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(71) Demandeur/Applicant:
GASFRAC ENERGY SERVICES INC., CA

(72) Inventeurs/Inventors:
LOREE, DWIGHT N., CA;
NEVISON, GRANT, CA

(74) Agent: LAMBERT, ANTHONY R.

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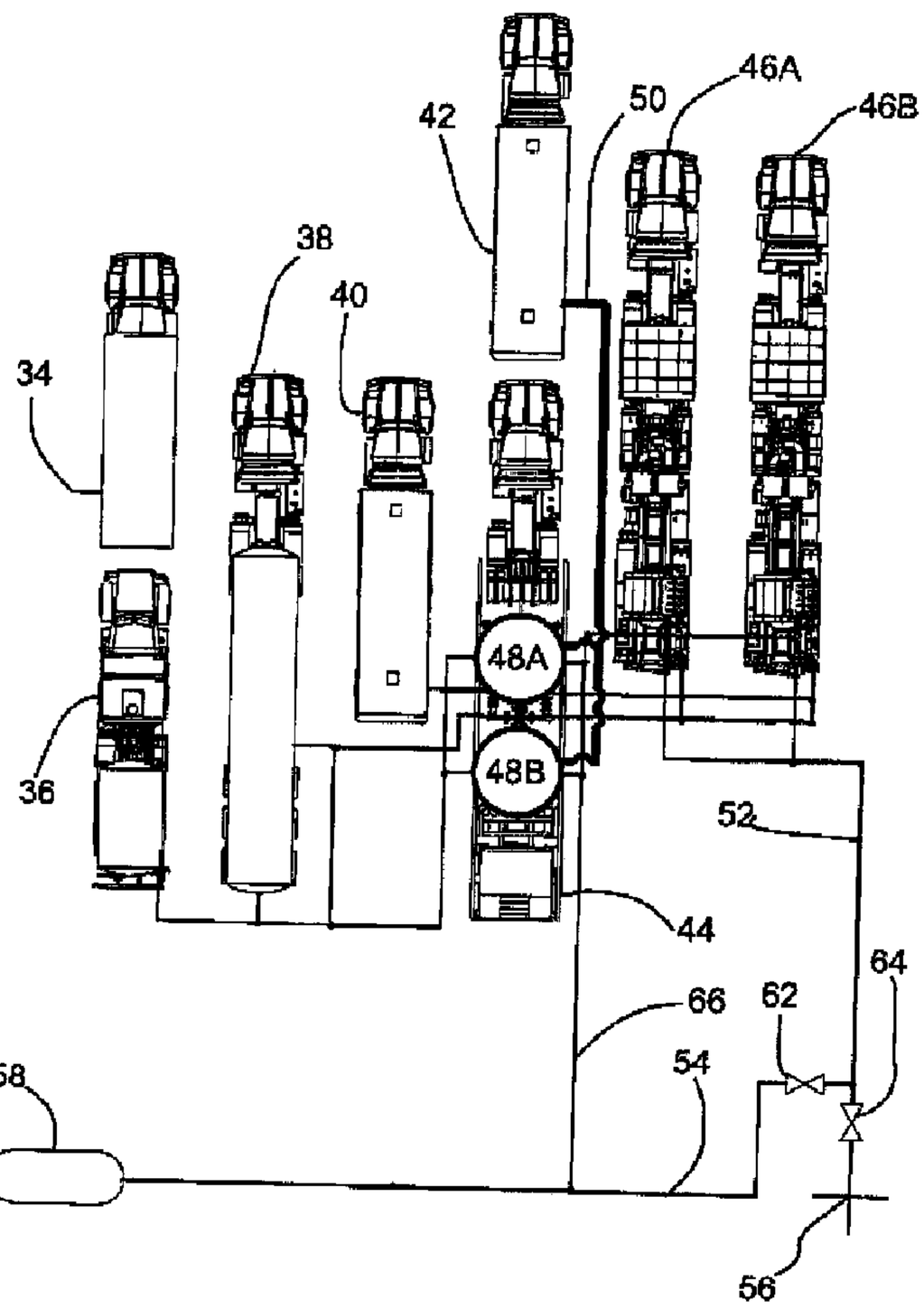

(57) Abrégé/Abstract:
Methods of tailoring a hydrocarbon fracturing fluid for a subterranean formation are disclosed. Fluid in the subterranean formation has a fluid temperature. A first critical temperature of a hydrocarbon fluid is adjusted to a critical temperature above the fluid

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(57) Abrégé(suite)/Abstract(continued):
temperature by adding a liquefied petroleum gas component to the hydrocarbon fluid to produce the hydrocarbon fracturing fluid. The liquefied petroleum gas component has a second critical temperature, and the hydrocarbon fluid comprises liquefied petroleum gas. A hydrocarbon fracturing fluid made by these methods are also disclosed. Methods of treating a subterranean formation are also disclosed. A hydrocarbon fracturing fluid is introduced into the subterranean formation, the hydrocarbon fracturing fluid having a critical temperature that is above a fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid is in the subterranean formation. The hydrocarbon fracturing fluid is subjected to pressures above the formation pressure

ABSTRACT OF THE DISCLOSURE

Methods of tailoring a hydrocarbon fracturing fluid for a subterranean formation are disclosed. Fluid in the subterranean formation has a fluid temperature. A first critical temperature of a hydrocarbon fluid is adjusted to a critical temperature above the fluid temperature by adding a liquefied petroleum gas component to the hydrocarbon fluid to produce the hydrocarbon fracturing fluid. The liquefied petroleum gas component has a second critical temperature, and the hydrocarbon fluid comprises liquefied petroleum gas. A hydrocarbon fracturing fluid made by these methods are also disclosed. Methods of treating a subterranean formation are also disclosed. A hydrocarbon fracturing fluid is introduced into the subterranean formation, the hydrocarbon fracturing fluid having a critical temperature that is above a fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid is in the subterranean formation. The hydrocarbon fracturing fluid is subjected to pressures above the formation pressure

LIQUIFIED PETROLEUM GAS FRACTURING METHODS

TECHNICAL FIELD

[0001] This application relates to the field of LPG fracturing and treatment systems and methods.

BACKGROUND

[0002] In the conventional fracturing of wells, producing formations, new wells or low producing wells that have been taken out of production, a formation can be fractured to attempt to achieve higher production rates. Proppant and fracturing fluid are mixed in a blender and then pumped into a well that penetrates an oil or gas bearing formation. High pressure is applied to the well, the formation fractures and proppant carried by the fracturing fluid flows into the fractures. The proppant in the fractures holds the fractures open after pressure is relaxed and production is resumed. Various fluids have been disclosed for use as the fracturing fluid, including various mixtures of hydrocarbons, nitrogen and carbon dioxide.

[0003] Care must be taken over the choice of fracturing fluid. The fracturing fluid must have a sufficient viscosity to carry the proppant into the fractures, should minimize formation damage and must be safe to use. A fracturing fluid that remains in the formation after fracturing is not desirable since it may block pores and reduce well production. For this reason, carbon dioxide has been used as a fracturing fluid because, when the fracturing pressure is reduced, the carbon dioxide gasifies and is easily removed from the well.

[0004] Lower order alkanes such as propane have also been proposed as fracturing fluids. Thus, United States patent no. 3,368,627 describes a fracturing method that uses a combination of a liquefied C2-C6 hydrocarbon and carbon dioxide mix as the fracturing fluid. The mix is designed to have a critical temperature below the formation temperature, and after stimulation is completed and the pressure reduced, the mix heats up to the formation temperature and is gasified. As a lower order alkane, ethane, propane, butane and

pentane are inherently non-damaging to formations. However, this patent does not describe how to achieve propane or butane injection safely, or how to inject proppant into the propane or butane frac fluid. Further, fracturing mixes contemplated by this patent are not intended to be left in the formation for long periods of time, since they gasify once heated to their critical temperature by the formation. United States patent no. 5,899,272 also describes propane as a fracturing fluid, but the injection system described in that patent has not been commercialized. Thus, while propane and butane are desirable fluids for fracturing due to their volatility, low weight and easy recovery, those very properties tend to make propane and butane hazardous, and thus LPG fracturing had been commercially abandoned by the industry until proposed by the inventor Dwight Loree in his Patent Cooperation Treaty application no. PCT/CA2007/000342 published September 7, 2007 and related applications.

SUMMARY

[0005] Methods of tailoring a hydrocarbon fracturing fluid for a subterranean formation are disclosed. Fluid in the subterranean formation has a fluid temperature. A first critical temperature of a base hydrocarbon fluid is adjusted for example to a critical temperature above the fluid temperature by adding a critical temperature adjusting fluid such as a liquefied petroleum gas component to the base hydrocarbon fluid to produce the hydrocarbon fracturing fluid. The liquefied petroleum gas component has a second critical temperature, and the base hydrocarbon fluid comprises liquefied petroleum gas. A hydrocarbon fracturing fluid made by these methods are also disclosed.

[0006] Methods of treating a subterranean formation are also disclosed. A hydrocarbon fracturing fluid is introduced into the subterranean formation, the hydrocarbon fracturing fluid having a critical temperature that is above a fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid is in the subterranean formation, the hydrocarbon fracturing fluid comprising liquefied petroleum gas. The hydrocarbon fracturing fluid is subjected to pressures above the formation pressure.

[0007] Methods of treating a subterranean formation are also disclosed. A hydrocarbon fracturing fluid comprising liquefied petroleum gas is introduced into the subterranean formation. The hydrocarbon fracturing fluid is subjected to pressures above the formation pressure. The hydrocarbon fracturing fluid is then shut-in in the subterranean formation for a period of at least 4 hours. The period may be, for example longer than 12 hours or 24 hours and could be more than two days.

[0008] Methods of treating plural zones of one or more hydrocarbon reservoirs penetrated by a well are also disclosed. Hydrocarbon fracturing fluid comprising liquefied petroleum gas is introduced through the well into a first zone of the one or more hydrocarbon reservoirs. The hydrocarbon fracturing fluid is subjected in the first zone to pressures above the formation pressure of the first zone. Hydrocarbon fracturing fluid comprising liquefied petroleum gas is introduced through the well into a second zone of the one or more hydrocarbon reservoirs. The hydrocarbon fracturing fluid is subjected in the second zone to pressures above the formation pressure of the second zone. The hydrocarbon fracturing fluid is at least partially removed from the first zone and the second zone.

[0009] A fluid is also disclosed, the fluid comprising hydrocarbon fracturing fluid at least partially removed from the subterranean formations of the methods disclosed herein. A subterranean formation is also disclosed comprising the hydrocarbon fracturing fluid introduced by any of the methods disclosed herein.

[0010] A method of treating under-pressured formations is also disclosed. The under-pressured subterranean formation has a formation pressure and contains formation fluids. A hydrocarbon fracturing fluid comprising liquefied petroleum gas is prepared, the hydrocarbon fracturing fluid having a density such that the static pressure of the hydrocarbon fracturing fluid at the under-pressured subterranean formation is less than the formation pressure. The hydrocarbon fracturing fluid is introduced into the under-pressured subterranean formation. The hydrocarbon fracturing fluid is subjected to pressures above the

formation pressure. The hydrocarbon fracturing fluid is then recovered along with formation fluids.

[0011] These and other aspects of the device and method are set out in the claims, which are incorporated here by reference.

BRIEF DESCRIPTION OF THE FIGURES

[0012] Embodiments will now be described with reference to the figures, in which like reference characters denote like elements, by way of example, and in which:

[0013] Fig. 1 is a graph of the saturation curve of propane, illustrating a fracturing process.

[0014] Fig. 2 is a graph of saturation curves of various mixtures of propane and methane.

[0015] Fig. 3 is a schematic of a fracture created by conventional fracturing techniques.

[0016] Fig. 4 is a schematic of a fracture created by the methods disclosed herein.

[0017] Fig. 5 is a top plan schematic of a fracturing system carrying out an embodiment of a method as disclosed herein, illustrating proppant being loaded into proppant supply vessels.

[0018] Fig. 6 is a top plan schematic of a fracturing system carrying out an embodiment of a method as disclosed herein, illustrating pressure testing the lines with inert gas.

[0019] Fig. 7 is a top plan schematic of a fracturing system carrying out an embodiment of a method as disclosed herein, illustrating the bleeding off of inert gas from the lines, and commencement of the frac.

[0020] Fig. 8 is a top plan schematic of a fracturing system carrying out an embodiment of a method as disclosed herein, illustrating the loading of frac fluid in the well.

[0021] Fig. 9 is a top plan schematic of a fracturing system carrying out an embodiment of a method as disclosed herein, illustrating the completion of a frac treatment.

[0022] Fig. 10 is a top plan schematic of a fracturing system carrying out an embodiment of a method as disclosed herein, illustrating the purging of LPG-filled lines with inert gas.

[0023] Fig. 11 is a top plan schematic of a fracturing system carrying out an embodiment of a method as disclosed herein, illustrating the purging of the process blender with inert gas.

[0024] Fig. 12 is a top plan schematic of a fracturing system carrying out an embodiment of a method as disclosed herein, illustrating the production of well fluids upon completion of a frac treatment.

[0025] Fig. 13 is a graph illustrating various specifications for an exemplary treatment carried out using an embodiment of a method as disclosed herein.

[0026] Figs. 14A-C illustrate a method of treating plural hydrocarbon reservoirs penetrated by a vertical well as disclosed herein.

[0027] Fig. 14D illustrates a method of treating plural hydrocarbon zones of a reservoir penetrated by a horizontal well as disclosed herein.

[0028] Fig. 15 is a graph illustrating the viscosity of water and LPG.

[0029] Fig. 16 is a graph illustrating the surface tension of water and LPG.

[0030] Fig. 17 is a graph illustrating a gelled hydrocarbon fracturing fluid breaking after a set amount of time.

[0031] Fig. 18 is a graph of the saturation curve of propane, illustrating the separator operating region.

[0032] Figs. 19A-B are tables that illustrate various examples of formations fractured using the methods disclosed herein.

[0033] Fig. 20 is a flow schematic illustrating a method of tailoring a hydrocarbon fracturing fluid for a subterranean formation, fluid in the subterranean formation having a fluid temperature.

[0034] Fig. 21 is a flow schematic illustrating a method of treating a subterranean formation with a fracturing fluid that has a critical temperature above the fluid temperature.

[0035] Fig. 22 is a flow schematic illustrating a further method of treating a subterranean formation involving shutting-in the fluid for an extended period of time.

[0036] Fig. 23 is a flow schematic illustrating a method of treating plural zones of one or more hydrocarbon reservoirs penetrated by a well.

[0037] Fig. 24 is a flow schematic illustrating a further method of tailoring a hydrocarbon fracturing fluid for a subterranean formation, fluid in the subterranean formation having a fluid temperature.

[0038] Fig. 25 is a flow schematic illustrating a method of treating an under-pressured subterranean formation having a formation pressure and containing formation fluids.

DETAILED DESCRIPTION

[0039] Immaterial modifications may be made to the embodiments described here without departing from what is covered by the claims.

[0040] Liquefied Petroleum Gases (hereinafter LPG) include a variety of petroleum and natural gases existing in a liquid state at ambient temperatures and moderate pressures. In some cases, LPG refers to a mixture of such fluids. These mixes are generally more affordable and easier to obtain than any one individual LPG, since they are hard to separate and purify individually. Unlike conventional hydrocarbon based fracturing fluids, common LPGs are tightly fractionated products resulting in a high degree of purity and very predictable performance. Exemplary LPGs used in this document include ethane, propane, butane, pentane, hexane, and various mixes thereof. Further examples include HD-5 propane, commercial butane, i-butane, i-pentane, n-pentane, and n-butane. The LPG mixture may be controlled to gain the desired hydraulic fracturing and clean-up performance.

[0041] LPGs tend to produce excellent fracturing fluids. LPG is readily available, cost effective and is easily and safely handled on surface as a liquid under moderate pressure. LPG is completely compatible with formations and formation fluids, is highly soluble in formation hydrocarbons and eliminates phase trapping - resulting in increased well production. LPG may be readily and predictably viscosified to generate a fluid capable of efficient fracture creation and excellent proppant transport. After fracturing, LPG may be

recovered very rapidly, allowing savings on clean up costs. Further, LPG may be recovered directly to sales gas without flaring. Referring to Figs. 3 and 4, fractures formed during fracturing with conventional and LPG fluids, respectively, are contrasted. Conventional stimulation techniques incorporate the use of fluids such as oil, water, methanol, CO_2, and N_2 for example. Referring to Fig. 3, the effective fracture length 12 is much shorter than the created fracture length 14. The effective fracture length 12 refers to the length of the created fracture through which well fluids may be produced into the well. This may occur as a result of the high surface tension of conventional fluids creating liquid blocks in the pores of a formation. Because the conventional fluids are not easily removed from the formation, the liquid blocks effectively eliminate a large portion of fracture through which fluids may otherwise be produced. Referring to Fig. 4, on the other hand, the effective fracture length 12 is the same as the created fracture length 14. This is due to the fact that the LPG fluid may be cleaned up quickly and completely. The LPG may clean up by vaporization with natural gas in the formation, or by dissolving into solution with formation oil, thus eliminating the relative permeability flow reduction seen with conventional fluids. The vaporization of LPG with natural gas and the extremely low viscosity of LPG permits rapid clean-up to be accomplished with minimal drawdown.

[0042] Referring to Fig. 16, the extremely low surface tension of the LPG eliminates or at least significantly reduces the formation of liquid blocks created by fluid trapping in the pores of the formation. This is contrasted with the high surface tension of water, which makes water less desirable as a conventional fluid. LPG is nearly half the density of water, and generates gas at approximately 272 m^3 gas/m^3 of liquid. LPG comprising butane and propane has a hydrostatic gradient at 5.1 kPa/m, which greatly assists any post-treatment clean-up required, by allowing greater drawdown. This hydrostatic head is approximately half the hydrostatic head of water, indicating that LPG is a naturally under balanced fluid. Referring to Fig. 15, LPG also has significantly lowered viscosity than water in an ungelled state, which further aids in the removal of LPG from a well.

[0043] Referring to Fig. 1, a propane saturation curve is illustrated. The * indicates the critical point of propane, and hence the critical temperature as well. The critical temperature is understood as the temperature beyond which the fluid exists as a gas, regardless of pressure. The region indicated by the reference numeral 10 corresponds to low-pressure surface handling, which refers to exemplary ranges of pressures and temperatures under which LPG is typically stored prior to use in fracturing. Exemplary critical temperatures of LPGs are denoted below in Table 1.

[0044] Table 1

LPG	Critical Temperature (°C)
Ethane	32
Propane	97
n-Butane	152
Pentane	197

[0045] Referring to Figs. 20 and 24, methods of tailoring a hydrocarbon fracturing fluid for a subterranean formation is illustrated. Fluid in the subterranean formation has a fluid temperature. This may be the temperature of fluids contained naturally in the formation, or the temperature of fracturing or treatment fluids that have been in the formation long enough to acclimatize with the formation. Referring to Fig. 20, in step 100, a first critical temperature of a hydrocarbon fluid (base fluid) is adjusted to a critical temperature above the fluid temperature by adding a critical temperature adjusting fluid such as liquefied petroleum gas component having a second critical temperature to the hydrocarbon fluid to produce the hydrocarbon fracturing fluid. The hydrocarbon fluid comprises liquefied petroleum gas. As a skilled worker would understand, the formation temperature of each formation to be fractured is different, as is the fluid temperature in each of these formations. Thus, it is desirable to tailor each hydrocarbon fluid such that it has a critical temperature that is above the fluid temperature. This customization of the critical temperature of the frac fluid composition allows one to improve the recovery performance of

the hydrocarbon fracturing fluid within the reservoir under certain application pressures and temperatures. In addition, this customization may allow one to maintain or improve gel performance during the fracturing operation. Also, the critical temperature may be adjusted to at or above the fluid temperature achieved during placement of the hydrocarbon fracturing fluid in order to avoid the degradation of the gel performance that may be experienced as the fluid temperature approaches or exceeds the mixture critical temperature due to heating in or by the formation. In some embodiments, the critical temperature of the hydrocarbon fracturing fluid needs only to be just above, for example by a fraction of a degree, the fluid temperature, although it could be a degree or more above such as at least 10, 20, 30, 50, 100 or 150, degrees higher than the fluid temperature. The base fluid may be one or more of propane, butane and pentane, and to adjust the critical temperature may be mixed with one or more of ethane, propane, butane and pentane. Adjusting the relative amounts of ethane, propane, butane and pentane allows key fluid performance aspects relating to recovery of the fracturing fluid to be maximized, including viscosity, volatility and surface tension. The added LPG component may comprise 1-99% by volume of the combined base fluid and LPG component.

