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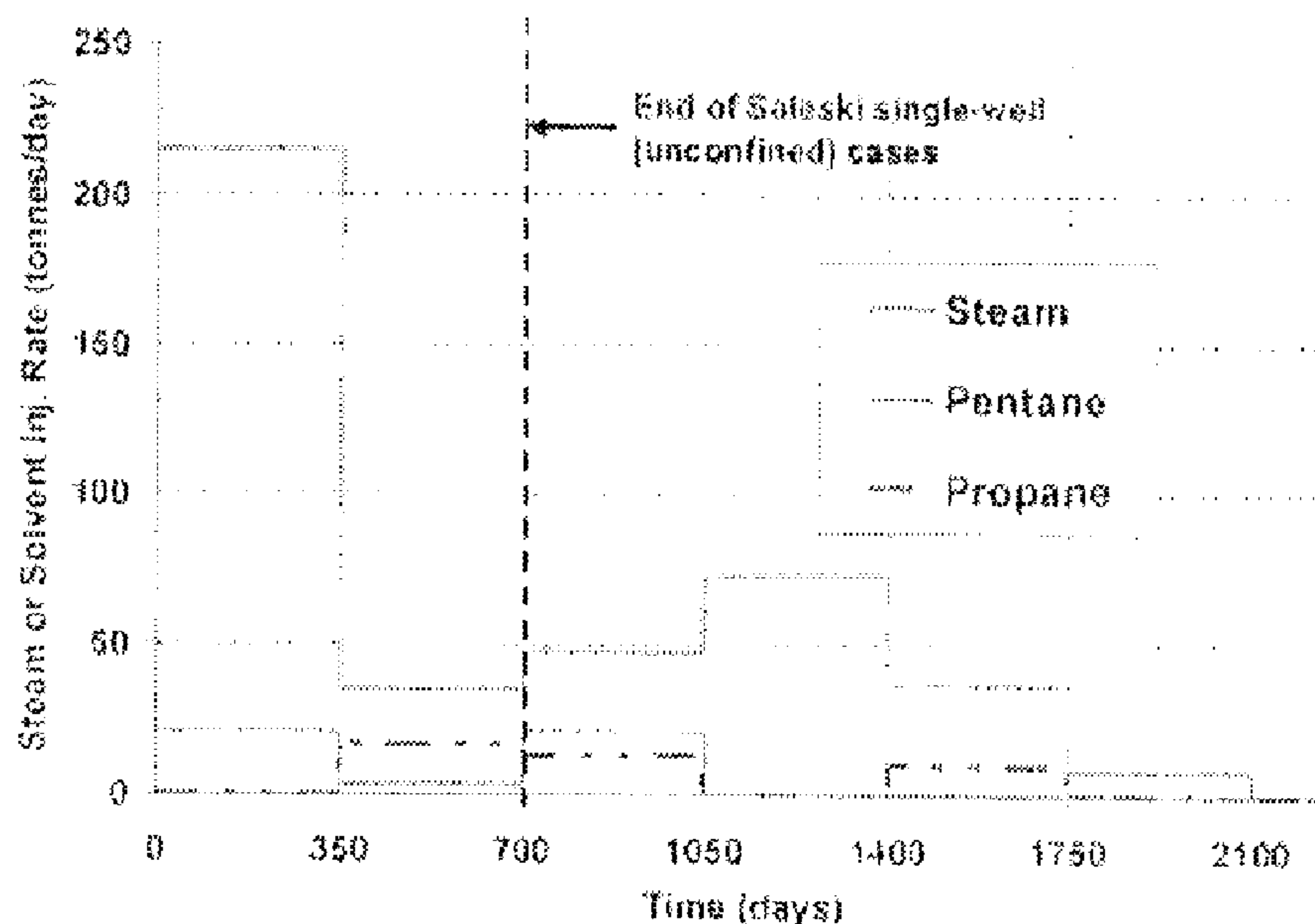
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(54) Titre : METHODE DE PRODUCTION D'HYDROCARBURES VISQUEUX COMPRENANT L'INJECTION CYCLIQUE
DE VAPEUR ET DE SOLVANT

(54) Title: METHOD FOR VISCOUS HYDROCARBON PRODUCTION INCORPORATING STEAM AND SOLVENT
CYCLING

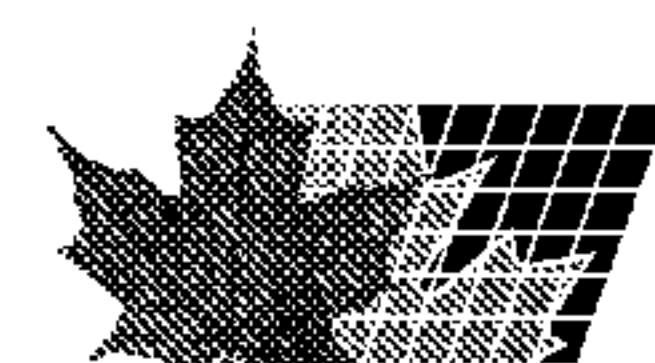
[Solvent-Cyclic SAGD Recipe]

As optimized for simple Grand Rapids, applied verbatim to the
Grosmont:



(57) Abrégé/Abstract:

A method for producing hydrocarbons from a reservoir containing the hydrocarbon comprises a steam assisted gravity drainage (SAGD) incorporating cyclic steam, heavy (e.g. greater than C4) solvent and light (e.g. C2 to C4) solvent injection. The method



(57) **Abrégé(suite)/Abstract(continued):**

involves a series of steps wherein the injection of the respective streams is varied. The method provides a significant improvement in hydrocarbon extraction efficiency as compared to a SAGD process alone and mitigates many of the drawbacks associated with typical SAGD operations.

ABSTRACT

A method for producing hydrocarbons from a reservoir containing the hydrocarbon comprises a steam assisted gravity drainage (SAGD) incorporating cyclic steam, heavy (e.g. greater than C4) solvent and light (e.g. C2 to C4) solvent injection. The method involves a series of steps wherein the injection of the respective streams is varied. The method provides a significant improvement in hydrocarbon extraction efficiency as compared to a SAGD process alone and mitigates many of the drawbacks associated with typical SAGD operations.

1 **METHOD FOR VISCOUS HYDROCARBON PRODUCTION**
2 **INCORPORATING STEAM AND SOLVENT CYCLING**

3 **FIELD OF THE INVENTION**

4 **[0001]** The present invention relates to the production of hydrocarbons, in particular viscous
5 hydrocarbons, from petroleum deposits. More specifically, the invention relates to an improved
6 method for producing hydrocarbons from formations, such as "oil sands", incorporating cyclic
7 applications of steam and solvent.

