

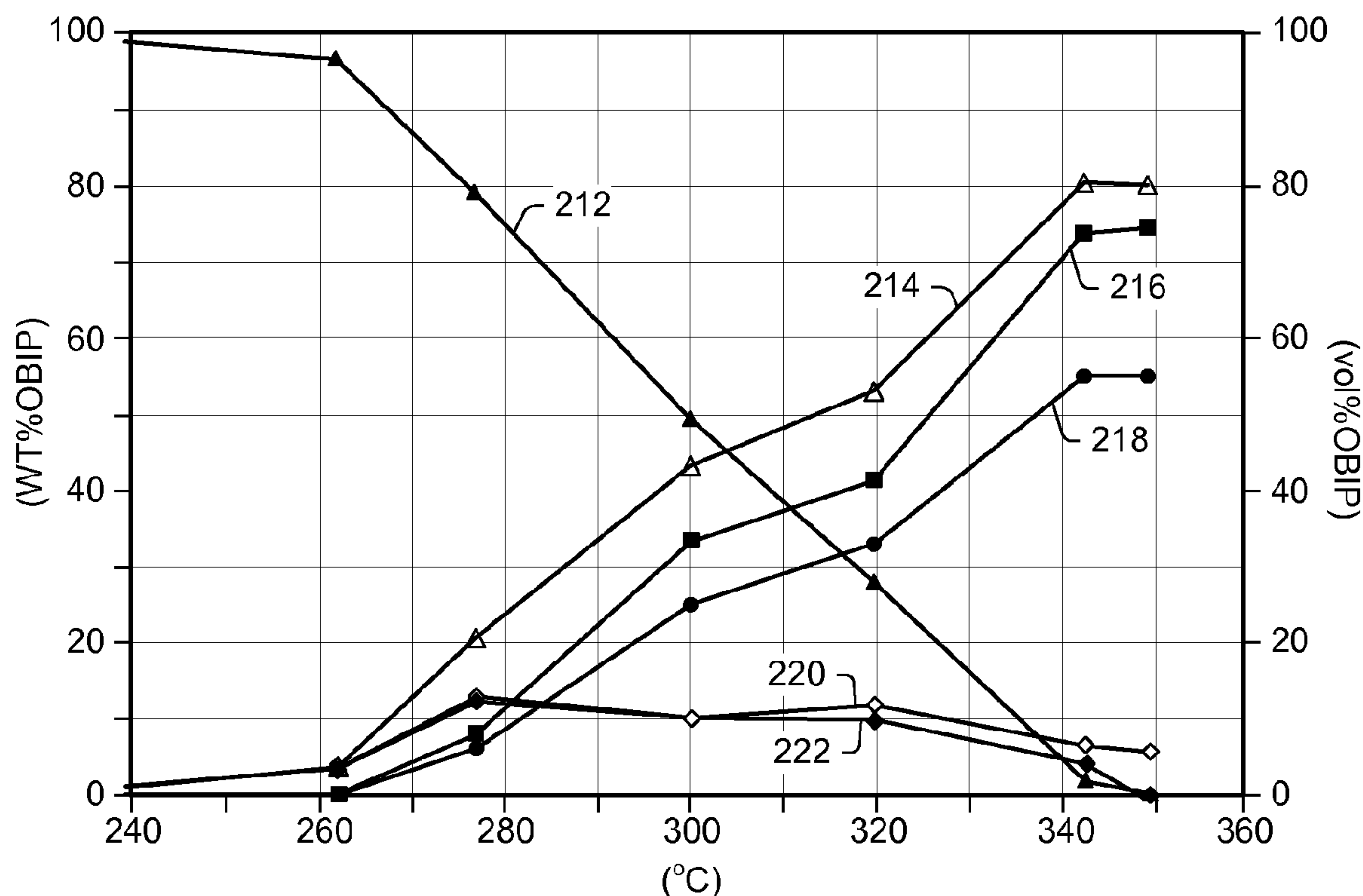


(86) **Date de dépôt PCT/PCT Filing Date:** 2008/04/18  
(87) **Date publication PCT/PCT Publication Date:** 2008/10/30  
(45) **Date de délivrance/Issue Date:** 2015/11/24  
(85) **Entrée phase nationale/National Entry:** 2009/10/16  
(86) **N° demande PCT/PCT Application No.:** US 2008/060757  
(87) **N° publication PCT/PCT Publication No.:** 2008/131182  
(30) **Priorités/Priorities:** 2007/04/20 (US60/925,685);  
2007/10/19 (US60/999,839)

(51) **Cl.Int./Int.Cl.** *E21B 43/16* (2006.01),  
*E21B 43/18* (2006.01), *E21B 43/24* (2006.01)  
(72) **Inventeurs/Inventors:**  
BEER, GARY LEE, US;  
ZHANG, ETUAN, US  
(73) **Propriétaire/Owner:**  
SHELL INTERNATIONALE RESEARCH  
MAARSCHAPPIJ B.V., NL  
(74) **Agent:** NORTON ROSE FULBRIGHT CANADA  
LLP/S.E.N.C.R.L., S.R.L.

(54) **Titre : CONTROLE ET EVALUATION DES CONDITIONS DE PRESSION AU COURS DU TRAITEMENT DE FORMATIONS DE SABLES BITUMINEUX**

(54) **Title: CONTROLLING AND ASSESSING PRESSURE CONDITIONS DURING TREATMENT OF TAR SANDS FORMATIONS**



(57) **Abrégé/Abstract:**

A method for treating a tar sands formation includes providing heat to at least part of a hydrocarbon layer in the tar sands formation from a plurality of heaters located in the formation. Heat is allowed to transfer from the heaters to at least a portion of the formation. A pressure in the portion of the formation is controlled such that the pressure remains below a fracture pressure of the formation overburden while allowing the portion of the formation to heat to a selected average temperature of at least about 280 °C and at most about 300 °C. The pressure in the portion of the formation is reduced to a selected pressure after the portion of the formation reaches the selected average temperature.

(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization  
International Bureau(43) International Publication Date  
30 October 2008 (30.10.2008)

PCT

(10) International Publication Number  
**WO 2008/131182 A1**(51) International Patent Classification:  
*E21B 43/16* (2006.01)

(21) International Application Number:

PCT/US2008/060757

(22) International Filing Date: 18 April 2008 (18.04.2008)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:

60/925,685 20 April 2007 (20.04.2007) US

60/999,839 19 October 2007 (19.10.2007) US

(71) Applicant (for SM only): **SHELL OIL COMPANY**  
[US/US]; One Shell Plaza, P.O. Box 2463, Houston, Texas  
77252-2463 (US).(71) Applicant (for all designated States except US): **SHELL  
INTERNATIONALE RESEARCH MAATSCHAPPIJ  
B.V.** [NL/NL]; Carel van Bylandtlaan 30, NL-2596 HR The  
Hague (NL).

(72) Inventors; and

(75) Inventors/Applicants (for US only): **BEER, Gary, Lee**  
[US/US]; 3231 Enclave Lane, Houston, Texas 77077 (US).  
**ZHANG, Etuan** [US/US]; 5425 Loch Lomond Drive,  
Houston, Texas 77096 (US).(74) Agent: **CHRISTENSEN, Del, S.**; SHELL OIL COM-  
PANY, One Shell Plaza, P.O. Box 2463, Houston, Texas  
77252-2463 (US).(81) Designated States (unless otherwise indicated, for every  
kind of national protection available): AE, AG, AL, AM,  
AO, AT, AU, AZ, BA, BB, BG, BH, BR, BW, BY, BZ, CA,  
CH, CN, CO, CR, CU, CZ, DE, DK, DM, DO, DZ, EC, EE,  
EG, ES, FI, GB, GD, GE, GH, GM, GT, HN, HR, HU, ID,  
IL, IN, IS, JP, KE, KG, KM, KN, KP, KR, KZ, LA, LC,  
LK, LR, LS, LT, LU, LY, MA, MD, ME, MG, MK, MN,  
MW, MX, MY, MZ, NA, NG, NI, NO, NZ, OM, PG, PH,  
PL, PT, RO, RS, RU, SC, SD, SE, SG, SK, SL, SM, SV,  
SY, TJ, TM, TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN,  
ZA, ZM, ZW.(84) Designated States (unless otherwise indicated, for every  
kind of regional protection available): ARIPO (BW, GH,  
GM, KE, LS, MW, MZ, NA, SD, SL, SZ, TZ, UG, ZM,  
ZW), Eurasian (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM),  
European (AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI,  
FR, GB, GR, HR, HU, IE, IS, IT, LT, LU, LV, MC, MT, NL,  
NO, PL, PT, RO, SE, SI, SK, TR), OAPI (BF, BJ, CF, CG,  
CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

Published:

— with international search report

[Continued on next page]

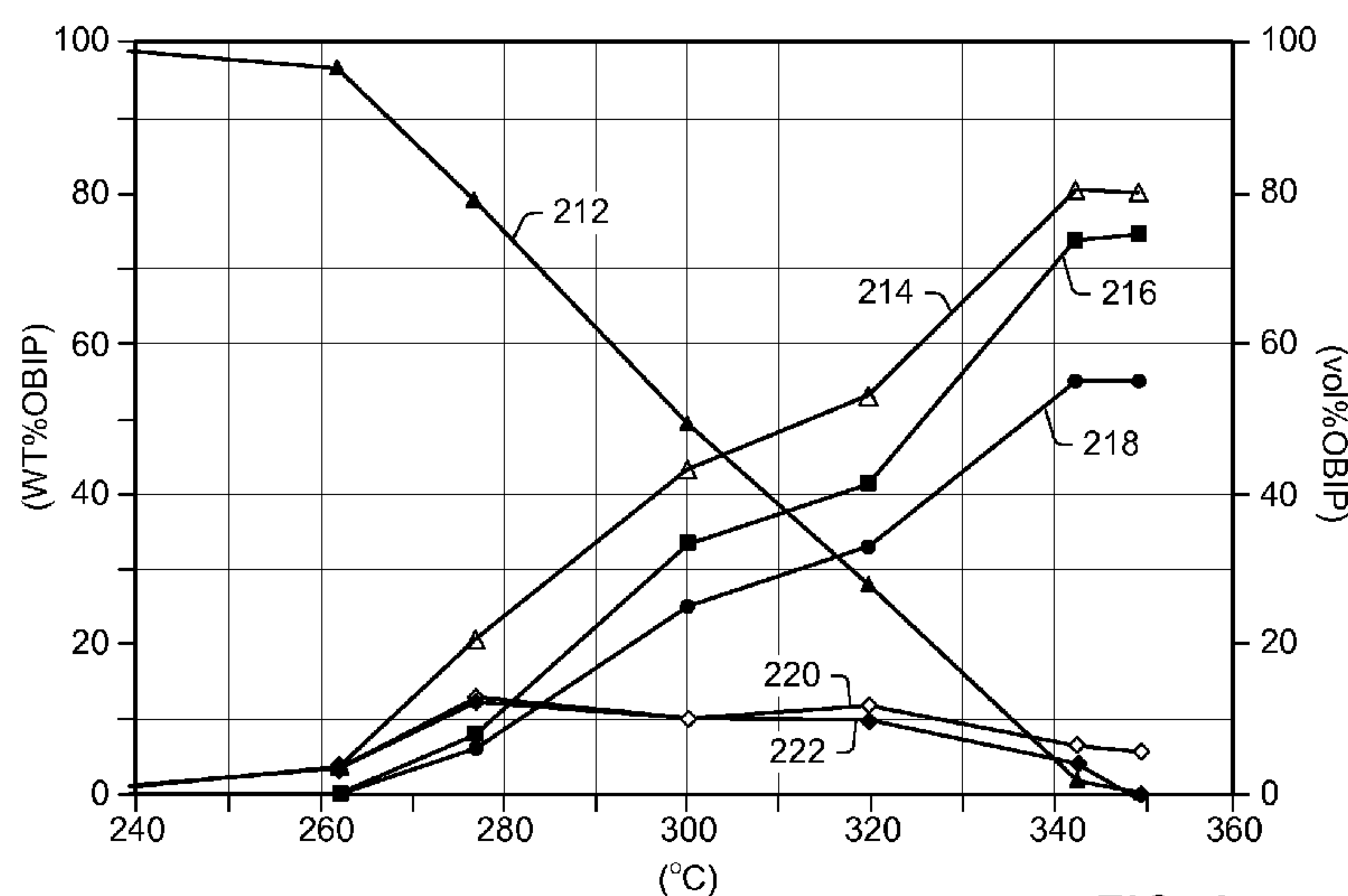
(54) Title: CONTROLLING AND ASSESSING PRESSURE CONDITIONS DURING TREATMENT OF TAR SANDS FOR-  
MATIONS

FIG. 3

(57) Abstract: A method for treating a tar sands formation includes providing heat to at least part of a hydrocarbon layer in the tar sands formation from a plurality of heaters located in the formation. Heat is allowed to transfer from the heaters to at least a portion of the formation. A pressure in the portion of the formation is controlled such that the pressure remains below a fracture pressure of the formation overburden while allowing the portion of the formation to heat to a selected average temperature of at least about 280 °C and at most about 300 °C. The pressure in the portion of the formation is reduced to a selected pressure after the portion of the formation reaches the selected average temperature.

WO 2008/131182 A1

**WO 2008/131182 A1**



- 
- *before the expiration of the time limit for amending the claims and to be republished in the event of receipt of amendments*

5                                   CONTROLLING AND ASSESSING PRESSURE CONDITIONS  
                                     DURING TREATMENT OF TAR SANDS FORMATIONS

**BACKGROUND**

1.       Field of the Invention

10    **[0001]** The present invention relates generally to methods and systems for production of hydrocarbons, hydrogen, and/or other products from various subsurface formations such as hydrocarbon containing formations (for example, tar sands formations).

2.       Description of Related Art

15    **[0002]** Hydrocarbons obtained from subterranean formations are often used as energy resources, as feedstocks, and as consumer products. Concerns over depletion of available hydrocarbon resources and concerns over declining overall quality of produced hydrocarbons have led to development of processes for more efficient recovery, processing and/or use of available hydrocarbon resources. In situ processes may be used to remove  
20    hydrocarbon materials from subterranean formations. Chemical and/or physical properties of hydrocarbon material in a subterranean formation may need to be changed to allow hydrocarbon material to be more easily removed from the subterranean formation. The chemical and physical changes may include in situ reactions that produce removable fluids, composition changes, solubility changes, density changes, phase changes, and/or viscosity  
25    changes of the hydrocarbon material in the formation. A fluid may be, but is not limited to, a gas, a liquid, an emulsion, a slurry, and/or a stream of solid particles that has flow characteristics similar to liquid flow.

**[0003]** Large deposits of heavy hydrocarbons (heavy oil and/or tar) contained in relatively permeable formations (for example in tar sands) are found in North America, South  
30    America, Africa, and Asia. Tar can be surface-mined and upgraded to lighter hydrocarbons such as crude oil, naphtha, kerosene, and/or gas oil. Surface milling processes may further separate the bitumen from sand. The separated bitumen may be converted to light hydrocarbons using conventional refinery methods. Mining and upgrading tar sand is usually substantially more expensive than producing lighter  
35    hydrocarbons from conventional oil reservoirs.

**[0004]** In situ production of hydrocarbons from tar sand may be accomplished by heating and/or injecting a gas into the formation. U.S. Patent Nos. 5,211,230 to Ostapovich et al.

5 and 5,339,897 to Leaute describe a horizontal production well located in an oil-bearing reservoir. A vertical conduit may be used to inject an oxidant gas into the reservoir for in situ combustion.

[0005] U.S. Patent No. 2,780,450 to Ljungstrom describes heating bituminous geological formations in situ to convert or crack a liquid tar-like substance into oils and gases.

10 [0006] U.S. Patent No. 4,597,441 to Ware et al. describes contacting oil, heat, and hydrogen simultaneously in a reservoir. Hydrogenation may enhance recovery of oil from the reservoir.

[0007] U.S. Patent No. 5,046,559 to Glandt and 5,060,726 to Glandt et al. describe preheating a portion of a tar sand formation between an injector well and a producer well.