[0046] It may be desirous to produce a hydrocarbon fracturing fluid that has a critical temperature that is above the fluid temperature, but not so far above the fluid temperature that subsequent removal from the formation is made difficult. The reason for this is that, as hydrocarbon liquids and their liquid mixtures approach the critical temperature, their properties become increasingly more gas-like and thereby easier to recover from the formation. These properties must be balanced, as gel degradation becomes an issue if the fluid temperature is too close to the critical temperature. This careful balance of the critical temperature is necessary in order to achieve maximum performance of the fluid. In some embodiments, the critical temperature of the hydrocarbon fracturing fluid is within 50 degrees of the fluid temperature. In further embodiments, the critical temperature of the hydrocarbon fracturing fluid is within 40 degrees of the fluid temperature. In other embodiments, the critical temperature of the hydrocarbon fracturing fluid is within, for example 30, 20, 15, 10, 5 or 1 degrees of the hydrocarbon fracturing fluid.

[0047] In some embodiments, the second critical temperature is higher than the first critical temperature. An example of this may occur if the base hydrocarbon fluid is propane, and the LPG component added to adjust the first critical temperature is butane. In some embodiments, the second critical temperature is lower than the first critical temperature, and the first critical temperature is above the fluid temperature. These situations may arise when the first critical temperature is far above the fluid temperature, and a frac operator desires to lower the first critical temperature to improve the recovery and performance of the hydrocarbon fracturing fluid. In some embodiments, the base fluid comprises propane and butane. In these embodiments, the critical temperature adjusting fluid may be, for example propane and ethane.

[0048] Referring to Fig. 24, a further method of tailoring a hydrocarbon fracturing fluid for a subterranean formation is disclosed, fluid in the subterranean formation having a fluid temperature. In step 122, a first critical temperature of a base hydrocarbon fluid is adjusted by adding a liquefied petroleum gas component having a second critical temperature to the base hydrocarbon fluid to produce the hydrocarbon fracturing fluid. As before, the base hydrocarbon fluid comprises liquefied petroleum gas. The first critical temperature may be adjusted to, for example above the fluid temperature. In some embodiments, it may be advantageous to adjust the first critical temperature to below, for example slightly below, the fluid temperature. The base hydrocarbon fluid may comprise one or more of propane, butane and pentane, and the liquefied petroleum gas component may comprise one or more of ethane, propane, butane and pentane.

[0049] The hydrocarbon fracturing fluid produced by the above methods may comprise at least one gelling agent. The gelling agent may be any suitable gelling agent for gelling LPG, including ethane, propane, butane, pentane or mixtures of ethane, propane, butane and pentane, and may be tailored to suit the actual composition of the frac fluid. One example of a suitable gelling agent is created by first reacting phosphorus oxychloride and an alcohol having hydrocarbon chains of 3-7 carbons long, or in a further for example

alcohols having hydrocarbon chains 4-6 carbons long. The orthophosphate acid ester formed is then reacted with an aluminum sulphate activator to create the desired gelling agent. The gelling agent created will have hydrocarbon chains from 3-7 carbons long or, as in the further example, 4-6 carbons long. The hydrocarbon chains of the gelling agent may be thus commensurate in length with the hydrocarbon chains of the liquid petroleum gas used for the frac fluid. This gelling agent may be more effective at gelling an ethane, propane or butane fluid than a gelling agent with longer hydrocarbon chains. The proportion of gelling agent in the frac fluid may be adjusted to obtain a suitable viscosity in the gelled frac fluid. As indicated above, the hydrocarbon fracturing fluid may comprise at least one activator. The gel chemistry employed in the embodiments of this document may result in visco-elastic rheology characteristics. In some embodiments, the hydrocarbon fracturing fluid may further comprise at least one breaker. Referring to Fig. 17, an exemplary plot of a gel containing a tailored breaker is illustrated. The breaker employed in this example has been tailored to begin to begin to break after 30-50 minutes, resulting in a full break at around 65 minutes. The system may be comprised of the base gel component, an activator and a breaker. Normal loadings at 8 L/m^3 may result in viscosities of 300 cP to 400 cP at 100 s^{-1}. Break times have been achieved from under 30 minutes to in excess of 4 hours. In some of the other methods disclosed herein of treating a subterranean formation, longer break times may be necessary. The broken fluid viscosity is that of the base LPG fluid (0.05 - 0.2 cP).

[0050] Referring to Fig. 21, a method of treating a subterranean formation is disclosed. In step 102, a hydrocarbon fracturing fluid is introduced into the subterranean formation, the hydrocarbon fracturing fluid having a critical temperature and comprising LPG. The critical temperature is above a fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid is in the subterranean formation. In step 104, the hydrocarbon fracturing fluid is subjected to pressures above the formation pressure. In some embodiments, the hydrocarbon fracturing fluid is subjected to pressures at or above fracturing pressures. The method may further comprise a step of at least partially removing the hydrocarbon fracturing fluid from the formation. As described above, the presence of LPG in the hydrocarbon fracturing fluid greatly aids this step.

[0051] In some embodiments, the critical temperature of the hydrocarbon fracturing fluid is within 100 degrees of the fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid is in the subterranean formation. In further embodiments, the critical temperature of the hydrocarbon fracturing fluid is within 50 degrees of the fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid is in the subterranean formation. In even further embodiments, the critical temperature of the hydrocarbon fracturing fluid is within 30 degrees of the fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid is in the subterranean formation. It should be understood that this hydrocarbon fracturing fluid may be the same as the hydrocarbon fracturing fluids disclosed throughout this document. Accordingly, the critical temperature of the hydrocarbon fracturing fluid may be at least 1, for example at least 10 degrees higher than the fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid is in the subterranean formation.

[0052] Referring to Fig. 22, another method of treating a subterranean formation is disclosed. In step 106, a hydrocarbon fracturing fluid comprising liquefied petroleum gas is introduced into the subterranean formation. In step 108, the hydrocarbon fracturing fluid is subjected to pressures above the formation pressure. In step 110, the hydrocarbon fracturing fluid is shut-in in the subterranean formation for a period of at least 1 hour. The shutting-in period may comprise at least two periods combined, for example if the period was broken up into two periods due to the addition of extra hydrocarbon fracturing fluid at the halfway point. Under conventional fracturing procedures, the hydrocarbon fracturing fluid may be shut-in, but only for short periods of time, usually until the fracturing itself has been completed. The extending of the shutting-in period disclosed herein following the fracture treatment enhances the subsequent clean-up of the fluid due to the mixing of the fracturing fluid with the reservoir gas. Mixing of the fracturing fluid with the reservoir gas results in vaporization of the fracturing fluid, providing improved fluid recovery properties from that of the fracturing fluid alone. Further, allowing this mixing to occur results in improved clean up capabilities as a result of the lowered properties of viscosity and density from that of the

fracturing fluid alone. The mixing of the fracturing fluid with the reservoir gas also results in the mixture having properties that significantly reduces the capillary pressure of the mixture from that of the fracturing fluid alone. This further prevents the liquid block situation discussed above, and improves the resulting production from the formation into the well.

[0053] In some embodiments, the hydrocarbon fracturing fluid is shut-in for a period of at least 4 hours. In further embodiments, the hydrocarbon fracturing fluid is shut-in for a period of at least 7 hours. In further embodiments, the hydrocarbon fracturing fluid is shut-in for a period of at least 10 hours. In even further embodiments, the hydrocarbon fracturing fluid is shut-in for a period of at least 15 hours. In even further embodiments, the hydrocarbon fracturing fluid is shut-in for longer periods, for example a period of at least 24 hours. The extended shut-in time may be determined in order to maximize the mixing of the hydrocarbon fracturing fluid with the reservoir gas in the most efficient manner possible. The hydrocarbon fracturing fluid may have a critical temperature that is above a fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid is in the subterranean formation. The hydrocarbon fracturing fluid may be shut in for a period longer than 4 hours, 12 hours or 24 hours. The method may further comprise producing the hydrocarbon fracturing fluid along with formation fluids to a sales line.

[0054] Referring to Fig. 23, a method of treating one or more plural hydrocarbon reservoirs 15 (shown in Fig. 14A-D) penetrated by a well 16 is illustrated. Figs. 14A-C illustrate the method being carried out on plural reservoirs in a vertical well, and in Fig. 14D, there is shown a horizontal well 16A penetrating multiple zones 70, 72 and 74 of a single reservoir 18. The description below refers to treatment of multiple reservoirs penetrated by a single vertical well, but applies equally to treating multiple portions of a single reservoir penetrated by a horizontal well. In each case, zones are treated, the zones corresponding to the portions 70, 72 and 74 penetrated by the horizontal well or the multiple reservoirs 18, 20 or 30 penetrated by the vertical well In the embodiment illustrated in Fig. 14D, a second hydrocarbon reservoir 20 may also be treated according to the same methods as an additional zone 76.

[0055] Referring to Fig. 14A, in step 112 (shown in Fig. 23), hydrocarbon fracturing fluid comprising liquefied petroleum gas is introduced through the well 16 into a first hydrocarbon reservoir 18 of the one or more hydrocarbon reservoirs 15. In step 114 (shown in Fig. 23), the hydrocarbon fracturing fluid in the first hydrocarbon reservoir 18 is then subjected to pressures above the formation pressure of the first hydrocarbon reservoir 18. Referring to Fig. 14B, in step 116 (shown in Fig. 23) hydrocarbon fracturing fluid comprising liquefied petroleum gas is introduced through the well 16 into a second hydrocarbon reservoir 20 of the plural hydrocarbon reservoirs 15. In step 118 (shown in Fig. 23), the hydrocarbon fracturing fluid in the second hydrocarbon reservoir 20 is subjected to pressures above the formation pressure of the second hydrocarbon reservoir 20. Referring to Fig. 23, in step 120 the hydrocarbon fracturing fluid is at least partially removed from the first hydrocarbon reservoir 18 and the second hydrocarbon reservoir 20. It should be understood that step 120 may comprise at least partially removing the hydrocarbon fracturing fluid from the first hydrocarbon reservoir 18, and at least partially removing the hydrocarbon fracturing fluid from the second hydrocarbon reservoir 20. In some embodiments, step 120 may comprise at least partially removing the hydrocarbon fracturing fluid from the second hydrocarbon reservoir 20, and at least partially removing the hydrocarbon fracturing fluid from the first hydrocarbon reservoir 18. Referring to Fig. 14A, the method may further comprise shutting in the first hydrocarbon reservoir 18 before introducing hydrocarbon fracturing fluid into the second hydrocarbon reservoir 20. In some embodiments, the second hydrocarbon reservoir 20 may be shut in prior to the recovery of the hydrocarbon fracturing fluids.

[0056] Referring to Figs. 14A-C, an exemplary method of treating plural hydrocarbon reservoirs 15 is illustrated. Referring to Fig. 14A, at least one packer 22 may be used to implement the method. Packers 22 and 24 may be oriented within well 16 in order to isolate at least first reservoir 18. Steps 112 and 114 are then carried out, introducing hydrocarbon fracturing fluid into reservoir 18 and pressuring up to fracture. It should be understood that pressures above the formation pressure include pressures above the

fracturing pressure. After reservoir 18 is fractured, reservoir 18 may be shut-in with packer 22, and optionally packer 24 if present. In general the first hydrocarbon reservoir 18 may be shut-in with at least one packer 22. Referring to Fig. 14B, packers 26 and 28 are then positioned around second hydrocarbon reservoir 20 as shown. Steps 116 and 118 are then carried out, introducing hydrocarbon fracturing fluid into reservoir 20 and pressuring up to fracture. After reservoir 20 is fractured, reservoir 20 may be shut-in with at least packer 28, and optionally packer 26 if present. The shutting in of the first zone may occur before at least partially removing the hydrocarbon fracturing fluid from the first zone. Referring to Fig. 14C, at this stage, a third hydrocarbon reservoir 30 may then be fractured, in a similar fashion as illustrated for reservoirs 18 and 20. It should be understood that these methods may be used to fracture more than 3 hydrocarbon reservoirs in a formation penetrated by well 16.

[0057] After all of the desired reservoirs have been fractured, step 120 may be carried out, at least partially removing the hydrocarbon fracturing fluid from reservoirs 18, 20, and 30. This method may be contrasted with conventional methods, which involve flowing back each reservoir individually before fracturing another reservoir. This method of sequential fracturing is much more cost effective and time efficient than conventional methods. In some embodiments, this method may be used to fracture reservoirs penetrated by a branched well, for example fracturing reservoirs in parallel. In other embodiments, reservoir 30 may be fractured, followed by reservoirs 18 and 20 respectively. By leaving the hydrocarbon fracturing fluid in the first hydrocarbon reservoir 18 while reservoirs 20 and 30 are being fractured, the fracturing fluid in reservoir 18 is allowed to mix with formation gas, making recovery of the fracturing fluid much easier as discussed in more detail above. In some embodiments, the shutting in of the second zone occurs before at least partially removing the hydrocarbon fracturing fluid from the second zone.

[0058] Each of reservoirs 18, 20, and 30 may be shut-in for extended amounts of time as disclosed in this document for example, in order to achieve this effect. In some embodiments, the hydrocarbon fracturing fluid introduced into the first hydrocarbon

reservoir 18 is different from the hydrocarbon fracturing fluid introduced into the second hydrocarbon reservoir 20. As each reservoir will have different conditions and temperatures, it may be desirable to tailor each hydrocarbon fracturing fluid to best operate in each respective reservoir. It should be understood that the hydrocarbon fracturing fluid(s) used in this method may be the same as the hydrocarbon fracturing fluids disclosed throughout this document. This method is illustrated as being carried out using packers, but other implements may be used to achieve the same result. In some embodiments, a single packer may be used, pulling up the packer to each respective reservoir after fracturing the previous one. For example, this method of isolating the intervals may include the use of plugs, with appropriate perforation of the wellbore to access the reservoir, or alternate mechanical diverting assemblies within the wellbore. Additionally, the process is applicable to deviated and horizontal wellbores and may access a single reservoir at multiple points along that wellbore. In some embodiments, at least a portion of the well is at least one of deviated and horizontal, and at least one of the first hydrocarbon reservoir and the second hydrocarbon reservoir is accessible from the portion of the well.

[0059] It should be understood that all of the embodiments and aspects of each of the methods disclosed herein may be combined and incorporated into one another. It should also be understood that the hydrocarbon fracturing fluid used at any point in this document may be the same as the hydrocarbon fracturing fluids disclosed throughout this document.

[0060] A fluid comprising the hydrocarbon fracturing fluid at least partially removed from the subterranean formations of any of the disclosed methods herein is also disclosed. Recovering this flowback fracturing fluid is advantageous, as it may in many cases be of suitable quality to pump directly to a sales line. Further, in the event that the fracturing fluids have been allowed to mix with the formation gas, the recovered fluid may be even more valuable. The gas mixture of hydrocarbon fracturing fluid pumped into a gas bearing formation that mixes with natural gas in the formation may be recovered (produced) into a typical gas collection system. In some embodiments, this collection or production may exclude the recovery of the initial returns to the system without extending the shut-in. In this

embodiment, a line heater may be employed to allow the recovery of the initial returns. In some embodiments, the LPG recovery can be to directed to a pipeline or flare, for example. Initial and immediate LPG recovery, certainly wellbore fluids, are typically recovered as a liquid, although later fluids may be predominantly gaseous in nature. The recovery of the LPG load fluid can be measured accurately with a gas chromatograph or estimated on dry gas wells using gas density. Referring to Fig. 18, the separator operating region 32 illustrates the phase region at which most of the LPG is recovered. To date, in excess of 90% of the LPG load fluid has been recovered on all applications.

[0061] Referring to Fig. 14A, also disclosed is a subterranean formation (illustrated by plural hydrocarbon reservoirs 15 for example) comprising the hydrocarbon fracturing fluid introduced into the formation by any of the methods disclosed herein. Because the formation, in this instance, contains salable product (the hydrocarbon fracturing fluid and the formation gas), the formation itself is quite valuable.

[0062] Referring to Figs. 5 - 12, an exemplary process of fracturing with LPG hydrocarbon fracturing fluid is illustrated. In the following example, darkened lines in the drawings refer to lines through which fluid is flowing. Referring to Fig. 5, an exemplary set-up includes a treatment control van 34, an N_2 storage truck 36, an LPG trailer 38, a chemical control unit 40, a sand truck 42, an LPG process blender 44, and LPG fracturing pumps 46A, 46B.

[0063] Treatment control van 34 provides centralized remote operating and monitoring of the equipment of the fracturing system. Van 34 may be provided with a Geo-Sat communication system, which allows for real time internet based monitoring and VOIP phone lines to communicate with systems operators. It also provides continuous environmental monitoring of 4 wireless remote LEL sensors, and wind direction and speed for example. Van 34 may perform all of the required calculations, such as the optimum blend of LPG components to add to tailor the hydrocarbon fracturing fluid to best fracture the

formation, as well as the optimum job program for fracturing multiple reservoirs, for example. Calculations and adjustments may be made on the fly, as needed.

[0064] The N_2 storage truck may comprise a flameless N_2 pumper, which is incorporated into the process to supply boost pressure to move the LPG product through the process, and to purge all equipment to a safe environment prior to and after the stimulation. In some embodiments, no centrifugal pumps are may be used in this process. The LPG fracturing process blender may be a closed, pressurized system that uses integrated Process Logic Control (PLC) to precisely control the addition of proppant to a stream of Liquid LPG. Blender 44 may be operated and monitored from the treatment control and command center (illustrated as treatment control van 34 for example). Blender 44 may be provided with two 16 tonne proppant vessels 48A, B, from which proppant may be metered by two automated density controlled augers. Monitoring of blender 44 includes monitoring of clean and slurry flow rate, Radioactive Densitometer, Inline Process Viscometer, 4 Point load cell, Pressure Transducers, and Closed Circuit cameras. The densitometer may determine the proppant concentration being added, while the viscometer determines the extent of gelling.

[0065] Chemical control unit 40 comprises an integrated and automated chemical addition system, that may be operated by remote or local operation. Control unit 40 may comprise six 4 stage progressive cavity pumps monitored with mass flow meters, in order to ensure the proper and precise addition of chemicals into blender 44. Such chemicals include, for example gelling agents, breakers, activators, and tailoring LPG components, for example. Unit 40 may further comprise an LEL monitoring and alarm system for safety purposes. Unit 40 may be climate controlled with a high rate air exchanger to ensure a safe working environment, and may further comprise a drip proof containment system to protect a user and the environment from chemicals.

[0066] The system may also comprise an Iron truck (not shown). The iron truck may operate, for example, 100 m of 76.2 mm (3 inch) 103.4 MPa Treating Iron. Also, the iron truck may comprise hydraulically operated PLC controlled Plug Valves, operated from

treatment control van 34 for example. Iron truck may further have an integrated equipment emergency shut down system, and a hydraulic accumulator system.

[0067] LPG Fracturing pumps 46A, B, are designed for increased operating range and redundancy. Pumps 46A, B, may comprise OEM rated 2,500 hhp Caterpillar motors, and may be designed to meet 2006 EPA Tier 2 Non-Road Emissions standards. Pumps 46A, B, may also comprise 7 speed Caterpillar Transmissions, Quint-plex pumps, and automatic over-speed emergency shut-down systems. LPG pumps 46A, B may be operated digitally from the Treatment Control and Command Centre (illustrated as treatment control van 34 for example). Operating features may include: One man operator control of all pumps from one integrated operating screen, automatic pressure testing modes, and automatically adjustments of individual pump rates based on the total required rate and maximum pressure.

