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- (71) **Applicant (for US only):** SCHLUMBERGER TECHNOLOGY CORPORATION [US/US]; 300 Schlumberger Drive, Sugar Land, TX 77478 (US).
- (71) **Applicant (for CA only):** SCHLUMBERGER CANADA LIMITED [CA/CA]; 125 - 9 Avenue SE, Calgary, Alberta, T2G 0P6 (CA).
- (71) **Applicant (for FR only):** SERVICES PETROLIERS SCHLUMBERGER [FR/FR]; 42 rue Saint Dominique, 75007 Paris (FR).
- (71) **Applicant (for all designated States except CA, FR, US):** GEOQUEST SYSTEMS B.V. [NL/NL]; Gevers Deynootweg 61, 2586 BJ The Hague (NL).
- (72) **Inventors:** KAMIL AMIN, Yousif, Izzeldin; Schlumberger House, Buckingham Gate, Gatwick Airport, Gatwick, West Sussex RH6 0NZ (GB). VERMEER, Pieter, Leonard; 4 Fair View, Horsham, West Sussex RH12 2PY (GB). VASSALLO, Massimiliano; WesternGeco Ltd, Buckingham Gate, Gatwick Airport, Gatwick, West Sussex RH6 0NZ (GB).
- (74) **Agents:** BUKOYE, Abimbola et al.; 1001 Richmond Avenue, IP Administration Center of Excellence, Room 4720, Houston, TX 77042 (US).
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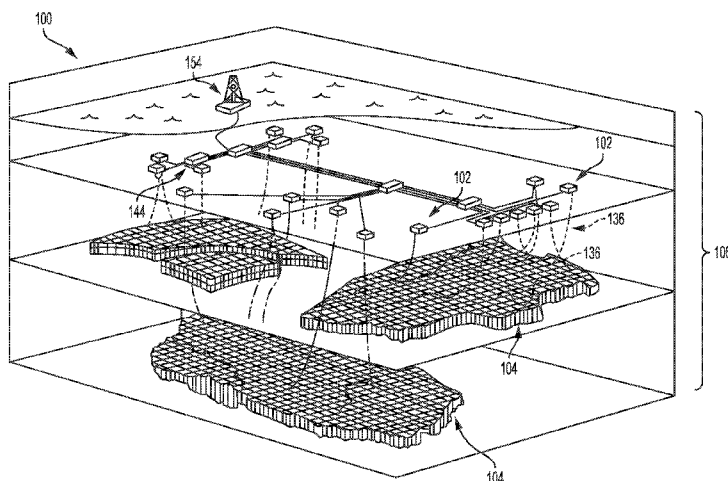
(54) **Title:** NOISE MITIGATION FOR SEISMIC SURVEY MULTI-DATASETS

FIG. 1

(57) **Abstract:** Techniques for mitigating noise in seismic data including a plurality of measured values of a plurality of components are disclosed. The techniques use relations among the plurality of components. The techniques are adapted to parallel processing computer hardware. The techniques can include obtaining seismic data including a plurality of values of a plurality of components, estimating a plurality of noise spectra values, the respective noise spectra values representing a noise content in a respective component of the plurality of components, computing a plurality of dynamic weights, the respective dynamic weights being a function of a respective one of the noise spectra values, generating a vector autoregressive model using the plurality of dynamic weights and the plurality of components, filtering the seismic data with the vector autoregressive model, such that noise-mitigated seismic data is produced, and providing the noise-mitigated seismic data.



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NOISE MITIGATION FOR SEISMIC SURVEY MULTI-DATASETS

Cross-Reference to Related Applications

[0001] This application claims priority to U.S. Provisional Patent Application having serial number 62/138,760, which was filed on March 26, 2015, and is hereby incorporated by reference in its entirety.

Background

[0002] In seismic data processing, multiple datasets that have partial correlation between them may be processed. These datasets may be subject to several different sources of noise that can limit the recoverable signal content. Many noise attenuation techniques rely on processing the individual datasets separately and independently. These techniques, in general, do not utilize the correlation between these datasets. Multicomponent seismic datasets are one example. Some noise attenuation techniques that are applied to each component independently do not preserve the vector fidelity.

[0003] One seismic data processing technique that has been proposed includes extending the traditional frequency-space (f x) prediction error filters to three-component seismic records by utilizing a vector autoregression (VAR) model to exploit correlation between the components. However, this model ignores the noise statistics on the different components and can result in a suboptimal performance.

Summary

[0004] According to various examples, a method of mitigating noise in seismic data representing a seismic survey, the seismic data including a plurality of measured values of a plurality of components, the method utilizing relations (e.g., correlations) among the plurality of components, is disclosed. The method includes obtaining, by at least one electronic processor, seismic data, the seismic data including a plurality of values of a plurality of components; estimating, by at least one electronic processor, a plurality of noise spectra values, the respective noise spectra values representing a noise content in a respective component of the plurality of components; computing, by at least one electronic processor, a plurality of dynamic weights, the dynamic weights being a function of a respective noise spectra value; generating, by at least one electronic processor, a

vector autoregressive model using the plurality of dynamic weights and the plurality of components; filtering the seismic data, by at least one electronic processor, with the vector autoregressive model, such that noise-mitigated seismic data is produced; and providing the noise-mitigated seismic data.

[0005] Various optional features of the above examples include the following. The obtaining may include measuring. The computing may include applying a weighted total least-squares technique using the plurality of noise spectra values. The computing may include estimating each of the noise spectra values independently. The plurality of components may include a pressure component and at least one directional component. Each dynamic weight of the plurality of noise dynamic weights may include a signal-to-noise ratio. The providing may include displaying in human-viewable form. The method may include identifying a location of a petroleum reservoir using the noise-mitigated seismic data. The method may include extracting petroleum from the petroleum reservoir. The seismic data may have been acquired by a marine seismic streamer.

[0006] According to various examples, a computing system is disclosed. The computing system includes one or more electronic processors; and an electronic memory system including one or more non-transitory, computer-readable media storing instructions which, when executed by at least one of the one or more processors, cause the computing system to perform operations for mitigating noise in seismic data representing a seismic survey, the seismic data including a plurality of measured values of a plurality of components, the operations utilizing relations (e.g., correlations) among the plurality of components, the operations including: obtaining, by at least one electronic processor, seismic data, the seismic data including a plurality of values of a plurality of components; estimating, by at least one electronic processor, a plurality of noise spectra values, the respective noise spectra value representing a noise content in a respective component of the plurality of components; computing, by the one or more electronic processors, a plurality of dynamic weights, the respective dynamic weights being a function of a respective noise spectra value; generating, by the one or more electronic processors, a vector autoregressive model using the plurality of dynamic weights and the plurality of components; filtering the seismic data, by the one or more electronic processors, with the vector autoregressive model, such that noise-mitigated seismic data is produced; and providing the noise-mitigated seismic data.

[0007] Various optional features of the above examples include the following. The obtaining may include measuring. The computing may include applying a weighted total least-squares

technique using the plurality of noise spectra values. The computing may include estimating each of the noise spectra values independently. The plurality of components may include a pressure component and at least one directional component. Each dynamic weight of the plurality of noise dynamic weights may include a signal-to-noise ratio. The method may include an electronic display, where the providing includes displaying in human-viewable form on the electronic display. The noise-mitigated seismic data may include a representation of a location of a petroleum reservoir capable of providing extractable petroleum. The seismic data may have been acquired by a marine seismic streamer.

[0008] According to various examples, a non-transitory, computer-readable medium storing instructions that, when executed by at least one processor of a computing system, cause the computing system to perform operations for mitigating noise in seismic data representing a seismic survey, the seismic data including a plurality of measured values of a plurality of components, the mitigating noise utilizing relations (e.g., correlations) among the plurality of components, is disclosed. The operations include: obtaining, by at least one electronic processor, seismic data, the seismic data including a plurality of values of a plurality of components; estimating, by at least one electronic processor, a plurality of noise spectra values, the respective noise spectra value representing a noise content in a respective component of the plurality of components; computing, by the one or more electronic processors, a plurality of dynamic weights, the respective dynamic weights being a function of a respective noise spectra value; generating, by the one or more electronic processors, a vector autoregressive model using the plurality of dynamic weights and the plurality of components; filtering the seismic data, by the one or more electronic processors, with the vector autoregressive model, such that noise-mitigated seismic data is produced; and providing the noise-mitigated seismic data.

[0009] The present disclosure provides systems, methods, and computer-readable media for noise mitigation in multiple correlated data sets. Examples of the disclosure may include extending VAR modeling to multiple correlated datasets. The VAR model may be extended by using adaptive weights to weight each dataset. The noise mitigation activity may then formulated as a weighted total least square. In addition, or in the alternative, a heuristic approach may be used to apply these weights to the estimation of the VAR model parameters from these datasets. In one example, the present disclosure may be applied to multimeasurement seismic streamer noise

attenuation. Thus, some examples solve the problem of noise attenuation in seismic data in an efficient manner that is particularly suitable for multimeasurement seismic data.

[0010] The foregoing summary is provided merely to introduce a subset of the aspects of the disclosure presented more fully below. This summary is, therefore, not to be considered exhaustive.

Brief Description of the Drawings

[0011] The accompanying drawings, which are incorporated in and constitute a part of this specification, illustrate examples of the present teachings and together with the description, serve to explain the principles of the present teachings.

[0012] Figure 1 shows a simplified, schematic view of an oilfield and its operation, according to some examples.

[0013] Figure 2 shows a simplified, schematic view of an oilfield with a seismic survey truck according to some examples.

[0014] Figure 3 shows a simplified, schematic view of an oilfield with a wireline tool according to some examples.

[0015] Figure 4 shows a simplified, schematic view of an oilfield with a marine seismic streamer according to some examples.

[0016] Figure 5 shows a schematic diagram of a sensor set according to some examples.

[0017] Figure 6 is a flowchart illustrating a method for noise mitigation in a multiple dataset according to some examples.

[0018] Figures 7A, 7B, 7C, 7D, 7E, and 7F illustrate seismic datasets of various components with and without added synthetic noise.

[0019] Figure 8 illustrates a power spectrum of noise synthetics in pressure and velocity according to some examples.

[0020] Figures 9A, 9B, 9C, 9D, 9E, 9F, 9G, 9H, and 9I illustrate de-noised pressure, crossline and vertical velocity data using Canales' f x de-noising, VAR, and weighted VAR, according to some examples.

[0021] Figures 10A, 10B, and 10C illustrate a difference of crossline velocity between the noisy measurement and Canales' f x de-noising, VAR, and weighted VAR, according to some examples.

[0022] Figure 11 illustrates a schematic view of a computing or processor system for performing the method according to some examples.

Detailed Description

[0023] Reference will now be made in detail to examples, which are illustrated in the accompanying drawings and figures. In the following detailed description, numerous specific details are set forth in order to provide a thorough understanding of the disclosure. However, it will be apparent to one of ordinary skill in the art that the disclosed techniques may be practiced without these specific details. In other instances, well-known methods, procedures, components, circuits and networks have not been described in detail so as not to unnecessarily obscure aspects of the examples.

[0024] It will also be understood that, although the terms first, second, etc. may be used herein to describe various elements, these elements should not be limited by these terms. These terms are only used to distinguish one element from another. For example, a first object or step could be termed a second object or step, and, similarly, a second object or step could be termed a first object or step, without departing from the scope of the claims. The first object or step, and the second object or step, are both, objects or steps, respectively, but they are not to be considered the same object or step.

[0025] The terminology used in the present description is for the purpose of describing particular examples only and is not intended to be limiting. As used in the description and the appended claims, the singular forms “a,” “an” and “the” are intended to include the plural forms as well, unless the context clearly indicates otherwise. It will also be understood that the term “and/or” as used herein refers to and encompasses any possible combinations of one or more of the associated listed items. It will be further understood that the terms “includes,” “including,” “comprises” and/or “comprising,” when used in this specification, specify the presence of stated features, integers, steps, operations, elements, and/or components, but do not preclude the presence or addition of one or more other features, integers, steps, operations, elements, components, and/or groups thereof. Further, as used herein, the term “if” may be construed to mean “when” or “upon” or “in response to determining” or “in response to detecting,” depending on the context.

