The figures are taken from data obtained by the United States Geological Survey.[c]

Production of gasoline from natural gas in the United States in 1913, by States.

State.	Number of operators.	Number of plants.	Yearly capacity.	Value of year's production.
			Gallons.	
West Virginia	63	115	7,662,493	$807,406
Pennsylvania	100	40	3,680,096	405,186
Ohio	25	113	2,072,687	212,404
Oklahoma	19	40	6,462,968	577,944
California	12	14	3,460,747	376,227
Illinois	6	12	721,826	79,276
Colorado	2	2		
New York	3	3		
Kentucky	1	(b)		
Kansas	1	1		
Total	232	....	24,060,817	2,458,443

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[a] Hill, B., Natural gas: Mineral Resources U. S. for 1913, U. S. Geol. Survey, 1914, pp. 1479–1480.
[b] Natural condensation in the pipes.
[c] Hill, B., Op. cit.

According to these figures the increase in the production of gasoline from natural gas in the United States for the year 1913 over the year 1912 was about 100 per cent. According to the United States Geological Survey figures, the rate of increase for 1912 over 1911 was 63 per cent.

According to Hill, the total estimated consumption of natural gas in the United States in 1912 was 562,203,452,000 cubic feet,[a] and the total quantity used for making gasoline was 4,687,796,329.[b] This latter figure represents gas not included in the total consumption, for it covered gas principally going to waste. At the close of the year 1913,[b] this figure was 9,899,441,500 cubic feet and the total quantity of gas used for all purposes was 581,898,239 cubic feet.[a] The percentage of natural gas used for making gasoline was 1.7.

CHEMISTRY OF NATURAL GAS.

In the gasoline industry natural gas is popularly classified in two great divisions—"wet" gas and "dry" gas. Gas not intimately associated with oil is known as "dry" gas; that in the same stratum with oil and in intimate contact with it is the so-called "wet" gas, from which gasoline is condensed. As the result of many analyses, the Bureau of Mines finds that natural gas is a mixture in which the hydrocarbons of the paraffin series predominate and that small proportions of nitrogen, carbon dioxide, and water vapor are present. In a few samples of natural gas the bureau has found that the carbon dioxide may amount to as much as 10 per cent; in one sample it amounted to 31 per cent. Another natural gas examined contained 97.9 per cent of nitrogen, 0.10 per cent of carbon dioxide, and 2 per cent of methane. Hence the proportions of carbon dioxide and nitrogen may in exceptional samples be large.

Carbon monoxide, hydrogen, hydrocarbons of the olefin series, or other gases that most textbooks state are constituents of natural gas are not present. Hydrogen sulphide is found in some natural gas.

NATURAL-GAS ANALYSES MADE BY THE BUREAU.

The results of some natural-gas analyses made by the bureau are shown in Table 2, following. They are given to show the variation in composition of different samples of natural gas:

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[a] Hill, B., Natural gas: Mineral Resources U. S. for 1913, Geol. Survey, 1914, p. 1414.
[b] Hill, B., op. cit., p. 1480.

TABLE 2.—*Results of analysis of samples of natural gas.*

[* Indicates that notes following table contain additional information regarding sample.]

Lab. No.	Date of sampling.	Oil fields.	County.	State.	Location.	Oil company holding lease.	CO_2.	O_2.	N_2.	Total paraffins.	Total.	CH_4.	C_2H_6.	Gross heating value per cubic foot, 0° C, 760 mm.	Specific gravity (air=1).
														B. t. u.	
9206	August, 1909	Santa Maria	Santa Barbara	Cal.	T. 9 N., R. 34 W.	Santa Maria Oil & Gas.	15.5	0.2	1.4	82.9	100.0	62.7	20.2	1,044	0.81
10576	February, 1910	Torrey	Ventura	do.		Torrey	6.8	.0	3.4	89.8	100.0	54.2	35.6	1,240	.81
10579	June, 1910	Coalinga	Fresno	do.	Sec. 25, T. 20 S., R. 15 E.	Kern Trading & Oil.	11.1	.0	.9	88.0	100.0	88.0	.0	937	.66
10000	September, 1909	McKittrick	Kings	do.	Sec. 29, T. 30 S., R. 22 E.	Dabney	30.4	.0	2.4	67.2	100.0	66.2	1.0	724	.85
9210	July, 1909	West Los Angeles.	Los Angeles	do.		Pacific Petroleum.	1.0	.1	5.2	93.7	100.0	91.0	2.7	1,019	.60
9213	do.	Sunset	Kings	do.	Sec. 31, T. 31 S., R. 23 E.	Crandall	10.5	.0	1.8	87.7	100.0	87.7	.0	934	.66
9211	do.	Fullerton	Orange	do.	Sec. 8, T. 3 S., R. 9 W.	C. V. Hall	1.7	.0	2.1	96.2	100.0	86.7	9.5	1,100	.63
10577	November, 1909	Kern River	Kern	do.	Sec. 32, T. 28 S., R. 28 E.	Associated	6.5	.0	1.2	92.3	100.0	84.3	8.0	1,047	.66
*1871	September, 1911		Clarion	Pa.	Near town of Mill Creek.		.0	.0	1.1	98.9	100.0	96.4	2.5	1,073	.57
*1889	do.		Forest	do.	3 miles east of Nebraska.		.0	.0	1.0	99.0	100.0	70.8	28.2	1,279	.70
*1872	February, 1911		Clarion	do.	Near Mill Creek	South Penn Oil	.0	.0	1.7	98.3	100.0	80.5	17.8	1,189	.65
*1848	September, 1911		Butler	do.	Concord Township, near Chicora.		.0	.0	.9	99.1	100.0	53.3	45.8	1,420	.78
*1838	do.		Armstrong	do.	6 miles from Bradford.		.05	.0	1.45	98.5	100.0	81.6	16.9	1,184	.64
*3177	December, 1912	Hogshooter	Osage	Okla.	North end of Hogshooter field.		1.1	.0	4.6	94.3	100.0	94.3	.0	1,004	.58
*2121	February, 1912		Creek	do.	Kiefer	D. W. Franchot	2.4	.0	1.8	95.8	100.0	64.1	31.7	1,273	.74
*2445	March, 1912		Barren	Ky.	5 miles from Glasgow.	Oskamp Development.	2.5	.0	1.3	93.3	a100.0	23.6	69.7	1,548	.91
*2444	do.		do.	do.	do.	do.	2.6	.0	5.1	92.3	b100.0	44.1	48.2	1,367	.84
*1031	September, 1910		Grand	Utah.	Moab		3.6	.0	5.6	90.8	100.0	90.8	.0	967	.61
*1033	do.		do.	do.	do.		3.5	.0	6.5	90.0	100.0	90.0	.0	959	.62

a H_2S, 2.9 per cent.

b H_2S, 0.1 per cent.

TABLE 2.—*Results of analysis of samples of natural gas*—Continued.

Lab. No.	Date of sampling.	Oil fields.	County.	State.	Location.	Oil company holding lease.	CO_2.	O_2.	N_2.	Total paraffins.	Total.	CH_4.	C_2H_6.	Gross heating value per cubic foot, 0° C, 760 mm.	Specific gravity (air=1).
														B. t. u.	
*1063	September, 1910			Oreg.	Sec. 26, T. 8 N., R. 10 W.		3.0	0.0	0.9	96.1	100.0	96.1	0.0	1,023	0.58
*1893	September, 1911		Crawford	Pa.	Titusville	Atlantic Refining.	.0	.0	2.3	97.7	100.0	6.6	91.1	1,765	.99
1065	September, 1910						.5	.0	12.5	87.0	100.0	87.0	.0	927	.60
*1066	do		Tillamook	Oreg.	5½ miles southeast of Tillamook, sec. 10, T. 2 S., R. 9 W.		.1	.0	97.9	2.0	100.0	2.0	.0	21	.96
*1378	do		Churchill	Nev.	Near Stillwater		1.3	.0	3.1	95.6	100.0	95.6	.0	1,018	.58
5101	July, 1914		Cuyahoga	Ohio.	Cleveland		.0	.0	1.3	98.7	100.0	80.5	18.2	1,196	.65
4982	February, 1914		Franklin	Ohio.	Columbus		.0	.0	1.5	98.5	100.0	80.4	18.1	1,193	.65
5269	March, 1914		Hamilton	Ohio.	Cincinnati		.0	.0	.7	99.2	100.0	79.8	19.5	1,213	.65
5277	April, 1914		Erie	N.Y.	Buffalo		.0	.0	4.9	95.1	100.0	79.9	15.2	1,134	.65
5588	November, 1914		Jasper	Mo.	Joplin		.6	.0	2.5	96.9	100.0	92.6	4.3	1,066	.59
5590	August, 1914		Jefferson	Ky.	Louisville		.0	.0	1.8	98.2	100.0	77.8	20.4	1,205	.66
5445	October, 1914		Dallas	Tex.	Dallas		.1	.0	38.4	61.5	100.0	50.6	10.9	742	.77
......	September, 1914		Nowata	Okla.	Nowata		1.3	.0	2.2	96.5	100.0	96.5	.0	1,038	.58

NOTES.

Sample 1871.—The gas sampled comes from the fourth sand, which is 800 feet deep. The rock pressure in the well was 300 pounds per square inch. The capacity of the well was 3,000 cubic feet of gas per day.

Sample 1889.—The sample came from the third sand. Five gas wells were tapped by the pipe line from which the gas sample was drawn. The rock pressure at the wells was 62 pounds per square inch.

Sample 1872.—Collected in Clarion County, Pa., near the town of Mill Creek. The sample came from the Bradford or Little Bradford sand, which is 2,100 feet deep. The rock pressure was 850 pounds per square inch and the capacity of the well 3,000,000 cubic feet a day. This gas contains a higher percentage of the heavier paraffin hydrocarbons than does the gas represented by sample 1871 that comes from the shallower sand.

Sample 1848.—The sample was collected at well No. 14 of the A. W. Starr farm. The gas is from the Speechley sand.

Sample 1838.—The sample was collected from the No. 1 well on the J. S. Somerville farm. The gas comes from the fourth sand.

Sample 3177.—The sample was taken from the Collinsville pipe line in the pumping station of the Kansas Natural Gas Co. at the north end of the Hogshooter field. This line tapped about 40 gas wells. The initial rock pressure of the wells was 490 pounds per square inch. At the date of collection of the sample the pressure had dropped to 120 pounds. This was one of the few samples of natural gas analyzed by the bureau that contained only methane as the combustible constituent when the sample came from a sand in close proximity to sands producing oil. Most gas from the oil regions contains other paraffin hydrocarbons besides methane, and gas coming from the same sand as the oil invariably contains other paraffin hydrocarbons. It is difficult to explain the presence of an enormous quantity of methane gas, such as is contained or was contained in the Hogshooter pool, in close proximity to oil sands. If gas and oil were of common origin in the particular region, one would suppose that the Hogshooter gas should contain higher members of the paraffin hydrocarbons than methane, as do the gases from neighboring oil wells. The phenomenon might be connected in some way with the movement of the gas through strata whereby ethane and still higher paraffin hydrocarbons were separated.

Sample 2121.—The sample represented a casing-head gas from the Glenn sand. It was collected about 2,000 feet east of the railroad station at Kiefer, Okla.

Sample 2445.—The sample was collected at the Cully well on the Ellis farm. The well was 340 feet deep and was drilled in 1903. A large amount of hydrogen sulphide was present in the sample. The determination of the hydrogen sulphide was made by absorbing the H_2S in a standard iodine solution and titrating with a standard sodium thiosulphate solution. Other sulphur compounds may have been present; hence the assumption that 2.9 per cent was all H_2S may be wrong. The gas possessed the odor of H_2S.

Sample 2444.—The sample was obtained in the same locality as sample 2445, but from a different well. The well was 280 feet deep. Both wells were drilled in 1903. The hydrogen sulphide content of this sample is much smaller than that of sample 2445.

Sample 1031.—The sample is classified as a marsh gas in distinction from those gases that are found in the oil field and contain appreciable quantities of the higher paraffin hydrocarbons.

Sample 1033.—The sample was collected at a near-by seepage in the same locality. The gas was simply bubbling up through marshy ground.

Sample 1063.—The sample was collected from a slough on the Brown farm. It also represented a marsh gas.

Sample 1893.—The sample was collected from 15 oil wells, Nos. 1 to 15, of the Atlantic Refining Co. (South Penn Oil Co.).

Sample 1066.—The striking feature of this sample is the high percentage of nitrogen. A well had been drilled and the gas was issuing from it in considerable quantity. For present purposes to which natural gas is put, the gas would of course be worthless.

Sample 1378.—The sample was collected from a slough about 15 feet in diameter. It represented what was seemingly another marsh gas.

The last eight samples given in the table were taken from natural gas supplied the city in which the sample was obtained.

COMMENTS ON THE ANALYSES.

It will be observed that the samples ranged in heating value from 724 to 1,657 British thermal units per cubic foot at 0° C. and 760 mm. normal pressure, except one sample which had the abnormally low heating value of 21 British thermal units per cubic foot.

The analytical results show only approximately the quantity of the individual hydrocarbons, although the percentages of total paraffin hydrocarbons are correct. The heating values of the samples, as calculated from the analyses, are also correct. A discussion of natural-gas analyses is found in Bulletin 42 of the Bureau of Mines.[a] The causes of erroneous results that are frequently reported are there explained.

METHOD OF ANALYSIS USED.

The ascertaining of the exact proportions of the different hydrocarbons that may be found in natural gas has long been a stumbling block in gas analysis. The ordinary eudiometric method of analysis offers little in the way of a complete separation of a natural gas into its various constituents. Determination of the total paraffin-hydrocarbon content, with an approximate determination of the individual paraffins present, has been the only end attained. The Bureau of Mines in working on this problem succeeded in separating a natural gas into its individual paraffins by means of fractional distillation at low temperatures. Natural gas was first liquefied by means of liquid air, and then separated into its constituents by fractionation in vacuum at different temperatures.

The results of a complete analysis, including the quantity of each paraffin hydrocarbon found by the above method follow. For comparison, the results of an eudiometric analysis of the natural gas of Pittsburgh are also included.

Analytical results obtained by two methods.

Constituent.	Results obtained by liquefaction and fractionation.	Results obtained by eudiometric analysis.
	Per cent.	*Per cent.*
Methane	84.7	79.2
Ethane	9.4	19.6
Propane	3.0	
Butane (chiefly)	1.3	
Nitrogen	1.6	1.2

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[a] Burrell, G. A., and Seibert, F. M., The sampling and examination of mine gases and natural gas, 1913, 116 pp.

Included in the nitrogen content of the above analyses is 0.03 per cent of carbon dioxide present in the natural gas. The natural gas supplied to Pittsburgh can not be used for the commercial production of gasoline, although it contains sufficient of the higher paraffin hydrocarbons, the butanes, pentanes, and hexanes, to produce some condensation (drip) in the pipe lines in the winter time. These hydrocarbons are present in small quantity, as shown by fractionation experiments conducted by the bureau. It is only because of the immense volume of gas passing through the lines that appreciable condensation of vapor occurs.

A "wet" natural gas from which gasoline is obtained commercially was also subjected to fractionation.[a] The results follow:

	Per cent.
Methane	36.8
Ethane	32.6
Propane	21.1
Butanes, pentanes, hexanes, etc	9.5
Total, including 1.00 per cent nitrogen and 0.03 per cent carbon dioxide	100.0

PROPERTIES OF THE PARAFFIN HYDROCARBONS.

The properties of those hydrocarbons of the paraffin series that concern the gasoline industry are given below:

Properties of seven paraffin hydrocarbons.

Hydrocarbon.	Formula.	Boiling point.[b]	Specific gravity (at 0° C. and 760 mm.; air=1).	Weight of 1 liter.	Heating value per cubic foot at 0° C. and 760 mm.[c]	Illuminating value.	Liquefaction point.	Calculated volume of gas (at 60° F. and 30 inches pressure) from 1 gallon.	Theoretical volume of air necessary to burn 1 cubic foot of gas.
		°C.		*Grams.*	*B.t.u.*	*British candle-power.*	*°C. Lbs. per sq. inch.*		*Cubic feet.*
Methane[d]	CH_4	−160	0.554	0.7159	1,065	[e] 5.0	−95.5 at 735[f] −81.8 at 807[g]		9.57
Ethane[d]	C_2H_6	−93	1.049	1.3567	1,861	[h] 35.0	+35 at 664[i]	53	16.72
Propane[d]	C_3H_8	−45	1.520	1.9660	2,654	[h] 53.9	+97 at 647[g]	45	23.92
Butane[d]	C_4H_{10}	1.0	2.004	2.594	3,447			37	31.10
Pentane[k]	C_5H_{12}	36.4			4,250			31	38.28
Hexane[k]	C_6H_{14}	68.9			5,012			27	
Heptane[k]	C_7H_{16}	98.4							

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[a] A technical paper covering in detail this method of separating gases and the results of experiments by the bureau is being prepared.

[b] Holleman, A. F., Organic chemistry, edited by A. J. Walker, 1910, p. 41.

[c] Landolt and Börnstein, Physikalisch-chemische Tabellen, 3d ed., 1905, pp. 416, 425 (J. Thomsen).

[d] Gas at ordinary temperature.

[e] Wright, L. T., Illuminating power of methane; Jour. Chem. Soc., vol. 47, 1885, p. 200.

[f] Landolt and Börnstein, Physikalisch-chemische Tabellen, 3d ed., 1905, pp. 185 (Dewar).

[g] Landolt and Börnstein, Physikalisch-chemische Tabellen, 3d ed., 1905, p. 185 (Olszewski).

[h] Frankland, P., Illuminating power of methane: Jour. Chem. Soc., vol. 47, 1885, p. 235.

[i] Landolt and Börnstein, Physikalisch-chemische Tabellen, 3d ed., 1905, p. 182 (Dewar).

[k] Liquid at ordinary temperature.

Methane, ethane, propane, and butane, as shown by the above table, are gases under ordinary atmospheric conditions. Pentane, hexane, and heptane are liquids and are the chief constituents of ordinary refinery gasoline. Of the four gases mentioned, methane is the most difficult to liquefy. At any temperature below −160° C. it becomes liquid when its pressure is 1 atmosphere. The boiling point of the liquid is −160° C. Above −160° C. greater pressures are necessary to liquefy methane, until at a temperature of −95.5° C. a pressure of 735 pounds per square inch is required. These two values are the critical temperature and the critical pressure, respectively, for methane. No matter what the pressure applied to the gas methane, it can not be liquefied at a temperature higher than −95.5° C. The above general statement holds true for all gases. They can be liquefied at atmospheric pressure if the temperature is lowered sufficiently, but great pressure will not accomplish the liquefaction until the critical temperature is reached. Ethane (critical temperature, 35° C.; critical pressure, 664 pounds per square inch), it will be observed, is more easily liquefied and in the liquid condition has a higher boiling point (−93° C.) than methane.

Propane (critical temperature, 97° C.; critical pressure, 647 pounds per square inch) is more easily liquefied than methane or ethane.

Butane, the critical constants of which have not been determined, must be still more easily liquefied than the three already mentioned, because in the liquid condition it boils at 1° C.

OCCURRENCE OF GASOLINE IN CASING-HEAD GAS

When a gas bubbles through or comes in contact with a liquid, it takes up and carries along vapor or minute particles from that liquid. The proportion of vapor increases as the temperature rises, and is quite independent of the nature of the gas as long as no chemical action takes place. When a natural gas in the earth comes in contact with petroleum, those fractions of the petroleum having the lower boiling points are principally taken up, inasmuch as their vapor pressures are much higher than those of the other fractions. If the well is under reduced pressure, products with higher boiling points will also be removed in the gas. The vapors are carried with the gases mentioned, in the same manner that water vapor exists in air.

At any particular temperature a fixed quantity of water vapor will be found in the atmosphere if the latter has reached complete saturation, a condition that seldom prevails. Usually a limited supply of water has been encountered by the air, and the atmosphere is spoken of as having a certain relative humidity, meaning that the saturation is incomplete at the existing temperature, or that more water vapor could exist in the air were a source of moisture available. In a similar manner gases in an oil well mix with heavy hydrocarbon vapors. The amount of vapor carried will depend on the temperature and pressure existing in the earth, on the readiness with which the vapors can be obtained, and on the gasoline content of the crude oil in the well. A certain maximum quantity of the heavy vapors will issue with the gases from a well under given conditions of temperature and pressure. The intimateness of contact between the oil and the gas is an important factor. The maximum content, or condition of complete saturation, is probably by no means generally prevalent. The porosity or closeness of the strata, the depth of the well, and the rapid expansion of the gas from the casing head cause variations in the temperature of the gas. The pronounced temperature effects, of course, appreciably change the capacity of the gas to hold gasoline vapor. Such rapid expansion of gas from a casing head may occur as to cause a heavy condensation of vapor at the casing head, owing to a lowering of the temperature of the gas.

At some operations, wells have been under reduced pressure for a long time, so long, in fact, that only small quantities of the four permanent gases already mentioned are left in the strata. Under such conditions the mixture that comes from the well may consist almost wholly of vapors of the liquid hydrocarbons, unless air has been drawn into the strata, owing to the reduced pressure.

RELATION OF CHARACTER OF OILS IN THE SAND.

The yield of gasoline from natural gas is largely determined by the proportion of the vapor of the liquid paraffins in the gas mixture. Therefore the character of the oils in a sand is of importance.

Crude oil (petroleum) is a mixture of closely related complex hydrocarbons and of various other organic substances. There are many different compounds (isomers) corresponding to a particular molecular weight, and the boiling points of these isomers lie so closely together that their separation by fractional distillation is impossible. The liquid hydrocarbons that mainly concern the gasoline industry are the petanes, hexanes, and heptanes. However, small quantities of even higher homologues are undoubtedly obtained.

Some information as to the gasoline content of a natural gas can be gained by determining the proportion of light constituents in the oil with which the gas is associated.

Many investigations have shown that the gasoline constituents for many oils range from zero to 30 or more per cent of the total volume of the oil. Consequently, many oils are so heavy and their vapor pressures so low at existing earth temperatures that the proportion of vapors to be derived from them is too small to warrant the installation of a plant.

The table following shows the vapor pressures of the liquid paraffin hydrocarbons at various temperatures.

Vapor pressures and boiling points of the liquid paraffin hydrocarbons.

Hydrocarbon.	Vapor pressure.[a]				
	0° C.	10° C.	20° C.	30° C.	Boiling point (° C.).
Normal pentane	183.3	281.8	420.2	610.9	37.0
Normal hexane	45.5	75.0	120.2	185.4	69.0
Normal heptane	11.5	20.5	35.5	58.4	98.4
Normal octane	2.9	5.6	10.5	18.4	125.5

[a] Millimeters of mercury.

From the table it may be inferred that the chief liquid constituents of gasoline made from natural gas are the pentanes and the hexanes as their vapor pressures at any temperature are far greater than those of the other liquid hydrocarbons.

EFFECT OF PRESSURE AND TEMPERATURE ON GASES IN THE STRATA.

Natural gases in the oil fields of the United States are principally mixtures of methane, ethane, propane, and butane. Methane is always present in a well in the gaseous condition. Ethane becomes a liquid at a temperature of 35° C. under a pressure of 664 pounds to the square inch. Hence if a natural gas consisted of ethane only and was subjected to a pressure in the earth greater than 664 pounds, it would be in the liquid condition.

The authors have no evidence that ethane occurs in anywhere near the pure condition in the earth. As the proportion of ethane in a mixture decreases, there is required a proportionally greater pressure than 664 pounds to liquefy it. If a sample contained 50 per cent ethane and 50 per cent methane, there would be required a pressure of at least twice 664 pounds, or 1,328 pounds, to liquefy the ethane at 35° C., and to liquefy the methane a pressure of at least twice 735 pounds, or 1,470 pounds, at $-95.5°$ C. Moreover, a temperature of $-95.5°$ C. is far below that prevailing in oil and gas sands. A pressure of 1,328 pounds per square inch is probably unknown in the gas fields, but pressures as high as 800 to 1,000 pounds have been measured. Propane and butane are each more easily liquefied than ethane.

The critical temperature of propane is 97° C., and its critical pressure is 647 pounds per square inch. According to analyses made by the authors the amount of propane in most natural gases is less than that of ethane, so pressures sufficient for its liquefaction do not exist in the sands penetrated by wells.

The natural gas of Pittsburgh, according to liquefaction experiments made by the authors, contains about 84.7 per cent methane, 9.4 per cent ethane, 3.0 per cent propane, 1.3 per cent butane, (chiefly), and 1.6 per cent nitrogen. To liquefy the methane in this mixture at a temperature of −95.5° C. would require a pressure of at least $\left(\frac{100}{84.7}\right)$ 735, or 868 pounds. To liquefy the ethane at 35° C. there would be required a pressure of $\left(\frac{100}{9.4}\right)$ 664, or 7,064 pounds, and to liquefy the propane at 22° C. there would be required a pressure of $\left(\frac{100}{3.0}\right)$ 132.3, or 4,410 pounds. It will be noted that the critical temperature of methane is so low that under no condition could one conceive of its being liquefied in the earth. The critical temperature of ethane is a temperature that prevails in some rock strata, but the amount of ethane present in natural gas is invariably so small that pressures much higher than those found in rock strata would be required to liquefy the ethane.

As the temperature of a gas is lowered from its critical temperature, less pressure is required to liquefy it until finally at a certain temperature it becomes liquid at ordinary pressures. Propane has a critical temperature of 97° C. This temperature is higher than that ordinarily found in the sands of oil or gas fields, where a thermal gradient of 1° C. for each 60 or 70 feet of depth may be assumed. The temperature has to be −45° C. at ordinary pressures, however, for liquefaction to occur. Such a temperature is much lower than rock-strata temperatures. At 22° C. there is required a pressure of 4,410 pounds.

It follows that temperatures found in rock strata are not low enough, that rock pressures are not high enough, and that the amount of propane in natural gases is too small to allow the existence of liquid propane in the sands penetrated by wells.

Butane gas becomes liquid at 1° C. at a pressure of 1 atmosphere. Its critical constants have not been determined, so far as the authors are aware. Its liquefaction point at ordinary pressures (15 pounds per square inch) is much closer to normal temperature than the liquefaction points of the three paraffin hydrocarbon gases already mentioned. Hence, if it constituted the whole of a natural gas, one could easily conceive that it would occur in the earth in the liquid condition. But in many natural-gas mixtures it appears to be present in even less amount than the other three gases. In Pittsburgh natural gas it is present in a proportion equal to about 1.3 per cent. With this quantity present, it would require a pressure of 1,077 pounds per square inch at 1° C. for liquefaction. At the higher temperatures of gas sands greater pressures would be required. If present to the extent of 20 per cent there would be required a pressure of 75 pounds at 1° C., and if it constituted 50 per cent of a gas a pressure of 30 pounds would be required. Gases that are used for the condensation of gasoline usually issue from the earth either under reduced pressure, atmospheric pressure, or just above atmospheric pressure. In exceptional instances the pressure may be 50 or even 100 pounds, but at most plants the gas used issues from the wells under reduced pressure. In those gases that are used for gasoline condensation, butane, and also propane and ethane, are found to be present in greater proportions than in the so-called "dry" gases that issue under much pressure and are so largely used for heating and lighting towns. The authors believe that butane may be present in the "wet" gases to the extent of 10 per cent. Hence one can conceive that the amount of butane may be high enough, also the rock pressures high enough and the earth temperature low enough, so that in some sands butane may be present in the liquid condition. But if reduced pressures prevail in wells, as in most wells used for gasoline condensation, the rock pressures are usually too low, even if the partial pressure of the butane in the gas mixture is high, to permit liquefaction to take place.

In summarizing, one may say that at those wells from which gas is drawn for gasoline condensation, the three gases, methane, ethane, and propane, invariably occur in the earth in the gaseous condition. Butane probably occurs as a gas in some places, but in others it is present as a liquid.

The question has been raised frequently as to whether natural gases are not accumulated as liquids in the underground reservoirs. If such were the case it would be possible for a single, comparatively small subterranean reservoir to yield for many years much larger quantities of gas than such reservoirs do yield.

As regards Pittsburgh natural gas and other similar gases that issue under considerable pressure from strata, none of the gaseous constituents present is liquid in the earth. However, where gases are associated with petroleum in the same strata, under heavy pressures, there is considerable solution of the gases in the oil. The natural gas used in Pittsburgh is not associated with oil in the earth.

TESTING NATURAL GASES FOR GASOLINE CONTENT.

