METHOD OF WAVELET ESTIMATION AND MULTIPLE PREDICTION IN FULL WAVEFIELD INVERSION

CROSS-REFERENCE TO RELATED APPLICATION

[0001] This application claims priority from U.S. Provisional Patent Application No. 61/470,237 filed on March 31, 2011, entitled Method of Wavelet Estimation and Multiple Prediction in Full Wavefield Inversion, which is incorporated by reference herein in its entirety.

FIELD OF THE INVENTION

[0002] This invention relates generally to the field of geophysical prospecting and, more particularly to seismic data processing. Specifically, the invention is a method of wavelet estimation and multiple prediction in full wavefield inversion of seismic data.

BACKGROUND OF THE INVENTION

[0003] Full waveform inversion ("FWI") is a method of inverting seismic data to infer earth subsurface properties that affect seismic wave propagation. Its forward modeling engine utilizes finite difference or other computational methods to model propagation of acoustic or elastic seismic waves through the earth subsurface model. FWI seeks the optimal subsurface model such that simulated seismic waveforms match field recorded seismic waveforms at receiver locations. The theory of FWI was initially developed by Tarantola (1989). Research and applications of FWI in exploration geophysics have been very active in the past decade, thanks to the dramatic increase of computing power.

[0004] It is well known that simulated waveforms depend linearly on the input source wavelet when linear acoustic or elastic wave equations are used to model seismic wave propagation. In fact, accurate estimation of source wavelet plays a critical role in FWI. Delprat-Jannaud and Lailly (2005) pointed that accurate wavelet measurements appear to be a major challenge for a sound reconstruction of impedance profiles in FWI. They noticed that a small error in the source wavelet leads to a strong disturbance in the deeper part of the inverted model due to the mismatch of multiple reflections. They concluded that "the classical approach for estimating the wavelet by minimizing the energy of the primary reflection waveform is not likely to provide the required accuracy except for very special cases".

[0005] Indeed, inversion of primary reflections without well control faces a fundamental non-uniqueness in estimating the wavelet. For example, larger reflection events can be caused by larger impedance contrasts or a stronger source. Similar ambiguity exits for wavelet phase and power spectrum. Well data are commonly used to constrain wavelet strength and phase. But well logs are not always available, especially in an early exploration setting, or in shallow subsurface cases.

[0006] There have been extensive studies of wavelet estimation in the geophysical literature. In particular, inversion of wavelet signature for FWI was discussed by Wang *et al.* (2009) and the references therein. However, these methods all implicitly rely on direct arrivals or refracted waves for wavelet estimation. Because these transmitted modes propagate along mostly horizontal ray paths, they are influenced by effects (e.g. radiation pattern, complex interaction with the free surface) not affecting the near-vertical reflection ray paths. Such effects are often difficult to describe accurately and to simulate. Hence, there is a need to estimate the wavelet for the vertically-propagated energy, and this is particularly relevant for reflection-dominated applications (e.g. deep-water acquisition, imaging of deeper targets).

[0007] Multiples are considered to be noise in traditional seismic processing since they often contaminate primary reflections and make interpretation more difficult. On the other hand, it is known that multiples may also be useful for constraining subsurface properties and the seismic source wavelet. Verschuur *et al.* (1989, 1992) proposed a method of surface-related multiple elimination (SRME), by which wavelet estimation can be performed along with multiple elimination. The principle of SRME has been extended to an inversion scheme by G.J.A. van Groenestijn *et al.* (2009) to reconstruct the missing near-offset primaries and the wavelet. However it is unclear whether the optimal wavelet for SRME is also optimal for FWI. Papers such as van Groenestijn and Verschuur perform their multiple modeling and wavelet estimation in the time domain, i.e., data-driven without a subsurface model.

SUMMARY OF THE INVENTION

[0008] In one embodiment, the invention is a computer-implemented seismic processing method comprising generating and simultaneously optimizing a source wavelet and subsurface model to an extendable depth, wherein simulated waveforms of both primary reflections and multiple reflections are generated from the source wavelet and the subsurface

model in the depth domain and are then compared for a match to waveforms as recorded at seismic receiver locations.

