ORTHOGONAL SOURCE AND RECEIVER ENCODING

CROSS-REFERENCE TO RELATED APPLICATION

[0001] This application claims priority from both U.S. Provisional Patent Application Nos. 61/608,435 filed on March 8, 2012, entitled Orthogonal Source and Receiver Encoding and U.S. Provisional Patent Application No. 61/726,319 filed on November 14, 2012 entitled Orthogonal Source and Receiver Encoding, both of which are incorporated by reference herein in their entirety.

FIELD OF THE INVENTION

[0002] The invention relates generally to the field of geophysical prospecting, and more particularly to geophysical data processing. Specifically, the invention is a method for inversion of data acquired from multiple geophysical sources such as seismic sources, involving geophysical simulation that computes the data from many simultaneously-active geophysical sources in one execution of the simulation.

BACKGROUND OF THE INVENTION

[0003] Even with modern computing power, seismic full wavefield inversion is still a computationally expensive endeavor. However, the benefit of obtaining a detailed representation of the subsurface using this method is expected to outweigh this impediment. Development of algorithms and workflows that lead to faster turn-around time is a key step towards making this technology feasible for field scale data. Seismic full waveform inversion involves several iterations of forward and adjoint simulation of the data. Therefore techniques that reduce the cost of forward and adjoint computation runs will allow users to solve larger scale problems in a reasonable amount of time.

[0004] Geophysical inversion [1,2] attempts to find a model of subsurface properties that optimally explains observed data and satisfies geological and geophysical constraints. There are a large number of well known methods of geophysical inversion. These well known methods fall into one of two categories, iterative inversion and non-iterative inversion. The following are definitions of what is commonly meant by each of the two categories:

Non-iterative inversion – inversion that is accomplished by assuming some simple background model and updating the model based on the input data. This method does not use the updated model as input to another step of inversion. For the case of seismic data these methods are commonly referred to as imaging, migration, diffraction tomography or Born inversion.

Iterative inversion – inversion involving repetitious improvement of the subsurface properties model such that a model is found that satisfactorily explains the observed data. If the inversion converges, then the final model will better explain the observed data and will more closely approximate the actual subsurface properties. Iterative inversion usually produces a more accurate model than non-iterative inversion, but is much more expensive to compute.

[0005] Iterative inversion is generally preferred over non-iterative inversion, because it yields more accurate subsurface parameter models. Unfortunately, iterative inversion is so computationally expensive that it is impractical to apply it to many problems of interest. This high computational expense is the result of the fact that all inversion techniques require many compute intensive simulations. The compute time of any individual simulation is proportional to the number of sources to be inverted, and typically there are large numbers of sources in geophysical data, where the term source as used in the preceding refers to an activation location of a source apparatus. The problem is exacerbated for iterative inversion, because the number of simulations that must be computed is proportional to the number of iterations in the inversion, and the number of iterations required is typically on the order of hundreds to thousands.

[0006] The most commonly employed iterative inversion method employed in geophysics is cost function optimization. Cost function optimization involves iterative minimization or maximization of the value, with respect to the model M, of a cost function S(M) which is a measure of the misfit between the calculated and observed data (this is also sometimes referred to as the objective function), where the calculated data are simulated with a computer using the current geophysical properties model and the physics governing propagation of the source signal in a medium represented by a given geophysical properties model. The simulation computations may be done by any of several numerical methods including but not limited to finite difference, finite element or ray tracing. The simulation computations can be performed in either the frequency or time domain.

[0007] Cost function optimization methods are either local or global [3]. Global methods simply involve computing the cost function S(M) for a population of models {M1, M2, M3,…} and selecting a set of one or more models from that population that approximately minimize S(M). If further improvement is desired this new selected set of models can then be used as a basis to generate a new population of models that can be again tested relative to the cost function S(M). For global methods each model in the test population can be considered to be an iteration, or at a higher level each set of populations

tested can be considered an iteration. Well known global inversion methods include Monte Carlo, simulated annealing, genetic and evolution algorithms.

[0008] Unfortunately global optimization methods typically converge extremely slowly and therefore most geophysical inversions are based on local cost function optimization. Algorithm 1 summarizes local cost function optimization.

1. selecting a starting model
2. computing the gradient of the cost function S(M) with respect to the parameters that describe the model
3. searching for an updated model that is a perturbation of the starting model in the negative gradient direction that better explains the observed data

Algorithm 1 – Algorithm for performing local cost function optimization.

[0009] This procedure is iterated by using the new updated model as the starting model for another gradient search. The process continues until an updated model is found that satisfactorily explains the observed data. Commonly used local cost function inversion methods include gradient search, conjugate gradients and Newton's method.

[0010] Local cost function optimization of seismic data in the acoustic approximation is a common geophysical inversion task, and is generally illustrative of other types of geophysical inversion. When inverting seismic data in the acoustic approximation the cost function can be written as:

$$S(M)=\sum_{g=1}^{N_g}\sum_{r=1}^{N_r}\sum_{t=1}^{N_t}W\left(\psi_{calc}\left(M,r,t,w_g\right)-\psi_{obs}\left(r,t,w_g\right)\right) \quad \text{(Eqn. 1)}$$

where:

S = cost function,

M = vector of N parameters, $(m_1, m_2, \ldots m_N)$ describing the subsurface model,

g = gather index,

w_g = source function for gather g which is a function of spatial coordinates and time, for a point source this is a delta function of the spatial coordinates,

N_g = number of gathers,

r = receiver index within gather,

N_r = number of receivers in a gather,

t = time sample index within a trace,

N_t = number of time samples,

W = minimization criteria function (a preferred choice is $W(x) = x^2$, which is the least squares (L2) criteria),

ψ_{calc} = calculated seismic pressure data from the model M,

ψ_{obs} = measured seismic pressure data.

[0011] The gathers can be any type of gather that can be simulated in one run of a seismic forward modeling program. Usually the gathers correspond to a seismic shot, although the shots can be more general than point sources. For point sources the gather index g corresponds to the location of individual point sources. For plane wave sources g would correspond to different plane wave propagation directions. This generalized source data, ψ_{obs}, can either be acquired in the field or can be synthesized from data acquired using point sources. The calculated data ψ_{calc} on the other hand can usually be computed directly by using a generalized source function when forward modeling. For many types of forward modeling, including finite difference modeling, the computation time needed for a generalized source is roughly equal to the computation time needed for a point source.