Before plants are erected for the purpose of extracting gasoline from natural gas the yield and quality of the gas should be thoroughly investigated. Also of much importance is the marketing of the gasoline.

CLASSIFICATION OF KINDS OF NATURAL GAS.

As stated before, as regards the making of gasoline, natural gas is popularly classified in two divisions—"wet" gas and "dry" gas. This classification has come largely into general use with the development of the gasoline industry. Between the two classes there is no sharp line of demarcation.

"DRY" NATURAL GAS.

Some natural gas contains only methane as the combustible constituent and according to the above classification may be considered the driest of natural gases. This kind of gas is rare in the oil fields, but is common in gas fields, or in marshy districts unassociated with oil. The Hogshooter pool of Oklahoma, according to tests made by the bureau, produces a natural gas that contains methane as the only combustible constituent.

This kind of gas is found in States or districts in which oil has never been found. Incidentally it might be mentioned that the occurrence of such gas naturally escaping from the surface of the earth affords some proof of the nonexistence of oil. However, the indication is not infallible, because some natural gas that contains only methane as the combustible constituent is found in the oil fields. This gas comes from sands that do not bear oil.

The next grade in the transition of "dry" to "wet" gas may be considered that at present obtained from the Appalachian oil fields and used in Pittsburgh, Pa., and other cities. This natural gas issues under considerable pressure from wells in or near the oil fields. It has varied little in composition from the figures given on page 24 for the three years that the Bureau of Mines has been testing it. Air has never been detected in the samples tested. Many wells are abandoned yearly by the company that furnishes the city the supply, and new wells are drawn upon, the wells being abandoned when the rock pressure becomes so low as to be insufficient to assist in forcing the gas to Pittsburgh and other points of consumption, or when the yield becomes too small even with the gas pumps that are used. In composition this gas is typical of the natural gas supplied to many cities. All of the ingredients present are gases at ordinary temperatures. Traces of butane and even of higher paraffin hydrocarbons are present—enough because of the many thousands of cubic feet of gas transported daily, especially in the winter time, to cause some condensation of vapors or drip, in the pipe lines. This gas has been said to pass at the rate of a mile a minute through mains connecting the wells to Pittsburgh. The drip is not sufficient to indicate that the gas is of value for gasoline extraction.

"WET" NATURAL GAS.

As to the so-called "wet" gas, or that from which gasoline can be extracted in quantity sufficient to warrant the installation of a plant, the proper testing of such gas in order to determine its gasoline content is of much importance. In the early days of the gasoline industry some failures of plants to fulfill expectations were due to inadequate testing of the gas before the construction of the plant had begun.

METHODS AND EQUIPMENT USED IN TESTS.

At present, tests have become better standardized, and there is scarcely any excuse for the failure of a plant because of inadequate preliminary tests. By itself, the ordinary eudiometric analysis is of little value for determining the gasoline content of natural gas. Moreover, it is extremely difficult to make, and the authors are safe in saying that a gas analyst must have had experience in refined analytical methods before he can make a satisfactory analysis of natural gas, especially of "wet" gas. In addition, the ordinary gas-analysis determination informs one only of the two predominating paraffins present but gives slight knowledge of the quantity of gasoline vapors. Early in the history of the industry, gas analysts turned their attention to other more easily conducted and more definite tests. Those laboratory methods adopted and at present in chief use have to do with solubility and specific-gravity tests.

SOLUBILITY TESTS.

Natural gases are soluble in various solvents, such as alcohol, claroline oil, olive oil, kerosene, sperm oil, and rape-seed oil, in proportions depending upon the amount of higher paraffin hydrocarbons present in the gas mixture. All of the solvents mentioned have been used. F. P. Peterson, of Tulsa, Okla., informed the authors that he found it expedient to use claroline oil.

USE OF CLAROLINE OIL.

The Bureau of Mines methods of testing are described in Bulletin 42[a] of the bureau. In using claroline oil the following procedure is adopted: 35 c. c. of the oil is placed over mercury in an ordinary Hempel gas pipette, and 100 c. c. of the natural gas to be tested is shaken with the oil until no further absorption of the gas mixture occurs. It was found that many natural gases from which gasoline is at present commercially obtained were soluble in the oil to the extent of 30 to 86 per cent of their volume.

In figure 1 is shown a gas-analysis apparatus for determining the solubility of natural gas in claroline oil or alcohol. It consists of a measuring burette, *e*, having a capacity of 100 c. c., and an absorption pipette, *c*. It is provided at the top with a three-way T stopcock, *d*, so that communication can be made between the burette and outside air, or between the burette and the pipette. Water is used in the burette and mercury in the pipette. To begin an analysis, 35 c. c. of claroline oil or 50 c. c. of alcohol is placed in the pipette *c* over the

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[a] Burrell, G. A., The sampling and examination of mine gases and natural gas, 1913, 116 pp., 2 pls., 23 figs.

mercury. A 100-c. c. part of the gas sample is then drawn into the burette, measured, and forced into the pipette *c*. The pipette *c* is shaken for about three minutes to thoroughly mix the oil or alcohol and gas. The gas is then transferred to the burette and measured, and the loss in volume is noted. The gas is again passed into the pipette and the shaking operation repeated. Finally the gas is measured again in the burette. The first and second readings should agree within 0.50 per cent. If they do not, the operation should be repeated until the burette readings become constant.

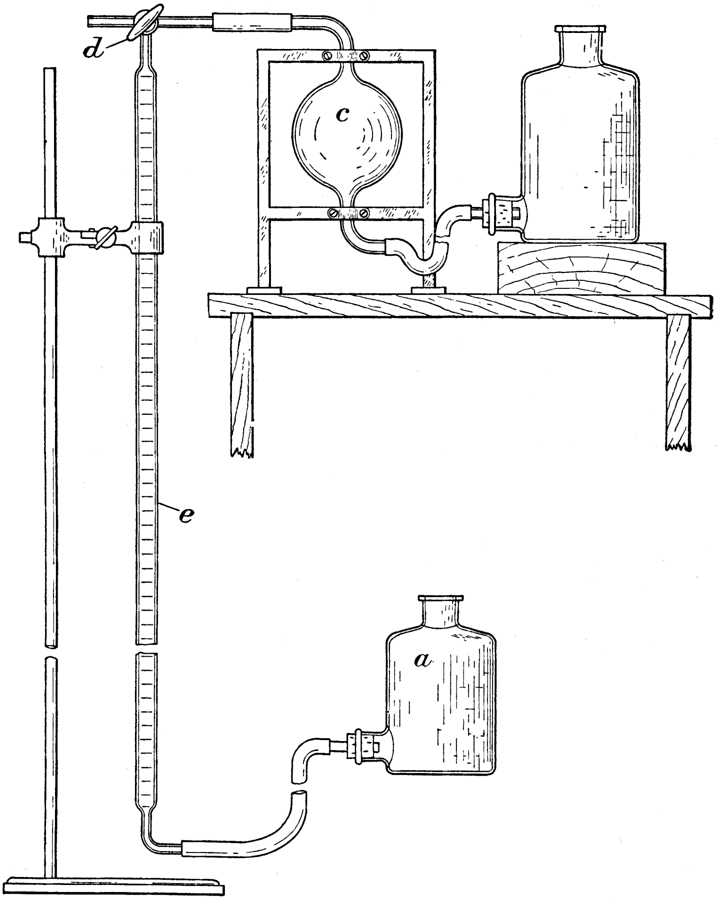

FIGURE 1.—Apparatus for determining the gasoline content of natural gas.

Below are given tables showing the solubility of natural gas and of methane and ethane in different oils. A 35-c. c. sample of the oil was shaken with 100 c. c. of the gas until absorption of gas by the oil ceased.

Solubility in different oils of the natural gas used at Pittsburgh.

Kind of oil used as solvent.	Character of oil.	Solubility of gas.
		Per cent.
Claroline	Mineral	15.5
Russian white (kerosene)	do	16.4
Sperm	Animal	16.5
Olive	Vegetable	13.7
Rapeseed	do	14.7
Cottonseed	do	14.8

It was possible to check the above determinations within 0.50 per cent. Considerable uniformity as regards the solubility of the natural gas in the different oils will be noticed. The claroline oil used had the following characteristics, as determined by I. C. Allen, chemist of the bureau:

Characteristics of claroline oil.

Specific gravity	0.8667 at 15° C.
Viscosity	4.4° Engler at 20° C.
Flash point	152° C., Pensky-Martens closed test.
Ignition point	270° C., Pensky-Martens closed test.

Solubility of pure methane in claroline and cottonseed oils.

Oil.	Character of oil.	Solubility of methane.
		Per cent.
Claroline	Mineral	11.0
Cottonseed	Vegetable	9.5

The solubility of pure ethane in claroline oil, as determined by the authors, was 68.5 per cent.

USE OF ALCOHOL AS A SOLVENT.

The Bureau of Mines has used ethyl alcohol in much the same manner that claroline oil is used for testing natural gas. Instead of 35 c. c. of the claroline oil, 50 c. c. of ethyl alcohol may be used. The procedure otherwise is exactly the same. The results obtained with alcohol are similar to those with claroline oil.

ORSAT APPARATUS FOR DETERMINATION OF CARBON DIOXIDE AND OXYGEN.

In figure 2 is shown an Orsat apparatus for the determination of carbon dioxide and oxygen in natural gas. The Orsat apparatus is so well known that it needs little description. It is sufficient to say that the burette has a capacity of 100 c. c. The pipette *b* contains caustic potash solution for the removal of carbon dioxide, and the pipette *a* contains alkaline pyrogallate solution for the removal of oxygen. The figure (fig. 2) shows the level bottle of the burette, the water jacket, and a three-way stopcock, *c*. This apparatus may be used to advantage for examining natural gases to determine whether air has leaked into mains, owing to the reduced pressures that are maintained in pipe lines at some gasoline plants.

SPECIFIC-GRAVITY TESTS.

Natural gas may vary in specific gravity from about 0.56 (air = 1) to as much as 1.65, or from a gas containing methane only as the paraffin hydrocarbon in proportions approaching 99 per cent or more of the total to an extremely "wet" gas, from which gasoline in quantities up to 4 or 5 gallons per 1,000 cubic feet can be obtained. Specific-gravity tests may be made either by weighing the gas in a small glass vessel or by means of Bunsen's effusion method. The weighing method is the more accurate. The following procedure is adopted by the Bureau of Mines:

A 100-c. c. glass globe, equipped with a stopcock, is exhausted of its contained air, thoroughly dried, and weighed. Natural gas is then introduced and a second weighing made. This weight as compared to that of an equal volume of air at the same temperature gives the specific gravity.

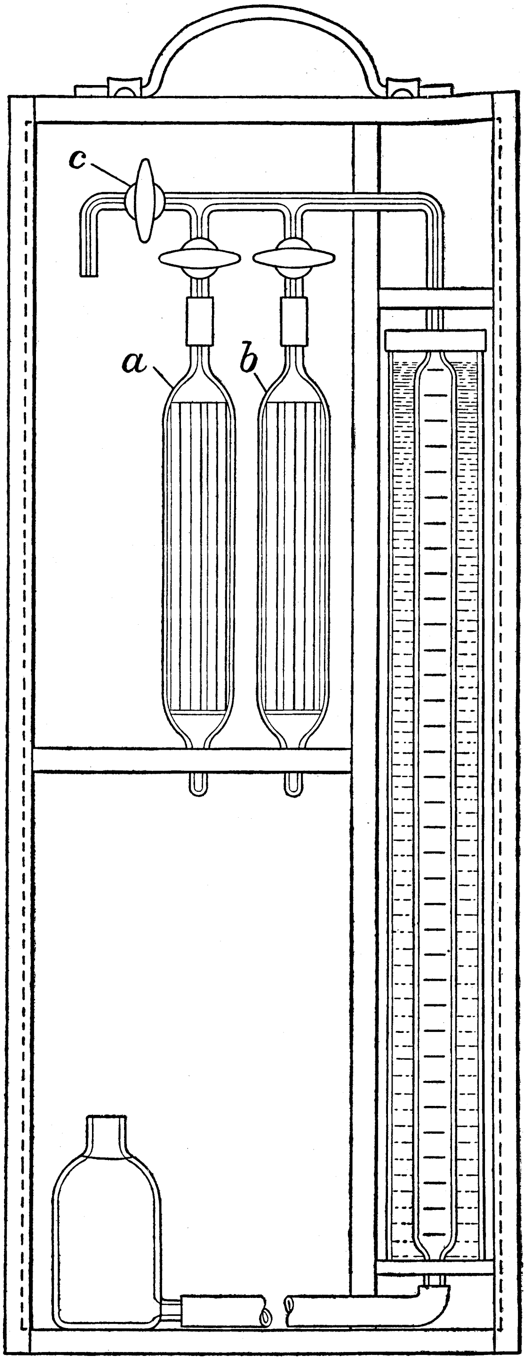

FIGURE 2.—Orsat apparatus for determining carbon dioxide and oxygen in natural gas.

EFFUSION METHOD.

In using the Bunsen effusion method, specific gravities are determined by noting the rate at which a certain volume of the gas passes through a small orifice. The rate at which a like volume of air passes through the orifice is also determined. The specific gravities of the natural gas and air are then in inverse ratio to the squares of the rates of effusion.

Some natural gas contains a large percentage of carbon dioxide. This is a heavy gas, having a specific gravity of 1.53 (air = 1). If it happened to be present in a natural gas mixture and a test were not made for it, an experimenter might be misled into believing that the gas was heavy, because of paraffin hydrocarbons present.

Many samples of natural gas contain large percentages of nitrogen. In an extreme instance the bureau found that a natural gas issuing from the earth in the State of Washington contained 98.5 per cent of nitrogen. Proportions of nitrogen as high as 10 per cent in natural gas are not uncommon. The specific gravity of nitrogen is 0.97. If much nitrogen were present an investigator might be misled by the specific-gravity test in that the test would not show the specific gravity of the paraffin hydrocarbons but the specific gravity of the entire mixture, which depends in part upon the content of nitrogen or carbon dioxide, or both.

CONSTRUCTION AND USE OF SCHILLING TYPE OF APPARATUS.

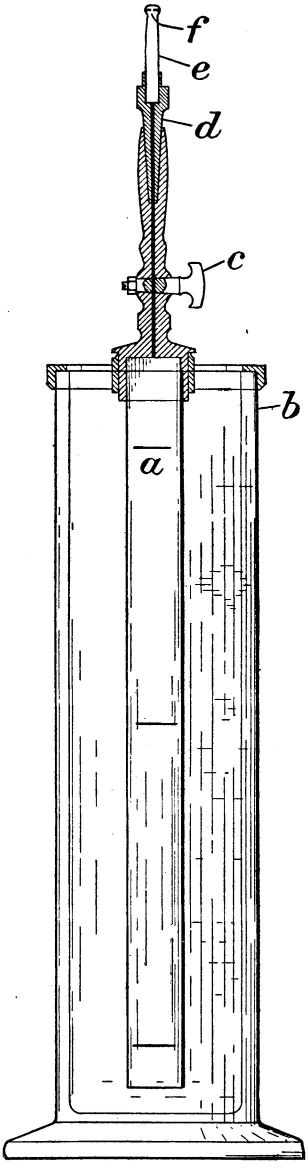

FIGURE 3.—Apparatus for determining specific gravity of gas.

The authors have used the particular type of apparatus known as the Schilling (fig. 3) for the specific-gravity determination. It consists of a glass jar, *b*, with a metal top into which fits a brass column having suspended from its base a long graduated tube, *a*, and at its top a cock, *c*, and a ground-joint socket, *d*, into which sets a socket holding a small glass tip, *e*, closed at the top with a thin piece of platinum, *f*. In this platinum is a minute hole to permit the passage of gas or air at a very slow rate. All metal parts are nickeled.

The mode of operation is as follows: The glass jar is filled with water to the top graduation of the tube or to a point a little above it. The tube is then withdrawn so that it may be filled with air. The cock on the standard is then closed and the tube replaced in the jar. The cock is then opened and with a stop watch the time is taken that elapses while the water passes from the lowest graduation to the graduation above. The tube is then withdrawn and filled with gas and the procedure repeated. The specific gravity, air being 1, is obtained by dividing the gas time squared by the air time squared. Thus, if A represents the time gas requires to pass through the orifice, and B represents the time air requires to pass through the orifice, the specific gravity of the gas will be represented by $\left(\frac{A}{B}\right)^2$.

USE OF THE PITOT TUBE FOR MEASURING THE OPEN FLOW OF GAS WELLS.

The quantity of natural gas that is discharged from a well is usually measured by means of a Pitot tube. (Fig. 4.) This instrument directly measures the velocity of the gas flow. In its most accurate form it consists essentially of two parts, first a tube pointing upstream for measuring the dynamic pressure and second a means of determining the static pressure. Two pressures are thus obtained. Their difference as read on a U gage gives the velocity or impact pressure of the flowing gas.

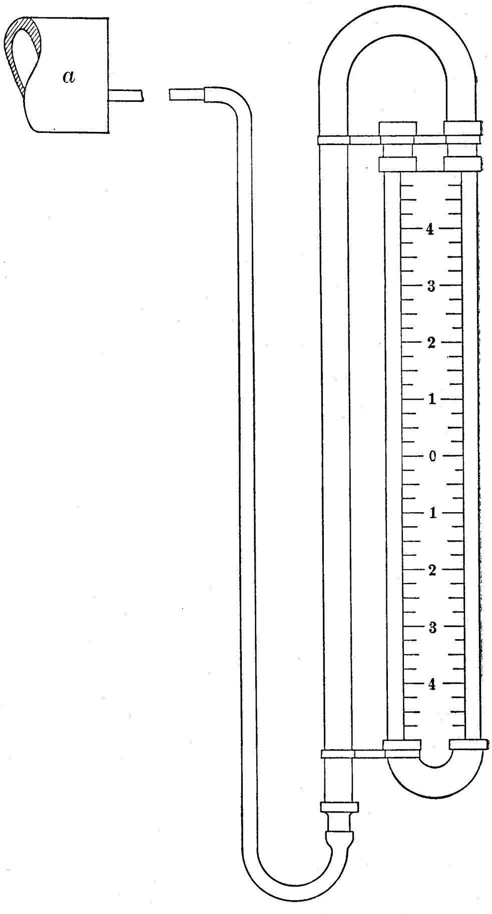

FIGURE 4.—U tube for measuring flow of gas.

As ordinarily used for field work the static pressure of the gas flow is not obtained, the instrument consisting simply of a small tube, which is inserted in the flowing gas (*a*, fig. 4), just inside the pipe or tubing, a distance of one-fourth to one-third of the pipe's diameter from the outer edge. The plane of the opening in the tube is held at right angles to the flowing gas. At a convenient distance, varying from 1 to 2 feet, a U-shaped gage (fig. 4) is attached to the other end, which is usually half filled with water. If the gas pressure is high enough to force the water out of the tube, mercury is used, and for pressures that are so great that mercury can not be used, a spring gage is attached. A scale graduated from the center in tenths of 1 inch is placed between the two limbs of the U gage. The distance above and below this center line at which the liquid stands in the gage should be added, the object being to determine the exact distance between the high and the low side of the fluid in inches and tenths.

The top joint of tubing or casing should be free from fittings for a distance of 10 feet below the mouth of the well where the test is made. The test should not be made in a collar or gate or at the mouth of any fitting. The well should be blown off at least three hours prior to making the test, and in some cases as much as 24 hours should be allowed. After the velocity pressure of the gas flowing from the well tubing has been determined in inches of water, inches of mercury, or pounds per square inch as outlined above, the corresponding rate of flow may be ascertained from Table 3, a table prepared by F. H. Oliphant[a] and presented below. The quantities of gas stated in the table are based on a pressure of 14.65 pounds per square inch absolute, and a flowing temperature of 60° F., for a gas having a specific gravity of 0.60 (air = 1). If the specific gravity of the gas is other than 0.6 the flow should be multiplied by

$$\sqrt{\frac{0.6}{\text{specific gravity of gas.}}}$$

For flowing temperatures above and below 60° F., 1 per cent should be deducted or added for each 10 degrees.

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[a] See Wescott, H. P., Handbook of natural gas, 1913, pp. 105–106.

TABLE 3.—*Table to be used in testing gas wells with Pitot tube*

Pressure in—			Discharge from—			
Inches of water.	Inches of mercury.	Pounds per square inch.	1-inch tubing.	2-inch tubing.	3-inch tubing.	4-inch tubing.
			Cubic feet.	*Cubic feet.*	*Cubic feet.*	*Cubic feet.*
0.10	....	....	11,880	47,520	106,920	190,080
.20	....	....	17,136	68,544	154,224	274,176
.30	....	....	20,568	82,272	185,112	329,088
.40	....	....	23,520	94,080	211,680	376,320
.50	....	....	26,544	106,176	238,896	424,704
.60	....	....	29,112	116,448	262,008	465,792
.7	....	....	31,440	125,760	282,960	503,040
.8	....	....	33,624	134,496	302,616	537,984
.9	....	....	35,640	142,560	320,760	570,240
1	....	....	37,320	149,280	335,880	597,120
1.25	....	....	41,712	166,848	375,408	667,392
1.5	....	....	45,960	183,840	413,640	735,360
1.75	0.12	....	49,680	198,720	447,120	794,880
2	.147	....	53,136	212,544	478,224	850,176
2.5	.184	....	59,400	237,600	534,600	950,400
3	.22	0.108	65,088	260,352	585,792	1,041,408
3.5	.257	.126	70,272	281,088	632,448	1,124,352
4	.294	.144	75,120	300,480	676,080	1,201,920
4.5	.331	.162	79,704	318,810	717,336	1,275,264
5	.368	.18	84,000	336,000	756,000	1,344,000
6	.441	.216	92,016	368,060	828,144	1,472,256
7	.515	.252	99,360	397,440	894,240	1,589,760
8	.588	.288	106,272	425,088	956,448	1,700,352
9	.662	.324	112,656	450,624	1,013,904	1,802,496
10	.736	.36	118,800	475,200	1,069,200	1,900,800
11	.8	.396	125,160	500,640	1,126,440	2,002,560
12	.88	.432	130,128	520,512	1,171,152	2,082,048
	1.02	.5	138,960	555,840	1,250,640	2,223,360
	1.52	.75	170,280	681,120	1,532,520	2,724,480
	2.03	1.00	196,680	786,720	1,770,120	3,146,880
	2.54	1.25	219,960	879,840	1,979,640	3,519,360
	3.05	1.5	240,720	962,880	2,166,480	3,851,520
	3.56	1.75	259,920	1,039,680	2,339,280	4,158,720
	4.07	2.00	272,640	1,090,560	2,453,760	4,362,240
	4.57	2.25	294,600	1,178,400	2,651,400	4,713,600
	5.08	2.50	310,800	1,243,200	2,797,200	4,972,800
	5.59	2.75	321,000	1,284,000	2,889,000	5,136,000
	6.10	3	340,200	1,360,800	3,061,800	5,443,200
	6.61	3.25	354,120	1,416,480	3,187,080	5,665,920
	7.11	3.50	367,680	1,470,720	3,309,120	5,882,880
	7.62	3.75	380,400	1,521,600	3,423,600	6,086,400
	8.13	4.00	392,880	1,571,520	3,535,920	6.286,080
	8.64	4.25	405,000	1,620,000	3,645,000	6,480,000
	9.15	4.50	416,640	1,666,560	3,749,760	6,666,240
	9.65	4.75	428,280	1,713,120	3,854,520	6,852,480
	10.16	5.00	439,920	1,759,680	3,959,280	7,038,720
	12.20	6	476,040	1,904,160	4,284,360	7,616,640
	....	7	517,320	2,069,280	4,655,880	8,277,120
	....	8	542,400	2,169,600	4,881,600	8,678,400
	....	9	569,640	2,278,560	5,126,760	9,114,240
	....	10	595,560	2,382,240	5,360,040	9,528,960
	....	11	621,960	2,487,840	5,597,640	9,951,360
	....	12	642,600	2.570,400	5,783,400	10,281,600
	....	13	664,680	2,658,720	5,982,120	10,634,880
	....	14	683,880	2,735,520	6,154,920	10,942,080
	....	15	703,080	2,812,320	6,327,720	11,249,280
	....	16	721,080	2,884,320	6,489,720	11,537,280
	....	17	738,120	2,952,480	6,643,080	11.809.920
	....	18	753,960	3,015,840	6,785,640	12,063,360
	....	20	785,520	3,142,080	7,069,680	12,568,320
	....	22	803,280	3,213,120	7,229,520	12,852,480
	....	25	854,880	3,419,520	7,693,920	13.678.080
	....	30	910,680	3,642,720	8,196,120	14,570,880
	....	35	960,960	3,843,840	8,648,640	15,375,360
	....	40	1,006.680	4,026,720	9,060,120	16,106.880
	....	45	1,046,520	4,186,080	9,418,680	16,744,320
	....	50	1,081,920	4,327.680	9,737,280	17 310,720
	....	60	1,137,120	4,548,480	10,234,080	18,193,920
	....	75	1,223,400	4,893,600	11,010,600	19,574,400
	....	90	1,304,400	5,217,600	11,739,600	20,870,400
	....	100	1,336,920	5,347,680	12,032,280	21,390,720

Multipliers for pipe diameters other than given in Table 3.

[Apply the multiplier to the figures given in Table 3 for 1-inch tubing.]

Diameter of pipe.	Multiplier.	Diameter of pipe.	Multiplier.	Diameter of pipe.	Multiplier.
Inches.		*Inches.*		*Inches.*	
$1\frac{1}{2}$	2.25	$5\frac{5}{8}$	31.64	$8\frac{1}{4}$	68
$2\frac{1}{2}$	6.25	6	36	9	81
$4\frac{1}{4}$	18	$6\frac{1}{4}$	39	10	100
$4\frac{5}{8}$	21.39	$6\frac{5}{8}$	43.9	12	144
5	25	8	64		

PITOT TUBE WITH ATTACHMENT FOR MEASURING STATIC PRESSURES.

For the most accurate measurements by means of the Pitot tube a device is attached for recording static pressures (fig. 5). According to Rowse[a] the piezometer or its equivalent is the most reliable means of obtaining the static pressure. This device embraces a pipe with a few very small circular holes in it, so combined with a larger pipe as to leave an annular space between them (fig. 5). This annular space is closed at the outer end, the other being connected to one end of the gage glass by means of a rubber tube. The other end of the gage glass is so connected to the Pitot tube as to give the dynamic pressure. The difference between the two pressures (the velocity head) is read on the gage glass.

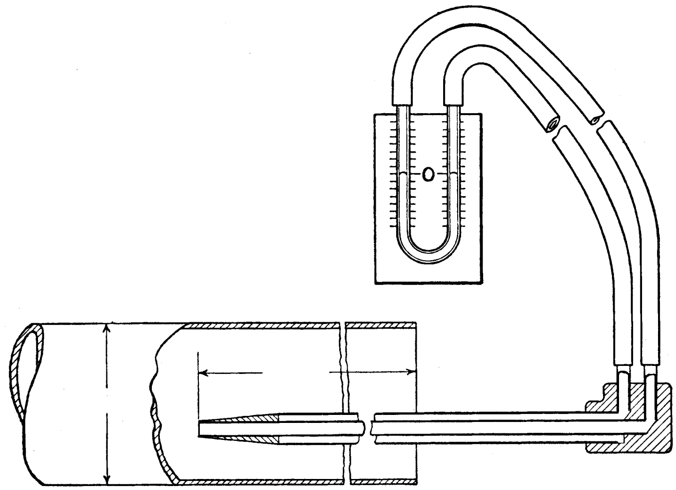

FIGURE 5.—Pitot tube with attachment for measuring static pressures.

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[a] Rowse, W. C., Pitot tubes for gas measurement: Jour. Am. Soc. Mech. Eng., vol. 39, September, 1913, p. 1341.

FORMULA FOR ACCURATE DETERMINATIONS.

The following data are given here in order to show the derivation of a formula for use in more accurately determining the flow of gas through a pipe than by means of the table given on page 38.

According to the well-known formula,

$$h=\frac{144WH}{X}$$

where

h=velocity head in feet of gas.
W=weight of water in pounds per cubic inch.
H=velocity head in inches of water.
X=weight of a cubic foot of gas.