[0026] Attention is now directed to processing procedures, methods, techniques and workflows that are in accordance with some examples. Some operations in the processing procedures,

methods, techniques and workflows disclosed herein may be combined and/or the order of some operations may be changed.

[0027] I. Oilfield Operations & Seismic Surveys

[0028] Figure 1, 2, 3 and 4 illustrate example oilfields as contemplated for various examples. Seismic surveys conducted on the oilfields, as shown and described in reference to these figures, may benefit from the noise mitigation techniques disclosed herein.

[0029] Figure 1 illustrates an oilfield 100 in accordance with implementations of various technologies and techniques described herein. As shown, the oilfield has a plurality of wellsites 102 operatively connected to central processing facility 154. The oilfield configuration of Figure 1 is not intended to limit the scope of the oilfield application system. Part, or all, of the oilfield may be on land and/or sea. Also, while a single oilfield with a single processing facility and a plurality of wellsites is depicted, any combination of one or more oilfields, one or more processing facilities and one or more wellsites may be present.

[0030] Each wellsite 102 has equipment that forms wellbores 136 into the earth. The wellbores extend through subterranean formations 106, including reservoirs 104. These reservoirs 104 contain fluids, such as hydrocarbons. The wellsites draw fluid from the reservoirs and pass them to the processing facilities via surface networks 144. The surface networks 144 have tubing and control mechanisms for controlling the flow of fluids from the wellsite to processing facility 154.

[0031] Figure 2 shows a simplified, schematic view of an oilfield with a seismic survey truck according to some examples. As shown, oilfield 200 has subterranean formation 202 containing petroleum reservoir 204 therein. Figure 2 also illustrates a seismic survey operation being performed by a survey tool, such as seismic survey truck 206a, to measure properties of the subterranean formation. The survey operation includes production of sound vibrations. In Figure 2, such sound vibration, e.g., sound vibration 212 generated by seismic source 210 (e.g., a seismic shot), reflects off horizons 214 in earth formation 216. A set of sound vibrations is received by sensors, such as geophone receivers 218 (a type of seismic receiver), situated on the earth's surface. Geophone receivers 218 may include multiple sensors that measure one or more of pressure, particle acceleration in the vertical direction, and/or particle acceleration in a direction within the horizontal plane (e.g., in one or both of the directions of x- and y-axes situated on a plane parallel to the ground). An example of such a sensor is further shown and described in reference to Figure 5. The data received 220 is provided as input data to a computer 222a of a seismic survey truck

206a, and responsive to the input data, computer 222a generates seismic data output 224. This seismic data output may be stored, transmitted or further processed as desired, for example, by data reduction or noise mitigation as disclosed herein.

[0032] Computer facilities may be positioned at various locations about the oilfield 200 and/or at remote locations, e.g., on seismic survey truck 206a. Such computer facilities may be used to communicate with the drilling tools and/or offsite operations, as well as with other surface or downhole sensors. Seismic survey truck 206a is capable of communicating with the drilling tools to send commands to the drilling tools, and to receive data therefrom. Seismic survey truck 206a may also collect data generated during the drilling operation and produce data output 235, which may then be stored or transmitted.

[0033] Figure 3 shows a simplified, schematic view of an oilfield with a wireline tool according to some examples. In particular, Figure 3 illustrates a wireline operation being performed by wireline tool 306c suspended by rig 328 and into wellbore 336. Wireline tool 306c is adapted for deployment into wellbore 336 for generating well logs, performing downhole tests and/or collecting samples. Wireline tool 306c may be used to provide another method and apparatus for performing a seismic survey operation. Wireline tool 306c may, for example, have an explosive, radioactive, electrical, or acoustic energy source 344 that sends and/or receives electrical or other signals to surrounding subterranean formations 302 and fluids therein. Wireline tool 306c may include one or more geophone receivers, which may include multiple sensors that measure one or more of pressure, particle acceleration in the vertical direction, and/or particle acceleration in a direction within the horizontal plane (e.g., in one or both of the directions of x- and y-axes situated on a plane parallel to the ground). An example of such a sensor is further shown and described in reference to Figure 5.

[0034] Note that the technology and elements of Figures 1, 2 and 3 may be present in the same oilfield and interact as described presently. That is, oilfield 100, oilfield 200 and oilfield 300 may be the same oilfield. Wireline tool 306c of Figure 3 may be operatively connected to, or provide sound or data signals to, for example, geophone receivers 218 and a computer 322a of seismic survey truck 306a of Figure 2. Wireline tool 306c may also provide data to surface unit 334. Surface unit 334 may collect data generated during the wireline operation and may produce data output 335 that may be stored or transmitted. Wireline tool 306c may be positioned at various depths in the wellbore 336 to provide a seismic survey or other information relating to the

subterranean formation 302. Source 210 may provide sound energy that is reflected and then detected by any of geophone receivers 218, sensors (S), or wireline tool 306c.

[0035] Sensors (S), such as gauges, geophone receivers 218 of Figure 2, or such as those shown and described in reference to Figure 5, that are capable of obtaining multiple correlated datasets, may be positioned about oilfield 300 to collect data relating to various field operations as described previously. As shown, sensor S is positioned in wireline tool 306c to measure downhole parameters which relate to, for example porosity, permeability, fluid composition and/or other parameters of the field operation.

[0036] Typically, the wellbore is drilled according to a drilling plan that is established prior to drilling. The drilling plan typically sets forth equipment, pressures, trajectories and/or other parameters that define the drilling process for the wellsite. The drilling operation may then be performed according to the drilling plan. However, as information is gathered, the drilling operation may need to deviate from the drilling plan. Additionally, as drilling or other operations are performed, the subsurface conditions may change. The earth model may also need adjustment as new information is collected

[0037] The data gathered by sensors (S) may be collected by surface unit 334 and/or other data collection sources such as computer 222a of a seismic survey truck 206a for analysis or other processing. The data collected by sensors (S) may be used alone or in combination with other data. The data may be collected in one or more databases and/or transmitted on or offsite. The data may be historical data, real time data, or combinations thereof. The real time data may be used in real time, or stored for later use. The data may also be combined with historical data or other inputs for further analysis. The data may be stored in separate databases, or combined into a single database.

[0038] Surface unit 334 may include transceiver 337 to allow communications between surface unit 134 and various portions of the oilfield 300 or other locations. Surface unit 134 may also be provided with or functionally connected to one or more controllers (not shown) for actuating mechanisms at oilfield 300. Surface unit 334 may then send command signals to any equipment in oilfield 300 in response to data received. Surface unit 334 may receive commands via transceiver 337 or may itself execute commands to the controller. A processor may be provided to analyze the data (locally or remotely), make the decisions and/or actuate the controller. In this manner, oilfield 300 may be selectively adjusted based on the data collected. This technique may

be used to optimize (or improve) portions of the field operation, such as controlling drilling, weight on bit, pump rates, wellbore location or trajectory, or other parameters. These adjustments may be made automatically based on computer protocol, and/or manually by an operator. In some cases, well plans may be adjusted to select optimum (or improved) operating conditions, or to avoid problems.

[0039] While Figures 2, and 3 illustrate tools used to measure properties of an oilfield, it will be appreciated that the tools may be used in connection with non-oilfield operations, such as gas fields, mines, aquifers, storage or other subterranean facilities. Also, while certain data acquisition tools are depicted, it will be appreciated that various measurement tools capable of sensing parameters, such as pressure, particle acceleration in the direction of any or all three-dimensional axes, seismic two-way travel time, density, resistivity, production rate, etc., of the subterranean formation and/or its geological formations may be used. Various sensors (S) may be located at various positions along the wellbore and/or the monitoring tools to collect and/or monitor the desired data. Other sources of data may also be provided from offsite locations.

[0040] The field configurations of Figures 1, 2, and 3 are intended to provide a brief description of an example of a field usable with oilfield application frameworks. Part, or the entirety, of oilfields 100, 200 and 300 may be on land, water and/or sea. Also, while a single field measured at a single location is depicted, oilfield applications may be utilized with any combination of one or more oilfields, one or more processing facilities and one or more wellsites.

[0041] Figure 4 shows a simplified, schematic view of an oilfield with a marine seismic streamer according to some examples. That is, Figure 4 illustrates a side view of a marine-based seismic survey 460 of a subterranean subsurface 462 in accordance with one or more implementations of various techniques described herein. Subsurface 462 includes seafloor surface 464. Seismic sources 466 may include marine sources such as vibroseis or airguns, which may propagate seismic waves 468 (e.g., energy signals) into the Earth over an extended period of time or at a nearly instantaneous energy provided by impulsive sources. The seismic waves may be propagated by marine sources as a frequency sweep signal. For example, marine sources of the vibroseis type may initially emit a seismic wave at a low frequency (e.g., 5 Hz) and increase the seismic wave to a high frequency (e.g., 80-90Hz) over time.

[0042] The component(s) of the seismic waves 468 may be reflected and converted by seafloor surface 464 (i.e., reflector), and seismic wave reflections 470 may be received by a plurality of

seismic receivers 472 (here, marine seismic receivers). Seismic receivers 472 may be disposed on a plurality of streamers (i.e., streamer array 474). The seismic receivers 472 may generate electrical signals representative of the received seismic wave reflections 470. The electrical signals may be embedded with information regarding the subsurface 462 and captured as a record of seismic data. Seismic receivers 472 may be as shown and described in reference to Figure 5, below.

[0043] In one implementation, each streamer may include streamer steering devices such as a bird, a deflector, a tail buoy and the like, which are not illustrated in this application. The streamer steering devices may be used to control the position of the streamers.

[0044] In one implementation, seismic wave reflections 470 may travel upward and reach the water/air interface at the water surface 476, a portion of reflections 470 may then reflect downward again (i.e., sea-surface ghost waves 478) and be received by the plurality of seismic receivers 472. The sea-surface ghost waves 478 may be referred to as surface multiples. The point on the water surface 476 at which the wave is reflected downward is generally referred to as the downward reflection point.

[0045] The electrical signals may be transmitted to a vessel 480 via transmission cables, wireless communication or the like. The vessel 480 may then transmit the electrical signals to a data processing center. Alternatively, the vessel 480 may include an onboard computer capable of processing the electrical signals (i.e., seismic survey data). Those skilled in the art having the benefit of this disclosure will appreciate that this illustration is highly idealized. For instance, surveys may be of formations deep beneath the surface. The formations may typically include multiple reflectors, some of which may include dipping events, and may generate multiple reflections (including wave conversion) for receipt by the seismic receivers 472. In one implementation, the seismic data may be processed to generate a seismic image of the subsurface 462.

[0046] Marine seismic acquisition systems tow each streamer in streamer array 474 at the same depth (e.g., 5-10m). However, marine based survey 460 may tow each streamer in streamer array 474 at different depths such that seismic data may be acquired and processed in a manner that avoids the effects of destructive interference due to sea-surface ghost waves. For instance, marine-based survey 460 of Figure 4 illustrates eight streamers towed by vessel 480 at eight different

depths. The depth of each streamer may be controlled and maintained using the birds disposed on each streamer.

[0047] Figure 5 shows a schematic diagram of a sensor set 506 according to some examples. Sensor set 506 (typically multiple such sensor sets) may be used to obtain seismic survey data as shown and described herein in reference to Figures 1, 2, 3, and 4. That is, sensor set 506 (of multiple instances thereof) may be included in, and provide data from, any of geophone receivers 218, sensors S, wireline tool 306c, and/or seismic receivers 472. Other arrangements are also possible.

[0048] As depicted, sensor set 506 is part of a seismic steamer portion 504; that is, sensor set 506 is depicted as attached to cable 508, however, such a cable may be omitted in some applications, e.g., as terrestrial sensors. The sensor set 506 may be a multi-sensor set capable of obtaining multimeasurement data. Further, a plurality of such sensor sets 506 may be included along a cable at intervals (e.g., 1-100 meter intervals) to form a single seismic streamer. A marine vehicle may tow many seismic streamers, spaced apart (e.g., 10-100 meters or more apart), as part of a seismic survey. Such a marine vehicle may also tow seismic sources to generate a signal whose reflection is captured by the sensor sets of the seismic streamers.