15 Steam may be injected from the injector well into the formation to produce hydrocarbons at the producer well.

[0008] As outlined above, there has been a significant amount of effort to develop methods and systems to economically produce hydrocarbons, hydrogen, and/or other products from hydrocarbon containing formations such as tar sands formations. At present, however,

20 there are still many tar sands formations from which hydrocarbons, hydrogen, and/or other products cannot be controllably produced and/or economically produced. Thus, there is still a need for improved methods and systems for producing hydrocarbons, hydrogen, and/or other products from various hydrocarbon containing formations as well as methods for assessing the heating and production process.

25 **SUMMARY**

[0009] Embodiments described herein generally relate to systems, methods, and heaters for treating a subsurface formation. Embodiments described herein also generally relate to heaters that have novel components therein. Such heaters can be obtained by using the systems and methods described herein.

30 [0010] In certain embodiments, the invention provides one or more systems, methods, and/or heaters. In some embodiments, the systems, methods, and/or heaters are used for treating a subsurface formation.

[0011] In certain embodiments, the invention provides a method for treating a tar sands formation, comprising: providing heat to at least part of a hydrocarbon layer in the tar  
35 sands formation from a plurality of heaters located in the formation; allowing the heat to transfer from the heaters to at least a portion of the formation; controlling a pressure in the portion of the formation such that the pressure remains below a fracture pressure of the

formation overburden while allowing the portion of the formation to heat to a selected average temperature of at least about 280 °C and at most about 300 °C; and reducing the pressure in the portion of the formation to a selected pressure after the portion of the formation reaches the selected average temperature.

- 5 [0011a] In accordance with one aspect of the present invention, there is provided a method for treating a tar sands formation, comprising: providing heat to at least part of a hydrocarbon layer in the tar sands formation from a plurality of heaters located in the formation; allowing the heat to transfer from the heaters to at least a portion of the formation; allowing an average temperature of the portion of the formation to increase to a  
10 selected average temperature between about 280 °C and about 300 °C while maintaining a pressure in the portion of the formation below a fracture pressure of the formation overburden; reducing the pressure in the portion of the formation to a lower pressure while the portion of the formation is at the selected average temperature; increasing the average temperature of the portion of the formation to a temperature of at most about 350 °C after  
15 reducing the pressure; and producing, after the pressure is reduced to the lower pressure, at least some mobilized, visbroken, or pyrolyzed fluids from the portion of the formation at the lower pressure.

10 [0012] In further embodiments, features from specific embodiments may be combined with features from other embodiments. For example, features from one embodiment may be combined with features from any of the other embodiments.

[0013] In further embodiments, treating a subsurface formation is performed using any of the methods, systems, or heaters described herein.

15 [0014] In further embodiments, additional features may be added to the specific embodiments described herein.

### **BRIEF DESCRIPTION OF THE DRAWINGS**

[0015] Advantages of the present invention may become apparent to those skilled in the art with the benefit of the following detailed description and upon reference to the accompanying drawings in which:

20 [0016] FIG. 1 depicts an illustration of stages of heating a hydrocarbon containing formation.

[0017] FIG. 2 shows a schematic view of an embodiment of a portion of an in situ heat treatment system for treating a hydrocarbon containing formation.

25 [0018] FIG. 3 depicts weight percentage of original bitumen in place (OBIP) (left axis) and volume percentage of OBIP (right axis) versus temperature (°C).

[0019] FIG. 4 depicts bitumen conversion percentage (weight percentage of OBIP) (left axis) and oil, gas, and coke weight percentage (weight percentage of OBIP) (right axis) versus temperature (°C).

30 [0020] FIG. 5 depicts API gravity (°) of produced fluids (left axis), blow down production, and oil left in place along with pressure (psig) (right axis) versus temperature (°C).

[0021] FIG. 6A-D depict gas-to-oil ratios (GOR) in thousand cubic feet per barrel (Mcf/bbl) (y-axis) versus temperature (°C) (x-axis) for different types of gas at a low temperature blow down (about 277 °C) and a high temperature blow down (at about 290 °C).

35 [0022] FIG. 7 depicts coke yield (weight percentage) (y-axis) versus temperature (°C) (x-axis).

- 5 [0023] FIG. 8A-D depict assessed hydrocarbon isomer shifts in fluids produced from the experimental cells as a function of temperature and bitumen conversion.
- [0024] FIG. 9 depicts weight percentage (Wt%) (y-axis) of saturates from SARA analysis of the produced fluids versus temperature (°C) (x-axis).
- 10 [0025] FIG. 10 depicts weight percentage (Wt%) (y-axis) of n-C<sub>7</sub> of the produced fluids versus temperature (°C) (x-axis).
- [0026] While the invention is susceptible to various modifications and alternative forms, specific embodiments thereof are shown by way of example in the drawings and may herein be described in detail. The drawings may not be to scale. It should be understood, however, that the drawings and detailed description thereto are not intended to limit the
- 15 invention to the particular form disclosed. The scope of the claims should not be limited by the preferred embodiments set forth in the examples, but should be given the broadest interpretation consistent with the description as a whole.

#### **DETAILED DESCRIPTION**

- 20 [0027] The following description generally relates to systems and methods for treating hydrocarbons in the formations. Such formations may be treated to yield hydrocarbon products, hydrogen, and other products.
- [0028] “API gravity” refers to API gravity at 15.5 °C (60 °F). API gravity is as determined by ASTM Method D6822 or ASTM Method D1298.
- 25 [0029] “Fluid pressure” is a pressure generated by a fluid in a formation. “Lithostatic pressure” (sometimes referred to as “lithostatic stress”) is a pressure in a formation equal to a weight per unit area of an overlying rock mass. “Hydrostatic pressure” is a pressure in a formation exerted by a column of water.
- 30 [0030] A “formation” includes one or more hydrocarbon containing layers, one or more non-hydrocarbon layers, an overburden, and/or an underburden. “Hydrocarbon layers” refer to layers in the formation that contain hydrocarbons. The hydrocarbon layers may contain non-hydrocarbon material and hydrocarbon material. The “overburden” and/or the “underburden” include one or more different types of impermeable materials. For example, the overburden and/or underburden may include rock, shale, mudstone, or wet/tight carbonate. In some embodiments of in situ heat treatment processes, the
- 35 overburden and/or the underburden may include a hydrocarbon containing layer or hydrocarbon containing layers that are relatively impermeable and are not subjected to temperatures during in situ heat treatment processing that result in significant characteristic

5 changes of the hydrocarbon containing layers of the overburden and/or the underburden. For example, the underburden may contain shale or mudstone, but the underburden is not allowed to heat to pyrolysis temperatures during the in situ heat treatment process. In some cases, the overburden and/or the underburden may be somewhat permeable.

[0031] “Formation fluids” refer to fluids present in a formation and may include  
10 pyrolyzation fluid, synthesis gas, mobilized hydrocarbons, and water (steam). Formation fluids may include hydrocarbon fluids as well as non-hydrocarbon fluids. The term “mobilized fluid” refers to fluids in a hydrocarbon containing formation that are able to flow as a result of thermal treatment of the formation. “Produced fluids” refer to fluids removed from the formation.

15 [0032] A “heat source” is any system for providing heat to at least a portion of a formation substantially by conductive and/or radiative heat transfer. For example, a heat source may include electric heaters such as an insulated conductor, an elongated member, and/or a conductor disposed in a conduit. A heat source may also include systems that generate heat by burning a fuel external to or in a formation. The systems may be surface burners,  
20 downhole gas burners, flameless distributed combustors, and natural distributed combustors. In some embodiments, heat provided to or generated in one or more heat sources may be supplied by other sources of energy. The other sources of energy may directly heat a formation, or the energy may be applied to a transfer medium that directly or indirectly heats the formation. It is to be understood that one or more heat sources that  
25 are applying heat to a formation may use different sources of energy. Thus, for example, for a given formation some heat sources may supply heat from electric resistance heaters, some heat sources may provide heat from combustion, and some heat sources may provide heat from one or more other energy sources (for example, chemical reactions, solar energy, wind energy, biomass, or other sources of renewable energy). A chemical reaction may  
30 include an exothermic reaction (for example, an oxidation reaction). A heat source may also include a heater that provides heat to a zone proximate and/or surrounding a heating location such as a heater well.

[0033] A “heater” is any system or heat source for generating heat in a well or a near wellbore region. Heaters may be, but are not limited to, electric heaters, burners,  
35 combustors that react with material in or produced from a formation, and/or combinations thereof.

- 5   **[0034]** “Heavy hydrocarbons” are viscous hydrocarbon fluids. Heavy hydrocarbons may include highly viscous hydrocarbon fluids such as heavy oil, tar, and/or asphalt. Heavy hydrocarbons may include carbon and hydrogen, as well as smaller concentrations of sulfur, oxygen, and nitrogen. Additional elements may also be present in heavy hydrocarbons in trace amounts. Heavy hydrocarbons may be classified by API gravity.
- 10   Heavy hydrocarbons generally have an API gravity below about 20°. Heavy oil, for example, generally has an API gravity of about 10-20°, whereas tar generally has an API gravity below about 10°. The viscosity of heavy hydrocarbons is generally greater than about 100 centipoise at 15 °C. Heavy hydrocarbons may include aromatics or other complex ring hydrocarbons.
- 15   **[0035]** Heavy hydrocarbons may be found in a relatively permeable formation. The relatively permeable formation may include heavy hydrocarbons entrained in, for example, sand or carbonate. “Relatively permeable” is defined, with respect to formations or portions thereof, as an average permeability of 10 millidarcy or more (for example, 10 or 100 millidarcy). “Relatively low permeability” is defined, with respect to formations or
- 20   portions thereof, as an average permeability of less than about 10 millidarcy. One darcy is equal to about 0.99 square micrometers. An impermeable layer generally has a permeability of less than about 0.1 millidarcy.
- 25   **[0036]** Certain types of formations that include heavy hydrocarbons may also include, but are not limited to, natural mineral waxes, or natural asphaltites. “Natural mineral waxes” typically occur in substantially tubular veins that may be several meters wide, several kilometers long, and hundreds of meters deep. “Natural asphaltites” include solid hydrocarbons of an aromatic composition and typically occur in large veins. In situ recovery of hydrocarbons from formations such as natural mineral waxes and natural asphaltites may include melting to form liquid hydrocarbons and/or solution mining of
- 30   hydrocarbons from the formations.
- 35   **[0037]** “Hydrocarbons” are generally defined as molecules formed primarily by carbon and hydrogen atoms. Hydrocarbons may also include other elements such as, but not limited to, halogens, metallic elements, nitrogen, oxygen, and/or sulfur. Hydrocarbons may be, but are not limited to, kerogen, bitumen, pyrobitumen, oils, natural mineral waxes, and asphaltites. Hydrocarbons may be located in or adjacent to mineral matrices in the earth. Matrices may include, but are not limited to, sedimentary rock, sands, silicilytes, carbonates, diatomites, and other porous media. “Hydrocarbon fluids” are fluids that

5 include hydrocarbons. Hydrocarbon fluids may include, entrain, or be entrained in non-hydrocarbon fluids such as hydrogen, nitrogen, carbon monoxide, carbon dioxide, hydrogen sulfide, water, and ammonia.

[0038] An “in situ conversion process” refers to a process of heating a hydrocarbon containing formation from heat sources to raise the temperature of at least a portion of the  
10 formation above a pyrolysis temperature so that pyrolyzation fluid is produced in the formation.

[0039] An “in situ heat treatment process” refers to a process of heating a hydrocarbon containing formation with heat sources to raise the temperature of at least a portion of the formation above a temperature that results in mobilized fluid, visbreaking, and/or pyrolysis  
15 of hydrocarbon containing material so that mobilized fluids, visbroken fluids, and/or pyrolyzation fluids are produced in the formation.

[0040] “Pyrolysis” is the breaking of chemical bonds due to the application of heat. For example, pyrolysis may include transforming a compound into one or more other substances by heat alone. Heat may be transferred to a section of the formation to cause  
20 pyrolysis.

[0041] “Pyrolyzation fluids” or “pyrolysis products” refers to fluid produced substantially during pyrolysis of hydrocarbons. Fluid produced by pyrolysis reactions may mix with other fluids in a formation. The mixture would be considered pyrolyzation fluid or pyrolyzation product. As used herein, “pyrolysis zone” refers to a volume of a formation  
25 (for example, a relatively permeable formation such as a tar sands formation) that is reacted or reacting to form a pyrolyzation fluid.

[0042] “Superposition of heat” refers to providing heat from two or more heat sources to a selected section of a formation such that the temperature of the formation at least at one location between the heat sources is influenced by the heat sources.

30 [0043] “Tar” is a viscous hydrocarbon that generally has a viscosity greater than about 10,000 centipoise at 15 °C. The specific gravity of tar generally is greater than 1.000. Tar may have an API gravity less than 10°.

[0044] A “tar sands formation” is a formation in which hydrocarbons are predominantly present in the form of heavy hydrocarbons and/or tar entrained in a mineral grain  
35 framework or other host lithology (for example, sand or carbonate). Examples of tar sands formations include formations such as the Athabasca formation, the Grosmont formation,

5 and the Peace River formation, all three in Alberta, Canada; and the Faja formation in the Orinoco belt in Venezuela.

[0045] “Thickness” of a layer refers to the thickness of a cross section of the layer, wherein the cross section is normal to a face of the layer.

[0046] “Upgrade” refers to increasing the quality of hydrocarbons. For example,  
10 upgrading heavy hydrocarbons may result in an increase in the API gravity of the heavy hydrocarbons.

[0047] “Visbreaking” refers to the untangling of molecules in fluid during heat treatment and/or to the breaking of large molecules into smaller molecules during heat treatment, which results in a reduction of the viscosity of the fluid.

15 [0048] “Viscosity” refers to kinematic viscosity at 40 °C unless specified. Viscosity is as determined by ASTM Method D445.

[0049] The term “wellbore” refers to a hole in a formation made by drilling or insertion of a conduit into the formation. A wellbore may have a substantially circular cross section, or another cross-sectional shape. As used herein, the terms “well” and “opening,” when  
20 referring to an opening in the formation may be used interchangeably with the term “wellbore.”

[0050] Hydrocarbons in formations may be treated in various ways to produce many different products. In certain embodiments, hydrocarbons in formations are treated in stages. FIG. 1 depicts an illustration of stages of heating the hydrocarbon containing  
25 formation. FIG. 1 also depicts an example of yield (“Y”) in barrels of oil equivalent per ton (y axis) of formation fluids from the formation versus temperature (“T”) of the heated formation in degrees Celsius (x axis).

[0051] Desorption of methane and vaporization of water occurs during stage 1 heating. Heating of the formation through stage 1 may be performed as quickly as possible. For  
30 example, when the hydrocarbon containing formation is initially heated, hydrocarbons in the formation desorb adsorbed methane. The desorbed methane may be produced from the formation. If the hydrocarbon containing formation is heated further, water in the hydrocarbon containing formation is vaporized. Water may occupy, in some hydrocarbon containing formations, between 10% and 50% of the pore volume in the formation. In  
35 other formations, water occupies larger or smaller portions of the pore volume. Water typically is vaporized in a formation between 160 °C and 285 °C at pressures of 600 kPa absolute to 7000 kPa absolute. In some embodiments, the vaporized water produces

5 wettability changes in the formation and/or increased formation pressure. The wettability changes and/or increased pressure may affect pyrolysis reactions or other reactions in the formation. In certain embodiments, the vaporized water is produced from the formation. In other embodiments, the vaporized water is used for steam extraction and/or distillation in the formation or outside the formation. Removing the water from and increasing the  
10 pore volume in the formation increases the storage space for hydrocarbons in the pore volume.

[0052] In certain embodiments, after stage 1 heating, the formation is heated further, such that a temperature in the formation reaches (at least) an initial pyrolyzation temperature (such as a temperature at the lower end of the temperature range shown as stage 2).

15 Hydrocarbons in the formation may be pyrolyzed throughout stage 2. A pyrolysis temperature range varies depending on the types of hydrocarbons in the formation. The pyrolysis temperature range may include temperatures between 250 °C and 900 °C. The pyrolysis temperature range for producing desired products may extend through only a portion of the total pyrolysis temperature range. In some embodiments, the pyrolysis  
20 temperature range for producing desired products may include temperatures between 250 °C and 400 °C or temperatures between 270 °C and 350 °C. If a temperature of hydrocarbons in the formation is slowly raised through the temperature range from 250 °C to 400 °C, production of pyrolysis products may be substantially complete when the temperature approaches 400 °C. Average temperature of the hydrocarbons may be raised  
25 at a rate of less than 5 °C per day, less than 2 °C per day, less than 1 °C per day, or less than 0.5 °C per day through the pyrolysis temperature range for producing desired products. Heating the hydrocarbon containing formation with a plurality of heat sources may establish thermal gradients around the heat sources that slowly raise the temperature of hydrocarbons in the formation through the pyrolysis temperature range.