Then when h is known the velocity of gas (in feet per second) is given by the formula,

$$V=\sqrt{2gh}$$

Multiplying through by A,

$$AV=A\sqrt{2gh} \qquad (1)$$

Then

$$Q=60A\times 8.019\sqrt{h} \qquad (2)$$

where

h=velocity head in feet of gas.
g=acceleration of gravity=32.16 feet per second.
A=cross-sectional area, in square feet, of the pipe from which the gas is flowing.
Q=quantity of gas in cubic feet per minute.

Substituting in *2* the value of h we have:

$$Q=60A\times 8.019\times\sqrt{\frac{144\ WH}{X}}$$

$$=60A\times 8.019\times 12\sqrt{\frac{WH}{X}}$$

As

X=specific gravity of gas times the weight of 1 cubic foot of air,

therefore

$$Q=60\times A\times 8.019\times 12\sqrt{\frac{WH}{\text{weight of 1 cubic foot of air}\times\text{specific gravity of gas}}}$$

$$=(5773.68)A\sqrt{\frac{WH}{\text{weight of 1 cubic foot of air}\times\text{specific gravity of gas.}}}$$

The latter equation is rather similar to that used by Rowse.[a] It requires the determination of the following values: The specific gravity of the gas at a certain temperature and pressure; the weight of a cubic foot of air under the same conditions; the weight of water in pounds per cubic foot at the same temperature; the determination of the differences in inches of the water levels in the gage glass, and the cross-sectional area, in square feet, of the pipe from which the gas is flowing.

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[a] Rowse, W. C., op. cit., p. 1372.

In figure 6 are shown the weights of 1 cubic foot of air at various temperatures, with a constant pressure of 30 inches of mercury.[a]

In figure 7 are shown the weights of water, in pounds per cubic inch, at different temperatures.[b]

Below are tabulated the cross-sectional areas of pipes of various diameters:

Cross-sectional areas of pipes of different diameters.

Diameter in inches.	Square feet.
1	0.006
1½	.0123
2	.0211
2½	.0341
3	.0491
3½	0.0668
4	.0872
4½	.1104
5	.1363
6	.1963

EXAMPLES SHOWING ACCURACY OF FORMULA.

The authors have worked out the following examples in order to show the variation in the results from using the more accurate formula given on page 41, as compared with the results obtained by using the table given on page 39.

EXAMPLE 1.

Suppose the atmospheric pressure to be 14.65 pounds per square inch, the temperature 60° F., the water-gage reading 2 inches, the diameter of the pipe 6 inches, and the specific gravity of the gas 0.60.

From the formula

$$Q=(5773.68)A\sqrt{\frac{WH}{\text{weight of 1 cubic foot of air}\times\text{specific gravity of gas.}}}$$

From figure 7 the weight of water (W) in pounds per cubic inch at 60° F. is found, and from figure 6 the weight of 1 cubic foot of air at 60° F. and 14.65 pounds per square inch is determined.

From the table above the area (A) in cubic feet for a 6-inch pipe is found. H, the inches of water, is read from the gage.

Substitution of these values gives:

$$Q=5773.68\times0.1963\sqrt{\frac{0.03608\times2}{0.0761\times0.6}}$$

$$=1428.17 \text{ cubic feet per minute.}$$

or 2,056,564 cubic feet of gas in 24 hours.

Using the same data but referring them to the approximate values given in the table on page 39, one finds the quantity of gas to be 2,103,185 cubic feet in 24 hours. The difference is 46,621 cubic feet, or 2.3 per cent of the first value.

EXAMPLE 2.

Suppose a water-gage reading of 0.3 inch on a 6-inch pipe at 60° F. and 14.65 pounds per square inch, the specific gravity of the gas being 0.6. Proceeding as in the first example, according to the formula:

$$Q=(5773.68)\times1963\sqrt{\frac{(.03608)\times0.3}{(.0766)\times0.60}}$$

$$Q=555.4 \text{ cubic feet of gas per minute.}$$

$$=799{,}800 \text{ cubic feet per 24 hours.}$$

By referring the given data to the table on page 39 one obtains a result of 740,448 cubic feet. The difference is 59,352 cubic feet, or 7.4 per cent of the first value.

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[a] Rowse, W. C., op. cit., p. 1379.

[b] Rowse, W. C., op. cit., p. 1380.

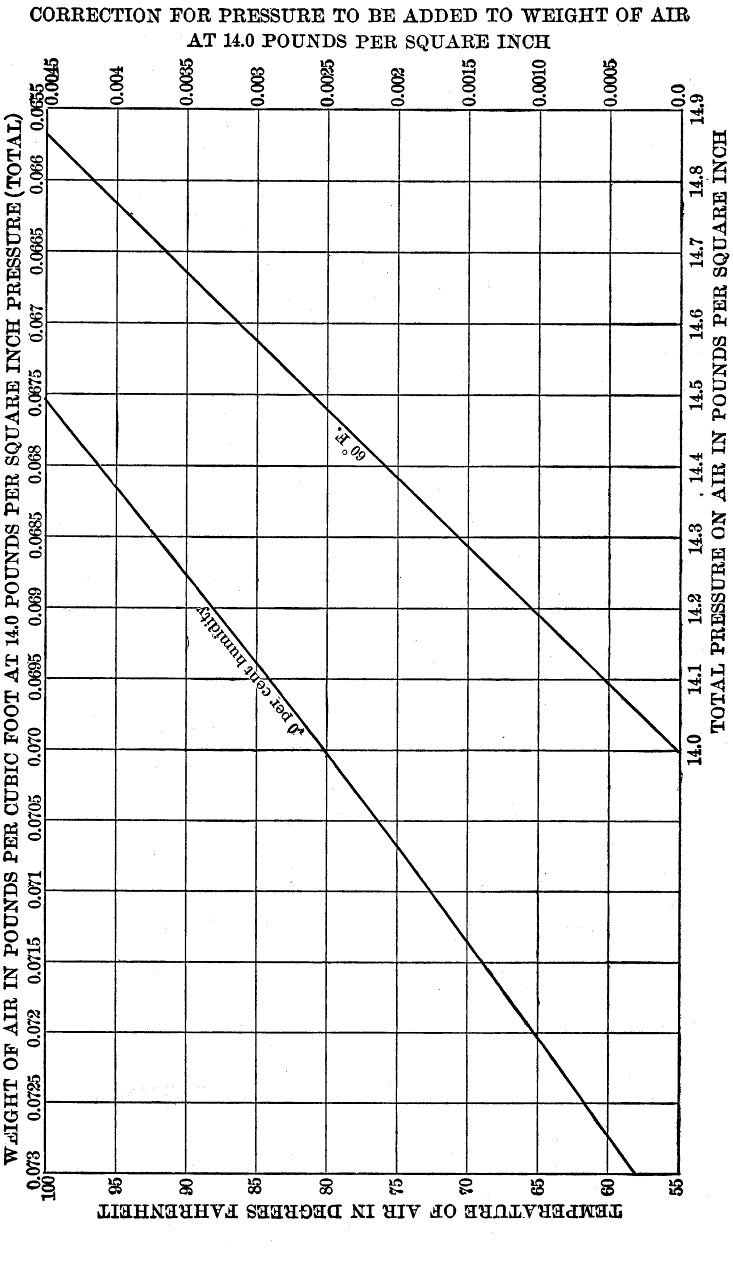

FIGURE 6.—Weights of 1 cubic foot of air at various temperatures, pressure being constant at 30 inches of mercury.

EXAMPLE 3.

Suppose a water-gage reading of 0.3 inch on a 1-inch pipe at 60° F. and 14.65 pounds per square inch, the specific gravity of the gas being 0.60.

From the table on page 39 the cubic feet of gas per 24 hours is found to be 20,568. If the more exact formula be used, the quantity of natural gas per 24 hours is found to be 21,824. The difference is 1,256, or 5.8 per cent.

These three examples will serve to show the errors involved in gas measurement by means of the Pitot tube when the static pressure of the gas is not measured. As regards the measurement of a gas flow on a lease for the purpose of determining the quantity available for gasoline making, the use of the more simple form of Pitot tube appears to be satisfactory.

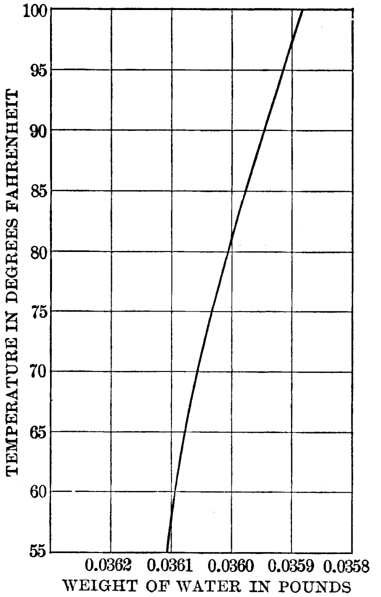

FIGURE 7.—Weights of water at different temperatures, pounds per cubic inch.

GENERAL COMMENTS ON USE OF PITOT TUBE.

The Pitot tube proves most satisfactory when an especially designed instrument is permanently installed. It can then be made an instrument of considerable precision. The use of the accurate form described by the authors is not advisable for field work, unless a device is attached whereby the tube can be rigidly held in place when the readings are made.

Rowse [a] sums up his experiments by saying that the results obtained in measuring gases by an absolutely correct Pitot tube may vary 1 per cent, more or less, from the correct results when the static pressure is correctly obtained and when all readings are taken with a reasonable degree of refinement.

NECESSITY OF ALLOWING A WELL TO VENT FREELY BEFORE PITOT-TUBE READINGS ARE MADE.

The authors know of a gasoline plant that failed because the gas flow from a well was not accurately measured before the plant equipment had been installed. Many wells on the lease had been open for some time and did not produce enough gas to warrant the installation of a plant. One well that had been closed, on measurement with the Pitot tube, registered a flow of gas of 200,000 cubic feet per 24 hours. A plant was installed against the advice of the

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[a] Rowse, W. C., op. cit., p. 1341.

company that sold the machinery and without its knowledge of the true condition of affairs. After the first day's operation of the plant there was not enough gas left to run the gas engine, and finally the flow practically stopped. The plant, which had cost $7,000, was a failure. This example illustrates the necessity of allowing wells to vent their gases freely before measurements are made, so that the operator may be assured that the quantity measured represents the quantity that will be available for operation of a gasoline plant. Some wells should be open for at least 24 hours before their flow is measured.

In the rush to install gasoline plants in the early days of the industry operators made great blunders. The authors know of one plant that was installed to work upon gas that had not been tested as to quality. The gas proved to be "dry" and the plant was a failure. The authors have heard of other similar mistakes.

INTERPRETATION OF RESULTS OF TESTS.

Considerable experimenting with plant operation on a large scale was necessary before results could be obtained from laboratory tests that could be used as a guide in making plant installations. The Bureau of Mines and different testing laboratories have at present records of the absorption results, specific gravities, and analyses of different natural gases from which gasoline is commercially produced. Reference is made to those results in the examination of new samples.

Many experiments have shown that gasoline may be obtained from natural gas having a specific gravity of 0.80 and higher (air = 1). Some inconsistencies have been noted, however, so that the authors would hesitate to recommend the installation of a plant to handle a gas that tests showed to have a specific gravity as low as 0.80 or to have an absorption percentage of 30.0 (Bureau of Mines test), although the gas might be all right for the purpose, especially if it were from wells in a field where other gases of low specific gravity were already producing gasoline. The authors do believe, however, that a gas with a tested specific gravity as high as 0.95 and an absorption percentage as high as 40 might warrant an installation.

Natural gases differ much in composition. A so-called "wet" gas might, for instance, contain a very large proportion of methane, with little ethane, propane, or butane, but enough of the gasoline hydrocarbons to warrant a plant installation. Such a gas when subjected to comparatively low pressures would deposit the gasoline vapors. Another gas of the same specific gravity might contain a comparatively small proportion of methane and ethane and a large proportion of propane and butane, but not enough of the gasoline hydrocarbons to warrant plant installation. Therein lies the reason why specific-gravity, solubility, or combustion tests can not always be relied on.

As regards a natural gas of low specific gravity and low absorption percentage (known as a "lean" gas), the safest recourse is to test by means of a portable outfit consisting of a gas meter, small gas engine, compressor, cooling coils, and receiver. Such an outfit can be hauled from place to place on a wagon. This method is in all cases to be recommended as having distinct advantages over laboratory tests. However, it is true that tests made with the portable outfit may be misleading unless in charge of a careful and experienced person.

The authors have also used a small stationary outfit consisting of a meter with a capacity of 15,000 cubic feet per 24 hours, a small compressor, driven by a steam engine, 100-foot cooling coils made of 1-inch pipe, immersed in a tank of water, and a storage tank 5 feet high made of a 6-inch piece of pipe. To the latter was attached a relief valve which could be set to operate at the desired pressure. A trap was installed between the compressor and the cooling coils to catch oil that was sometimes brought from the wells with the gas. A glass gage was connected to the storage tank to indicate the volume of condensate produced.

In conducting tests of a gasoline plant the plant is first operated for an hour or two to insure that everything is working well. The meter and all pressure gages must be in good order. The cooling coils should dip enough to drain readily the gasoline into the storage tank. The efficiency of the cooling coils can be ascertained fairly well by measuring the temperature at different places in the water of the tank. At the point where the coil enters the water it will be hot enough to warm the water appreciably, but if the tank is large and a sufficient length of pipe for cooling purposes is installed this warming of water is only local.

There follows a form used by the authors in testing wells on a given lease. The data shown represent an actual "plant" test:

Date, *March 7, 1913.*
Number of wells, *4.*
Temperature of gas at meter, *58° F. (14° C.).*
Pressure of gas at meter, *Atmospheric.*
Pressure in accumulator tank, *300 pounds per square inch.*
Temperature of water in cooler, *54° F. (12° C.)*
Gas used, *1,100 cubic feet.*
Condensate produced, *0.83 gallon per 1,000 cubic feet.*
Gravity of gasoline produced, *85° B.*
Evaporation loss of condensate on exposure to air, *11 per cent in 3 hours.*
Gravity of gasoline after evaporation loss, *82° B.*

Table 4 following shows the quantity of gas issuing from 16 wells on the same lease. The gas all comes from the same sand, the Berea grit, in West Virginia. The wells had been drilled about 10 years and the oil production averages about 25 or 30 barrels a day from 52 wells. The gas from all of the wells was not tested by the authors.

TABLE 4.—*Results of laboratory and field tests of 16 different wells on the same lease.*

Number of well.	Flow.	Specific gravity of gas (air=1).	Claroline and alcohol absorption.
	Cubic feet per 24 hours.		
1	25,000	0.79	33
2	21,500	.67	23
3	26,000	.74	28
4	12,000	.74	28
5	55,500	.71	34
6	41,000	.78	32
7	46,000	.70	23
8	84,000	.71	21
9	9,000	.78	31
10	17,000 to 29,000	0.75	24
11	76,000	.73	27
12	80,000	.73	27
13	27,000	.76	27
14	36,000	.83	42
15	23,000	.84	39
16	13,100	.72	30

A gasoline plant capable of taking care of 100,000 cubic feet of gas daily was in operation on this lease and was connected to wells 1, 6, 14, and 15, mentioned in the above table. Some gasoline was produced, but the successful operation of the plant had not been assured when the authors visited the lease. About 1,200,000 cubic feet of gas was available. Certain wells, among them many of high capacity, notably Nos. 2, 3, 4, 5, 7, 8, 10, 11, 12, and 16, appeared to be too dry for consideration for use in the condensation of gasoline from the gas.

RESULTS OF ANALYSES OF NATURAL GASES OF OKLAHOMA.

Following are the results of a laboratory analysis of a natural gas that is used for the condensation of gasoline from natural gas at a plant in the Glenn pool district; 250,000 cubic feet of gas was being used from eight wells. The operators claimed that they obtained about 1¼ gallons of gasoline from each 1,000 cubic feet of gas treated in the plant.

Results of analysis of casing-head gas from Oklahoma.

[Laboratory No. 3868.]

CO_2	0.60
O_2	[a] .20
CH_4	60.10
C_2H_6	35.70
N_2	3.40
	100.00

The oil absorption was 20.0 per cent and the specific gravity (air = 1) was 0.75.

The analytical results are interesting as showing a gas from which gasoline is condensed, although it is low in specific gravity and oil absorption as compared with similar values of other samples tabulated below

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[a] The oxygen is undoubtedly due to a slight leakage of air in the sample container.

The following table shows the specific gravity and the oil absorption of gases obtained from the casing heads of different wells on the same lease in the Glenn pool district of Oklahoma. A gasoline plant had not been installed at the time the authors collected the samples, but one was contemplated. The results show the variation in gases from the same lease and are in marked contrast to the values for the gas mentioned above, which was also collected in the Glenn pool district but from a different lease.

Specific-gravity and oil-absorption values of Glenn pool gas samples.

Laboratory No.	Specific gravity.	Oil absorption.	Laboratory No.	Specific gravity.	Oil absorption.
		Per cent.			*Per cent.*
3787	1.15	55.0	3790	1.11	56.0
3788	....	72.0	3785	1.31	67.0
3784	1.13	37.0	3786	1.43	78.0

COMPRESSION AND LIQUEFACTION OF THE CONSTITUENTS OF NATURAL GAS IN PLANT OPERATION.

The condensation of gasoline from natural gas is essentially a physical process. If any chemical reactions take place, they are slight and inappreciable. The authors tested residual gases from 10 different plant operations to determine whether carbon monoxide or olefin hydrocarbons were produced. These gases with others are found when the higher paraffins are decomposed at high temperatures and pressures in the absence of air. Neither carbon monoxide nor olefin hydrocarbons were found.

THREE COMMERCIAL PROCESSES.

At present three processes for the extraction of gasoline from natural gas are used commercially. The one most generally used involves compressing the gas to a certain pressure and subsequently cooling it by means of water or air. A second consists in simply cooling the gas without compression by means of a refrigerant, such as liquid ammonia, evaporating under reduced pressure. A third is a combination of the other two.

RELATION OF PRESSURES EXERTED BY GAS MIXTURES.

In order to understand changes that take place in the gas mixture as it passes through the compressors, knowledge of pressures exerted by gas mixtures is essential. In a mixture of gases exerting a certain total pressure each individual constituent of the mixture exerts a part of the pressure. Atmospheric pressure at sea level is about 15 pounds per square inch, of which about 3 pounds is due to the oxygen and about 12 pounds to the nitrogen. In order to be liquefied, a gas must be compressed or cooled or both. If it is to be liquefied by pressure alone, the pressure applied must be greater than the vapor pressure of the liquefied gas when boiling.

When a vapor is mixed with other gases or vapors, only a part of the total pressure is exerted on the vapor. If the vapor constitutes 10 per cent of the mixture, the pressure on the vapor is 10 per cent of the total pressure. For such a mixture, it being assumed that the vapor under consideration will be the first to condense out, a pressure of 150 pounds would be required to have a pressure of 15 pounds on the vapor. Under a pressure of 15 pounds the vapor would begin to condense to a liquid at the temperature at which the liquid would normally boil. Butane boils at 1° C. (34° F.), when its vapor exerts a pressure of 15 pounds per square inch. Hence, to condense butane vapor to liquid at 1° C. (34° F.), there would be required a pressure of at least 15 pounds on the vapor. If the butane constituted 20 per cent of a mixture, there would be needed a total pressure of 75 pounds in order to have a 15-pound pressure on the butane vapor, and to cause condensation to begin. As condensation took place, butane vapor would, of course, be removed from the mixture; that is, its partial pressure would diminish and a pressure greater than 75 pounds would have to be applied to cause the condensation to proceed. Hence, if one knew the exact quantity of butane vapor in a particular natural gas, a pressure greater than that theoretically required to start the condensation would have to be applied in practice. From the above discussion it will be seen why one gas may produce condensate under a pressure of 75 to 100 pounds, whereas another gas may need a pressure of 200 to 300 pounds to produce the same quantity of condensate of the same constituent.

A similar calculation can be made for pentane or other vapors of the liquid paraffin hydrocarbons. The vapor pressures of three of these liquids and of two of the gaseous paraffin hydrocarbons when liquefied are tabulated here.

Vapor pressures of three liquid hydrocarbons at different temperatures.[a]

Temperature.	Vapor pressure of—		
	Pentane.	Hexane.	Heptane.
° C.	*Pounds per square inch.*	*Pounds per square inch.*	*Pounds per square inch.*
0	3.5	0.9	0.2
10	5.4	1.5	.4
20	8.1	2.4	.7
30	11.8	3.1	1.1

[a] Landolt and Börnstein, Physikalisch-chemische Tabellen, 1905, 3d ed., p. 137.

Vapor pressures of two gaseous paraffin hydrocarbons at different temperatures.

Temperature.	Vapor pressure of—	
	Ethane.	Propane.
° C.	*Pounds per square inch.*	*Pounds per square inch.*
0	342.5	
12.5		104.4
15.0	474.8	
22.0		132.3
34.5 [a]	735.0	
53.0		249.9
102.0 [a]		713.0

[a] Critical temperature.

If one were to make the assumption that the vapor of pentane only was present in a natural-gas mixture it would be possible to ascertain the pressure necessary to condense this vapor at any desired temperature.

For example, suppose that gas available for gasoline production contains 3 per cent of pentane vapor, and suppose that determination of the pressure necessary to condense this vapor at 20° C. (68° F.) is desired. The above table shows that pentane has a vapor pressure of 8.1 pounds per square inch at 20° C. (68° F.); therefore the pressure required to start the condensation is $\frac{8.1}{0.03}$, or 270 pounds per square inch. As shown on page 25, 1 gallon of pentane will produce when volatilized about 31 cubic feet of vapor at 0° F. (32° C.), and 30 inches of mercury. If a gas yields 1 gallon of pentane per 1,000 cubic feet of gas, then there must be $\frac{31}{1000}$ part, or about 3 per cent of vapor in the mixture. Consequently, when less than 3 per cent of vapor occurs the pressure would have to be raised above 270 pounds to condense the vapor. If a pressure above 270 pounds per square inch and subsequent cooling below 20° C. were not employed, the vapor would not condense.

It has been stated that methane and ethane are never liquefied in plant operation. But propane and butane may be liquefied under certain conditions. At 22° C. (72° F.), to liquefy the vapors of pure propane, a pressure of 132.3 pounds per square inch is required. If 50 per cent of the vapor is present, a pressure of twice 132.3, or 264.6, pounds per square inch is required at a temperature of 22° C. (72° F.). As far as the authors are aware, no vapor-pressure curves for butane have been determined.

But as the boiling point of propane (—45° C.; —49° F.) is much lower than that of butane, the latter will be liquefied more easily than propane. As no data are available, no figures can be given. That butane is a constituent of some natural-gas condensates is shown by the fact that nearly all condensates obtained under high pressure (200 to 300 pounds per square inch) boil at temperatures near 0° C. Of course, the boiling point is modified by the presence of other constituents. Pentane, the next highest homologue to butane, boils at 36.4° C. (97.5° F.).

GASOLINE-PLANT METHODS AND EQUIPMENT.

USE OF COMPRESSORS.

Single and two stage compressors are generally used in gasoline-plant operations. Single-stage compressors are generally used where pressures of 110 pounds per square inch are not exceeded, although they are used at some plants where pressures up to 150 pounds per square inch are employed. At higher pressures, higher temperatures are produced. One of the makers of compressors states that with a 100-pound compressor volumetric efficiencies of 65 per cent are obtained, and with 50-pound compressors efficiencies of 80 to 85 per cent. A 150-pound compressor gives only about 50 per cent efficiency

LOW-STAGE COMPRESSION.

In the initial stage the gas is subjected to pressures varying from 20 to 50 pounds per square inch. Probably 35 pounds per square inch is an average value. The temperature of the gas may rise to 450° F. (232° C.) in the low-compressor cylinder, but no liquefaction of gas or condensation of vapor will occur. As stated elsewhere, gases can not be liquefied by the application of pressure alone at temperatures above their critical temperature, and at higher temperatures they would have a greater capacity than ever for the vapors present, so that no condensation of the vapors would occur.

COOLING OF MIXTURE.

During the next stage of operation, the mixture passes through a water-cooled 2-inch iron pipe, probably 100 feet long for every 100 cubic feet of gas passed per minute.[a] The cooling is effected at the same pressure as maintained in the low-stage compressor.

Usually little liquid is obtained at this stage of the operation, but that obtained is sometimes collected in the main receiving tank of the plant or in separators provided for the purpose. At a few plants, however, the condensate collected is considerable, being as much as 10 per cent or more of the total, but this yield is exceptional. The quantity of condensate obtained must, of course, principally depend upon the extent of the saturation of the original gas mixture with gasoline vapors. The quantity of gasoline vapors in the gas mixture

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[a] One firm that installs gasoline plants allows 1 square foot of radiating surface for each cubic foot of natural gas passing through the coils, an allowance stated to be largely in excess of the needs. The cooling coils are frequently equipped with a by-pass, so that only part of the coil need be used in cold weather.

depends upon many conditions, such as the quantity of gasoline peculiar to the oil, temperature and pressure conditions in the well, intimateness of contact between the oil and gas in the well, composition of the gas, and the treatment the gas receives in the plant.

HIGH-STAGE COMPRESSION.

After the mixture of gas and vapor has left the first cooler it is conducted to the high-pressure cylinder of the compressor and subjected to a pressure varying, perhaps, from 250 to 350 pounds per square inch. The temperature is raised probably to 250° C. (482° F.) in the compression cylinder. Under these conditions no liquefaction or condensation occurs for reasons already mentioned in connection with the discussion of the low-stage compressor. The mixture, still under pressure, is next forced through 2-inch pipe coils, on which water of ordinary temperature falls. In some plants the coils are immersed in tanks of water. An average temperature of probably 32° C. (90° F.) in summer and 4° C. (°39 F.) in winter is maintained. The temperature is further reduced by expanding the gas under the pressure mentioned through a valve into a pipe that envelops the final section of pipe through which the compressed gas travels on its way to the accumulator tank. Expansion against a reduced pressure of 30 pounds per square inch occurs at some plants. A temperature of about 4° C. (39° F.) is normal for a plant using this plan.

CLOSED-EXPANSION SYSTEM.

F. P. Peterson, general manager in the state of Oklahoma for the Riverside Western Oil Co., informed the authors that according to his experience the results obtained from direct expansion of the gases usually fall far short of expectation and that efforts in the direction of more efficient cooling by expansion are being made through what is termed a system of closed expansion. This system involves the use of a cylinder with a piston and a means of resistance against which the gas is made to do work in expanding. Water cooling is avoided as in several other different types of installation.

In the standard type of device for cooling and compressing, as above described, methane and ethane are not liquefied, but butane and, in some plants, propane are. A heavy condensation of gasoline vapors usually takes place, the final mixture containing principally butane, pentane, and hexane. Propane and also heptane may be present. There will also be found some of the gases methane and ethane dissolved in the liquid produced.

CHANGES IN GAS ON COMPRESSION AND COOLING.

The gas, in passing through the compression and cooling coils, undergoes several changes; one has to do with the condensation of vapor, another with the liquefaction of gas, and a third with the solution of gases and vapors in the liquid produced. The vapor condensation depends simply upon the reduced capacity of the different gases to carry the vapors when subjected to increased pressure and lowered temperature. The liquefaction of natural gas depends upon the temperatures and pressures at which the gases butane and propane are liquefied at their partial pressures. The solubility depends upon the solubility of the gases in the liquids produced at the particular temperature and pressures encountered. The three changes mentioned are so intimately concerned with each other that one factor can not be disturbed without affecting the others. For instance, such a pressure above and temperature below those at present ordinarily used could be maintained as to increase to some extent condensation of the most desired constituents, pentane, hexane, and heptane, but with increasing pressure and lowered temperature more of the undesirable gaseous constituents would become liquefied. These, when exposed to the atmosphere, immediately volatilize, carrying with them some of the gasoline constituents. At increasing pressures more of the gases methane and ethane dissolve. With release of pressure they would escape with violent agitation and further loss of the condensate.

Present methods of treating the raw gas have resulted from actual plant experiments on a large scale. Little record of these experiments has ever been published. The standard equipment herein mentioned is the result to date. Improvements in the process are bound to take place, but they must follow established laws of condensation, liquefaction, solubility, etc. The authors know of commercial ventures that were failures because of the management's lack of knowledge of the fundamental laws of physics and chemistry and of the nature of the material they were dealing with.

For the purpose of picturing just the physical changes that take place in the process a diagram such as that constituting figure 8 is instructive.