[0049] To establish an orientation of an example, Figure 5 depicts axes 502, which represent spatial dimensions relative to seismic steamer portion 504, with the x-axis running in a left and right direction relative to the page, the y-axis running into and out of the page, and the z-axis running in an up and down direction relative to the page. In an example, the plane defined by the x-axis and y-axis may be parallel to the surface of a body of water, and the z-axis may be perpendicular to the surface of such a body of water. A marine vehicle may tow multiple seismic streamers, including seismic steamer portion 504, in the direction of the x-axis.

[0050] In an example, the sensor set 506 may be a multi-sensor set 506 as depicted in Figure 5. Such multi-sensor sets 506 may, in some examples, include four sensors: a hydrophone (or geophone) pressure sensor, and at least one, e.g., three, particle motion sensors, which may measure velocity, acceleration, and/or pressure gradients. For example, such particle motion sensors may be or include accelerometers. Particle accelerometers may include micro-electromechanical systems, or MEMs. The particle accelerometers may measure particle acceleration in specific orientations as generated by a wavefield. For example, the particle accelerometers may measure particle acceleration in the direction of the y-axis, i.e., in a crossline

direction relative to a tow direction, particle acceleration in the direction of the x-axis, i.e., in an inline direction, and/or particle acceleration in the direction of the z-axis, i.e., in a vertical direction. The hydrophone may measure ambient pressure generated by a wavefield. Note that data produced by the individual component sensors of multi-sensor sets 506 are typically correlated with each other.

[0051] Any recorded energy that interferes with the desired signal measured by the multimeasurement towed marine streamer can be considered noise. In multimeasurement marine seismic acquisition, several different sources of noise may affect the quality of the measurements and result in a suboptimal performance for further processing procedures, such as wavefield three-dimensional deghosting (see below) and crossline reconstruction. The motion of towed-streamers is an energetic source of noise on particle velocity measurements (and hence, pressure gradient signal). The particle motion sensors measure streamer-borne noise such as longitudinal, transversal and torsional noise. The dominant noise modes are the torsional vibrations. This noise is typically several orders of magnitude stronger than the noise measured by hydrophones at low and high frequencies. This noise can be nonstationary in space and can also change considerably within a single record.

[0052] Wavefield deghosting may generally refer to removing downgoing waves from the wavefield. In marine seismic acquisitions, the sensors record not only the desired upgoing wavefield reflected from geological formations, but also its reflections from the sea surface known as downgoing wavefield, or seismic ghost. Multi-sensor seismic streamers that include multi-sensor sets 506 may collect data suitable for algorithmic identification and separation of upgoing and reflected downgoing wavefields. This may provide for the ability to algorithmically deghost (e.g., remove reflected downgoing wavefields from) the signal. Deghosting may address the temporal frequency bandwidth, overcoming notches in the frequency band that originate from positive and destructive interferences. Such interferences may result from the presence of a free surface, such as the sea or land surface. Note that the noise mitigation techniques disclosed herein may be applied to seismic survey data prior, or subsequent, to deghosting.

[0053] Thus Figures 1, 2, 3, 4, and 5 depict contexts and technologies related to acquiring seismic survey data that includes multi-datasets of correlated data. Such multi-datasets may be processed to remove noise as described herein.

[0054] II. Noise & Noise Mitigation

[0055] In seismic processing, multiple datasets that have partial correlation between them may be processed. These datasets may be affected by noise that has different characteristics. Examples of such datasets include 4-D seismic processing, multicomponent seismic, multimeasurement streamer seismic survey data. Examples of expedients for obtaining such data are presented herein in reference to Figures 1, 2, 3, 4, and 5. In general, different approaches may be taken to reduce the impact of noise in multi-dataset data. For example, the noise modes may be separated from the desired signal in some data-domains, and therefore able to be attenuated by digital noise processing techniques. This way, the relation between the signal in the multiple datasets may be preserved. In order to further attenuate the residual noise that might not be separated from the desired signal, different methods may be applied in each dataset independently. For example, a 2D (time-space) seismic signal that includes solely linear events may have an $f-x$ domain representation that is predictable in space for each frequency f . Autoregressive prediction filters may then be used for de-noising. However, independent multi-dataset prediction filters ignore the inherent signal correlation.

[0056] The $f-x$ random noise attenuation may be expanded to three-component seismic records by utilizing the VAR model to exploit coherencies between each pair of components and achieve further noise reduction. The VAR model parameters may be estimated using the least-squares minimization of forward and backward prediction errors. However, the VAR de-noising approach may give equal importance to each measurement and may ignore the different noise statistics between the different datasets. To reduce the impact of noise in multiple datasets, the VAR approach may be expanded to any number of datasets. Moreover, adaptive weights for the multi-dataset may be employed. These weights may be assigned to each dataset and may be proportional to the signal-to-noise ratio (SNR) estimated from that dataset. Therefore, some examples of the present disclosure may use the correlation between the different datasets to achieve more powerful noise attenuation and preserve the signal relation between these datasets. This technique may be general to any datasets that have correlation between them but for the sake of simplicity, the particular example of multimeasurement streamer data denoising may be illustrative.

[0057] In a multimeasurement data streamer, for example, the vibration noise propagating along the cable may be dominant on the accelerometer measurements. This noise may propagate along the cable more slowly than the seismic events reflected from the subsurface. Other sources of noise also affects the accelerometers, also propagating very slowly along the cable: among others,

examples of such noise generation include torsional noise, weather related noise, noise associated to positioning equipment, currents, noise generated by external sources of perturbation such as barnacles on the cables, between others.

[0058] In at least some cases, the noise is much stronger in amplitude than most reflected seismic signals, and thus noise results in fine sampling (and hence very high acquisition costs) to safely remove the noise with a time-space filter during processing. If the noise is not sampled correctly, often due to cost efficiency reasons, its spatial alias may compromise the usable signal. This may be challenging to attenuate during processing, due to both sampling ability and high dynamic range. The multimeasurement streamer data may be affected by different types of noise; the noise measured by accelerometers may be several orders of magnitude stronger than the noise measured by hydrophones, especially at low frequencies. A noise attenuation approach in dealing with multimeasurement (pressure inline, crossline and vertical particle velocity or acceleration) towed marine seismic data is to process each measurement separately, as is done by examples disclosed herein. In order to preserve the signal and vector fidelity in a multimeasurement data, these techniques may be applied to attenuate the noise outside the signal cone.

[0059] Multimeasurement streamer data may be related to each other through the ghost model. Therefore, apart from the frequency ghost notches, they may be correlated. As a result, by utilizing the multimeasurement signal coherencies, the noise within the signal cone may be tackled while preserving the vector fidelity in multimeasurement data. Some approaches utilize the correlation between the pressure and other components and mainly use the pressure to de-noise the other components.

[0060] Let $\{d_k(f, x)\}_{k=1}^K$ represent the K dataset in the frequency-space (f vs x), where K represents the dimensionality of the data (e.g., the number of components, typically $K=3$ or 4). The spatial variable x is replaced by its discrete counterpart $x_l = (l - 1) \Delta x$ where Δx is the trace spacing. For the sake of simplicity, frequency may be omitted from the notation, $d_k(f, x) = d_{kl}$.

[0061] Assuming that the available data may be represented as a superposition of R events with linear moveout, the multi-datasets data of N sensors may be represented in the forward and backward direction by difference equations of order r as follows:

$$\begin{aligned} \underline{m}_n &= \sum_{r=1}^R \mathbf{A}_r^T \underline{m}_{n-r} \quad n = R + 1, \dots, N \\ \underline{m}_n &= \sum_{r=1}^R \mathbf{A}_r^T \underline{m}_{n+r} \quad , n = 1, \dots, N - R \end{aligned} \quad (1)$$

where $\underline{m}_n = [d_{1n} \ d_{2n} \ \dots \ d_{Kn}]^T$ is the multimeasurement vector at the n^{th} location. The superscripts $*$ and T denote the complex conjugate and transpose. The matrix $\mathbf{A}_r \in \mathbb{C}^{K \times K}$ represents the vector autoregressive model (VAR) defined as

$$\mathbf{A}_r = \begin{bmatrix} a_{d_1 d_1, r} & a_{d_1 d_2, r} & a_{d_1 d_K, r} \\ a_{d_2 d_1, r} & a_{d_2 d_2, r} & a_{d_2 d_K, r} \\ a_{d_K d_1, r} & a_{d_K d_2, r} & a_{d_K d_K, r} \end{bmatrix} = [\underline{A}_{d_1, r} \ \underline{A}_{d_2, r} \ \dots \ \underline{A}_{d_K, r}], \quad (2)$$

where $a_{YX, r}$ denotes the r^{th} filter coefficient to model X by applying it to Y. The equations in (1) represent a R -order vector autoregressive model for multimeasurement data. To estimate the VAR model, a linear system of equations may be built as follows:

$$\begin{array}{ccccccc} \underline{m}_{R+1}^T & & \underline{m}_R^T & & \dots & & \underline{m}_1^T \\ & \underline{m}_N^T & & \underline{m}_{N-1}^T & & \dots & \underline{m}_{N-R}^T \\ & \underline{m}_1^H & & \underline{m}_2^H & & \dots & \underline{m}_{R+1}^H \\ & \underline{m}_{N-R}^H & & \underline{m}_{N-R+1}^H & & \dots & \underline{m}_N^H \end{array} = \begin{array}{c} \underline{A}_1 \\ \underline{A}_2 \\ \vdots \\ \underline{A}_R \\ \underline{A} \end{array}, \quad (3)$$

$\underbrace{\hspace{10em}}_M \quad \underbrace{\hspace{10em}}_D$

$$\text{Or } \mathbf{M} = \mathbf{D}\mathbf{A}$$

where the superscript H denotes the complex conjugate transpose. The elements of $\mathbf{A}_k$ in (3) may then be obtained using least-squares. Once the VAR model $\hat{\mathbf{A}}$ is estimated, it may be applied to the data to obtain the filtered data matrix $\hat{\mathbf{M}}$:

$$\hat{\mathbf{M}} = \mathbf{D}\hat{\mathbf{A}}, \quad (4)$$

from which the filtered multimeasurement streamer data can be obtained by averaging repeated entries.

[0062] The filtering operation in (4) can be rewritten as:

$$\begin{aligned} \hat{\mathbf{M}} &= [\mathbb{D}_1 \ \mathbb{D}_2 \ \dots \ \mathbb{D}_K] \begin{bmatrix} \hat{\mathbf{A}}_1 \\ \hat{\mathbf{A}}_2 \\ \vdots \\ \hat{\mathbf{A}}_K \end{bmatrix} \\ &= \mathbb{D}_1 \hat{\mathbf{A}}_1 + \mathbb{D}_2 \hat{\mathbf{A}}_2 + \dots + \mathbb{D}_K \hat{\mathbf{A}}_K \end{aligned} \quad (5)$$

where $\mathbb{D}_n$ are submatrices from the matrix $\mathbf{D}$ arranged from the individual measurements d_n . The matrices $\hat{\mathbf{A}}_n$ are also rearranged from $\mathbf{A}$. For instance, $\hat{\mathbf{A}}_1$ is defined as:

$$\hat{\mathbf{A}}_1 = \begin{matrix} \hat{a}_{d_1 d_1,1} & \hat{a}_{d_1 d_2,1} & \hat{a}_{d_1 d_K,1} \\ \hat{a}_{d_1 d_1,2} & \hat{a}_{d_1 d_2,2} & \hat{a}_{d_1 d_K,2} \\ \hat{a}_{d_1 d_1,R} & \hat{a}_{d_1 d_2,R} & \hat{a}_{d_1 d_K,R} \end{matrix} \quad (6)$$

[0063] The measurements in $\{\mathbb{D}_k\}_{k=1}^K$ may be affected by different types of noise. For example, in the case of multimeasurement streamer data, the noise measured by accelerometers may be several orders of magnitude stronger than the noise measured by hydrophones, especially at low frequencies. The least squares estimate $\hat{\mathbf{A}}$ minimizes the square of the error giving equal weight to the datasets. To reduce the impact of noise, adaptive weights for the multi-dataset may be used. These weights correspond to each measurement in the system of equations and may be inversely proportional to the noise model estimated from each dataset for noise models that estimate an amount of noise (e.g., in decibels), or may be proportional for models that estimate SNR. When the noise power is high in the measurement, the weight decreases, reflecting a high degree of uncertainty in the dataset. On the other hand, when the noise power is low, the weight increases indicating high confidence in the measurement. Different approaches can then be used to combat the noise effects in the data matrix $\mathbf{D}$ and the observation matrix $\mathbf{M}$. For example, a weighted total least-squares approach (WTLS) may be used. A new matrix $\mathbf{C}$ may be defined as follows:

$$\mathbf{C} = [\mathbf{D} \quad \mathbf{M}] \quad (7)$$

and a corresponding weight matrix $\mathbf{W}$ and define a weighted matrix norm as:

$$\|\mathbf{C}\|_w = \sqrt{\text{vec}^H(\mathbf{C}^H) \mathbf{W} \text{vec}(\mathbf{C}^H)} \quad (8)$$

and the weighted total squares misfit function as

$$\min_{\hat{\mathbf{C}}} \|\mathbf{C} - \hat{\mathbf{C}}\|_w \quad (9)$$

[0064] The weight matrix $\mathbf{W}$ may be variable with frequency, or space and time, i.e., it may be dynamic. There are several methods to solve this optimization, any of which may be employed. The multimeasurement streamer data may be an example of this technique.