[0012] Equation(1) can be simplified to:

$$S(M) = \sum_{g=1}^{N_g} W\left(\delta\left(M, w_g\right)\right). \qquad \text{(Eqn. 2)}$$

where the sum over receivers and time samples is now implied and,

$$\delta\left(M, w_g\right) = \psi_{calc}\left(M, w_g\right) - \psi_{obs}\left(w_g\right). \qquad \text{(Eqn. 3)}$$

[0013] Inversion attempts to update the model M such that $S(M)$ is a minimum. This can be accomplished by local cost function optimization which updates the given model $M^{(k)}$ as follows:

$$M^{(k+1)} = M^{(k)} - \alpha^{(k)} \nabla_M S(M) \qquad \text{(Eqn. 4)}$$

where k is the iteration number, α is the scalar size of the model update, and $\nabla_M S(M)$ is the gradient of the misfit function, taken with respect to the model parameters. The model perturbations, or the values by which the model is updated, are calculated by multiplication of the gradient of the objective function with a step length α, which must be repeatedly calculated.

[0014] From equation (2), the following equation can be derived for the gradient of the cost function:

$$\nabla_M S(M) = \sum_{g=1}^{N_g} \nabla_M W(\delta(M, w_g)) \qquad \text{(Eqn. 5)}$$

[0015] So to compute the gradient of the cost function one must separately compute the gradient of each gather's contribution to the cost function, then sum those contributions. Therefore, the computational effort required for computing $\nabla_M S(M)$ is N_g times the compute effort required to determine the contribution of a single gather to the gradient. For geophysical problems, N_g usually corresponds to the number of geophysical sources and is on the order of 10,000 to 100,000, greatly magnifying the cost of computing $\nabla_M S(M)$.

[0016] Note that computation of $\nabla_M W(\delta)$ requires computation of the derivative of W(δ) with respect to each of the N model parameters m_i. Since for geophysical problems N is usually very large (usually more that one million), this computation can be extremely time consuming if it had to be performed for each individual model parameter. Fortunately, the adjoint method can be used to efficiently perform this computation for all model parameters at once [1]. The adjoint method for the least squares objective function and a gridded model parameterization is summarized by the following algorithm:

1. Compute forward simulation of the data using the current model and the gather signature w_g as the source to get $\psi_{calc}(M^{(k)}, w_g)$,
2. Subtract the observed data from the simulated data giving $\delta(M^{(k)}, w_g)$,
3. Compute the reverse simulation (i.e. backwards in time) using $\delta(M^{(k)}, w_g)$ as the source producing $\psi_{adjoint}(M^{(k)}, w_g)$,

4. Compute the integral over time of the product of $\psi_{calc}(M^{(k)},w_g)$ and $\psi_{adjoint}(M^{(k)},w_g)$ to get $\nabla_M W(\delta(M,w_g))$.

Algorithm 2 – Algorithm for computing the least-squares cost-function gradient of a gridded model using the adjoint method.

[0017] While computation of the gradients using the adjoint method is efficient relative to other methods, it is still very costly. In particular the adjoint methods requires two simulations, one forward in time and one backward in time, and for geophysical problems these simulations are usually very compute intensive. Also, as discussed above, this adjoint method computation must be performed for each measured data gather individually, increasing the compute cost by a factor of N_g.

[0018] The compute cost of all categories of inversion can be reduced by inverting data from combinations of the sources, rather than inverting the sources individually. This may be called simultaneous source inversion. Several types of source combination are known including: coherently sum closely spaced sources to produce an effective source that produces a wavefront of some desired shape (e.g. a plane wave), sum widely spaces sources, or fully or partially stacking the data before inversion.

[0019] The compute cost reduction gained by inverting combined sources is at least partly offset by the fact that inversion of the combined data usually produces a less accurate inverted model. This loss in accuracy is due to the fact that information is lost when the individual sources are summed, and therefore the summed data does not constrain the inverted model as strongly as the unsummed data. This loss of information during summation can be minimized by encoding each shot record before summing. Encoding before combination preserves significantly more information in the simultaneous source data, and therefore better constrains the inversion [4]. Encoding also allows combination of closely spaced sources, thus allowing more sources to be combined for a given computational region. Various encoding schemes can be used with this technique including time shift encoding and random phase encoding. The remainder of this Background section briefly reviews various published geophysical simultaneous source techniques, both encoded and non-encoded.

[0020] Van Manen [6] suggests using the seismic interferometry method to speed up forward simulation. Seismic interferometry works by placing sources everywhere on the boundary of the region of interest. These sources are modeled individually and the wavefield at all locations for which a Green's function is desired is recorded. The Green's function

between any two recorded locations can then be computed by cross-correlating the traces acquired at the two recorded locations and summing over all the boundary sources. If the data to be inverted have a large number of sources and receivers that are within the region of interest (as opposed to having one or the other on the boundary), then this is a very efficient method for computing the desired Green's functions. However, for the seismic data case it is rare that both the source and receiver for the data to be inverted are within the region of interest. Therefore, this improvement has very limited applicability to the seismic inversion problem.

[0021] Berkhout [7] and Zhang [8] suggest that inversion in general can be improved by inverting non-encoded simultaneous sources that are summed coherently to produce some desired wave front within some region of the subsurface. For example, point source data could be summed with time shifts that are a linear function of the source location to produce a down-going plane wave at some particular angle with respect to the surface. This technique could be applied to all categories of inversion. A problem with this method is that coherent summation of the source gathers necessarily reduces the amount of information in the data. So for example, summation to produce a plane wave removes all the information in the seismic data related to travel time versus source-receiver offset. This information is critical for updating the slowly varying background velocity model, and therefore Berkhout's method is not well constrained. To overcome this problem many different coherent sums of the data (e.g. many plane waves with different propagation directions) could be inverted, but then efficiency is lost since the cost of inversion is proportional to the number of different sums inverted. Herein, such coherently summed sources are called generalized sources. Therefore, a generalized source can either be a point source or a sum of point sources that produces a wave front of some desired shape.