Suppose one starts with a natural gas at atmospheric temperature and pressure, and suppose it contains a certain weight of a vapor of a liquid hydrocarbon, M, which exerts a part of the total pressure of the mixture. This vapor must be dry, saturated, or superheated. Assuming it to be superheated the condition of 1 pound of it may be represented by the point a, figure 8. In the diagram the ordinates represent pressures and the abscissas, volumes. The point a fixes the volume Va and the pressure Pa of a pound of the vapor at the temperature t. Now the pressure is increased until the point b is reached, representing the boiling point of the liquid at a certain temperature and pressure; condensation begins and continues at constant pressure until complete at b_1b. The line abb_1c is the isothermal line at the temperature t.

As the vapor of the liquid hydrocarbon constitutes only a part of the gas mixture, as was first assumed, in order for condensation to begin it is necessary that the gas mixture be compressed to pressures above atmospheric, depending on the partial pressure of the vapor, in order to have a pressure (ordinate of *b*) on the vapor. In practice, however, the problem is complicated. The amount and character of the vapors are only imperfectly known. The most suitable pressures for any given plant operation can be obtained only by actual trial

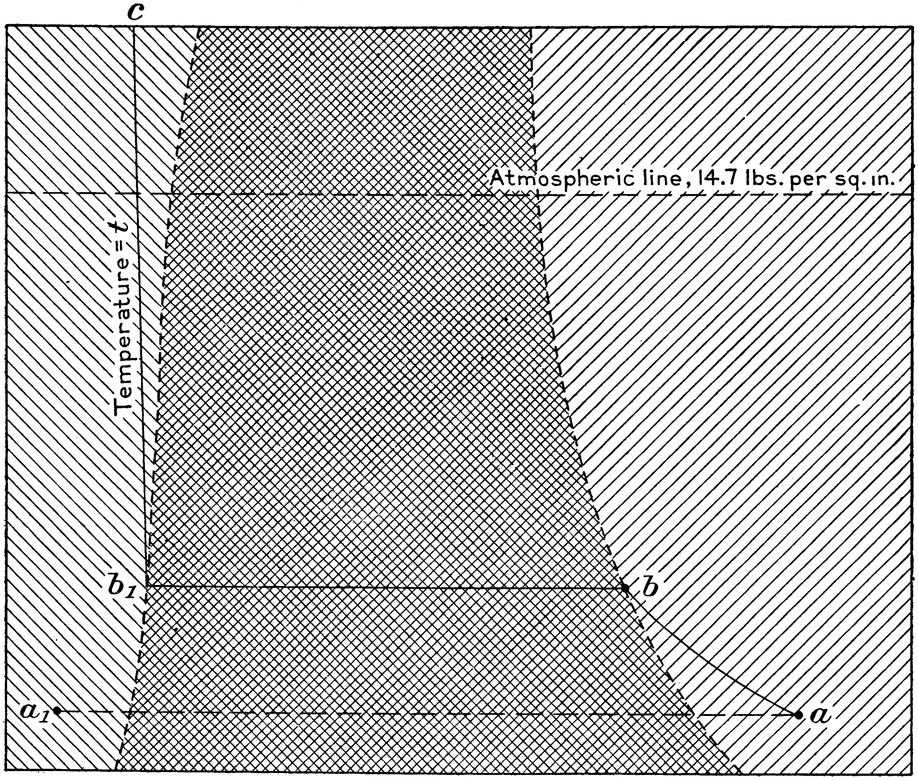


FIGURE 8.—Diagram illustrating physical changes that take place in the production of gasoline from natural gas.

DETAILS OF EQUIPMENT OF GASOLINE PLANTS.

In figures 9 and 10 are shown the plan and elevation of a plant for making gasoline from natural gas by the compression method.

The gas from the wells enters the plant by means of a gas line. After passing through a drip tank *a*, for the removal of oil that might be carried with the gas, it partly circles the compressor building and enters the low-stage compressor; after compression it is conducted to the low-stage cooling coils, and thence to the high-stage compressor *e*. From this compressor it passes to the cooling coils *c*, and is from them expanded into the cooling coils *d*.

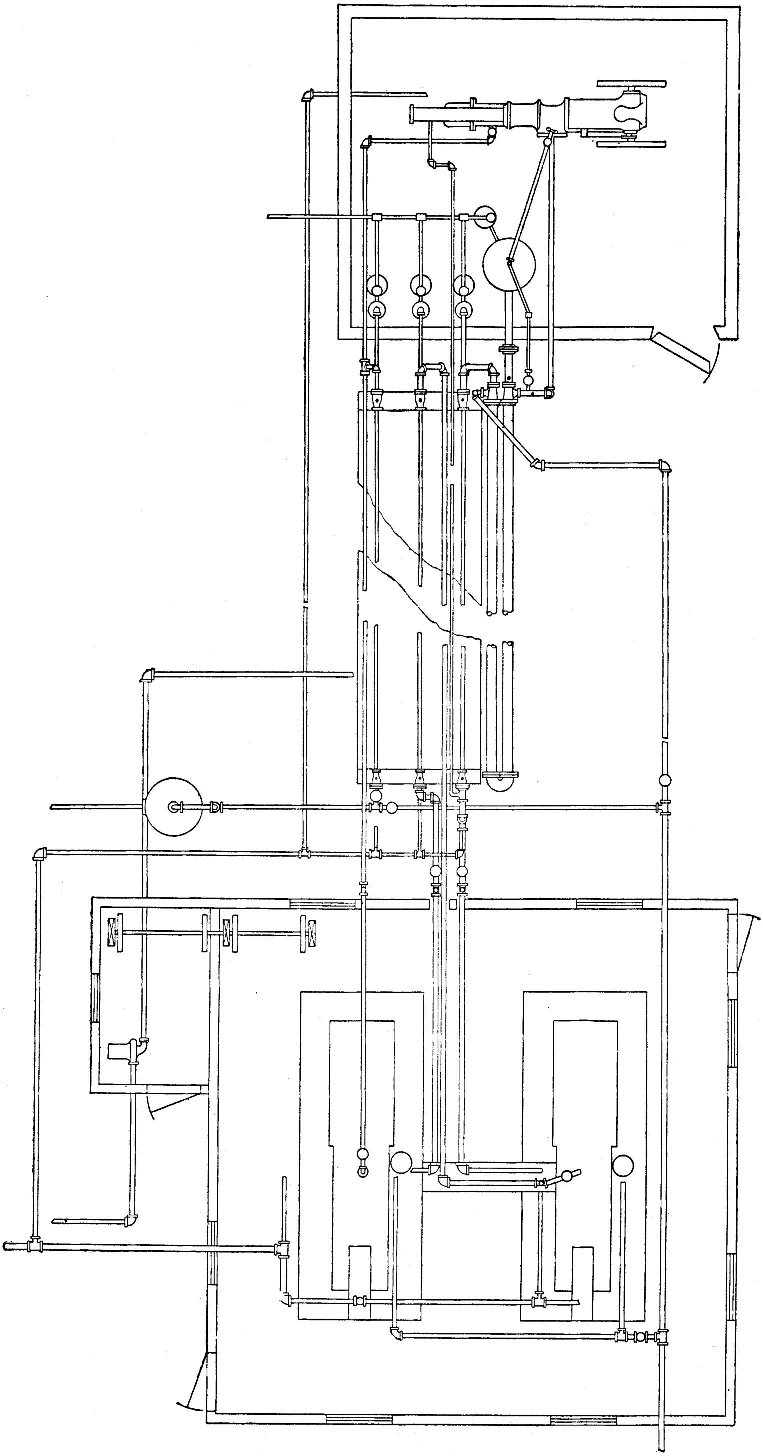


FIGURE 9.—Compression type of plant for making gasoline from natural gas. Plan.

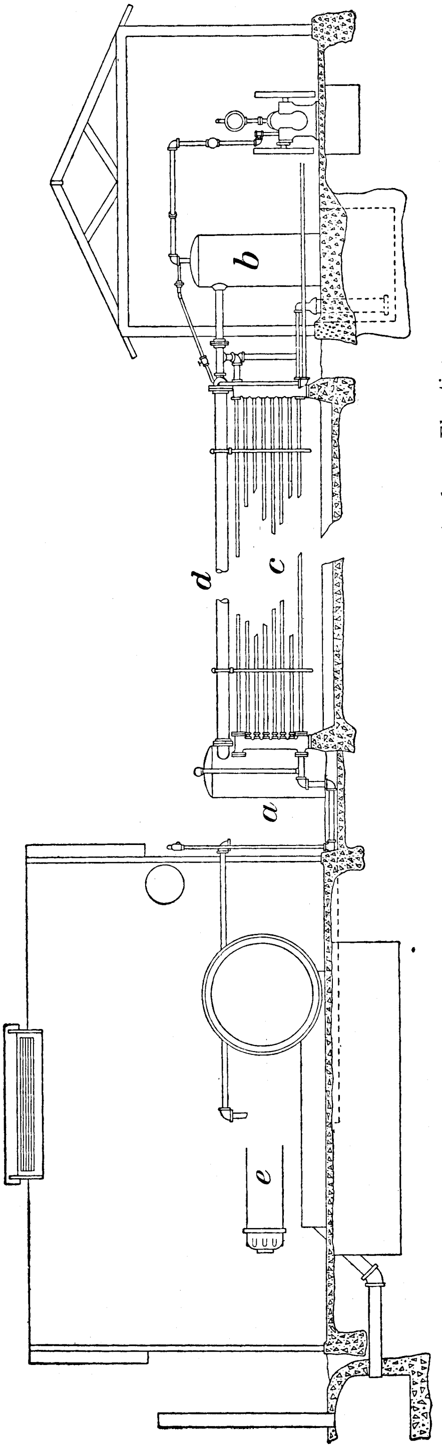


FIGURE 10.—Compression type of plant for making gasoline from natural gas. Elevation.

The condensate is trapped into the accumulator tank *b*, and the residual gas may again be passed back into the compressors through a conducting pipe line. The authors believe that this latter arrangement results in the obtaining of no more condensate, for the residual gas is subjected to the same treatment to which it has already been subjected. In fact the method appears to be wasteful, because the residual gas simply takes the place in the compressors of some gas direct from the wells that could be profitably treated. However the authors have made no experiments to determine this point.

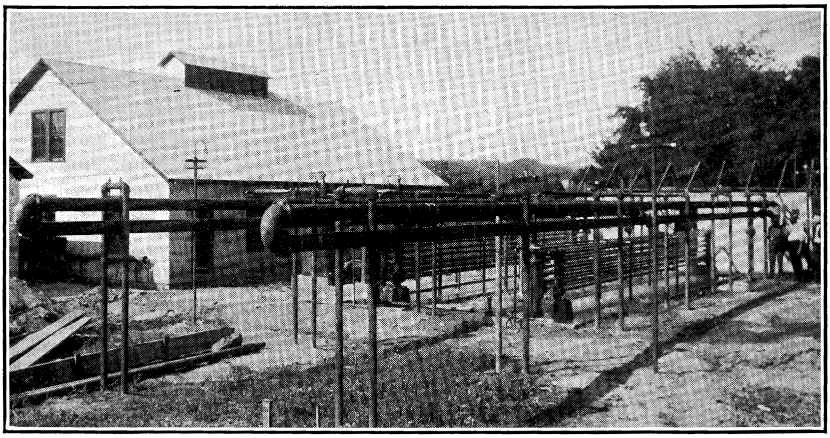
In Plate I, *A*, is shown an exterior view of a gasoline plant at Sistersville, W. Va. The small cooling coils for water cooling and the larger pipes for expansion cooling are shown distinctly.

Plate I, *B*, shows a plant in process of erection in the Glenn pool district, Okla. The expansion coils are jacketed.

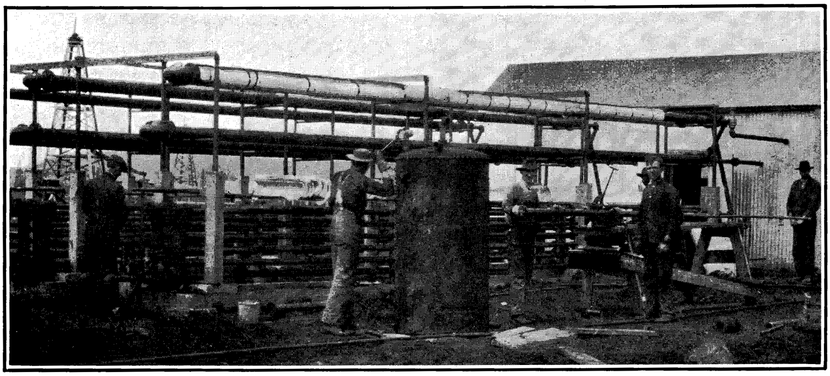
Plate I, *C*, shows a small plant at Reno, W. Va. There are many of the smaller plants of this type throughout the Appalachian fields.

Plate II, *A*, shows the cooling coils and accumulator tanks of another gasoline plant.

Plate II, *B*, shows the interior view of an accumulator-tank house.

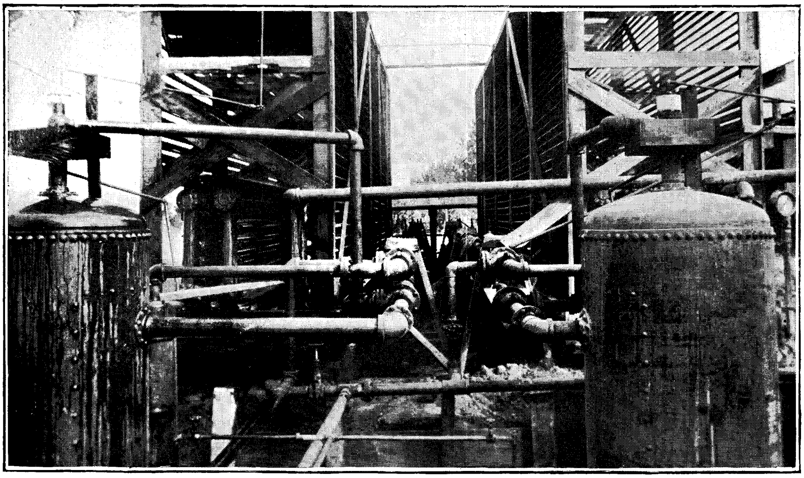


A. EXTERIOR VIEW OF GASOLINE PLANT AT SISTERSVILLE, W. VA.

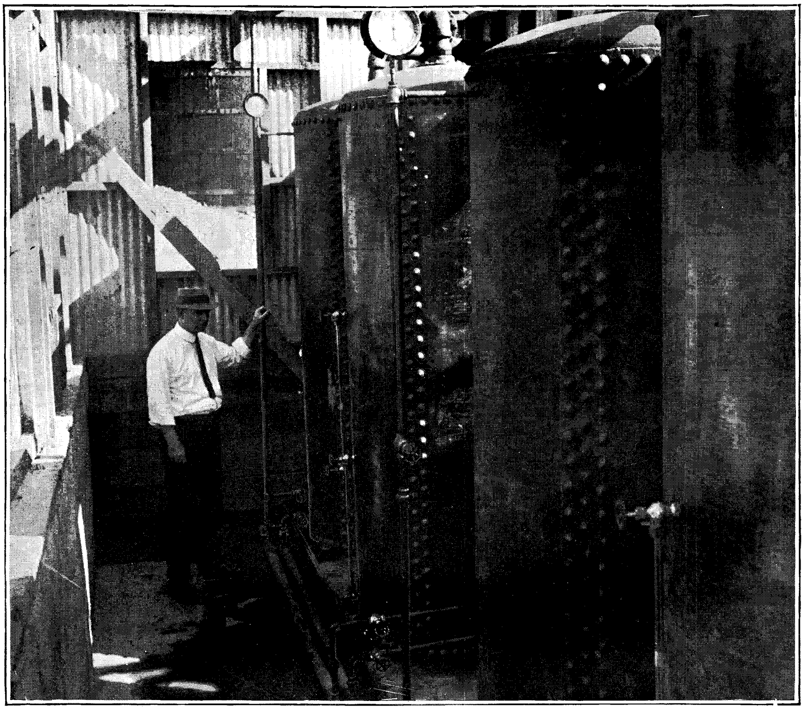


B. GASOLINE PLANT BEING ERECTED NEAR KIEFER, GLENN POOL, OKLA.

C. SMALL GASOLINE PLANT AT RENO, W. VA.



A. COOLING COILS AND ACCUMULATOR TANKS OF GASOLINE PLANT.



B. GASOLINE-PLANT ACCUMULATOR TANKS.

Plate III, *A*, shows a gas engine and belt-driven compressor of another gasoline plant.

Plate III, *B*, shows an interior view of a plant having both a low-stage and a high-stage belt-driven compressor.

Plate IV, *A*, shows the ruins of a natural-gas gasoline plant that was destroyed by an explosion.

Plate IV, *B*, and Plate IV, *C*, show views of a plant in California that is operated by an ammonia refrigerative system.

Plate V, *A*, shows an oil well from which casing-head gas is drawn for a near-by gasoline plant. The pump shown in the foreground to the left of the picture for pumping the gas from the well is connected to several other wells besides that one shown to the right of the figure. The gas-pipe connection to the oil well is not shown in the view, because it is on the other side of the casing.

Plate V, *B*, shows an exterior view of another gasoline plant in the Glenn pool district. Cooling and storage tanks and oil-well derricks and oil tanks are shown. Ice may be seen on two of the gasoline storage tanks.

Plate VI shows the interior view of the compressor building. Six 50-horsepower direct-driven gas compressors are contained in this room. Such an outfit can handle about 2,500,000 cubic feet of gas per 24 hours.

PLANT TESTS TO DETERMINE EFFECT OF DIFFERENT PRESSURES ON YIELD OF GASOLINE.

Some tests were conducted by the authors to show the grade and quantity of gasoline produced when the crude natural gas was subjected to different pressures during actual plant operation. The natural gas issued from the wells under slight pressure. Meters were being used constantly to measure the gas. The pressure to which the gas is ordinarily subjected is about 140 to 150 pounds per square inch. The following table shows the results of the authors' experiments:

Results of tests of the grade and quantity of gasoline produced when crude natural gas is subjected to different pressures.

Pressure.	Temperature of cooling water.	Gravity of gasoline.	Yield of gasoline per 1,000 cubic feet of gas.
Pounds per square inch.	°*C.*	°*B.*	*Cubic feet.*
110	10	....	1.8
140	10	90	3.0
190	10	94	4.5

It had been found by experiment at this plant that pressures of 140 to 150 pounds per square inch produced the most marketable gasoline. It will be observed that a pressure of 190 pounds produced more gasoline. The extra 1½ gallons, however, was of such a volatile character that it only escaped into the atmosphere upon exposure to the air; hence high pressures at this plant were unnecessary. Gasoline could be obtained by the application of pressures as little as 50 pounds per square inch, but the yield was small.

As natural gas is of different character in many different sections of the country and even in the same oil field, data obtained at one plant can not always be used as a basis for operating other plants—that is, as far as the pressures that should be used are concerned. Each operator should thoroughly test his own gas. Different pressures should be applied and the quantity and character of the gasoline noted. A reliable meter for measuring the gas becomes indispensable. If, in certain plants operating to-day, meters were installed and a series of tests conducted as above outlined much greater efficiency of operation could be attained. Other apparatus that could be used to advantage are thermometers, graduated vessels for measuring the gasoline, hydrometers for determining the specific gravity of the gasoline, and gas-analysis apparatus, especially an apparatus for detecting air leaks in pipes through analyses of the gas for oxygen.

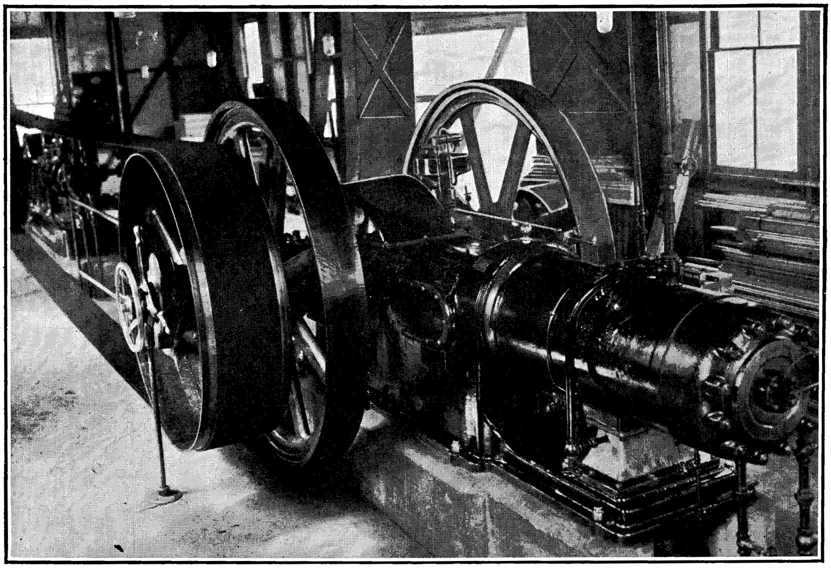
COMMENTS ON METHODS AND EQUIPMENT OF VARIOUS PLANTS.

One plant in McKean County, Pa., obtains only about 72,000 cubic feet per 24 hours from 91 producing oil wells subjected to a reduced pressure of only 1 or 2 inches of mercury. About 4 gallons of gasoline per 1,000 cubic feet of gas is obtained.

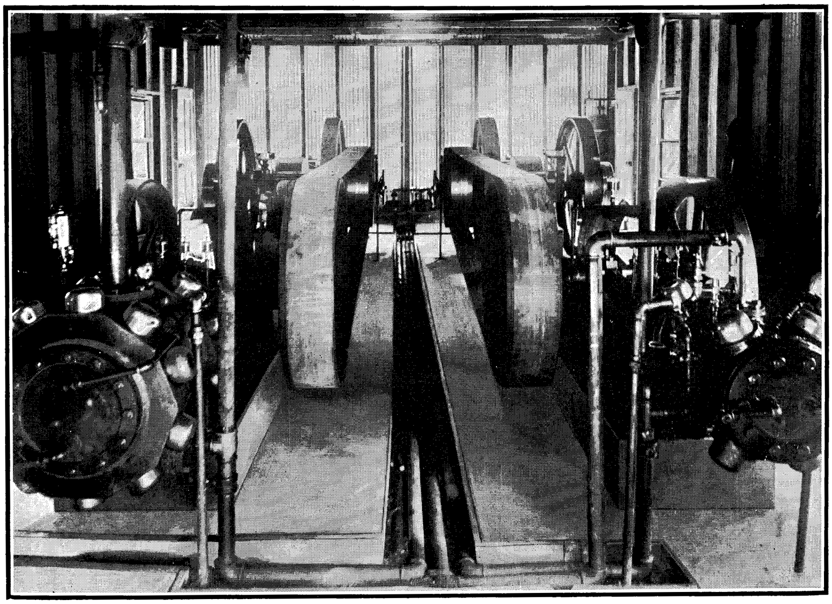
Another plant, about 2 miles distant, obtains about 30,000 cubic feet of gas per hour from 57 wells under a similar reduced pressure.

The only plant in New York situated in the same field as those mentioned above is about 10 miles distant and obtains about 72,000 cubic feet of gas from 60 wells in 24 hours. The wells are drilled in what is known as the third sand. The sand in this locality is spoken of as being "close." At a compression of 250 pounds per square inch and with cooling to about 20° C. (68° F.), the yield of gasoline approximates closely 4 gallons per 1,000 cubic feet of gas. The specific gravity of the condensate is 90° to 95° B.

In the region around Tidioute, Warren County, Pa., there is a condition that exists in no other field in the United States as far as the authors are aware. The producing wells tap the third sand, and are subjected to a reduced pressure of about 20 inches of mercury. Any gases and vapors obtained are simply cooled in water and the condensate collected. The amount of vapors obtained per well is rather small and the methods of extraction of gasoline are crude. At only two "plants" is any attempt made to compress the gas, but connected to these are 50 or 60 wells. The majority of the producers in this region pump only a few wells.

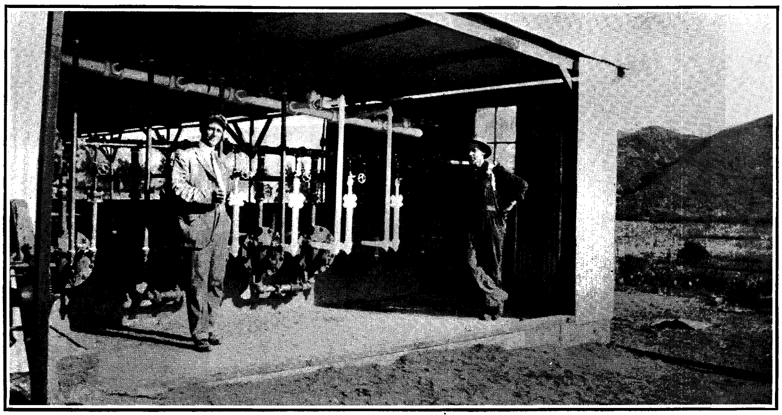


A. GAS ENGINE AND BELT-DRIVEN COMPRESSOR IN GASOLINE PLANT.

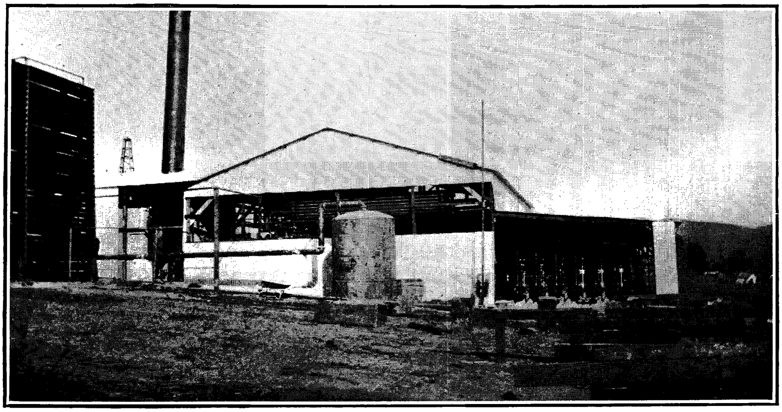


B. DOUBLE-STAGE BELT-DRIVEN COMPRESSOR.

A. RESULTS OF AN EXPLOSION IN A GASOLINE PLANT.



B. PART OF STILL HOUSE OF A PLANT FOR CONDENSING GASOLINE BY REFRIGERATION.



C. GENERAL VIEW OF PLANT FOR CONDENSING GASOLINE BY REFRIGERATION. FROM LEFT TO RIGHT ARE SHOWN THE WATER TOWER, GAS RECEIVER, REFRIGERATING COILS, AND STILLS.

At Hastings, Warren County, Pa., and in the surrounding region the average quantity of gas per well increases over that in the other regions operated in the northern Pennsylvania fields. The quantity of gasoline obtained per 1,000 cubic feet of gas under conditions similar to those in the northern fields is approximately the same.

The oil fields extend south into Butler, Allegheny, and Washington Counties, and many successful plants are in operation in all those counties, although most of them are small. The wells utilized for gasoline production constitute a small proportion of the total number of oil wells, being less than 1 per cent.

As the oil fields extend into West Virginia and Ohio, especially those along the Ohio River on both sides from Steubenville to Marietta, Ohio, more wells are utilized—probably between 25 and 50 per cent of the total number of wells.

In this region are situated some of the largest and best equipped plants in the United States. The gas is as a rule rich in the gasoline-making constituents, approximating on the average close to 3 gallons of 90° to 95° B. gasoline per 1,000 cubic feet of gas treated. Compression at 200 pounds pressure per square inch is employed.

COST OF GASOLINE-PLANT EQUIPMENT.

Compression and condensing equipment that will handle 120,000 cubic feet of gas per 24 hours costs about $2,800. This includes a 15-horsepower gas engine and low-stage compressor for a discharge pressure of 50 pounds per square inch, a 15-horsepower gas engine and high-stage compressor with a discharge pressure of 250 pounds per square inch, intercooler, aftercooler, accumulator tank, expansion coils, and refrigerating coil, and a lighting-plant equipment consisting of a 5-horsepower engine, generator, safety lamps, incandescent lamps, wiring, etc. The gas engines and the compressors are direct connected. The price of equipment varies from $2,800 for equipment for handling the smaller quantities of gas up to $7,800 for equipment capable of handling 600,000 to 700,000 cubic feet of gas. Foundations and housing for machinery, pipe lines to wells, railroad sidings, storage tanks, etc., are extra.