30 [0053] The rate of temperature increase through the pyrolysis temperature range for desired products may affect the quality and quantity of the formation fluids produced from the hydrocarbon containing formation. Slowly raising the temperature of the formation through the pyrolysis temperature range for desired products may allow for the production of high quality, high API gravity hydrocarbons from the formation. Slowly raising the  
35 temperature of the formation through the pyrolysis temperature range for desired products may allow for the removal of a large amount of the hydrocarbons present in the formation as hydrocarbon product.

5     **[0054]** In some in situ heat treatment embodiments, a portion of the formation is heated to a desired temperature instead of slowly heating the temperature through a temperature range. In some embodiments, the desired temperature is 300 °C, 325 °C, or 350 °C. Other temperatures may be selected as the desired temperature. Superposition of heat from heat sources allows the desired temperature to be relatively quickly and efficiently established  
10     in the formation. Energy input into the formation from the heat sources may be adjusted to maintain the temperature in the formation substantially at the desired temperature. The heated portion of the formation is maintained substantially at the desired temperature until pyrolysis declines such that production of desired formation fluids from the formation becomes uneconomical. Parts of the formation that are subjected to pyrolysis may include  
15     regions brought into a pyrolysis temperature range by heat transfer from only one heat source.

**[0055]** In certain embodiments, formation fluids including pyrolyzation fluids are produced from the formation. As the temperature of the formation increases, the amount of condensable hydrocarbons in the produced formation fluid may decrease. At high  
20     temperatures, the formation may produce mostly methane and/or hydrogen. If the hydrocarbon containing formation is heated throughout an entire pyrolysis range, the formation may produce only small amounts of hydrogen towards an upper limit of the pyrolysis range. After all of the available hydrogen is depleted, a minimal amount of fluid production from the formation will typically occur.

25     **[0056]** After pyrolysis of hydrocarbons, a large amount of carbon and some hydrogen may still be present in the formation. A significant portion of carbon remaining in the formation can be produced from the formation in the form of synthesis gas. Synthesis gas generation may take place during stage 3 heating depicted in FIG. 1. Stage 3 may include heating a hydrocarbon containing formation to a temperature sufficient to allow synthesis gas  
30     generation. For example, synthesis gas may be produced in a temperature range from about 400 °C to about 1200 °C, about 500 °C to about 1100 °C, or about 550 °C to about 1000 °C. The temperature of the heated portion of the formation when the synthesis gas generating fluid is introduced to the formation determines the composition of synthesis gas produced in the formation. The generated synthesis gas may be removed from the  
35     formation through a production well or production wells.

**[0057]** Total energy content of fluids produced from the hydrocarbon containing formation may stay relatively constant throughout pyrolysis and synthesis gas generation. During

5     pyrolysis at relatively low formation temperatures, a significant portion of the produced fluid may be condensable hydrocarbons that have a high energy content. At higher pyrolysis temperatures, however, less of the formation fluid may include condensable hydrocarbons. More non-condensable formation fluids may be produced from the formation. Energy content per unit volume of the produced fluid may decline slightly  
10     during generation of predominantly non-condensable formation fluids. During synthesis gas generation, energy content per unit volume of produced synthesis gas declines significantly compared to energy content of pyrolyzation fluid. The volume of the produced synthesis gas, however, will in many instances increase substantially, thereby compensating for the decreased energy content.

15     **[0058]** FIG. 2 depicts a schematic view of an embodiment of a portion of the in situ heat treatment system for treating the hydrocarbon containing formation. The in situ heat treatment system may include barrier wells 200. Barrier wells are used to form a barrier around a treatment area. The barrier inhibits fluid flow into and/or out of the treatment area. Barrier wells include, but are not limited to, dewatering wells, vacuum wells, capture  
20     wells, injection wells, grout wells, freeze wells, or combinations thereof. In some embodiments, barrier wells 200 are dewatering wells. Dewatering wells may remove liquid water and/or inhibit liquid water from entering a portion of the formation to be heated, or to the formation being heated. In the embodiment depicted in FIG. 2, the barrier wells 200 are shown extending only along one side of heat sources 202, but the barrier  
25     wells typically encircle all heat sources 202 used, or to be used, to heat a treatment area of the formation.

30     **[0059]** Heat sources 202 are placed in at least a portion of the formation. Heat sources 202 may include heaters such as insulated conductors, conductor-in-conduit heaters, surface burners, flameless distributed combustors, and/or natural distributed combustors. Heat sources 202 may also include other types of heaters. Heat sources 202 provide heat to at least a portion of the formation to heat hydrocarbons in the formation. Energy may be supplied to heat sources 202 through supply lines 204. Supply lines 204 may be structurally different depending on the type of heat source or heat sources used to heat the formation. Supply lines 204 for heat sources may transmit electricity for electric heaters,  
35     may transport fuel for combustors, or may transport heat exchange fluid that is circulated in the formation. In some embodiments, electricity for an in situ heat treatment process may be provided by a nuclear power plant or nuclear power plants. The use of nuclear

5 power may allow for reduction or elimination of carbon dioxide emissions from the in situ heat treatment process.

[0060] Production wells 206 are used to remove formation fluid from the formation. In some embodiments, production well 206 includes a heat source. The heat source in the production well may heat one or more portions of the formation at or near the production well. In some in situ heat treatment process embodiments, the amount of heat supplied to the formation from the production well per meter of the production well is less than the amount of heat applied to the formation from a heat source that heats the formation per meter of the heat source.

[0061] In some embodiments, the heat source in production well 206 allows for vapor phase removal of formation fluids from the formation. Providing heating at or through the production well may: (1) inhibit condensation and/or refluxing of production fluid when such production fluid is moving in the production well proximate the overburden, (2) increase heat input into the formation, (3) increase production rate from the production well as compared to a production well without a heat source, (4) inhibit condensation of high carbon number compounds (C6 and above) in the production well, and/or (5) increase formation permeability at or proximate the production well.

[0062] Subsurface pressure in the formation may correspond to the fluid pressure generated in the formation. As temperatures in the heated portion of the formation increase, the pressure in the heated portion may increase as a result of thermal expansion of fluids, increased fluid generation, and vaporization of water. Controlling rate of fluid removal from the formation may allow for control of pressure in the formation. Pressure in the formation may be determined at a number of different locations, such as near or at production wells, near or at heat sources, or at monitor wells.

[0063] In some hydrocarbon containing formations, production of hydrocarbons from the formation is inhibited until at least some hydrocarbons in the formation have been pyrolyzed. Formation fluid may be produced from the formation when the formation fluid is of a selected quality. In some embodiments, the selected quality includes an API gravity of at least about 20°, 30°, or 40°. Inhibiting production until at least some hydrocarbons are pyrolyzed may increase conversion of heavy hydrocarbons to light hydrocarbons. Inhibiting initial production may minimize the production of heavy hydrocarbons from the formation. Production of substantial amounts of heavy hydrocarbons may require expensive equipment and/or reduce the life of production equipment.

5 [0064] After pyrolysis temperatures are reached and production from the formation is allowed, pressure in the formation may be varied to alter and/or control a composition of formation fluid produced, to control a percentage of condensable fluid as compared to non-condensable fluid in the formation fluid, and/or to control an API gravity of formation fluid being produced. For example, decreasing pressure may result in production of a larger  
10 condensable fluid component. The condensable fluid component may contain a larger percentage of olefins.

[0065] In some in situ heat treatment process embodiments, pressure in the formation may be maintained high enough to promote production of formation fluid with an API gravity of greater than 20°. Maintaining increased pressure in the formation may inhibit formation  
15 subsidence during in situ heat treatment. Maintaining increased pressure may facilitate vapor phase production of fluids from the formation. Vapor phase production may allow for a reduction in size of collection conduits used to transport fluids produced from the formation. Maintaining increased pressure may reduce or eliminate the need to compress formation fluids at the surface to transport the fluids in collection conduits to treatment  
20 facilities.

[0066] Maintaining increased pressure in a heated portion of the formation may surprisingly allow for production of large quantities of hydrocarbons of increased quality and of relatively low molecular weight. Pressure may be maintained so that formation fluid produced has a minimal amount of compounds above a selected carbon number. The  
25 selected carbon number may be at most 25, at most 20, at most 12, or at most 8. Some high carbon number compounds may be entrained in vapor in the formation and may be removed from the formation with the vapor. Maintaining increased pressure in the formation may inhibit entrainment of high carbon number compounds and/or multi-ring hydrocarbon compounds in the vapor. High carbon number compounds and/or multi-ring  
30 hydrocarbon compounds may remain in a liquid phase in the formation for significant time periods. The significant time periods may provide sufficient time for the compounds to pyrolyze to form lower carbon number compounds.

[0067] Formation fluid produced from production wells 206 may be transported through collection piping 208 to treatment facilities 210. Formation fluids may also be produced  
35 from heat sources 202. For example, fluid may be produced from heat sources 202 to control pressure in the formation adjacent to the heat sources. Fluid produced from heat sources 202 may be transported through tubing or piping to collection piping 208 or the

5 produced fluid may be transported through tubing or piping directly to treatment facilities  
210. Treatment facilities 210 may include separation units, reaction units, upgrading units,  
fuel cells, turbines, storage vessels, and/or other systems and units for processing produced  
formation fluids. The treatment facilities may form transportation fuel from at least a  
portion of the hydrocarbons produced from the formation. In some embodiments, the  
10 transportation fuel may be jet fuel, such as JP-8.

[0068] In certain embodiments, in situ heat treatment of the relatively permeable formation  
containing hydrocarbons (for example, the tar sands formation) includes heating the  
formation to visbreaking temperatures. For example, the formation may be heated to  
temperatures between about 100 °C and 260 °C, between about 150 °C and about 250 °C,  
15 between about 200 °C and about 240 °C, between about 205 °C and 230 °C, between about  
210 °C and 225 °C. In one embodiment, the formation is heated to a temperature of about  
220 °C. In one embodiment, the formation is heated to a temperature of about 230 °C. At  
visbreaking temperatures, fluids in the formation have a reduced viscosity (versus their  
initial viscosity at initial formation temperature) that allows fluids to flow in the formation.  
20 The reduced viscosity at visbreaking temperatures may be a permanent reduction in  
viscosity as the hydrocarbons go through a step change in viscosity at visbreaking  
temperatures (versus heating to mobilization temperatures, which may only temporarily  
reduce the viscosity). The visbroken fluids may have API gravities that are relatively low  
(for example, at most about 10°, about 12°, about 15°, or about 19° API gravity), but the  
25 API gravities are higher than the API gravity of non-visbroken fluid from the formation.  
The non-visbroken fluid from the formation may have an API gravity of 7° or less.

[0069] In some embodiments, heaters in the formation are operated at full power output to  
heat the formation to visbreaking temperatures or higher temperatures. Operating at full  
power may rapidly increase the pressure in the formation. In certain embodiments, fluids  
30 are produced from the formation to maintain a pressure in the formation below a selected  
pressure as the temperature of the formation increases. In some embodiments, the selected  
pressure is a fracture pressure of the formation. In certain embodiments, the selected  
pressure is between about 1000 kPa and about 15000 kPa, between about 2000 kPa and  
about 10000 kPa, or between about 2500 kPa and about 5000 kPa. In one embodiment, the  
35 selected pressure is about 10000 kPa. Maintaining the pressure as close to the fracture  
pressure as possible may minimize the number of production wells needed for producing  
fluids from the formation.

5 [0070] In certain embodiments, treating the formation includes maintaining the temperature at or near visbreaking temperatures (as described above) during the entire production phase while maintaining the pressure below the fracture pressure. The heat provided to the formation may be reduced or eliminated to maintain the temperature at or near visbreaking temperatures. Heating to visbreaking temperatures but maintaining the  
10 temperature below pyrolysis temperatures or near pyrolysis temperatures (for example, below about 230 °C) inhibits coke formation and/or higher level reactions. Heating to visbreaking temperatures at higher pressures (for example, pressures near but below the fracture pressure) keeps produced gases in the liquid oil (hydrocarbons) in the formation and increases hydrogen reduction in the formation with higher hydrogen partial pressures.  
15 Heating the formation to only visbreaking temperatures also uses less energy input than heating the formation to pyrolysis temperatures.

[0071] Fluids produced from the formation may include visbroken fluids, mobilized fluids, and/or pyrolyzed fluids. In some embodiments, a produced mixture that includes these fluids is produced from the formation. The produced mixture may have assessable  
20 properties (for example, measurable properties). The produced mixture properties are determined by operating conditions in the formation being treated (for example, temperature and/or pressure in the formation). In certain embodiments, the operating conditions may be selected, varied, and/or maintained to produce desirable properties in hydrocarbons in the produced mixture. For example, the produced mixture may include  
25 hydrocarbons that have properties that allow the mixture to be easily transported (for example, sent through a pipeline without adding diluent or blending the mixture and/or resulting hydrocarbons with another fluid).

[0072] In some embodiments, after the formation reaches visbreaking temperatures, the pressure in the formation is reduced. In certain embodiments, the pressure in the formation  
30 is reduced at temperatures above visbreaking temperatures. Reducing the pressure at higher temperatures allows more of the hydrocarbons in the formation to be converted to higher quality hydrocarbons by visbreaking and/or pyrolysis. Allowing the formation to reach higher temperatures before pressure reduction, however, may increase the amount of carbon dioxide produced and/or the amount of coking in the formation. For example, in  
35 some formations, coking of bitumen (at pressures above 700 kPa) begins at about 280 °C and reaches a maximum rate at about 340 °C. At pressures below about 700 kPa, the coking rate in the formation is minimal. Allowing the formation to reach higher

5 temperatures before pressure reduction may decrease the amount of hydrocarbons produced from the formation.

[0073] In certain embodiments, the temperature in the formation (for example, an average temperature of the formation) when the pressure in the formation is reduced is selected to balance one or more factors. The factors considered may include: the quality of  
10 hydrocarbons produced, the amount of hydrocarbons produced, the amount of carbon dioxide produced, the amount hydrogen sulfide produced, the degree of coking in the formation, and/or the amount of water produced. Experimental assessments using formation samples and/or simulated assessments based on the formation properties may be used to assess results of treating the formation using the in situ heat treatment process.  
15 These results may be used to determine a selected temperature, or temperature range, for when the pressure in the formation is to be reduced. The selected temperature, or temperature range, may also be affected by factors such as, but not limited to, hydrocarbon or oil market conditions and other economic factors. In certain embodiments, the selected temperature is in a range between about 275 °C and about 305 °C, between about 280 °C  
20 and about 300 °C, or between about 285 °C and about 295 °C.

[0074] In certain embodiments, an average temperature in the formation is assessed from an analysis of fluids produced from the formation. For example, the average temperature of the formation may be assessed from an analysis of the fluids that have been produced to maintain the pressure in the formation below the fracture pressure of the formation.

25 [0075] In some embodiments, values of the hydrocarbon isomer shift in fluids (for example, gases) produced from the formation is used to indicate the average temperature in the formation. Experimental analysis and/or simulation may be used to assess one or more hydrocarbon isomer shifts and relate the values of the hydrocarbon isomer shifts to the average temperature in the formation. The assessed relation between the hydrocarbon  
30 isomer shifts and the average temperature may then be used in the field to assess the average temperature in the formation by monitoring one or more of the hydrocarbon isomer shifts in fluids produced from the formation. In some embodiments, the pressure in the formation is reduced when the monitored hydrocarbon isomer shift reaches a selected value. The selected value of the hydrocarbon isomer shift may be chosen based on the  
35 selected temperature, or temperature range, in the formation for reducing the pressure in the formation and the assessed relation between the hydrocarbon isomer shift and the average temperature. Examples of hydrocarbon isomer shifts that may be assessed include,

5 but are not limited to, n-butane- $\delta^{13}\text{C}_4$  percentage versus propane- $\delta^{13}\text{C}_3$  percentage, n-pentane- $\delta^{13}\text{C}_5$  percentage versus propane- $\delta^{13}\text{C}_3$  percentage, n-pentane- $\delta^{13}\text{C}_5$  percentage versus n-butane- $\delta^{13}\text{C}_4$  percentage, and i-pentane- $\delta^{13}\text{C}_5$  percentage versus i-butane- $\delta^{13}\text{C}_4$  percentage. In some embodiments, the hydrocarbon isomer shift in produced fluids is used to indicate the amount of conversion (for example, amount of pyrolysis) that has taken  
10 place in the formation.