[0022] Van Riel [9] suggests inversion by non-encoded stacking or partial stacking (with respect to source-receiver offset) of the input seismic data, then defining a cost function with respect to this stacked data which will be optimized. Thus, this publication suggests improving cost function based inversion using non-encoded simultaneous sources. As was true of the Berkhout's [6] simultaneous source inversion method, the stacking suggested by this method reduces the amount of information in the data to be inverted and therefore the inversion is less well constrained than it would have been with the original data.

[0023] Mora [10] proposes inverting data that is the sum of widely spaced sources. Thus, this publication suggests improving the efficiency of inversion using non-encoded simultaneous source simulation. Summing widely spaced sources has the advantage of

preserving much more information than the coherent sum proposed by Berkhout. However, summation of widely spaced sources implies that the aperture (model region inverted) that must be used in the inversion must be increased to accommodate all the widely spaced sources. Since the compute time is proportional to the area of this aperture, Mora's method does not produce as much efficiency gain as could be achieved if the summed sources were near each other.

[0024] Ober [11] suggests speeding up seismic migration, a special case of non-iterative inversion, by using simultaneous encoded sources. After testing various coding methods, Ober found that the resulting migrated images had significantly reduced signal-to-noise ratio due to the fact that broad band encoding functions are necessarily only approximately orthogonal. Thus, when summing more than 16 shots, the quality of the inversion was not satisfactory. Since non-iterative inversion is not very costly to begin with, and since high signal-to-noise ratio inversion is desired, this technique is not widely practiced in the geophysical industry.

[0025] Ikelle [12] suggests a method for fast forward simulation by simultaneously simulating point sources that are activated (in the simulation) at varying time intervals. A method is also discussed for decoding these time-shifted simultaneous-source simulated data back into the separate simulations that would have been obtained from the individual point sources. These decoded data could then be used as part of any conventional inversion procedure. A problem with Ikelle's method is that the proposed decoding method will produce separated data having noise levels proportional to the difference between data from adjacent sources. This noise will become significant for subsurface models that are not laterally constant, for example from models containing dipping reflectors. Furthermore, this noise will grow in proportion to the number of simultaneous sources. Due to these difficulties, Ikelle's simultaneous source approach may result in unacceptable levels of noise if used in inverting a subsurface that is not laterally constant.

[0026] Source encoding proposed by Krebs et al. in PCT Patent Application Publication No. WO 2008/042081, which is incorporated herein by reference in all jurisdictions that allow it, is a very cost effective method to invert full wave field data. (The same approach of simultaneous inversion of an encoded gather will work for receivers, either via source-receiver reciprocity or by encoding the actual receiver locations in common-source gathers of data.) For fixed receivers, the forward and adjoint computations only need to be performed for a single effective source; see PCT Patent Application Publication No. WO 2009/117174 [reference 4], which is incorporated herein by reference in all jurisdictions

that allow it. Given the fact that hundreds of shots are recorded for typical 2D acquisition geometries, and thousands in the case of 3D surveys, computational savings from this method are quite significant. In practice, a fixed receiver assumption is not strictly valid for most common field data acquisition geometries. In the case of marine streamer data, both sources and receivers move for every new shot. Even in surveys where the locations of receivers are fixed, the practice often is that not all receivers are "listening" to every shot, and the receivers that are listening can vary from shot-to-shot. This also violates the "fixed-receiver assumption." In addition, due to logistical problems, it is difficult to record data close to the source, and this means that near-offset data are typically missing. This is true for both marine and land surveys. Both of these factors mean that for a simultaneous source gather, every receiver location will be missing data for some source shots; those sources are said not to have *illuminated* the receiver location. In summary, in simultaneous encoded-source inversion, for a given simultaneous encoded gather, data are required at all receiver locations for every shot, and this may be referred to as the fixed-receiver assumption of simultaneous encoded-source inversion. In WO 08/042081 [reference 5], some of the disclosed embodiments may work better than others when the fixed-receiver assumption is not satisfied. Therefore, it would be advantageous to have an accommodation or adjustment to straightforward application of simultaneous encoded sources (and/or receivers) inversion that would enhance its performance when the fixed-receiver assumption is compromised. The present invention provides a way of doing this. Other approaches to the problem of moving receivers are disclosed in the following U.S. Patent Applications 12/903,744, 12/903,749 and 13/224,005. Haber et al. [15] also describe an approach to the problem of moving receivers in simultaneous encoded source inversion using a stochastic optimization method, and apply it to a direct current resistivity problem.

[0027] Young and Ridzal [16] use a dimension reduction technique called random projection to reduce the computational cost of estimating unknown parameters in models based on partial differential equations (PDEs). In this setting, the repeated numerical solution of the discrete PDE model dominates the cost of parameter estimation. In turn, the size of the discretized PDE corresponds directly to the number of physical experiments. As the number of experiments grows, parameter estimation becomes prohibitively expensive. In order to reduce this cost, the authors develop an algorithmic technique based on random projection that solves the parameter estimation problem using a much smaller number of so-called encoded experiments, which are random sums of physical experiments. Using this construction, the authors provide a lower bound for the required number of encoded

experiments. This bound holds in a probabilistic sense and is independent of the number of physical experiments. The authors also show that their formulation does not depend on the underlying optimization procedure and may be applied to algorithms such as Gauss-Newton or steepest descent.

SUMMARY OF THE INVENTION

[0028] In one embodiment, the invention is a computer implemented method for iterative inversion of measured geophysical data to determine a physical properties model for a subsurface region, comprising using a computer to sum a plurality of encoded gathers of the measured geophysical data, each gather being associated with a single source and encoded with a different encoding function selected from a set of encoding functions that are orthogonal or pseudo-orthogonal with respect to cross-correlation, thereby forming a simultaneous encoded gather of measured geophysical data representing a plurality of sources, then using an assumed physical properties model or an updated physical properties model from a prior iteration to simulate the simultaneous encoded gather of measured geophysical data, then computing an objective function measuring misfit between the simultaneous encoded gather of measured geophysical data and the simulated simultaneous encoded gather, then optimizing the objective function to determine a model update, wherein receivers are encoded to make computation of the objective function less sensitive to one or more of the plurality of sources for a given receiver.