[0068] Proppant is first loaded from a supply truck (illustrated as sand truck 42) into the two proppant vessels 48A, 48B of the LPG process blender 44 from a proppant line 50. Referring to Fig. 6, air is then displaced out of the LPG process blender 44 proppant blender vessels 48A, B using pressurized N_2 gas supplied from N_2 storage truck 36. The LPG trailer 38 is also pressure balanced with the blender 44 using N_2 gas. In some embodiments, plural LPG sources are supplied, for example in the form of two or more LPG trailers 38. Each source may carry different LPG components, for example, in order to tailor the final mixture of LPG fracturing fluid. All lines are pressure tested with N_2, then with LPG, including lines 52,54 that lead to wellhead 56, sand separation tank 58, and flare stack 60, however, wellhead 56 is not pressurized at this point. Referring to Fig. 7, the LPG pressure is then bled off to flare stack 60, to complete the pressure test. Valve 62 is thus opened to open wellhead 56, and the treatment commences, with hydrocarbon fracturing fluid being provided to wellhead 56. Referring to Fig. 13, this point may correspond to time =5 minutes on the graph. At this stage, the LPG being pumped into the well may be ungelled, and the clean rate equals the slurry rate. At this stage, steps 102 and 104 of the method illustrated in Fig. 21 are being carried out, if the hydrocarbon fracturing fluid has a critical temperature that is above a fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid

is in the subterranean formation. The bottom hole pressure (Meas'd btmh) is only slightly higher than the treating pressure, due at least partially to the hydrostatic head and the formation pressure. Referring to Fig. 1, the phase of the LPG fluid, if propane, follows path A at this stage, as it is passes through blender 44 and through the HP pumps 46A, B, to the wellhead 56. Referring to Fig. 8, wellhead 56 is then filled with gelled LPG fluid. Valve 64 is closed, preventing any flow to flare stack 60. At this stage, chemical control van 34 is supplying gelling agents and other fracturing chemicals into LPG process blender 44. In addition, LPG trailer 38 is supplying LPG to blender 44, and N_2 storage truck 36 continues to provide pressure balancing between LPG trailer 38 and blender 44. Blender 44 blends and mixes the hydrocarbon fracturing fluid, while LPG fracturing pumps 46A, B are operating to pump the fracturing fluid mix into wellhead 56. Chemical control van 34 may provide a tailored amount of gelling agents, as well as any additional LPG components required to tailor the fracturing fluid to the subterranean formation being fractured. In some embodiments, the additional LPG components may be provided by separate LPG trailers 38 (not shown). As the fracturing continues, the formation is broken down, and a feed rate is established. Referring to Fig. 13, this may correspond to time =14 minutes, where gelled and proppant loaded fracturing fluid is being pumped into the well. Blender concentration indicates the concentration of proppant in the frac fluid. Slurry rate refers to overall rate of fluid entering the wellhead 56. Referring to Fig. 8, a pad of frac fluid may be pumped down as per the job program selected, as is illustrated in Fig. 13 from time =0 minutes to time = 12 minutes. Proppant is added to the gelled LPG as per the selected job program, through vessels 48A,B. N_2 gas replaces the surface volume of the displaced proppant and LPG in vessels 48A,B and LPG trailer 38, respectively. The proppant is under flushed to the perforations created downhole using the LPG fluid. Referring to Fig. 1, the phase of the LPG fluid, if propane, follows path B as it passes from the wellhead 56, through the tubular, and into the fractures. As the LPG enters the fracture and leaks-off to the reservoir conditions, the LPG fluid follows path C.

[0069] Referring to Fig. 9, upon completion of the treatment, the wellhead 56 is closed. The supply from LPG trailer 38, proppant supply vessels 48A,B, and chemical

control van 40 are each closed and isolated, for safety precautions. At this stage, wellhead 56 may be shut-in for an appropriate amount of time, as in the methods disclosed herein, for example an extended amount of time. Step 110 of the method illustrated in Fig. 22 may be carried out at this stage. Referring to Fig. 13, this may correspond to time =38 minutes, for example. Referring to Fig. 1, the phase of the LPG fluid, if propane, follows path D as it flows back from the reservoir to the surface, becoming more gas-like in the process. Referring to Fig. 9, upon completion of the shut-in period, if any, all high-pressure lines containing LPG frac fluid may be de-pressurized to flare stack 60. Referring to Fig. 10, all LPG-filled lines are then purged with N_2 to flare stack 60. Referring to Fig. 11, LPG Process blender 44 is then purged with N_2 to the flare stack 60 via line 66. All of the LPG fracturing process equipment is then rigged out. Referring to Fig. 12, given that a flow line 68 is available on location, the wellhead 56 can be produced back to the production facilities saving the cost of testing equipment, and resulting in no damage, limited cleanup, and no disposal.

[0070] It should be understood that the systems disclosed above may be used to carry out the methods illustrated and described for Fig. 23. The job program required for this would be delegated from treatment control van 34, and would involve manipulation of the same system to achieve the goals of the method.

[0071] The LPG fracturing processes disclosed herein should be implemented with design considerations to mitigate and eliminate the potential risks, such as by compliance with the Enform Document: Pumping of Flammable Fluids Industry Recommended Practice (IRP), Volume 8-2002, and NFPA 58 "Liquefied Petroleum Gas Code".

[0072] These methods may be used on sub-normally saturated and under-pressured reservoirs, including gas, oil and water wells, to eliminate altered saturations and relative permeability effects, accelerate clean-up, realize full frac length, and improve long-term production. Further, these methods may be used on reservoirs that exhibit high capillary pressures with conventional fluids to eliminate phase trapping. These methods may also be

used on low permeability reservoirs, which normally require long effective frac lengths to sustain economic production, to accelerate clean-up, realize full frac length quicker, and improve production. These methods may also be used on recompletions with recovery through existing facilities, in order to recover all LPG fluid to sales gas - thus reducing clean-up costs, avoiding conventional fluid recovery and handling costs, and eliminating flaring. Multiple frac treatments may be completed without the need for immediate frac clean-up between treatments, as the extended shut-in simplifies and speeds the clean-up without detriment to formation. These methods may also be used in exploration, as the pumping of a completely reservoir compatible fluid provides excellent stimulation plus rapid cleanup and evaluation, which gives a fast turnaround and zero-damage evaluation in potentially unknown reservoir and reservoir fluid characteristics.

[0073] Figs. 19A and B illustrate examples of successful fracturing procedures carried out using the methods as disclosed herein. Various specifications of each job are indicated in those figures.

[0074] Hydraulic fracturing with LPG has been done in the past, but has since been deemed too dangerous by others, and as a result, most development in this area has slowed or stopped. However, by combining safety techniques, LPG fracturing can be made safe. LPG Processes disclosed herein require no load fluids, CO_2 or N_2 during initial production which is less taxing on the production equipment, which results in reduced well clean-up time, although in specific instances, there may be additional fluids pumped with the LPG fluids.

[0075] Tailoring of the LPG component mix also enhances recovery in under-pressured reservoirs via the combination of low hydrostatic, mixing with native reservoir hydrocarbons, low viscosity and minimized surface tension/capillary pressure. Under-pressured refers to the formation pressure being lower than the hydrostatic pressure at the formation depth. The density of a hydrocarbon fracturing fluid comprising LPG may be adjusted by selection of LPG components to produce a hydrocarbon fracturing fluid, the

density of which makes the static pressure of the hydrocarbon fracturing fluid at the formation depth less than the formation pressure. All frac fluid components may be recovered directly to the sales or pipeline with no flaring or collection of liquids at surface by making the hydrostatic pressure of the fracturing fluid in the formation being treated low enough for the well to have a flowing pressure that permits clean-up, and composition suitable for the pipeline (no CO2, N2, methanol or water). Referring to Fig. 25, a method is disclosed of treating an under-pressured subterranean formation having a formation pressure and containing formation fluids. In step 124, a hydrocarbon fracturing fluid comprising liquefied petroleum gas is prepared, the hydrocarbon fracturing fluid having a density such that the static pressure of the hydrocarbon fracturing fluid at the under-pressured subterranean formation is less than the formation pressure. In some embodiments the hydrocarbon fracturing fluid is prepared. In step 126, the hydrocarbon fracturing fluid is introduced into the under-pressured subterranean formation. In step 128, the hydrocarbon fracturing fluid is subjected to pressures above the formation pressure. In step 130, the hydrocarbon fracturing fluid is recovered along with formation fluids. In some embodiments, the hydrocarbon fracturing fluid has a critical temperature that is above a fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid is in the subterranean formation. In some embodiments, the hydrocarbon fracturing fluid is subjected to pressures at or above fracturing pressures. In some embodiments, the recovered fluids are directed to a sales line.

[0076] In any of the disclosed embodiments of the methods described here, when the fluid in the subterranean formation comprises formation gas such as methane, the formation gas mixes with the hydrocarbon fracturing fluid to alter the critical temperature of the hydrocarbon fracturing fluid in the subterranean formation. When the critical temperature is lowered as for example in the case of mixing with methane, the resulting transition of the hydrocarbon fracturing fluid to a more gaseous state assists in expelling the hydrocarbon fracturing fluid from the subterranean formation and the well.

[0077] In particular in the case of an under-pressured gas reservoir, the LPG mixes with the reservoir gas, resulting in vaporization and subsequent reduction in density much beyond the originally low hydrostatic provided by the LPG fluid by itself. This benefit is important when treating under-pressured reservoirs. Thus, Fig. 2 shows the mixture properties of propane with methane. The particular lines shown are the vapor-lines, that being the pressure temperature relationship below which the mixture exists as 100% vapors. The end point of each curve is the critical temperature of the mixture. The mixing desirably results in a frac-fluid/reservoir composition where the critical temperature is below the reservoir temperature. This mixing is intended to occur within the formation following the fracturing treatment, during shut-in and subsequent clean-up. Hence, the LPG mix is designed to promote mixing with reservoir gas to achieve vaporization as another primary mechanism for developing a suitable hydrostatic for ready clean-up. The hydrostatic is important as it sets the surface flowing pressure of the well during clean-up. If the surface flow pressure is too low, then the well may not have sufficient pressure to clean-up into the pipeline. This pipeline pressure may range from under 20 psi to over 1,000 psi and the well flow condition must exceed this pressure in order to enter it.

[0078] In the claims, the word "comprising" is used in its inclusive sense and does not exclude other elements being present. The indefinite article "a" before a claim feature does not exclude more than one of the feature being present. Each one of the individual features described here may be used in one or more embodiments and is not, by virtue only of being described here, to be construed as essential to all embodiments as defined by the claims.

THE EMBODIMENTS OF THE INVENTION IN WHICH AN EXCLUSIVE PROPERTY OR PRIVILEGE IS CLAIMED ARE DEFINED AS FOLLOWS:

1. A method of tailoring a hydrocarbon fracturing fluid for a subterranean formation, fluid in the subterranean formation having a fluid temperature, the method comprising:

adjusting a first critical temperature of a base hydrocarbon fluid to a critical temperature above the fluid temperature by adding a critical temperature adjusting fluid having a second critical temperature to the hydrocarbon fluid to produce the hydrocarbon fracturing fluid, the hydrocarbon fluid comprising liquefied petroleum gas.

2. The method of claim 1 in which the critical temperature adjusting fluid comprises a liquefied petroleum gas component.

3. The method of claim 2 in which the base hydrocarbon fluid comprises one or more of propane, butane and pentane, and the critical temperature adjusting fluid comprises one or more of ethane, propane, butane and pentane.

4. The method of claim 2 or 3 in which the second critical temperature is higher than the first critical temperature.

5. The method of claim 4 in which the base hydrocarbon fluid comprises propane.

6. The method of claim 5 in which the critical temperature adjusting fluid comprises butane.

7. The method of any one of claims 1 - 6 in which the first critical temperature is below the fluid temperature.

8. The method of claim 1 in which the second critical temperature is lower than the first critical temperature, and the first critical temperature is above the fluid temperature.

9. The method of claim 8 in which the base hydrocarbon fluid comprises at least one of propane and butane.

10. The method of claim 9 in which the critical temperature adjusting fluid comprises one or more of propane and ethane.

11. The method of claim 10 in which the critical temperature adjusting liquid comprises ethane.

12. The method of any one of claims 1-11 in which the critical temperature of the base hydrocarbon fracturing fluid is adjusted by mixing with critical temperature adjusting fluid to be sufficiently close to the fluid temperature that mixing of the hydrocarbon fracturing fluid with formation gas reduces the critical temperature of the hydrocarbon fracturing fluid to below the fluid temperature.

13. The method of any one of claims 1-12 in which the critical temperature of the hydrocarbon fracturing fluid is within 1 degree C of the fluid temperature.

14. A method of tailoring a hydrocarbon fracturing fluid for a subterranean formation, fluid in the subterranean formation having a fluid temperature, the method comprising:

adjusting a first critical temperature of a base hydrocarbon fluid by adding a liquefied petroleum gas component having a second critical temperature to the base hydrocarbon fluid to produce the hydrocarbon fracturing fluid, the base hydrocarbon fluid comprising liquefied petroleum gas.

15. The method of claim 14 in which the base hydrocarbon fluid comprises one or more of propane, butane and pentane, and the liquefied petroleum gas component comprises one or more of ethane, propane, butane and pentane.

16. A hydrocarbon fracturing fluid made by the methods of any one of claim 1-15.

17. The hydrocarbon fracturing fluid of claim 16 further comprising at least one gelling agent.

18. The hydrocarbon fracturing fluid of claim 17 further comprising at least one activator.

19. The hydrocarbon fracturing fluid of claim 17 or 18 further comprising at least one breaker.

20. A method of treating a subterranean formation containing formation fluids, the method comprising:

introducing a hydrocarbon fracturing fluid into the subterranean formation, the hydrocarbon fracturing fluid having a critical temperature that is above a fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid is in the subterranean formation, the hydrocarbon fracturing fluid comprising liquefied petroleum gas; and

subjecting the hydrocarbon fracturing fluid to pressures above the formation pressure.

21. The method of claim 20 in which the hydrocarbon fracturing fluid is subjected to pressures at or above fracturing pressures.

22. The method of claim 20 or 21 where fluid in the subterranean formation comprises formation gas, and the formation gas mixes with the hydrocarbon fracturing fluid to reduce the critical temperature of the hydrocarbon fracturing fluid in the subterranean formation and assist in expelling the hydrocarbon fracturing fluid from the subterranean formation and the well.

23. The method of claim 22 where the formation gas comprises methane.

24. The method of any one of claims 20-23 further comprising shutting-in the hydrocarbon fracturing fluid in the subterranean formation for a period of at least 4 hours.

25. The method of claim 24 further comprising shutting-in the hydrocarbon fracturing fluid in the subterranean formation for a period of at least 24 hours.

26. The method of any one of claims 20-25 further comprising producing the hydrocarbon fracturing fluid along with formation fluids to a sales line.

27. The method of claim 26 where mixing of the hydrocarbon fracturing fluid with formation gas assists in propelling recovered hydrocarbon fracturing fluid into the sales line.

28. A method of treating an under-pressured subterranean formation having a formation pressure and containing formation fluids, the method comprising:

providing a hydrocarbon fracturing fluid comprising liquefied petroleum gas, the hydrocarbon fracturing fluid having a density such that the static pressure of the hydrocarbon fracturing fluid at the under-pressured subterranean formation is less than the formation pressure;

introducing the hydrocarbon fracturing fluid into the under-pressured subterranean formation;

subjecting the hydrocarbon fracturing fluid to pressures above the formation pressure; and

recovering the hydrocarbon fracturing fluid along with formation fluids.

29. The method of claim 28 in which the hydrocarbon fracturing fluid has a critical temperature that is above a fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid is in the subterranean formation.

30. The method of claim 29 in which the hydrocarbon fracturing fluid is subjected to pressures at or above fracturing pressures.

31. The method of claim 28, 29 or 30 where fluid in the subterranean formation comprises formation gas, and the formation gas mixes with the hydrocarbon fracturing fluid to reduce the critical temperature of the hydrocarbon fracturing fluid in the subterranean formation and assist in expelling the hydrocarbon fracturing fluid from the subterranean formation and the well.

32. The method of claim 31 where the formation gas comprises methane.

33. The method of any one of claims 28-32 in which the recovered fluids are directed to a sales line.

34. A method of treating a subterranean formation, the method comprising:

introducing a hydrocarbon fracturing fluid comprising liquefied petroleum gas into the subterranean formation;

subjecting the hydrocarbon fracturing fluid to pressures above the formation pressure; and

shutting-in the hydrocarbon fracturing fluid in the subterranean formation for a period of at least 4 hours.

35. The method of claim 34 in which the hydrocarbon fracturing fluid is shut-in for a period of at least 24 hours.

36. A method of treating one or more hydrocarbon reservoirs penetrated by a well, the method comprising:

introducing hydrocarbon fracturing fluid comprising liquefied petroleum gas through the well into a first zone of the one or more hydrocarbon reservoirs;

subjecting the hydrocarbon fracturing fluid in the first zone to pressures above the formation pressure of the first zone;

introducing hydrocarbon fracturing fluid comprising liquefied petroleum gas through the well into a second zone of the one or more hydrocarbon reservoirs;

subjecting the hydrocarbon fracturing fluid in the second zone to pressures above the formation pressure of the second zone; and

at least partially removing the hydrocarbon fracturing fluid from the first zone and the second zone.

37. The method of claim 36 in which the well is a predominantly horizontal well penetrating a hydrocarbon reservoir and the first zone and the second zone are both in the hydrocarbon reservoir.

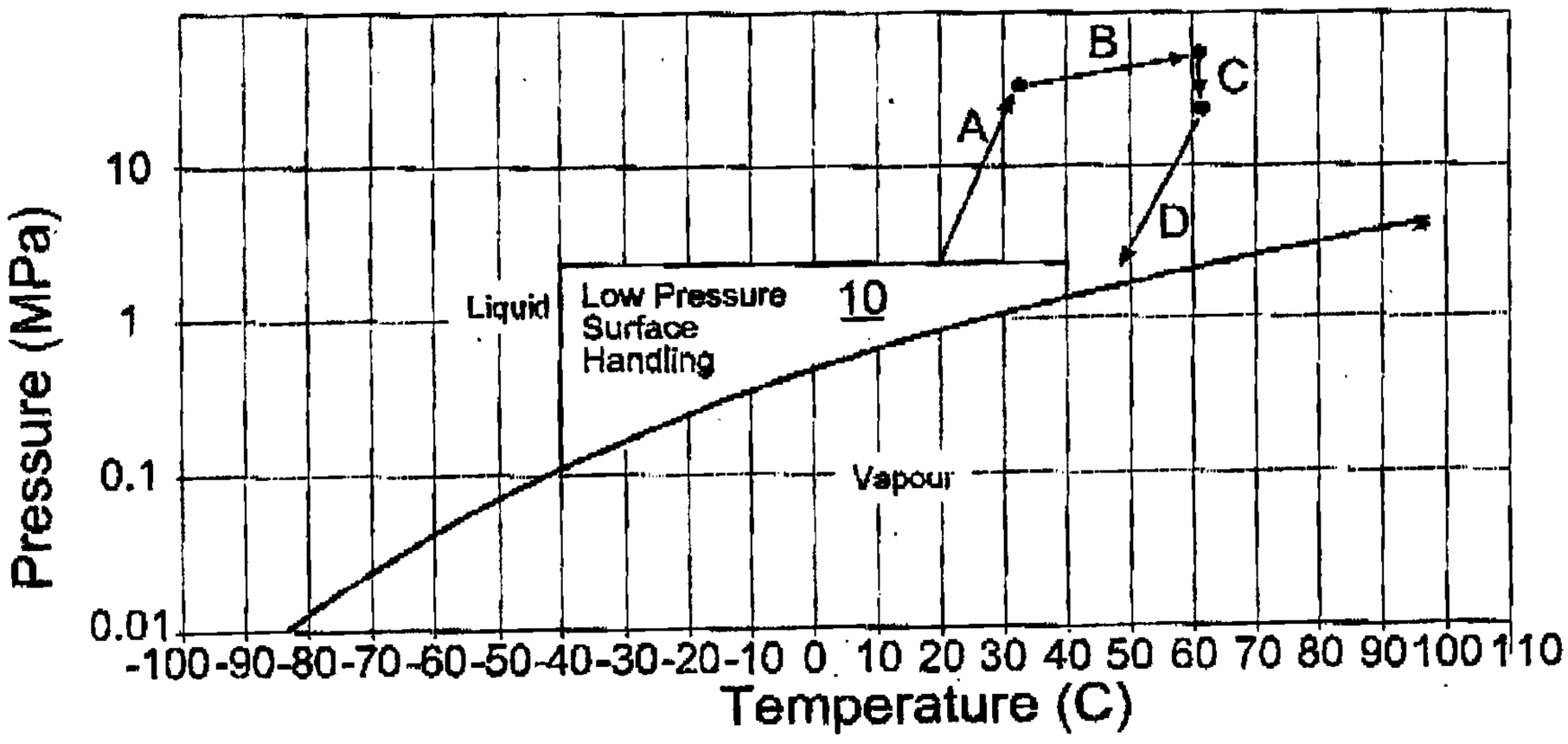
38. The method of claim 36 in which the well is a predominantly vertical well penetrating at least a first hydrocarbon reservoir and a second hydrocarbon reservoir and the first zone comprises at least a portion of the first hydrocarbon reservoir and the second zone comprises at least a portion of the second hydrocarbon reservoir..

39. The method of claims 36, 37 or 38 further comprising shutting in the first zone before introducing hydrocarbon fracturing fluid into the second zone.

40. The method of claim 39 in which the first zone is shut-in for a period of at least 4 hours.

41. The method of any one of claims 36-40 further comprising shutting in the second zone before at least partially removing the hydrocarbon fracturing fluid from the second zone.