The authors are aware of one small plant from which the owner claims he derives a net income of $150 per month with a small equipment which handles only 60,000 cubic feet of gas in 24 hours. Conditions are such that this man is enabled to attend to this plant in addition to his regular duties. The gas used is exceedingly rich in gasoline vapors.

The authors have knowledge of two plants that cost $40,000 for complete installation, including the cost of compressors, two of them of 50 horsepower, two of 40 horsepower, two of 35 horsepower, and two of 20 horsepower, storage tanks, railroad sidings, and buildings at the sidings, pipe lines to about 120 wells, foundation and housing for equipment, etc. The operating expenses for one year were $11,000. The cost for the salaries of six men included in the operating expenses was $7,000. The other $4,000 was paid for repairing the plant and for waste, oil, etc. The two plants sold 490,000 gallons of gasoline in 1913. For most of the gasoline the company received 13½ cents per gallon. Probably 11¼ cents would be an average price; hence the gross income was 11¼ multiplied by 490,000, or $55,125, the net income therefore being $55,125 less $11,000, or $44,125. The company running these plants, by an unusual agreement, paid to a party from whom they bought the plant a royalty per year of 50 per cent of the profits, hence the owners' net gain was $22,062. Therefore, on the original investment, they realized about 55 per cent return for the year 1913.

PERCENTAGE OF VAPOR CONDENSED BY COMPRESSION AND COOLING.

The change in the raw gas that takes place in the compressors and coolers of a plant consists in the conversion of certain vapors and gases into liquid condition, and the solution of gases in these liquids. To give exact figures for the proportions of gas and vapor that disappear is impossible. An approximation can be reached, however. One gallon of liquid pentane when converted into gas produces about 31 cubic feet of gas at 0° C. and 760 mm. pressure. One gallon of propane in the liquid condition produces about 45 cubic feet of gas. One gallon of butane produces 37 cubic feet of gas. Butane and pentane are probably the two paraffins that are removed in greatest quantity.

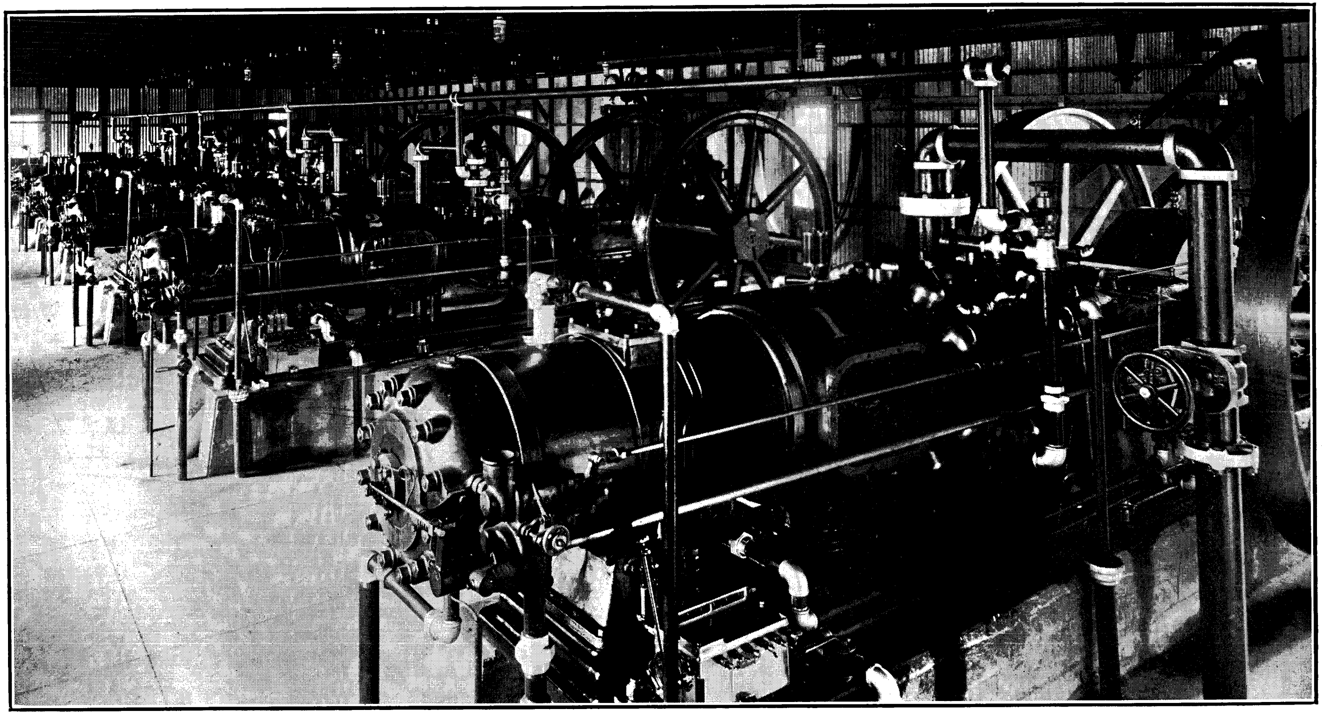
Aside from such liquefaction a certain amount of gas is absorbed by the liquid, as stated above. It is small as regards the total disappearance of gas. The authors estimate that at some plants about 35 cubic feet of gas disappears for each gallon of condensate produced from 1,000 cubic feet of gas. If 4 gallons of condensate per 1,000 cubic feet of gas is obtained, then 140 cubic feet, or about 14 per cent of the gas treated, has disappeared. At some plants, however, as much as 50 per cent of gas disappears, and at others the quantity of residual gas is almost insignificant.

RESULTS OF ANALYSES OF GASES FROM DIFFERENT STAGES OF PLANT OPERATION.

Table 5 following shows the results of laboratory tests of various gases derived from the different stages of plant operation. The percentage of air was calculated from the oxygen content as determined by analysis.

A. OIL WELL FROM WHICH CASING HEAD GAS IS DRAWN FOR NEAR-BY GASOLINE PLANT.

B. EXTERIOR VIEW OF GASOLINE PLANT. COOLING AND STORAGE TANKS, OIL-WELL DERRICKS, AND OIL TANKS ARE SHOWN.



INTERIOR OF A GASOLINE PLANT EQUIPPED WITH SIX 50-HORSEPOWER DIRECT-CONNECTED COMPRESSORS.

TABLE 5.—*Results of laboratory tests of samples of gas from different gasoline plants.*

PLANT 1,[a] NEAR FOLLANSBEE, W. VA.

Condition of gas.	Calculated gross heating value per cubic foot at 0° C. and 760 mm.	Specific gravity at 0° C. and 760 mm. (air=1).	Proportion absorbed by 35 cc. of oil.	Composition.								Remarks.
				Air.	CH_4.	C_2H_6.	C_3H_8.	C_4H_{10}.	N_2.	CO_2.	Total.	
	B.t.u.			*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	
Natural gas as drawn from the well.	2,544	1.46	85.7	......	......	10.8	88.3	......	0.9	......	100	The gas was drawn from 75 producing oil wells, under a reduced pressure of 20 inches of mercury. The gasoline produced was shipped in drums to Pittsburgh, Pa., where it was blended with refinery naphtha for the market.
Residual gas after removal of 50 pounds of compression product.	2,515	1.46	......	......	......	16.9	82.9	......	0.2	......	100	
Residual gas after removal of 250 pounds of compression product.	2,171	1.23	78.2	......	......	59.2	40.3	......	0.5	......	100	
Natural gas as drawn from the well.....	2,474	1.41	83.6	......	......	21.4	78.2	......	.4	......	100	These samples were taken from the same plant as those above, but were taken two months previous.
Residual gas after removal of 50 pounds of compression product.	2,415	1.38	82.0	......	......	26.5	72.4	......	1.1	......	100	
Residual gas after removal of 250 pounds of compression product.	2,022	1.15	63.6	......	......	77.3	22.0	......	.7	......	100	
PLANT 2, NEAR McDONALD, PA.												
Natural gas as drawn from the well......	*B.t.u.* 1,817 1,273	1.03	38.5 27.0	(b) c30.1	2.7 1.9	96.1 67.3	......	......	1.0 .6	0.2 .1	100 100	Air was leaking into the pipes in large amount. The output of gasoline was 1½ gallons per 1,000 cubic feet of crude gas. The gas used was that from producing wells. The gas was obtained under a reduced pressure of 20 inches of mercury. This gasoline was blended with refinery naphtha and then marketed.
Residual gas after removal of 20 pounds of compression product.	1,303	c.02	c30.2	29.0	.7	69.6	......	......	.6	.1	100	
Residual gas after removal of 80 pounds of compression product.	1,220	......	25.0	30.0	7.2	62.0	......	......	.7	.1	100	

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[a] Plant numbers arbitrarily assigned for convenience of reference.

[b] Analysis calculated "air free" to show composition of crude gas. The crude gas was obtained after the gas had been first compressed but not cooled.

[c] Actual composition of the gas delivered to the compressor.

TABLE 5.—*Results of laboratory tests of samples of gas from different gasoline plants*—Continued.

PLANT 3, NEAR McDONALD, PA.

Condition of gas.	Calculated gross heating value per cubic foot at 0° C. and 760 mm.	Specific gravity at 0° C. and 760 mm. (air=1).	Proportion absorbed by 35 cc. of oil.	Composition.								Remarks.
				Air.	CH_4.	C_2H_6.	C_3H_8.	C_4H_{10}.	N_2.	CO_2.	Total.	
	B. t. u.			*P. ct.*	*P. ct.*	*P. ct.*	*P. ct.*	*P. ct.*	*P. ct.*	*P. ct.*	*P. ct.*	
Natural gas as drawn from the well	2,310	1.59	43.0	(a)	......	......	34.3	40.6	23.0	2.1	100	The output of gasoline was 3 to 4 gallons of gasoline (90° B.) per 1,000 cubic feet of gas. The gas was drawn from producing wells, under a reduced pressure of 20 inches of mercury. The gasoline was blended with refinery naphtha and then marketed.
	1,650	......	33.0	b28.5	......	......	24.5	29.0	16.5	1.5	100	
Residual gas after removal of 20 pounds of compression product	1,220	......	17.7	b29.6	......	25.5	28.1	......	16.0	.8	100	
Residual gas after removal of 80 pounds of compression product	1,050	......	20.6	b30.7	......	43.5	9.0	......	16.0	.8	100	

PLANT 4, NEAR KIEFER, OKLA. (GLENN POOL).

Condition of gas.	Calculated gross heating value per cubic foot at 0° C. and 760 mm.	Specific gravity at 0° C. and 760 mm. (air=1).	Proportion absorbed by 35 cc. of oil.	Air.	CH_4.	C_2H_6.	C_3H_8.	C_4H_{10}.	N_2.	CO_2.	Total.	Remarks.
Natural gas as drawn from the well	*B. t. u.* 1,344	0.83	......	......	49.1	44.1	......	......	0.7	6.1	100	The output of gasoline was 1½ gallons of "wild" gasoline per 1,000 cubic feet of gas. The gas was drawn from the wells under a reduced pressure of 20 inches of mercury. The gasoline was blended with refinery naphtha and then marketed.
Residual gas after removal of 250 pounds of compression product	1,313	.76	22.4	......	60.7	35.8	......	......	.6	2.9	100	

PLANT 5, NEAR FOLLANSBEE, W. VA.

Condition of gas.	Calculated gross heating value per cubic foot at 0° C. and 760 mm.	Specific gravity at 0° C. and 760 mm. (air=1).	Proportion absorbed by 35 cc. of oil.	Air.	CH_4.	C_2H_6.	C_3H_8.	C_4H_{10}.	N_2.	CO_2.	Total.	Remarks.
Natural gas as drawn from well	*B.t.u.* 2,417	1.380	64.7	(a)	......	28.5	71.1	......	0.4	100	......	The output of gasoline was 500 gallons in 24 hours from two 35-horsepower compressors.
	2,103	......	57.0	b13.0	......	24.8	61.9	......	.3	100	......	
Residual gas after removal of 50 pounds of compression product	2,015	......	b56.6	b11.5	......	34.8	53.4	......	.3	100	......	
Residual gas after removal of 225 pounds of compression product	1,576	......	b42.2	b18.0	......	74.3	7.3	......	.4	100	......	

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[a] Analysis calculated "air free" to show composition of crude gas.

[b] Analysis shows actual composition of gas delivered to compressor.

TABLE 5.—*Results of laboratory tests of samples of gas from different gasoline plants*—Continued.

PLANT 6, NEAR RIVERSIDE, W. VA.

Condition of gas.	Calculated gross heating value per cubic foot at 0° C. and 760 mm.	Specific gravity at 0° C. and 760 mm. (air=1).	Proportion absorbed by 35 cc. of oil.	Composition.								Remarks.
				Air.	CH_4.	C_2H_6.	C_3H_8.	C_4H_{10}.	N_2.	CO_2.	Total.	
	B.t.u.			*P. ct.*	*P. ct.*	*P. ct.*	*P. ct.*	*P. ct.*	*P. ct.*	*P. ct.*	*P. ct.*	
Natural gas as taken from the well......	2,369	1.37	48.3	(a)	......	32.2	66.7	......	1.1	100	......	The gas was drawn from the wells under a reduced pressure of 20 inches of mercury.
	1,720	1.27	33.4	b27.4	......	23.4	48.4	......	.8	100	......	
Residual gas after compression to a few ounces...	1,657	1.26	31.8	b29.4	......	23.9	45.7	......	1.0	100	......	
	2,348	1.36	45.0	(a)	......	33.9	64.7	......	1.4	100	......	
Residual gas after removal of 70 pounds of compression product.	1,119	.98	23.1	b34.9	10.7	54.0	......	......	.4	100	......	
	1,729	.97	53.6	(a)	16.4	83.0	......	......	.6	100	......	

PLANT 7, NEAR RIVERSIDE, W. VA. (PLANT NO. 9).

Natural gas as drawn from the well......	*B.t.u.* 1,669	......	27.8	b31.1	......	12.4	54.2	......	2.3	100	......	The gas was drawn from 49 wells.
	2,424	1.38	44.1	(a)	......	18.0	78.7	......	3.3	100	......	
Residual gas after removal of 90 pounds of compression product.	1,178	......	23.5	b37.0	......	52.2	7.8	......	3.0	100	......	
	1,872	1.06	37.3	(a)	......	82.9	12.4	......	4.7	100	......	

PLANT 8, NEAR STEUBENVILLE, OHIO.

Natural gas as drawn from the well......	*B.t.u.* 1,810	1.15	51.2	b12.6	......	64.3	23.1	......	......	100	......	
	2,070	1.21	53.7	(a)	......	73.6	26.4	......	......	100	......	
Residual gas after removal of 90 pounds of compression product.	1,615	......	42.5	b15.3	......	79.8	4.9	......	......	100	......	
	1,907	1.08	50.2	(a)	......	94.2	5.8	......	......	100	......	
Residual gas after removal of 160 pounds of compression product.	1,874	1.06	51.3	(a)	......	98.3	1.7	......	......	100	......	
	1,559	......	42.7	b16.8	......	81.8	1.4	......	......	100	......	

PLANT 9, W. VA.

Natural gas as drawn from the well......	*B.t.u.* 2,231	1.29	49.7	(a)	......	47.6	50.7	......	1.7	100	......	Gas was drawn from 35 wells.
	1,444	......	32.8	b 5.2	......	30.8	32.8	......	1.2	100	......	
Residual gas after removal of 100 pounds of compression product.	1,931	1.12	39.5	(a)	......	84.3	13.7	......	2.0	100	......	
	1,225	......	25.1	b36.5	......	53.5	8.7	......	1.3	100	......	

a Analysis calculated "air free" to show composition of crude gas.
b Actual composition of gas delivered to compressor.

TABLE 5.—*Results of laboratory tests of samples of gas from different gasoline plants*—Continued.

PLANT 10, W. VA.

Condition of gas.	Calculated gross heating value per cubic foot at 0° C. and 760 mm.	Specific gravity at 0° C. and 760 mm. (air=1).	Proportion absorbed by 35 cc. of oil.	Composition.								Remarks.
				Air.	CH_4.	C_2H_6.	C_3H_8.	C_4H_{10}.	N_2.	CO_2.	Total.	
	B.t.u.			*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	
Natural gas as drawn from the well......	1,916	1.07	38.4	(a)	......	93.1	6.9	......	......	100	......	Gas was drawn from 100 wells.
	1,521	......	30.7	[b]20.6	......	73.9	5.5	......	......	100	......	
Residual gas after removal of 125 pounds of compression product..	1,635	......	34.5	(a)	28.4	71.6	......	......	......	100	......	
	1,311	.91	27.7	[b]19.8	22.8	57.4	......	......	......	100	......	

PLANT 11, NEAR STEUBENVILLE, OHIO.

Condition of gas.	Calculated gross heating value per cubic foot at 0° C. and 760 mm.	Specific gravity at 0° C. and 760 mm. (air=1).	Proportion absorbed by 35 cc. of oil.	Air.	CH_4.	C_2H_6.	C_3H_8.	C_4H_{10}.	N_2.	CO_2.	Total.	Remarks.
	B.t.u.											
Natural gas as drawn from the well......	1,784	1.00	36.9	(a)	9.7	90.3	......	......	......	100	......	Gas was drawn from 26 wells.
	1,616	......	33.1	[b] 9.4	8.8	81.8	......	......	......	100	......	
Residual gas after removal of 25 pounds of compression product.	1,697	.95	36.3	(a)	20.6	79.4	......	......	......	100	......	
	1,519	......	32.0	[b]10.5	18.4	71.1	......	......	......	100	......	
Residual gas after removal of 160 pounds of compression product.	1.598	.89	[a]34.9	(a)	33.0	67.0	......	......	......	100	......	
	1,381	......	[b]30.2	[b]13.6	28.5	57.9	......	......	......	100	......	

[a] Analysis calculated "air free" to show composition of crude gas.

[b] Actual composition of gas delivered to compressor.

SIGNIFICANCE OF RESULTS TABULATED.

It is well to again call attention to the fact that the percentages of paraffin hydrocarbons shown in the preceding results of analyses are only approximate. Only the two predominating paraffin hydrocarbons are shown. For instance, in plant 2 the hydrocarbon content of the crude gas is given as CH_4, 2.7 per cent, and C_2H_6, 96.1 per cent. Propane, butane, and vapors of the liquid hydrocarbons must be present, else gasoline could not be condensed from the gas. The total hydrocarbon content is correct or nearly correct, however, as is the specific gravity and heating value. The oil absorption shows only the relative solubilities of the different gases under a certain condition. One can determine approximately the relative changes that take place in the plant operation by comparing the different analytical results. For instance, the figures for plant 6, near Riverside, W. Va., indicate that the gas underwent only a small change after compression in the first stage to a pressure of a few ounces. The specific gravity changed only from 1.27 to 1.26, the heating value dropped inappreciably, the oil absorption was only slightly different, and there was scarcely any change in the chemical analysis. After compression to 70 pounds per square inch, however, the gas changed markedly.

Regarding the results for plant 1, the chemical analysis, the specific gravity determination, and the claroline oil absorption show the gas represented to be a rich one. It will be seen that little difference existed between the composition of the crude gas and the same gas after it had been compressed to a pressure of 50 pounds per square inch. Only after the compression to a pressure of 250 pounds per square inch and cooling, did the composition of the gas mixture change appreciably.

The results obtained with the gas from plant 2, a small plant near McDonald, Pa., show that the crude gas was not very "wet." The absorption by claroline oil was rather low, and the gas was probably near the lower limit of a gas adapted for the production of gasoline. The composition of the gas was not changed to a very marked degree at any stage in the plant operation.

The results obtained with the gas from plant 3, 1 mile from plant 2, and the results with the gas from the latter plant show in a marked degree how natural-gas samples may vary in the same field. After the sample from plant 3 had been compressed to 20 pounds per square inch and cooled, a considerable change in the composition took place. The composition also changed considerably after compression to 80 pounds per square inch and cooling. Nearly 50 per cent of the gas delivered to the compressor consisted of air and nitrogen.

The results for plant 4, in the Glenn pool district, Okla., cover a gas probably about as poor as can be handled commercially. The condensate produced is extremely volatile. Other samples of gas from this same field are rich in gasoline vapors.

The results for plant 5 represent a gas that was derived from wells in the immediate vicinity of those connected with plant 1. The gas is of the same general character. The greatest change occurs after compression to 225 pounds per square inch and cooling.

Regarding plant 6, near Sistersville, W. Va., compression to a few ounces per square inch and cooling produced no gasoline, but after compression to 70 pounds per square inch and cooling, the gas underwent a considerable change in composition. A heavy condensation of gases and vapors occurred.

As regards the results for plant 8, near Steubenville, Ohio, most of the condensate was produced after the gas had been compressed to 90 pounds per square inch and cooled. Increasing the pressure to 160 pounds per square inch and cooling gave little additional yield, as is shown by the test results.

In plant 9 one-stage compression and cooling was practiced. High-grade plant equipment and excellent methods of handling the product were in use.

In plant 10 the composition of the gas, after compression to 125 pounds per square inch and cooling, changed markedly. Compression to any higher pressures would probably be useless, in view of the composition of the waste gas.

GENERAL CONCLUSIONS.

In general the preceding table shows that under existing methods of plant operation condensate is extracted from natural gas that ranges in specific gravity from as low as 0.83 to as high as 1.59 (air = 1) and that the solubilities of the gas in claroline oil ranges from 36.9 (air free) to 85.7 per cent, according to the well from which it comes.

The authors hesitate to recommend the installation of a plant to handle natural gas that shows results as poor as the minimum values given in the table. Such gas might produce gasoline in paying quantities and might not. Probably the safest extremes would be a specific gravity of 0.95 (air = 1), and a claroline-oil absorption of 40 per cent. The natural gas supplied to Pittsburgh, Pa., with which the authors are most familiar, contains little of the gaseous hydrocarbons, has a specific gravity of 0.64 (air = 1), and has a claroline-oil absorption of about 16 per cent. It is a dry gas and is unsuitable for gasoline production.

It will be seen that in many of the plants the gas delivered to the compressor contained 20 to 40 per cent of air due to inleakage either through the rock strata or through defective connections in the gas lines. Such leakage is obviously undesirable and every effort should be directed toward its prevention.

The waste gases from some plants seem to contain considerable quantities of gasoline-making constituents, as may be observed from the analytical results, including the specific gravity determinations, and the percentages of gas that was absorbed by claroline oil. The waste gases escape directly from the accumulator tank containing the last-stage compression products. These products at the existing temperatures have high vapor pressures, and consequently the escaping gases carry with them some of the vapors of the liquid in the tank.

SPECIFIC GRAVITIES AND ABSORPTION NUMBERS OF NATURAL GASES USED FOR CONDENSATION OF NATURAL GAS.

The authors have compiled the following table to show at a glance the specific gravities and absorption numbers of natural gases used for the condensation of natural gas. The table is compiled from the results shown in the large table preceding. The compilation will be useful for reference in predicting the results that may be obtained from other samples of natural gas.

Specific gravities and absorption numbers of samples of natural gas used for making gasoline.

No.	Specific gravity (air=1).	Absorption number.	No.	Specific gravity (air=1).	Absorption number.
1	1.46	86	7	1.37	48
2	1.41	84	8	1.38	44
3	1.03	39	9	1.21	54
4	1.59	43	10	1.29	50
5	.83	23	11	1.07	38
6	1.38	65	12	1.00	37

FIRE HAZARD AT GASOLINE PLANTS.

Serious accidents have occurred in the manufacture of gasoline from natural gas and in the transportation of the gasoline. Several plants have been completely wrecked through the explosions of gas-air mixtures that have resulted from the escape and ignition of natural gas in the engine and compressor rooms. Storage tanks have also been demolished when they have burst owing to excessive pressures put on them. Safety valves must be in good working order, and great care should be exercised in installing electric wiring systems and magnetos. All electric wiring should be properly placed, well insulated and made secure on supports. Fuses or electric switches should never be placed inside of buildings where gas might escape. Lighting dynamos and magnetos should be installed in small buildings outside the main building. Electric-light bulbs should be protected by wire guards, because they may ignite explosive mixtures if they are accidentally smashed.[a]

The following table shows the small percentages of gases and vapors occurring in natural gas that are required to form explosive mixtures with air:

Low explosive limits for paraffin gases and vapors.[b]

Hydrocarbon.	Proportion of gas-air mixture constituting low explosive limit.	Hydrocarbon.	Proportion of gas-air mixture constituting low explosive limit.
	Per cent.		*Per cent.*
Methane	5.60 to 5.70	N butane	1.60 to 1.70
Ethane	3.00 to 3.20	N pentane	1.35 to 1.40
Propane	2.15 to 2.30		

According to the above table, even if a natural gas consisted almost entirely of methane, as some natural gases do, an explosion would follow an ignition of a mixture of air and natural gas containing 5.50 per cent of methane. The natural gas of Pittsburgh contains an

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[a] Clark, H. H., and Ilsley, L. C., Ignition of mine gases by the filaments of incandescent lamps: Bull. 52, Bureau of Mines, 1913, 31 pp.

[b] Burgess, M. J., and Wheeler, R. V., The lower limit of the inflammability of mixtures of the paraffin hydrocarbons with air: Trans. Chem. Soc., vol. 99, 1911, pp. 2013, 2030.

appreciable quantity of ethane and propane. The authors have determined its explosive limits to be about 5 per cent gas, low limit, and about 11.6 per cent gas, high limit. The "wet" gases, or those from which gasoline is condensed, contain a much higher proportion of the higher paraffin hydrocarbons than does the natural gas of Pittsburgh, and consequently have narrower explosive limits. Their low explosive limits are much lower. The authors have made no determination of the explosive limits of the "wet" natural gases from which gasoline is condensed, but they can closely estimate for many "wet" gases that such limits will range from about 3.5 per cent gas, low limit, to about 9.5 per cent gas, high limit. That is, when some "wet" natural gases are present in the mixture of the gas and air, an explosion will occur between these limits, although the limits for different natural gases will vary somewhat from the figures mentioned.

It will be observed then that only a small proportion of the gas need be mixed with air to form an explosive mixture, and that great care should be exercised to guard against leaks of the gas in plant buildings.

EFFECT OF LEAKAGE OF AIR INTO PIPES AND CONNECTIONS.

As mentioned before, at many oil wells that are connected to gasoline plants the gas is drawn at reduced pressures as low as 25 inches of mercury. Manifestly, under such low pressure, pipe and other connections must be very tight in order to avoid inflow of air. The authors have found as much as 40 per cent of air in the mixture drawn into some compressors. In some instances the air is drawn into the rock strata through old and abandoned wells that have not been properly plugged.

Introduction of air of course cuts down gasoline production and may lead the operator into believing that the quality of his gas as regards gasoline content is low. Residual gas may contain so much air as to be objectionable for further use. A determination of the oxygen in the gas as it comes to the plant would give complete information as to the air content. The authors know of few plants where such determinations are made. Oxygen is not a constituent of natural gas as it occurs in the earth. Hence, its presence in a pipe line shows inflow of air. Pure dry air contains 20.93 per cent of oxygen. Consequently, if the oxygen content of a gas is known, the percentage of air can readily be calculated.

CHARACTER AND USES OF RESIDUAL GAS.

In some gasoline plants gas issuing after some of the condensate has been removed is sent to mains and used for consumption in ordinary ways or returned to the leases to be used for pumping purposes. In some plants it is wasted. As far as the quality of most of the gas is concerned, unless greatly contaminated with air, it is superior to that ordinarily used in cities and towns. Originally, as mentioned heretofore, it contains the permanent gases methane and ethane that are also contained in the natural gases ordinarily used for supplying cities. In addition there are contained considerable quantities of the more easily liquefied gases propane and butane, and some gasoline vapors. As the gas passes through the plant the gasoline vapors are to a large extent removed. Some of the propane and butane is liquefied and some of the methane and ethane goes into solution. The proportions of propane, butane, methane, and ethane that disappear may be small. The residual gas as it leaves the plant will contain all of the above-named constituents, because a complete removal of even the gasoline vapors is not accomplished in plant practice. The results of analyses on page 61 show the composition of raw and natural gases before and after passing through the plant. The high heating value of the residual gas is apparent, being in one instance almost twice as high as the heating value of the natural gas of Pittsburgh which has a gross heating value of 1,179 British thermal units per cubic foot at 0° C. and 760 mm. pressure.

