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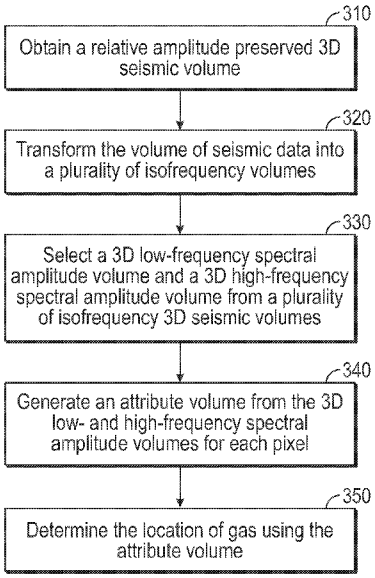
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(54) Title: ISOFREQUENCY VOLUMES RATIO WORKFLOW TO DETECT GAS RESERVOIRS IN 3D DOMAIN

(57) Abstract: A method that includes transforming a relative amplitude preserved 3D seismic volume acquired in the time-domain into a plurality of isofrequency volumes, extracting from the plurality of isofrequency volumes a first isofrequency spectral amplitude volume and a second isofrequency spectral amplitude volume. The method further includes determining an attribute volume from the two isofrequency spectral amplitude volumes, and determining a presence of gas in a subterranean region of interest based on the attribute volume.



An embodiment of a workflow finding the indication of gas

FIG. 3

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[Continued on next page]

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ISOFREQUENCY VOLUMES RATIO WORKFLOW TO DETECT GAS RESERVOIRS IN 3D DOMAIN

BACKGROUND

[0001] In some situations, a portion of the reservoir within the subterranean region of interest may contain a gas deposit. In some situations, it may be desirable to detect the gas deposit using a seismic survey. Portions of the reservoir containing a gas deposit may affect the characteristics of the reflected seismic waves and refracted seismic waves differently from portions of the reservoir contains fluids, whether oil or water. In some situations, it may be desirable to drill a wellbore into a gas deposit to produce the gas to the surface. Such a wellbore may be a vertical wellbore or may be a horizontal wellbore constructed using geosteering methods.

SUMMARY

[0002] This summary is provided to introduce a selection of concepts that are further described below in the detailed description. This summary is not intended to identify key or essential features of the claimed subject matter, nor is it intended to be used as an aid in limiting the scope of the claimed subject matter.

[0003] In general, in one aspect, embodiments relate to a method that includes transforming a relative amplitude preserved 3D seismic volume acquired in the time-domain into a plurality of isofrequency volumes, extracting from the plurality of isofrequency volumes a first isofrequency spectral amplitude volume and a second isofrequency spectral amplitude volume. The method further includes determining an attribute volume from the two isofrequency spectral amplitude volumes, and determining a presence of gas in a subterranean region of interest based on the attribute volume.

[0004] In general, in one aspect, embodiments relate to a system including a seismic processor composed of a computer processing unit capable of executing the instructions stored in the non-transitory computer storage medium. The seismic processor transforms a relative amplitude preserved 3D seismic volume acquired in the time-domain into a plurality of isofrequency volumes and extracts from the plurality of isofrequency volumes a first isofrequency spectral amplitude volume and a second isofrequency spectral amplitude volume. The seismic processor further calculates an attribute volume from the two isofrequency spectral amplitude volumes, and interprets anomalies in the attribute volume as indicative of a presence of gas.

[0005] Other aspects and advantages of the claimed subject matter will be apparent from the following description and the appended claims.

BRIEF DESCRIPTION OF DRAWINGS

[0006] Specific embodiments of the disclosed technology will now be described in detail with reference to the accompanying figures. Like elements in the various figures are denoted by like reference numerals for consistency.

[0007] FIG. 1 depicts a seismic survey in accordance with one or more embodiments.

[0008] FIG. 2 shows a relative amplitude preserved 3D seismic volume in accordance with one or more embodiments.

[0009] FIG. 3 shows a workflow in accordance with one or more embodiments.

[0010] FIG. 4A, 4B, and 4C show isofrequency spectral amplitude volumes in accordance with one or more embodiments.

[0011] FIG. 5A and 5B show systems in accordance with one or more embodiments.

[0012] FIG. 6 shows a computer system in accordance with one or more embodiments.

DETAILED DESCRIPTION

[0013] In the following detailed description of embodiments of the disclosure, numerous specific details are set forth in order to provide a more thorough understanding of the disclosure. However, it will be apparent to one of ordinary skill in the art that the disclosure may be practiced without these specific details. In other instances, well-known features have not been described in detail to avoid unnecessarily complicating the description.

[0014] Throughout the application, ordinal numbers (e.g., first, second, third, etc.) may be used as an adjective for an element (i.e., any noun in the application). The use of ordinal numbers is not to imply or create any particular ordering of the elements nor to limit any element to being only a single element unless expressly disclosed, such as using the terms "before", "after", "single", and other such terminology. Rather, the use of ordinal numbers is to distinguish between the elements. By way of an example, a first element is distinct from a second element, and the first element may encompass more than one element and succeed (or precede) the second element in an ordering of elements.

[0015] FIG. 1 shows a seismic survey (100) of a subterranean region of interest (102), which may contain a reservoir (104), may utilize a seismic source (106) that may generate radiated seismic waves (108). The radiated seismic waves (108) may return to the surface as refracted seismic waves (110), or may be reflected by geological discontinuities (112) and return to the surface as reflected seismic waves (114). At the surface, the refracted seismic waves (110) and reflected seismic waves (114) may be detected by seismic receivers (116).

[0016] In some embodiments, the refracted seismic waves (110) and reflected seismic waves (114) generated by a single activation of the seismic source (106) may be recorded by a seismic receiver (116) as a time-series representing the amplitude of ground-motion at a sequence of discreet times. The seismic receivers (116) may be positioned at a plurality of seismic receiver locations which we may denote (x_r, y_r) where x and y represent orthogonal axes on the

earth's surface above the subterranean region of interest (102). Thus, the refracted seismic waves (110) and reflected seismic waves (114) generated by a single activation of the seismic source (106) may be represented as a three-dimensional "3D" volume with axes (x_r, y_r, t) where (x_r, y_r) represents the location of the seismic receiver (116) and t delimits the time sample at which the amplitude of ground-motion was measured.

[0017] However, a seismic survey (100) may include recordings of seismic waves generated by a seismic source (106) that may be positioned at a plurality of seismic source locations which we may denote (x_s, y_s). Thus, the seismic volume for a seismic survey (100) may be resented as a five-dimensional volume, denoted (x_s, y_s, x_r, y_r, t).

[0018] FIG. 2 shows a 3D seismic volume in accordance with some embodiments. Seismic processing reduces a five-dimensional seismic volume produced by a seismic survey (100) to a 3D seismic volume (200) with one depth dimension (202), a first horizontal dimension (204) orthogonal to a second horizontal direction (206) representing a 3D image of the subterranean region of interest. Seismic processing performs this reduction from a five-dimensional seismic volume to a 3D seismic volume by correcting the recorded time of seismic waves for the time of travel ("migration") from the seismic source (106) to the seismic receiver (116) and summing ("stacking") samples over two space dimensions.

[0019] According to some embodiments, the migration is performed after approximating the velocity of seismic wave propagation as a function only of depth position, but not of horizontal position. Migration using this approximation is called "time-migration." According to some embodiments, the migration is performed without constraining the manner in which the velocity of seismic wave propagation varies. Migration using this approximation is called "depth-migration."