42. The method of any one of claims 36-41 in which the hydrocarbon fracturing fluid introduced into the first zone has a different composition from the hydrocarbon fracturing fluid introduced into the second zone.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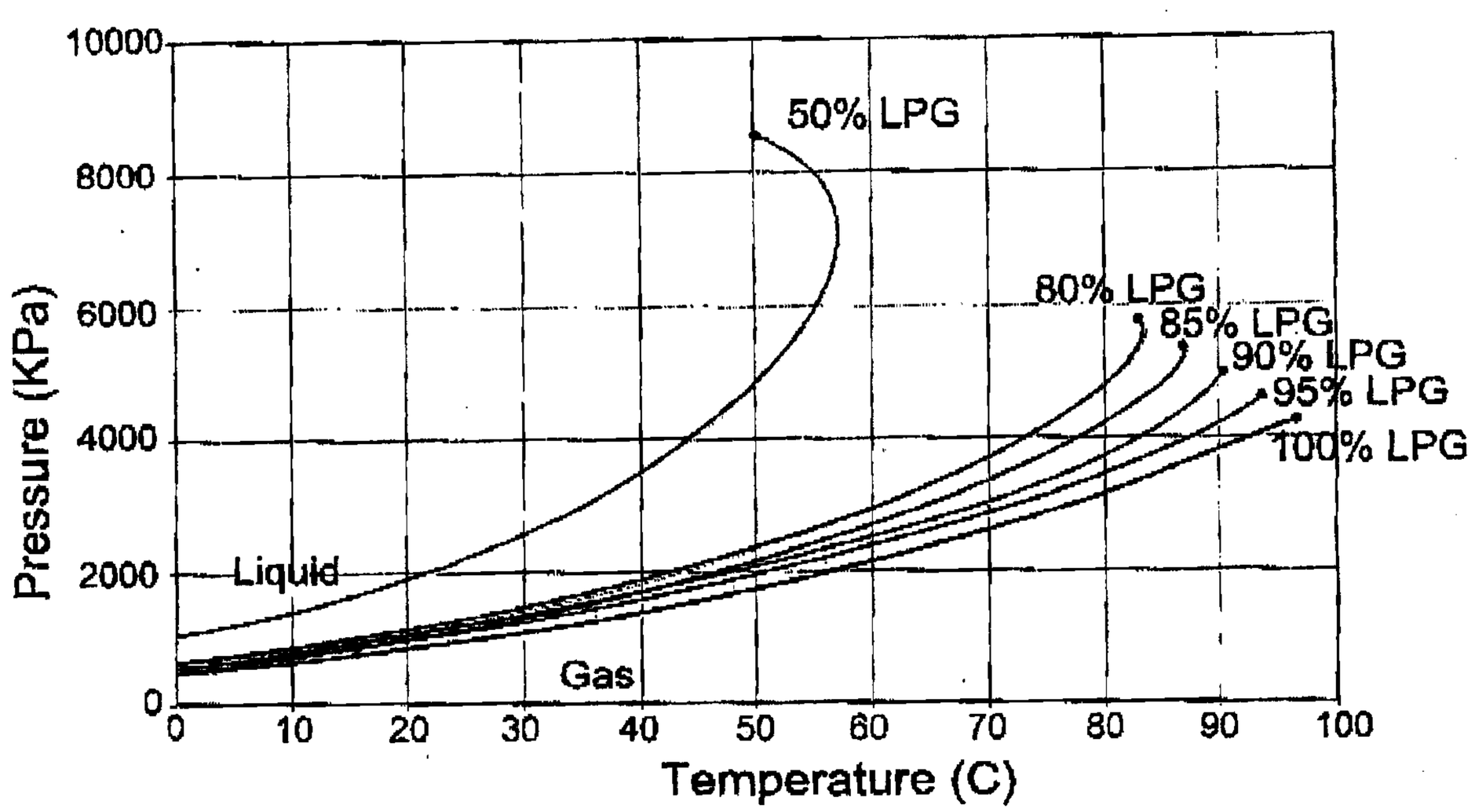
0.1
0.01
A
B
C
D
Liquid
Low Pressure
Surface
Handling
10
Vapour
-100 -90 -80 -70 -60 -50 -40 -30 -20 -10 0 10 20 30 40 50 60 70 80 90 100 110
Temperature (C)

Fig. 1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8000
6000
4000
2000
0
50% LPG
80% LPG
85% LPG
90% LPG
95% LPG
100% LPG
Liquid
Gas
0 10 20 30 40 50 60 70 80 90 100
Temperature (C)