[0076] In some embodiments, weight percentages of saturates in fluids produced from the formation is used to indicate the average temperature in the formation. Experimental analysis and/or simulation may be used to assess the weight percentage of saturates as a function of the average temperature in the formation. For example, SARA (Saturates,  
15 Aromatics, Resins, and Asphaltenes) analysis (sometimes referred to as Asphaltene/Wax/Hydrate Deposition analysis) may be used to assess the weight percentage of saturates in a sample of fluids from the formation. In some formations, the weight percentage of saturates has a linear relationship to the average temperature in the formation. The relation between the weight percentage of saturates and the average  
20 temperature may then be used in the field to assess the average temperature in the formation by monitoring the weight percentage of saturates in fluids produced from the formation. In some embodiments, the pressure in the formation is reduced when the monitored weight percentage of saturates reaches a selected value. The selected value of the weight percentage of saturates may be chosen based on the selected temperature, or  
25 temperature range, in the formation for reducing the pressure in the formation and the relation between the weight percentage of saturates and the average temperature. In some embodiments, the selected value of weight percentage of saturates is between about 20% and about 40%, between about 25% and about 35%, or between about 28% and about 32%. For example, the selected value may be about 30% by weight saturates.

30 [0077] In some embodiments, weight percentages of n-C<sub>7</sub> in fluids produced from the formation is used to indicate the average temperature in the formation. Experimental analysis and/or simulation may be used to assess the weight percentages of n-C<sub>7</sub> as a function of the average temperature in the formation. In some formations, the weight percentages of n-C<sub>7</sub> has a linear relationship to the average temperature in the formation.  
35 The relation between the weight percentages of n-C<sub>7</sub> and the average temperature may then be used in the field to assess the average temperature in the formation by monitoring the weight percentages of n-C<sub>7</sub> in fluids produced from the formation. In some embodiments,

5 the pressure in the formation is reduced when the monitored weight percentage of n-C<sub>7</sub> reaches a selected value. The selected value of the weight percentage of n-C<sub>7</sub> may be chosen based on the selected temperature, or temperature range, in the formation for reducing the pressure in the formation and the relation between the weight percentage of n-C<sub>7</sub> and the average temperature. In some embodiments, the selected value of weight  
10 percentage of n-C<sub>7</sub> is between about 50% and about 70%, between about 55% and about 65%, or between about 58% and about 62%. For example, the selected value may be about 60% by weight n-C<sub>7</sub>.

[0078] The pressure in the formation may be reduced by producing fluids (for example, visbroken fluids and/or mobilized fluids) from the formation. In some embodiments, the  
15 pressure is reduced below a pressure at which fluids coke in the formation to inhibit coking at pyrolysis temperatures. For example, the pressure is reduced to a pressure below about 1000 kPa, below about 800 kPa, or below about 700 kPa (for example, about 690 kPa). In certain embodiments, the selected pressure is at least about 100 kPa, at least about 200 kPa, or at least about 300 kPa. The pressure may be reduced to inhibit coking of asphaltenes or  
20 other high molecular weight hydrocarbons in the formation. In some embodiments, the pressure may be maintained below a pressure at which water passes through a liquid phase at downhole (formation) temperatures to inhibit liquid water and dolomite reactions. After reducing the pressure in the formation, the temperature may be increased to pyrolysis temperatures to begin pyrolyzation and/or upgrading of fluids in the formation. The  
25 pyrolyzed and/or upgraded fluids may be produced from the formation.

[0079] In certain embodiments, the amount of fluids produced at temperatures below visbreaking temperatures, the amount of fluids produced at visbreaking temperatures, the amount of fluids produced before reducing the pressure in the formation, and/or the amount of upgraded or pyrolyzed fluids produced may be varied to control the quality and amount  
30 of fluids produced from the formation and the total recovery of hydrocarbons from the formation. For example, producing more fluid during the early stages of treatment (for example, producing fluids before reducing the pressure in the formation) may increase the total recovery of hydrocarbons from the formation while reducing the overall quality (lowering the overall API gravity) of fluid produced from the formation. The overall  
35 quality is reduced because more heavy hydrocarbons are produced by producing more fluids at the lower temperatures. Producing less fluids at the lower temperatures may increase the overall quality of the fluids produced from the formation but may lower the

5 total recovery of hydrocarbons from the formation. The total recovery may be lower because more coking occurs in the formation when less fluids are produced at lower temperatures.

[0080] In some embodiments, production of fluids is continued after reducing and/or turning off heating of the formation. The formation may be heated for a selected time.

10 The formation may be heated until it reaches a selected average temperature. Production from the formation may continue after the selected time. Continuing production may produce more fluid from the formation as fluids drain towards the bottom of the formation and/or as fluids are upgraded by passing by hot spots in the formation. In some embodiments, a horizontal production well is located at or near the bottom of the formation  
15 (or a zone of the formation) to produce fluids after heating is turned down and/or off.

[0081] In certain embodiments, initially produced fluids (for example, fluids produced below visbreaking temperatures), fluids produced at visbreaking temperatures, and/or other viscous fluids produced from the formation are blended with diluent to produce fluids with lower viscosities. In some embodiments, the diluent includes upgraded or pyrolyzed fluids  
20 produced from the formation. In some embodiments, the diluent includes upgraded or pyrolyzed fluids produced from another portion of the formation or another formation. In certain embodiments, the amount of fluids produced at temperatures below visbreaking temperatures and/or fluids produced at visbreaking temperatures that are blended with upgraded fluids from the formation is adjusted to create a fluid suitable for transportation  
25 and/or use in a refinery. The amount of blending may be adjusted so that the fluid has chemical and physical stability. Maintaining the chemical and physical stability of the fluid may allow the fluid to be transported, reduce pre-treatment processes at a refinery and/or reduce or eliminate the need for adjusting the refinery process to compensate for the fluid.

30 [0082] In certain embodiments, formation conditions (for example, pressure and temperature) and/or fluid production are controlled to produce fluids with selected properties. For example, formation conditions and/or fluid production may be controlled to produce fluids with a selected API gravity and/or a selected viscosity. The selected API gravity and/or selected viscosity may be produced by combining fluids produced at  
35 different formation conditions (for example, combining fluids produced at different temperatures during the treatment as described above). As an example, formation

5 conditions and/or fluid production may be controlled to produce fluids with an API gravity of about 19° and a viscosity of about 0.35 Pa·s (350 cp) at 5 °C.

[0083] In certain embodiments, a drive process (for example, a steam injection process such as cyclic steam injection, a steam assisted gravity drainage process (SAGD), a solvent injection process, a vapor solvent and SAGD process, or a carbon dioxide injection  
10 process) is used to treat the tar sands formation in addition to the in situ heat treatment process. In some embodiments, heaters are used to create high permeability zones (or injection zones) in the formation for the drive process. Heaters may be used to create a mobilization geometry or production network in the formation to allow fluids to flow through the formation during the drive process. For example, heaters may be used to  
15 create drainage paths between the heaters and production wells for the drive process. In some embodiments, the heaters are used to provide heat during the drive process. The amount of heat provided by the heaters may be small compared to the heat input from the drive process (for example, the heat input from steam injection).

20 [0084] Non-restrictive examples are set forth below.

#### *Tar Sands Example*

[0085] A STARS simulation was used in combination with experimental analysis to simulate an in situ heat treatment process of a tar sands formation. Heating conditions for the experimental analysis were determined from reservoir simulations. The experimental  
25 analysis included heating a cell of tar sands from the formation to a selected temperature and then reducing the pressure of the cell (blow down) to 100 psig. The process was repeated for several different selected temperatures. While heating the cells, formation and fluid properties of the cells were monitored while producing fluids to maintain the pressure below an optimum pressure of 12 MPa before blow down and while producing fluids after  
30 blow down (although the pressure may have reached higher pressures in some cases, the pressure was quickly adjusted and does not affect the results of the experiments). FIGS. 3-10 depict results from the simulation and experiments.

[0086] FIG. 3 depicts weight percentage of original bitumen in place (OBIP)(left axis) and volume percentage of OBIP (right axis) versus temperature (°C). The term “OBIP” refers,  
35 in these experiments, to the amount of bitumen that was in the laboratory vessel with 100% being the original amount of bitumen in the laboratory vessel. Plot 212 depicts bitumen

5 conversion (correlated to weight percentage of OBIP). Plot 212 shows that bitumen conversion began to be significant at about 270 °C and ended at about 340 °C. The bitumen conversion was relatively linear over the temperature range.

[0087] Plot 214 depicts barrels of oil equivalent from producing fluids and production at blow down (correlated to volume percentage of OBIP). Plot 216 depicts barrels of oil

10 equivalent from producing fluids (correlated to volume percentage of OBIP). Plot 218 depicts oil production from producing fluids (correlated to volume percentage of OBIP). Plot 220 depicts barrels of oil equivalent from production at blow down (correlated to volume percentage of OBIP). Plot 222 depicts oil production at blow down (correlated to volume percentage of OBIP). As shown in FIG. 3, the production volume began to

15 significantly increase as bitumen conversion began at about 270 °C with a significant portion of the oil and barrels of oil equivalent (the production volume) coming from producing fluids and only some volume coming from the blow down.

[0088] FIG. 4 depicts bitumen conversion percentage (weight percentage of (OBIP))(left axis) and oil, gas, and coke weight percentage (as a weight percentage of OBIP)(right axis)

20 versus temperature (°C). Plot 224 depicts bitumen conversion (correlated to weight percentage of OBIP). Plot 226 depicts oil production from producing fluids correlated to weight percentage of OBIP (right axis). Plot 228 depicts coke production correlated to weight percentage of OBIP (right axis). Plot 230 depicts gas production from producing fluids correlated to weight percentage of OBIP (right axis). Plot 232 depicts oil production

25 from blow down production correlated to weight percentage of OBIP (right axis). Plot 234 depicts gas production from blow down production correlated to weight percentage of OBIP (right axis). FIG. 4 shows that coke production begins to increase at about 280 °C and maximizes around 340 °C. FIG. 4 also shows that the majority of oil and gas production is from produced fluids with only a small fraction from blow down production.

30 [0089] FIG. 5 depicts API gravity (°)(left axis) of produced fluids, blow down production, and oil left in place along with pressure (psig)(right axis) versus temperature (°C). Plot 236 depicts API gravity of produced fluids versus temperature. Plot 238 depicts API gravity of fluids produced at blow down versus temperature. Plot 240 depicts pressure versus temperature. Plot 242 depicts API gravity of oil (bitumen) in the formation versus

35 temperature. FIG. 5 shows that the API gravity of the oil in the formation remains relatively constant at about 10° API and that the API gravity of produced fluids and fluids produced at blow down increases slightly at blow down.

5 [0090] FIGS. 6A-D depict gas-to-oil ratios (GOR) in thousand cubic feet per barrel (Mcf/bbl)(y-axis) versus temperature ( $^{\circ}\text{C}$ )(x-axis) for different types of gas at a low temperature blow down (about  $277^{\circ}\text{C}$ ) and a high temperature blow down (at about  $290^{\circ}\text{C}$ ). FIG. 6A depicts the GOR versus temperature for carbon dioxide ( $\text{CO}_2$ ). Plot 244 depicts the GOR for the low temperature blow down. Plot 246 depicts the GOR for the high temperature

10 blow down. FIG. 6B depicts the GOR versus temperature for hydrocarbons. FIG. 6C depicts the GOR for hydrogen sulfide ( $\text{H}_2\text{S}$ ). FIG. 6D depicts the GOR for hydrogen ( $\text{H}_2$ ). In FIGS. 6B-D, the GORs were approximately the same for both the low temperature and high temperature blow downs. The GORs for  $\text{CO}_2$  (shown in FIG. 6) was different for the high temperature blow down and the low temperature blow down. The reason for the

15 difference in the GORs for  $\text{CO}_2$  may be that  $\text{CO}_2$  was produced early (at low temperatures) by the hydrous decomposition of dolomite and other carbonate minerals and clays. At these low temperatures, there was hardly any produced oil so the GOR is very high because the denominator in the ratio is practically zero. The other gases (hydrocarbons,  $\text{H}_2\text{S}$ , and  $\text{H}_2$ ) were produced concurrently with the oil either because they were all generated by the

20 upgrading of bitumen (for example, (hydrocarbons,  $\text{H}_2$ , and oil)) or because they were generated by the decomposition of minerals (such as pyrite) in the same temperature range as that of bitumen upgrading. Thus, when the GOR was calculated, the denominator (oil) was non zero for hydrocarbons,  $\text{H}_2\text{S}$ , and  $\text{H}_2$ .

[0091] FIG. 7 depicts coke yield (weight percentage)(y-axis) versus temperature ( $^{\circ}\text{C}$ )(x-axis). Plot 248 depicts bitumen and kerogen coke as a weight percent of original mass in the formation. Plot 250 depicts bitumen coke as a weight percent of original bitumen in place (OBIP) in the formation. FIG. 7 shows that kerogen coke is already present at a temperature of about  $260^{\circ}\text{C}$  (the lowest temperature cell experiment) while bitumen coke begins to form at about  $280^{\circ}\text{C}$  and maximizes at about  $340^{\circ}\text{C}$ .

30 [0092] FIGS. 8A-D depict assessed hydrocarbon isomer shifts in fluids produced from the experimental cells as a function of temperature and bitumen conversion. Bitumen conversion and temperature increase from left to right in the plots in FIGS. 8A-D with the minimum bitumen conversion being 10%, the maximum bitumen conversion being 100%, the minimum temperature being  $277^{\circ}\text{C}$ , and the maximum temperature being  $350^{\circ}\text{C}$ . The

35 arrows in FIGS. 8A-D show the direction of increasing bitumen conversion and temperature.

- 5 [0093] FIG. 8A depicts the hydrocarbon isomer shift of n-butane- $\delta^{13}\text{C}_4$  percentage (y-axis) versus propane-  $\delta^{13}\text{C}_3$  percentage (x-axis). FIG. 8B depicts the hydrocarbon isomer shift of n-pentane-  $\delta^{13}\text{C}_5$  percentage (y-axis) versus propane-  $\delta^{13}\text{C}_3$  percentage (x-axis). FIG. 8C depicts the hydrocarbon isomer shift of n-pentane-  $\delta^{13}\text{C}_5$  percentage (y-axis) versus n-butane-  $\delta^{13}\text{C}_4$  percentage (x-axis). FIG. 8D depicts the hydrocarbon isomer shift of i-pentane-  $\delta^{13}\text{C}_5$  percentage (y-axis) versus i-butane-  $\delta^{13}\text{C}_4$  percentage (x-axis). FIGS. 8A-D show that there is a relatively linear relationship between the hydrocarbon isomer shifts and both temperature and bitumen conversion. The relatively linear relationship may be used to assess formation temperature and/or bitumen conversion by monitoring the hydrocarbon isomer shifts in fluids produced from the formation.
- 10 [0094] FIG. 9 depicts weight percentage (Wt%)(y-axis) of saturates from SARA analysis of the produced fluids versus temperature ( $^{\circ}\text{C}$ )(x-axis). The logarithmic relationship between the weight percentage of saturates and temperature may be used to assess formation temperature by monitoring the weight percentage of saturates in fluids produced from the formation.
- 15 [0095] FIG. 10 depicts weight percentage (Wt%)(y-axis) of n-C<sub>7</sub> of the produced fluids versus temperature ( $^{\circ}\text{C}$ )(x-axis). The linear relationship between the weight percentage of n-C<sub>7</sub> and temperature may be used to assess formation temperature by monitoring the weight percentage of n-C<sub>7</sub> in fluids produced from the formation.
- 20 [0096] Further modifications and alternative embodiments of various aspects of the invention may be apparent to those skilled in the art in view of this description. Accordingly, this description is to be construed as illustrative only and is for the purpose of teaching those skilled in the art the general manner of carrying out the invention. It is to be understood that the forms of the invention shown and described herein are to be taken as the presently preferred embodiments. Elements and materials may be substituted for those illustrated and described herein, parts and processes may be reversed, and certain features of the invention may be utilized independently, all as would be apparent to one skilled in the art after having the benefit of this description of the invention. Changes may be made in the elements described herein.
- 25
- 30
- 35 In addition, it is to be understood that features described herein independently may, in certain embodiments, be combined.