[0020] Thus, there are four possible combinations of the stacking and migration processes. Stacking before migration may produce "post-stack time-migration" if time-migration is used, and "post-stack depth-migration" if depth-migration is used. Migrating before stacking may produce "pre-stack time-migration" if time-migration is used, and "pre-stack depth-migration" if depth-migration is used. Each combination may be a relative amplitude preserved 3D seismic volume (200) representing a 3D image of the subterranean region of interest. FIG. 2 depicts a 2-D slices through a three dimensional seismic volume. A 3D pixel ("voxel") (208) of the 3D seismic volume (200) may have a value representing an estimate of an attribute of the subterranean volume of interest at the position of the voxel. For example, the attribute may be without limitation, a seismic wave reflection amplitude, or an isofrequency amplitude, or a coherence value. FIG. 2 shows a two-dimensional "2D" vertical slice (210) and a 2D horizontal slice (212) though the 3D seismic volume (200).

[0021] FIG. 3 shows a workflow in accordance with some embodiments. In Block 310, a relative amplitude preserved 3D seismic volume (200) resulting from processing a seismic survey (100) for a subterranean region of interest is obtained. This seismic volume (200) may be a post-stack time-migration, a post-stack depth-migration, a pre-stack-time migration, or a pre-stack depth-migration.

[0022] In Block 320 the relative amplitude preserved 3D seismic volume (200) acquired in the time-domain is transformed into a plurality of isofrequency volumes. According to some embodiments, this transformation may be performed by applying a short-time window Fourier transform along the depth axis of the relative amplitude preserved 3D seismic volume (200). According to some embodiments, this transformation may be performed by applying a Gabor transform along the depth axis of the relative amplitude preserved 3D seismic volume (200). According to some embodiments, this transformation may be performed by applying a Continuous Wavelet transform along the depth axis of the relative amplitude preserved 3D seismic volume (200). According to some

embodiments, this transformation may be performed by applying a Discrete Wavelet transform along the depth axis of the relative amplitude preserved 3D seismic volume (200). Other methods for transforming the relative amplitude preserved 3D seismic volume (200) acquired in the time-domain into a plurality of isofrequency volumes may be apparent to one skilled in the art.

[0023] Block 320 may also include, in accordance to some embodiments, the application of spatial filters to the the relative amplitude preserved 3D seismic volume. The result of the application of spatial filters may include, without limitation, the reduction or removal of noise spikes, the removal, or outliers, or the increase in spatial smoothness of the relative amplitude preserved 3D seismic volume. Block 320 may also include, in accordance to some embodiments, the application of frequency filters to the relative amplitude preserved 3D seismic volume. The result of the application of spatial filters may include, without limitation, the reduction or removal of noise spikes, the removal, or outliers, or the increase in spatial smoothness of the relative amplitude preserved 3D seismic volume.

[0024] In Block 330, in accordance with some embodiments, a plurality of isofrequency spectral amplitude volumes may be generated from the relative amplitude preserved 3D seismic volume. From this plurality of isofrequency spectral amplitude volumes two isofrequency spectral amplitude volumes may be extracted. One isofrequency spectral amplitude volume may be a low-frequency isofrequency spectral amplitude volume and one isofrequency spectral amplitude volume may be a high-frequency isofrequency spectral amplitude volume.

[0025] The choice of the frequencies of the low-frequency isofrequency, and high-frequency isofrequency spectral amplitude volumes may be based, in part, upon the spatial smoothness of the isofrequency spectral amplitude volume, or upon the signal-to-noise ratio of the isofrequency spectral amplitude volume. Typically, the optimum low frequency and, in particular, the optimum high frequency values are lower for reservoirs located at greater depth because of the

preferential absorption of higher frequencies during propagation of seismic waves through the earth above the reservoir.

[0026] In Block 340, according to some embodiments, an attribute volume may be generated from the low-frequency isofrequency spectral amplitude volume and the high-frequency isofrequency spectral amplitude volume. This attribute volume may be generated on a voxel-by-voxel basis, such that one voxel from the low-frequency isofrequency spectral amplitude volume and one voxel from the high-frequency isofrequency spectral amplitude volume uniquely determines one voxel in the 3D attribute volume. In other embodiments, a plurality of voxels from the low-frequency isofrequency spectral amplitude volume and a plurality of voxels from the high-frequency isofrequency spectral amplitude volume may contribute to one, or to a plurality of voxels in the 3D attribute volume.

[0027] In some embodiments, the attribute volume may be calculated on a voxel-by-voxel basis by calculating the ratio of a low-frequency isofrequency spectral amplitude volume to a high-frequency isofrequency spectral amplitude volume. In some embodiments, the attribute volume may be calculated on a voxel-by-voxel basis by calculating the ratio of a high-frequency isofrequency spectral amplitude volume to a low-frequency isofrequency spectral amplitude volume. In some embodiments, the attribute volume may be calculated on a voxel-by-voxel basis by calculating the difference between a high-frequency isofrequency spectral amplitude volume and a low-frequency isofrequency spectral amplitude volume. In still other embodiments, the voxel-by-voxel computations may be supplemented by first calculating an average over a portion of voxels in either, or both, a low-frequency and a high-frequency isofrequency spectral amplitude volume. An average may be defined as, without limitation, the mean, or, trimmed mean, or median or harmonic average.

[0028] In Block 350, according to some embodiments, the presence of gas, and its location, within the reservoir may be determined. In some embodiments, the presence of gas may be indicated by values of the attribute above a threshold value. In some embodiments, the presence of gas may be indicated by values of

the attribute below a threshold value. The threshold values may be user determined, or may be calculated based upon the range of values in the attribute volume

[0029] FIGs. 4A, 4B, and 4C show isofrequency spectral amplitude volumes in accordance with one or more embodiments. As an example, FIG. 4A depicts a low-frequency spectral amplitude volume. Three orthogonal intersecting planes through the spectral amplitude volume are shown. The shading of FIG. 4A represents the spectral amplitude values on the three intersecting orthogonal planes. In addition, the reservoir top (412) and two wellbore are shown (410A, 410B). Wellbore A (410A) produces gas, and wellbore B (411B) produces water.

[0030] FIG. 4B depicts a high-frequency spectral amplitude volume for the same subterranean region of interest. The same three intersecting orthogonal planes and the same wellbore A (410A) and wellbore B (410B) are shown as are shown in FIG. 4A. FIG. 4C shows the attribute volume generated from the low-frequency spectral amplitude volume shown in FIG. 4A, divided on a voxel-by-voxel bases by the high-frequency spectral amplitude volume shown in FIG. 4B. FIG. 4C shows the same three intersecting orthogonal planes and the same wellbore A (410A) and wellbore B (410B) as are shown in FIG. 4A. The high values of the attribute, depicted by the dark shading indicate the presence of gas. A portion of the locations with high values of the attribute are intersected by wellbore A (410A), and wellbore A (410A) produces gas. No portion of the locations with high values of the attribute are intersected by wellbore B (410B), and wellbore B (410B) produces water, not gas.