[0065] An alternative to solving a weighted least square is a simple heuristic approach, which may be used to apply the introduced weight $\mathbf{W}$ to the estimation of the VAR model parameters. Let $P(f, x)$, $Y(f, x)$ and $Z(f, x)$ represent the frequency-space (f - x) transformed data of pressure crossline and vertical particle velocity recorded at depth z_r below the sea surface. The spatial variable x is replaced by its discrete counterpart $x_k = (k - 1) \Delta x$ where Δx is the trace

spacing. For the sake of simplicity, frequency may be omitted from the notation, $P(f, x_k) = P_k$, $Y(f, x_k) = Y_k$, $Z(f, x_k) = Z_k$.

[0066] The filtering operation in (5) may be rewritten as:

$$\begin{aligned}\hat{\mathbf{M}} &= [\mathbb{D}_P \quad \mathbb{D}_Y \quad \mathbb{D}_Z] \begin{bmatrix} \hat{\mathbf{A}}_P \\ \hat{\mathbf{A}}_Y \\ \hat{\mathbf{A}}_Z \end{bmatrix} \\ &= \mathbb{D}_P \hat{\mathbf{A}}_P + \mathbb{D}_Y \hat{\mathbf{A}}_Y + \mathbb{D}_Z \hat{\mathbf{A}}_Z\end{aligned}\tag{10}$$

where $\mathbb{D}_P, \mathbb{D}_Y, \mathbb{D}_Z$ are submatrices from the matrix $\mathbf{D}$ arranged from the individual measurements $\mathbf{P}$, $\mathbf{Y}$ and $\mathbf{Z}$. The matrices $\mathbf{A}_P, \mathbf{A}_Y, \mathbf{A}_Z$ may also be rearranged from $\mathbf{A}$. For instance, $\hat{\mathbf{A}}_P$ may be defined as:

$$\hat{\mathbf{A}}_P = \begin{bmatrix} \hat{a}_{PP,1} & \hat{a}_{PY,1} & \hat{a}_{PZ,1} \\ \hat{a}_{PP,2} & \hat{a}_{PY,2} & \hat{a}_{PZ,2} \\ \hat{a}_{PP,r} & \hat{a}_{PY,r} & \hat{a}_{PZ,r} \end{bmatrix}\tag{11}$$

where $a_{YX,k}$ denotes the k^{th} filter coefficient to model X by applying it to Y. The measurements in $\mathbb{D}_P, \mathbb{D}_Y, \mathbb{D}_Z$ may be affected by different types of noise; the noise measured by accelerometers may be several orders of magnitude stronger than the noise measured by hydrophones, especially at low frequencies. To reduce the impact of noise in multimeasurement streamer data, adaptive weights for the multimeasurement data ($w_{P,YZ}$) may be used.

[0067] A heuristic approach used to apply weights to each measurement is disclosed presently. The weights may be proportional to the SNR in each measurement. An autoregressive model for each measurement may be used independently. This simplifies the VAR model into three separate equations as follows:

$$\begin{aligned}\mathbf{M} &= \mathbb{D}_P \mathbf{A}_P \\ &= \mathbb{D}_Y \mathbf{A}_Y \\ &= \mathbb{D}_Z \mathbf{A}_Z\end{aligned}\tag{12}$$

[0068] The models may be estimated in a least square way from these equations independently and the filtered measurements may be obtained from:

$$\hat{\mathbf{M}} = w_P \mathbb{D}_P \hat{\mathbf{A}}_P + w_Y \mathbb{D}_Y \hat{\mathbf{A}}_Y + w_Z \mathbb{D}_Z \hat{\mathbf{A}}_Z,\tag{13}$$

where the weights in the previous equation are normalized such that ($w_P + w_Y + w_Z = 1$).

[0069] To simplify the formulation, the weights in (13) are assumed to be scalar quantities as a function of frequency and time. For the general case as in equation (9), these weights can be matrices (i.e., function of space, frequency and time).

[0070] In contrast to the solution given by (10), the models may be estimated independently, and then the filtered data gives different weights to the filtered data using different measurements according to their SNR. In a sense, the technique of Equations (8)-(10) provides a more accurate, but more computationally expensive solution, in comparison to the technique of Equations (12) and (13), which provides a solution that is both relatively quick to compute and sufficiently accurate for most applications.

[0071] The independent estimation of models simplifies the formulation and yields further insight in the solution. For instance, the filtered vertical velocity data can be obtained from:

$$\underline{\hat{Z}} = w_P \mathbb{D}_P \underline{\hat{A}}_{PZ} + w_Y \mathbb{D}_Y \underline{\hat{A}}_{YZ} + w_Z \mathbb{D}_Z \underline{\hat{A}}_{ZZ}, \quad (14)$$

where $\underline{\hat{A}}_{PZ}$, $\underline{\hat{A}}_{YZ}$, $\underline{\hat{A}}_{ZZ}$ are the third columns from $\underline{\hat{A}}_P$, $\underline{\hat{A}}_Y$ and $\underline{\hat{A}}_Z$, respectively. $\underline{\hat{A}}_{PP}$, $\underline{\hat{A}}_{YZ}$ are estimated using the pressure and crossline velocity data which have complementary frequency notches to the vertical velocity data due to the ghost reflection. Since the weights may be proportional to the SNR, the weights may decrease (e.g., to zero at the pressure (and crossline velocity)) notches while being maximum of (1) at the vertical velocity and for those frequencies, weighted VAR filtering reduces to conventional single component $f \times x$ random noise attenuation.

[0072] Figure 6 illustrates a flowchart of a method for noise mitigation in a multiple dataset, according to various examples. The method may be implemented by an implementation system as shown and described in reference to Figure 11, for example.

[0073] At block 602, the method obtains multiple (correlated) datasets representing seismic survey data. Such data sets may represent measurements of individual components, e.g., as shown and described herein in reference to Figures 2-5. The method may obtain such data over a computer network, by retrieval from persistent storage, or by empirical measurement, for example. The data may be represented and/or formatted as described in reference to Equation (1), above.

[0074] At block 604, the method estimates the noise spectra values of the individual correlated components. That is, at block 604, the method estimates a noise model, which may model noise or a SNR. Any of a variety of techniques may be used to estimate noise content in the components.

[0075] At block 606, the method computes dynamic weights out of each model. The method may compute the weights out of each model, either inversely proportional to the gross noise estimated by the noise model of block 604, or proportional to the SNR estimated by the noise model of block 604.

[0076] At block 608, the method estimates a VAR model filter. The model may be represented as described herein in reference to Equations (2) and (3). The model is computer implemented, e.g., using the system shown and described in reference to Figure 11. The VAR model filter may be estimated by either of two approaches as disclosed herein. For example, the VAR model filter may be estimated by using weighted total least squares, or, alternatively, using a heuristic approach. The total least squares technique is disclosed herein in reference to Equations (7)-(10). The heuristic approach is described in reference to Equations (12)-(14).

[0077] At block 610, the method filters the seismic data using the VAR model. This may be accomplished as described in reference to Equation (4). The result is noise-mitigated seismic survey data.

[0078] At block 612, the method provides the noise-mitigated seismic survey data. The output may be accomplished by visual display on a hardware computer monitor, for example, may be to a separate seismic analysis system, may be to persistent storage, or may be to another receptacle.

[0079] Once the noise-mitigated seismic survey data is provided, the method may use such data to identify a location of a petroleum reservoir, for example. The method may identify a specific location within or on the boundary of the petroleum reservoir that is suitable for accepting a wellbore. This may be followed by petroleum extraction, e.g., as shown and described in reference to Figures 1-4.

[0080] III. Variations & Comparisons to Other Techniques

[0081] Figures 7A-7F illustrates seismic datasets of various components with and without added synthetic noise. These data are subjected to various noise-mitigation techniques for purposes of comparison to the disclosed techniques. Thus, images 702, 704, and 706 depict, respectively, clean pressure, crossline (Y), and vertical (Z) components. Images 708, 710, and 712 depict, respectively, pressure, Y, and Z components with synthetic correlated noise added to each measurement (A t-gain was applied to the traces). A realistic synthetic data set may be used, generated by finite-difference modeling. The data set may simulate a 3D multimeasurement streamer survey over a geological environment representative of some areas of the Barents Sea.

The source signature spectrum bandwidth is set to 30 Hz. An inline shot of receivers is regularly spaced at 25 m. The receiver point records pressure, crossline and vertical velocity. Realistic correlated noises are added to the data.

[0082] Figure 8 depicts the spectrum of the noise added to the data of Figures 7A-7F according to some examples. Specifically, curve 802 represents the power spectrum of the noise synthetics in the pressure component, and curve 804 represents the power spectrum of the noise synthetics in the velocity components.

[0083] Figures 9A– 9I compares the performance of different de-noising methods applied to the seismic data of Figure 7 (respectively, 708, 710, 712). Figure 9A-9I shows the performance of the scalar Canales method applied individually to each measurement P, Y, Z (respectively, 902, 904, 906). Images 908, 910, 912 depict un-weighted VAR. Images 914, 916, 918 show the performance of the weighted VAR method as proposed herein. The order of the autoregressive model in all methods equals 5 (i.e., $r = 5$). Space-time windowing is applied in the methods to fulfill the linear seismic events assumption. For the weighted VAR method, the SNR is estimated from the noisy measurements using any suitable method. The pressure de-noising performance may be similar between the three methods. However, the improvement of the weighted VAR method (compared to VAR and Canales method) in terms of reducing the noise leakage in the crossline and vertical velocity data is visible particularly at low frequencies. Some examples use the disclosed techniques to mitigate noise in the crossline and vertical velocity components.

[0084] Figure 10A-10C shows the difference between the noisy crossline velocity and the various de-noising methods. Thus, image 1006 represents Canales' de-noising, image 1008 represents a VAR approach, and image 110 represents a weighted VAR approach. It can be seen that the VAR and the weighted VAR method contain less signal leakage compared to the Canales' method. This shows that using adaptive weights in VAR modelling performs better for de-noising multimeasurement streamer data since it can effectively uses information from the measurements.

[0085] As stated above, examples of the present disclosure may be applied to data acquired in a variety of configurations. This may involve multiple prestack or poststack datasets acquired in land or marine (streamer marine or ocean bottom nodes).

[0086] In at least some cases, the present disclosure may employ a correlation between different datasets to achieve further noise attenuation assuming a vector autoregressive model.

[0087] **IV. Example Implementation Systems**

[0088] In some examples, the methods of the present disclosure may be executed by a computing system.