8 **BACKGROUND OF THE INVENTION**

9 **[0002]** Oil sand deposits are found predominantly in the Middle East, Venezuela, and
10 Western Canada. The Canadian bitumen deposits, being the largest in the world, are estimated
11 to contain between 1.6 and 2.5 trillion barrels of oil, so the potential economic benefit of this
12 invention carries significance within this resource class. The term "oil sands" refers to large
13 subterranean land forms composed of reservoir rock, water and heavy oil and/or bitumen.
14 Bitumen is a heavy, black oil which, due to its high viscosity, cannot readily be pumped from the
15 ground like other crude oils. Therefore, alternate processing techniques must be used to extract
16 the bitumen deposits from the oil sands, which remain a subject of active development in the
17 field of practice. The basic principle of known extraction processes is to lower the viscosity of
18 the bitumen by applying heat, injecting chemical solvents, or a combination thereof, to a deposit
19 layer, thereby promoting flow of the material throughout the treated reservoir area, in order to
20 allow for recovery of bitumen from that layer.

21 **[0003]** A variety of known extraction processes are commercially used to recover bitumen
22 from oil deposits. Steam-Assisted Gravity Drainage, commonly referred to as SAGD, is one
23 known method. A SAGD process is described, for example, in Canadian patent number
24 1,304,287. In a SAGD process, steam is injected into a target reservoir through a horizontal
25 injection well to heat heavy crude oil within a reservoir. The range of temperatures, and
26 corresponding viscosities, required to achieve an economic flow rate is dependent on the
27 permeability of the reservoir in question. SAGD, as with most recovery strategies, is focused on
28 increasing bitumen temperature within a limited region around a steam injection well. The
29 reduced-viscosity oil is then allowed to flow by gravity drainage to an underlying point of the
30 reservoir and to be collected by a horizontal production well. The heavy oil/bitumen is then
31 brought to the surface for further processing. Various pumping equipment and/or systems may

1 be used in association with the production well. Although effective, stand alone SAGD
2 processes have several associated inefficiencies. Firstly, the process is very energy intensive,
3 requiring a great amount of energy for heating the volumes of water to generate the steam used
4 for the heat transfer process. In addition, the amount of steam required is usually dictated by
5 the need to maintain a certain pressure in the reservoir; this usually translates into a higher
6 temperature than is optimally needed to mobilize the bitumen. Further, upon releasing its heat
7 to the formation, the injected steam condenses into water, which mixes with the mobilized
8 bitumen and often leads to additional inefficiencies. For example, the water must be recycled
9 through the boilers, requiring costly de-oiling and softening processes. In addition, the original
10 or initial separation of the bitumen and water requires further processing and costs associated
11 with such procedures. Also, as common with other known active heating methods, the energy
12 input to the deposit is often transferred to neighbouring geological structures and lost by way of
13 conduction. Thus, the process becomes considerably energy intensive in order to achieve
14 sufficient heating of the target formation. As a result, SAGD processes are typically only
15 commercially viable for reservoirs having a minimum volume and concentration of
16 hydrocarbons.

17 **[0004]** Dilution is another technique that has been used for the extraction of bitumen from oil
18 sand or heavy oil deposits. Such methods, often referred to as vapour extraction methods, or
19 VAPEX, involve a dilution process wherein solvents, such as light alkanes or other relatively
20 light hydrocarbons, are injected into a deposit to dilute the heavy oil or bitumen. This technique
21 also reduces the viscosity of the heavy hydrocarbon component, thereby facilitating recovery of
22 the bitumen-solvent mixture that is mobilized throughout the reservoir. The injected solvent is
23 produced along with bitumen material and some solvent can be recovered by further
24 processing. Although VAPEX methods avoid the costs associated with SAGD methods, the
25 production rate of solvent based methods has been found to be less than steam based
26 processes. A VAPEX method also requires processing facilities for the extraction of the injected
27 solvent. Finally, VAPEX methods tend to accumulate material quantities of liquid solvent within
28 the depleted part of the reservoir. Such solvents cannot be recovered until the end of the
29 process thereby representing an economically significant cost for the solvent inventory.

30 **[0005]** A combination of SAGD and VAPEX methods has also been proposed in order to
31 combine the benefits of both while mitigating the drawbacks associated therewith. Known as a
32 solvent aided, or solvent assisted process, or SAP, this method involves the injection of both
33 steam and a low molecular weight hydrocarbon into the formation. Gupta et al. (J. Can. Pet.

1 Tech., 2007, 46(9), pp. 57-61) teach a SAP method, which comprises a SAGD process wherein
2 a solvent is simultaneously injected into the formation with the steam. As indicated in this
3 reference, a SAP process has been found to improve the economics of SAGD methods. This
4 reference also teaches that, due to such improved economics, it is possible to widen the
5 spacing of wells used in a SAP process, thereby reducing capital costs as compared to SAGD
6 alone. Gupta et al. also teach that using solvents with successively decreasing molecular
7 weights allows for increased recovery rates of the heavier solvents at the cost of the lighter
8 ones. This is beneficial as the heavier solvents are generally more expensive.

9 **[0006]** Other examples of SAP types of methods are described in US Patent nos. 6,230,814
10 and 6,591,908. Patent no. 6,591,908 also teaches a steam and solvent process wherein the
11 ratio of the two components is varied over time. However, both steam and solvent are injected
12 at all times during the process. A further type of a SAP method is taught in US Patent no.
13 4,513,819, which involves cyclical steam/solvent injection and production steps.

14 **[0007]** Gates et al., in US Patent no. 7,464,756, proposes a further variation in a bitumen
15 recovery process. Referred to as the solvent-assisted vapour extraction with steam (SAVES)
16 process, the proposed method involves a sequence of solvent/steam injections to recover
17 bitumen. The SAVES method comprises three phases. In the first phase, steam and a heavy
18 solvent (C5+) are injected into a formation. In the second phase, the steam and heavy solvent
19 flow rates are gradually reduced while a light solvent (C1- C4) is introduced with a gradually
20 increasing flow rate. In the third phase, injection of the steam and heavy solvent is stopped and
21 the injection of the light solvent continues at a higher rate. After the third phase, a "blow down"
22 procedures is used to recover the injected solvents.

23 **[0008]** Zhao et al. (J. Can. Pet. Tech., 2005, 44(9), pp. 37-43) teach a hydrocarbon
24 production method involving alternating steam and solvent injection, referred to as the steam
25 alternating solvent (SAS) process. In this method, steam and solvent are injected in an
26 alternating manner without any co-injection of the two.

27 **[0009]** Further examples of bitumen recovery processes known in the art are provided in US
28 Patent nos. 4,519,454; 6,662,872; and 6,708,759, and US Application publication no.
29 2008/0017372.