Frequently the quantity of gasoline vapors in casing-head gas is so high as to cause trouble in gas-engine cylinders from premature ignition. The fact that casing-head gases vary so widely in composition can not of course be anticipated by engine builders. It is also true that casing-head gases may be unsatisfactory for lighting if mantles are used because the standard burner can not be adjusted for complete combustion of the gas. The result is sooty mantles and imperfect light. Removal of the gasoline vapors sometimes overcomes this objection.

SOLUTION OF GAS IN CONDENSATES.

As previously stated, one of the physical changes occurring in the operation of a gasoline plant has to do with the solution of gas in the condensate, that is, when the residual gas is in contact with the condensate in the storage tank. The following experiment and calculation by the authors will serve to show how small and insignificant this change may be.

A residual gas from an operating plant was shaken with refinery naphtha. The naphtha had a specific gravity of 61° B. The solution was effected at a temperature of 20° C. (68° F.) and atmospheric pressure. The naphtha was shaken with the gas supply until no more gas would go into solution. It was found that 1 liter of the naphtha dissolved 1.760 liters of the gas; or 500 gallons of the naphtha would have dissolved 3,331.7 liters of the gas. If the assumption be made that this residual gas was ethane only, then it can be calculated that 3,331.7 liters of gaseous ethane at 16° C. (60° F.) and 30 inches of mercury is equivalent to 2.7 gallons of liquid ethane. This quantity of liquid is so small as to seem insignificant, although as regards raising the vapor pressure of the condensate it is important.

LIFE OF WELLS AS REGARDS PROFITABLE GASOLINE EXTRACTION.

Some conclusion regarding the length of time that gasoline may be profitably extracted from the natural gas of a given well may be gained by referring to the history of past operations. In the East gasoline-extraction plants have been in operation for several years. An important factor is the quantity of oil present. Neither gas nor oil wells are as long lived in the Mid-Continent as in the Eastern fields. It would appear therefore that in the Mid-Continent field, gasoline operations will not have as long life as those in the Eastern fields. They will probably last longer, however, than those in the California fields. Operations for the recovery of gasoline from casing-head gas in the old Tidioute, Pa., region, where profitable yields of gasoline are obtained at very low pressures, have continued for five years. These wells have been producing gas and oil under vacuum for 40 years prior to the actual installation of gasoline plants. The authors have definite information regarding the installation of a plant at Parkersburg, W. Va., that operates on wells that have been under vacuum for 29 years. After two years' operation of the gasoline plant the quantity of gas began to decline rapidly. General conclusions can not, however, be drawn from this plant.

Around Sisterville, W. Va., there are probably more plants for the recovery of gasoline from casing-head gas than at any other place in the United States. Oil wells in that district have operated under a vacuum for 15 or 20 years. Within the town limits some wells operating under a reduced pressure of 24 inches of mercury produce 1 barrel of gasoline a day. The fact that the engines use city gas, there being no residual gas left, shows the absence of much permanent gas in the wells. Certain oil wells may produce considerable gas when gasoline recovery is started but eventually the gas ceases to flow, and a reduction of pressure withdraws no gas from the well but simply removes the gasoline fractions.

The Glenn pool in the Oklahoma fields has, the authors believe, already shown indications of having a long life. The application of reduced pressure to the wells has increased both the gasoline and the oil yield.

The authors can not predict the life of gasoline-plant operations in general in the Oklahoma fields. With reference to the Glenn pool fields, however, they believe that it would be entirely safe to predict a life of profitable gasoline operation equal to that which can be realized with the oil itself. There are some other regions in Oklahoma that have shown particularly unreliable indications as to casing-head gas, there having been a considerable volume of gas in new wells, which later dwindled rapidly. This tendency seems to be common with the shallow sands, a possible exception being a pool known as the Childer's pool in the Delaware region. When gas escapes freely from wells that have been producing oil for two or three years, they may be expected to produce gas enough to assure the return of the initial investment with profit.

CONDENSATION OF GASOLINE BY REFRIGERATION.

METHODS OF PLANT AT OLINDA, CAL.

In a plant at Olinda, Cal., the gasoline is condensed by refrigeration at low temperatures. Ammonia is the refrigerating agent used. Plate IV, *C*, shows a general view of this plant.

In a letter to the authors, the president of the company stated that in a day of 24 hours 300,000 cubic feet of gas was used, from which was extracted 1,200 gallons of condensate.

Seven condensing coils are used. They are laid side by side and connected to each other by headers. In the first two ammonia refrigeration is not used. A considerable drop of temperature is obtained in these coils, however, by causing the gas to expand into them. The temperature in No. 1 and No. 2 stills is approximately 150° F. (66° C.), in No. 3 still 65° F. (18° C.), in No. 4 still 50° F. (10° C.), in No. 5 still 40° F. (4° C.), in No. 6 still 30° F. (−1° C.), and in No. 7 still 14° F. (−10° C.) The condensate precipitated in the No. 1 still is said to have a specific gravity of about 60° B., in the No. 2 still 62° B., in the No. 3 still 70° B., in the No. 4 still 74° B., in the the No. 5 still 80° B., in the No. 6 still 84° B., and in the No. 7 still 95° B. The condensates are finally all mixed together, producing a mixture with a specific gravity of 80° B.

The company pays 32 cents per pound for ammonia. Approximately 400 pounds was required to charge the machine in September, 1913. Up to March 5, 1914, the charge had not been renewed. The ammonia is delivered to the compressor at a pressure of approximately 15 pounds per square inch, and leaves the compressor at a pressure of 150 pounds.

DESCRIPTION OF ORDINARY AMMONIA REFRIGERATING MACHINE.

An ordinary ammonia refrigerating machine such as is used for cooling purposes in general consists essentially of three parts—a refrigerator or evaporator, a compression pump, and a condenser.

The refrigerator, which consists of a coil or a series of coils, is connected to the suction side of the pump, and the delivery from the pump is connected to the condenser, which is generally of a somewhat similar construction to the refrigerator. The condenser and the refrigerator are joined by a pipe in which is a valve called the regulator. Outside the refrigerating coils is the air, brine, or other substance that is to be cooled in the refrigeration system; and outside the condenser is the cooling medium, which is water. The liquid ammonia passes from the bottom of the condenser through the regulating valve into the refrigerator in a continuous stream. As the pressure in the refrigerator is reduced by the pump and maintained at such a degree as to give the desired boiling point—which is, of course, always lower than the temperature outside the coils—heat passes from the substance outside through the coil surfaces and is taken up by the entering liquid, which is converted into vapor. The vapors thus generated are drawn into the pump, compressed, and discharged into the condenser, the temperature of which is somewhat above that of the cooling water. Heat is transferred from the compressed vapor to the cooling water, and the vapor is converted into a liquid which collects at the bottom and returns by the regulating valve into the refrigerator. The compressor may be driven by a gas engine or in any other convenient manner. The pressure in the condenser varies according to the temperature of the cooling water, and that in the refrigerator is dependent upon the temperature to which the outside substance is cooled.

Anhydrous ammonia is a gas at ordinary temperatures and under atmospheric temperatures. The liquid anhydrous ammonia is commercially sold in iron drums in which it is contained under a pressure varying between 120 and 200 pounds per square inch, the pressure in the drum depending on the temperature of the liquid in it.

Some idea of the nature of the natural-gas condensate obtained can be had by considering the liquefaction points of the constituents that are found in natural gases used for gasoline condensation. The boiling point of liquid propane is $-45°$ C. ($-49°$ F.), and of liquid butane 1° C. (34° F.).

The lowest temperature obtained in the refrigerating coils of the Olinda plant is $-10°$ C. (14° F.). Hence it can be accepted that no propane is liquefied, but some butane and higher paraffins are. The efficiency of the extraction of the condensible constituents from the natural gas for any given temperature will depend upon the velocity of the gas through the coils, or, what is the same thing, the area of cooling surface. Heat is of course extracted from the natural gas when it enters the cooling system. If the cooling area of the pipes is not great enough, the residual natural gas will leave the system still containing gasoline vapors that could have been condensed by further cooling treatment. By proper experimentation the amount of cooling surface required to produce the greatest quantity of salable condensate can be ascertained. Presumably the operators of the Olinda plant have made such a determination. The authors are not closely acquainted with its operations. They believe that the refrigeration method offers much promise and that more plants of this type will be installed.

In the United States at least 85 per cent of the refrigeration plants used for various purposes use ammonia as the refrigerant. Other refrigerants that may be used are sulphur dioxide, carbon dioxide, and water vapor.

TRANSPORTATION OF NATURAL-GAS GASOLINE.

After the production of gasoline from natural gas became a commercial success, the matter of the best methods of transporting it became important. Some of the product when first drawn from the storage tanks may have a specific gravity as high as 100° B. Some condensates are even lighter than this. The exact nature of the product was not clearly understood during the inception of the industry, and in transporting it pressures developed in the containers great enough to burst some of them. Several serious accidents occurred. It was quickly recognized that the material as freshly drawn was not suitable for transportation in containers such as were used for handling ordinary gasoline. Weathering the condensate and blending it with refinery naphtha so that a liquid was obtainable that upon evaporation would not develop excessive pressures overcame the difficulty. However, compulsory rules for its transportation that could be met by the producers were recognized as necessary. Consequently B. W. Dunn, Chief of the Bureau for the Safe Transportation of Explosives, called a meeting of producers at Pittsburgh, Pa., on May 26, 1911. Recommendations were adopted indicating the method of shipping the condensate pending the drafting of final regulations.

Col. Dunn recommended that the producers determine the vapor pressure of their product at 100° F. (38° C.), and sent inspectors to those producers who used tank cars in shipping their product. A tentative maximum vapor pressure was set at 10 pounds per square inch for a temperature of 100° F. (38° C.).

Tank cars differed widely in their construction and many were not suitable for carrying a highly volatile liquid. Consequently, it was recommended that only standard tank cars should be employed.

RULES OF THE INTERSTATE COMMERCE COMMISSION.

The final rules of the Interstate Commerce Commission regarding the shipment of natural-gas gasoline are presented below.

REGULATIONS FOR THE TRANSPORTATION ON RAILROADS OF NATURAL-GAS GASOLINE.[a]

Liquefied petroleum gas is a condensate from the "casing-head gas" of petroleum oil wells, whose vapor tension at 100° F. (38° C.) (90° F.—32° C.—November 1 to March 1) exceeds 10 pounds per square inch. Liquefied petroleum gas must be shipped in metal drums or barrels which comply with "Shipping-Container Specifications No. 5," or in tank cars especially constructed and approved for this service by the Master Car Builders' Association.

When the vapor tension at 100° F. (38° C.) exceeds 25 pounds per square inch, cylinders as prescribed for compressed gas must be used.

(The commission has not deemed it best at this time to prohibit the use of good wooden barrels in shipping inflammable liquids with a flash point below 20° F. (—7° C.). It is, however, expected that their use for that purpose will be gradually discontinued and that within a reasonable time metal barrels will come into general use for such shipments.)

Packages containing inflammable liquids must not be entirely filled. Sufficient interior space must be left vacant to prevent distortion by containers when heated to a temperature of 120° F. (49° C.). This vacant space must not be less than 2 per cent of the capacity of the container, including the dome capacity of tank cars.

1. The provisions of "Shipping-Container Specifications No. 5" apply to all containers specified therein that are purchased after December 31, 1911, and used for the shipment of dangerous articles other than explosives. Each such container purchased subsequently to December 31, 1911, shall have plainly stamped thereon the date of manufacture thereof.

2. An iron or steel barrel or drum with a capacity of from 50 to 55 gallons must have a minimum weight in the black, exclusive of the weight of rolling hoops, of 70 pounds, and the minimum thickness of metal in any part of the completed barrel must not be less than that of No. 16 gage United States standard.

3. An iron or steel barrel or drum with a capacity of from 100 to 110 gallons must have a minimum weight in the black, exclusive of the rolling hoops, of not less than 130 pounds, and the minimum thickness of metal in any part of the completed barrel or drum must not be less than that of full No. 14 gage United States standard.

4. Each barrel or drum must stand without leaking a manufacturers' test under water by interior compressed air at a pressure of not less than 15 pounds per square inch sustained for not less than two minutes, and the type of barrel or drum must be capable of standing without any serious permanent deformation and without leaking a hydrostatic test pressure of not less than 40 pounds per square inch, sustained for not less than five minutes.

5. When filled with water to 98 per cent of its capacity, the type of barrel or drum must also be capable of standing without leakage a test drop on its chime for a height of 4 feet upon a solid concrete foundation.

6. Bungs and other openings must be provided with secure closing devices that will not permit leakage through them. Threaded metal plugs must be close fitting. Gaskets must be made of lead, leather, or other suitable material. Wooden plugs must be covered with a suitable coating and must have a driving fit into a tapered hole.

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[a] From "Regulations of the Interstate Commerce Commission for the Transportation of Explosives and Other Dangerous Articles by Freight and by Express, and Specifications for Shipping Containers," published by the Bureau for the Safe Transportation of Explosives and Other Dangerous Articles, in January, 1912, pp. 72, 143, 144, and 145. Effective Mar. 31, 1912.

7. The method of manufacturing the barrel or drum and the materials used must be well adapted to producing a uniform product. Leaks in a new barrel or drum must not be stopped by soldering, but must be repaired by the method used in constructing the barrel or drum.

BLENDING GASOLINE WITH NAPHTHA.

In the foregoing pages the word "gasoline" has been loosely applied by the authors to mean the liquid obtained from natural gas subjected to treatment. The term has been retained because it has become a trade name. The term "condensate" would be more suitable, because the liquid first obtained is usually so volatile that it comes quite outside the meaning that is usually applied to the term gasoline. The refinery gasoline as prepared for the trade is not a definite compound, nor is the natural-gas condensate, as it is collected in storage tanks before it is prepared for market. After this preparation, if properly done, natural-gas condensate comes under the same category as refinery gasoline.

At present practically all natural-gas condensate is mixed with lower grade refinery naphthas. This process constitutes the so-called blending. In the early days of the industry the handling of the natural-gas condensate involved its weathering or the evaporation of its light constituents until a product was obtained that could be used as refinery gasoline is ordinarily used and could be safely transported under rules promulgated by the Bureau for the Safe Transportation of Explosives. By the process of "weathering" a loss of material as much as 60 or 70 per cent of the total quantity frequently occurred. Sometimes the loss was even greater. By the process of blending a product is obtained that has a slower rate of evaporation than the natural-gas condensate used in making the blend.

COMMERCIAL NAMES OF DISTILLATION PRODUCTS FROM CRUDE OIL.

Below is presented a table showing the commercial names of different grades of naphthas, gasolines, kerosenes, etc., their gravities, boiling points, and the chemical names of the constituents that comprise them:

Data regarding distillation products of crude oil.

Name of product.	Gravity.	Boiling point.	Constituents.
	°*B*.	°*C*.	
Cymogene	108	0	Chiefly butanes.
Rhigolene	92-94	18	Chiefly butanes and pentanes.
Petroleum ether	80-94	70-90	Chiefly pentanes and hexanes.
Naphtha	58	90-120	Chiefly hexanes, heptanes, and octanes.
Benzine		120-150	Chiefly octanes and nonanes.
Kerosene	48		
Vaseline			
Solid paraffin			

DISCUSSION OF THE PRODUCTS.

According to this table, any condensate having a gravity of 94° to 108° B. will contain a large proportion of pentane and butane. Probably most of the condensate having a gravity of 108° B. will be butane and most of that having a gravity of 94° B. will be pentane, although a certain proportion of each will consist of the heavier constituents, among which will be those of ordinary gasoline. Butane and pentane have boiling points of 0° C. (32° F.) and 36° C. (97° F.), respectively. These temperatures (especially that of butane) are below ordinary atmospheric temperature; hence a rapid loss of these constituents in a natural-gas condensate will occur when the condensate is exposed to the air.

Rhigolene, it will be noticed, consists chiefly of butane and pentane. The boiling point of rhigolene is given as 18° C. (64° F.). This boiling temperature is midway between that of butane and pentane. Most natural-gas condensates have a gravity of 80° to 94° B. Such a mixture is classified as petroleum ether in the above scale. This scale has reference to refinery products. Such mixtures are of a more uniform composition than natural-gas condensates that are freshly drawn from accumulator tanks, whereas petroleum ether may be a mixture that contains chiefly pentane and hexane and will not boil when freshly prepared, yet natural-gas condensates, especially those of the higher gravity, may boil violently. The ebullition is probably due chiefly to the escape of butane and some propane. In the natural-gas condensate there will be more of these constituents and less of the pentane and hexane. There will also be some of the still higher liquid paraffins and some of the dissolved gases methane and ethane. The above table, as far as the intermediate members are concerned, can scarcely be applied to natural-gas condensates, because the latter are of a more complex composition. It is inserted here only because its use brings out several instructive points. Probably the above classification is little used in the trade. Different trade names for practically the same distillates from petroleum are used by different refiners.

EVAPORATION LOSSES IN BLENDING.

The following tables (Tables 6 to 9) show the results of some blending tests made by the authors. The condensate as it was drawn from the storage tank was allowed to stand in graduated vessels, and the loss sustained by evaporation over different periods of time was noted. The containers were graduated glass cylinders having a capacity of 1,000 c. c. Their inside diameter was 2$\frac{3}{8}$ inches and they were 13 inches high. Some of the same condensate, as it was drawn from the storage tanks, was also mixed with naphtha and allowed to stand and the loss noted.

TABLE 6.—*Evaporation losses*[a] *of natural-gas condensate from plant A when allowed to stand exposed to the air.*

Test No.	Gravity of gasoline.	Temperature of gasoline at start.		Temperature of outside air.		End of 1 hour.				End of 2 hours.		End of 3 hours.		End of 18 hours.		End of 24 hours.	
						Loss.	Specific gravity.	Temperature.		Loss.	Specific gravity.	Loss.	Specific gravity.	Loss.	Specific gravity.	Loss.	Specific gravity.
	° *B.*	° *F.*	° *C*	° *F.*	° *C.*	*P. ct.*	° *B.*	° *F.*	° *C.*	*P. ct.*	° *B.*	*P. ct.*	° *B.*	*P. ct.*	° *B.*	*P. ct.*	° *B.*
1	82.5	20	− 6.7	60	16	4.5	81	50	10	8.5	80.0	9.5	80.0	18.0	78.0		
2	88.0	8	−13											25.0	82.0		
3	88.5			60	16	8.0	88	54	12	10.0	87.5	13.0	87.0	25.0	82.0		
4	94.0	6	−18	60	16	12.0	90	38	3	22.0	89.5	26.0	88.5				
5	95.0	0	−18	54	12	19.0	92					40.0	88.0			53.0	84.5
6	96.0	5	−15	55	13	24.0	92	30	1	33.0	91.0					50.0	84.0
7	100.0	10	−12	55	13			25	−4					54.0	89.5		

[a] Computed from original volume of condensate.

TABLE 7.—*Evaporation losses of natural-gas condensate from plants B and C when allowed to stand exposed to the air.*

PLANT B.

Test No.	Specific gravity of gasoline.	Temperature of gasoline.		Temperature of outside air.		End of 24 hours.	
						Loss.	Specific gravity.
	° *B.*	° *F.*	° *C.*	° *F.*	° *C.*	*P. ct.*	° *B.*
1	69	40	4	50	10	8	69
2	88	30	−1	50	10	25	87

PLANT C.

Test No.	Specific gravity of gasoline.	Temperature of gasoline.		End of 10 hours.	
				Loss.	Specific gravity.
	° *B.*	° *F.*	° *C.*	*P. ct.*	° *B.*
1	75.5	30	− 1	6.5	73.5

TABLE 8.—*Evaporation losses of natural-gas condensate from plant A mixed with refinery naphtha.*

Test No.	Proportions in mixture.		Specific gravity of—		Specific gravity of mixture.	Temperature of mixture.		End of 5 hours.		End of 18 hours.		End of 24 hours.	
	Gasoline.	Naphtha.	Gasoline.	Naphtha.				Loss.	Specific gravity.	Loss.	Specific gravity.	Loss.	Specific gravity.
	P. ct.	*P. ct.*	° *B.*	° *B.*	° *B.*	° *F.*	° *C.*	*P. ct.*	° *B*	*P. ct.*	° *B.*	*P. ct.*	° *B.*
1	70	30	87	57	77							25	70
2	50	50	92	57	73							62	66
3	70	30	94	57	81			27	75			36	72
4	73	27	93	57	83	10	−12	22				44	
5	70	30	96	57	84							62	71
6	50	50	94	48	77					64.0	55		
7	70	30	92	48	74			28	69			43	66
8	80	20	93	48	83	15	− 9			32	73		

TABLE 9.—*Evaporation losses of different mixtures of natural-gas condensates and refinery naphthas.*

Test No.	Proportions in mixture.		Specific gravity of—		Specific gravity of mixture.	End of 1 hour.		End of 2 hours.		End of 3 hours.		End of 4 hours.	
	Condensate.	Naphtha.	Condensate.	Naphtha.		Specific gravity.	Loss.	Specific gravity.	Loss.	Specific gravity.	Loss.	Specific gravity.	Loss.
	P. ct.	*P. ct.*	°*B.*	°*B.*	°*B.*	°*B.*	*Per ct.*	°*B.*	*Per ct.*	°*B.*	*Per ct.*	°*B.*	*Per ct.*
1.....	50	50	93	60	76.5	76	4	75	10	75	12	74	16
2.....	70	30	93	44	76	75.5	6	74.5	14	73.5	20	72.5	24
3[a]....	70	30	95	44	74.5	74	13	72.5	20	72	26	71.5	29
4[a]....	50	50	95	44	67	65.5	8	65	16	64	20	64	22

Test No.	Proportions in mixture.		Specific gravity of—		Specific gravity of mixture.	End of 5 hours.		End of 6 hours.		End of 7 hours.		End of 24 hours.		Temperature of atmosphere.	
	Condensate.	Naphtha.	Condensate.	Naphtha.		Specific gravity.	Loss.	Specific gravity.	Loss.	Specific gravity.	Loss.	Specific gravity.	Loss.		
	P. ct.	*P. ct.*	°*B.*	°*B.*	°*B.*	°*B.*	*P. ct.*	°*B.*	*P. ct.*	°*B.*	*P. ct.*	°*B.*	*P. ct.*	°*F.*	°*C.*
1.....	50	50	93	60	76.5	74	18	73	22	70.5	31	67	43	65 to 70	18 to 21
2.....	70	30	93	44	76	71.5	29	71	30	......	......	......	......	....	....
3[a]....	70	30	95	44	74.5	71	30	69	34	68.5	37	65	50	60 to 70	16 to 21
4[a]....	50	50	95	44	67	63	25	62	30	61	36	56	54	60 to 70	16 to 21

[a] In conducting this test the mixture was exposed to the atmosphere to a greater extent than in tests 1 and 2. It was poured from one vessel to another eight times, thus exposing more liquid surface to the atmosphere and causing more rapid evaporation than would have occurred if it had been allowed to remain in the same vessel all the time without disturbance.

REMARKS ON TABULATED DATA.

As regards the results shown in Table 6, the condensate was exposed to the air in the graduated glass cylinders already mentioned.

The pressure exerted on the natural gas in making the condensate varied between 140 and 200 pounds per square inch. The storage tank was so arranged that after each test the entire volume of condensate could not be removed in order to provide an empty tank for a succeeding test. Hence, the condensate from one test was always mixed with some condensate from a preceding test. For this reason the exact pressure that was exerted on the gas for any particular test is not recorded here. A gas meter was not connected to the "plant," so that the quantity of gas used in making the condensate could not be measured.

It will be observed that as the gravity of the condensates increased the losses by evaporation also increased, ranging from 4.5 per cent to 24 per cent at the end of one hour, from 8.5 to 33 per cent at the end of two hours, from 9.5 to 40 per cent at the end of three hours, and as much as 53 and 54 per cent at the end of 24 hours and 18 hours.

The condensate used in test 1 started to boil slightly when first drawn from the storage tank and continued to do so for two hours.

This boiling was probably due mainly to the liquid butane present in the mixture changing to the gaseous condition. Butane boils at 1° C. (34° F.), and when exposed to the temperature of this particular condensate, which was 20° F. (–7° C.), the liquid of course changed to the gaseous condition. A small part of the gaseous butane remained dissolved in the condensate, but the proportion that could not be held in solution escaped.

The condensate used in test 3 lost 8 per cent by evaporation during the first hour and 13 per cent at the end of three hours; at the end of 18 hours 25 per cent of the original mixture had evaporated. The original condensate must have contained considerable quantities of butane and pentane to account for such a loss. Most of the butane was probably eliminated during the first two hours, and then a much slower evaporation of the other constituents, principally pentane, followed.

The condensate used in test 7 was a very volatile product, being nearly the lightest gasoline obtained in the plant operation.

The results mentioned above are presented to show actual losses sustained at the particular plants where the tests were conducted under certain conditions—that is, exposure of the condensates to atmospheric pressure and temperatures in certain forms of containers.

The total loss through evaporation was not exactly determined. This total loss includes the losses shown in the above tables plus that sustained when the condensate was removed from the storage tank. As soon as the valve on the storage tank was opened and the condensate came in contact with the outside air in flowing to the graduated vessel provided to catch it, the evaporation commenced; hence some loss of liquid occurred before the condensate could be measured in the vessel provided to receive it. The storage tank was provided with a glass gage which showed the height of the liquid therein. As the liquid was drawn from the tank its level, of course, fell in the gage. By noting this level before and after some of the liquid from the tank had been drawn into the graduated glass vessel, the loss of liquid occurring could be approximately determined. The loss amounted to about 10 per cent, and was of course due principally to the volatilization of the liquid gases. This loss is to be added to the losses shown in the preceding table in order to get the total loss.

In Tables 7 and 8 are shown the evaporation losses that resulted when freshly drawn condensate from plants B and C were allowed to stand exposed to the atmosphere for 10 and 24 hours. The losses shown are much smaller than those from plant A. This result is to be expected, because more of the heavier paraffin hydrocarbons were contained in the condensates. The temperatures of the freshly drawn condensates were also higher than the temperature of the condensate obtained at plant A. Hence the constituents present in the condensate had higher boiling points and evaporated more slowly.

The condensate represented by test 2 (Table 7) was obtained when the pressure on the natural gas was 210 pounds per square inch. The liquid did not boil when withdrawn from the tank, although a bubble of gas would occasionally issue during the first hour of exposure. Hence the condensate probably contained only a small quantity of liquid butane. Likewise the proportion of pentane must have been smaller than in the condensates obtained from plant A.

The condensates represented in Tables 7 and 8 were obtained from different plants than those represented in Table 6. The pressures employed were practically the same, yet the character of the condensates differed. For instance, all of the condensates obtained in the tests conducted at plant A would boil more or less at first, owing to escaping gas. Those obtained at plants B and C bubbled only a little. This difference was largely due to differences in the composition of the natural gases used at the plants.

In Table 9 are shown the results of blending natural-gas condensate (specific gravity 48° B.) from plant A (Table 1) with naphtha having a specific gravity of 57° B. The percentages of losses are calculated to percentage losses of the natural-gas condensate and not of the mixture.

The conditions under which these tests were conducted would not warrant definite conclusions regarding the decrease of evaporation rate to be effected by blending. However, the losses after blending were still large.

If the evaporation loss were to be calculated to the percentage loss of the mixture of condensate and naphtha the percentage of losses on the blends would be much reduced, but the figures so obtained would not show the true loss of condensate. Some experimenters have probably done this and misled themselves into believing that the percentage so calculated represented the actual loss of condensate. The authors calculated the blending losses by throwing the loss wholly on the condensate. They determined by experiment that the evaporation loss of the refinery naphtha used in making the blends was so small as to be inappreciable as compared to condensate losses.

RESULTS OF EVAPORATION TESTS IN WEST VIRGINIA.

Table 10, following, shows the evaporation losses when natural-gas condensates from a different plant than those mentioned previously had been exposed to the atmosphere. The evaporation losses shown in the preceding tables occurred at plants along the Allegheny River near the New York State line. The tests represented in the table following were made at a plant in West Virginia. Plant operations were so conducted as regards pressures that condensates of different specific gravities were obtained. The condensates were allowed to evaporate in graduated glass cylinders of the same form as those used in the tests covered by Tables 6 to 9.