[0031] FIGs. 4A, 4B, and 4C depict an example where the reservoir is deemed to be a "thick" reservoir. A thick reservoir is one in which the vertical extent of the reservoir is significantly larger than one seismic wavelength for the frequency value used for the high-frequency isofrequency spectral amplitude volume. In one or more embodiments, the reservoir may be three times thicker than one seismic wavelength. In other embodiments the reservoir may be five

times thicker than one seismic wavelength. The embodiments shown in FIG. 3 may work better in thick reservoirs than in reservoirs which are not thick.

[0032] FIGs. 5A and 5B illustrate systems in accordance with one or more embodiments. As shown in FIG. 5A, a drilling system (500) may include a top drive drill rig (510) arranged around the setup of a drill bit logging tool (520). A top drive drill rig (510) may include a top drive (511) that may be suspended in a derrick (512) by a travelling block (513). In the center of the top drive (511), a drive shaft (514) may be coupled to a top pipe of a drill string (515), for example, by threads. The top drive (511) may rotate the drive shaft (514), so that the drill string (515) and a drill bit logging tool (520) cut the rock at the bottom of a wellbore (516). A power cable (517) supplying electric power to the top drive (511) may be protected inside one or more service loops (518) coupled to a control system (544). As such, drilling mud may be pumped into the wellbore (516) through a mud line, the drive shaft (514), and/or the drill string (515).

[0033] Moreover, when completing a well, casing may be inserted into the wellbore (516). The sides of the wellbore (516) may require support, and thus the casing may be used for supporting the sides of the wellbore (516). As such, a space between the casing and the untreated sides of the wellbore (516) may be cemented to hold the casing in place. The cement may be forced through a lower end of the casing and into an annulus between the casing and a wall of the wellbore (516). More specifically, a cementing plug may be used for pushing the cement from the casing. For example, the cementing plug may be a rubber plug used to separate cement slurry from other fluids, reducing contamination and maintaining predictable slurry performance. A displacement fluid, such as water, or an appropriately weighted drilling mud, may be pumped into the casing above the cementing plug. This displacement fluid may be pressurized fluid that serves to urge the cementing plug downward through the casing to extrude the cement from the casing outlet and back up into the annulus.

[0034] As further shown in FIG. 5A, sensors (521) may be included in a sensor assembly (523), which is positioned adjacent to a drill bit (524) and coupled to

the drill string (515). Sensors (521) may also be coupled to a processor assembly (523) that includes a processor, memory, and an analog-to-digital converter (522) for processing sensor measurements. For example, the sensors (521) may include acoustic sensors, such as accelerometers, measurement microphones, contact microphones, and hydrophones. Likewise, the sensors (521) may include other types of sensors, such as transmitters and receivers to measure resistivity, gamma ray detectors, etc. The sensors (521) may include hardware and/or software for generating different types of well logs (such as acoustic logs or density logs) that may provide well data about a wellbore, including porosity of wellbore sections, gas saturation, bed boundaries in a geologic formation, fractures in the wellbore or completion cement, and many other pieces of information about a formation. If such well data is acquired during drilling operations (i.e., logging-while-drilling), then the information may be used to make adjustments to drilling operations in real-time. Such adjustments may include rate of penetration (ROP), drilling direction, altering mud weight, and many others drilling parameters.

[0035] In some embodiments, acoustic sensors may be installed in a drilling fluid circulation system of a drilling system (500) to record acoustic drilling signals in real-time. Drilling acoustic signals may transmit through the drilling fluid to be recorded by the acoustic sensors located in the drilling fluid circulation system. The recorded drilling acoustic signals may be processed and analyzed to determine well data, such as lithological and petrophysical properties of the rock formation. This well data may be used in various applications, such as steering a drill bit using geosteering, casing shoe positioning, etc.

[0036] The control system (544) may be coupled to the sensor assembly (523) in order to perform various program functions for up-down steering and left-right steering of the drill bit (524) through the wellbore (516). More specifically, the control system (544) may include hardware and/or software with functionality for geosteering a drill bit through a formation in a lateral well using sensor signals, such as drilling acoustic signals or resistivity measurements. For

example, the formation may be a reservoir region, such as a pay zone, bed rock, or cap rock.

[0037] Turning to geosteering, geosteering may be used to position the drill bit (524) or drill string (515) relative to a boundary between different subsurface layers (e.g., overlying, underlying, and lateral layers of a pay zone) during drilling operations. In particular, measuring rock properties during drilling may provide the drilling system (500) with the ability to steer the drill bit (524) in the direction of desired hydrocarbon concentrations. As such, a geosteering system may use various sensors located inside or adjacent to the drilling string (515) to determine different rock formations within a wellbore's path. In some geosteering systems, drilling tools may use resistivity or acoustic measurements to guide the drill bit (524) during horizontal or lateral drilling.

[0038] Turning to FIG. 5B, FIG. 5B illustrates some embodiments for steering a drill bit through a lateral pay zone using a geosteering system (590). As shown in FIG. 5B, the geosteering system (590) may include the drilling system (500) from FIG. 5A. In particular, the geosteering system (590) may include functionality for monitoring various sensor signatures (e.g., an acoustic signature from acoustic sensors) that gradually or suddenly change as a well path traverses a cap rock (530), a pay zone (540), and a bed rock (550). Because of the sudden change in lithology between the cap rock (530) and the pay zone (540), for example, a sensor signature of the pay zone (540) may be different from the sensor signature of the cap rock (530). When the drill bit (524) drills out of the pay zone (540) into the cap rock (530), a detected amplitude spectrum of a particular sensor type may change suddenly between the two distinct sensor signatures. In contrast, when drilling from the pay zone (540) downward into the bed rock (550), the detected amplitude spectrum may gradually change.

[0039] During the lateral drilling of the wellbore (516), preliminary upper and lower boundaries of a formation layer's thickness may be derived from a geophysical survey and/or an offset well obtained before drilling the wellbore (516). If a vertical section (535) of the well is drilled, the actual upper and lower

boundaries of a formation layer (i.e., actual pay zone boundaries (A, A′)) and the pay zone thickness (i.e., A to A′) at the vertical section (535) may be determined. Based on this well data, an operator may steer the drill bit (524) through a lateral section (560) of the wellbore (516) in real time. In particular, a logging tool may monitor a detected sensor signature proximate the drill bit (524), where the detected sensor signature may continuously be compared against prior sensor signatures, e.g., of the cap rock (530), pay zone (540), and bed rock (550), respectively. As such, if the detected sensor signature of drilled rock is the same or similar to the sensor signature of the pay zone (540), the drill bit (524) may still be drilling in the pay zone (540). In this scenario, the drill bit (524) may be operated to continue drilling along its current path and at a predetermined distance (0.5h) from a boundary of a formation layer. If the detected sensor signature is same as or similar to the prior sensor signatures of the cap rock (530) or the bed rock (550), respectively, then the control system (544) may determine that the drill bit (524) is drilling out of the pay zone (540) and into the upper or lower boundary of the pay zone (540). At this point, the vertical position of the drill bit (524) at this lateral position within the wellbore (516) may be determined and the upper and lower boundaries of the pay zone (540) may be updated, (for example, positions B and C in FIG. 5B). In some embodiments, the vertical position at the opposite boundary may be estimated based on the predetermined thickness of the pay zone (540), such as positions B′ and C′.

[0040] While FIGs. 5A, and 5B shows various configurations of components, other configurations may be used without departing from the scope of the disclosure. For example, various components in FIGs. 5A, and 5B may be combined to create a single component. As another example, the functionality performed by a single component may be performed by two or more components.