## CLAIMS:

1. A method for treating a tar sands formation, comprising:
  - providing heat to at least part of a hydrocarbon layer in the tar sands formation from a plurality of heaters located in the formation;
  - allowing the heat to transfer from the heaters to at least a portion of the formation;
  - allowing an average temperature of the portion of the formation to increase to a selected average temperature between about 280 °C and about 300 °C while maintaining a pressure in the portion of the formation below a fracture pressure of the formation overburden;
  - reducing the pressure in the portion of the formation to a lower pressure while the portion of the formation is at the selected average temperature;
  - increasing the average temperature of the portion of the formation to a temperature of at most about 350 °C after reducing the pressure; and
  - producing, after the pressure is reduced to the lower pressure, at least some mobilized, visbroken, or pyrolyzed fluids from the portion of the formation at the lower pressure.
2. The method of claim 1, wherein the fracture pressure is between 1000 kPa and 15000 kPa.
3. The method of claim 1 or 2, wherein the lower pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is at most 300 °C.
4. The method of any one of claims 1 to 3, wherein the lower pressure is between 100 kPa and 1000 kPa or between 200 kPa and 800 kPa.
5. The method of any one of claims 1 to 4, further comprising producing fluids from the formation.
6. The method of any one of claims 1 to 5, further comprising producing fluids from the formation to control the pressure to remain below the fracture pressure.

7. The method of any one of claims 1 to 6, wherein the selected average temperature is between about 285 °C and about 295 °C.
8. The method of any one of claims 1 to 7, further comprising providing a drive fluid to the formation.
9. The method of any one of claims 1 to 8, further comprising providing steam to the formation.
10. The method of any one of claims 1 to 9, further comprising:
  - producing fluids from the formation;
  - reducing heat output from two or more of the heaters after a selected time; and
  - continuing producing fluids from the formation after reducing the heat output from the two or more heaters.
11. The method of any one of claims 1 to 10, further comprising assessing the average temperature in the portion by analyzing at least some of the produced fluids.
12. The method of any one of claims 1 to 11, further comprising analyzing gases in the produced fluids to assess the average temperature in the portion.
13. The method of any one of claims 1 to 12, further comprising assessing the average temperature in the portion based on, at least in part, a hydrocarbon isomer shift in the produced fluids, a weight percentage of saturates in the produced fluids, and/or a weight percentage of n-C<sub>7</sub> in the produced fluids.
14. The method of any one of claims 1 to 13, further comprising:
  - assessing a hydrocarbon isomer shift of at least a portion of the fluid produced from the formation; and
  - reducing the pressure in the formation to a lower pressure when the assessed hydrocarbon isomer shift reaches a selected value.

15. The method of claim 13 or 14, wherein the hydrocarbon isomer shift comprises n-butane- $\delta^{13}\text{C}_4$  percentage versus propane-  $\delta^{13}\text{C}_3$  percentage, n-pentane-  $\delta^{13}\text{C}_5$  percentage versus propane-  $\delta^{13}\text{C}_3$  percentage, n-pentane-  $\delta^{13}\text{C}_5$  percentage (y-axis) versus n-butane-  $\delta^{13}\text{C}_4$  percentage, or i-pentane-  $\delta^{13}\text{C}_5$  percentage (y-axis) versus i-butane-  $\delta^{13}\text{C}_4$  percentage.

16. The method of any one of claims 1 to 15, further comprising:

assessing a weight percentage of saturates in at least a portion of the fluid produced from the formation; and

reducing the pressure in the formation to a lower pressure when the assessed weight percentage of saturates reaches a selected value.

17. The method of claim 16, wherein the selected value of the weight percentage of saturates is between 25% and 35%.

18. The method of claim 17, wherein the selected value is 30%.

19. The method of any one of claims 1 to 17, further comprising:

assessing a weight percentage of n-C<sub>7</sub> in at least a portion of the fluid produced from the formation; and

reducing the pressure in the formation to a lower pressure when the assessed n-C<sub>7</sub> reaches a selected value.

20. The method of claim 18, wherein the selected value of the weight percentage of n-C<sub>7</sub> is between 50% and 70%.

21. The method of claim 20, wherein the selected value is 60%.

22. The method of any one of claims 1 to 19, wherein the lower pressure is a pressure below which substantial hydrocarbon coking in the formation occurs when the average temperature in the formation is less than 300 °C.