TABLE 10.—*Evaporation losses of condensates from the same plant, but of different specific gravities.*

Test No.	Gravity of condensate at start.	Temperature of condensate at start.		End of 1st hour.		End of 2 hours.		End of 3 hours.		End of 4 hours.		End of 5 hours.	
				Gravity.	Loss.	Gravity.	Loss.	Gravity.	Loss.	Gravity.	Loss.	Gravity.	Loss.
	°*B.*	°*F.*	°*C.*	°*B.*	*Per cent.*	°*B.*	*Per cent.*	°*B.*	*Per cent.*	°*B.*	*Per cent.*	°*B.*	*Per cent.*
1......	79	35	2	79	0	79	0	79	1	78.5	2	78.5	2
2......	81.5	20	− 7	81	2	81	4	80	9	79.5	13	79	16
3......	93	0	−48	93	9	92.5	21	92	27	91	33	90.5	35
4......	94	0	−18	93.5	15	93.5	20	93	25	93	29	92.5	30
5......	94.5	8	−13.3	94	13	93.5	24	93	28	92	34	91.5	35
7......	95.0	5	−15	....	17	91	25	89.5	34	89	38	88	42
8......	96.0	5	−15	93	19	92	26	90.5	31	90	37	90	40
9......	98.0	15	− 9.4	97	11	96	19	95	24	94.5	26	94.5	29
10......	83.5	18	− 8	....	......	83.5	3	83	4	82.5	6	82.0	7

Test No.	Gravity of condensate at start.	Temperature of condensate at start.		End of 6 hours.		End of 7 hours.		End of 8 hours.		End of 24 hours.		Temperature of atmosphere.	
				Gravity.	Loss.	Gravity.	Loss.	Gravity.	Loss.	Gravity.	Loss.		
	°*B.*	°*F.*	°*C.*	°*B.*	*Per cent.*	°*B.*	*Per cent.*	°*B.*	*Per cent.*	°*B.*	*Per cent.*	°*F.*	°*C.*
1......	79	35	2	78	3	78	4	78	4	77	10	55 to 60	13 to 16
2......	81.5	20	− 7	79	18	78.5	20	......	......	74.5	31	60 to 65	16 to 18
3......	93	0	−48	90	40	89.5	41	89	43	87.5	50	60 to 70	16 to 21
4......	94	0	−18	92	33	91.5	34	91.5	35	89.5	45	55 to 60	13 to 16
5......	94.5	8	−13.3	91	36	90.5	37	......	......	88.5	44	50 to 60	10 to 16
7......	95.0	5	−15	87.5	45	87	48	......	......	......	65	60 to 65	16 to 18
8......	96.0	5	−15	90	42	89.5	45	89.5	46	86	53	60 to 62	16 to 17
9......	98.0	15	− 9.4	94	30	94	31	94	32	92.5	43	40 to 50	4 to 10
10......	83.5	18	− 8	82	9	81	13	81	15	80	25	40 to 50	4 to 10

Table 11, following, shows results obtained when mixtures of natural-gas condensate and refinery naphtha were exposed to the air and allowed to evaporate. The tests were made at the same plant as the tests covered by Table 10, and with the same condensates.

TABLE 11.—*Evaporation losses of mixtures of natural-gas condensates and refinery naphthas.*

Test No.	Proportions in mixture.		Specific gravity of—		Specific gravity of mixture.	End of 1 hour.		End of 2 hours.		End of 3 hours.		End of 4 hours.		End of 5 hours.	
	Condensate.	Naphtha.	Condensate.	Naphtha.		Specific gravity.	Loss.	Specific gravity.	Loss.	Specific gravity.	Loss.	Specific gravity.	Loss.	Specific gravity.	Loss.
	P. ct.	*P. ct.*	°*B.*	°*B.*	°*B.*	°*B.*	*P. ct.*	°*B.*	*P. ct.*	°*B.*	*P. ct.*	°*B.*	*P. ct.*	°*B.*	*P. ct.*
1....	50	50	98	60	76	76	10	76	12	76	16	76	18	76	20
2....	70	30	98	60	86	86	7	84.5	13	84	17	84	20	83.5	23
3....	70	30	97	60	84	83	14	81.5	20	81	23	80	29	80	30
4....	50	50	97	60	76	75	4	74	6	73.5	12	73	16	73	17
5....	50	50	95	60	76	75.5	4	75	10	74	15	74	18	74	20
6*a*...	50	50	95	60	77	76.5	5	74	24	72.5	36	71.5	46	70	54
7....	70	30	95	60	84.5	83	11	82	19	81.5	21	81	26	80	27
8*a*...	70	30	95	60	83.5	83	10	81.5	17	80.5	23	79	27	78.5	30
9....	60	40	95	60	80.5	79.5	8	79	15	78.5	18	77.5	22	77.5	23
10....	70	30	95	60	84	82.5	10	81	17	80.5	21	79.5	24	79	27
11....	70	30	83.5	60	74.5	74.5	0	74.5	0	74.5	1	74	3	74	7
12....	70	30	93.5	44	76.5	75	10	74.5	14	74	19	73	21	72.5	23

a Test conducted in a shallow pan, 8 inches in diameter and 1 inch deep.

TABLE 11.—*Evaporation losses of mixtures of natural-gas condensates and refinery naphthas*—Continued.

Test No.	Proportions in mixture.		Specific gravity of—		Specific gravity of mixture.	End of 6 hours.		End of 7 hours.		End of 8 hours.		End of 24 hours.		Temperature of atmosphere.	
	Condensate.	Naphtha.	Condensate.	Naphtha.		Specific gravity.	Loss.	Specific gravity.	Loss.	Specific gravity.	Loss.	Specific gravity.	Loss.		
	P. ct.	*P. ct.*	*°B.*	*°B.*	*°B.*	*°B.*	*P. ct.*	*°B.*	*P. ct.*	*°B.*	*P. ct.*	*°B.*	*P. ct.*	*°F.*	*°C.*
1...	50	50	98	60	76	75.5	22	75.5	23	.....	.....	73	38	40 to 50	4 to 10
2...	70	30	98	60	86	83	24	83	26	83	27	80	40	40 to 50	4 to 10
3...	70	30	97	60	84	79.5	33	79	37	79	39	76	47	60 to 70	16 to 21
4...	50	50	97	60	76	73	20	72.5	20	.....	.....	69	38	60 to 70	16 to 21
5...	50	50	95	60	76	73.5	22	73.5	24	.....	.....	70.5	40	60 to 70	16 to 21
6*a*..	50	50	95	60	77	69	60	.....	.....	.....	.....	65	96	60 to 70	16 to 21
7...	70	30	95	60	84.5	80	29	80	29	.....	.....	77	33	60 to 70	16 to 21
8*a*..	70	30	95	60	83.5	77.5	34	77	39	.....	.....	70	63	50 to 60	10 to 16
9...	60	40	95	60	80.5	77.5	25	77	27	.....	.....	74	38	50 to 60	10 to 16
10...	70	30	95	60	84	79	29	78.5	31	.....	.....	75.5	43	60 to 70	16 to 21
11...	70	30	83.5	60	74.5	73.5	9	73	10	.....	.....	71	19	55 to 60	13 to 16
12...	70	30	93.5	44	76.5	72	24	72	27	.....	.....	68	39	50 to 60	10 to 16

[a] Test conducted in a shallow pan, 8 inches in diameter and 1 inch deep.

DISCUSSION OF RESULTS SHOWN IN TABLES 8 TO 11.

As shown in Table 10 the losses when condensates of gravities between 79° and 98° B. were exposed to the atmosphere were as follows: One hour, 0 to 19 per cent; 2 hours, 0 to 26 per cent; 3 hours, 1 to 34 per cent; 4 hours, 2 to 38 per cent; 5 hours, 2 to 42 per cent; 6 hours, 3 to 45 per cent; 7 hours, 4 to 48 per cent; 8 hours, 4 to 46 per cent; and for 24 hours, 10 to 65 per cent. At the end of 24 hours the temperatures of the condensates were practically the same as the temperature of the atmosphere.

If tests 1 and 2, Table 10, be excepted, the largest losses occurred during the first hour and the rate of evaporation gradually decreased. This is to be expected. Most of the material that first evaporated was liquid butane. Liquid butane boils at 1° C. (34° F.); hence it would evaporate rapidly. The rate of evaporation of the pentanes and hexanes is, of course, much slower. The curves shown elsewhere clearly illustrate these points.

Table 11 shows the evaporation losses when the natural-gas condensates were mixed with refinery naphthas and allowed to evaporate. The rate of evaporation for tests 1 and 2 (Table 11) are almost the same, but slightly slower than of test 9 (Table 10), which represents the evaporation loss when the condensate alone was allowed to evaporate. The difference is especially noticeable at the end of the second hour, being 19 per cent as against 12 and 13 per cent. The rates are not widely different for the remaining period, but still noticeable. Tests 3, 4, 5, 7, and 9, Table 11, may be compared to tests 4, 5, 6, 7, and 8, Table 10. In the former when condensates alone were allowed to evaporate the losses for the first hour ranged from 13 to 19 per cent. When condensates of approximately the same specific gravity were mixed with naphtha and allowed to evaporate, the losses for the first hour ranged from 4 to 14 per cent.

DIFFERENCE IN EVAPORATION RATES OF MIXTURES.

The difference in the evaporation rates, shown for the mixtures, is marked all through the tests. The following tabulation clearly brings out this variation:

Evaporation losses of condensates and "blends" for periods ranging from 1 to 24 hours.

	Loss in 1 hour.	Loss in 2 hours.	Loss in 3 hours.	Loss in 4 hours.	Loss in 5 hours.	Loss in 6 hours.	Loss in 7 hours.	Loss in 24 hours.
	Per cent.	*Per cent.*	*Per cent.*	*Per cent.*	*Per cent.*	*Per cent.*	*Per cent.*	*Per cent.*
Condensates [a]........	11 to 19	19 to 26	25 to 34	26 to 38	29 to 42	30 to 45	31 to 48	43 to 65
"Blends"............	4 to 14	6 to 19	12 to 23	16 to 29	17 to 30	20 to 33	24 to 39	33 to 47

[a] Specific gravities, 94° to 98° B.

In the tests represented in the foregoing table for all of the "blends," condensates with specific gravities of 94° to 98° B. were used. However, Table 11 shows that in preparing the "blends," different amounts of the condensate were used for different tests. In some of the tests the "blends" were prepared by mixing the condensates and naphtha in equal proportions. In others, the proportions were 70 per cent of condensate and 30 per cent of naphtha; in others, 60 and 40. Table 11 shows that the evaporation rates were slower when the smaller quantities of condensate were used, as was to be expected.

COMPARATIVE EVAPORATION LOSSES OF MIXTURES AND CONDENSATES.

Table 12 shows the evaporation losses when the condensates alone were exposed to the atmosphere and when the condensates were mixed in various proportions with the naphtha. This table was compiled from the results of tests 1, 2, 3, 4, 5, 9, 10, and 12, Table 11, and tests 3, 4, 5, 7, 8, and 9, Table 10.

TABLE 12.—*Comparative evaporation losses of blends prepared by mixing different proportions of condensate and naphtha and of condensate alone.*

Test No.	Table No.	Proportions in mixtures.		Specific gravity of—		Specific gravity of mixture.	Loss at end of—								
		Condensate.	Naphtha.	Condensate.	Naphtha.		1 hour.	2 hours.	3 hours.	4 hours.	5 hours.	6 hours.	7 hours.	8 hours.	24 hours.
		P.ct.	*P.ct.*	°*B.*	°*B.*	°*B.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*	*P.ct.*
1	11	50	50	98	60	76	10	12	16	18	20	22	23	......	38
2	11	70	30	98	60	86	7	13	17	20	23	24	26	27	40
4	11	50	50	97	60	76	4	6	12	16	17	20	20	......	38
3	11	70	30	97	60	84	14	20	23	29	30	33	37	39	47
9	10	100	0	98	......	......	11	19	24	26	29	30	31	32	43
8	10	100	0	96	......	......	19	26	31	37	40	42	45	46	53
5	11	50	50	95	60	76	4	10	15	18	20	22	24	......	40
7	11	70	30	95	60	84.5	11	19	21	26	27	29	29	......	33
10	11	70	30	95	60	84	10	17	21	24	27	29	31	......	43
5	10	100	0	94.5	......	......	13	24	28	34	35	36	37	......	44
4	10	100	0	94.0	......	......	15	20	25	29	30	33	34	35	45
7	10	100	0	95.0	......	......	17	25	34	38	42	45	48	......	65
12	11	70	30	93.5	44	76.5	10	14	19	21	23	24	27	......	39
3	10	100	0	93	......	......	9	21	27	33	35	40	41	43	50
11	11	70	30	83.5	60	74.5	0	0	1	3	7	9	10	......	39
2	10	100	0	81.5	......	......	2	4	9	13	16	18	20	......	31

The slower rates of evaporation of the mixtures of condensates and naphtha as compared to those of the condensates alone follow from the fact that if two liquids dissolve each other in all proportions, and if they have widely different vapor pressures and boiling points, the vapor pressure of the mixture frequently falls between the vapor pressures of the components, and the boiling point of the mixture falls between the boiling points of the components. The more volatile liquid evaporates principally, at first, during the distillation, the less volatile liquid remaining behind, so that by a repetition of the process the two may be more or less completely separated. As evaporation continues a mixture is finally left that contains components whose boiling points and vapor pressures lie near together.

FACTORS AFFECTING RATE OF EVAPORATION.

Attention should be called to the higher evaporation rates of tests 3 and 4, Table 9, as compared to tests 1 and 2, Table 9. Tests 3 and 4 were conducted in shallow pans, whereas tests 1 and 2 were conducted in tall narrow cylinders. For a given temperature, other things being equal, the rate of evaporation is almost proportional to the area of the surface of the liquid.

In actual operation different evaporation losses will be sustained than those mentioned above, depending upon the shape of the container that is used for holding the liquid when the latter is exposed to the air. If the mixture be placed in a drum such as is ordinarily used for transporting natural-gas gasoline, and the bunghole left open there will occur a much slower rate of evaporation than if the entire surface of the liquid be exposed to the air by means of an opening, say, as large as the area of the liquid.

In the former case the rate of evaporation will approach evaporation conditions in a closed space. In a closed chamber evaporation will take place more or less rapidly at first. After some time, however, the space above the liquid will become partly filled with stray molecules that have escaped through the surface film. These, after escape, move about indiscriminately in the chamber and are reflected from its walls and from each other. Some return to the liquid, and once they fall on its surface they may be attracted into the interior. It thus happens that a certain stage is ultimately attained at which as many molecules return to the liquid per second as leave it and an equilibrium is established; at this stage evaporation may be said to have ceased. There is no further loss to the liquid or gain to the vapor outside it; there is, however, a continual exchange going on, new molecules are being continually projected from the surface and others are falling into the liquid in equal numbers. The chamber is then said to be filled with saturated vapor, or the vapor is said to be saturated; in any stage before this final stage has been reached the vapor is said to be nonsaturated. A saturated vapor is thus one that is in equilibrium with its own liquid.

If there is any means of escape, however, as from the bunghole of the drum, some of the molecules, in wandering about inside the drum, will make their exit through the bunghole and into the atmosphere, never returning to the liquid. There will be thus a continual flow of molecules from the surface of the liquid to the atmosphere, and evaporation will continue in this manner at a steady rate as long as the temperature is maintained constant. If the area of the hole be expanded to the size of the surface of the liquid, much faster evaporation will take place, because there will be a much wider avenue of escape opened for the wandering molecules.

When natural-gas condensates or any liquids are exposed to the air, as in transferring the condensates from accumulator tanks to storage tanks or to drums, evaporation takes place much more rapidly than when the condensate is lying quietly in the container. This increased rate results from the much greater surface of the liquid that is exposed to the air.

The authors of this publication found that from 2,040 gallons of condensate transferred from a storage tank to a loading station at a railroad siding by means of a pipe line 1,500 feet long, there was lost by evaporation 747 gallons, or 36 per cent. This loss occurred at the plant at which the tests shown in Tables 10 and 11 were conducted. The material was allowed to run down the pipe line by gravity to the loading stations. This experiment shows that evaporation rates may be much faster than in the tests conducted by the authors in glass cylinders. Evaporation losses may be also hastened when the atmospheric temperature is high. The atmospheric temperature, when the authors conducted the tests, ranged from 40° to

70° F. (4° to 21° C.), but most of the time the temperature ranged between 50° and 60° F. (10° to 16° C.). During the summer time temperatures are much higher and evaporation losses will be correspondingly greater. In colder weather they would be smaller.

CURVES SHOWING EVAPORATION LOSSES.

The authors have plotted certain curves to show the evaporation losses resulting when natural-gas condensates and mixtures of condensates and naphtha are exposed to the air. The curve results shown in figure 11 are plotted from data from Table 10. It will be observed that the rate of evaporation of condensates of high specific gravity is rapid for the first eight hours. The rate of evaporation of a condensate with a specific gravity of 79° B. is fairly uniform. A condensate with a specific gravity of 98° B. underwent a slower rate of evaporation than four condensates of lower specific gravity. This difference was probably due in part to the fact that during the tests

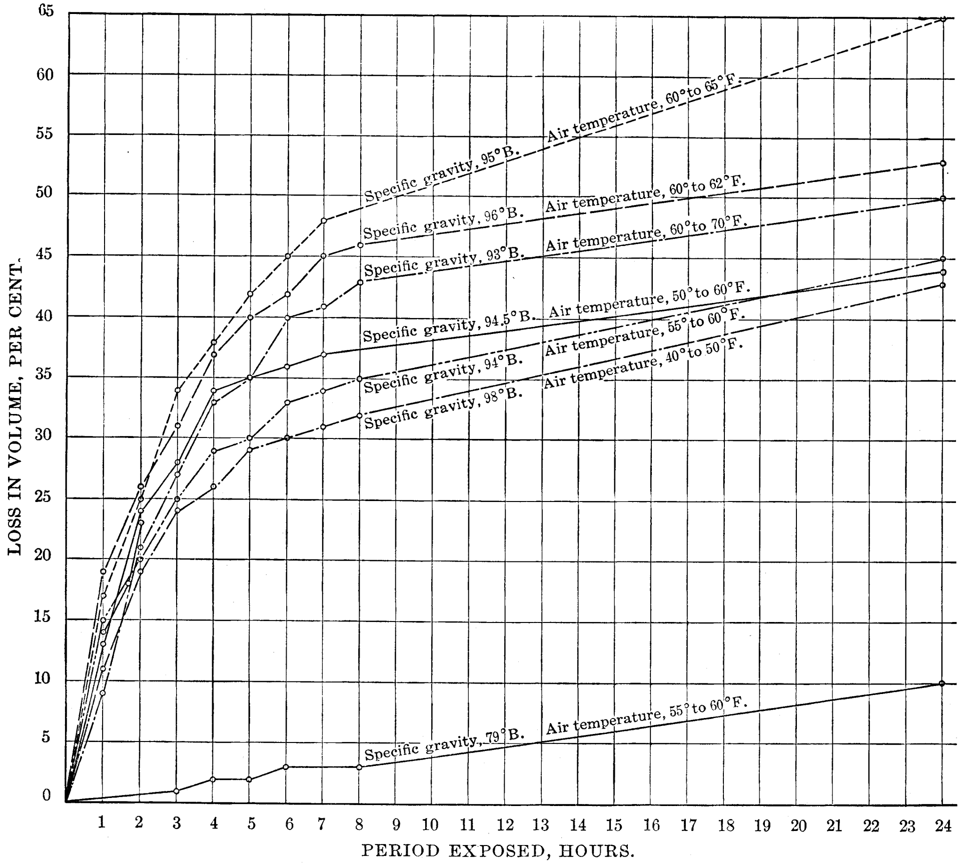


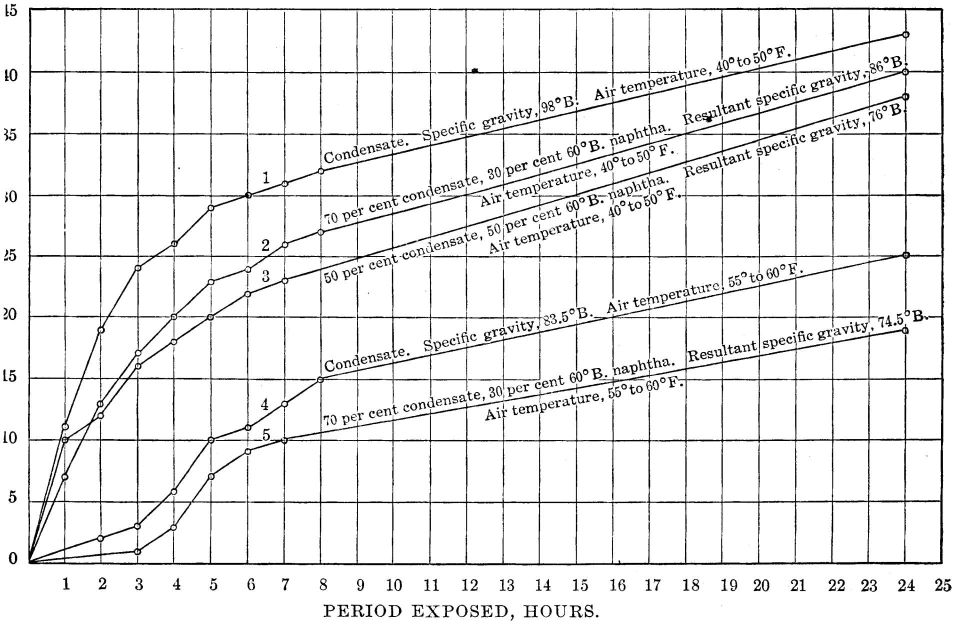
FIGURE 11.—Evaporation losses of natural-gas condensates.

of condensates of high specific gravity the temperature of the atmosphere was about 10° F. (6° C.) lower.

In figure 12 are shown the evaporation losses that resulted when two natural-gas condensates, with gravities of 98° and 83.5° B., were mixed with naphtha in different proportions. The curves were prepared from Tables 10 and 11.

Figure 13 shows the evaporation losses resulting when a condensate with a specific gravity of 93° B. was exposed to the air and when it was mixed with naphtha. The curves were prepared from Table 9.

Figure 14 shows the evaporation losses when a condensate, with a specific gravity of 95° B., was exposed to the air and when it was mixed with naphthas of different specific gravities and exposed. Smaller losses resulted when a naphtha with a specific gravity of 60° B. was used than when a naphtha with a specific gravity of 44° B. was used.



IGURE 12.—Evaporation losses when two natural-gas condensates were mixed with naphtha in different proportions.

VAPOR-PRESSURE TESTS.

Figures 15, 16, 17, and 18 show the results of tests made by the authors to determine the pressures exerted by the vapors of condensates and of blends. In making the tests a small steel container of about 2-liter capacity was fitted with a pressure gage. A hole was bored in the bottom of the container for the introduction of the liquid. This hole could be securely closed with a small threaded steel plug. To determine the pressure exerted at different temperatures, the container was placed in a water bath heated by a gas burner. Pressure, temperature, and specific-gravity observations were made.

In figure 15, curve 1 shows the vapor pressures of a freshly drawn condensate having a specific gravity of 93° B. The vapor pressures ranged from 19 pounds per square inch at 55° F. (13° C.) to 48 pounds per square inch at 100° F. (38° C.).

After the test represented by curve 1 had been completed, the steel plug was removed from the container and the liquid allowed to volatilize until it had lost 10 per cent of its original volume. Then the plug was again inserted and the vapor pressures were again noted for different temperatures, as shown by curve 2. Curves 3, 4, and 5 show the vapor pressures at different temperatures after the original condensate had lost 20, 30, and 40 per cent of its original volume. It will be observed that the greatest drop in vapor pressure occurred after the first 10 per cent loss. This is due to the fact that the liquefied gases, propane and butane, were escaping in largest quantities during the first part of the exposure. There was not much difference in the vapor pressures after 30 and 40 per cent losses, as shown by curves 4 and 5.

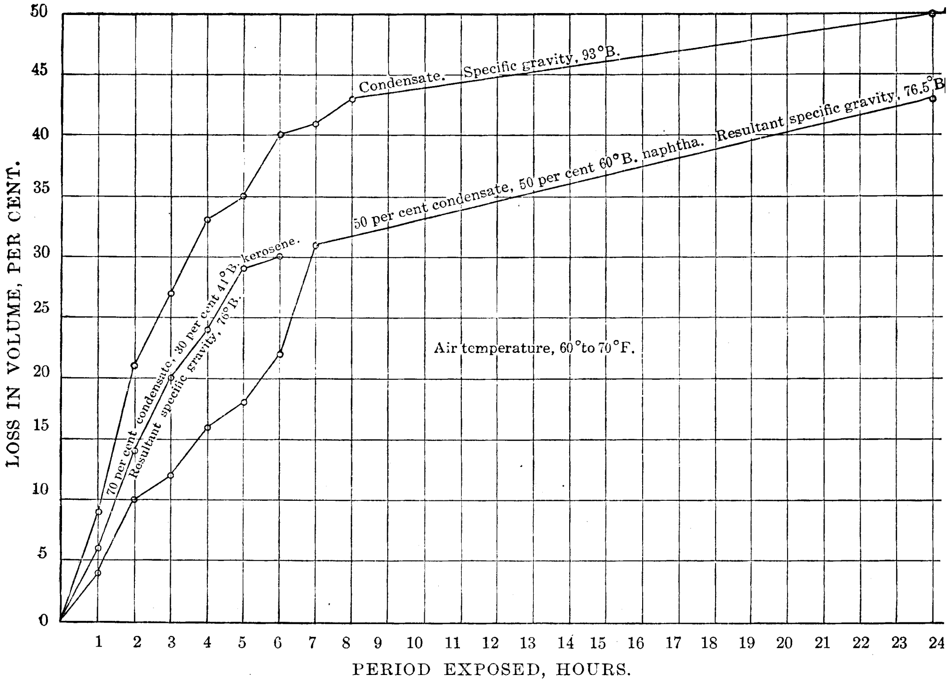
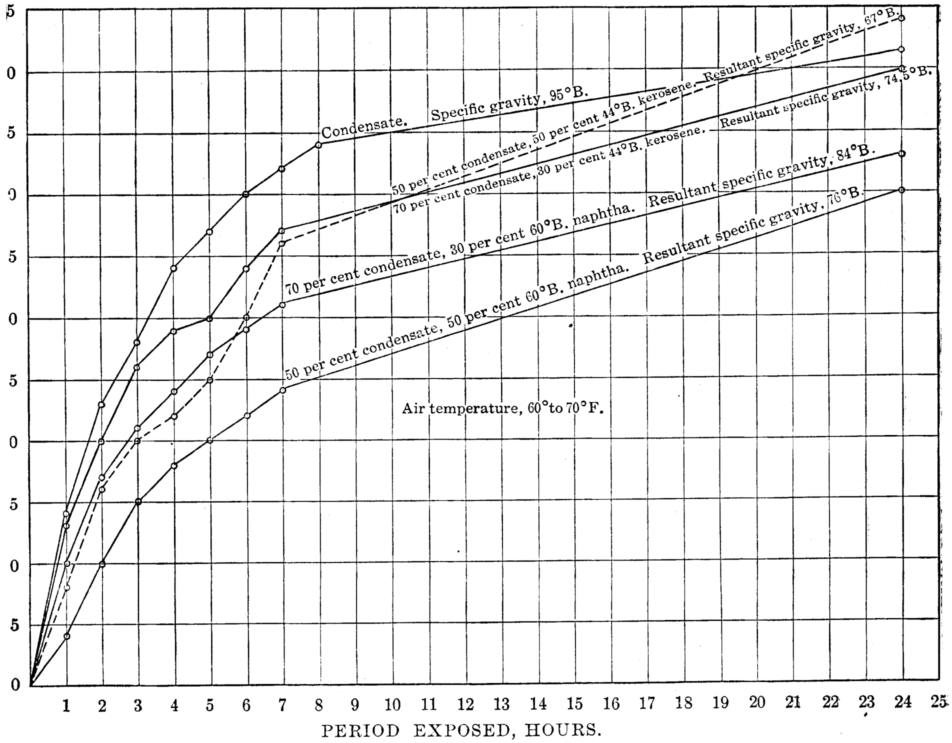


FIGURE 13.—Evaporation losses from a condensate with a specific gravity of 93° B., and from the same conden mixed with kerosene and with naphtha. Sudden bend in lower curve at 7 hours due to accidental violent agita of mixture, causing more rapid loss.