BRIEF DESCRIPTION OF THE DRAWINGS

[0009] The present invention and its advantages will be better understood by referring to the following detailed description and the attached drawings in which:

Figure 1 is a flowchart showing basic steps in the present inventive method;

Figure 2 shows a diagrammatic illustration of multiple reflections in seismic acquisition with source S1 and receiver R1;

Figure 3 shows a shot gather of deep water seismic data, showing shallow primaries arriving before the multiples of interest, which are water-surface related multiples;

Figure 4 shows an inverted shallow subsurface model from the shallow primaries in Fig. 3;

Figure 5 shows a recorded shot gather, a simulated shot gather based on the inverted shallow subsurface model in Fig. 4, and their data residual;

Figure 6 shows recorded data having both deep primaries and multiples, simulated multiples based on the shallow subsurface model in Fig. 4, and the subtraction of the simulated multiples from the recorded data;

Figure 7 shows blow-up of Fig. 6 (3.8 s to 4.5 s) to clearly demonstrate quality of multiple prediction, with the frame showing data selected to perform wavelet estimation;

Figure 8 shows multiple modeling with 30-deg phase rotation applied to the optimal wavelet: (from left) recorded data, simulated multiples based on rotated wavelet and inverted subsurface model, and their residual;

Figure 9 shows results of multiple modeling based on a wavelet with an incorrect power spectrum (rich in low frequency compared with the optimal wavelet): (from left) recorded data, simulated multiples based on low frequency wavelet, and their residual;

Figure 10 shows a power spectrum of recorded multiples and that of simulated multiples, used to design a shaping filter of the present invention;

Figure 11 shows power spectrum of recorded multiples, and that of simulated multiples after applying the shaping filter to the wavelet used in Figs. 9 and 10;

Figure 12 illustrates how a decision made in step **103** of Fig. 1 is likely changed in step **106**; and

Figure 13 illustrates recursion of the present inventive method from shallow to deep.

[0010] 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 the invention, as defined by the appended claims. Persons skilled in the technical field will readily recognize that in practical applications of the present inventive method, it must be performed on a suitably programmed computer.

DETAILED DESCRIPTION OF EXAMPLE EMBODIMENTS

[0011] The present invention is a wavelet estimation method for FWI applications that makes use of both the primary and multiple reflections in the data. The present inventive method uses the FWI algorithm to generate a subsurface model from primary reflections. The model is then used to simulate multiples. The wavelet is subsequently modified such that the simulated multiples closely match the true recorded multiples.

[0012] In addition to providing an accurate wavelet estimate, this method may provide some benefits as a multiple elimination strategy. In particular, it has no need for dense cross-line sampling to model multiples in 3D: once a model of the shallow subsurface has been built with FWI, modeling multiples is straightforward for any acquisition configuration. Also, because the method is model-based and does not rely on primary/multiple moveout separability, it naturally offers good protection of primaries.

[0013] Following the Fig. 1 flow chart showing basic steps in one embodiment of this invention, deep water seismic data is used as an example to demonstrate the inventive method. Attention is primarily directed to wavelet estimation and modeling of water-surface related multiples, but persons skilled in the technical field will readily understand that a similar approach can be applied to other types multiples, an example of which is shown in Fig. 2.

[0014] Figure 2 shows a diagrammatic illustration of multiple reflections in seismic acquisition with source S1 and receiver R1. Multiples are considered as signals reflected more than once between any subsurface boundary Ai and any subsurface boundary Bi in the figure. In practice, at least one strong reflector is present to make an interesting scenario. Assume A1 in the figure is a strong reflector, which could be the water-air interface in marine

data or air-earth interface in land acquisition, or salt boundary, or any high-contrast subsurface. The *multiples of interest* are now defined as signals reflected more than once between A1 and any of the Bi's. The term *shallow primaries* means signals arriving before the first arrival of the multiples of interest. Accordingly, *deep primaries* are defined as primary reflections arriving after the first arrival of the multiples of interest.

[0015] In step **101** of Fig. 1, a shallow subsurface model is inverted from shallow primaries. Figure 3 shows one shot-gather of this deep water seismic data set. In this case, the shallow primaries **7** refer to arrivals before 3.7 s since the water-surface related multiple arrives after 3.7 s. We are able to identify water-surface related multiples because the earliest arrival of these multiples should be 2x water bottom reflection time, by definition. That is approximately 3.7 s. (Time is shown on the vertical scale in Fig. 3, increasing downward.) The multiples of interest are water-surface related multiples. Relating back to Fig. 2, A1 is now the water-air interface and B1 represents the water-bottom. The "shallow primaries" used for inverting a shallow subsurface model are in frame **7**, which arrive before water-bottom multiples **8**.