[0029] In a more detailed embodiment, with reference to the flowchart of Fig. 3, the invention is a computer-implemented method for inversion of measured geophysical data to determine a physical properties model for a subsurface region, comprising:

(a) obtaining a group of two or more gathers **30** of the measured geophysical data, wherein each gather is associated with a single source;

(b) encoding each gather with a different encoding function **32** wherein the encoding is orthogonal or pseudo-orthogonal with respect to cross-correlation;

(c) summing **35** the encoded gathers in the group by summing all data records in each gather that correspond to a single receiver and repeating for each different receiver, resulting in a simultaneous encoded-source gather;

(d) assuming a physical properties model **33** of the subsurface region, said model providing values of at least one physical property at locations throughout the subsurface region;

(e) using the assumed physical properties model, simulating the simultaneous encoded-source gather, encoding source signatures **31** in the simulation using the same encoding functions **32** used to encode corresponding gathers of measured data, wherein an entire simultaneous encoded-source gather is simulated in a single simulation operation **34**;

(f) calculating a difference **36** for each receiver between the simultaneous encoded-source gather made up of measured geophysical data and the simulated simultaneous encoded-source gather, said difference being referred to as the residual **37** for that receiver;

(g) applying receiver encoding **38** to each residual, said receiver encoding being selected to attenuate contributions from sources for which the receiver was inactive;

(h) computing an objective function **39** from the receiver-encoded residuals, and updating the assumed physical properties model **40** based on the objective function computation;

(i) repeating (b)-(h) at least one more iteration, using the updated physical properties model **41** from the previous iteration as the assumed physical properties model, to produce a further updated physical properties model of the subsurface region; and

(j) downloading the further updated physical properties model or saving it to computer storage;

wherein, at last one of (a)-(j) are performed using a computer.

[0030] Efficiency of the method may be further improved by grouping several sources into a super-source, grouping the corresponding gathers into a super-gather, and then applying the above encoding strategy. For each group, the gathers -- both simulated measured – may be adjusted to contain traces that all sources in the group illuminate. Alternatively, one may first group all shots into one global group, simulate once, and then gradually remove the errors from the result. The errors consist of responses to a source at traces which the source did not illuminate in the acquisition survey. Thus, the additional groups, which may be called error groups, of this scheme aim to compute the combined effect of such errors. Further efficiency may be achieved by doubly encoding source signatures and source gathers; one encoding may be the orthogonal, frequency-based encoding of the present invention, and the other encoding may be the +1/-1 encoding of reference [17].

[0031] It should be noted that the roles of source and receiver may be interchanged using the reciprocity theorem of acoustics, elastic wave propagation, and electricity and

magnetism. It will be understood throughout, including in the claims, that whenever "source" or "receiver" are referred to, those designations will be understood to include the reverse resulting from application of reciprocity.

BRIEF DESCRIPTION OF THE DRAWINGS

5 **[0032]** The patent or application file contains at least one drawing executed in color. Copies of this patent or patent application publication with color drawings will be provided by the Office upon request and payment of the necessary fee.

[0033] The present invention and its advantages will be better understood by referring to the following detailed description and the attached drawings in which:

10 Fig. 1 is a diagram illustrating data acquired from a non-fixed receiver spread;

Fig. 2 is a diagram illustrating the source and receiver encodings, corresponding to the acquisition illustrated in Fig. 1, for one embodiment of the present invention; and

Fig. 3 is a flowchart showing basic steps in one embodiment of the present inventive method.

15 **[0034]** Due to patent law restrictions, one or more of the drawings are black-and-white reproductions of color originals. The color originals have been filed in the counterpart U.S. application. Copies of this patent or patent application publication with the color drawings may be obtained from the US Patent and Trademark Office upon request and payment of the necessary fee.

20 **[0035]** The invention will be described in connection with example embodiments. However, to the extent that the following detailed description is specific to a particular embodiment or a particular use of the invention, this is intended to be illustrative only, and is not to be construed as limiting the scope of the invention. On the contrary, it is intended to cover all alternatives, modifications and equivalents that may be included within the scope of 25 the invention, as defined by the appended claims.

DETAILED DESCRIPTION OF EXAMPLE EMBODIMENTS

[0036] Simultaneous source encoding disclosed by Krebs et al. [5, 17] has significantly reduced the computational cost of full waveform inversion. The savings are significant when several hundreds of shots for 2D surveys and thousands for 3D surveys are 30 reduced to a single simultaneous source simulation for forward and the adjoint computations. However, the simultaneous encoding of the data assumes fixed receiver geometry i.e., for each receiver all shots are live. Otherwise, for any given receiver location, the measured

simultaneous source trace will not contain contributions that came from sources for which that receiver location was inactive. Yet, for that same receiver location, the simulated simultaneous source trace will contain contributions from all sources. Thus, even for the case of an exactly correct model and no noise, the difference between the measured and simulated simultaneous source data will not be zero. Even worse, it is unlikely that a perfectly correct model will minimize the residual. Minimization for the exact model is a requirement for iterative inversion to produce an accurate model. A majority of the data in hydrocarbon exploration are not acquired with fixed-receiver geometry. The present invention is a method for making simultaneous encoded source inversion more accurate when the fixed receiver assumption is not satisfied, and thus to make full waveform inversion technology more feasible in such situations.

[0037] As stated previously, in a typical marine streamer and land acquisition, the data coverage is insufficient to satisfy the fixed receiver geometry thus limiting the benefits of simultaneous source full wave inversion (FWI) proposed by Krebs et al. [5,17] In addition to geometry considerations, the field data need to be processed to conform to the physics of the forward simulation used in the inversion. For example to use acoustic inversion for inverting elastic data, far offsets are typically muted and the data are processed to remove other elastic effects. Other practical aspects such as event (reflections, refractions, multiples) based windowing for FWI inversion do not work with fixed receiver geometry.

[0038] The present inventive method uses simultaneous source encoding using codes that are orthogonal or nearly orthogonal (sometimes referred to as pseudo-orthogonal), and simultaneously encodes receivers so that they are not sensitive to sources that were not active when that receiver was active. The main difference between this approach and the most common embodiment of simultaneous encoded source inversion that would be used when the fixed receiver assumption is satisfied is that receivers are also encoded rather than encoding sources only.