1 / 7

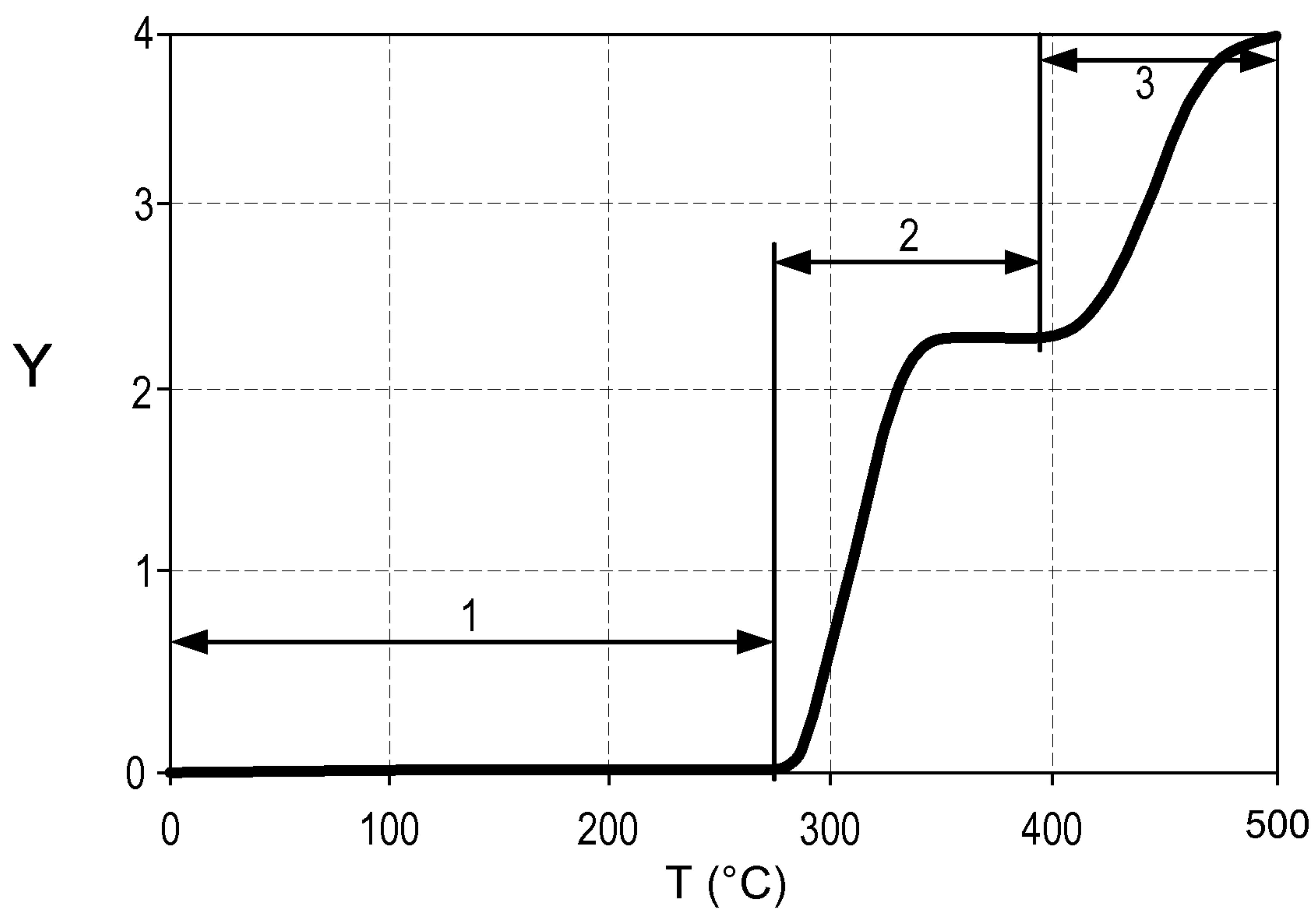


FIG. 1

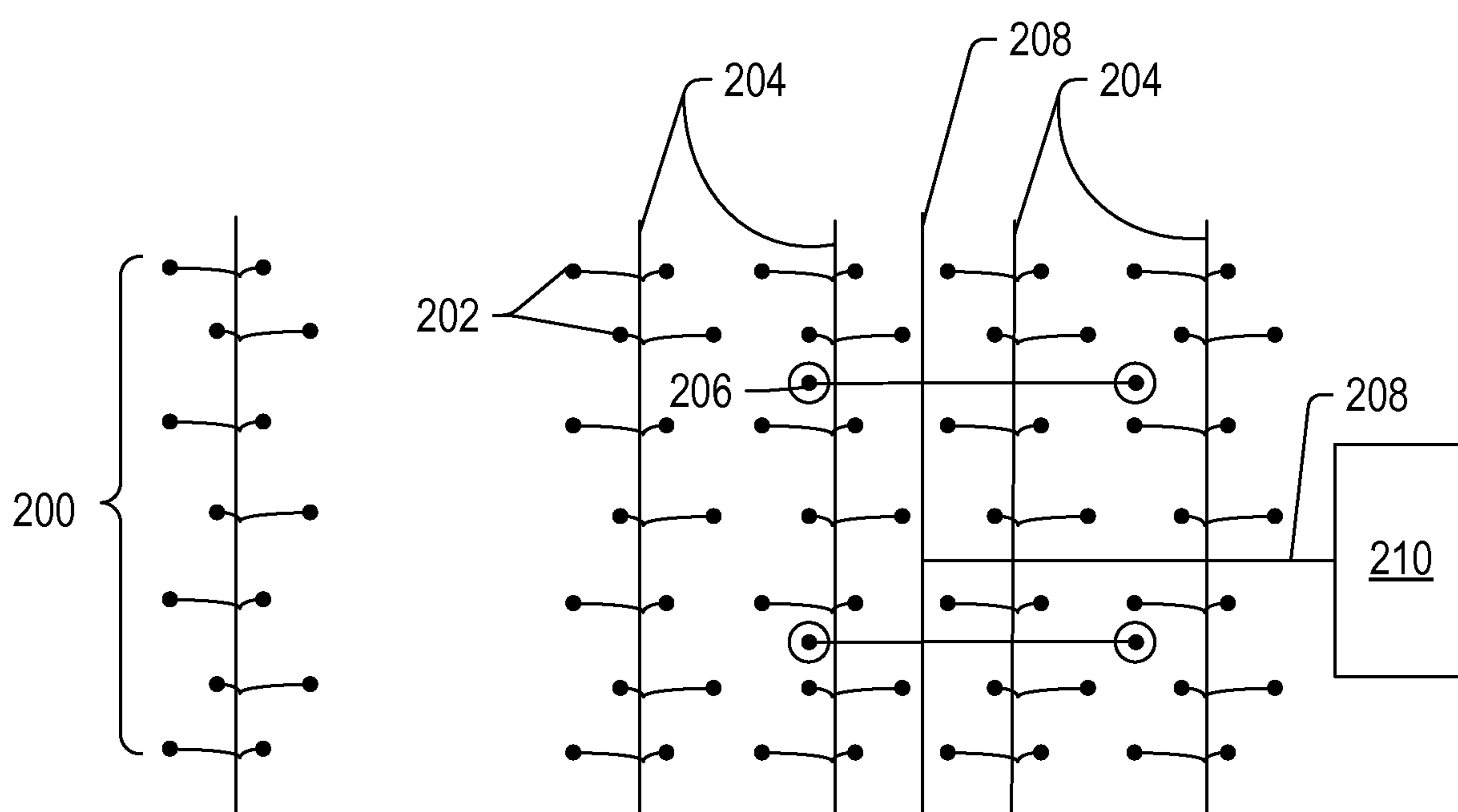


FIG. 2

2/7

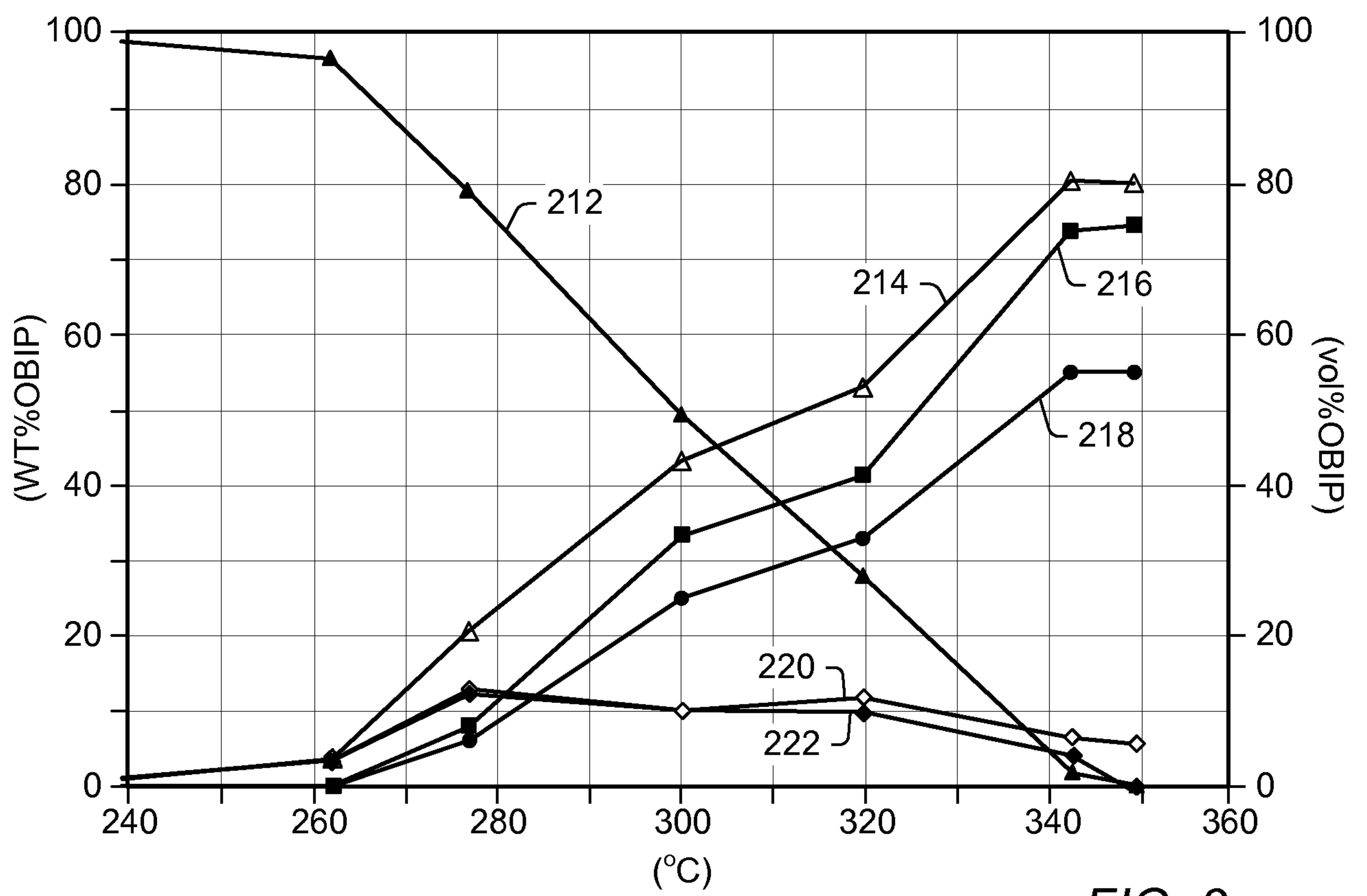


FIG. 3

3/7

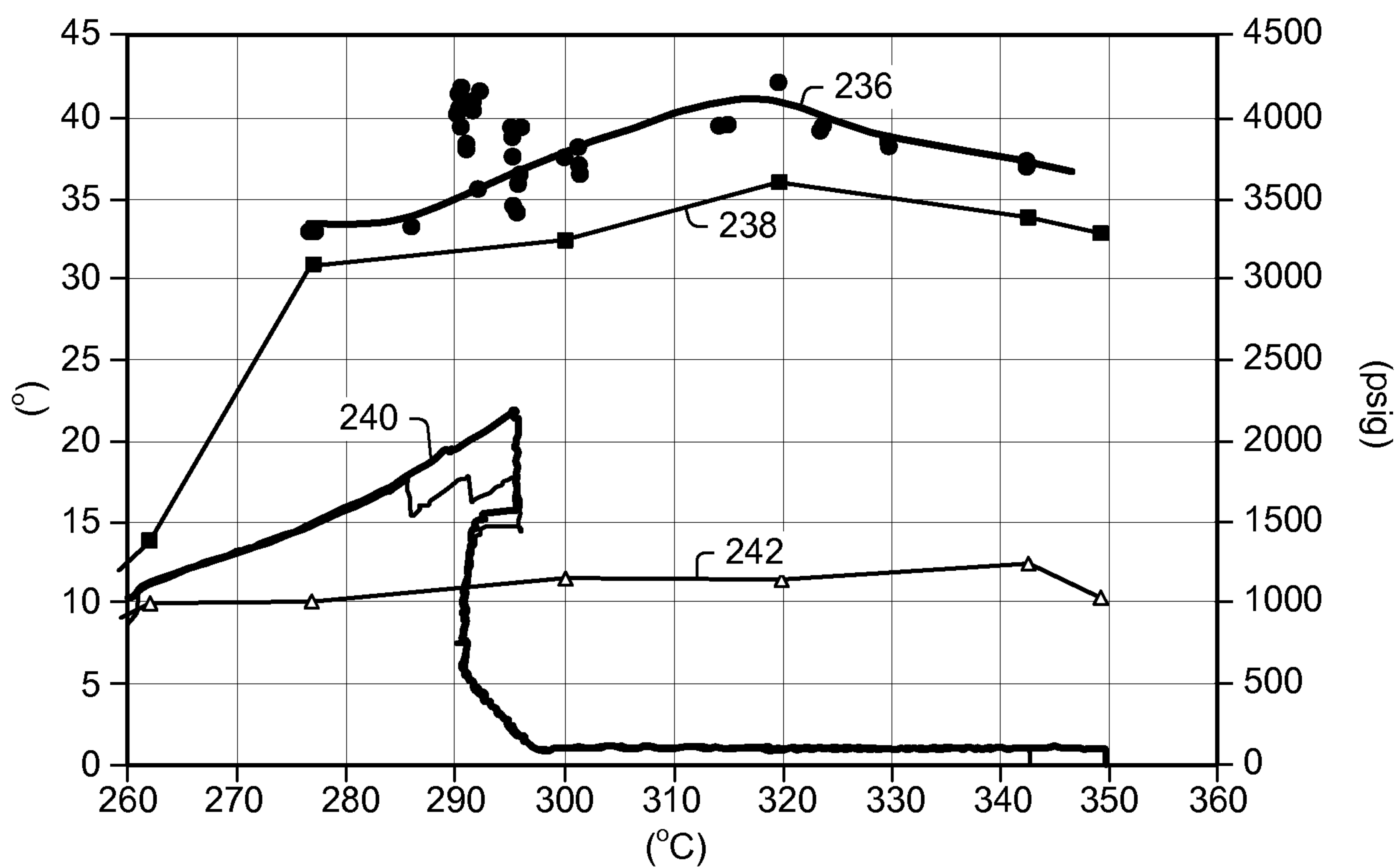
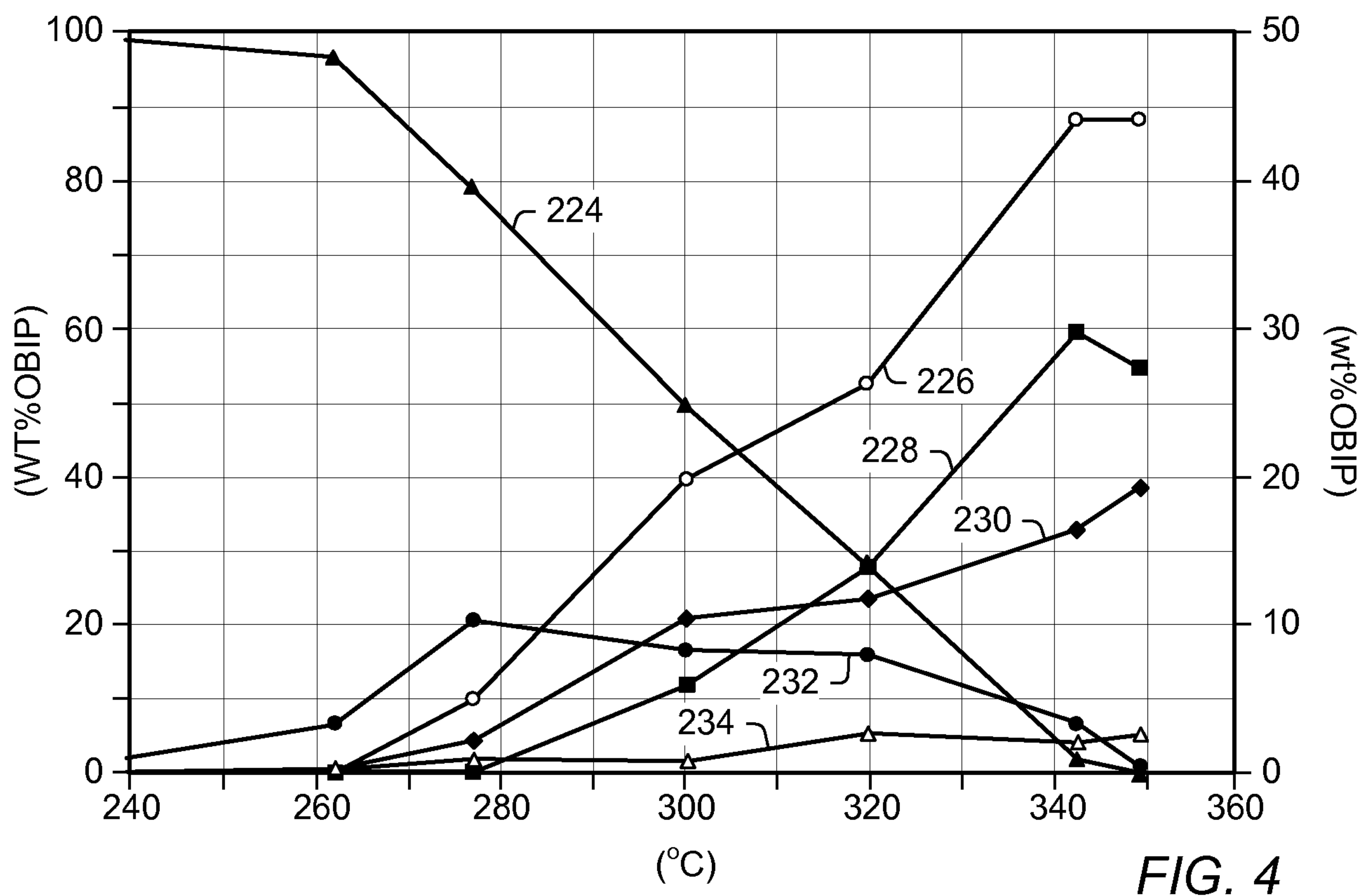