[0016] A P-wave velocity model in the depth domain is now constructed from the shallow primaries referred to above, using a standard velocity model building tool. Applying acoustic FWI to the shallow primary gives the shallow acoustic impedance in Fig. 4, which is in the depth-cdp domain. Thus, Fig. 4 shows the inverted shallow subsurface model from "shallow primaries" **7** in Fig. 3. The water-surface location is denoted by **9** and water-bottom is denoted by **10**. Notice that elastic FWI or more sophisticated physics could be applied in this step to capture waveforms more accurately up to longer offsets.

[0017] Figure 5 shows recorded shot-gather **11** (which is just region **7** from Fig. 3 with the time scale expanded), a simulated shot-gather **12** based on subsurface model in Fig. 4, and the difference between **11** and **12** is shown in **13**. The inverted shallow earth model in Fig. 4 explains the measured data very well, as evidenced by the small data residual **13**. Notice that surface-related multiples are simulated by having the air-water interface in the model, although they are not present before 3.7 s, and hence are not shown in Fig. 5.

[0018] In step **102**, multiple reflections are simulated, i.e. modeled, using the shallow subsurface velocity model obtained by inversion in step **101** and an assumed seismic wavelet. By extending the simulation time to 5.5 s, we are able to simulate water-surface related multiples based on the subsurface model in Fig. 4. In Fig. 6, **14** shows recorded seismic data in a 1 km common offset domain, which includes both deep primaries and water-surface

related multiples generated from shallow sub-surfaces; **15** shows simulated water-surface related multiples based on the shallow subsurface model in Figure 4; and **16** is a subtraction of **15** from **14**, and so **16** are the estimated deep primaries.

[0019] In step **103**, the simulated multiples are compared to the recorded data within a selected window to determine the degree of mismatch. Figure 7 shows a blow-up of Fig. 6 (3.8 s to 4.5 s) to clearly demonstrate the quality of the multiple prediction. The window **17** was chosen in the recorded data, trying to minimize overlapping between multiple and primary reflections. The corresponding window in the simulated multiples is denoted by **18**. Data in the windows **17** and **18** are selected to perform wavelet estimation. The objective in the wavelet estimation is to minimize differences between recorded data **17** and simulated multiples **18**, since the window was chosen to avoid containing strong deep primaries in the data. The difference resulting from an optimal wavelet is shown in **19**.

[0020] If the match between simulated multiples and recorded data in step **103** is not satisfactory, the wavelet used to simulate the multiples may be adjusted in step **104** by correcting any one or more of the three wavelet properties that go into estimating the wavelet, i.e. wavelet amplitude, phase and power spectrum. Simulated multiples in **18** will not match recorded multiples in **17** unless optimal wavelet estimation is achieved. **19** shows the difference between **17** and **18** when the optimal wavelet estimation is used to generate the sub-surface model in Fig. 4. The three wavelet adjustments are discussed next in more detail.

[0021] ***Wavelet amplitude***. The amplitude of the primary reflection p is determined by the source wavelet S, source (receiver) ghost G_{src} (G_{src}), subsurface reflectivity R_i and geometric spreading factor L_p:

$$p = \left(S * G_{src} * G_{rec}\right) \cdot R_i / L_p. \tag{1}$$

Similarly, the amplitude of the multiple reflection m is determined by the free-surface reflectivity R_{fs} and the reflectivity of multiple reflection locations. For instance, a “pegleg” multiple is related to the water-bottom reflectivity R_{wb} by:

$$m = \left(S * G_{src} * G_{rec}\right) \cdot R_i \cdot R_{wb} \cdot R_{fs} / L_m. \tag{2}$$

Dividing (2) by (1) produces the following relation between relative multiple/primary amplitude ratio and wavelet amplitude, assuming perfect reflection at the water-surface (R_{fs} = 1):

$$\frac{m}{p} \propto R_{wb} \propto \frac{1}{S} \tag{3}$$

where L_p and L_m are fixed relative to R_{wb} and are hence treated as proportionality constants. The second proportionality in (3) comes from equation (1) which, where the subsurface reflector is the water bottom, can be written as

$$R_{wb} \propto \frac{1}{S}$$

where the remaining terms from equation (1) make up a proportionality constant independent of S. Given that the primary reflections in the field data were matched by the inverted model using a wavelet of strength S at step **101**, equation (3) then indicates that

$$m \propto \frac{1}{S}.$$

Thus, if the simulated multiples are too large or too small compared to the multiples in the recorded data, this can be adjusted by increasing or decreasing the source wavelet's strength proportionately. In other words, the geophysical meaning of equation (3) is that, the relative water-bottom multiple/primary amplitude ratio constrains the water-bottom reflectivity. Knowledge of the water-bottom reflectivity allows us then to estimate the wavelet amplitude by matching the amplitude of the water-bottom primary reflection.