[0039] Basic steps in the present inventive method are represented symbolically in Fig. 2. In Fig. 2, the diagram represents the acquisition for a hypothetical seismic survey shown in Fig. 1. Using colors selected to correspond to the filters in Fig. 2, the diagram in Fig. 1 shows which receiver locations are active, i.e. are listening, for each source location. Each receiver (five receiver locations are shown in this example, numbered 1 to 5) is not active for all sources (five source locations are shown in this example, numbered 1 to 5), i.e. the fixed-receiver assumption, preferred for conventional simultaneous source inversion, is not satisfied. This is indicated by red boxes for receivers that are not active for a given

source and green boxes of receivers that are active for a given source. In this diagram, encoding is represented as a set of temporal filters whose amplitude (A) versus frequency (*f*) is shown in the row of graphs below the acquisition table. These filters are tight bandpass filters that are centered on different frequencies for different sources. To the right of the diagram are corresponding receiver filters that are designed to notch out frequencies corresponding to sources for which that receiver was not active. This will ensure that, when simulation and adjoint computations are performed, those receivers will not record energy from those sources that were not acquired in the field data to be inverted. These receiver filters are a key technique that allows simultaneous source inversion to be performed on data from non-fixed spreads in the present invention.

[0040] Within each box of the table in Fig. 2 is illustrated the product of the source encoding filter and the receiver encoding filter. Note that in the red boxes the product is zero while in the green boxes the product is just the original source encoding filter. This is the mechanism by which the receivers are made insensitive to the sources for which they were not active in the data acquisition.

[0041] The efficiency gained by the present invention can be estimated as follows. The number of approximately non-overlapping filters determines the number of sources that can be encoded into one simultaneous encoded source. This is approximately equal to the bandwidth of the data divided by the bandwidth of a filter (Eqn. 6). The time length of the time domain code corresponding to the encoding filter is proportional to the inverse of the filter's bandwidth (Eqn 7). The simulation compute effort for encoded simultaneous source data is proportional to the number of time steps that must be computed, which is proportional to sum of the trace length and code length (Eqn. 8). The efficiency gained by this invention is proportional to the simulation effort for unencoded data (N_{src} x T_{trace}) divided by the time to simulate the encoded source (T_{trace}+T_{code}) (Eqn. 9). Note that Eqn. 9 implies that the efficiency will improve by increasing the code length, implying it is advantageous to use tighter bandpass filters in the encoding. However, there are diminishing returns from increasing the time length of the code, while on the other hand longer codes may increase the number of iterations needed to converge the inversion.

$$N_{src} \approx \frac{\Delta f_{data}}{\Delta f_{filter}} \quad \text{(Eqn. 6)}$$

$$\Delta f_{filter} \propto \frac{1}{T_{code}} \quad \text{(Eqn. 7)}$$

$$T_{encoded\ simulation} \propto T_{trace} + T_{code} \quad \text{(Eqn. 8)}$$

$$Efficiency \propto \frac{N_{src}T_{trace}}{T_{encoded\ simulation}} = \frac{\Delta f_{data}T_{trace}T_{code}}{(T_{trace}+T_{code})} \qquad \text{(Eqn. 9)}$$

[0042] The receiver filters can be naturally implemented within FWI as the covariance matrix that is often included in the objective function norm. This is explained in more detail next.

[0043] The iterative method most commonly employed in wave inversion is objective function optimization. Objective function optimization involves iterative minimization of the value, with respect to the model **M**, of an objective function $S(\mathbf{M})$ which is a measure of the misfit between the calculated and observed data (this is also sometimes referred to as the cost function). The calculated data are simulated with a computer programmed to use the physics governing propagation of the source signal in a medium represented by the current model. The simulation computations may be done by any of several numerical methods including but not limited to finite differences, finite elements or ray tracing. Following Tarantola [1], the most commonly employed objective function is the least squares objective function:

$$S(\mathbf{M}) = \left(\mathbf{u}(\mathbf{M}) - \mathbf{d}\right)^T \mathbf{C}^{-1}\left(\mathbf{u}(\mathbf{M}) - \mathbf{d}\right), \qquad \text{(Eqn. 10)}$$

where T represent the vector transpose operator and:

M = the model which is a vector of N parameters $[m_1, m_2, \ldots m_N]^T$,

d = measured data vector (sampled with respect to source, receiver and time),

u(**M**) = simulated data vector for model **M** (sampled with respect to source, receiver and time),

C = the covariance matrix.

[0044] More details may be found in U.S. Patent Application 13/020,502 and in PCT Patent Application Publication No. WO 2009/117174, both of which are incorporated by reference herein in in all jurisdictions that allow it.

[0045] The codes used in the present inventive method do not necessarily have to be bandpass filters as illustrated in Fig. 1. Other orthogonal or pseudo-orthogonal codes may be used, for example, Kasami sequences. See "Quasi-orthogonal sequences for code-division multiple-access systems," Kyengcheol Yang, Young-Ky Kim, Vijay Kumar, *Information Theory, IEEE Transactions* **46**(3), 382-993 (2000). The codes could also be non-overlapping combs of bandpass filters or other quasi-orthogonal sequences besides Kasami sequences, e.g. Walsh sequences.

[0046] The simultaneous source inversion of the present invention may be further enhanced by exploiting structure from the acquisition geometry. Specifically, it is possible to group several sources into a super-source (the group of simultaneous sources), group the corresponding gathers into a super-gather, and then apply the encoding strategy outlined in the present invention. The benefit of such an approach is to multiply the efficiency of the present method by the efficiency of the grouping method. Next, two possible grouping strategies are briefly outlined, and then it is explained how a grouping strategy may be combined with the frequency encoding strategy of the present invention.