[0089] Figure 11 illustrates an example of such a computing system 1100, in accordance with some examples. The computing system 1100 may include a computer or computer system 1101A, which may be an individual computer system 1101A or an arrangement of distributed computer systems. The computer system 1101A includes one or more analysis modules 1102 that are configured to perform various tasks according to some examples, such as one or more methods disclosed herein. To perform these various tasks, the analysis module 1102 executes independently, or in coordination with, one or more processors 1104, which is (or are) connected to one or more storage media 1106. The processor(s) 1104 is (or are) also connected to a network interface 1107 to allow the computer system 1101A to communicate over a data network 1109 with one or more additional computer systems and/or computing systems, such as 1101B, 1101C, and/or 1101D (note that computer systems 1101B, 1101C and/or 1101D may or may not share the same architecture as computer system 1101A, and may be located in different physical locations, e.g., computer systems 1101A and 1101B may be located in a processing facility, while in communication with one or more computer systems such as 1101C and/or 1101D that are located in one or more data centers, and/or located in varying countries on different continents).

[0090] A processor can include a microprocessor, microcontroller, processor module or subsystem, programmable integrated circuit, programmable gate array, or another control or computing device.

[0091] The storage media 1106 can be implemented as one or more computer-readable or machine-readable storage media. Note that while in Figure 11, storage media 1106 is depicted as within computer system 1101A, in some examples, storage media 1106 may be distributed within and/or across multiple internal and/or external enclosures of computing system 1101A and/or additional computing systems. Storage media 1106 may include one or more different forms of memory including semiconductor memory devices such as dynamic or static random access memories (DRAMs or SRAMs), erasable and programmable read-only memories (EPROMs), electrically erasable and programmable read-only memories (EEPROMs) and flash memories, magnetic disks such as fixed, floppy and removable disks, other magnetic media including tape, optical media such as compact disks (CDs) or digital video disks (DVDs), BLUERAY® disks, or other types of optical storage, or other types of storage devices. Note that the instructions discussed

above can be provided on one computer-readable or machine-readable storage medium, or alternatively, can be provided on multiple computer-readable or machine-readable storage media distributed in a large system having possibly plural nodes. Such computer-readable or machine-readable storage medium or media is (are) considered to be part of an article (or article of manufacture). An article or article of manufacture can refer to any manufactured single component or multiple components. The storage medium or media can be located either in the machine running the machine-readable instructions, or located at a remote site from which machine-readable instructions can be downloaded over a network for execution.

[0092] In some examples, computing system 1100 contains one or more noise mitigation module(s) 1108. In the example of computing system 1100, computer system 1101A includes the noise mitigation module 1108. In some examples, a single noise mitigation module may be used to perform at least some aspects of one or more examples of the methods disclosed herein. In alternate examples, a plurality of noise mitigation modules may be used to perform at least some aspects of methods disclosed herein.

[0093] It should be appreciated that computing system 1100 is but one example of a computing system, and that computing system 1100 may have more or fewer components than shown, may combine additional components not depicted in the example of Figure 11, and/or computing system 1100 may have a different configuration or arrangement of the components depicted in Figure 11. The various components shown in Figure 11 may be implemented in hardware, software, or a combination of both hardware and software, including one or more signal processing and/or application specific integrated circuits.

[0094] Further, the steps in the processing methods described herein may be implemented by running one or more functional modules in information processing apparatus such as general purpose processors or application specific chips, such as ASICs, FPGAs, PLDs, or other appropriate devices. These modules, combinations of these modules, and/or their combination with general hardware are included within the scope of this disclosure.

[0095] The foregoing description, for purpose of explanation, has been described with reference to specific examples. However, the illustrative discussions above are not intended to be exhaustive or to limit the claims to the precise forms disclosed. Many modifications and variations are possible in view of the above teachings. Moreover, the order in which the elements of the methods

described herein are illustrate and described may be re-arranged, and/or two or more elements may occur simultaneously.

CLAIMS

What is claimed is:

1. A method of mitigating noise in seismic data representing a seismic survey, the seismic data comprising a plurality of measured values of a plurality of components, the method utilizing relations among the plurality of components, the method comprising:

obtaining, by at least one electronic processor, seismic data, the seismic data comprising a plurality of values of each of a plurality of components;

estimating, by at least one electronic processor, a plurality of noise spectra values, the respective noise spectra values representing a noise content in a respective component of the plurality of components;

computing, by at least one electronic processor, a plurality of dynamic weights, the respective dynamic weights being a function of a respective one of the plurality of noise spectra values;

generating, by at least one electronic processor, a vector autoregressive model using the plurality of dynamic weights and the plurality of components;

filtering the seismic data, by at least one electronic processor, with the vector autoregressive model, whereby noise-mitigated seismic data is produced; and

providing the noise-mitigated seismic data.

2. The method of claim 1, wherein the obtaining comprises measuring.

3. The method of claim 1, wherein the computing comprises applying a weighted total least-squares technique using the plurality of noise spectra values.

4. The method of claim 1, wherein the computing comprises estimating the noise spectra values independently of one another.

5. The method of claim 1, wherein the plurality of components comprise a pressure component and at least one directional component.

6. The method of claim 1, wherein the dynamic weight of the plurality of noise dynamic weights comprises a signal-to-noise ratio.
7. The method of claim 1, wherein the providing comprises displaying in human-viewable form.
8. The method of claim 1, further comprising identifying a location of a petroleum reservoir using the noise-mitigated seismic data.
9. The method of claim 8, further comprising extracting petroleum from the petroleum reservoir.
10. The method of claim 1, wherein the seismic data was acquired by a marine seismic streamer.
11. A computing system, comprising
one or more electronic processors; and
an electronic memory system comprising one or more non-transitory, computer-readable media storing instructions which, when executed by at least one of the one or more processors, cause the computing system to perform operations for mitigating noise in seismic data representing a seismic survey, the seismic data comprising a plurality of measured values of a plurality of components, the operations utilizing relations among the plurality of components, the operations comprising:
 - obtaining, by at least one electronic processor, seismic data, the seismic data comprising a plurality of values of each of a plurality of components;
 - estimating, by at least one electronic processor, a plurality of noise spectra values, the respective noise spectra values representing a noise content in a respective component of the plurality of components;

computing, by at least one electronic processor, a plurality of dynamic weights, the respective dynamic weights being a function of a respective one of the plurality of noise spectra values;

generating, by at least one electronic processor, a vector autoregressive model using the plurality of dynamic weights and the plurality of components;

filtering the seismic data, by at least one electronic processor, with the vector autoregressive model, whereby noise-mitigated seismic data is produced; and

providing the noise-mitigated seismic data.

12. The system of claim 11, wherein the obtaining comprises measuring.

13. The system of claim 11, wherein the computing comprises applying a weighted total least-squares technique using the plurality of noise spectra values.

14. The system of claim 11, wherein the computing comprises estimating the noise spectra values independently of one another.

15. The system of claim 11, wherein the plurality of components comprise a pressure component and at least one directional component.

16. The system of claim 11, wherein each dynamic weight of the plurality of noise dynamic weights comprises a signal-to-noise ratio.

17. The system of claim 11, further comprising an electronic display, wherein the providing comprises displaying in human-viewable form on the electronic display.

18. The system of claim 11, wherein the noise-mitigated seismic data comprises a representation of a location of a petroleum reservoir capable of providing extractable petroleum.

19. The system of claim 11, wherein the seismic data was acquired by a marine seismic streamer.

20. A non-transitory, computer-readable medium storing instructions that, when executed by at least one processor of a computing system, cause the computing system to perform operations for mitigating noise in seismic data representing a seismic survey, the seismic data comprising a plurality of measured values of a plurality of components, the operations for mitigating noise utilizing relations among the plurality of components, the operations comprising:

obtaining, by at least one electronic processor, seismic data, the seismic data comprising a plurality of values of each of a plurality of components;

estimating, by at least one electronic processor, a plurality of noise spectra values, the respective noise spectra values representing a noise content in a respective component of the plurality of components;

computing, by at least one electronic processor, a plurality of dynamic weights, the respective dynamic weights being a function of a respective one of the plurality of noise spectra values;

generating, by at least one electronic processor, a vector autoregressive model using the plurality of dynamic weights and the plurality of components;

filtering the seismic data, by at least one electronic processor, with the vector autoregressive model, whereby noise-mitigated seismic data is produced; and

providing the noise-mitigated seismic data.