[0041] Embodiments may be implemented on a computer system. FIG. 6 is a block diagram of a computer system (602) used to provide computational functionalities associated with described algorithms, methods, functions,

processes, flows, and procedures as described in the instant disclosure, according to an implementation. The illustrated computer (602) is intended to encompass any computing device such as a server, desktop computer, laptop/notebook computer, wireless data port, smart phone, personal data assistant (PDA), tablet computing device, one or more processors within these devices, or any other suitable processing device, including both physical or virtual instances (or both) of the computing device. Additionally, the computer (602) may include a computer that includes an input device, such as a keypad, keyboard, touch screen, or other device that can accept user information, and an output device that conveys information associated with the operation of the computer (602), including digital data, visual, or audio information (or a combination of information), or a GUI.

[0042] The computer (602) can serve in a role as a client, network component, a server, a database or other persistency, or any other component (or a combination of roles) of a computer system for performing the subject matter described in the instant disclosure. The illustrated computer (602) is communicably coupled with a network (630). In some implementations, one or more components of the computer (602) may be configured to operate within environments, including cloud-computing-based, local, global, or other environment (or a combination of environments).

[0043] At a high level, the computer (602) is an electronic computing device operable to receive, transmit, process, store, or manage data and information associated with the described subject matter. According to some implementations, the computer (602) may also include or be communicably coupled with an application server, e-mail server, web server, caching server, streaming data server, business intelligence (BI) server, or other server (or a combination of servers).

[0044] The computer (602) can receive requests over network (630) from a client application (for example, executing on another computer (602)) and responding to the received requests by processing the said requests in an

appropriate software application. In addition, requests may also be sent to the computer (602) from internal users (for example, from a command console or by other appropriate access method), external or third-parties, other automated applications, as well as any other appropriate entities, individuals, systems, or computers.

[0045] Each of the components of the computer (602) can communicate using a system bus (603). In some implementations, any or all of the components of the computer (602), both hardware or software (or a combination of hardware and software), may interface with each other or the interface (604) (or a combination of both) over the system bus (603) using an application programming interface (API) (612) or a service layer (613) (or a combination of the API (612) and service layer (613). The API (612) may include specifications for routines, data structures, and object classes. The API (612) may be either computer-language independent or dependent and refer to a complete interface, a single function, or even a set of APIs. The service layer (613) provides software services to the computer (602) or other components (whether or not illustrated) that are communicably coupled to the computer (602). The functionality of the computer (602) may be accessible for all service consumers using this service layer. Software services, such as those provided by the service layer (613), provide reusable, defined business functionalities through a defined interface. For example, the interface may be software written in JAVA, C++, or other suitable language providing data in extensible markup language (XML) format or other suitable format. While illustrated as an integrated component of the computer (602), alternative implementations may illustrate the API (612) or the service layer (613) as stand-alone components in relation to other components of the computer (602) or other components (whether or not illustrated) that are communicably coupled to the computer (602). Moreover, any or all parts of the API (612) or the service layer (613) may be implemented as child or sub-modules of another software module, enterprise

application, or hardware module without departing from the scope of this disclosure.

[0046] The computer (602) includes an interface (604). Although illustrated as a single interface (604) in FIG. 6, two or more interfaces (604) may be used according to particular needs, desires, or particular implementations of the computer (602). The interface (604) is used by the computer (602) for communicating with other systems in a distributed environment that are connected to the network (630). Generally, the interface (604 includes logic encoded in software or hardware (or a combination of software and hardware) and operable to communicate with the network (630). More specifically, the interface (604) may include software supporting one or more communication protocols associated with communications such that the network (630) or interface's hardware is operable to communicate physical signals within and outside of the illustrated computer (602).

[0047] The computer (602) includes at least one computer processor (605). Although illustrated as a single computer processor (605) in FIG. 6, two or more processors may be used according to particular needs, desires, or particular implementations of the computer (602). Generally, the computer processor (605) executes instructions and manipulates data to perform the operations of the computer (602) and any algorithms, methods, functions, processes, flows, and procedures as described in the instant disclosure.

[0048] The computer (602) also includes a memory (606) that holds data for the computer (602) or other components (or a combination of both) that can be connected to the network (630). For example, memory (606) can be a database storing data consistent with this disclosure. Although illustrated as a single memory (606) in FIG. 6, two or more memories may be used according to particular needs, desires, or particular implementations of the computer (602) and the described functionality. While memory (606) is illustrated as an integral component of the computer (602), in alternative implementations, memory (606) can be external to the computer (602).

[0049] The application (607) is an algorithmic software engine providing functionality according to particular needs, desires, or particular implementations of the computer (602), particularly with respect to functionality described in this disclosure. For example, application (607) can serve as one or more components, modules, applications, etc. Further, although illustrated as a single application (607), the application (607) may be implemented as multiple applications (607) on the computer (602). In addition, although illustrated as integral to the computer (602), in alternative implementations, the application (607) can be external to the computer (602).

[0050] There may be any number of computers (602) associated with, or external to, a computer system containing computer (602), wherein each computer (602) communicates over network (630). Further, the term "client," "user," and other appropriate terminology may be used interchangeably as appropriate without departing from the scope of this disclosure. Moreover, this disclosure contemplates that many users may use one computer (602), or that one user may use multiple computers (602).

[0051] Although only a few example embodiments have been described in detail above, those skilled in the art will readily appreciate that many modifications are possible in the example embodiments without materially departing from this invention. Accordingly, all such modifications are intended to be included within the scope of this disclosure as defined in the following claims. In the claims, any means-plus-function clauses are intended to cover the structures described herein as performing the recited function(s) and equivalents of those structures. Similarly, any step-plus-function clauses in the claims are intended to cover the acts described here as performing the recited function(s) and equivalents of those acts. It is the express intention of the applicant not to invoke 35 U.S.C. § 112(f) for any limitations of any of the claims herein, except for those in which the claim expressly uses the words "means for" or "step for" together with an associated function.

CLAIMS

What is claimed is:

1. A method, comprising:

transforming, by a computer processor, a relative amplitude preserved 3D seismic volume acquired in the time-domain into a plurality of isofrequency volumes;

extracting, by the computer processor, from the plurality of isofrequency volumes, a first isofrequency spectral amplitude volume and a second isofrequency spectral amplitude volume;

determining, by the computer processor, an attribute volume from the two isofrequency spectral amplitude volumes, and

determining, by the computer processor, a presence of gas in a subterranean region of interest based on the attribute volume.

2. The method of claim 1, further comprising:

determining, by the computer processor, a well path through the subterranean region of interest using the attribute volume; and

performing the well path using a drilling system.

3. The method of claim 1:

wherein, the relative amplitude preserved 3D seismic volume acquired in the time-domain is selected from the group consisting of a Pre-Stack Time Migration volume, a Post-Stack Time Migration volume, a Pre-Stack Depth Migration volume, and a Post-Stack Depth Migration volume.

4. The method of claim 1:

wherein, the transforming of the relative amplitude preserved 3D seismic volume acquired in the time-domain into the plurality of isofrequency volumes is performed using a method selected from the group consisting of a continuous waveform transform, a discrete waveform transform, a short

time-window Fourier transform, a Gabor transform, and instantaneous spectral analysis.

5. The method of claim 1:

wherein, the transforming of the relative amplitude preserved 3D seismic volume acquired in the time-domain further comprises:

applying a spatially-smoothing operator to the plurality of isofrequency volumes

6. The method of claim 1:

wherein, the transforming of relative amplitude preserved 3D seismic volume acquired in the time-domain further comprises:

applying a filter to the plurality of isofrequency volumes.