[0047] One version of the grouping method was disclosed in Ref. [20], "Random-Beam Full-Wavefield Inversion", Nathan Downey, Partha Routh and Young Ho Cha, SEG Expanded Abstracts **30**, 2423 (2011), DOI:10.1190/1.3627695, which publication is incorporated herein by reference in all jurisdictions that allow it. This method groups the data recorded during a seismic survey into several encoded multi-shot gathers each of which can be modeled using a single numerical simulation. For each group, the gathers—both simulated measured—are adjusted to contain traces that all sources in the group illuminate. In particular, the multi-shot full-wavefield inversion (FWI) scheme developed in Ref. [17] by Krebs et al. may be applied to encode the shots. Thus, if the computational cost of simulating each shot independently is n and the number of groups that sufficiently cover the survey is m, then the gains in efficiency are n / m relative to sequential-source inversion.

[0048] An alternative grouping scheme is obtained by first grouping all shots into one global group, simulating once, and then gradually removing the errors from the result. The errors consist of responses to a source at traces which the source did not illuminate in the acquisition survey. Thus, the additional groups, which may be called error groups, of this scheme aim to compute the combined effect of such errors. Once computed, the resulting simulated gather of a group is restricted to traces that at least one source in the group does not illuminate. These traces are then subtracted from the corresponding traces in the global gather. So, with each subsequent error group the global group is improved until, eventually, no more errors remain. This requires m error group removals (the same number as in the previous method), which leads to a total computational cost of $m+1$ simulations. The gain in efficiency is $n/(m+1)$, which is comparable to the gain of the previous grouping method.

[0049] In more detail, a data inversion method using the alternative grouping scheme, in one of its embodiments, can be described by the following series of basic steps:

1. Perform one simulation of synthetic data ("SD") where every source in the survey is simultaneously active. The sources are encoded. Any of various encoding schemes may be

used, including those described in U.S. Patent No. 8,121,823 (Ref. [5]) and also including the +1/-1 and other encoding schemes disclosed in Ref. [17], both of which references are incorporated herein by reference in all jurisdictions that allow it; however, if orthogonal or pseudo-orthogonal encoding as described herein is used, additional gains in efficiency may be realized. In one embodiment of the inversion method being described here, the orthogonal encoding is the frequency encoding of step **38** in the Fig. 3 flow chart.

2. Determine a grouping strategy (i.e. which sources to treat simultaneously), where the strategy relates to moving receivers and the desire not to simulate a seismic trace corresponding to a receiver that did not listen to that source. The strategy of the first grouping scheme discussed above (Ref. [20]) is also a preferred option for this alternative grouping scheme.

3. For each group, encode the sources, with each source being encoded with the same encoding used in step 1, and then do the following:

i. Perform a simulation in which every source in the current group is simultaneously active, and produce simultaneous simulated data for the current group of sources ("GSD"). (Note: these data are contained in the SD) The resulting gain in efficiency is $n/(m+1)$ relative to sequential-source inversion; however, if orthogonal or pseudo-orthogonal encoding as described herein is used, several groups may be simulated simultaneously, which will improve the efficiency gain to $k \cdot n/(m+1)$, where the number of groups that are simulated simultaneously is k.

ii. Determine receiver locations in the GSD that were not illuminated by *at least one of* the sources in the current group.

iii. For each of those locations, retrieve the corresponding signal from the GSD and subtract it from the same location in the SD. Note that this signal includes the error contained in the SD due to the fixed-receiver assumption's not being satisfied. In fact, the subtraction removes more than just the error. It also removes some good data, i.e. simulated data from receivers that were listening to the corresponding sources. However, this is an acceptable price to pay in order to remove all the error from the SD. The full data set is more than is needed to make the inversion work. Moreover, the amount of valid data that are removed can be controlled: the more groups in the grouping strategy, the less valid data are removed. Thus, these groups may be called "error groups" as compared to the groups used in the Ref. [20] alternative.

4. Compute the data residual relative to the encoded measured data, with the measured data being encoded using the same encoding function selected for each source in step 1, so

that the errors are reproduced exactly as they appear in the simulation of step 1. Before computing the residual, the measured data are adjusted to contain only the valid data remaining after step 3(iii). To do that, it may be noted that the measured data consist of individual source-receiver pairs (or may be converted into that format), so adjusting the measured data consists of adding together the measured source-receiver pairs for all such pairs that were left (i.e., are valid) after step 3(iii), i.e. all sources in a given group and all receivers that would not introduce errors in the computation of the objective function.

5. Adjust the velocity model to reduce the misfit, i.e. to reduce the data residual.

6. Repeat steps 1-5. Note that in the simulations in steps 1 and 3(i), since the velocity model was updated in step 5, the SD and the GSD's will not be the same as in the previous iteration, and therefore the simulations must be performed again.

[0050] The present invention may further improve the efficiency of the grouping methods by encoding each group with a code that is orthogonal or pseudo-orthogonal to all other codes. Thus, if k mutually (pseudo-)orthogonal codes are available, then k groups may be simulated simultaneously. The total cost of the grouping methods then becomes m/k for method 1 and $(m+1)/k$ for method two. Compared to the sequential shot scheme, this combined approach incurs $k*n/m$ times less computational cost. The overall method (for the Ref. [20] grouping scheme) therefore may be described by the flowchart of Fig. 3 where the gathers **30** are the multi-shot gathers described above, i.e. groups of shot gathers where the grouping is based on illuminated receivers, and each individual shot gather in a multi-shot gather is encoded with the same encoding function. Similarly, the source signatures **31** are each a group of source signatures corresponding to the groups of shot gathers, and each source signature in a group is encoded with the same encoding. It is of note that the frequency encoding of the present invention does not interfere with the encoding of the multi-shot scheme such as is described in Ref. [17] and which may be used in the grouping methods above; i.e. they are compatible. So, in this combined scheme, a source and corresponding gather are doubly-encoded. It may be possible to alternatively use some other form of encoding, for example phase encoding, as the orthogonal or pseudo-orthogonal encoding in a double encoding scheme. The non-orthogonal encoding in a double encoding scheme may be any encoding as long as it does not affect the orthogonal encoding, i.e. change the frequencies used in the case of frequency encoding.