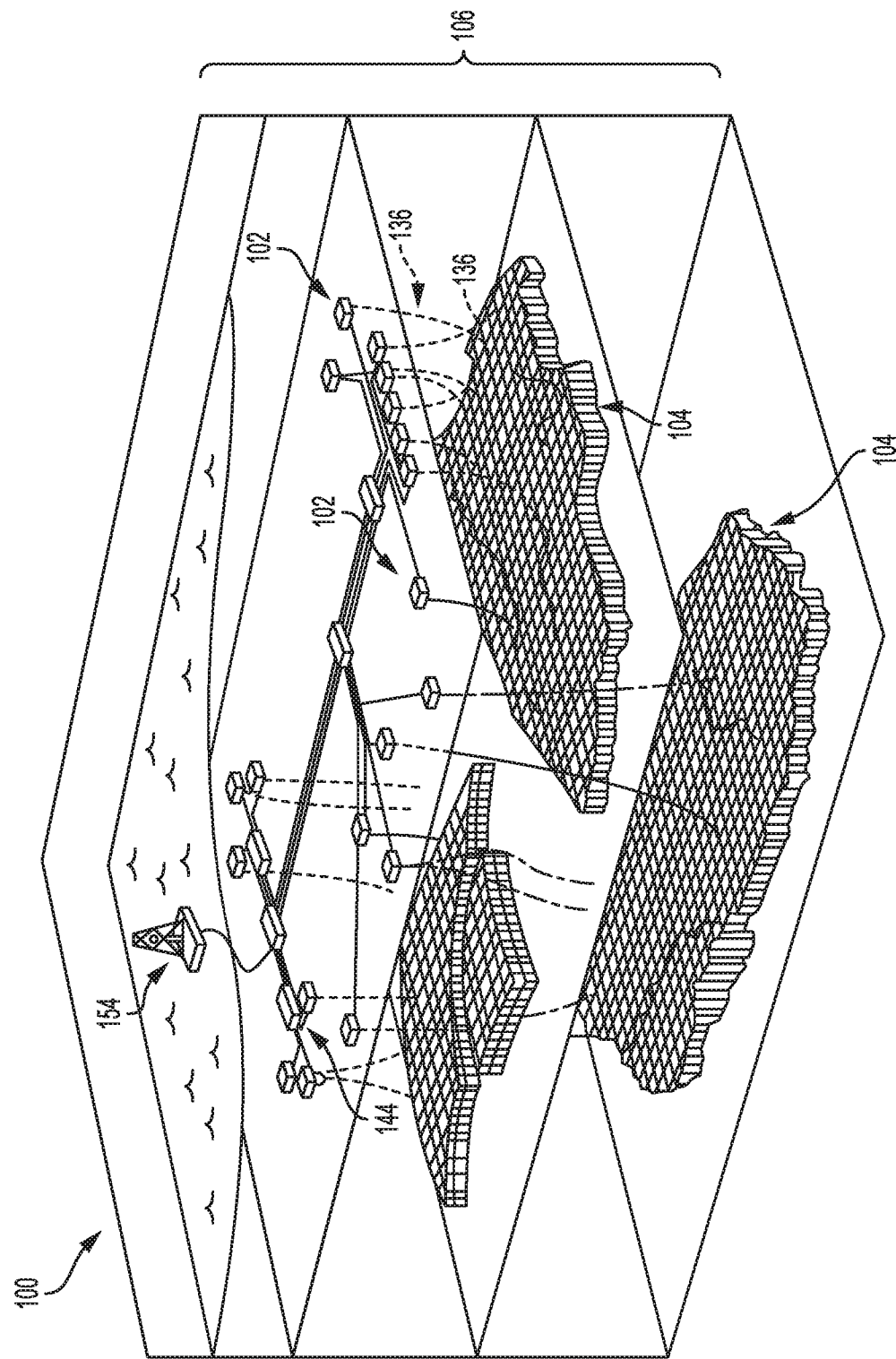


FIG. 1

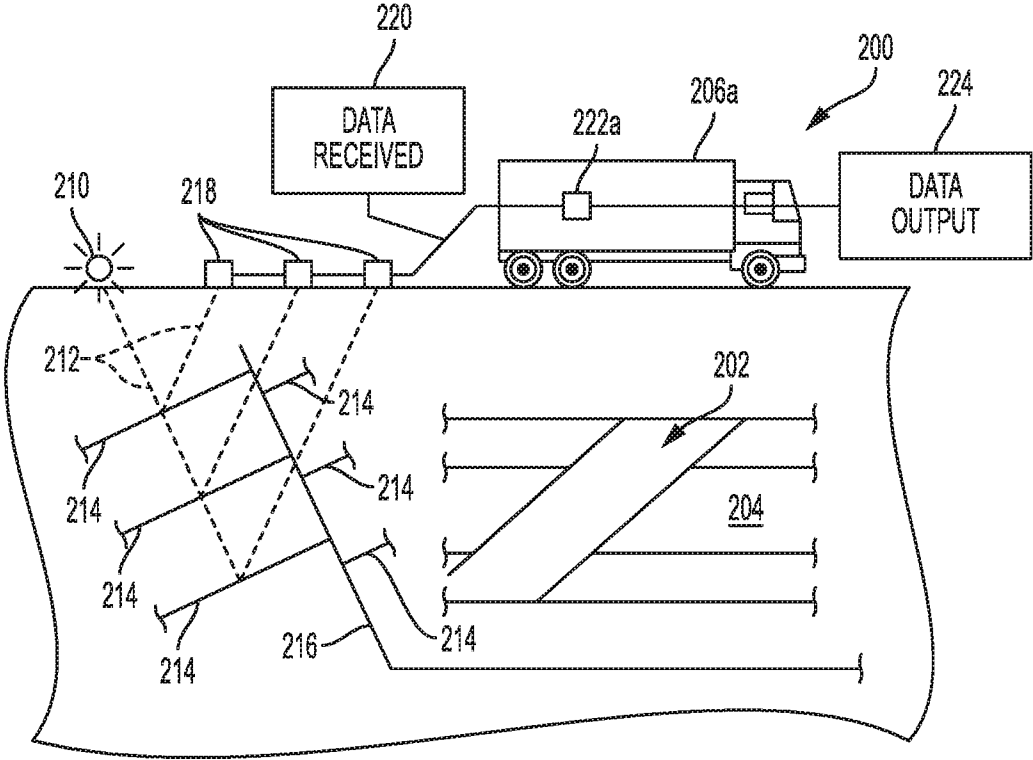


FIG. 2

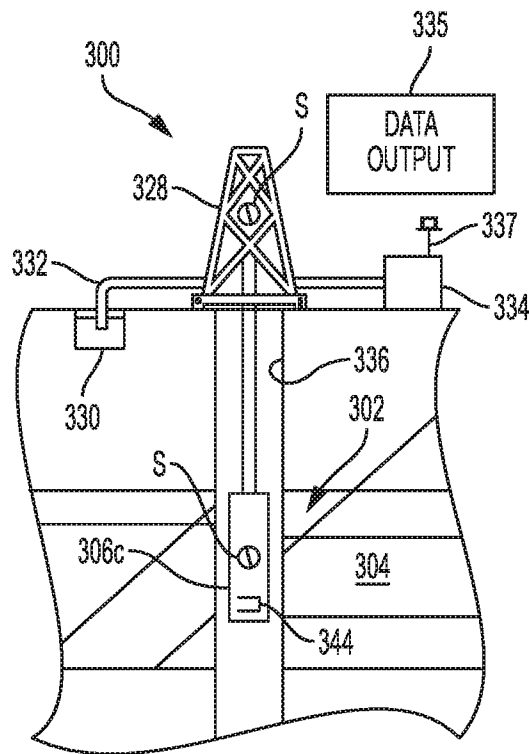
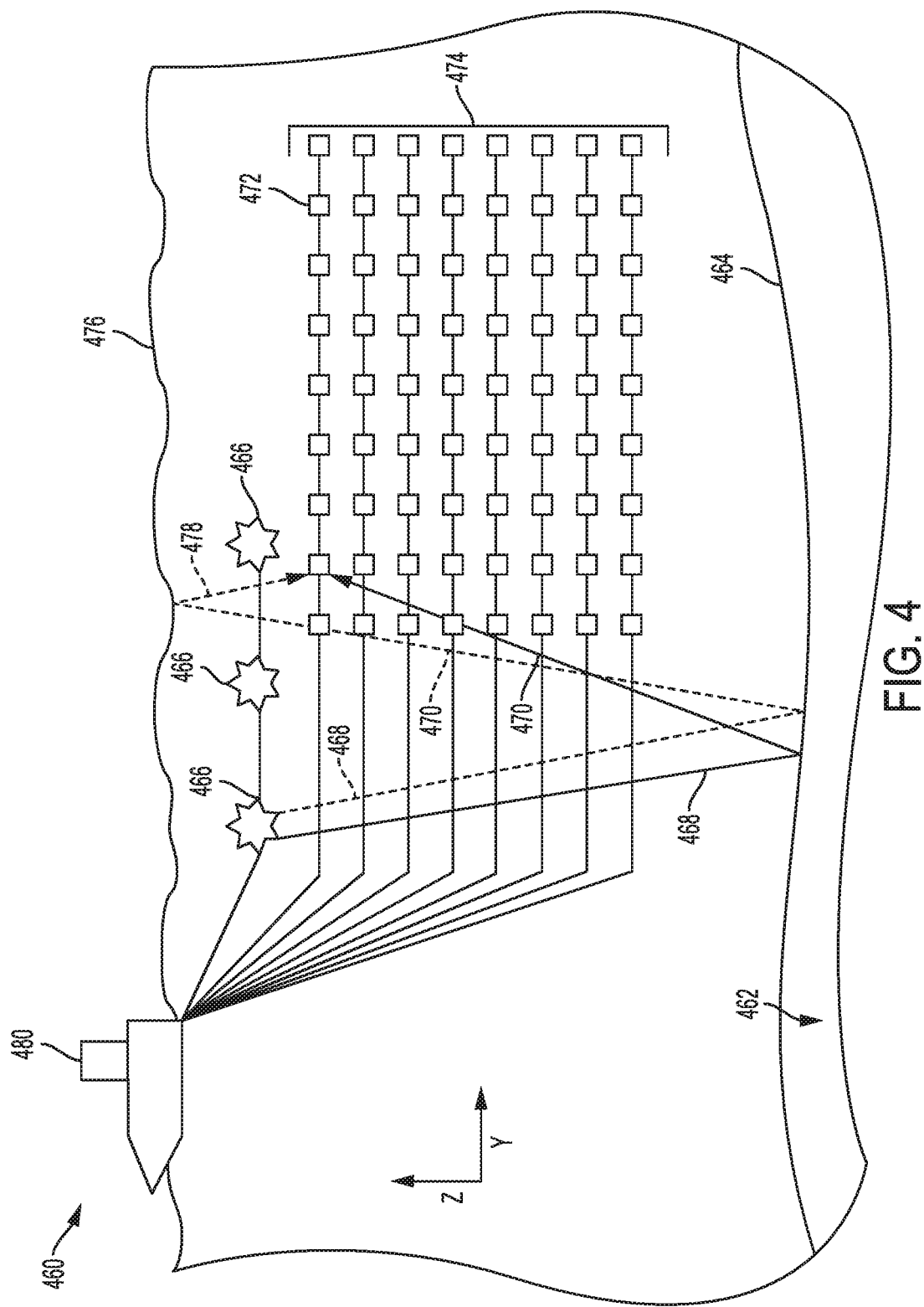


FIG. 3



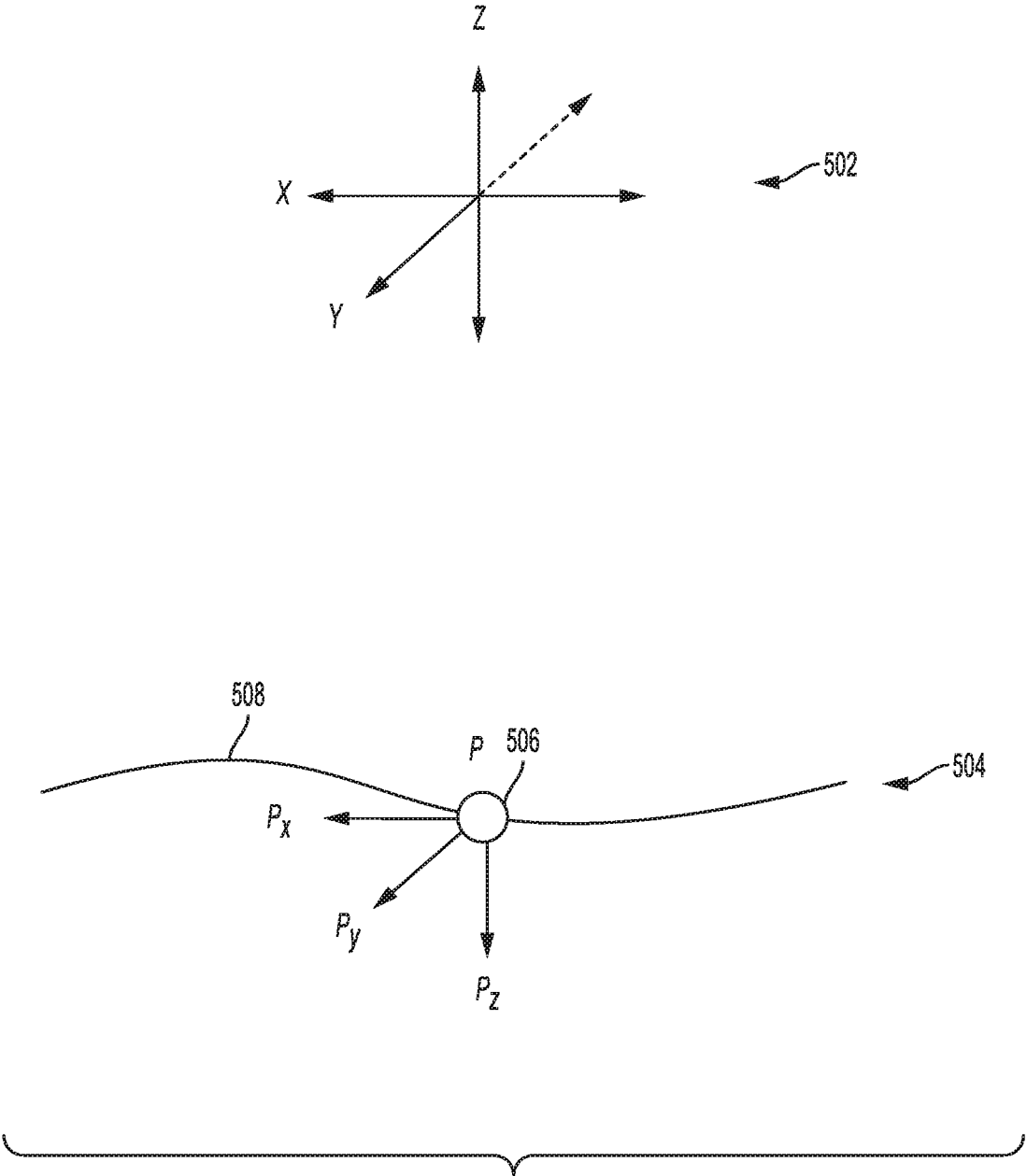


FIG. 5

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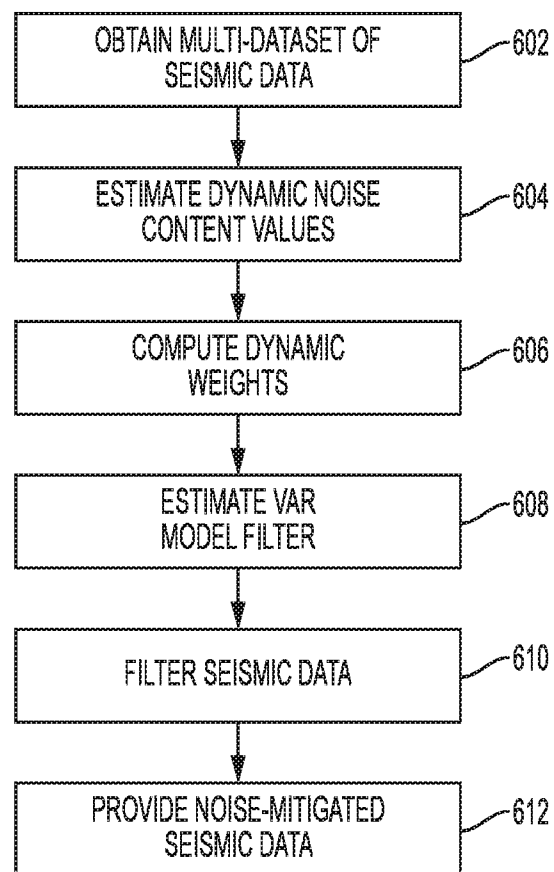