30 **[0010]** The recovery of bitumen from reservoirs such as oil sands continues to be of interest
31 particularly in view of the world's increasing energy demand. As such, the need to improve
32 extraction efficiency of hydrocarbon containing reservoirs continues to gain importance. Despite

the various prior art attempts discussed above, there exists a need for an efficient and cost-effective method for in situ recovery of bitumen.

SUMMARY OF THE INVENTION

[0011] In one aspect, the invention provides an improved SAGD method for extracting hydrocarbons from a reservoir containing hydrocarbons, wherein the method comprises the cyclic injection of steam and heavy and light solvents.

[0012] Thus, in one aspect, the invention provides a method of producing hydrocarbons from a subterranean reservoir containing the hydrocarbons, the reservoir including at least one generally horizontal injection well and at least one generally horizontal production well, the production well being located vertically below the injection well and proximal thereto, the method comprising:

[0013] a) injecting steam and a heavy solvent into the reservoir through the at least one injection well, the heavy solvent comprising a hydrocarbon having a carbon chain length of C4 or greater;

[0014] b) reducing the steam injection rate, stopping the heavy solvent injection, and injecting a light solvent, the light solvent comprising a hydrocarbon having a carbon chain length less than the heavy solvent;

[0015] c) increasing the steam injection rate to above the rate of step (b), restarting the heavy solvent injection, and continuing the light solvent injection;

[0016] d) increasing the steam injection rate to above the rate of step (c), stopping the heavy and light solvent injection; and,

[0017] e) reducing the steam injection rate and restarting the light solvent injection.

BRIEF DESCRIPTION OF THE DRAWINGS

[0018] Exemplary embodiments of the invention will now be described by way of example only with reference to the accompanying drawings, in which:

[0019] Figure 1 is a graph illustrating the correlation between Canadian Athabasca heavy oil/bitumen viscosity and the temperature of the deposit.

[0020] Figure 2 is a graph illustrating the correlation between Athabasca bitumen viscosity and the volume of solvent added to the deposit.

1 **[0021]** Figure 3 illustrates the injection profiles of the steam and solvent components used
2 in the present invention.

3 **[0022]** Figures 4 to 6 illustrate a comparison of performance efficiencies of the method of
4 the invention and a typical SAGD method.

5 **DETAILED DESCRIPTION OF THE INVENTION**

6 **[0023]** For clarity of understanding, the following terms used in the present description will
7 have the definitions as stated below.

8 **[0024]** As used herein, the terms "reservoir", "formation", "deposit", are synonymous and
9 refer to generally subterranean reservoirs containing hydrocarbons. As discussed further
10 below, such hydrocarbons may comprise bitumen and bitumen like materials.

11 **[0025]** "Oil sands", as used herein, refers to deposits containing heavy hydrocarbon
12 components such as bitumen or "heavy oil", wherein such hydrocarbons are intermixed with
13 sand. Although the invention is described herein as being applicable to oil sands, it will be
14 understood by persons skilled in the art that the invention may also be applicable to other types
15 reservoirs containing bitumen or heavy oil, or other such hydrocarbon materials (i.e. heavy
16 crude oil). However, for convenience, the terms "oil sands" and "bitumen" are used for the
17 purposes of the following description and will be understood to refer generally to any of the
18 above mentioned hydrocarbon reservoirs and materials. The choice of such terms serves to
19 facilitate the description of the invention and is not intended to limit the invention in any way.

20 **[0026]** The term "solvent" refers to one or more hydrocarbon solvents used in hydrocarbon
21 recovery methods as known in the art. In a preferred embodiment, the solvents of the invention
22 are hydrocarbons comprising chain lengths of C2 to C10. Examples of suitable solvents for
23 bitumen extraction processes are known in the art, and can include alkanes, naphtha, CO₂ and
24 combinations thereof. The solvent may comprise a mixture of one or more hydrocarbon
25 components. As used herein, the terms "light solvent" or "light hydrocarbon" will be understood
26 as comprising one or more alkane components preferably having a length of C2 to C4, and
27 more preferably C3 (i.e. propane). Similarly, the terms "heavy solvent" or "heavy hydrocarbon"
28 as used herein will be understood as comprising one or more alkane components preferably
29 having a length of at least C4, and more preferably at least C5 (i.e. pentane). It will also be
30 understood that the heavy and light solvents can comprise mixtures of solvents having a desired
31 average chain length. For example the heavy solvent may comprise a mixture of hydrocarbons,

each preferably having a length greater than C4 and wherein the mixture has an average chain length of approximately C5. In a further preferred aspect, at least 1/3 v/v of the heavy solvent mixture is comprised of pentane (C5) and/or hexane (C6). Similarly, the light solvent may comprise a mixture of hydrocarbons, each preferably having a length less than C4 and wherein the mixture has an average chain length of approximately C3. In a further preferred aspect, at least 1/2 v/v of the light solvent mixture is comprised of propane (C3). In a further preferred aspect, the light solvent contains less than about 25 mole% of methane (C1) and ethane (C2). As known in the art, the choice of solvents depends on the reservoir or anticipated operating pressure. The heavy solvent should condense at a temperature that is less than that for steam but higher than the average of steam temperature and initial reservoir temperature. Similarly the light solvent, at operating pressure, should condense at a temperature which is less than the average between steam and initial temperatures. The choice of an appropriate solvent for use in the invention will, therefore, be apparent to persons skilled in the art in view of the teaching provided herein.

[0027] The term "natural gas liquids" or "NGL" will be understood as comprising alkane hydrocarbons generally having lengths of C2 to C6, and which are normally condensation products in the course of natural gas processing.

[0028] As discussed above, various methods have been proposed for extracting, or producing, bitumen from oil sands. These generally include gravity driven heating methods, such as SAGD, and dilution methods, such as VAPEX. Figure 1 illustrates the effect of heat on bitumen viscosity. The curves for varying oil density, or API gravity, show a maximum slope at the lower temperatures, indicating that small initial in-situ formation temperature increases produce the largest reductions in oil viscosity per degree of temperature rise. Figure 2 illustrates the effect of solvent injection on bitumen viscosity. The graph shows the correlation of the mole fraction of solvent 14, the solvent in this example being hexane, with the bitumen viscosity 11. The top dotted curve 4 for solvent at 10°C demonstrates that as the mole fraction of hexane 12 in a hexane/bitumen solution increases, the viscosity 11 of the mixture can be reduced from millions of centipoises a viscosity of less than 10 centipoise. However, in comparison with described SAGD processes, pure unheated solvent applications have proven much more difficult to execute in practice, with at least two uneconomic field trials attempted.