FIG. 5

FIG. 6B

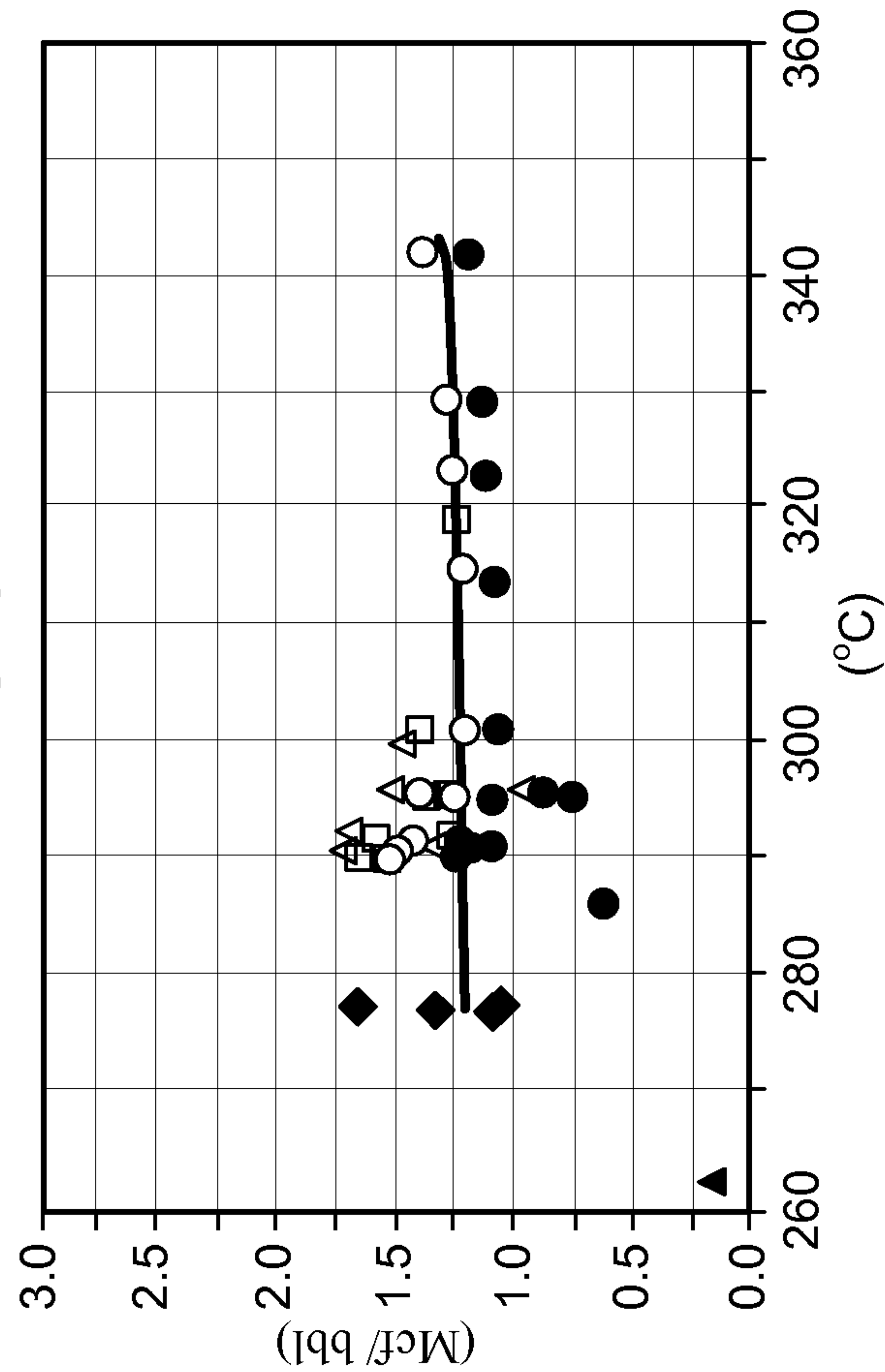


FIG. 6A

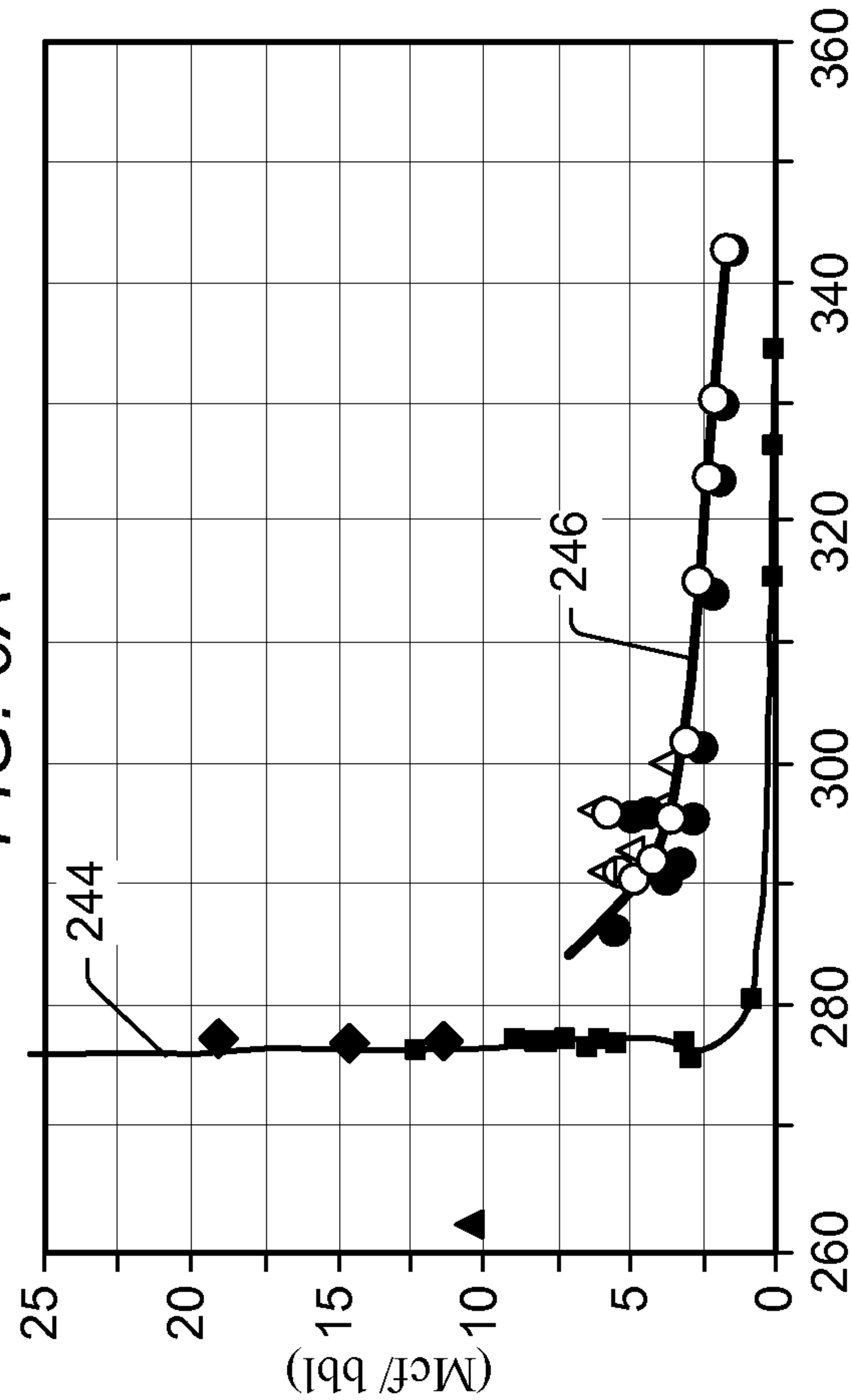


FIG. 6D

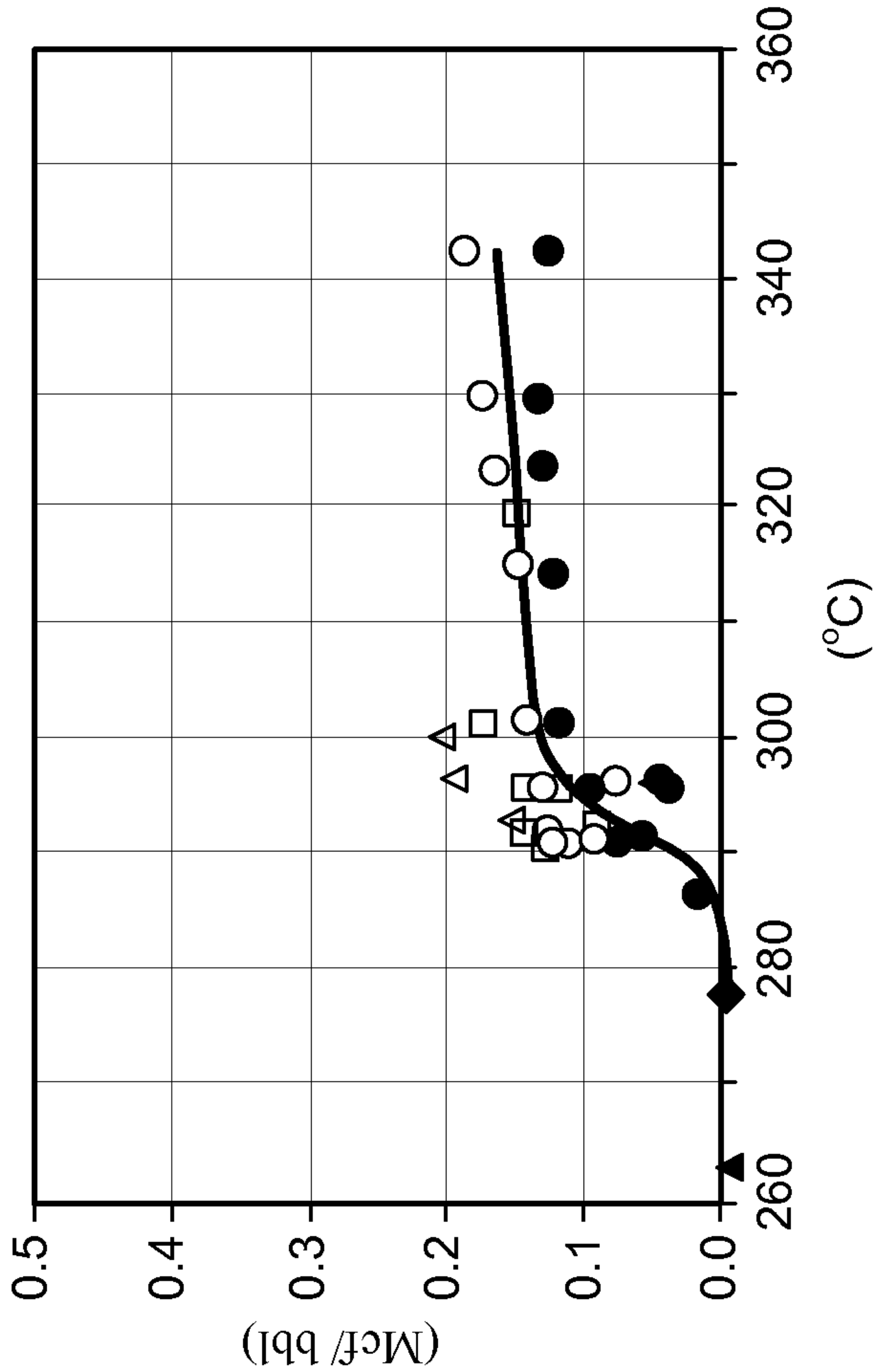
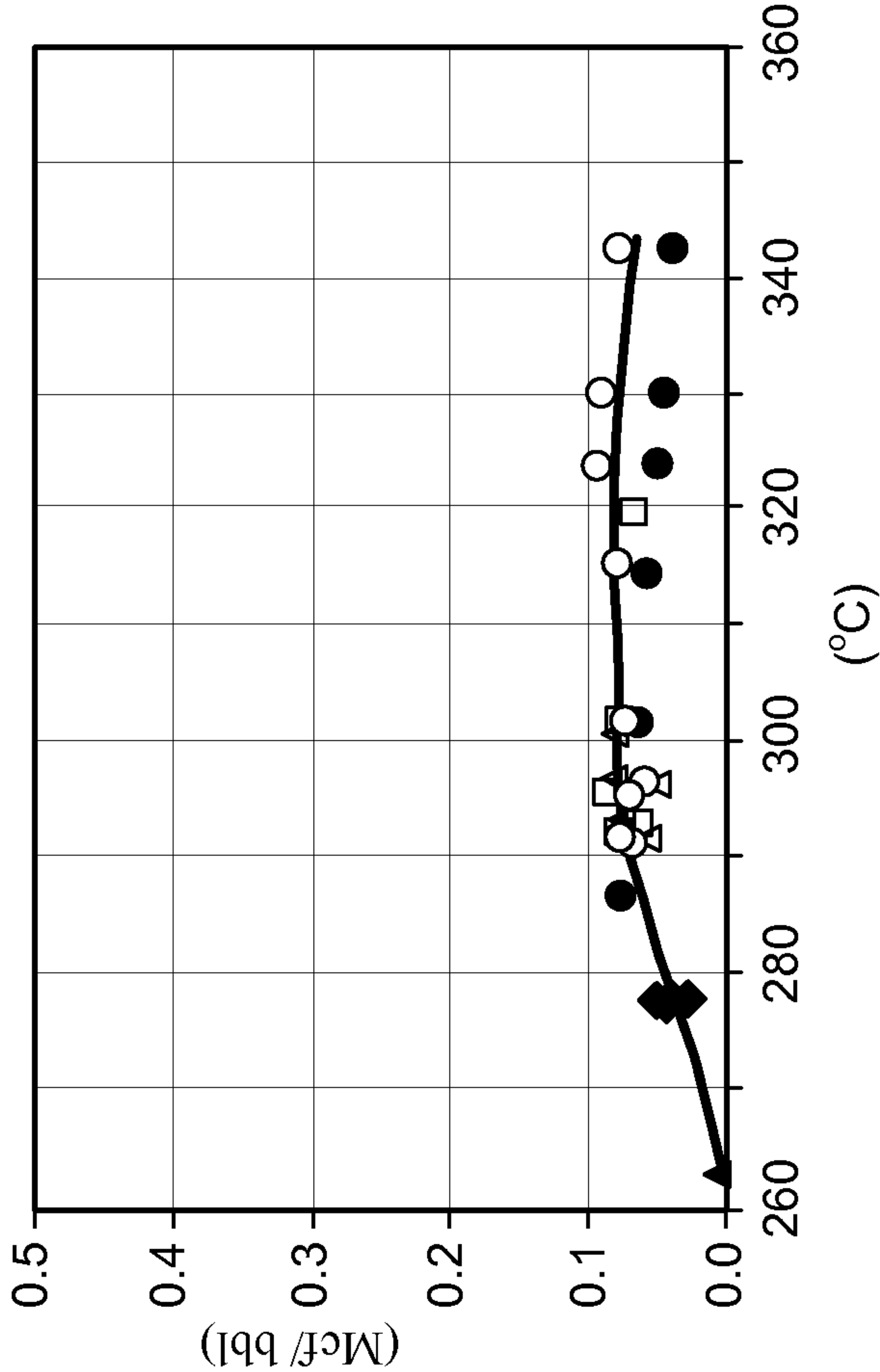