[0022] ***Wavelet phase.*** To demonstrate how wavelet phase may be corrected in the present inventive method, we applied a 30-deg phase rotation to the optimal wavelet, and repeated the FWI process of step **101** in Figure 1 to build a new shallow earth model which is different from the model in Figure 4. However, simulated primaries match measured primaries equally well in both of the two models. (Not shown in the drawings.) While inversion is not able to detect a wavelet phase rotation based on primary reflections only, multiples are used to retrieve wavelet phase rotation. Figure 8 shows that simulated water-bottom multiple **21** cannot match recorded water-bottom multiple **20**, as evidenced by data residual in **22**. (This may be compared to Fig. 6 which shows corresponding results for the optimal wavelet.) If we apply phase rotation operator Φ to the simulated water bottom multiples in **21** until the best match with measured water bottom multiple in **20** is achieved, we are able to retrieve the phase rotation of the wavelet (30-deg rotation in this case) by applying Φ to the wavelet. In this step, we have chosen the water-bottom multiple as the event to design phase rotation operator Φ. In general, we can pick any local events with good separation of multiple and primary.

[0023] ***Wavelet power spectrum***. To demonstrate how the wavelet's power spectrum, i.e. the absolute value of the coefficients of a Fourier expansion of the wavelet's waveform, can affect the agreement between simulated and measured multiples, a zero-phase shaping filter was applied to the optimal wavelet to suppress its high frequency energy. By then conducting steps **101** and **102** in Figure 1, the result is now simulated multiples with a power spectrum **27** compared with the power spectrum of the recorded multiples **26**, as shown in Fig. 10. It is clear that the simulated multiples have richer high frequency energy than the recorded multiples. This is expected as can be seen by the following. The inverted earth power spectrum E = P/S, where P and S are the power spectrum of primaries and wavelet, respectively. Since first order multiples are primaries reflected one more time by earth, the power spectrum of multiples is $M = E*P = P^2/S$. Since P is always matched by FWI on primaries, richer low frequencies in S results in richer high frequencies in M. As further evidence that the simulated multiples have richer high frequency energy than the recorded multiples, Fig. 9 shows that the multiple residual **25** of simulated multiples **24** and recorded multiples **23** contains high frequency energy. If this were the case at step **103** in the course of applying the present inventive method, we may design in step **104** a zero-phase shaping filter H that transforms power spectrum **26** to **27**. The same shaping filter is then applied to the wavelet to get an optimal wavelet. As a result, after applying H to the wavelet used in Figs. 9 and 10, the power spectrum of simulated multiples **29** is closer to the power spectrum of recorded multiples **28** in Figure 11. (Curve **28** would have been identical to curve **26** if the same traces had been chosen to calculate power spectrum in each case.)

[0024] Upon finishing step **104** and cycling through step **101** a second time, we have now the optimal wavelet and shallow subsurface model which predict the multiples of interest in step **102**. By subtracting simulated multiples from recorded data in step **105**, we extend primary reflections from "shallow" to "deep". Performing FWI on the deep primaries with the optimal wavelet generates a deep subsurface model to match the deep primaries.

[0025] In step **106**, the comparison in step **103** is repeated. In other words, multiple reflections are simulated again, but now using the model resulting from step **105**, and these multiple predictions are compared to the recorded data in the selected window. Figure 12 illustrates how the decision in step **103** may be changed after having the deep primaries inverted in step **105**. If no strong primaries appear in the recorded data window during step **103**, the wavelet estimated without inversion of deep primaries will be the final wavelet. This is the case in the field data study used as an example to illustrate the method here. In the case

of strong deep primaries intersecting or overlapping with multiples in the selected window, it will now be possible to separate primary from multiple after step **105**. Therefore, wavelet estimation in step **104** needs to be repeated, along with steps **101-106**, in order to match simulated multiples with the multiples separated from deep primaries.