Fig. 2

PRIOR ART

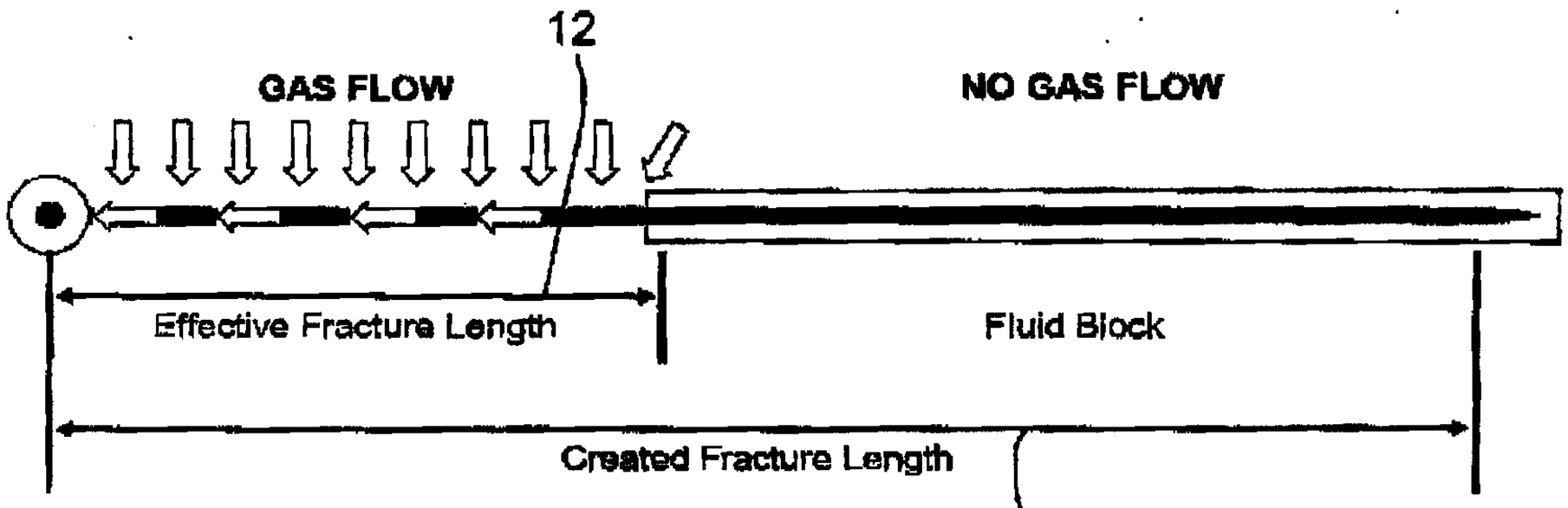


Fig. 3

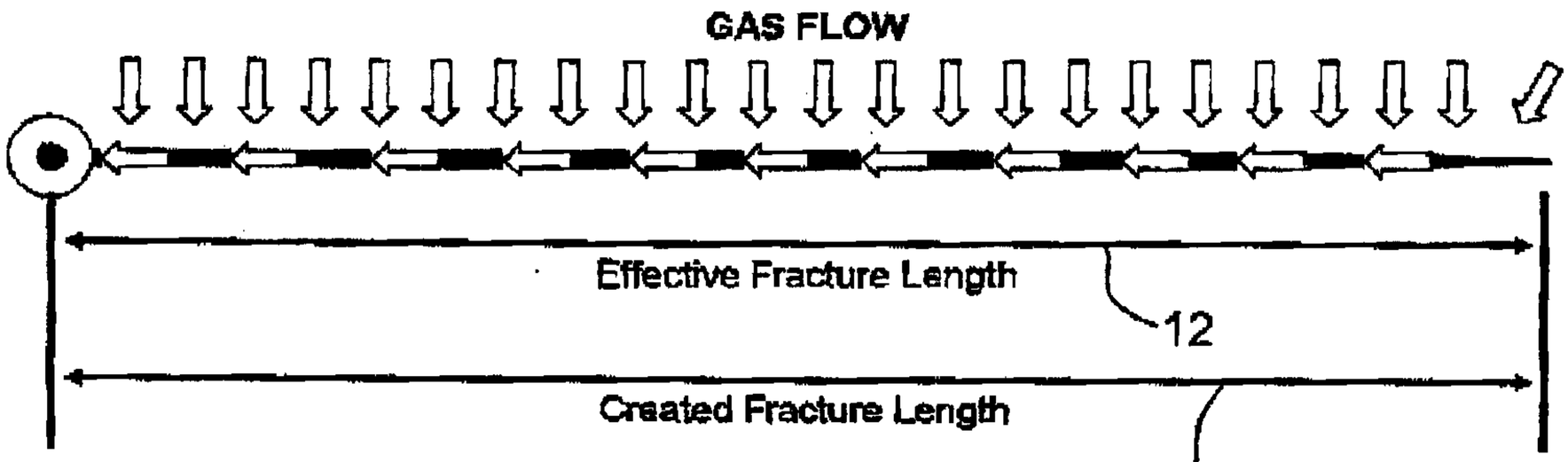


Fig. 4

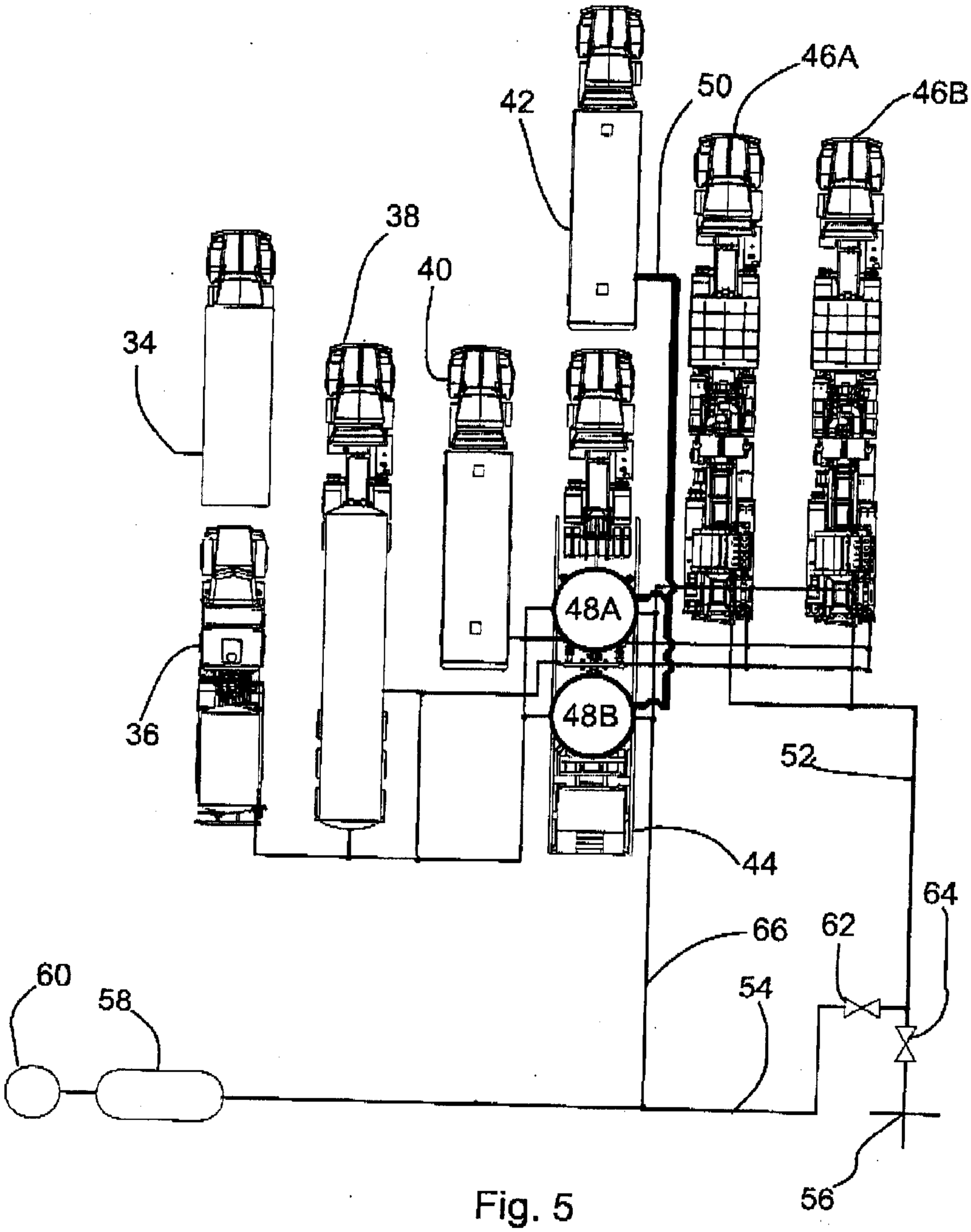


Fig. 5

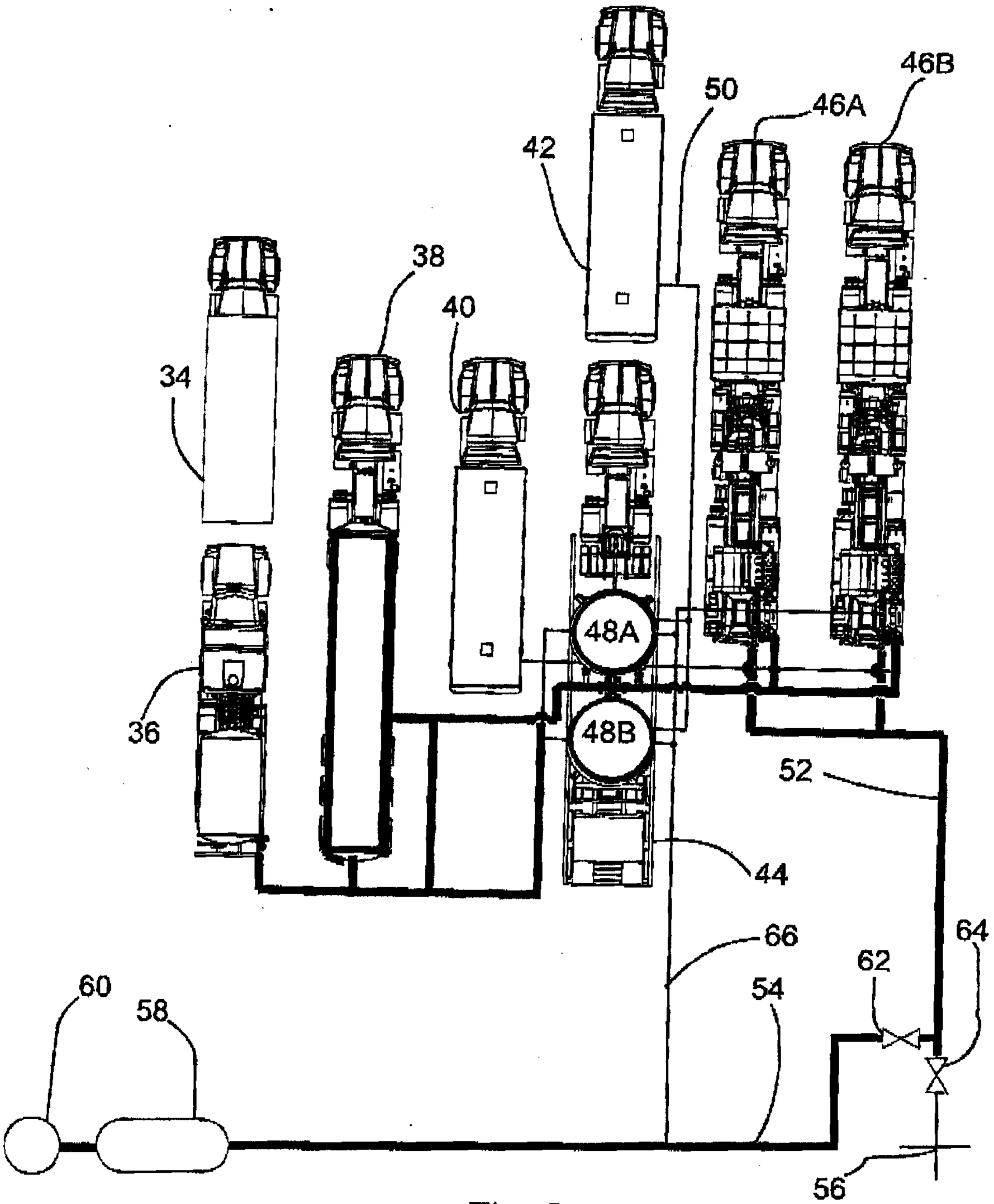


Fig. 6

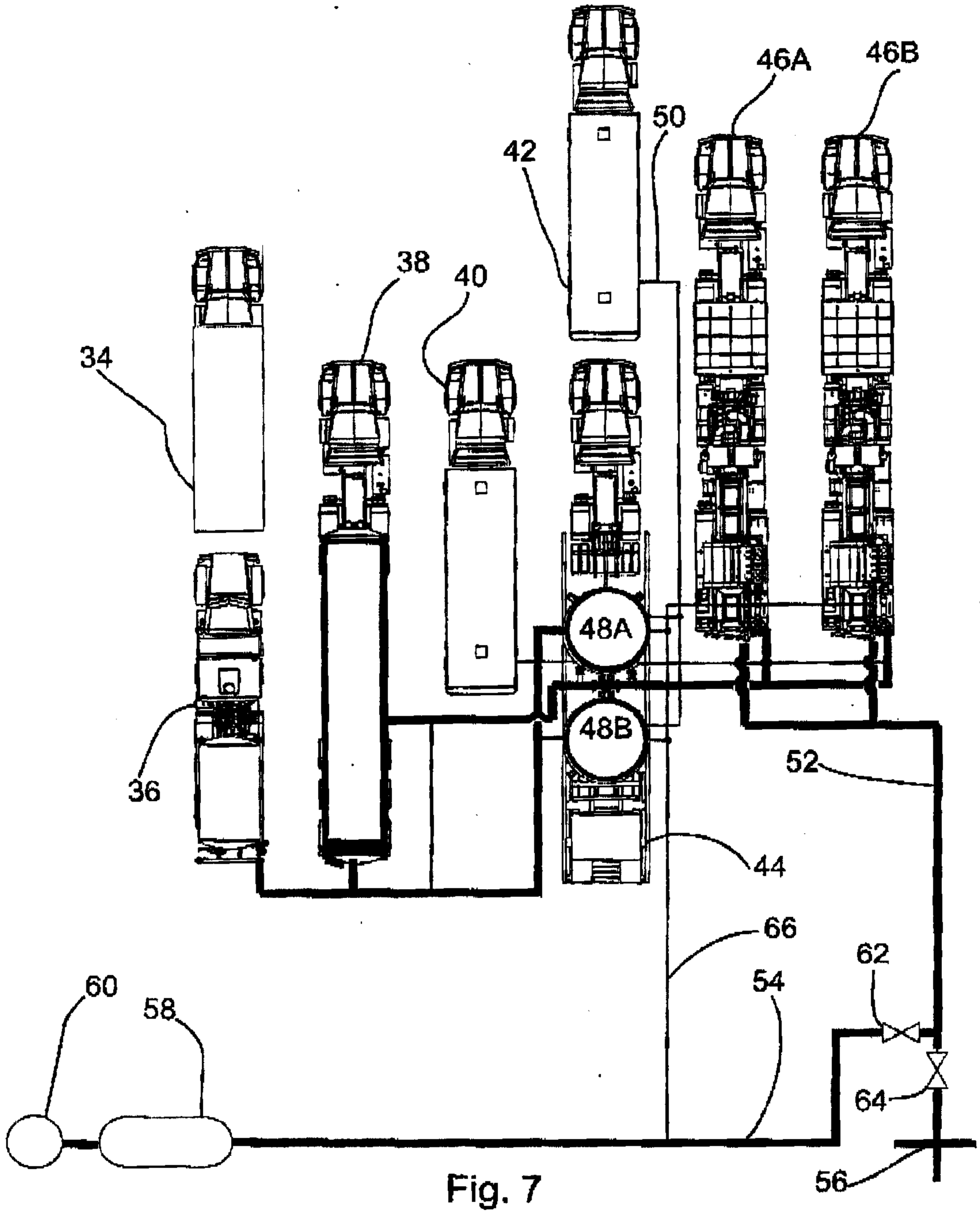


Fig. 7

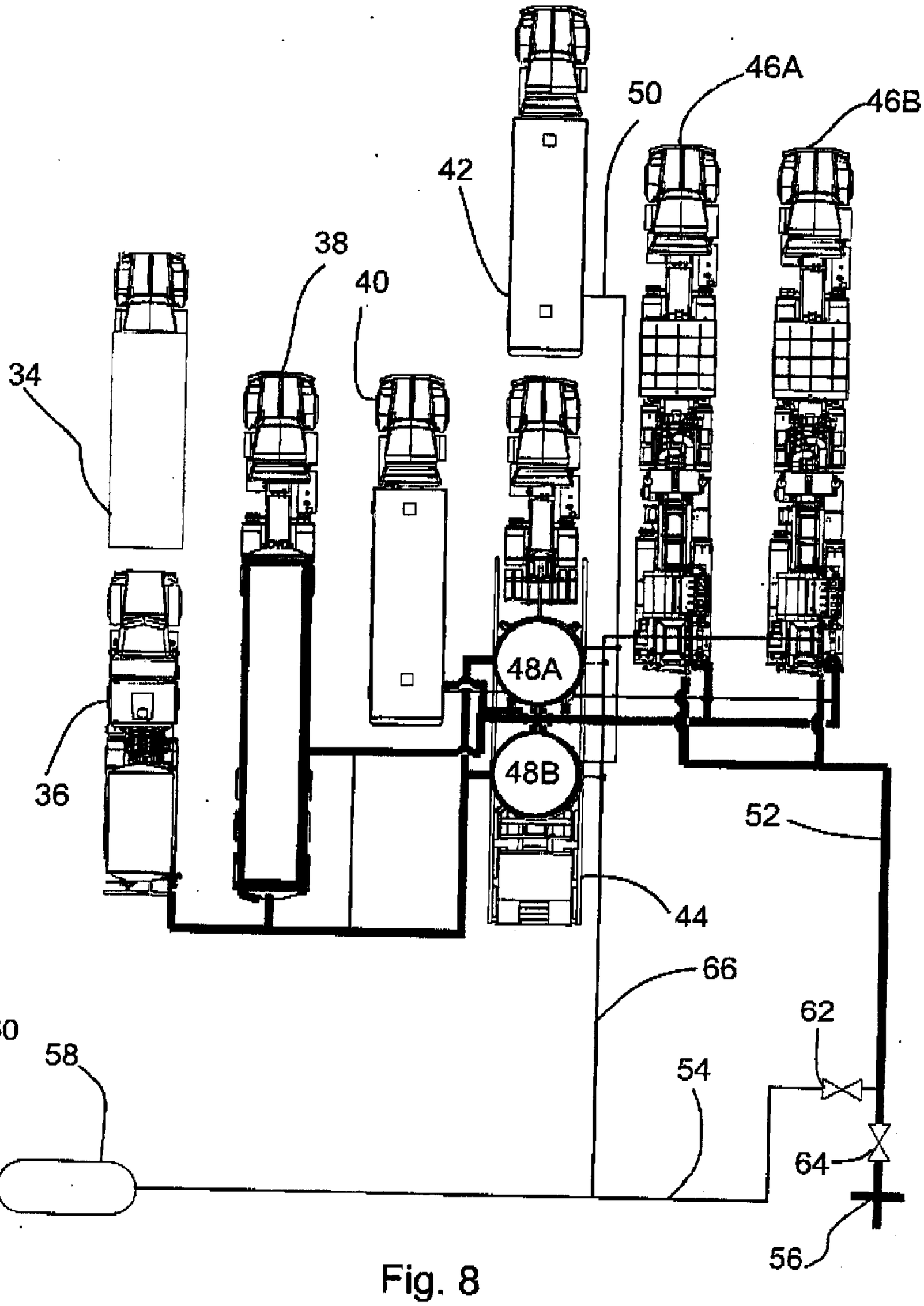


Fig. 8

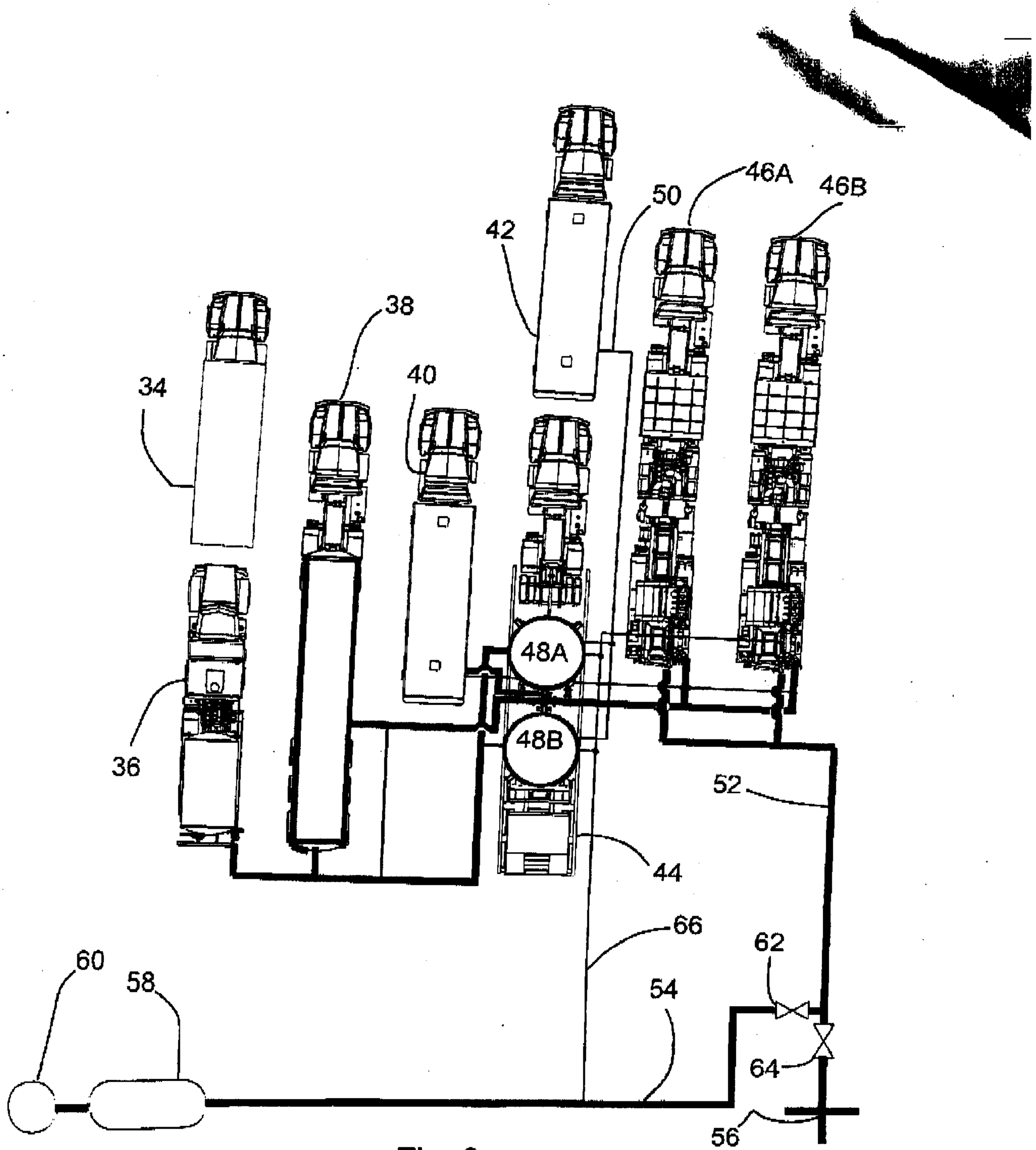


Fig. 9

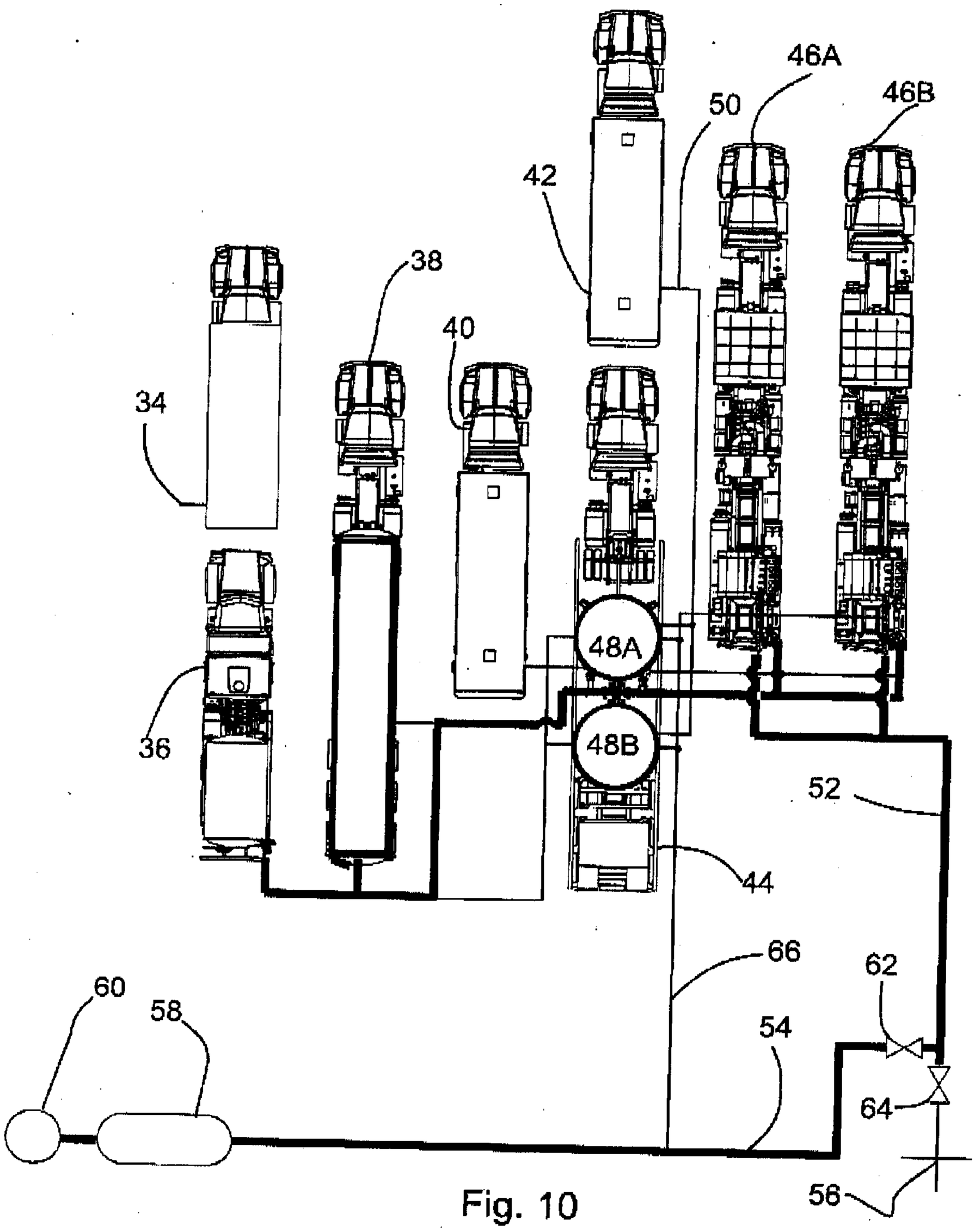


Fig. 10

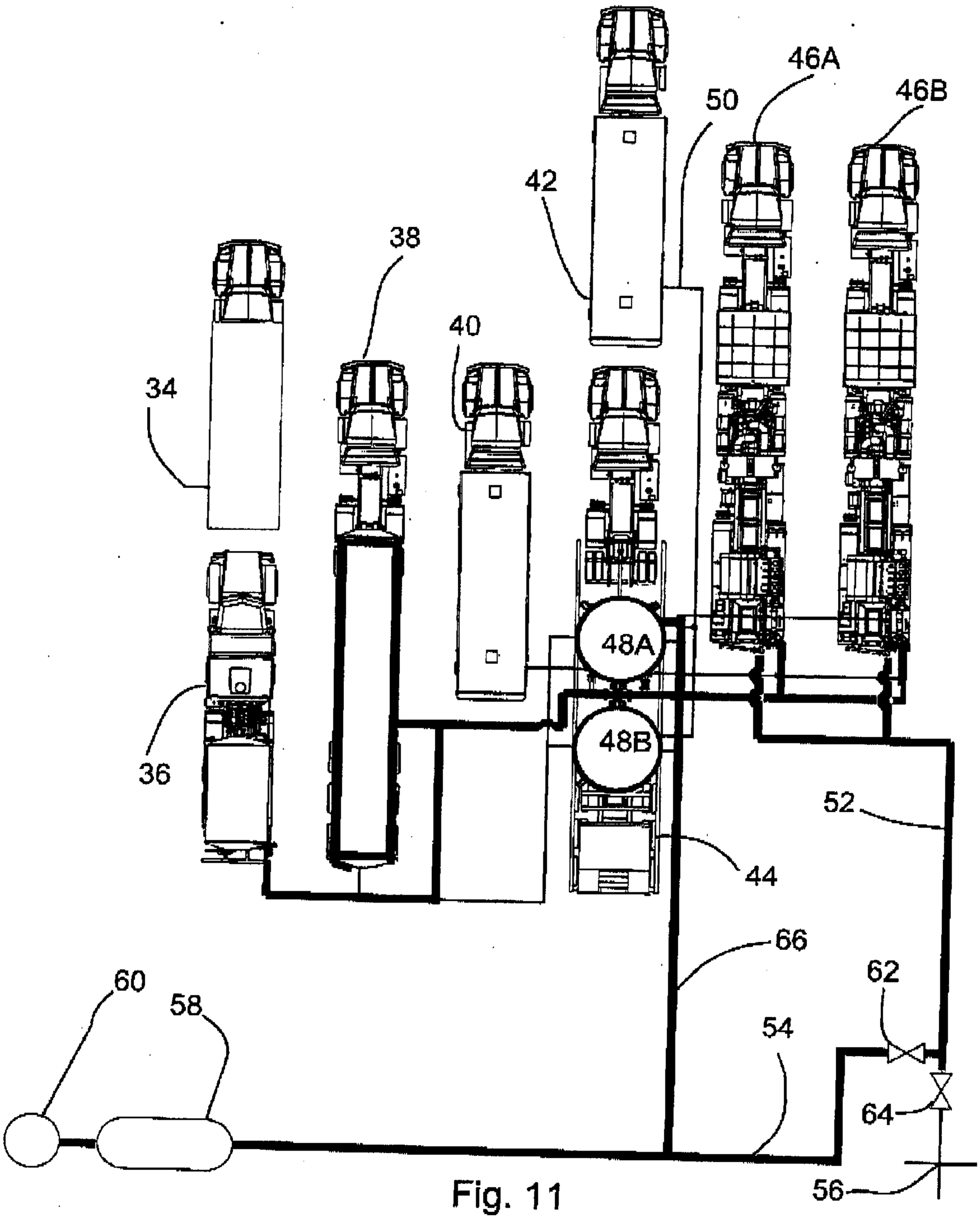


Fig. 11

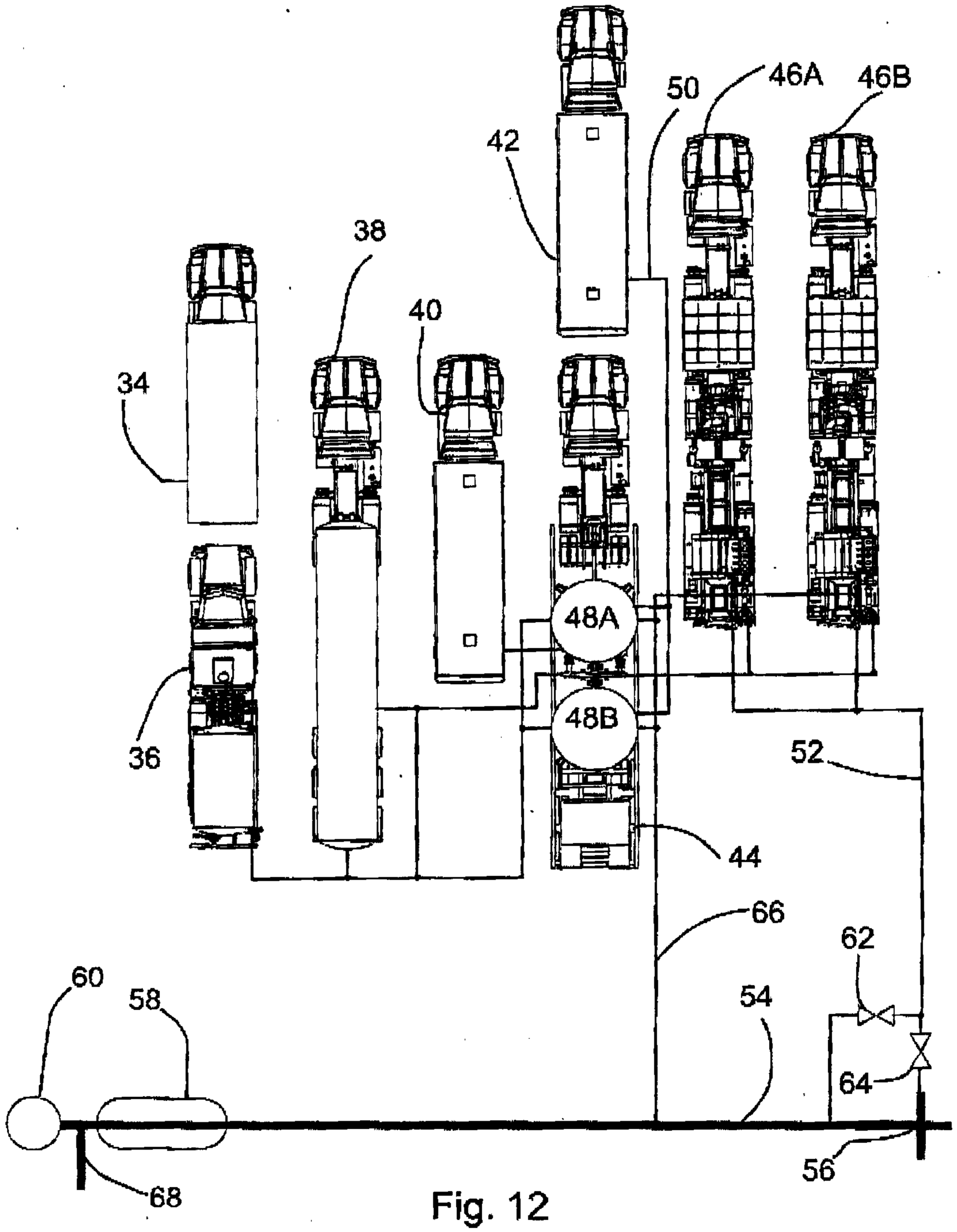


Fig. 12

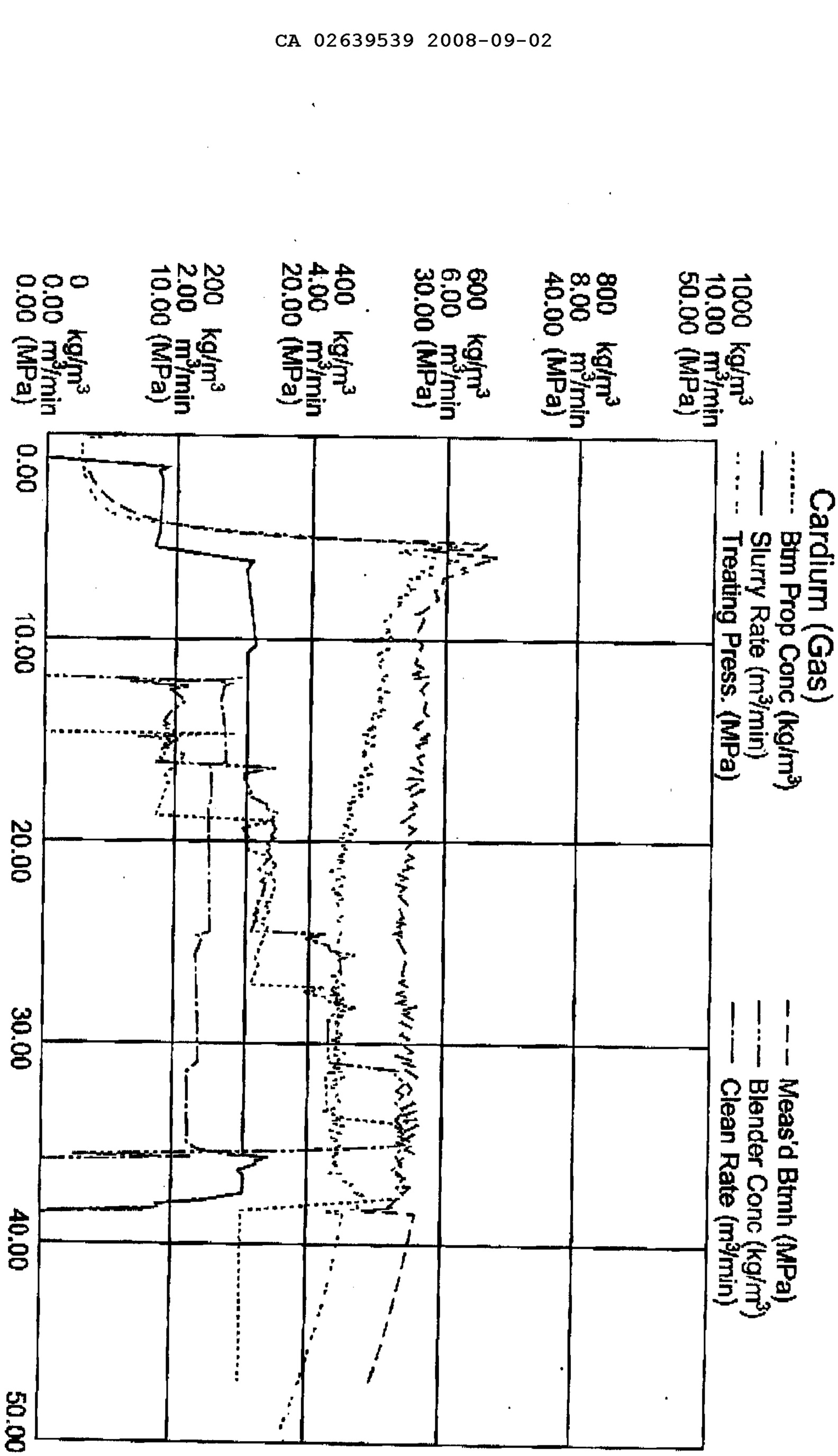

Cardium (Gas)
Btm Prop Conc (kg/m3)
Slurry Rate (m3/min)
Treating Press. (MPa)
Meas'd Btmh (MPa)
Blender Conc (kg/m3)
Clean Rate (m3/min)
Time (min)
0.00
10.00
20.00
30.00
40.00
50.00
1000 kg/m3
10.00 m3/min
50.00 (MPa)
800 kg/m3
8.00 m3/min
40.00 (MPa)
600 kg/m3
6.00 m3/min
30.00 (MPa)
400 kg/m3
4.00 m3/min
20.00 (MPa)
200 kg/m3
2.00 m3/min
10.00 (MPa)
0 kg/m3
0.00 m3/min
0.00 (MPa)