7. The method of claim 1:

wherein, the calculating an attribute volume further comprises:

calculating a ratio of a value of at least one voxel in the first isofrequency spectral amplitude volume to a value of at least one voxel in the second isofrequency spectral amplitude volume.

8. The method of claim 1:

wherein, the calculating an attribute volume further comprises:

calculating a product of a value of at least one voxel in the first isofrequency spectral amplitude volume to a value of at least one voxel in the second isofrequency spectral amplitude volume.

9. The method of claim 1:

wherein determining, by the computer processor, a presence of gas in a subterranean region of interest based on the attribute volume further comprises:

specifying a threshold value; and

identifying at least one voxel whose value exceed the threshold value.

10. The method of claim 1:

wherein

determining, by the computer processor, a presence of gas in a subterranean region of interest based on the attribute volumefurther comprises:

specifying a threshold value; and

identifying at least one voxel whose value does not exceed the threshold value.

11. A system, comprising:

a seismic processor comprising a computer processing unit capable of executing the instructions stored in a non-transitory computer storage medium comprising:

means for transforming, a relative amplitude preserved 3D seismic volume acquired in the time-domain into a plurality of isofrequency volumes;

means for extracting, from the plurality of isofrequency volumes , a first isofrequency spectral amplitude volume and a second isofrequency spectral amplitude volume;

means for calculating an attribute volume from the two isofrequency spectral amplitude volumes, and

means for determining, by the computer processor, a presence of gas in a subterranean region of interest based on the attribute volume.

12. The system of claim 11, further comprising:

a non-transitory computer storage medium for storing a location at which the presence of gas is indicated.

13. The system of claim 11:

wherein, the means for transforming the relative amplitude preserved 3D seismic volume acquired in the time-domain into a plurality of isofrequency volumes is performed using a continuous waveform transform.

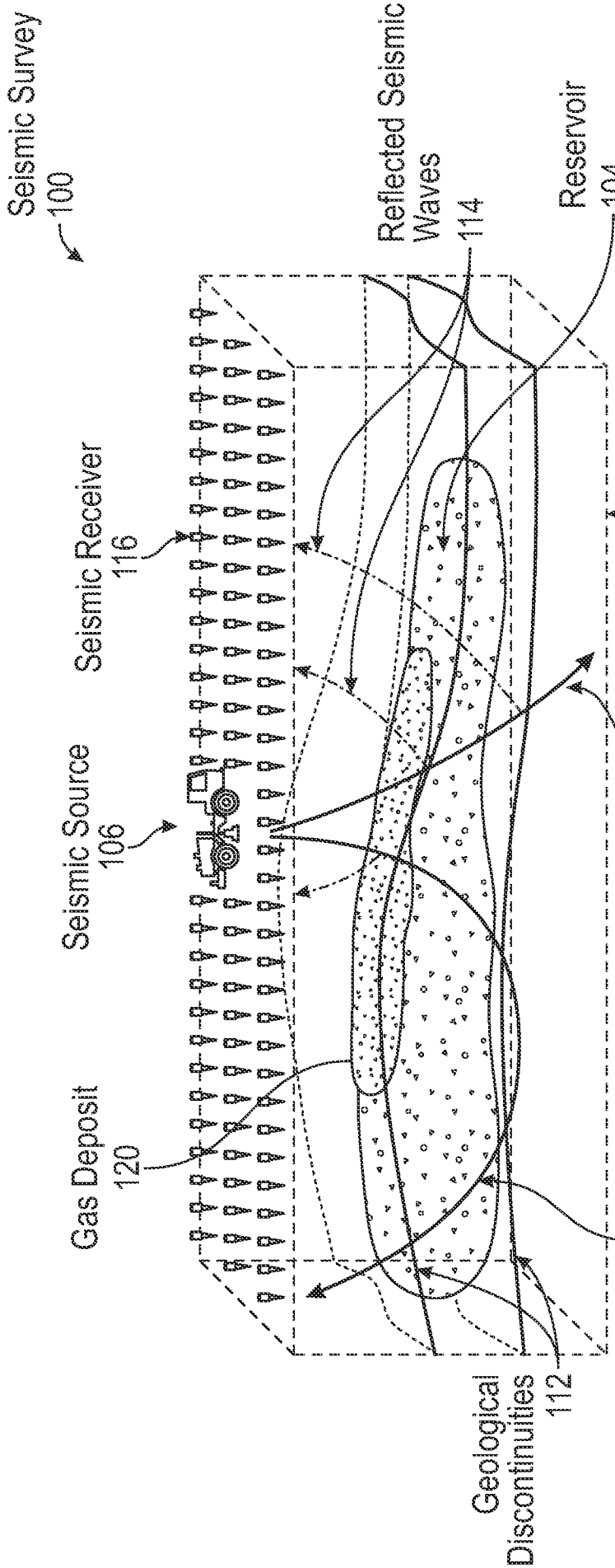
14. The system of claim 11, further comprising:

wherein, the means for calculating an attribute volume further comprises:

means for calculating a ratio of a value of, at least, one voxel in the first isofrequency spectral amplitude volume to a value of, at least, one voxel in the second isofrequency spectral amplitude volume.

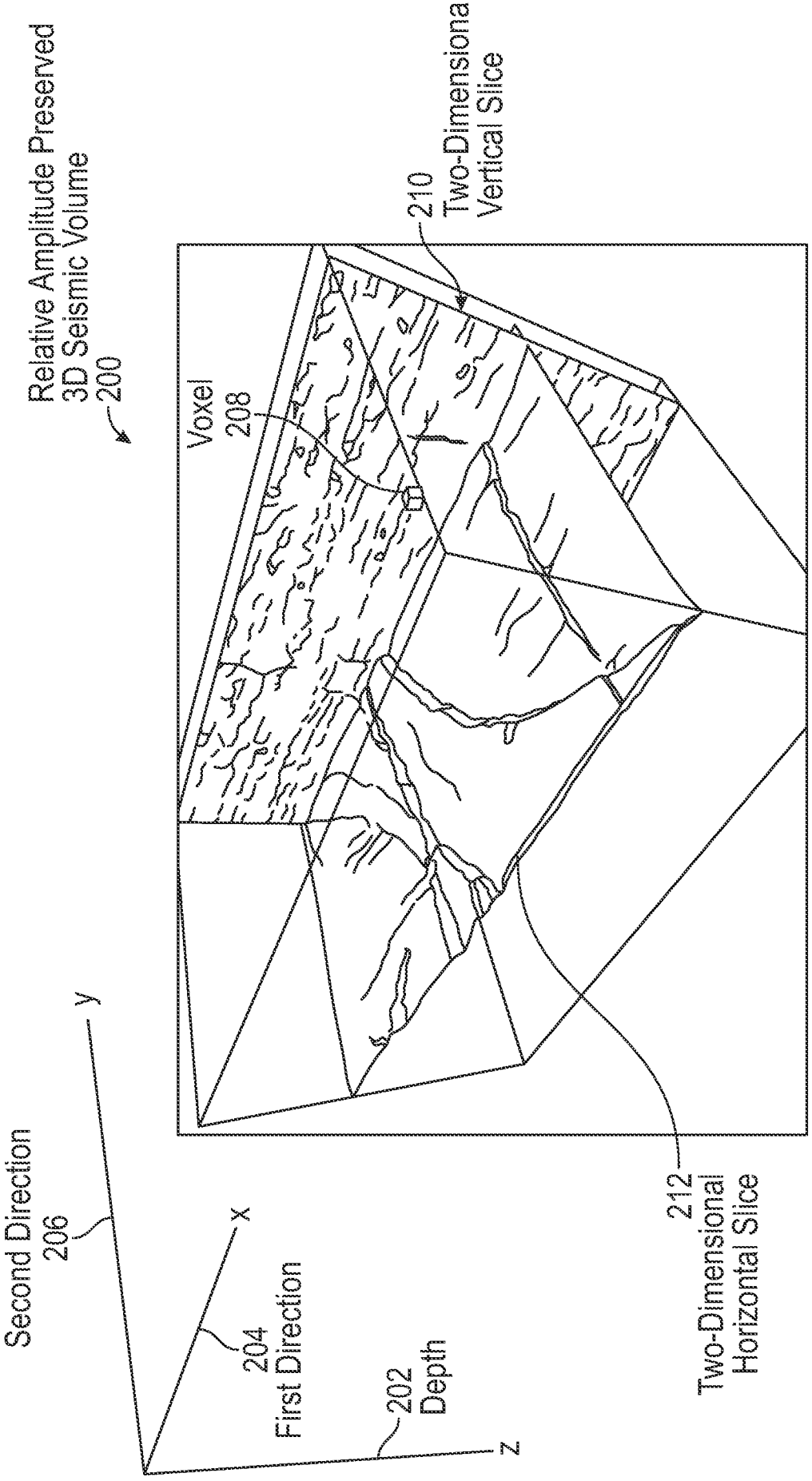
15. The system of claim 11:

wherein, the means for transforming the relative amplitude preserved 3D seismic volume acquired in the time-domain into a plurality of isofrequency volumes is performed using a Gabor transform.



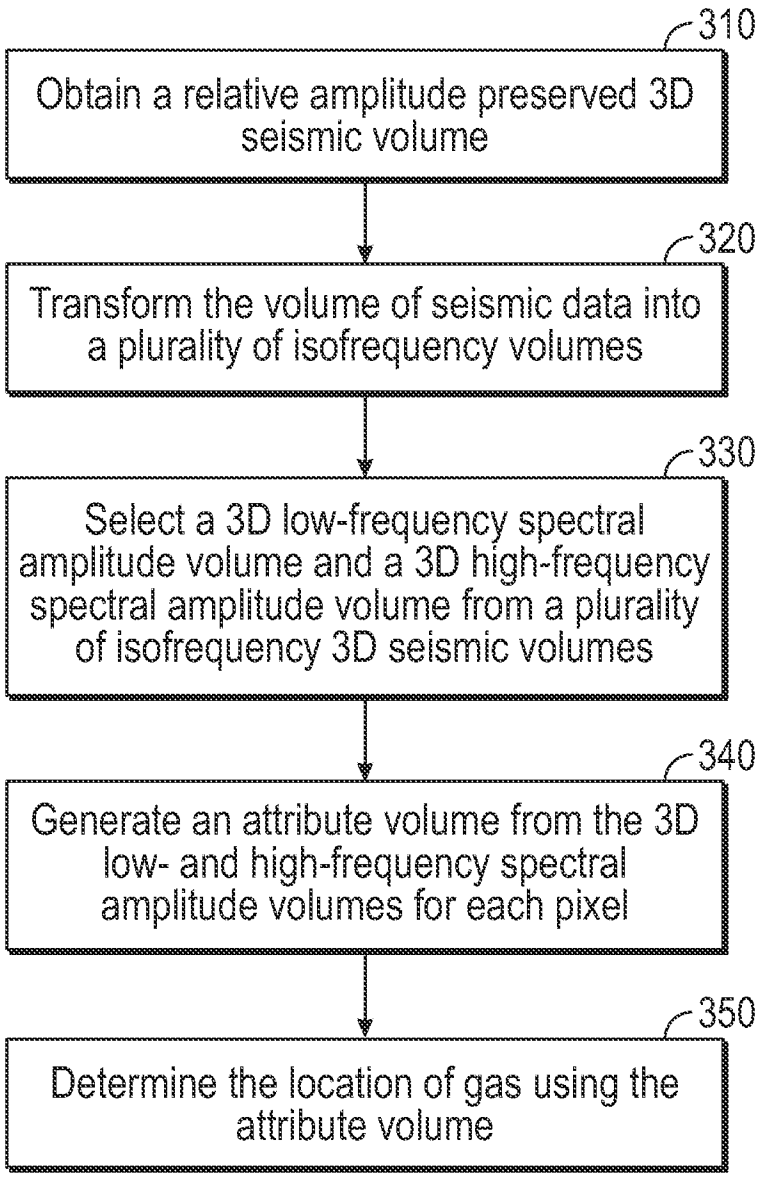
An embodiment of an acquisition of a seismic survey for use in locating hydrocarbons

FIG. 1
(Prior Art)



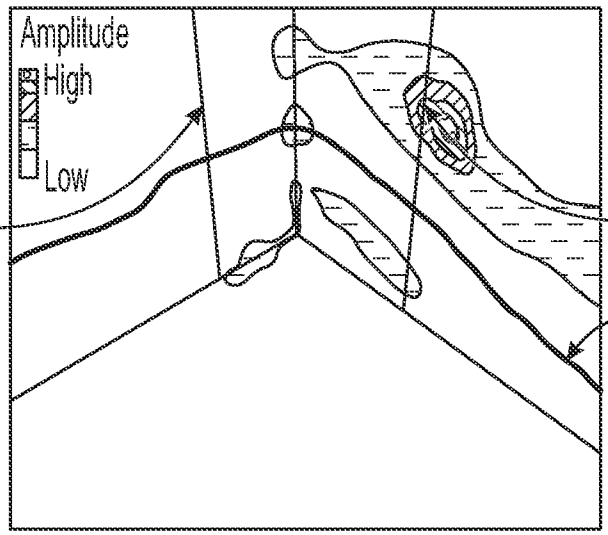
An Example of an Attribute Volume

FIG. 2



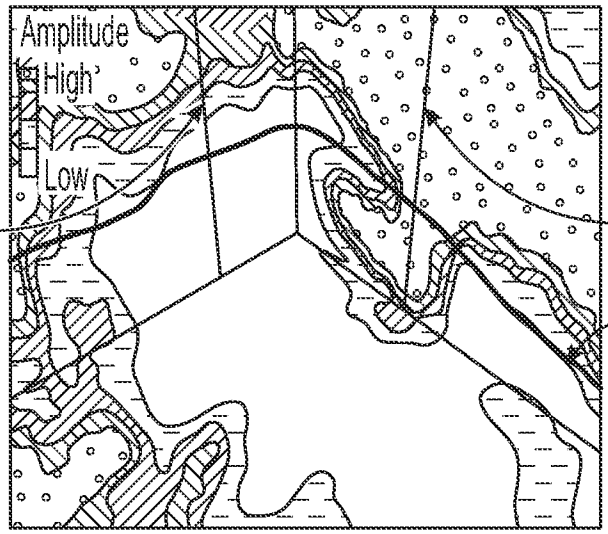
An embodiment of a workflow finding the indication of gas