FIG. 6

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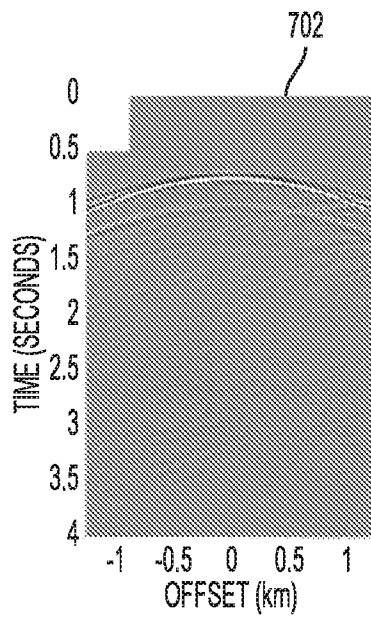


FIG. 7A

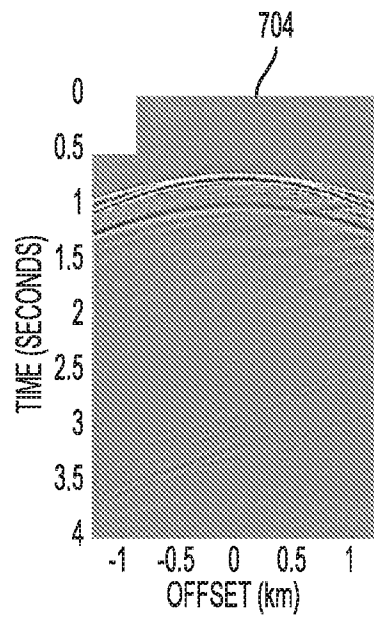


FIG. 7B

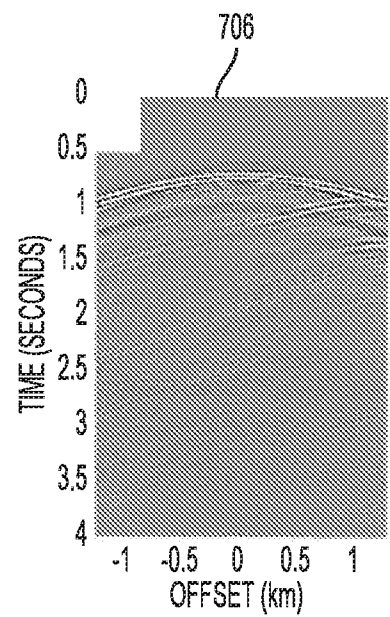


FIG. 7C

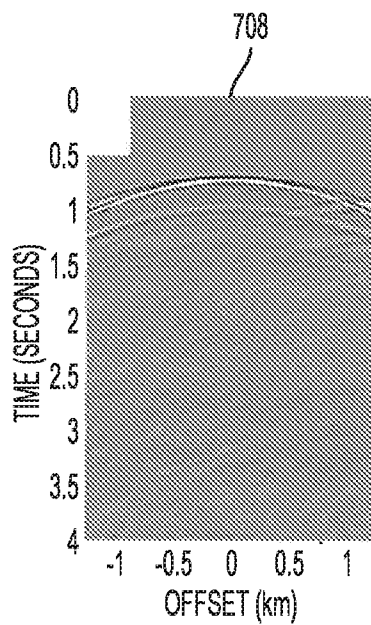


FIG. 7D

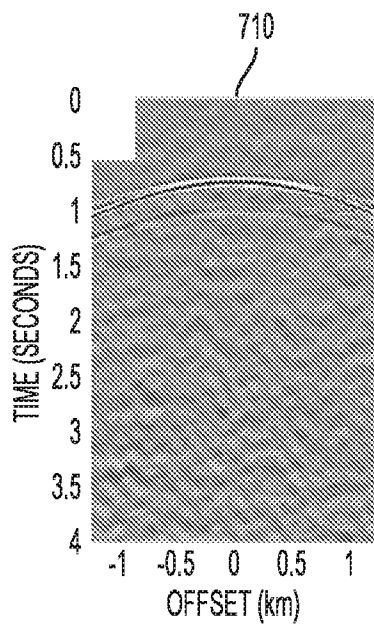


FIG. 7E

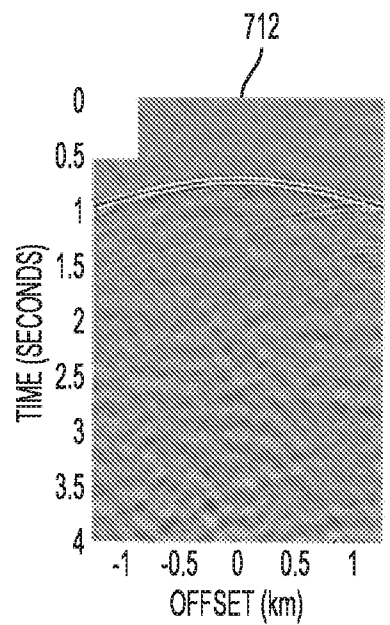


FIG. 7F

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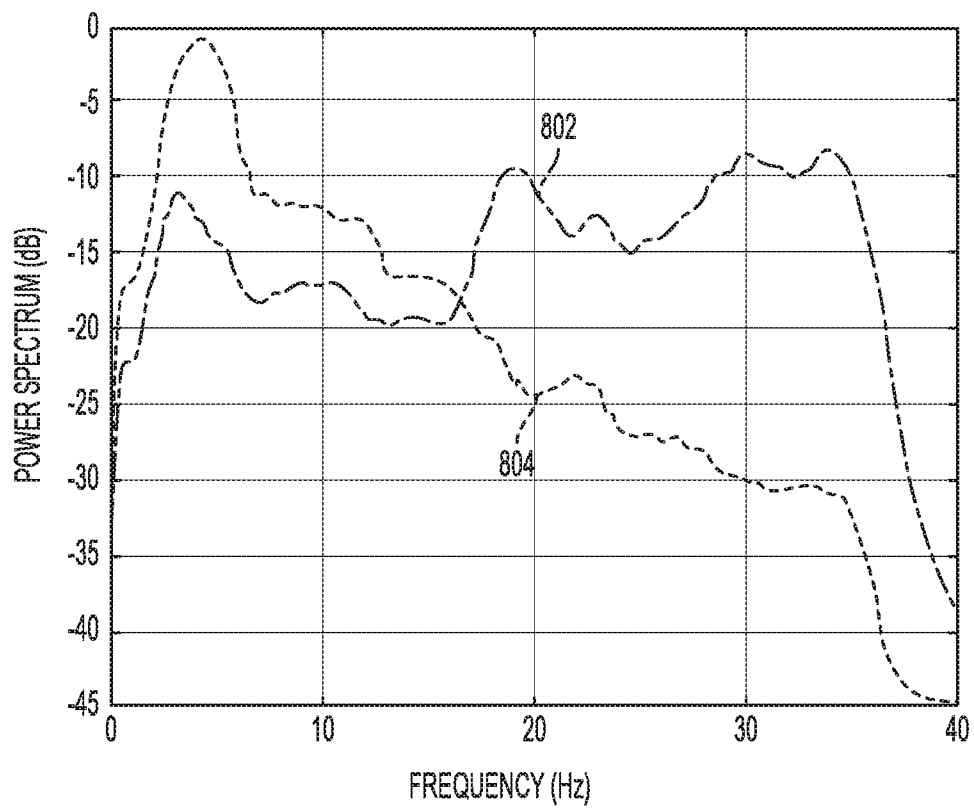


FIG. 8

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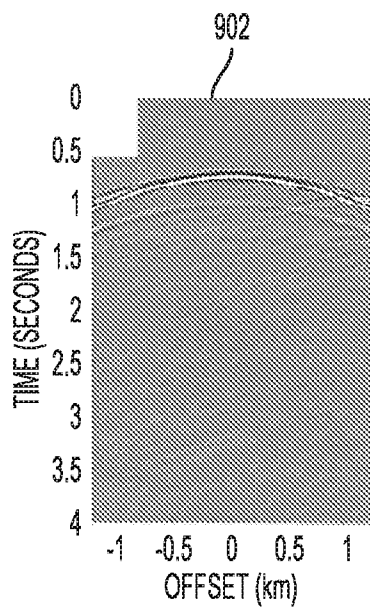