[0026] By repeating the process above, if necessary, the present inventive method will generate the optimal wavelet and subsurface model such that simulated primaries (shallow and deep), and multiples match recorded data. Notice that the concept of "shallow/deep primaries" and "multiples of interest" are defined recursively, i.e., "deep primary" will become "shallow primary" after "multiples of interest" are modeled and separated, and the multiples that are "of interest" will be the strong multiples in the depth layer to which the model is being extended in the recursive sequence. Figure 13 illustrates this recursion. **131** shows the deep primary (lower - - - curve) masked by a multiple (solid line) generated from the shallow primary (upper - - - line). With the multiple thus revealed, it can be removed as shown in **132**, where a multiple appearing at a greater depth can now be modeled, and so on until all primaries are inverted (**133**). Thus, the whole process can be repeated until a final wavelet and subsurface model (**107**) are achieved.

[0027] The foregoing patent 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.

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CLAIMS

1. A computer-implemented method for inversion of measured seismic data from a subsurface region comprising:

(a) selecting a shallow layer from the measured seismic data with the layer's depth determined to include primary reflections (shallow primaries), but exclude first arrivals of multiple reflections of interest (multiples);
(b) inverting the shallow primaries using an estimated seismic source wavelet to obtain a shallow model of a physical property affecting propagation of seismic waves;
(c) computer-simulating the multiples using the inverted shallow model and the estimated seismic source wavelet;
(d) comparing the simulated multiples to the corresponding multiples in the seismic data, and adjusting the estimated seismic source wavelet to reduce misfit;
e) repeating (b) - (d) at least once, or until the misfit is reduced below a predetermined level or other stopping condition is met; and
(f) outputting a simultaneously optimized seismic source wavelet and shallow model.

2. The method of claim 1, further comprising extending applicability of the shallow model and the seismic source wavelet to a greater depth by inserting after (e) and before (f) a step comprising:

(e1) subtracting the simulated multiples from the seismic data, then extending the shallow layer to a greater depth, and then repeating (b) – (e) for the extended shallow layer.

3. The method of claim 2, wherein

the multiple reflections of interest-are strong multiples "strong" being determined based on a preselected reflectivity threshold;
the inverting of the shallow primaries comprises generating predicted data and optimizing the shallow model in depth domain to match the measured data in the shallow layer; and

the comparing the simulated multiples to corresponding multiples in the seismic data is performed within a window selected to contain multiples and to minimize overlapping between multiples and primaries.

4. The method of claim 3, further comprising further extending the physical property model's depth range by repeating (e1) at least once.

5. The method of claim 3, wherein said adjusting the estimated seismic source wavelet comprises at least one of:

applying a phase rotation to the estimated seismic source wavelet;
applying an amplitude correction factor to the estimated seismic source wavelet;
applying a spectral shaping filter to the estimated seismic source wavelet.

6. The method of claim 5, wherein the amplitude correction factor is amplitude of said simulated multiple reflection data divided by amplitude of said measured seismic data within a window selected to contain multiples and to minimize overlapping between multiples and primaries.

7. The method of claim 5, wherein the phase rotation is determined by varying the source wavelet's phase and repeating (b) - (d) and examining effect of the varied phase on the comparison in (d) for a water-bottom multiple reflection event or another seismic reflection event selected based on separation of multiple and primary reflections.

8. The method of claim 5, wherein the spectral shaping filter is designed based at least partly on an analysis of said mismatch in (d) for frequency content.

9. A computer program product, comprising 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 optimizing a source wavelet and a physical property model for a subsurface region from seismic data utilizing multiple reflections in the seismic data, said method comprising:

(a) selecting a shallow layer from the measured seismic data with the layer's depth determined to include primary reflections (shallow primaries), but exclude first arrivals of multiple reflections of interest (multiples);

(b) inverting the shallow primaries using an estimated seismic source wavelet to obtain a shallow model of a physical property affecting propagation of seismic waves;

(c) computer-simulating the multiples using the inverted shallow model and the estimated seismic source wavelet;

(d) comparing the simulated multiples to the corresponding multiples in the seismic data, and adjusting the estimated seismic source wavelet to reduce misfit;

e) repeating (b) - (d) at least once, or until the misfit is reduced below a predetermined level or other stopping condition is met; and

(f) outputting a simultaneously optimized seismic source wavelet and shallow model.