Fig. 13

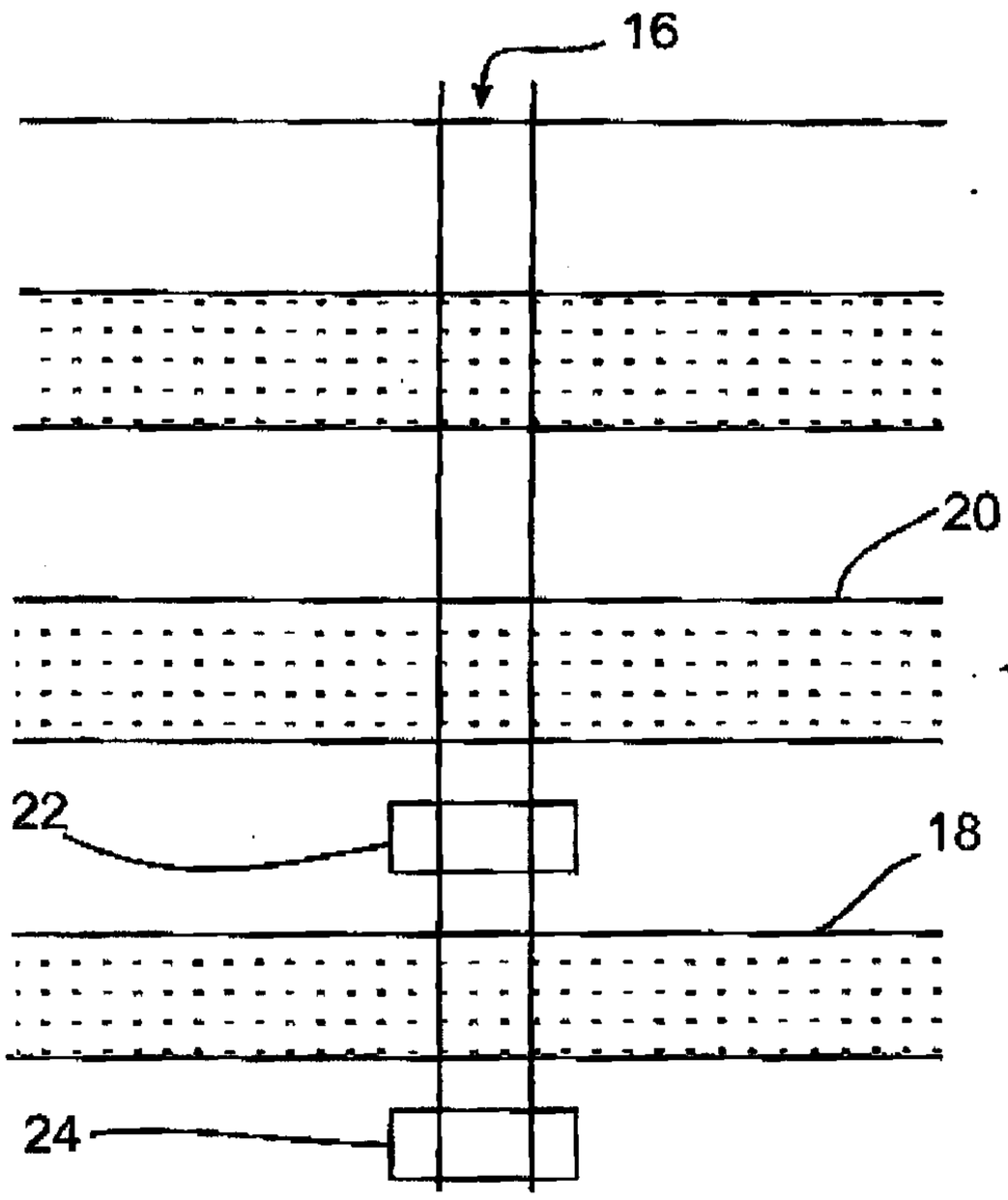


Fig. 14A

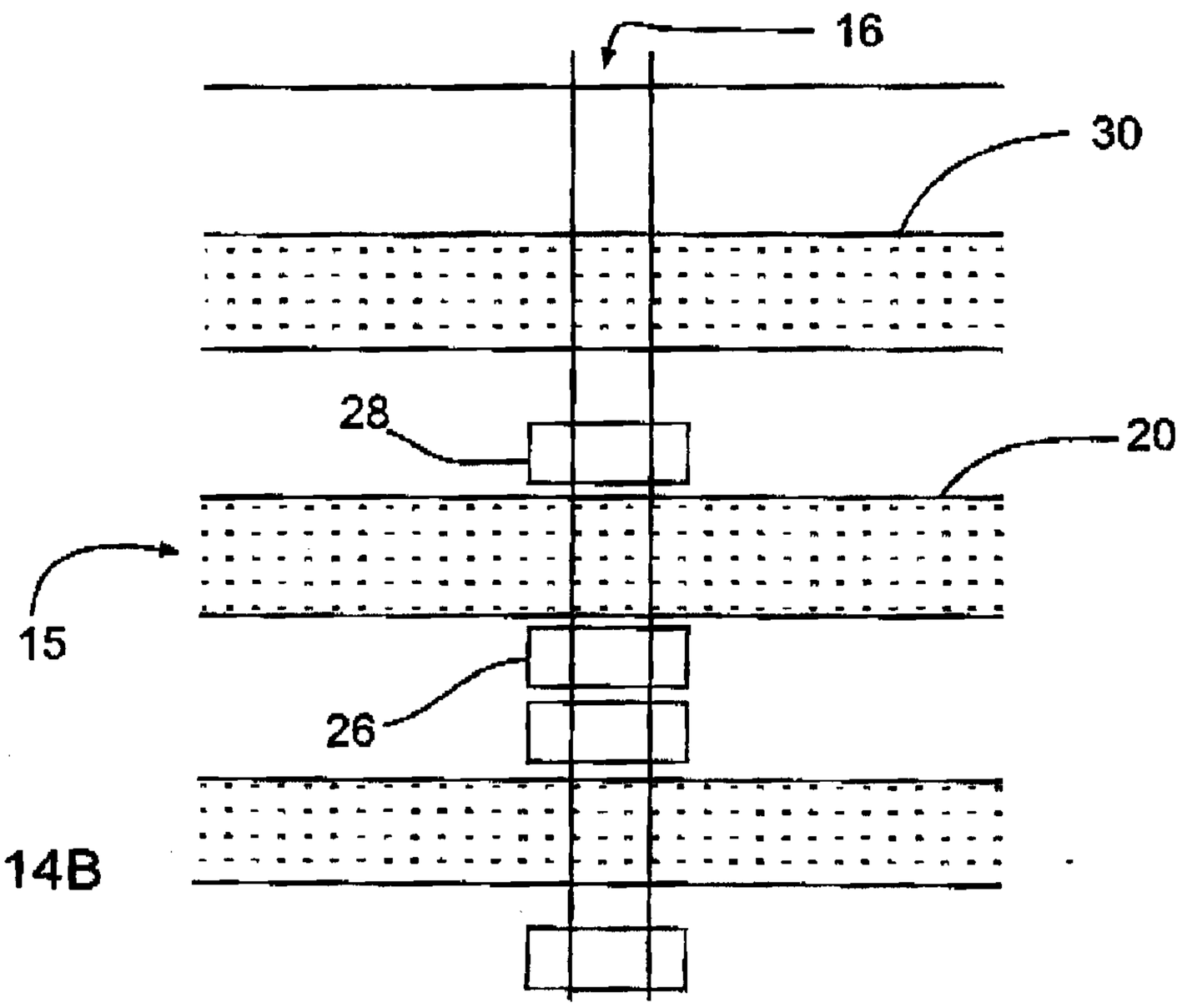


Fig. 14B

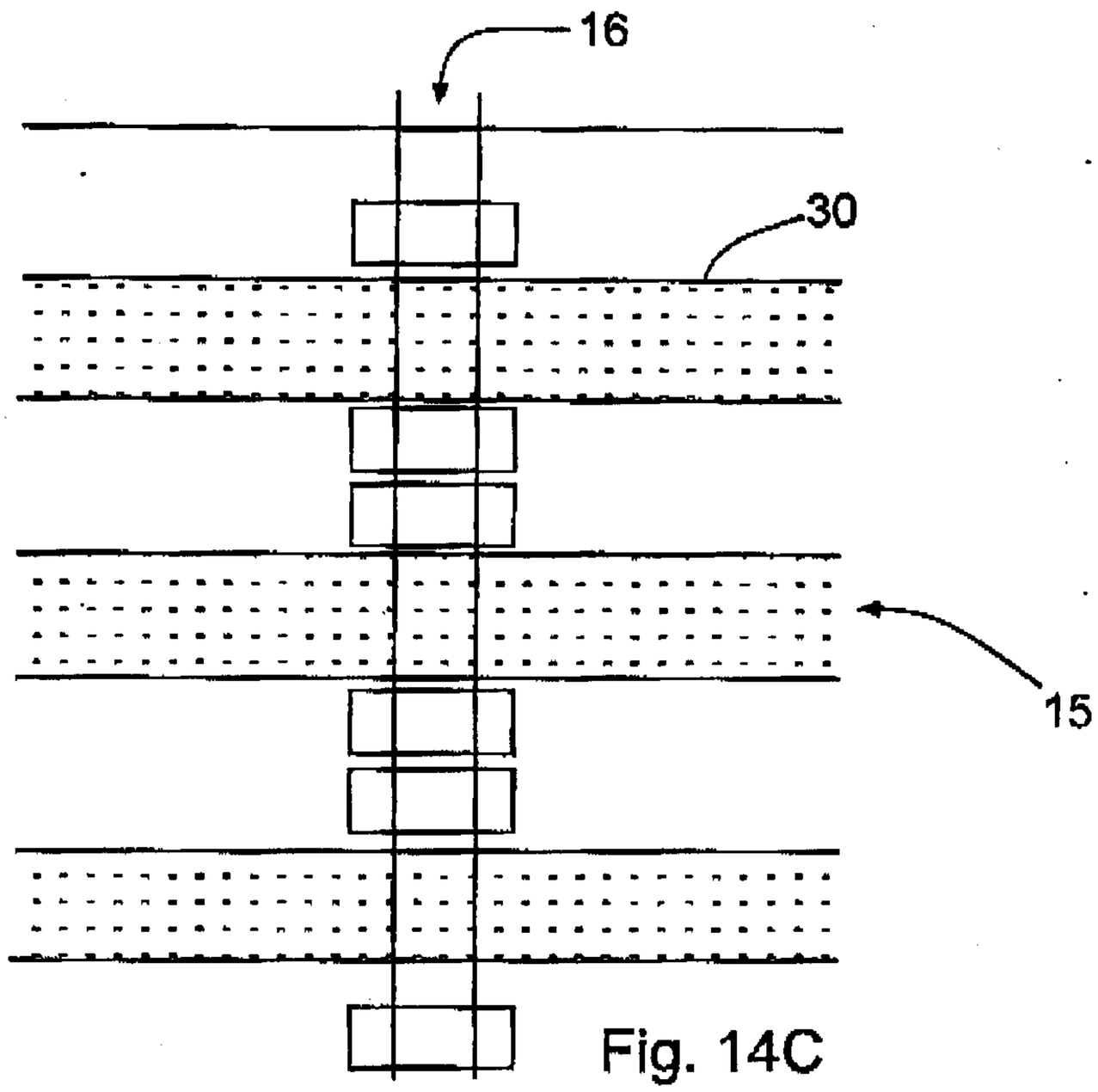


Fig. 14C

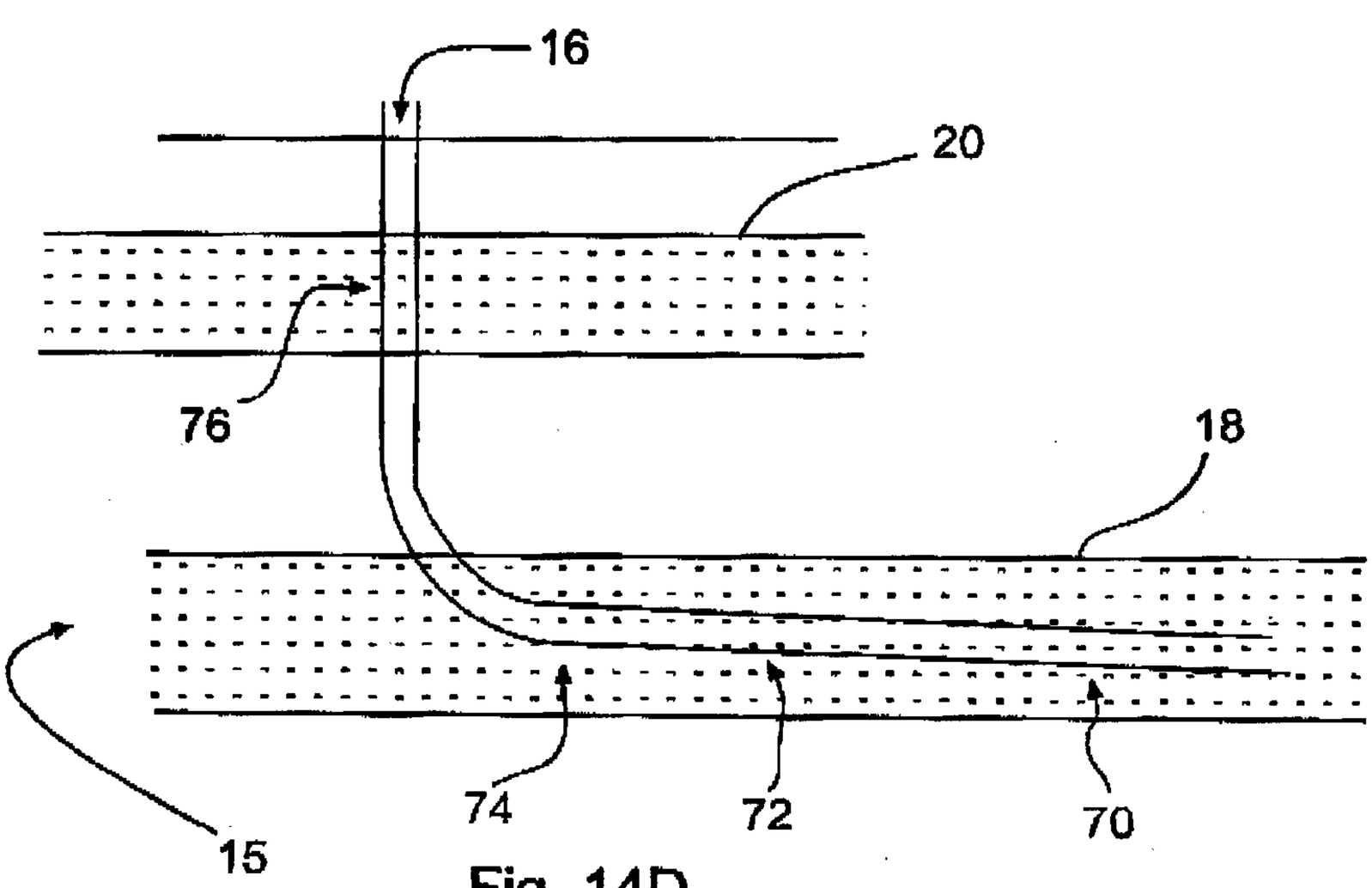


Fig. 14D

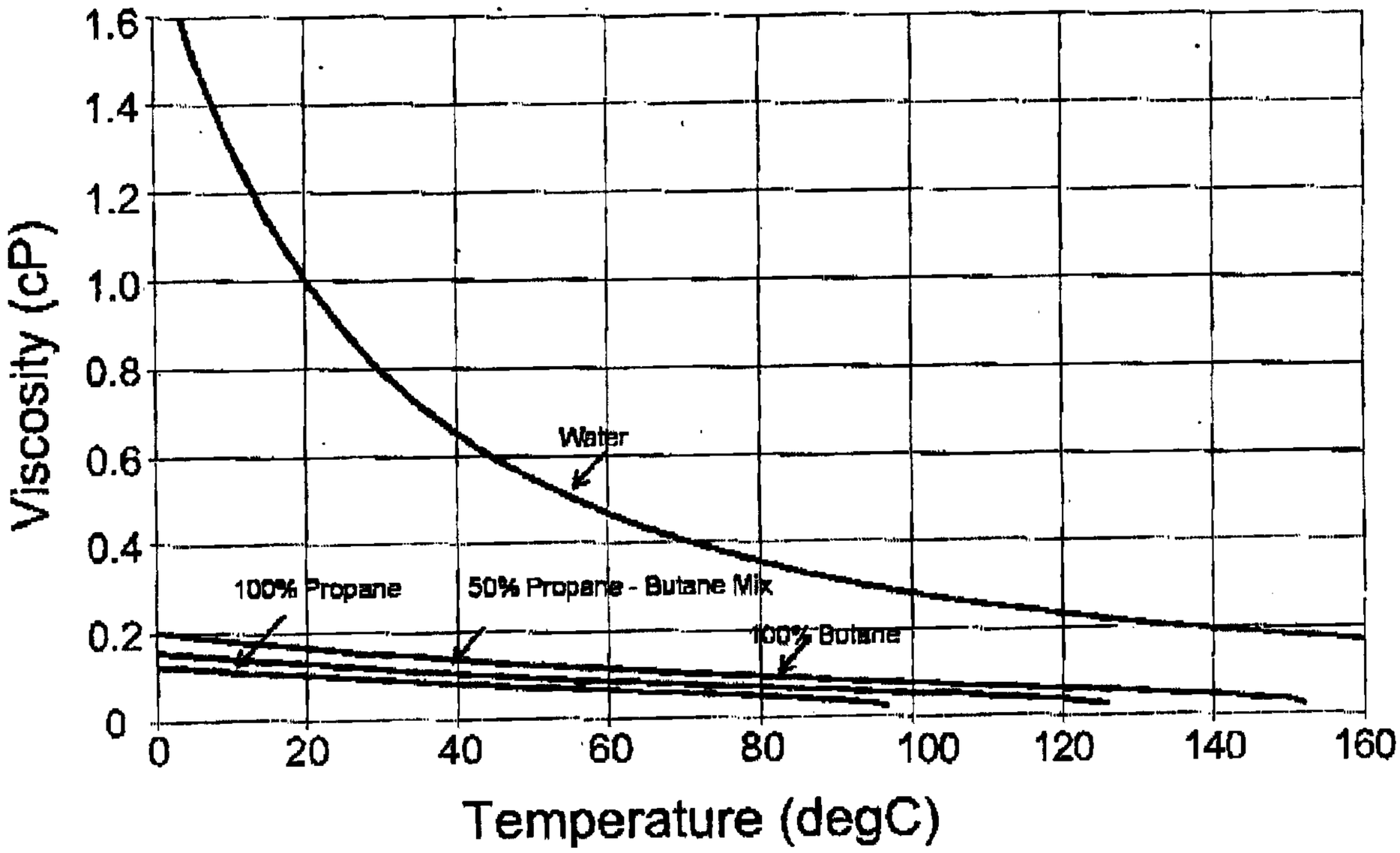

Viscosity (cP)
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0
0
20
40
60
80
100
120
140
160
Water
100% Propane
50% Propane - Butane Mix
100% Butane
Temperature (degC)