[0029] The present invention provides an improved method for recovering hydrocarbons and, more particularly, viscous hydrocarbons from subterranean deposits. In a preferred

1 application, the invention provides a method for recovering bitumen from oil sands and the like,
2 which incorporates a combination of SAGD and solvent techniques. In general, the invention
3 requires at least one injection well and at least one production well. Both the injection and
4 production wells are provided in a reservoir containing hydrocarbons to be produced (or
5 extracted). The wells are arranged generally horizontally as in a typical SAGD process, wherein
6 the injection wells are positioned vertically above the production wells. As discussed further
7 below, steam and/or one or more solvents are injected into the reservoir, which results in
8 mobilization of the bitumen material within the reservoir. The mobilization of bitumen is caused
9 by a reduction in its viscosity due to the heating effect of the injected steam and/or the diluting
10 effect of the injected solvent. In either case, the mobilized bitumen is allowed to travel
11 downward due to gravity and is collected in the lower production well. The bitumen entering the
12 production well is then transported, using pumps and other associated equipment known in the
13 art, to the surface for subsequent processing.

14 **[0030]** According to the method of the invention, the injection and production wells are first
15 positioned in the same manner as with known SAGD processes. The arrangement and
16 positioning of the wells is known in the art and described, for example in Canadian patent
17 number 1,304,287. However, as discussed below, in one aspect of the invention, the well
18 spacing may be reduced by half as compared with typical SAGD processes due to the efficiency
19 of the present method. It will be understood that this is an advantage of the invention and not a
20 restriction. Alternatively, the method can be applied to a field already prepared for a SAGD
21 process without altering the well positioning. Once the wells are positioned and the initial start-
22 up of the SAGD process has been effected, the method of the invention can then be
23 commenced. The method can be divided into six main phases or stages, I to VI, each taking
24 place sequentially over a period of time. The switching of one phase to another is preferably
25 based on a recovery factor, quantified as the percentage of oil in place (OIP) that has been
26 recovered. These phases are discussed further below.

27 **[0031] Phase I**

28 **[0032]** The first phase of the method begins with the co-injection of steam and a heavy
29 (preferably C5 or greater) solvent into the reservoir. The steam injection rate is preferably the
30 same as that normally associated with SAGD processes. As known in the art, the steam
31 injection rate will vary according to various physical characteristics of the reservoir and other
32 such criteria. The present invention is not limited to any particular rate of steam injection. The

1 steam flow rate for Phase I will be referred to herein as the maximum steam flow rate, SFmax,
2 and will be understood to mean a mass flow rate. It will be chosen or determined so as to result
3 in or maintain the desired or necessary pressure in the reservoir. Similarly, all flow rates of
4 solvents will also be understood to mean mass flow rates.

5 **[0033]** The preferred, but not exclusive, solvent for Phase I is pentane (C5) or a heavier
6 hydrocarbon, or some combination thereof. The flow rate of the heavy solvent is about 0-20%,
7 and preferably about 4-20%, and more preferably 8-20% of SFmax. Preferably, no other
8 solvent is injected during this phase. As indicated in the range of heavy solvent flow rate, it will
9 be understood that the use of such heavy solvent (e.g. pentane or another "heavy" hydrocarbon
10 as defined herein) may be omitted in some situations. One factor for considering the use of the
11 heavy solvent in Phase I is the relative value of such solvent as compared to the bitumen
12 product. For example, it may be found that the cost of using the heavy solvent is outweighed by
13 the economic benefit of the recovered bitumen. A further factor that determines the amount of
14 heavy solvent used in Phase I is the rate of recovery of the heavy solvent. Such recovery will
15 be controlled, inter alia, by the geological properties of the deposit.

16 **[0034]** In the preferred embodiment, the steam and heavy solvent co-injection of Phase I is
17 continued until about 25-30% of the OIP has been recovered.

18 **[0035]** **Phase II**

19 **[0036]** In the second phase, steam injection is continued but at a much reduced level as
20 compared to Phase I. Preferably, the steam injection rate is reduced to about 8-20%, and
21 preferably 15-20%, of SFmax. The injection of heavy solvent is stopped and the injection of a
22 light solvent (i.e. C2 to C4) is commenced. In one preferred aspect of the invention, the light
23 solvent is propane (C3). In another preferred aspect, the flow rate of the light solvent is about 4-
24 8% of SFmax.

25 **[0037]** Phase II is preferably continued until about 40-45% of the OIP is recovered.

26 **[0038]** **Phase III**

27 **[0039]** In Phase III, the steam flow rate is increased slightly to about 20-25% of SFmax and
28 both light and heavy solvents are injected. The flow rate of the heavy solvent is about 0-10%,
29 and preferably about 2-10%, of SFmax and the flow rate of the light solvent is preferably about
30 3-6% of SFmax. As noted, the flow rate of the light solvent is preferably slightly reduced as
31 compared to Phase II. Phase III may therefore be characterized as a spike in the heavy solvent

1 injection rate. As with Phase I, the amount of the heavy solvent (e.g. pentane) will depend on
2 certain cost and recovery factors. Thus, in some cases, it may be found more economically
3 efficient to avoid using any heavy solvent in Phase III.

4 **[0040]** Phase III is preferably continued until about 56-66%, and preferably 58-64%, of the
5 OIP is recovered.

6 **[0041]** **Phase IV**

7 **[0042]** In Phase IV, the steam flow rate is increased slightly from that of Phase III to about
8 30-35% of SFmax. The injection of both heavy and light solvents is stopped. Thus, for Phase
9 IV, only steam is injected into the reservoir and, as such, this phase may be characterized as a
10 spike in the steam injection rate.

11 **[0043]** Phase IV is preferably continued until about 66-72% of the OIP is recovered.

12 **[0044]** **Phase V**

13 **[0045]** In Phase V, steam injection is reduced to about 15-20% of SFmax. No injection of
14 heavy solvent is made; however, light solvent injection is recommenced at a flow rate of about
15 2-5% of SF max. This phase may therefore be characterized as a spike in light solvent
16 injection.

17 **[0046]** Phase V is preferably continued until about 75-80% of the OIP is recovered.

18 **[0047]** **Phase VI**

19 **[0048]** Phase VI comprises a blow out phase wherein residual solvent is recovered, or
20 scavenged, along with a portion of the bitumen in the reservoir. During this phase, no steam or
21 the above mentioned solvents are injected into the reservoir. The solvent recovery is effected
22 by various methods known in the art such as injection of methane and/or by depressurizing the
23 reservoir. For example, the preferred method of scavenging residual solvent is to inject a non-
24 condensible gas such as methane, nitrogen, or CO₂ into one or both of the injection and
25 production wells of wells arranged in alternating pairs, and to produce the same volume from
26 intervening pairs of wells. It will be understood that the invention is not limited to any particular
27 method of solvent recovery. It will also be understood that Phase VI may be eliminated in cases
28 where solvent recovery or further bitumen production is not economically viable or sustainable.