[0051] The advantage to double encoding is that more gathers can be simulated simultaneously. Using frequency encoding only, the nature of the source signature is exploited, so the number of efficient, different, orthogonal codes is limited. This limit may

be increased by grouping shot gathers whenever data redundancy allows it. In essence, each group is constructed to behave like a small fixed-spread problem (discussed in Ref. 20), so a +1/-1 encoding within a group may efficiently solve this smaller problem. In other words, this double encoding exploits two distinct and independent characteristics of the problem: (1) the nature of the source signature, and (2) the geometry of the survey (data acquisition).

The sources may all be doubly encoded in both of the grouping schemes described above. The measured data corresponding to a given source must also be encoded in the same way as the source signature is encoded for simulation. However, to perform the residual calculations, the receivers may be decoded using only a combination of frequency filters.

[0052] A preferred embodiment of the invention using double encoding in the alternative scheme described above, where the groups are error groups, will now be described. In a first phase (not in the Fig. 3 flowchart, but described in step 1 of the six-step description given above for the alternative grouping scheme), a super-gather is computed, one containing all shots. Here, the +1/-1 encoding of Ref. 17 may be used, ignoring for the moment that errors will be introduced due to receivers not illuminated by a particular source. That is, a +1 or a -1 multiplicative factor is assigned to each source and related measured data. Each error group in the steps to come will be assigned part of the frequency spectrum for the orthogonal encoding (step 3i above, with orthogonal (frequency) encoding), but those assignments may be made in this first phase. Thus, each source-data pair is doubly encoded: with a +1/-1 multiplicative factor and by modifying their spectrum. Then, in a second phase, corresponding to step 3 above, the errors are removed as described there by progressively subtracting the result of smaller multi-gathers—the error grouping—from the super-gather obtained in phase 1. Here, we use the same multiplicative (+1/-1) factor as in the first phase. Also, each group is filtered to have the same spectrum as chosen in phase 1. In other words, the same double encoding is used again. Finally, in the third phase, the residuals are computed (step 4 above), then the model update is computed (step 5 above), possibly using a gradient method. This concludes one iteration, and a next iteration may follow (step 6 above).

[0053] It may be noted that the embodiment of the invention using the first grouping scheme, i.e. the grouping of Ref. 20, also has a first phase (not shown in Fig. 3) in which the groups are chosen. Double encoding of the sources and corresponding measured data may also be performed with this grouping scheme. It may be noted that the +1/-1 encoding may be used to mitigate cross-talk noise during the residual calculation of each group. This noise is specific to a group; noise from one group does not affect other groups. The orthogonal

encoding ensures that behavior. Therefore, the +1/-1 encoding in this scheme may be applied to each group independently, without consideration of elements in other groups. Also, as Ref. [5] was the first to discover, it may be advantageous to change the specific encoding functions each iteration.

[0054] The simultaneous source inversion of the present invention can be further enhanced by changing the encoding functions used between iterations. This is because changing the amplitude spectrum and/or phase of the filters between iterations will result in producing a model that fits more frequencies from each source. Changing the encodings will also reduce crosstalk noise which will occur for encoding functions which are not perfectly orthogonal. The change of encoding may include, for example, either or both of changing the central frequency of the source filters and changing their phase.

[0055] The foregoing application is directed to particular embodiments of the present invention for the purpose of illustrating it. It will be apparent, however, to one skilled in the art, that many modifications and variations to the embodiments described herein are possible. All such modifications and variations are intended to be within the scope of the present invention, as defined in the appended claims. For example, persons skilled in the art will readily recognize that it is not required that all sources be encoded into a single simultaneous source, but instead sub-groups of sources could be encoded and the gradients results from each sub-group could then be summed to produce a total gradient. (Computing the gradient of the objective function with respect to each of the model parameters is a common way of determining an update to the model.) Persons skilled in the art will readily recognize that in preferred embodiments of the invention, at least some of the steps in the present inventive method are performed on a computer, i.e. the invention is computer implemented. In such cases, the resulting updated physical properties model may either be downloaded, displayed, or saved to computer storage.

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CLAIMS

1. A computer implemented method for iterative inversion of measured geophysical data to determine a physical properties model for a subsurface region, comprising using a computer to sum a plurality of encoded gathers of the measured geophysical data, each gather being associated with a single source or group of sources and encoded with a different encoding function selected from a set of encoding functions that are orthogonal or pseudo-orthogonal with respect to cross-correlation, thereby forming a simultaneous encoded gather of measured geophysical data representing a plurality of sources, then using an assumed physical properties model or an updated physical properties model from a prior iteration to simulate the simultaneous encoded gather of measured geophysical data, then computing an objective function measuring misfit between the simultaneous encoded gather of measured geophysical data and the simulated simultaneous encoded gather, then optimizing the objective function to determine a model update, wherein receivers are encoded to make computation of the objective function less sensitive to one or more of the plurality of sources for a given receiver.

2. The method of claim 1, wherein the encoding functions for sources are a set of bandpass filters, differing from each other in central frequency, phase, or both.

3. The method of claim 2, wherein the phase differences include polarity switches.

4. The method of claim 1, wherein the encoding of the receivers is performed using a different encoding function for each receiver, selected to be orthogonal or pseudo-orthogonal with respect to the encoding functions for sources to which the receiver did not listen when the measured geophysical data were measured.

5. The method of claim 4, wherein the encoding functions for receivers are a set of notch filters, differing from each other in central frequency, phase, or both, and wherein each receiver filter is designed to notch out bandpass frequencies of the encoding functions corresponding to sources for which that receiver was not active.

6. The method of claim 1, wherein the simulated simultaneous encoded gather is simulated in a single simulation operation, wherein source signatures in the simulation are encoded using the same encoding used to encode corresponding gathers of the measured geophysical data.

7. The method of claim 1, wherein the misfit is measured as a norm of a difference between the simultaneous encoded gather of measured geophysical data and the simulated simultaneous encoded gather or as a cross-correlation between the simultaneous encoded gather of measured geophysical data and the simulated simultaneous encoded gather.

8. The method of claim 1, wherein the measured geophysical data are acquired under conditions where the fixed-receiver assumption of simultaneous encoded-source inversion is not valid.

9. The method of claim 1, wherein the measured geophysical data are full wavefield data from a seismic survey.

10. The method of claim 1, wherein the sources to which the computation is made less sensitive are the sources that the given receiver did not listen to.