Fig. 15

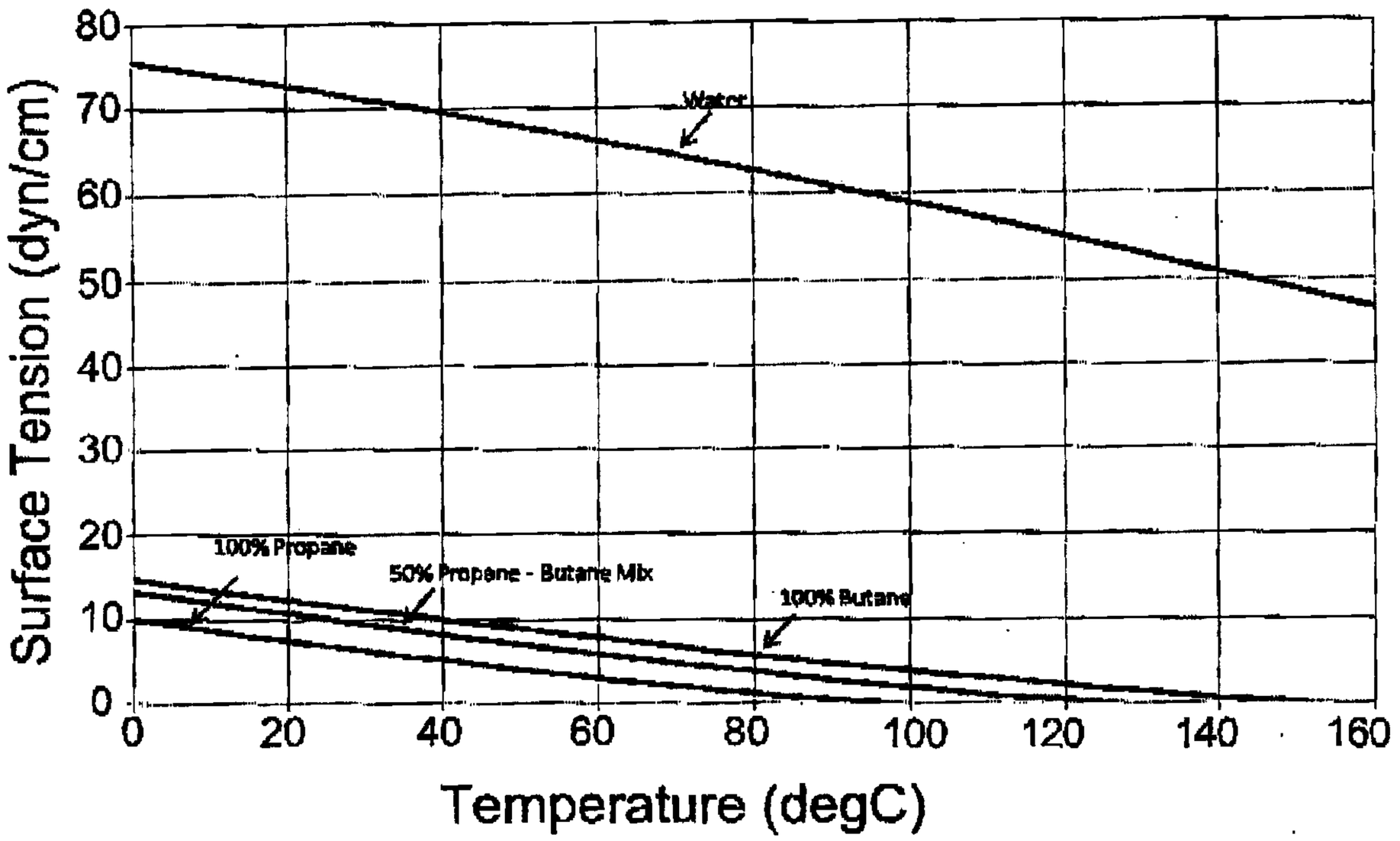

Surface Tension (dyn/cm)
80
70
60
50
40
30
20
10
0
0
20
40
60
80
100
120
140
160
Water
100% Propane
50% Propane - Butane Mix
100% Butane
Temperature (degC)

Fig. 16

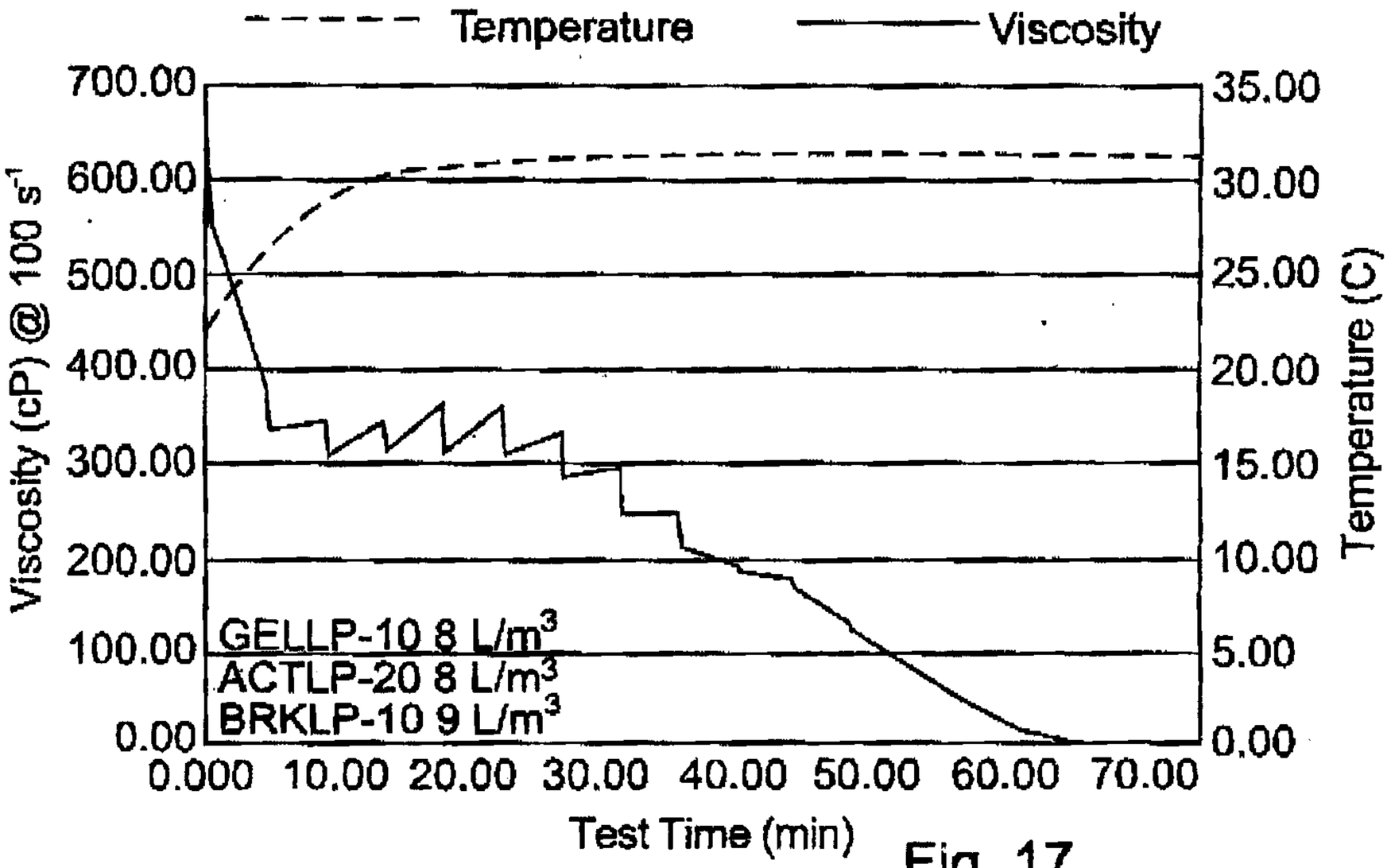

Temperature
Viscosity
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
Viscosity (cP) @ 100 s-1
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Temperature (C)
GELLP-10 8 L/m3
ACTLP-20 8 L/m3
BRKLP-10 9 L/m3
0.000 10.00 20.00 30.00 40.00 50.00 60.00 70.00
Test Time (min)

Fig. 17

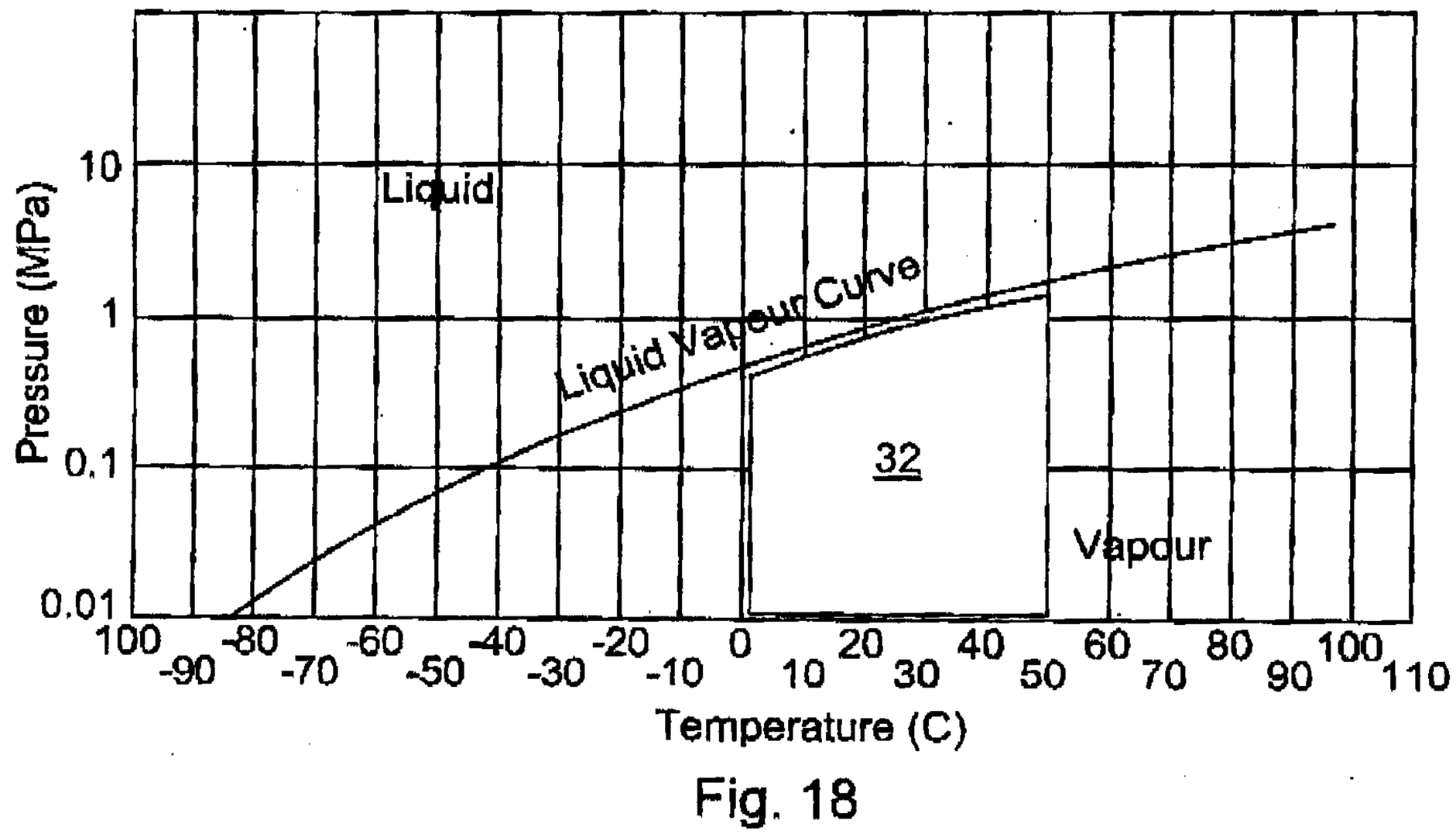

Pressure (MPa)
10
1
0.1
0.01
Liquid
Liquid Vapour Curve
32
Vapour
100
-90
-80
-70
-60
-50
-40
-30
-20
-10
0
10
20
30
40
50
60
70
80
90
100
110
Temperature (C)

Fig. 18

Job Date	Formation	BHT	Depth	RATE (m^3/min)	Placement Size (kg)	Treatment Mode
10-Jan-08	Colorado	12 °C	245 m	3.5	10,000	Casing
24-Jan-08	Bluesky	79 °C	1987 m	3.5	17,000	Annulus
06-Feb-08	Tight Hole Sand	40 °C	984 m	3	30,000	Casing
18-Feb-08	Tight Hole Sand	38 °C	995 m	2.5	30,000	Casing
20-Feb-08	Montney	89 °C	2808 m	3	10,000	Tubing
22-Feb-08	Viking	18 °C	302 m	3.5	15,000	Casing
23-Feb-08	Viking	18 °C	310 m	3.5	15,000	Casing
24-Feb-08	Viking	18 °C	296 m	3.5	15,000	Casing
27-Feb-08	Tight Hole Sand	38 °C	1208 m	3	30,000	Annulus
01-Mar-08	Tight Hole Sand	42 °C	1359 m	3.5	20,000	Casing
03-Mar-08	Tight Hole Sand	40 °C	1208 m	2.5	28,000	Annulus
06-Mar-08	Chinkeh	53 °C	1681 m	5.5	8,000	Casing
07-Mar-08	Chinkeh	53 °C	1486 m	5	8,000	Casing
19-Mar-08	Tight Hole Lime	35 °C	997 m	3	30,000	Tubing
21-Mar-08	Gething	96 °C	3085 m	3.5	21,000	Tubing
24-Mar-08	Artex	56 °C	1110 m	3	30,000	Tubing
29-Mar-08	Notikewin	53 °C	1695 m	3.5	32,000	Annulus
03-Apr-08	Chinook	65 °C	2095 m	3.5	20,000	Casing
09-Apr-08	Tight Hole Sand	63 °C	1830 m	3.5	32,000	Packers+
05-May-08	Bow Island	30 °C	991 m	3.0	18,000	Casing
11-May-08	Ostracod	77 °C	2411 m	4.0	31,000	Packers+

Fig. 19A

Job Date	Formation	BHT	Depth	RATE (m^3/min)	Placement Size (kg)	Treatment Mode
20-May-08	Viking	20 °C	555 m	2.5	5,000	Casing
21-May-08	Viking	20 °C	555 m	2.5	15,000	Casing
21-May-08	Viking	20 °C	555 m	2.5	15,000	Casing
01-Jun-08	Dunvegan	42 °C	1235 m	3.0	32,000	Tubing
03-Jun-08	Paddy	55 °C	1484 m	3.0	21,000	Casing
04-Jun-08	Tight Hole	32 °C	1030 m	3.0	8,500	Tubing
06-Jun-08	Dunvegan	50 °C	1121 m	3.0	20,000	Casing
08-Jun-08	Doe Creek	50 °C	951 m	3.0	20,000	Casing
10-Jun-08	Belly River	15 °C	312 m	2.0	5,000	Tubing
14-Jun-08	Paddy	36 °C	785 m	3.0	5,000	Tubing
16-Jun-08	Montney	65 °C	1818 m	3.0	32,000	Casing
21-Jun-08	Basal Colorado	30 °C	1215 m	2.5	5,000	Tubing
22-Jun-08	Dinosaur Park	29 °C	543 m	4.0	12,000	Casing
24-Jun-08	Belly River	30 °C	958 m	4.0	64,000	Packers+
28-Jun-08	Dunvegan	72 °C	2310 m	5.0	31,000	Casing
29-Jun-08	Dunvegan	72 °C	2310 m	3.0	30,000	Casing
01-Jul-08	Cardium	53 °C	1804 m	4.0	32,000	Casing
02-Jul-08	Cardium	38 °C	1510 m	4.5	28,000	Tubing
03-Jul-08	Halfway	61 °C	1921 m	3.0	32,000	Tubing
04-Jul-08	Nikanassin	70 °C	2204 m	1.5	3,000	Casing
06-Jul-08	Blue Sky	65 °C	1959 m	3.5	29,000	Casing

Fig. 19B

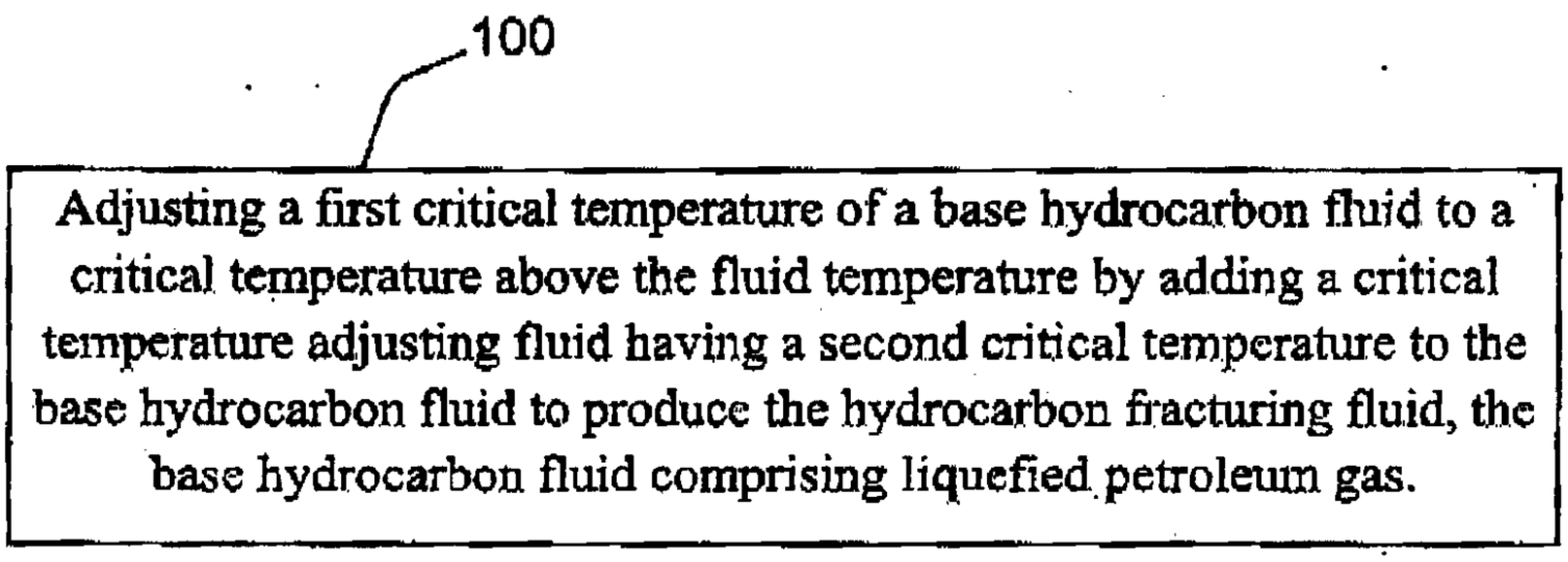

100
Adjusting a first critical temperature of a base hydrocarbon fluid to a critical temperature above the fluid temperature by adding a critical temperature adjusting fluid having a second critical temperature to the base hydrocarbon fluid to produce the hydrocarbon fracturing fluid, the base hydrocarbon fluid comprising liquefied petroleum gas.