29 **[0049]** The final phase may be continued for any required amount of time until, for example,
30 about 85% of the OIP is recovered. However, the duration of this phase would be primarily

based on the need to scavenge residual solvent and other economic considerations. For example, if the efficiency of production drops below a certain threshold, Phase VI can be terminated.

[0050] Table 1 below summarizes an example of the above described phases.

[0051] Table 1

Phase	Ends @ %OIP	Steam flow rate % Maximum Steam Rate (SFmax)	Heavy solvent (pentane) flow rate mass % of SFmax	Light solvent (propane) flow rate mass % of SFmax	Example elapsed time, years
I	25-30	100	0-20 (pref. 4-20)	0	1
II	40-45	8-20 (pref. 15-20)	0	4-8	2
III	56-66 (pref. 58-64)	20-25	0-10 (pref. 2-10)	3-6	3
IV	66-72	30-35	0	0	4
V	75-80	15-20	0	2-5	5
VI	~85	0	0	0	10

Although the above table provides examples of the lengths of time for each phase, the duration of each phase would vary based on various factors such as the physical characteristics of the reservoir and the bitumen contained therein, the extraction efficiencies of the equipment, and the number and spacing of the wells. In practice, each phase may be conducted up till a desired recovery threshold of the Oil in Place (OIP) is reached. However, in typical cases, the time period of each stage may be measured by years.

Various numerical simulations of the method of the invention were conducted. Figure 3 illustrates the flow rates of the respective steam, heavy solvent and light solvent injection streams used in one of the tests as each of the above phases was carried out. As can be seen, the flow rate conditions and timing of the phases were similar to that described above in Table 1.

Figure 4 illustrates a comparison between extraction of a reservoir using a typical SAGD process and a process according to the present invention, namely a solvent cycle SAGD

(or SC-SAGD). As can be seen, the present invention provides a 30% improvement in bitumen extraction efficiency.

[0055] Figures 5 and 6 illustrate the performance efficiency of the present invention (SC-SAGD) as compared to typical SAGD methods. As shown, the method of the present invention provides a higher oil recovery while requiring a much reduced steam to oil ratio (SOR).

[0056] As indicated above, the "heavy" and "light" solvents used in the present method may be either single types of hydrocarbons or may comprise a mixture of hydrocarbons. In the typical scenario, the solvents will comprise such a mixture and, preferably, with a greater proportion being made up of a desired weight of solvent. For example, although pentane is indicated above as a "heavy" solvent, a natural gas condensate, or natural gas liquid (NGL) may be used, consisting of preferably more than 1/3 (v/v) of pentanes plus hexanes. The liquid volume of the NGL used for this purpose would be the same as indicated above with respect to pentane by itself. Alternatively, butane may be substituted for pentane as the heavy solvent. In addition, unlike other solvent based extraction methods, the purity of the solvent is not critical for the method of the invention; however, when recycling propane, the presence of methane or other light gases should preferably be limited to less than about 25% mole fraction. As such, the operating costs associated with solvent refining are mitigated by the present invention.

[0057] As will be understood, the method of the invention provides an improved and more efficient process for recovering bitumen than a SAGD process alone. Although the invention is adapted to be used for an existing SAGD well arrangement, in new fields, the spacing of wells for the purpose of the invention can be reduced by 50%, thereby reducing the facility and operating costs associated with the recovery process. In particular, by allowing a reduced well spacing, the invention reduces by as much as 50% the amount of heat consumption normally associated with SAGD methods. Further, the solvent scavenging process can also be brought forward in time, which will reduce the cost associated with the solvent inventory during recovery.

[0058] By combining solvent injection with steam, the invention is able to realize a major reduction in the steam to oil ratio (SOR) and cumulative steam to oil ratio (CSOR) as compared a SAGD process alone.

1 **[0059]** Although the invention has been described with reference to certain specific
2 embodiments, various modifications thereof will be apparent to those skilled in the art without
3 departing from the purpose and scope of the invention as outlined in the claims appended
4 hereto. The drawings provided herein are solely for the purpose of illustrating various aspects
5 of the invention and are not intended to be drawn to scale or to limit the invention in any way.
6 The disclosures of all prior art recited herein are incorporated herein by reference in their
7 entirety.

8

WHAT IS CLAIMED IS:

1. A method of producing hydrocarbons from a subterranean reservoir containing said hydrocarbons, the reservoir including at least one generally horizontal injection well and at least one generally horizontal production well, the production well being located vertically below the injection well and proximal thereto, the method comprising:
 - a) injecting steam and, optionally, a heavy solvent into the reservoir through the at least one injection well, the heavy solvent comprising one or more hydrocarbons having a carbon chain length of C4 or greater;
 - b) reducing the steam injection rate, stopping the heavy solvent injection, and injecting a light solvent, the light solvent comprising one or more hydrocarbons having a carbon chain length less than the heavy solvent;
 - c) increasing the steam injection rate to above the rate of step (b), optionally restarting the heavy solvent injection, and continuing the light solvent injection;
 - d) increasing the steam injection rate to above the rate of step (c), stopping the heavy and light solvent injection; and,
 - e) reducing the steam injection rate and restarting the light solvent injection.
2. The method of claim 1, further comprising a further step of:
 - f) stopping injection of the steam and light solvent and scavenging residual solvents from the reservoir.
3. The method of claim 1, wherein the heavy solvent is pentane or a hydrocarbon mixture having an average chain length of about C5 or greater and comprising at least 1/3 by volume of pentane and/or hexane.
4. The method of claim 1, wherein the light solvent is propane or a hydrocarbon mixture having an average chain length of about C3 and comprising at least 1/2 by volume of propane.
5. The method of claim 4, wherein the light solvent contains less than about 25 mole% of methane and ethane.
6. The method of claim 1, wherein step (a) is continued until about 25-30% of the oil in place has been recovered.

7. The method of claim 1, wherein step (b) is continued until about 40-45% of the oil in place has been recovered.
8. The method of claim 1, wherein step (c) is continued until about 56-66%, or about 58-64%, of the oil in place has been recovered.
9. The method of claim 1, wherein step (d) is continued until about 66-72% of the oil in place has been recovered.
10. The method of claim 1, wherein step (e) is continued until about 75-80% of the oil in place has been recovered.
11. The method of claim 2, wherein step (f) is continued until about 85% or more of the oil in place has been recovered.
12. The method of claim 1, wherein, in step (a), the flow rate of the heavy solvent is 0-20% of the flow rate of the steam.
13. The method of claim 1, wherein, in step (a), the flow rate of the heavy solvent is 4-20% of the flow rate of the steam.
14. The method of claim 1, wherein, in step (b), the flow rate of the steam is 8-20% of the steam flow rate of step (a) and wherein the flow rate of the light solvent is 4-8% of the steam flow rate of step (a).
15. The method of claim 1, wherein, in step (c):
 - the flow rate of the steam is 20-25% of the steam flow rate of step (a);
 - the flow rate of the heavy solvent is 0-10% of the steam flow rate of step (a); and
 - the flow rate of the light solvent is 3-6% of the steam flow rate of step (a).
16. The method of claim 1, wherein, in step (d), the flow rate of the steam is 30-35% of the steam flow rate of step (a).