FIG. 3



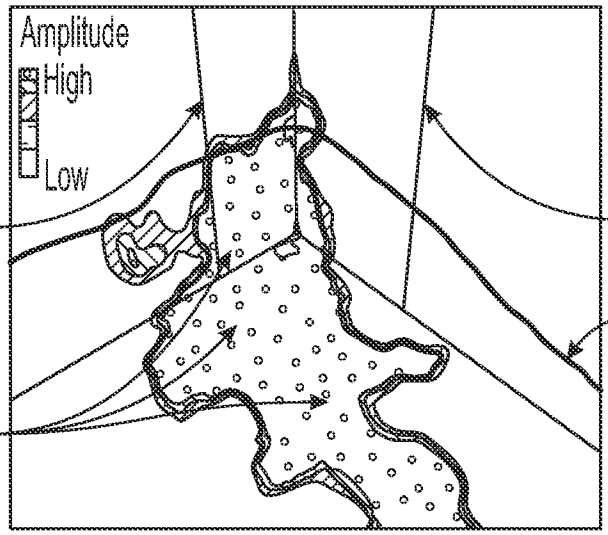
A first embodiment of an instantaneous mono-frequency volume.

FIG. 4A



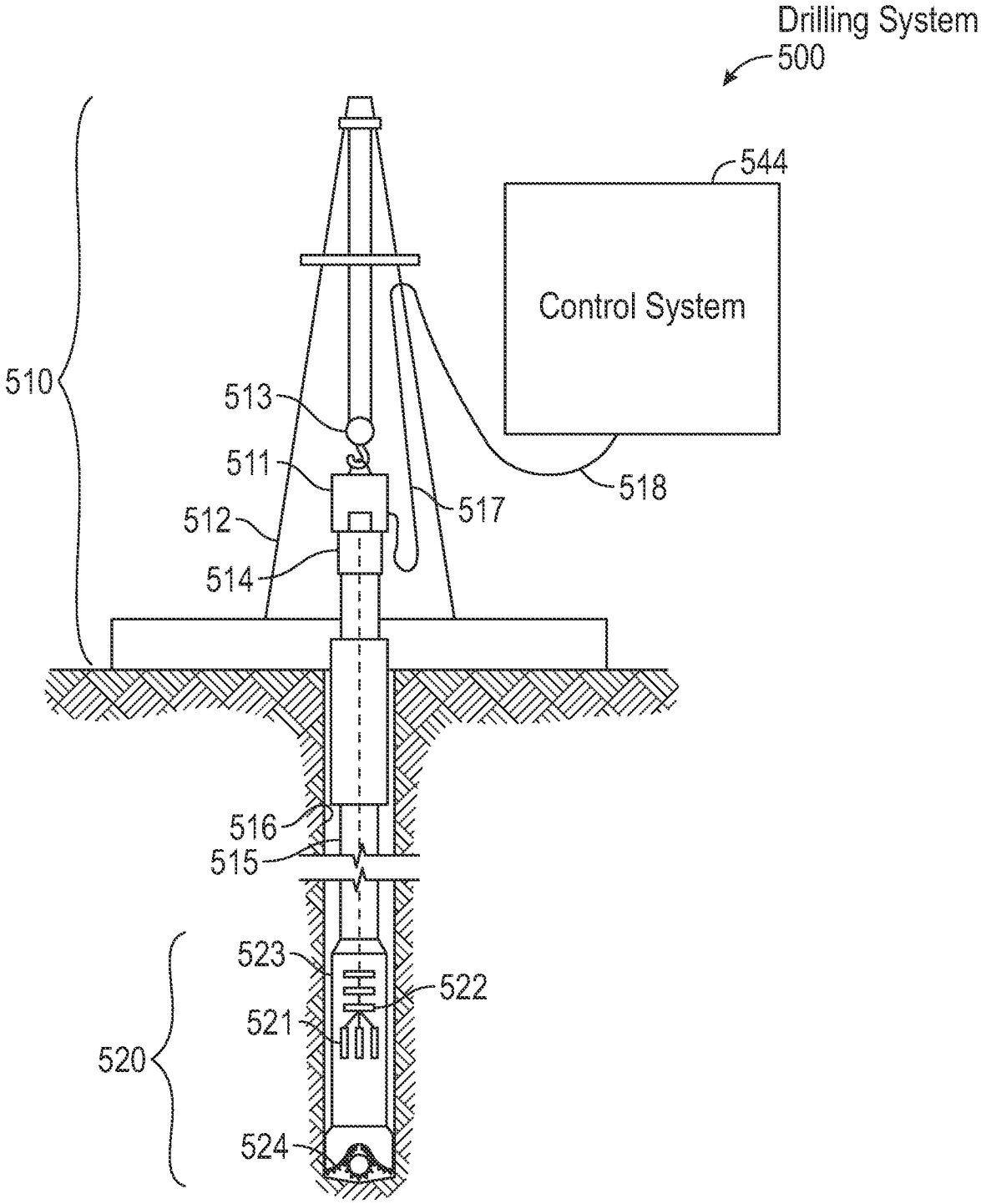
A second embodiment of an instantaneous mono-frequency volume.

FIG. 4B



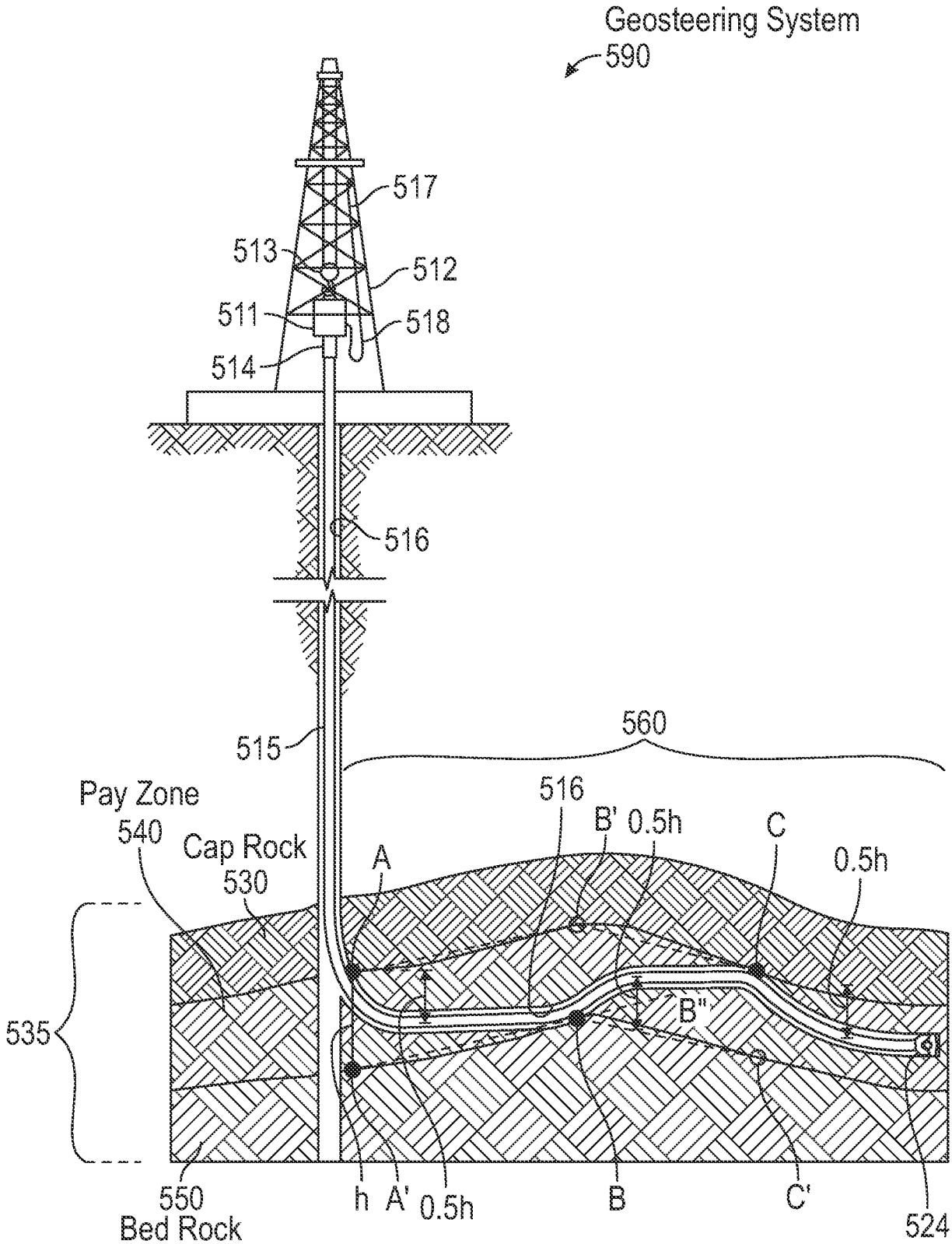
A first embodiment of an attribute volume.