Figure 16 shows the vapor pressures of a condensate obtained at the same plant as that represented in figure 15, but at a different time. It will be observed that the condensate represented by curve 1, figure 16, and that represented by curve 1, figure 15, were of the same specific gravity, but produced appreciably different vapor pressures at the same temperatures. In other words, condensates of same specific gravity may produce quite different vapor pressures. A striking instance of such a variation can be noticed by comparing curve 3, figure 16, representing the vapor pressure of a condensate with a specific gravity of 78° B., with curve 5, figure 15, representing the vapor pressure of a condensate with a specific gravity of 88° B. The condensate with a specific gravity of 88° B. had a lower vapor pressure than the condensate with a specific gravity of 78° B. However, the condensate represented by curve 5, figure 15, had weathered long enough to lose 40 per cent of its original volume, and the condensate represented by curve 3, figure 16, was freshly drawn. From the former, liquefied gases and liquids of low boiling point had been largely removed, and in the latter there may have been enough of the liquefied gases to exert a pronounced vapor pressure, but not enough to greatly affect the specific gravity. After exposure to the atmosphere for an hour or even less, the condensate with a specific gravity



URE 14.—Evaporation losses from a condensate with a specific gravity of 95° B., and from the same condensate mixed with kerosene and with naphtha.

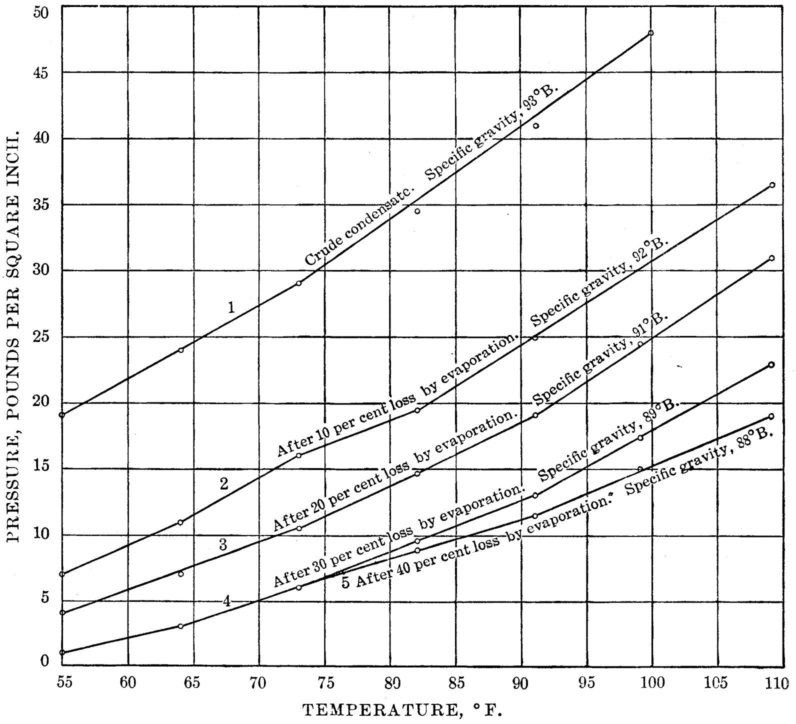


FIGURE 15.—Vapor-pressure curves of natural-gas condensate under different conditions.

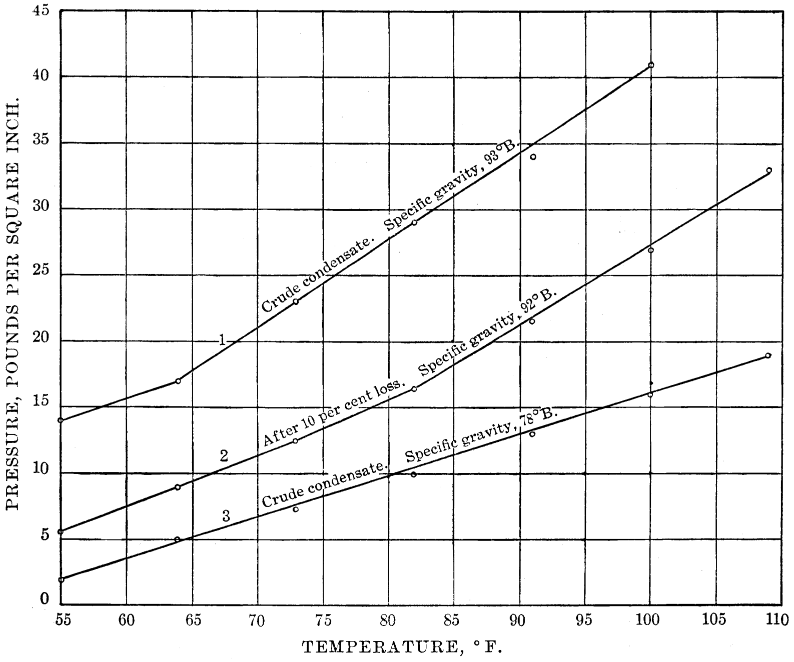


FIGURE 16.—Vapor-pressure curves of two condensates.

of 78° B. would have been greatly diminished in vapor pressure owing to the rapid evaporation of liquid gases, principally propane and butane.

In figure 17 are shown the vapor pressures of a freshly drawn condensate (curve 1), and of a blend prepared by mixing this condensate with refinery naphtha in equal proportions (curves 2 to 6). The naphtha had a specific gravity of 60° B. When the fresh condensate was mixed with the naphtha the vapor pressure (curve 2) was lowered between 6 and 14 pounds per square inch over a range of temperature from 55° to 110° F. (13° to 43° C.). Curves 3 to 6 show the vapor pressures at different temperatures after the condensate had lost 10, 20, 30, and 40 per cent of its original volume by evaporation. The condensate represented by curve 1 was the same as that represented by curve 1, figure 16. Comparison of curve 2, figure 17, with curve 3, figure 17, again brings out the fact that mixtures of the same specific gravity may have different vapor pressures at the same temperature. In this instance both condensates were used when freshly drawn. Curve 2, figure 17, represents the fresh condensate mixed with naphtha in equal proportions, producing a mixture having a specific gravity of

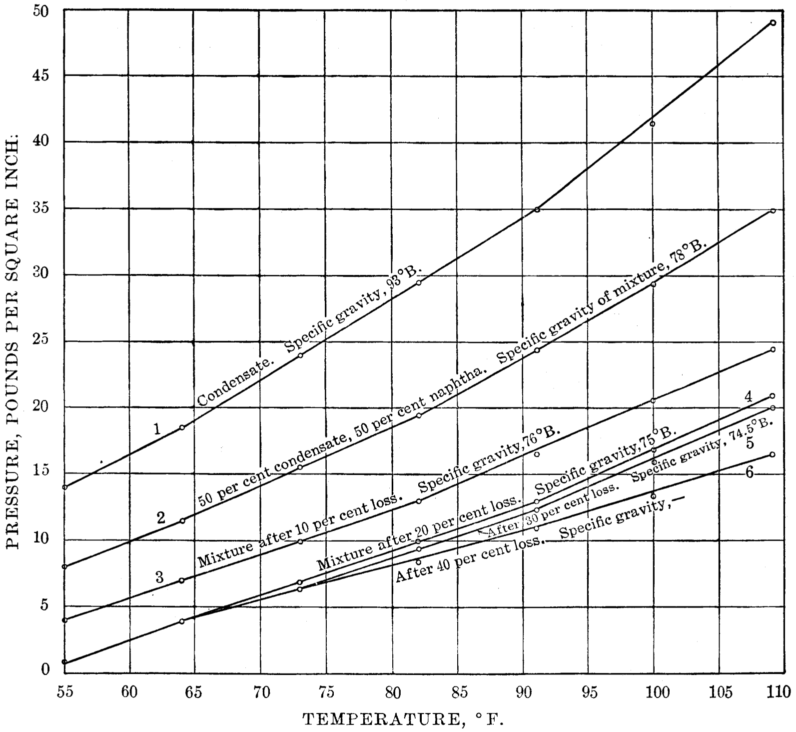


FIGURE 17.—Vapor-pressure curves of a freshly drawn condensate and of a blend of 50 per cent of the condensate and 50 per cent of refinery naphtha.

78° B. Curve 3, figure 16, represents freshly drawn condensate with a specific gravity of 78° B. The vapor pressure of the latter was lower than that of the former.

In figure 18 are shown the vapor pressures of different mixtures of a condensate with naphtha (specific gravity, 60° B.) and with kerosene (specific gravity, 44°B.). The condensate used in making the blends had a specific gravity of 93° B. It was the same condensate as that represented by curve 1, figure 17, and curve 1, figure 16. Curve 1 of figure 18 shows the vapor pressures at different temperatures when 70 per cent of freshly drawn condensate was mixed with 30 per cent of naphtha. Curve 3 shows the vapor pressures at different temperatures after the mixture represented by curve 1 had lost 10 per cent of its original volume by evaporation.

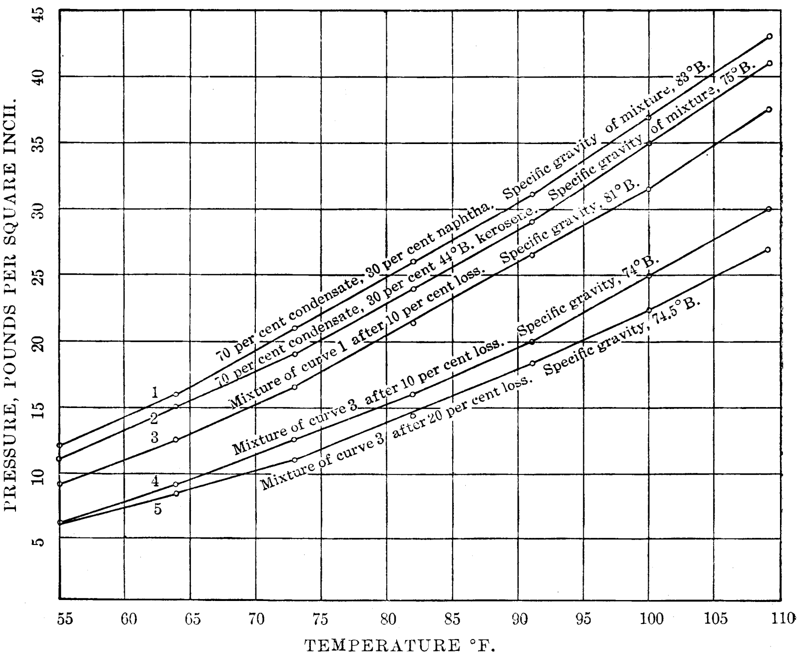


FIGURE 18.—Vapor pressures of different mixtures of a condensate with naphtha and with kerosene.

Curve 2 of figure 18 shows the vapor pressures at different temperatures when 70 per cent of the freshly drawn condensate was mixed with 30 per cent of kerosene. Curve 4 shows the vapor pressures at different temperatures when the mixture represented by curve 2 had lost 10 per cent of its original volume by evaporation. Curve 5 shows the vapor pressures at different temperatures after the mixture represented by curve 2 had lost 20 per cent of its volume by evaporation.

METHODS OF BLENDING.

Methods of mixing the natural-gas condensate and naphtha differ in detail in different sections of the country and even at some plants in the same section of the country. In some plants mixing is performed at the plant; that is, the naphtha is brought to the plant. The mixture is made and the blended material is hauled away in wagons or forced through pipe lines to the railroad.

The condensate from other plants is hauled in wagons, boats, or tank cars to central blending stations, and the mixture with the naphtha is made there.

One company in the Glenn pool district, Okla., has an elaborate system of blending. Naphtha is unloaded at the little town of Kiefer on the edge of the pool, where large storage tanks are provided for receiving it. The naphtha is then forced from the tanks through pipe lines to many different gasoline plants in the Glenn pool district. At each of these plants a mixing tank, the property of the company, is installed. The condensate from the storage tanks of the plant is forced into the mixing tank where it mixes with the naphtha. After the blend has become uniform the mixture is forced back through pipes to the railroad station at Kiefer, where it is received in tanks to await shipment to consuming centers.

In the region around Bradford, Pa., wagons partly loaded with naphtha are sent from a refinery. At each gasoline plant where this wagon stops it receives a quota of natural-gas condensate, which is mixed with the naphtha already in the wagon.

At a large blending station in Pittsburgh the natural-gas gasoline is received by freight in steel drums. The drums are emptied while still in the car, their contents being forced through a pipe to a container that holds the proper quantity of naphtha. A great deal of the natural-gas condensate is blended at Parkersburg, W Va., in this manner. Much of the condensate is shipped by boat on the Ohio River to Parkersburg.

One operator in Oklahoma forces the condensate through a pipe line about 12 miles long to a railroad siding, where the mixing with the naphtha is accomplished.

At one plant the condensate is not blended, but shipped to a point of consumption, where it is used for the purpose of making gasoline-air gas.

At a plant at Alluwee, Okla., the gasoline is forced into the same pipe lines that convey oil. At the refinery the mixture of oil and gasoline is subjected to distillation, and the gasoline is reclaimed along with that originally in the oil. The refinery is at Coffeyville, Kans.

It follows from what has already been said that the blending of natural-gas condensates with refinery naphthas results in lower vapor pressures and slower rates of evaporation of the condensate; hence, in order to conserve the condensate as much as possible, it should be blended with naphtha as soon as practicable after it has been made.

SUMMARY.

Below is presented a brief summary of some of the more important details discussed herein.

GROWTH OF INDUSTRY.

The making of gasoline from natural gas increased from a production of a few thousand gallons in 1904 to about 24,000,000 gallons in 1913. Not until 1909 did the industry assume commercial importance, having its commercial inception in Pennsylvania, around Tidioute, Titusville, and Warren.

According to the United States Geological Survey the increase in production of gasoline for the year 1912 over 1911 was 63 per cent. The rate of increase for the year 1913 over 1912 was 100 per cent. It is reasonable to expect a greater increase for the year 1914. The gas used represents that which previous to the installation of plants for the production of gasoline was principally wasted.

CONSTITUENTS OF NATURAL GAS.

Natural gases are mixtures in which the hydrocarbons of the paraffin series predominate. Small quantities of nitrogen, carbon dioxide, and water vapor are also present. In some gases, however, the percentages of nitrogen and carbon dioxide are large. One analysis is shown in which nitrogen comprised 98.5 per cent of the total, and another in which the carbon dioxide equaled about 30 per cent of the total.

The exact proportions of constituents in natural gases can not be determined by ordinary methods of analysis, although the total quantity of paraffin hydrocarbons can be thus obtained and the heating value and specific gravity determined. Natural gas may be separated into its constituents by liquefying it by means of liquid air and separating the constituents of the liquified gas by fractional distillation. By this means the authors showed that the natural gas used in Pittsburgh contained 84.7 per cent methane, and that an extremely "wet" gas from which gasoline is condensed commercially contained only 36.8 per cent methane.

The paraffin hydrocarbons that principally concern the gasoline producer are methane, ethane, propane, and the butanes, pentanes, hexanes, and heptanes. The first four are gases at ordinary temperatures, the last three liquids. The gases after contact with the oil in the earth bring with them the vapors of the liquid hydrocarbons. The vapors are carried along with the permanent gases in the same manner that water vapor exists with air. After treatment in the gasoline plant, where the capacity of the gases to carry the vapors is much lessened, the vapors are deposited.

FACTORS AFFECTING YIELD OF GASOLINE FROM NATURAL GAS.

The quantity of gasoline vapors in any particular gas mixture is dependent upon the character of the oil in the sand, the temperature and pressure existing in the sands, the porosity or closeness of the strata, the intimateness of contact between gas and oil, and other less important factors. The pentanes, hexanes, and heptanes are the only constituents of crude oil that, at earth temperatures, have vapor pressures of such magnitude that they are distilled in quantity from the crude oil; hence, they are the chief liquid constituents of natural-gas gasoline.

In wells yielding gas suitable for gasoline condensation, the three gases, methane, ethane, and propane, invariably occur in the gaseous condition, and butane also is usually present in the gaseous condition.

METHODS OF TESTING FOR GASOLINE YIELD.

By itself the ordinary eudiometric analysis is of little use for testing a sample of natural gas in order to determine its suitability for gasoline production. Laboratory methods in principal use have to do with solubility and specific-gravity tests. The Bureau of Mines has used alcohol and claroline oil; 100 c.c. of the gas is shaken with 35 c.c. of the oil or with 50 c.c. of the alcohol until absorption ceases. For the determination of specific gravity the authors have both weighed the gas and used Bunsen's effusion method. The authors have found that natural gases at present used for gasoline production have a specific gravity of 0.80 or higher, and are soluble to the extent of 30 per cent or more in the solvents used. Laboratory tests serve best as preliminary indications previous to tests of the gas at the well by means of an experimental compressing plant.

USE OF PITOT TUBE AND GAS-ANALYSIS APPARATUS.

The Pitot tube as ordinarily used for measuring the flow of gases, that is, where the static pressure is not obtained, may give results that are 8 per cent in error, even though the tube is correctly used. When the static pressure is obtained and all readings are taken with a sufficient degree of refinement, they may vary only 1 per cent more or less from the correct results. The amount of casing-head gas that flows from a casing head may vary from little or nothing up to 500,000 or more cubic feet of gas. Wells should be allowed to vent from 3 to 24 hours before measurements of the flow are made.

A simple gas-analysis determination will show an operator whether air is leaking into his gas mains. Some gases that are used for condensing gasoline contain 40 per cent or more of air due to leakage.

LIFE OF WELLS AS REGARDS GASOLINE PRODUCTION.

Regarding the life of wells as to flow of gas for gasoline condensation, it can be stated that wells from which gas has been escaping freely for several years will be long enough lived to insure a return of the initial investment with profit, that is, if the gas contains the necessary quantity of gasoline vapors.

DATA REGARDING COMPRESSION.

The condensation of gasoline from natural gas is a physical process. The process in principal use at the present time consists essentially in compressing the gas to pressures up to 300 pounds and cooling it with water of ordinary temperature. Cooling the gas by means of a refrigerant without compression, or using a refrigerant other than water in conjunction with compressors, are processes that are coming into use.

The pressure best suited for the condensation of gasoline from natural gas depends upon the partial pressures of the gases and vapors present in the mixture. The partial pressures are difficult to determine. Hence the best that one can do in plant operation is to experiment until the most suitable pressures are found.

Single-stage and two-stage compressors are generally used in gasoline-plant operations. Single-stage compressors are generally used where pressures of 110 pounds per square inch are not exceeded.

In most two-stage plants little condensate is obtained after the first compression.

Several changes occur in the gas when it is treated in a gasoline plant for the condensation of gasoline. One has to do with the condensation of vapor, another with the liquefaction of gas, and a third with the solubility of gases in the liquids produced.

The condensate as it is received in the accumulator tanks consists principally of the liquids pentane and hexane and the liquefied gas butane. Some heptane and liquid propane may also be present.

For a particular natural gas there is a certain pressure best suited to produce the most salable gasoline. Increasing the pressure may result in producing more condensate in the accumulator tanks, but the additional yield may be so volatile as to quickly escape after exposure to air.

The quantity of gas that dissolves in the condensate in the accumulator tank is so small as to be insignificant.

At least one plant in the United States using a refrigerative method with low pressures is in successful operation.

COST DATA.

Exclusive of foundations and housing for machinery, pipe lines to wells, railroad sidings, storage tanks, etc., the compression and condensing equipment for gasoline plants costs from about $2,800 for a plant for handling 120,000 cubic feet of gas up to $7,800 for a plant for handling 600,000 to 700,000 cubic feet of gas. Two plants that produced 490,000 gallons of gasoline in 1913 cost $40,000 to complete. The owners realized 55 per cent on their investment the first year.

About 35 cubic feet of gas disappears at some plants for each gallon of condensate produced from 1,000 cubic feet of gas. At other plants, as much as 500 cubic feet of gas may disappear.

HEATING VALUES AND EXPLOSIVE LIMITS OF NATURAL GASES.

The heating value of the natural gas used for the condensation of gasoline from natural gas may be as high as 2,500 British thermal units at 0° C. and 760 mm. pressure. None of the residual gases that the authors tested had a heating value lower than 1,000 British thermal units. At one plant the residual gas had a heating value of almost 2,300 British thermal units.

The explosive limits of the natural gases used for the condensation of gasoline from natural gas are low and narrow. These limits are approximately, for the low limit, 3.5 per cent gas, and for the high limit, 9.5 per cent gas. Special precautions must be taken to avoid explosions.

EVAPORATION LOSSES.

Evaporation losses that resulted when natural-gas condensates of different specific gravities were exposed to the atmosphere in certain forms of containers ranged at one plant from 4.5 per cent to 24 per cent at the end of the first hour, from 8.5 to 33 per cent at the end of the second hour, from 9.5 to 40 per cent at the end of the third hour, and about 54 per cent at the end of 18 and 24 hours.

At another plant the losses for condensate ranging from a specific gravity of 79° to 98° B. were 0 to 19 per cent for the first hour, 0 to 26 per cent for 2 hours, 1 to 34 per cent for 3 hours, 2 to 38 per cent for 4 hours, 3 to 45 per cent for 6 hours, 4 to 48 per cent for 7 hours, 4 to 46 per cent for 8 hours, and 10 to 65 per cent for 24 hours.

A slower rate of evaporation occurs from a mixture of refinery naphtha and a condensate than when the condensate is allowed to evaporate separately. In some tests conducted by the authors, the saving at the end of the first hour was about 6 per cent in favor of the blends; at the end of the second hour, about 10 per cent; at the end of the third hour, about 11 per cent; at the end of the fourth hour, about 10 per cent; at the end of the fifth hour, about 12 per cent; at the end of the sixth hour, about 11 per cent; at the end of the seventh hour, about 8 per cent; and at the end of the twenty-fourth hour, about 14 per cent.

VAPOR PRESSURES.

Freshly drawn condensates with a specific gravity of 93° B. may have a vapor pressure of 14 to 48 pounds per square inch at temperatures of 55° to 100° F. (13° to 38° C.). Condensates with a specific gravity of 78° B. may have vapor pressures ranging from 3 to 19 pounds per square inch at temperatures of 55° to 109° F. (13° to 43° C.).

After a condensate with a specific gravity of 93° B. has lost 40 per cent of its volume by evaporation the vapor pressures may range from 1 pound to 19 pounds per square inch at temperatures ranging from 55° to 109° F. (13° to 43° C.).

When a freshly drawn condensate having a specific gravity of 93° B. is mixed with refinery naphtha with a specific gravity of 60° B. the vapor pressures may be 57 to 70 per cent of the vapor pressure of the condensate alone.

Condensates of the same specific gravity may have different vapor pressures

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APPENDIX.

PATENTS COVERING THE SEPARATION AND USE OF THE LIGHT PARAFFIN HYDROCARBONS IN NATURAL GAS.

In Technical Paper 10[a] of the Bureau of Mines there were published experiments relating to the use of the light paraffin hydrocarbons in natural gas. It was recommended that some of these constituents be used as a liquefied gas in the same manner that Pintsch, Blau, and other gases, transportable in containers under pressure, are used. At least one company developed the industry to the point of making gas installations. Some patents relating to this phase of the use of liquid products of natural gas are noted here.

U. S. patent 1031664, issued to F. P. Peterson July 2, 1912, discloses a process of condensing and separating different compounds in natural gas at different pressures and temperatures and collecting the condensate for each stage separately. The expanded residue of the gases is caused to flow countercurrent to the compressed gases and thereby cool them.

U. S. patent 1056845, issued to W. O. Snelling March 25, 1913, also discloses a process of separating some of the compounds from natural gas. A heated mixture of the gases is subjected under pressure to the condensing action of a series of condensers, each of which is maintained at a temperature just below the boiling point, at the high pressure to which the mixture is subjected, of the constituents condensed thereby.

U. S. patent 1094864, issued to F. P. Peterson April 28, 1914, claims a new composition of matter, consisting of a liquefied mixture of ethane, propane, and butane, produced from natural gas and substantially free from other hydrocarbons. Peterson claims as an advantageous process for obtaining the above mixture, the process patented by him on July 2, 1912 (U. S. patent 1031664).

TRAP FOR SAVING GAS FROM GUSHERS.

An elaborate trap for saving the gas from large gushers and separating the gasoline from the gas is described in the California Derrick,[b] the statement being made that this new method of conserving the gasoline in the escaping gas has taken the place of the gas compressor on certain properties in California. The principle underlying the method

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[a] Allen, I. C., and Burrell, G. A.: Liquefied products from natural gas, their properties and uses: Technical Paper 10, Bureau of Mines, 1912, 23 pp.

[b] Conservation of gas and oil in California. California Derrick, vol. 7, Sept. 10, 1914.

is the natural separation of associated oil and gas in a long chamber—a 10-inch pipe 800 feet long—which is tapped at short intervals by "risers" (separately controllable) into which the gas flows while the oil and sand under the pressure from the well, flow through the 10-inch pipe. When the oil and sand reach the end of the pipe, they are drawn into a receiving tank where the sand settles. As the gas is tapped at various points on the upper surface of the pipe, a rush of gas is prevented and the pressure is uniformly maintained over the entire surface of the oil as it passes along the pipe. When the gas leaves the oil it is said to contain only such of the light products as are proportionate to the temperature and pressure. The trap was devised by Dr. Eric A. Starke, who patented it October 8, 1912.

PUBLICATIONS ON PETROLEUM TECHNOLOGY.

A limited supply of the following publications of the Bureau of Mines is temporarily available for free distribution. Requests for all publications can not be granted, and to insure equitable distribution applicants are requested to limit their selection to publications that may be of especial interest to them. Requests for publications should be addressed to the Director, Bureau of Mines.

BULLETIN 19. Physical and chemical properties of the petroleums of the San Joaquin Valley, Cal., by I. C. Allen and W. A. Jacobs, with a chapter on analyses of natural gas from the southern California oil fields, by G. A. Burrell. 1911. 60 pp., 2 pls., 10 figs.

TECHNICAL PAPER 3. Specifications for the purchase of fuel oil for the Government, with directions for sampling oil and natural gas, by I. C. Allen. 1911. 13 pp.

TECHNICAL PAPER 10. Liquefied products from natural gas; their properties and uses, by I. C. Allen and G. A. Burrell. 1912. 23 pp.

TECHNICAL PAPER 25. Methods for the determination of water in petroleum and its products, by I. C. Allen and W. A. Jacobs. 1912. 13 pp., 2 figs.

TECHNICAL PAPER 32. The cementing process of excluding water from oil wells as practiced in California, by Ralph Arnold and V. R. Garfias. 1913. 12 pp., 1 fig.

TECHNICAL PAPER 37. Heavy oil as fuel for internal-combustion engines, by I. C. Allen. 1913. 36 pp.

TECHNICAL PAPER 38. Wastes in the production and utilization of natural gas and means for their prevention, by Ralph Arnold and F. G. Clapp. 1913. 29 pp.

TECHNICAL PAPER 42. The prevention of waste of oil and gas from flowing wells in California, with a discussion of special methods used by J. A. Pollard, by Ralph Arnold and V. R. Garfias. 1913. 15 pp., 2 pls., 4 figs.

TECHNICAL PAPER 45. Waste of oil and gas in the Mid-Continent fields, by R. S. Blatchley. 1914. 54 pp., 2 pls., 15 figs.

TECHNICAL PAPER 49. The flash point of oils; methods and apparatus for its determination, by I. C. Allen and A. S. Crossfield. 1913. 31 pp., 2 figs.

TECHNICAL PAPER 51. Possible causes of the decline of oil wells and suggested methods of prolonging yield, by L. G. Huntley. 1913. 52 pp., 9 figs.

TECHNICAL PAPER 57. A preliminary report on the utilization of oil and natural gas in Wyoming, by W. R. Calvert, with a discussion of the suitability of natural gas for making gasoline, by G. A. Burrell. 1913. 23 pp.

TECHNICAL PAPER 66. Mud-laden fluid applied to well drilling, by J. A. Pollard and A. G. Heggem. 1914. 21 pp., 12 figs.

TECHNICAL PAPER 68. Drilling wells in Oklahoma by the mud-laden fluid method, by A. G. Heggem and J. A. Pollard. 1914. 27 pp., 5 figs.

TECHNICAL PAPER 70. Methods of oil recovery as practiced in California, by Ralph Arnold and V. R. Garfias. 1914. 57 pp., 7 figs.

TECHNICAL PAPER 72. Problems of the petroleum industry; results of conferences at Pittsburgh, Pa., August 1 and September 10, 1913, by I. C. Allen. 1914. 20 pp.

TECHNICAL PAPER 74. Physical and chemical properties of the petroleums of California, by I. C. Allen, W. A. Jacobs, A. S. Crossfield, and R. R. Matthews. 1914. 38 pp., 1 fig.

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