11. The method of claim 10, wherein the receiver encoding is chosen such that the selected encoding function for a given source is orthogonal or pseudo-orthogonal with respect to encoding functions of receivers that did not listen to that source.

12. The method of claim 1, wherein in some or all of the iterations, different encoding functions are used compared to a preceding iteration.

13. The method of claim 1, further comprising forming one or more additional simultaneous encoded gathers of measured geophysical data, wherein the model update is

determined based on a sum of the objective functions corresponding to each simultaneous encoded gather.

14. The method of claim 1, wherein computing the objective function comprises computing differences, called residuals, by receiver between the simultaneous encoded gather of measured geophysical data and the simulated simultaneous encoded gather, and applying the receiver encoding to each receiver residual, said receiver encoding being selected to attenuate contributions from sources for which the receiver was inactive, then computing the objective function from the receiver-encoded residuals.

15. A computer-implemented method for inversion of measured geophysical data to determine a physical properties model for a subsurface region, comprising:

(a) obtaining a group of two or more gathers of the measured geophysical data, wherein each gather is associated with a single source or group of sources;

(b) encoding each gather with a different encoding function wherein the encoding is orthogonal or pseudo-orthogonal with respect to cross-correlation;

(c) summing the encoded gathers in the group by summing all data records in each gather that correspond to a single receiver and repeating for each different receiver, resulting in a simultaneous encoded-source gather;

(d) assuming a physical properties model of the subsurface region, said model providing values of at least one physical property at locations throughout the subsurface region;

(e) using the assumed physical properties model, simulating the simultaneous encoded-source gather, encoding source signatures in the simulation using the same encoding functions used to encode corresponding gathers of measured data, wherein an entire simultaneous encoded-source gather is simulated in a single simulation operation;

(f) calculating a difference for each receiver between the simultaneous encoded-source gather made up of measured geophysical data and the simulated simultaneous encoded-source gather, said difference being referred to as the residual for that receiver;

(g) applying receiver encoding to each residual, said receiver encoding being selected to attenuate contributions from sources for which the receiver was inactive;

(h) computing an objective function from the receiver-encoded residuals, and updating the assumed physical properties model based on the objective function computation;

(i) repeating (b)-(h) at least one more iteration, using the updated physical properties model from the previous iteration as the assumed physical properties model, to produce a further updated physical properties model of the subsurface region; and

(j) downloading the further updated physical properties model or saving it to computer storage;

wherein, at least one of (a)-(j) are performed using a computer.

16. The method of claim 15, wherein each gather in (a) is a multi-shot gather, each multi-shot gather consisting of a plurality of individual-shot gathers having a common set of illuminated receivers.

17. The method of claim 16, wherein the receiver encoding is a set of frequency filters, differing from each other in central frequency, phase, or both.

18. The method of claim 17, wherein both the encoding in (b) and the encoding in (e) are accompanied by a second encoding, making the gathers in (b) and the source signatures in (e) doubly encoded.

19. The method of claim 18, wherein the second encoding is +1/-1 encoding.

20. A non-transitory computer usable medium having a computer readable program code embodied therein, said computer readable program code adapted to be executed to implement a method for iterative inversion of measured geophysical data to determine a physical properties model for a subsurface region, said method comprising:

summing a plurality of encoded gathers of the measured geophysical data, each gather being associated with a single source or group of sources and encoded with a different encoding function selected from a set of encoding functions that are orthogonal or pseudo-orthogonal with respect to cross-correlation, thereby forming a simultaneous encoded gather

of measured geophysical data representing a plurality of sources, then using an assumed physical properties model or an updated physical properties model from a prior iteration to simulate the simultaneous encoded gather of measured geophysical data, then computing an objective function measuring misfit between the simultaneous encoded gather of measured geophysical data and the simulated simultaneous encoded gather, then optimizing the objective function to determine a model update, wherein receivers are encoded to make computation of the objective function less sensitive to one or more of the plurality of sources for a given receiver.

21. The method of claim 20, wherein the encoding of the receivers is performed using a different encoding function for each receiver, selected to be orthogonal or pseudo-orthogonal with respect to the encoding functions for sources to which the receiver did not listen when the measured geophysical data were measured.

22. A method for producing hydrocarbons, comprising:

conducting a seismic survey have a subsurface region;

inverting measured seismic data from the seismic survey by a method of claim 1 to determine a physical properties model of the subsurface region;

using the physical properties model to process the measured seismic data;

using the processed seismic data to assess hydrocarbon potential of the subsurface region; and

upon identifying hydrocarbon potential from the processed seismic data, drilling a well into the subsurface region and producing hydrocarbons.

23. A computer-implemented method for inversion of measured geophysical data to determine a physical properties model for a subsurface region, comprising:

(a) obtaining a group of two or more multi-shot gathers of the measured geophysical data, each multi-shot gather consisting of a plurality of individual-shot gathers having a common set of illuminated receivers;

(b) encoding each multi-shot gather with a different encoding function selected from a set of encoding functions that are orthogonal or pseudo-orthogonal with respect to cross-correlation;

(c) summing the encoded multi-shot gathers by summing all data records in each gather that correspond to a single receiver and repeating for each different receiver, resulting in a simultaneous encoded-source gather;

(d) assuming a physical properties model of the subsurface region, said model providing values of at least one physical property at locations throughout the subsurface region;

(e) using the assumed physical properties model, simulating the simultaneous encoded-source gather, encoding source signatures in the simulation using the same encoding functions used to encode corresponding gathers of the measured data, wherein an entire simultaneous encoded-source gather is simulated, using a programmed computer, in a single simulation operation;

(f) calculating a difference for each receiver between the simultaneous encoded-source gather and the simulated simultaneous encoded-source gather, said difference being referred to as the residual for that receiver;

(g) applying receiver encoding to each residual, said receiver encoding being selected to attenuate contributions from sources for which the receiver was inactive;

(h) computing an objective function from the receiver-encoded residuals, and updating the assumed physical properties model based on the objective function computation;

(i) repeating (b)-(h) at least one more iteration, using the updated physical properties model from the previous iteration as the assumed physical properties model, to produce a further updated physical properties model of the subsurface region; and

(j) downloading the further updated physical properties model or saving it to computer storage.