FIG. 9A

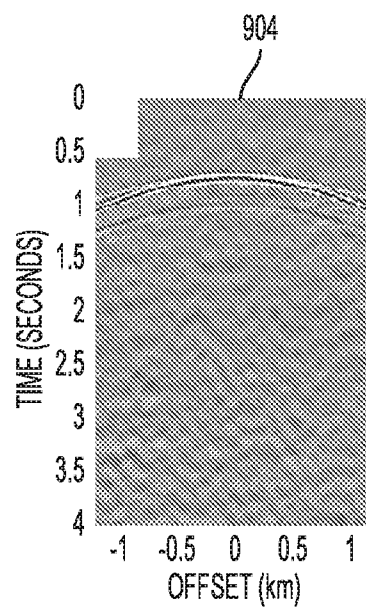


FIG. 9B

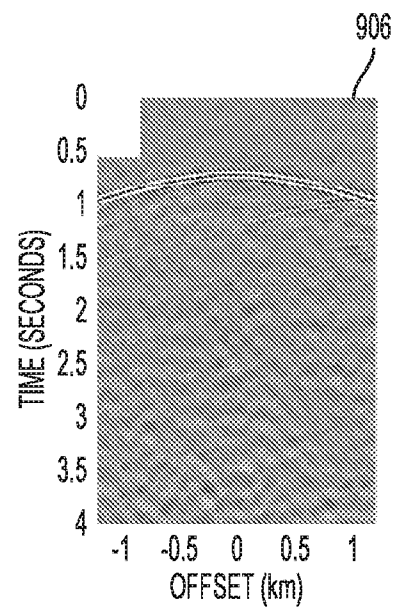


FIG. 9C

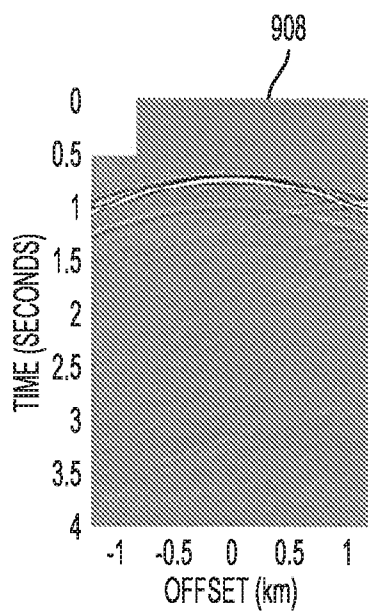


FIG. 9D

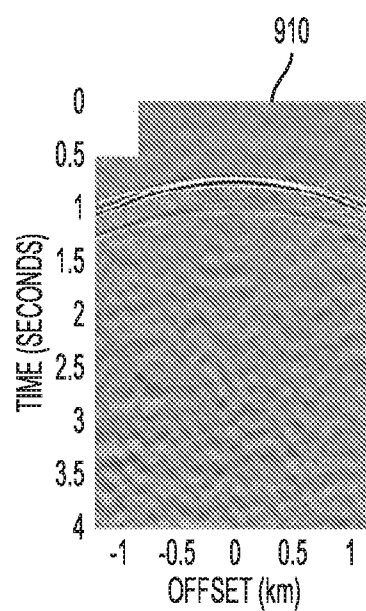


FIG. 9E

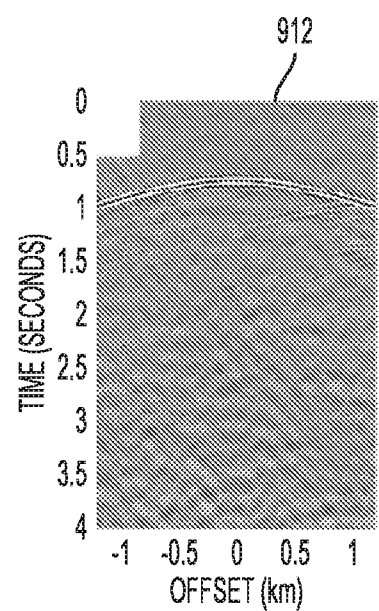


FIG. 9F

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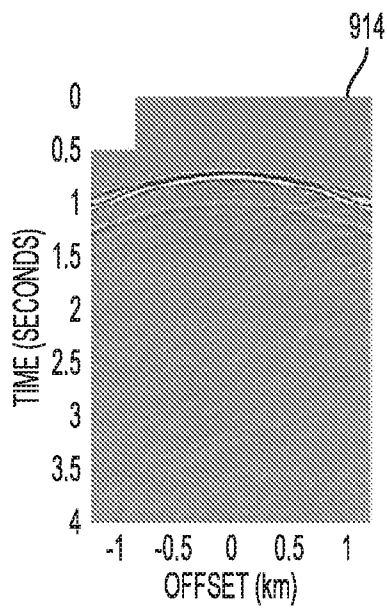


FIG. 9G

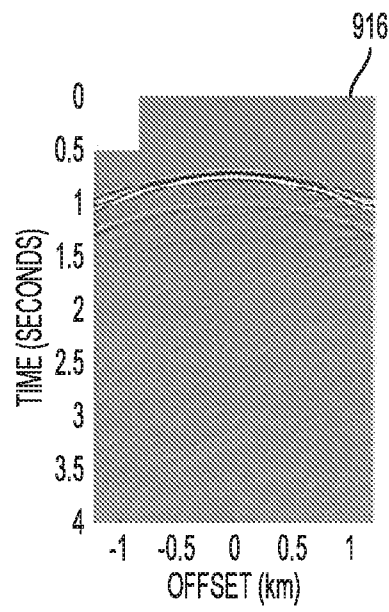


FIG. 9H

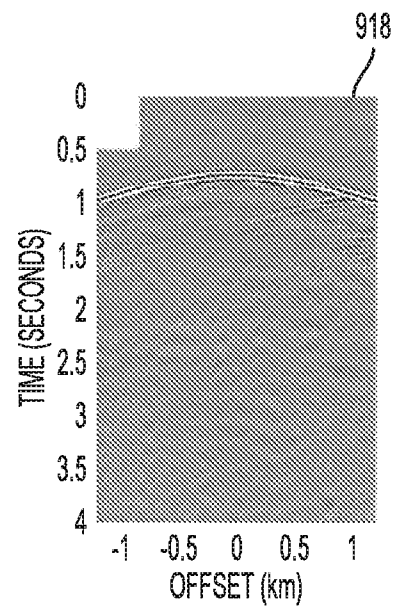


FIG. 9I

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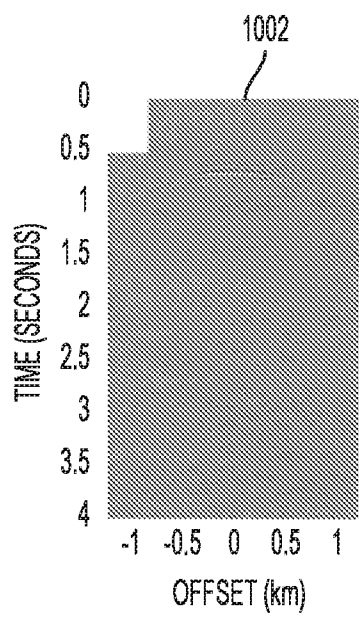


FIG. 10A

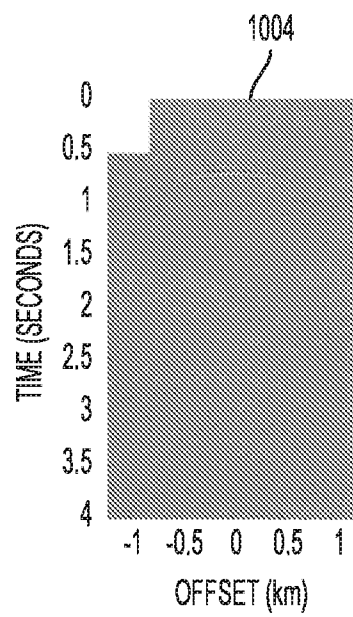


FIG. 10B

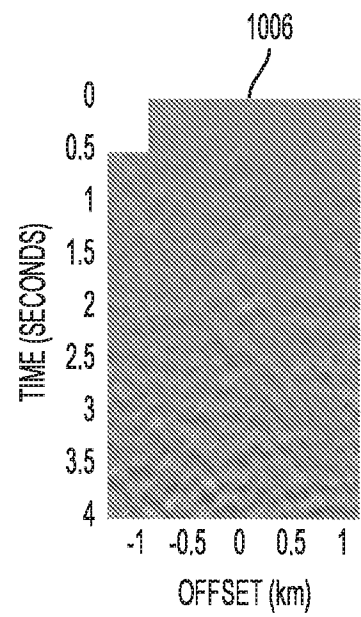


FIG. 10C

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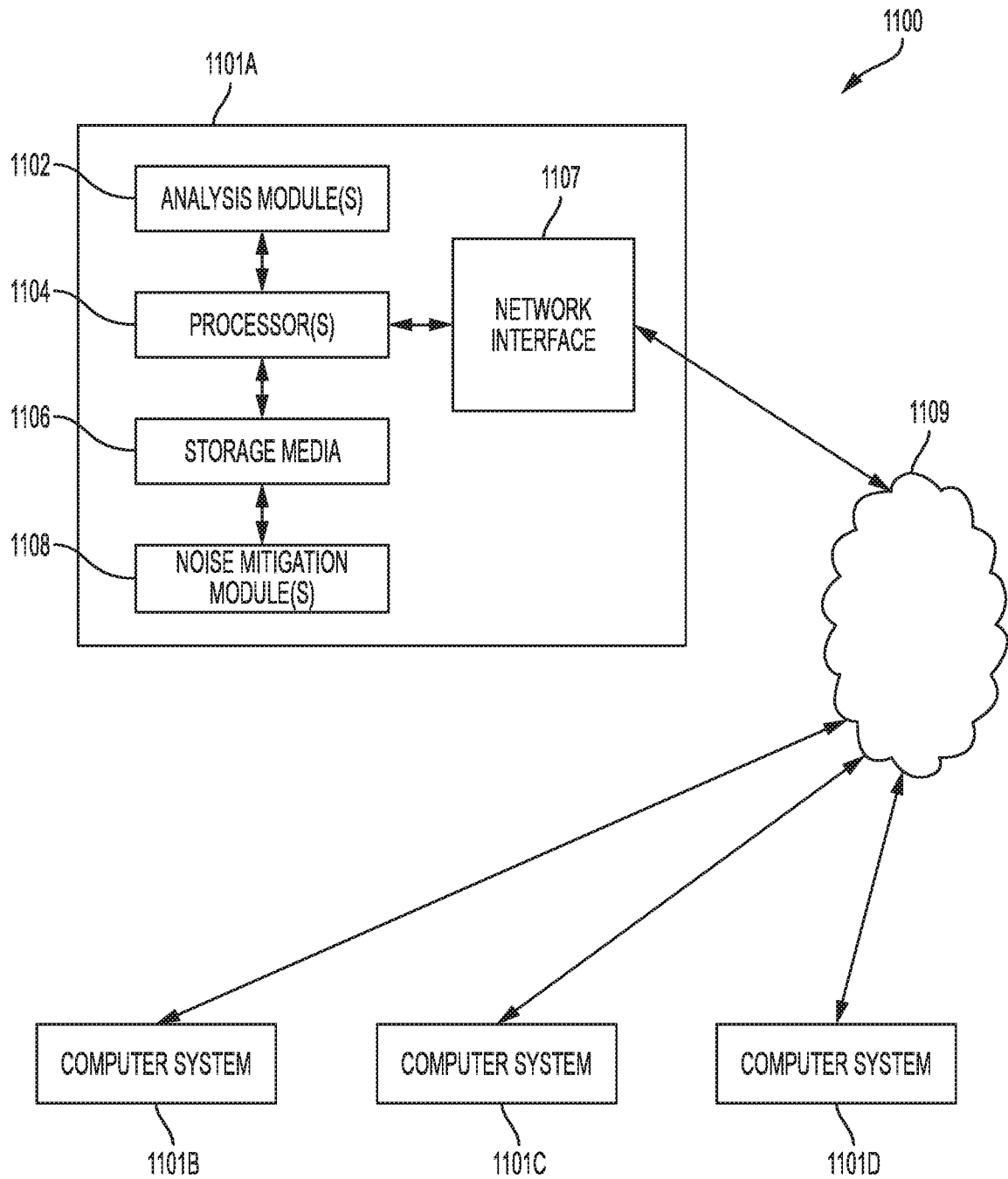


FIG. 11

A. CLASSIFICATION OF SUBJECT MATTER**E21B 47/00(2006.01)i, G01V 1/40(2006.01)i, G01V 1/50(2006.01)i**

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)

E21B 47/00; G06F 19/00; G01M 13/02; G01V 1/36; G01V 1/34; G01V 1/00; G01M 13/04; G01V 1/40; G01V 1/50

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

Korean utility models and applications for utility models

Japanese utility models and applications for utility models

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

eKOMPASS(KIPO internal) & Keywords: mitigate, seismic, noise, dynamic weight, autoregressive model, filter

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	US 2014-0200820 A1 (WESTERNGECO L.L.C.) 17 July 2014 See paragraphs [0002], [0026], [0039]-[0058], [0062]-[0072], [0088]; and figures 1-2.	1-20
Y	US 5191526 A (LASTER et al.) 02 March 1993 See column 1, line 51 - column 2, line 2; column 3, lines 26-44; column 5, line 59 - column 6, line 12; and figures 1A-1C.	1-20
A	US 2014-0249759 A1 (SAUDI ARABIAN OIL COMPANY) 04 September 2014 See paragraphs [0064]-[0067], [0074]; and figures 1-5.	1-20
A	US 2014-0019055 A1 (KUSTOWSKI et al.) 16 January 2014 See paragraphs [0026], [0035]-[0036]; and figures 1, 6.	1-20
A	WO 2013-180727 A1 (UNIVERSITY OF CONNECTICUT et al.) 05 December 2013 See page 34, line 18 - page 35, line 26; and figures 19-20, 23.	1-20



Further documents are listed in the continuation of Box C.



See patent family annex.

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Date of the actual completion of the international search

09 July 2016 (09.07.2016)

Date of mailing of the international search report

19 July 2016 (19.07.2016)

Name and mailing address of the ISA/KR

International Application Division

Korean Intellectual Property Office

189 Cheongsa-ro, Seo-gu, Daejeon, 35208, Republic of Korea

Facsimile No. +82-42-481-8578

Authorized officer

LEE, Dal Kyong

Telephone No. +82-42-481-8440



INTERNATIONAL SEARCH REPORT

Information on patent family members

International application No.

PCT/US2016/023968

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