Fig. 20

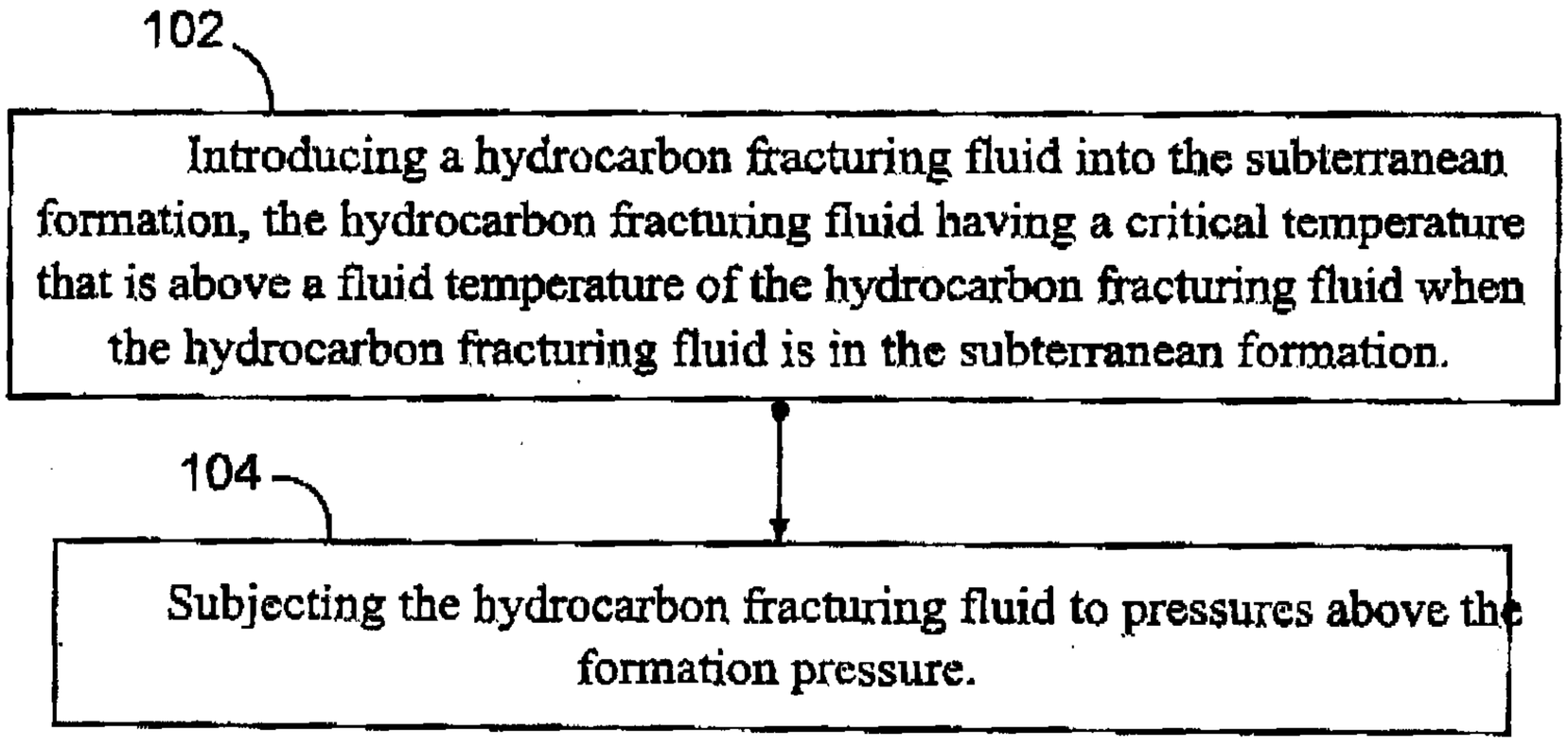

102
Introducing a hydrocarbon fracturing fluid into the subterranean formation, the hydrocarbon fracturing fluid having a critical temperature that is above a fluid temperature of the hydrocarbon fracturing fluid when the hydrocarbon fracturing fluid is in the subterranean formation.
104
Subjecting the hydrocarbon fracturing fluid to pressures above the formation pressure.

Fig. 21

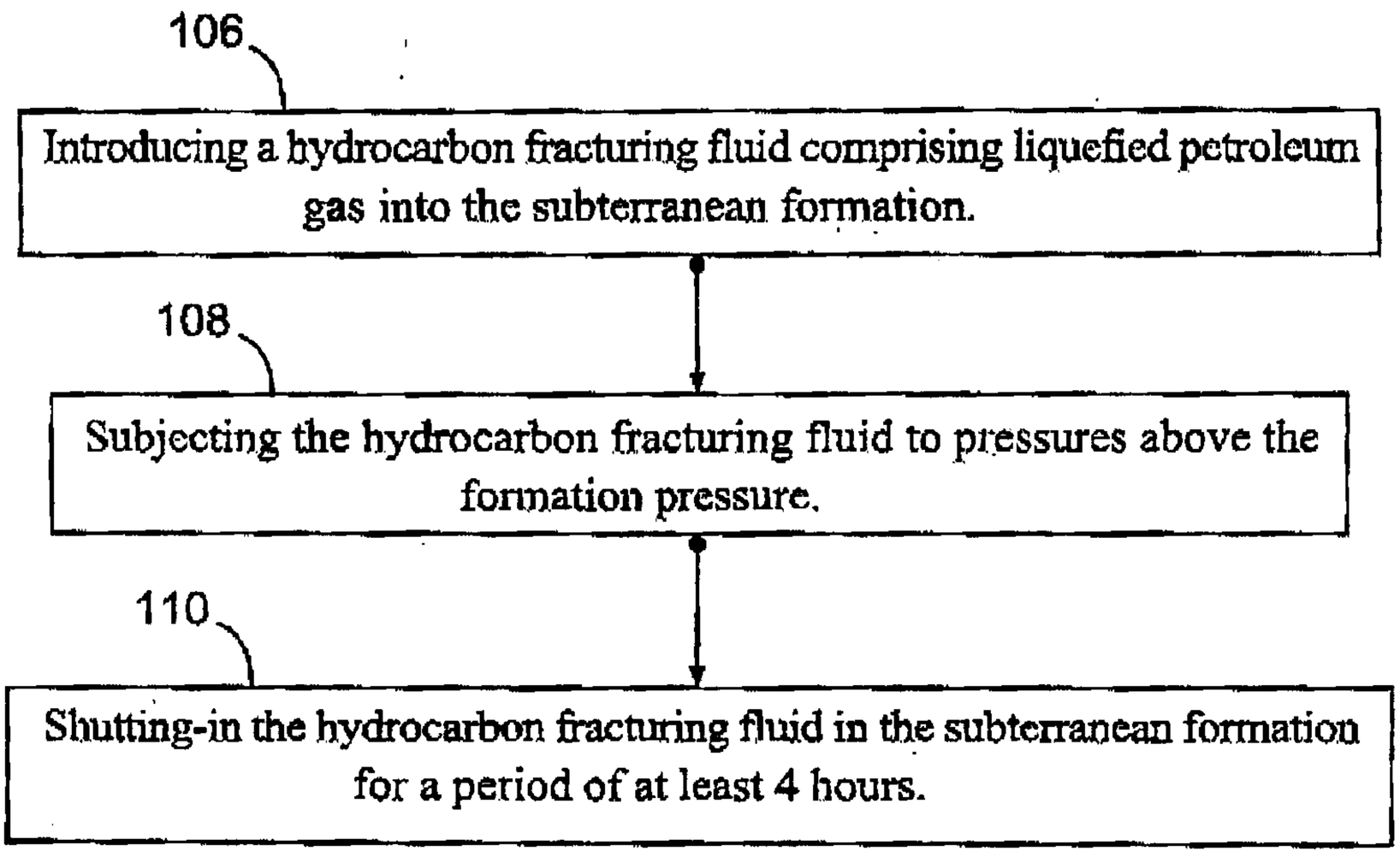

106
Introducing a hydrocarbon fracturing fluid comprising liquefied petroleum gas into the subterranean formation.
108
Subjecting the hydrocarbon fracturing fluid to pressures above the formation pressure.
110
Shutting-in the hydrocarbon fracturing fluid in the subterranean formation for a period of at least 4 hours.

Fig. 22

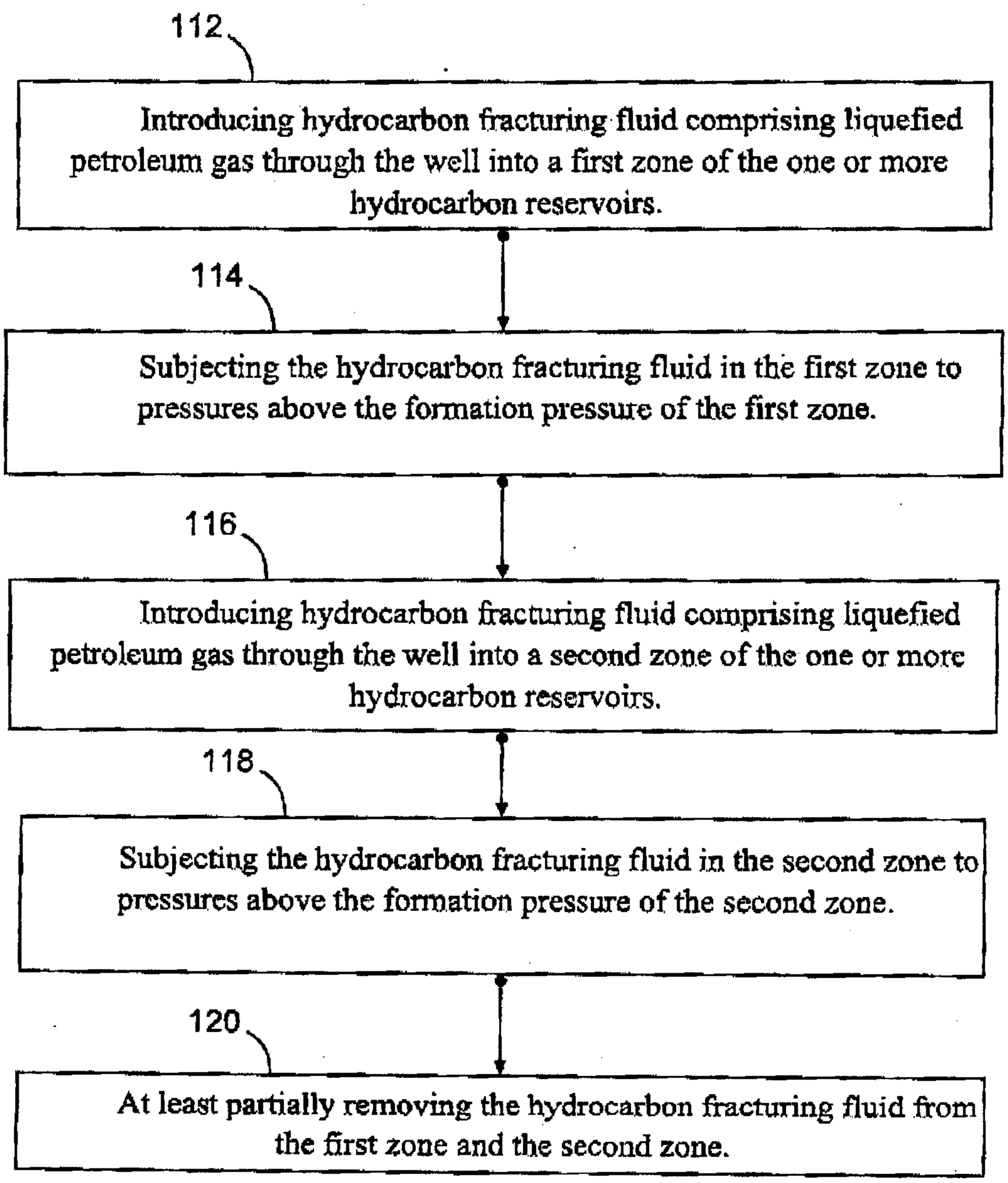

112
Introducing hydrocarbon fracturing fluid comprising liquefied petroleum gas through the well into a first zone of the one or more hydrocarbon reservoirs.
114
Subjecting the hydrocarbon fracturing fluid in the first zone to pressures above the formation pressure of the first zone.
116
Introducing hydrocarbon fracturing fluid comprising liquefied petroleum gas through the well into a second zone of the one or more hydrocarbon reservoirs.
118
Subjecting the hydrocarbon fracturing fluid in the second zone to pressures above the formation pressure of the second zone.
120
At least partially removing the hydrocarbon fracturing fluid from the first zone and the second zone.

Fig. 23

Adjusting a first critical temperature of a base hydrocarbon fluid by adding a liquefied petroleum gas component having a second critical temperature to the hydrocarbon fluid to produce the hydrocarbon fracturing fluid, the hydrocarbon fluid comprising liquefied petroleum gas.

122

Fig. 24

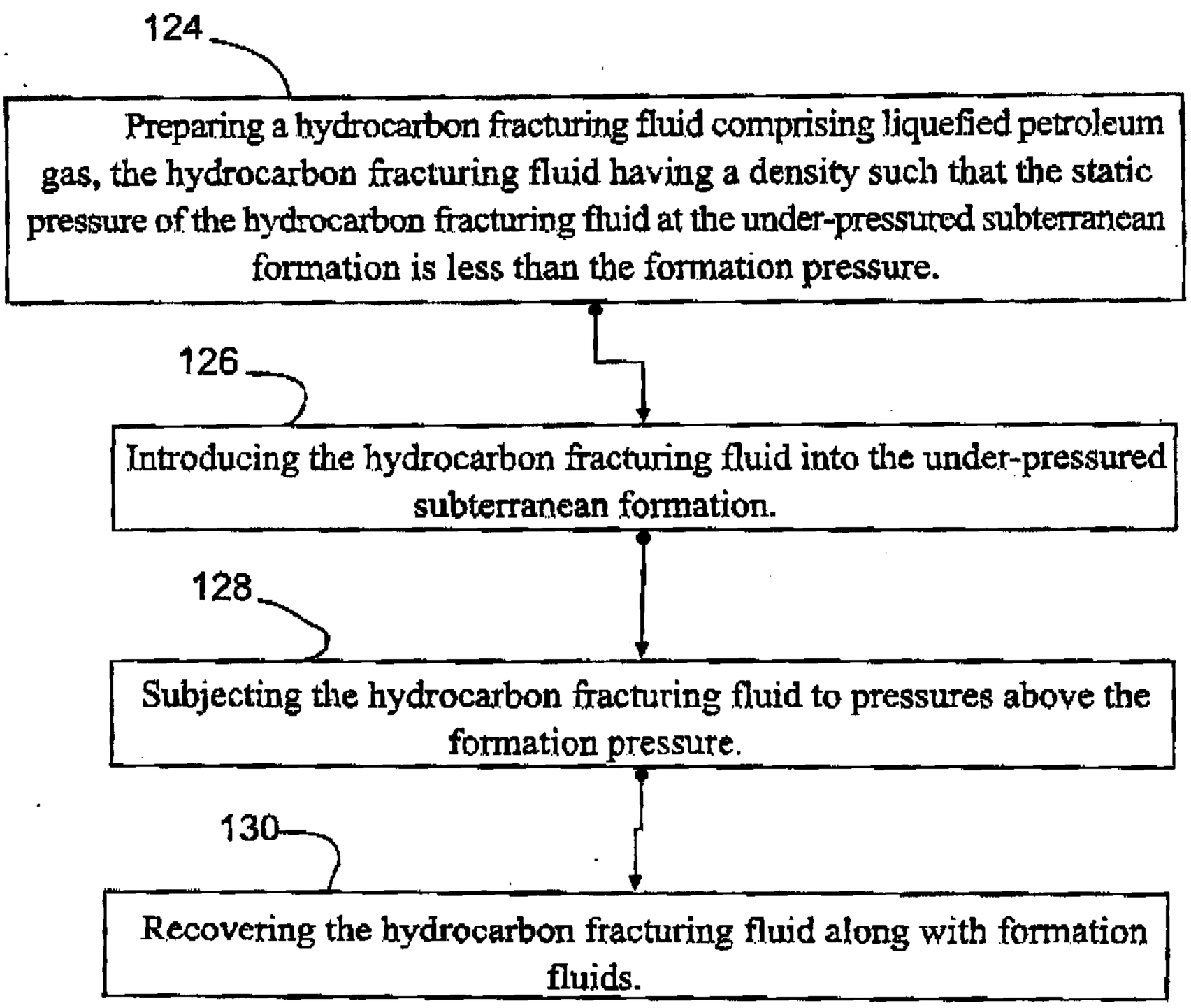
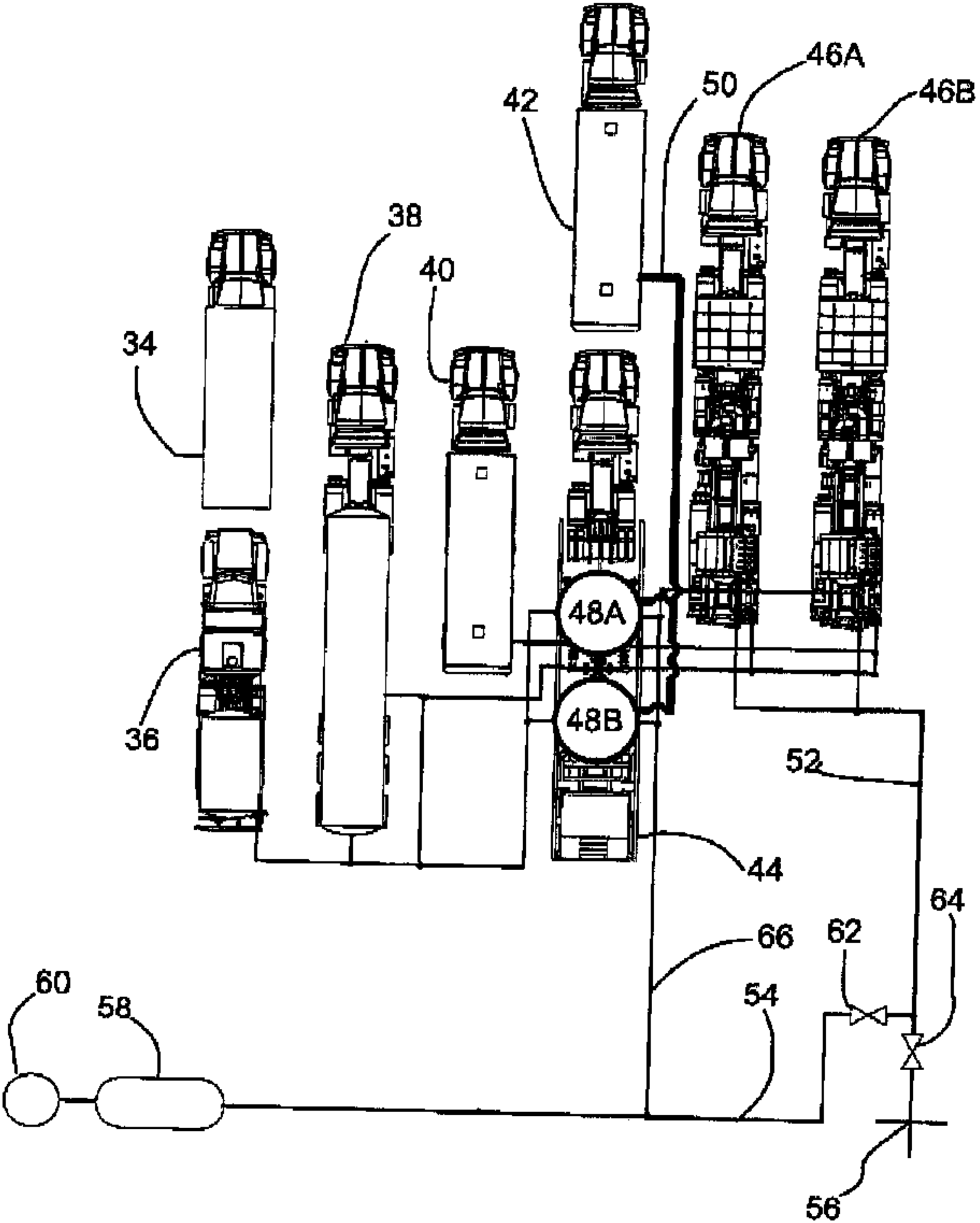


Fig. 25


34
36
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46A
46B
48A
48B
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