FIG. 4C



Show systems in accordance with one or more embodiments

FIG. 5A



Show systems in accordance with one or more embodiments

FIG.5B

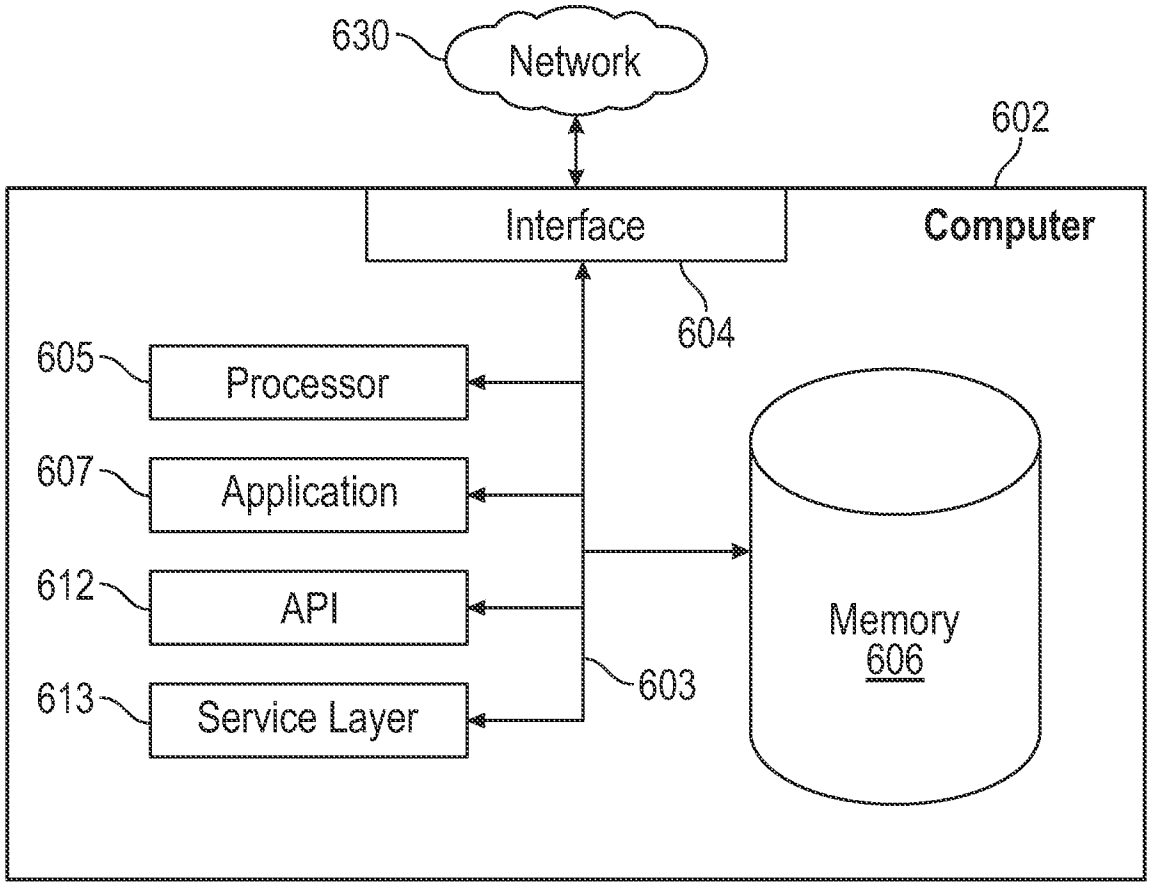

630
Network
602
Interface
Computer
604
605
Processor
607
Application
612
API
613
Service Layer
603
Memory
606

FIG. 6

INTERNATIONAL SEARCH REPORT

International application No
PCT/US2021/053551

A. CLASSIFICATION OF SUBJECT MATTER
INV. G01V1/30 G01V1/34
ADD.

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
G01V

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
EPO-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	TAHER M SODAGAR: "Iso Frequency Spectral Decomposition Ratio Technology Workflow for Gas Carbonate Field Developments and Characterization", FIRST EAGE RESERVOIR CHARACTERIZATION AND MODELLING WORKFLOWS FOR GIANT CARBONATE FIELD, 18 February 2019 (2019-02-18), XP055715145, DOI: 10.3997/2214-4609.201900192 figures 1,2 pages 1-4 ----- -/--	1-15

[x] Further documents are listed in the continuation of Box C. [ ] See patent family annex.

* Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance

"E" earlier application or patent but published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance;; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance;; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
13 January 2022	21/01/2022

Name and mailing address of the ISA/	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Fax: (+31-70) 340-3016	Meyer, Matthias

2

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INTERNATIONAL SEARCH REPORT

International application No
PCT/US2021/053551

C(Continuation). DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	GUIZADA PABLO ET AL: "Application of Underbalanced Coiled Tubing Drilling Technology to Enhance Gas Production in Deep Carbonate Reservoirs", ABU DHABI INTERNATIONAL PETROLEUM EXHIBITION & CONFERENCE, vol. 192786, 12 November 2018 (2018-11-12) , pages 1-8, XP055834012, Abu Dhabi Retrieved from the Internet: URL:https://watermark.silverchair.com/spe-192786-ms.pdf?token=AQECAHi208BE49Ooan9kkhW_Ercy7Dm3ZL_9Cf3qfKAc485ysgAAAvcwggLzBgkqhkiG9w0BBwagggLkMIIC4AIBADCCAtkGCSqGSIb3DQEHATAeBglghkgBZQMEAS4wEQQM-BJi3d0s65gPWP6UAgEQgIICqm18t9dkK6-q1f5XIAGmWkxOYAz6a63hY_sMhJLANXdDwR3TSktw3e8hzzIE__N5VEZ7SONOIZXP_h1cVw_LcR> figures 1,5-8 pages 1-5,8 _____	1-15

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