17. The method of claim 1, wherein, in step (e), the flow rate of the steam is 15-20% of the steam flow rate of step (a) and wherein the flow rate of the light solvent is 2-5% of the steam flow rate of step (a).

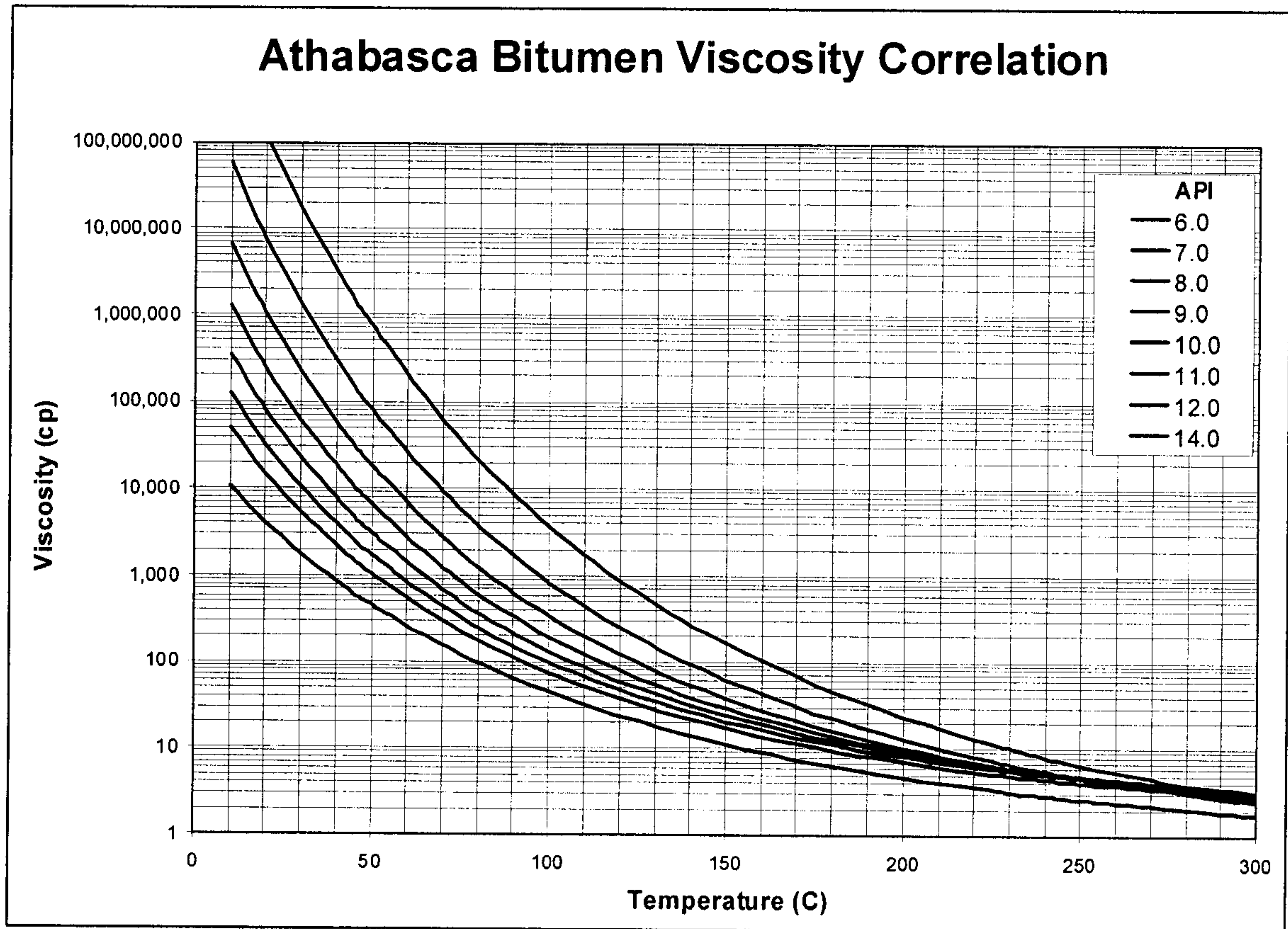


FIGURE 1