FIG. 6C



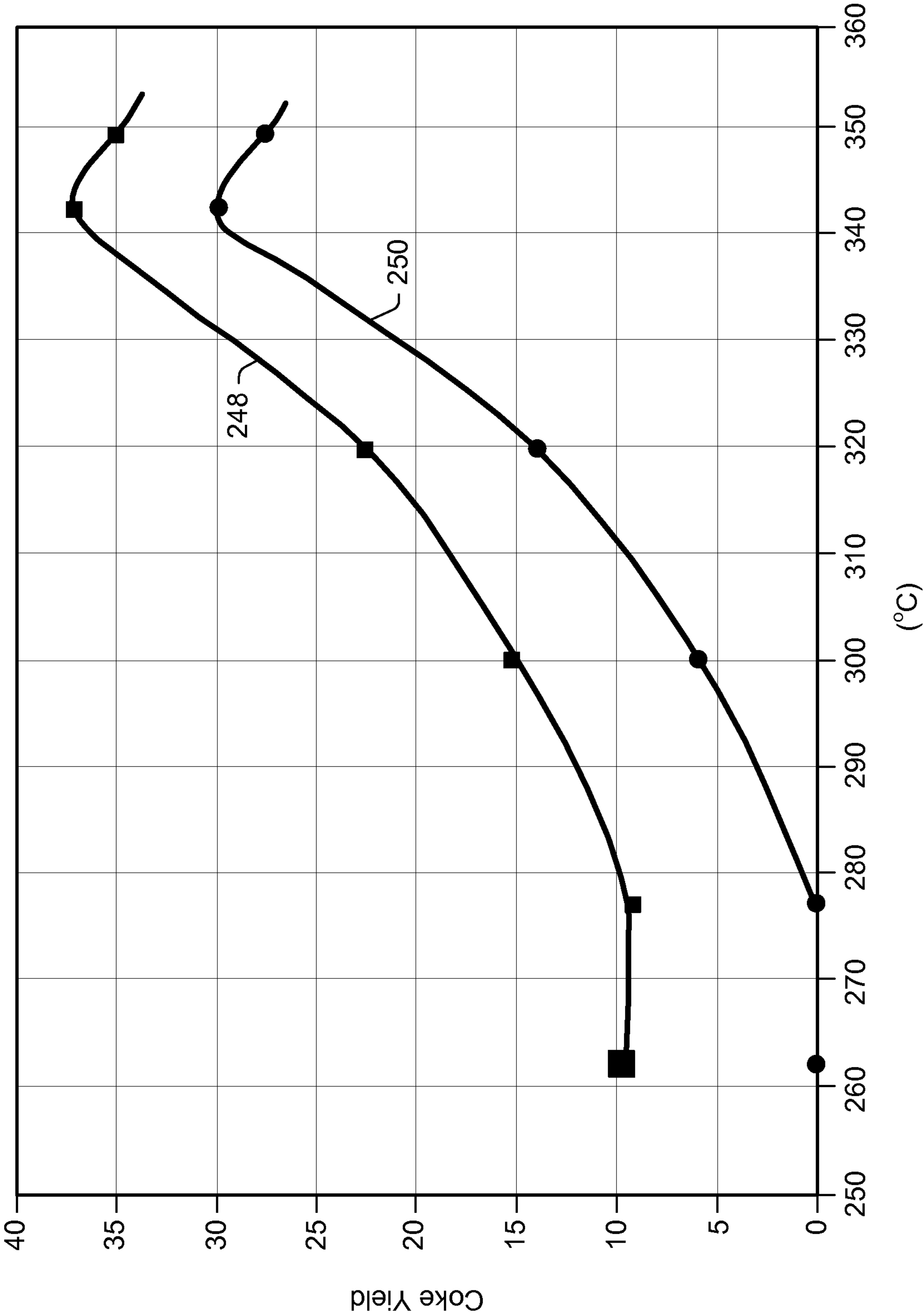


FIG. 7

FIG. 8A

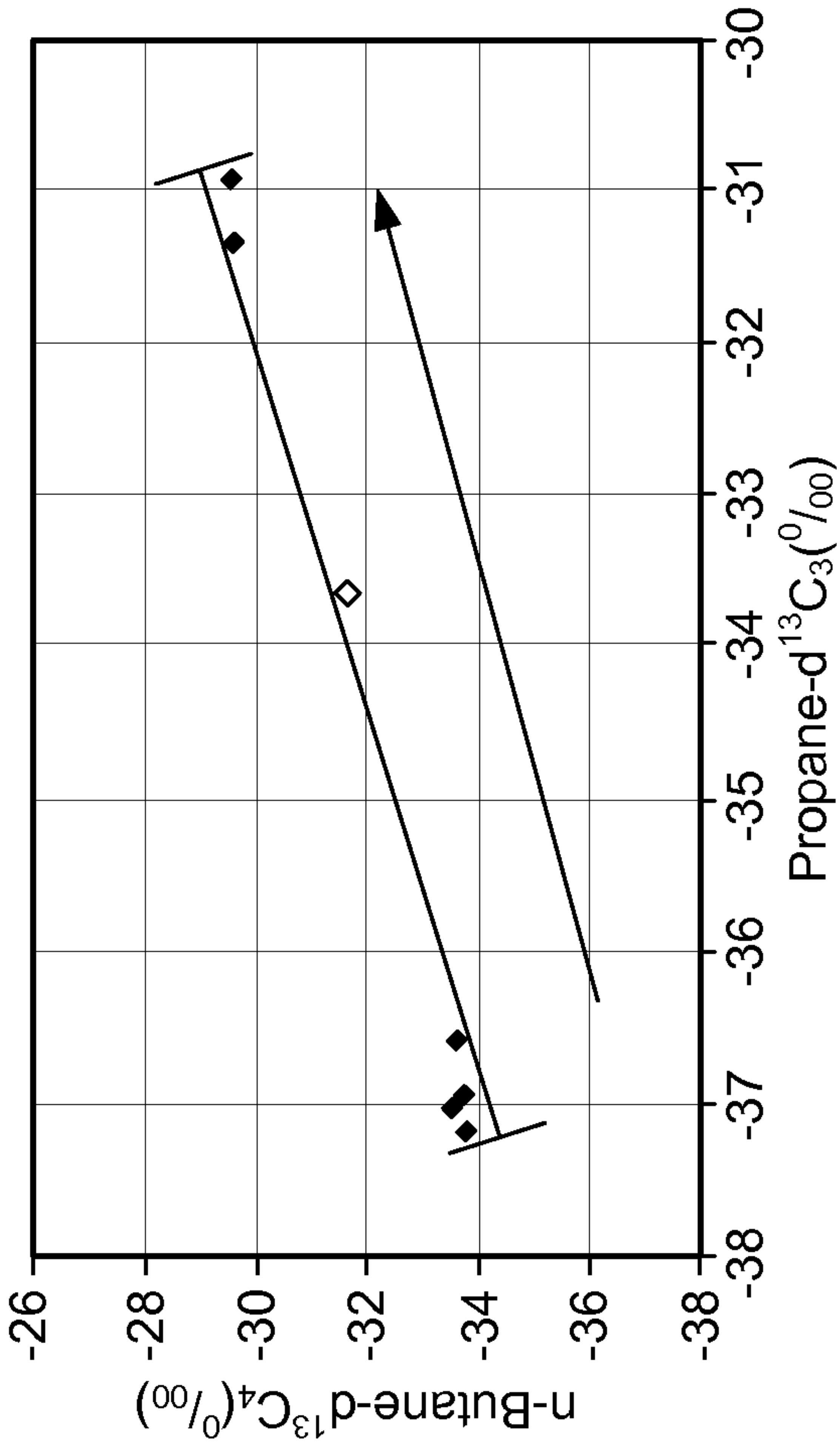


FIG. 8B

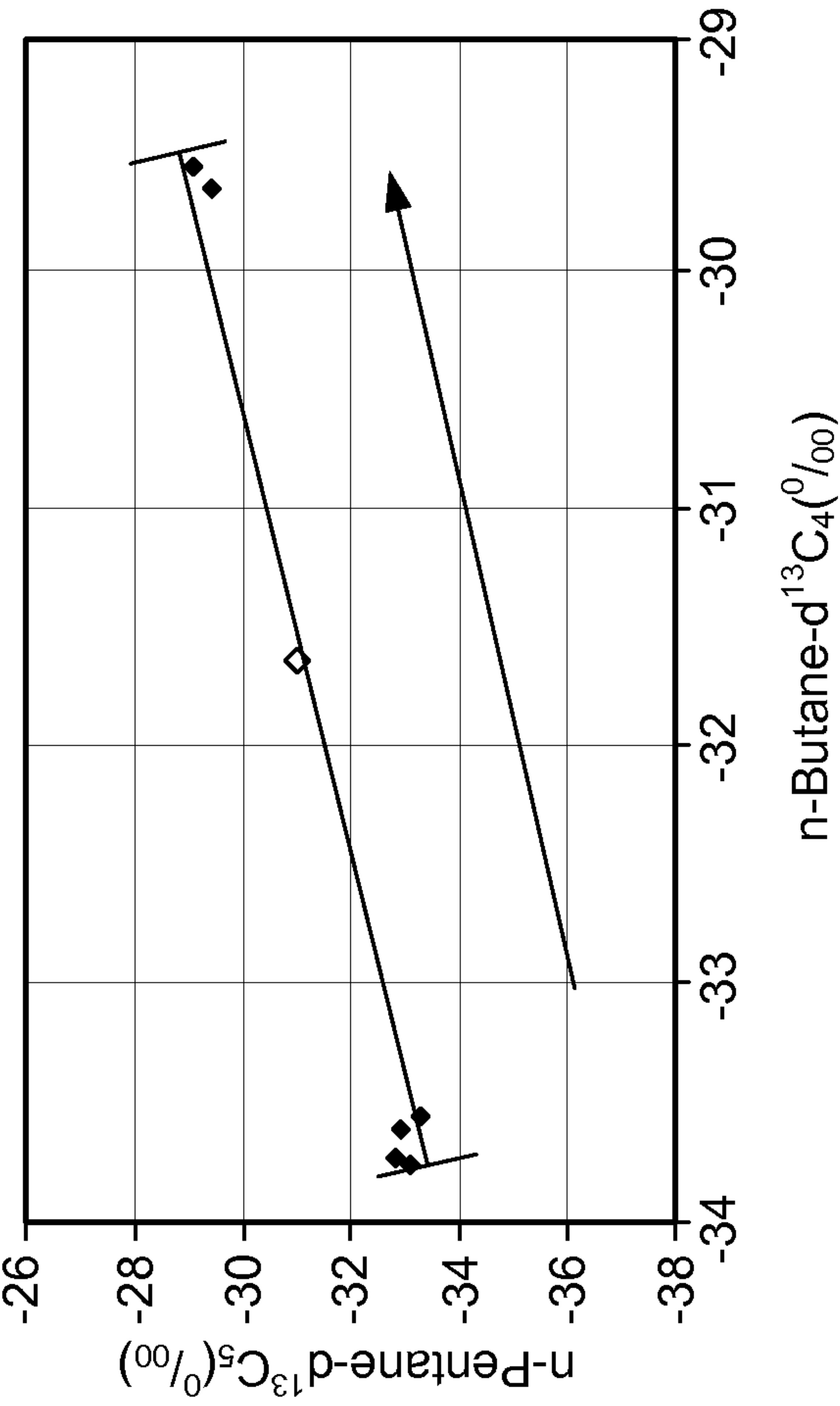
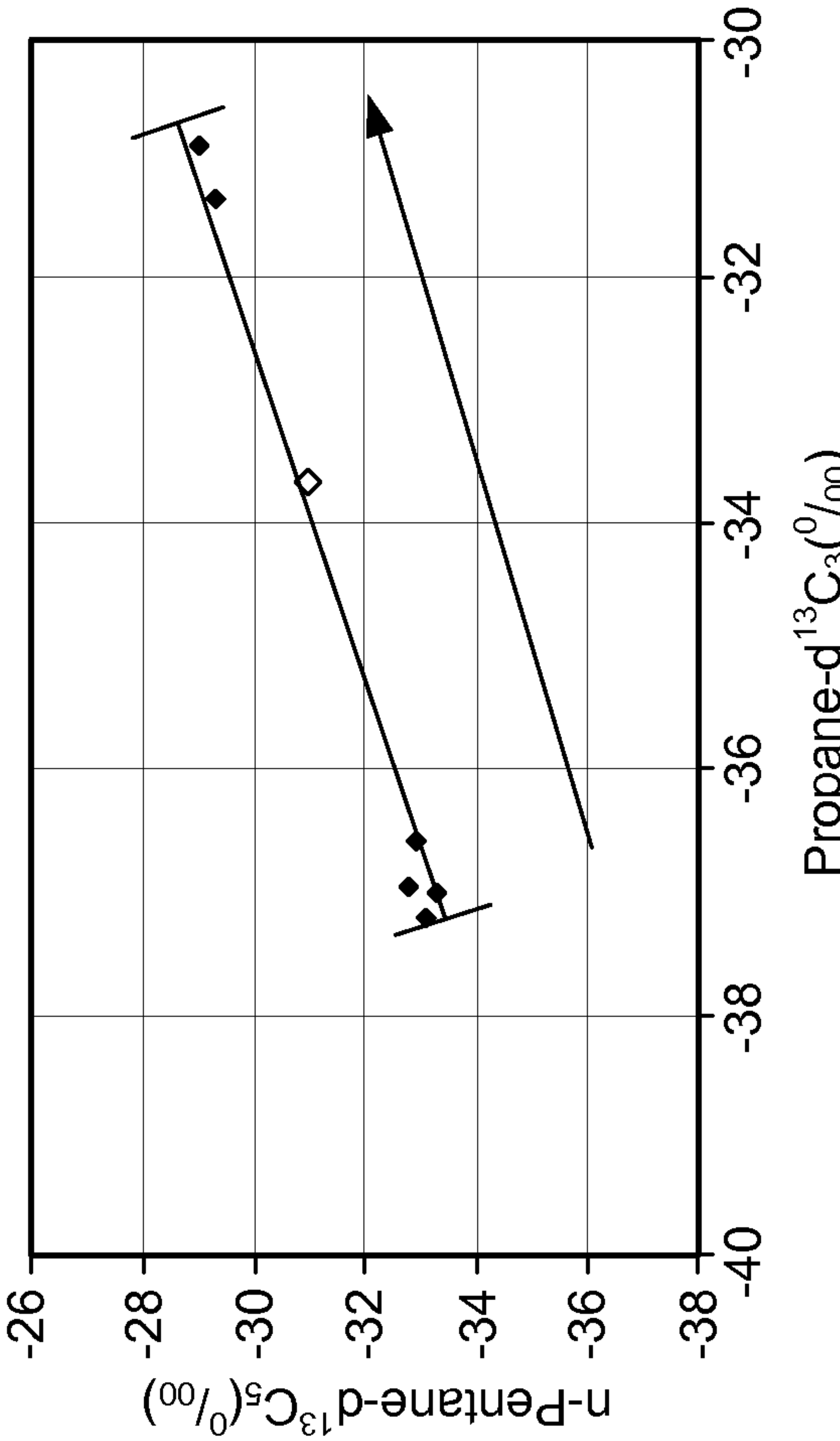


FIG. 8C

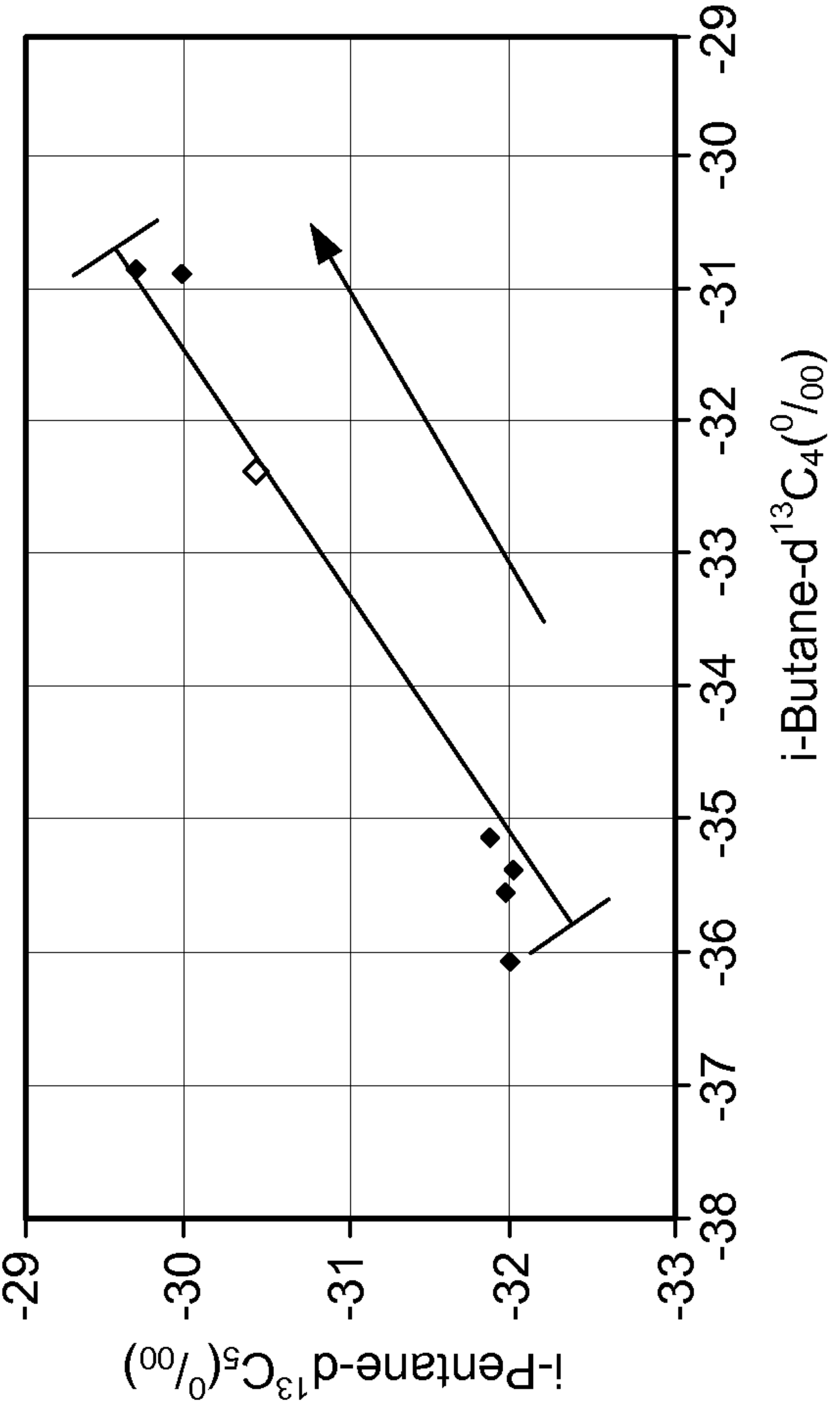


FIG. 8D

7/7

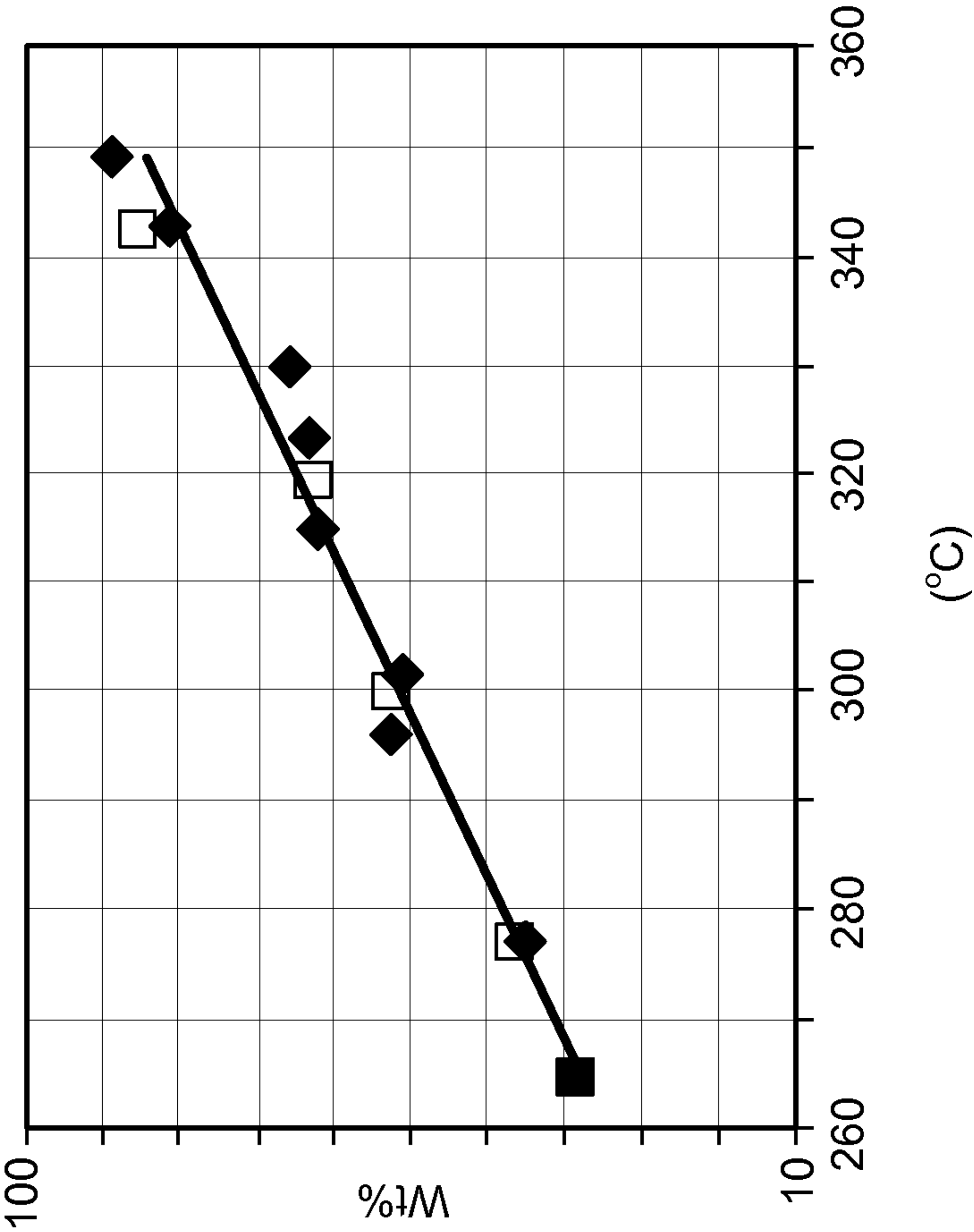


FIG. 10

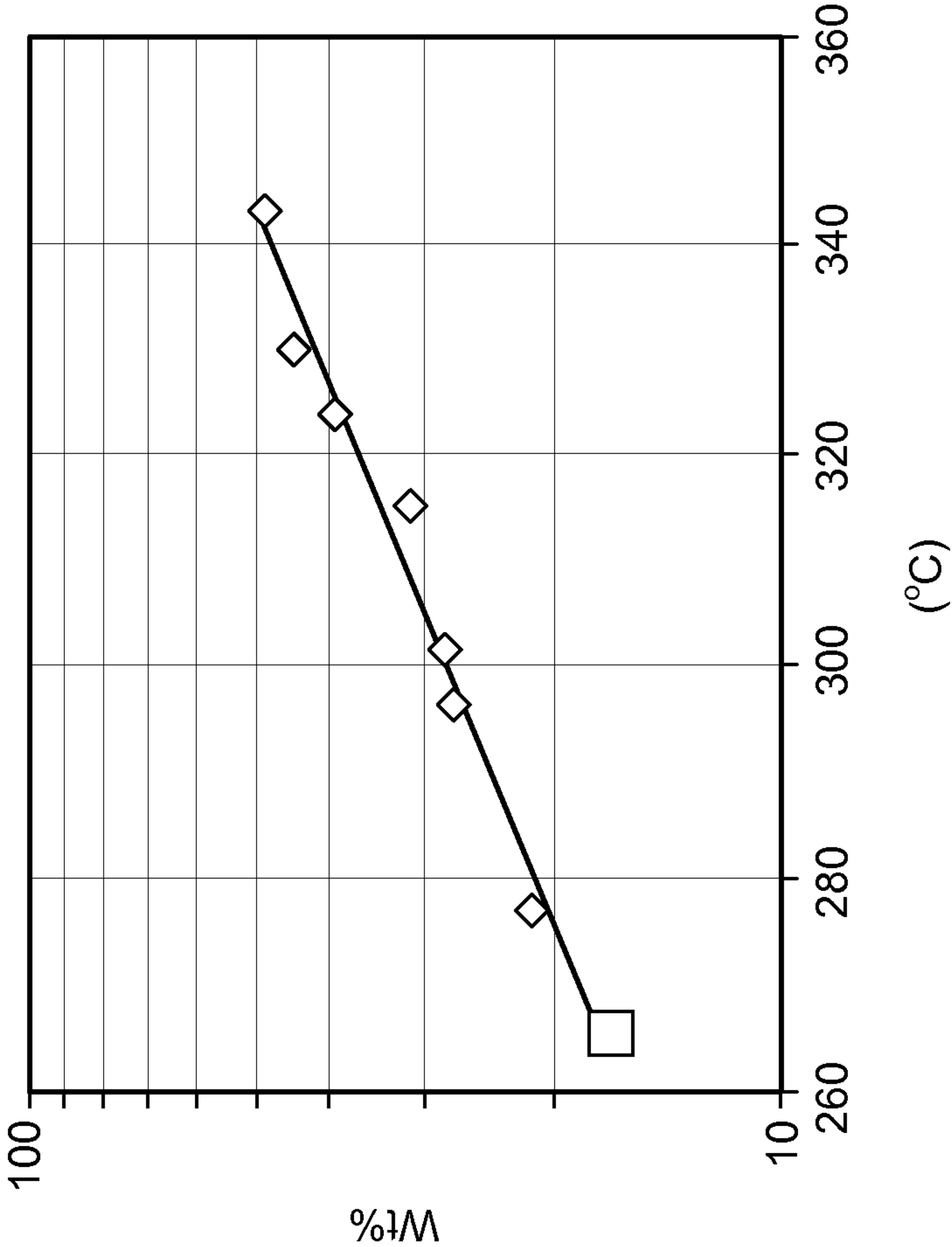


FIG. 9