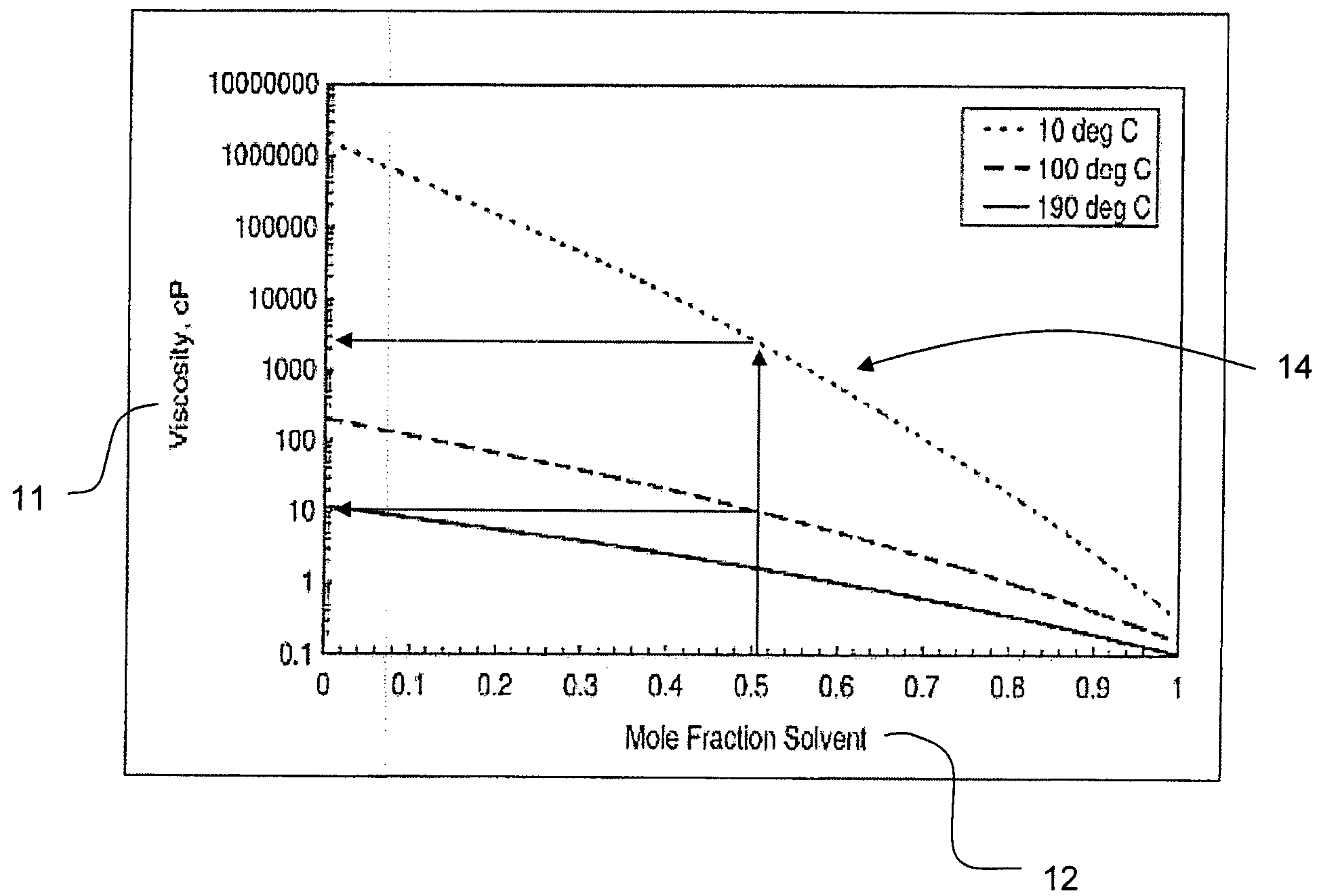


FIGURE 2

FIGURE 3

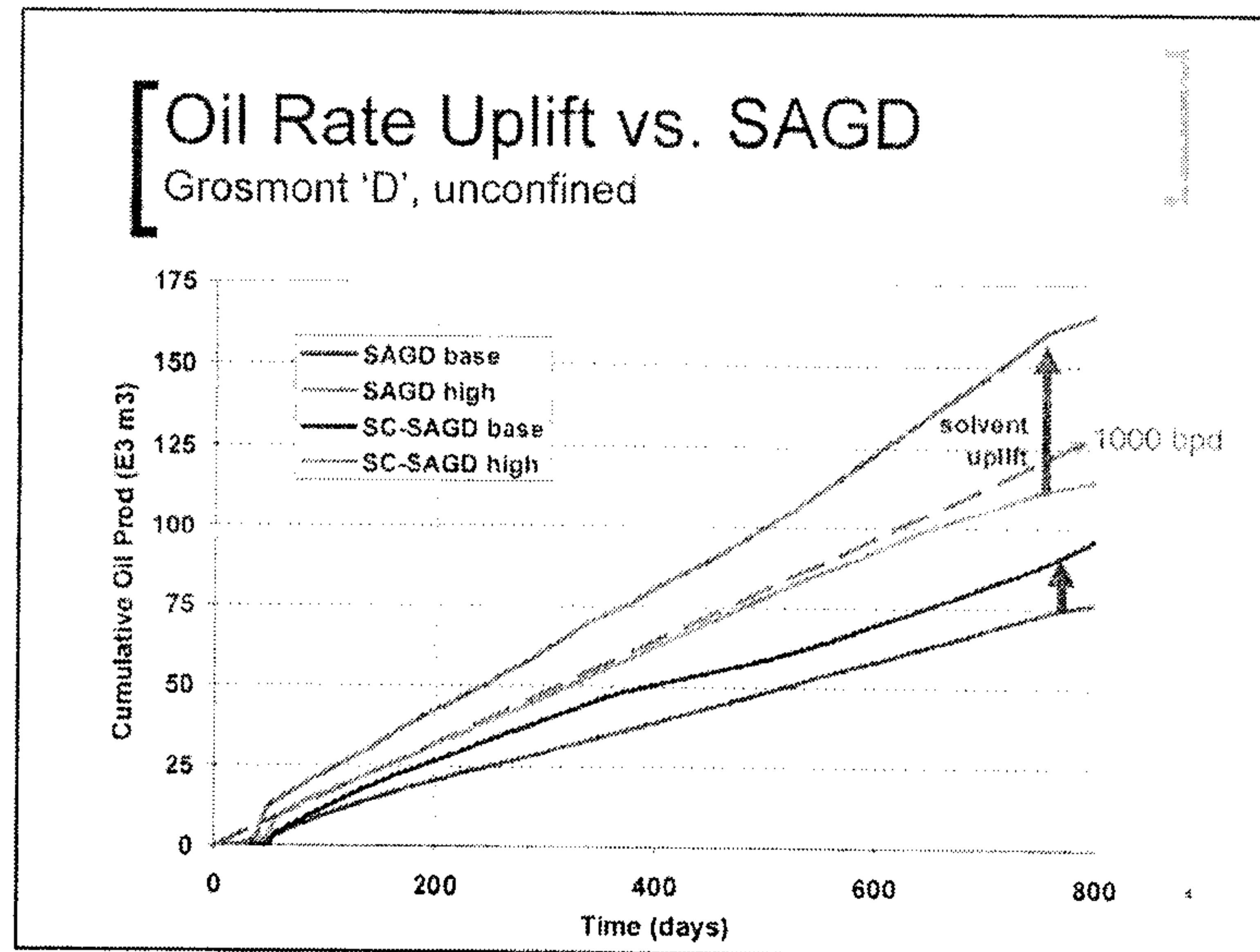
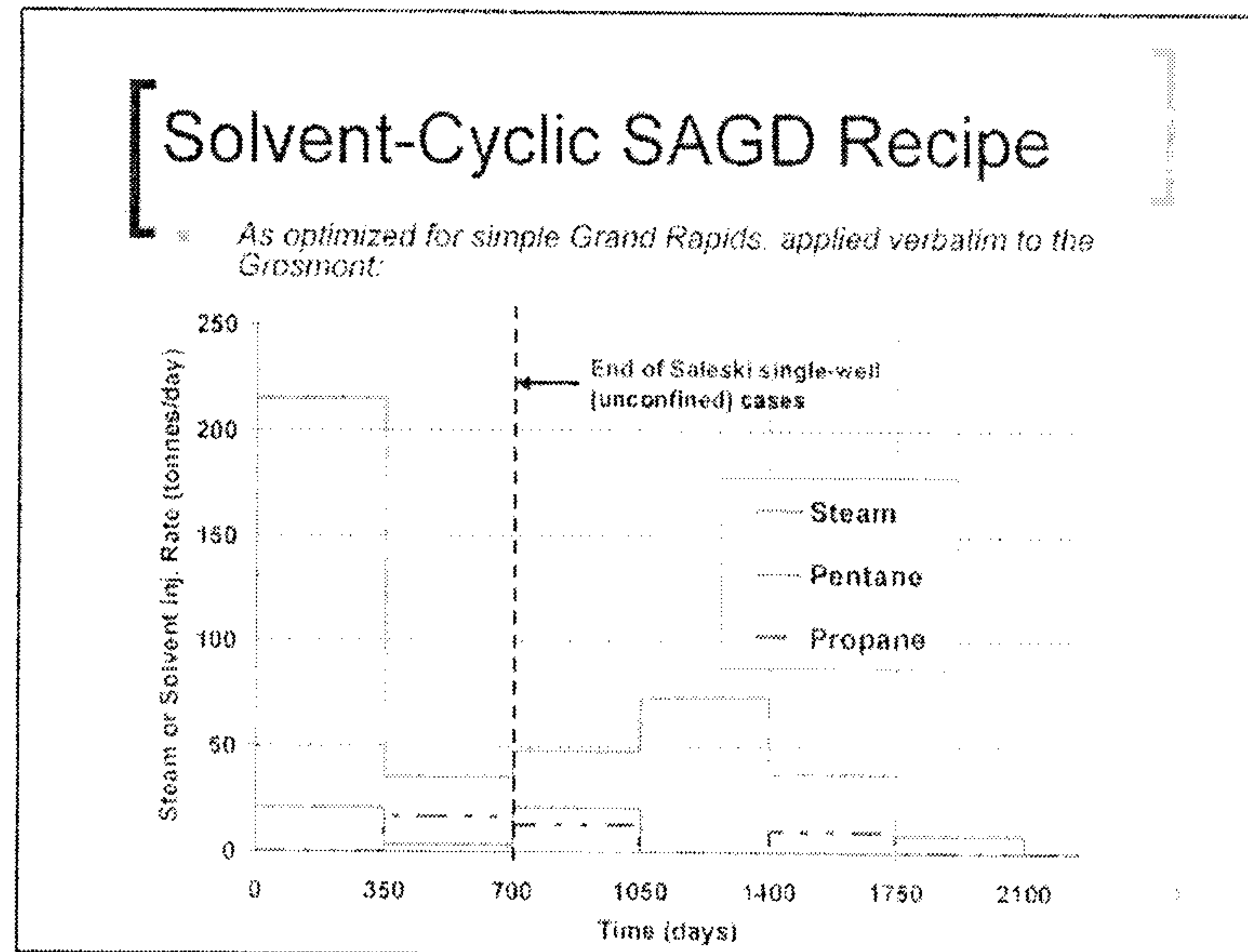
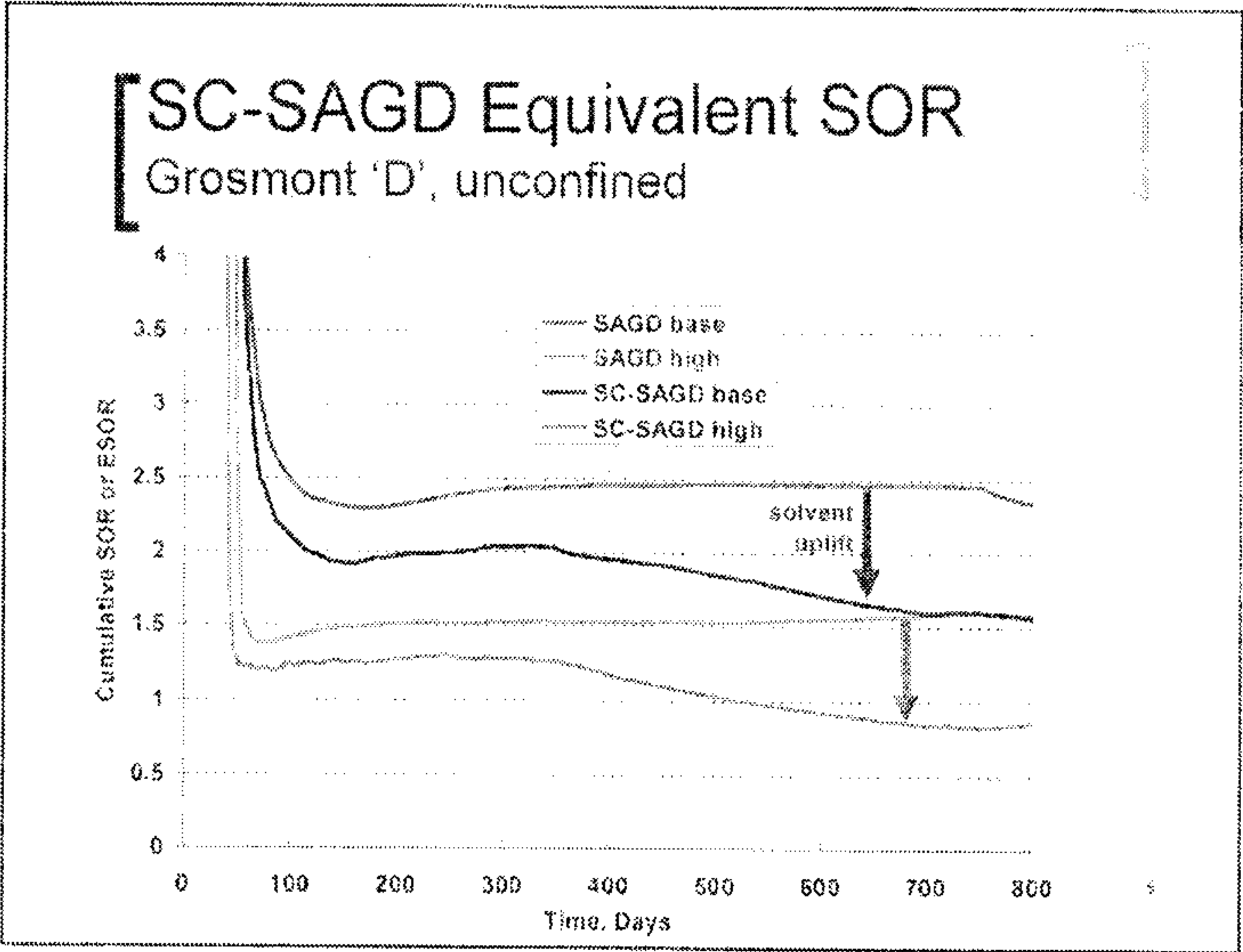


FIGURE 4

FIGURE 5



[SC-SAGD: 2 x the NPV

■ Results of a Germain-optimized recipe, applied to an unconfined pair in Grosmont 'D' (base-case permeabilities):

Performance after 2 yrs:	Cum. Oil, bbls	Phys. CSOR	Equiv. CSOR
SAGD	470,000		2.5
SC-SAGD	600,000	1.0	1.6

FIGURE 6

Solvent-Cyclic SAGD Recipe

※ *As optimized for simple Grand Rapids, applied verbatim to the Grosmont:*

