Virtual source applications to imaging and reservoir monitoring

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The virtual source method is a breakthrough that allows us to image and monitor the subsurface in cases where surface seismic or VSP fail to deliver. In settings where the overburden is complex or changing, traditional time-lapse signals are weak or nonrepeatable, leading to ineffective seismic input to reservoir modeling and little of value generated by repeated seismic surveys. On the other hand, the virtual source method allows us to image under complex overburden, yields repeatable data for reservoir monitoring, enables shear seismic, and may help us "look ahead" as we drill.

Virtual source technology circumvents overburden-induced problems by synthesizing controllable sources at the locations of sensors placed underneath complicated or changing overburden. This results in a buried seismic survey with fixed source and receiver locations that illuminates the underlying reservoir section. These virtual sources can harness all kinds of scattered energy that reaches them (P or S) and as such are completely data-driven. We don't need to know any details of the overburden to create them.

Shell operating units have used virtual source technology in exploration wells in the deepwater Gulf of Mexico to look ahead and pinpoint drilling hazards and image reservoirs with high resolution. Cost benefits can be substantial, given that each drilling incident or geologic sidetrack can cost US$5–10 million. Repeatable virtual sources are critical to enhance the sensitivity of time-lapse seismic in areas of low signal, to increase hydrocarbon recovery, and to unlock the potential of unconventional resources. We illustrate these advances through a series of field examples and discuss opportunities for wider deployment and the practical issues that need to be overcome.

Basic concept. While many formal derivations of the technique have appeared in the literature, for the geophysical practitioner, the logic depicted in Figure 1 seems to best capture the essence of the virtual source method, as it is explained below through a reverse-time experiment.

Professor Fink and colleagues at the École Supérieure de Physique et de Chimie Industrielles de la Ville de Paris focus acoustic energy at a point (R_α) using a surface array of actuators (S_k) that send time-reversed signals of original recordings from a real source at the target location (R_α). They call the actuator array a time-reversal mirror, as the energy back-propagation requires no knowledge of the medium and, in fact, the more complex the medium the better the focusing. Such reverse-time focusing is routinely applied in the medical field for the treatment of kidney stones, brain tumors, and other abnormalities.

The virtual source method goes two steps beyond the reverse-time acoustic experiments. First, it recognizes that, after focusing at the target location, energy reradiates from this focal point (not an energy sink) that we call a virtual source. Second, it recognizes that propagation from the virtual source onward approximates that from a real source at this point (R_α). Therefore, we can use the wavefield radiated from the virtual source location to image the surrounding medium just as we would use the wavefield from a physical source at that point. To create a virtual source below the surface of the Earth using seismic data, we need a VSP-type experiment. In a VSP survey, we have sources where Fink et al. had actuators (S_k) and a receiver where they had a physical source (R_α). Using reciprocity and linearity, we can turn the VSP data around and computationally create a virtual source at R_α.

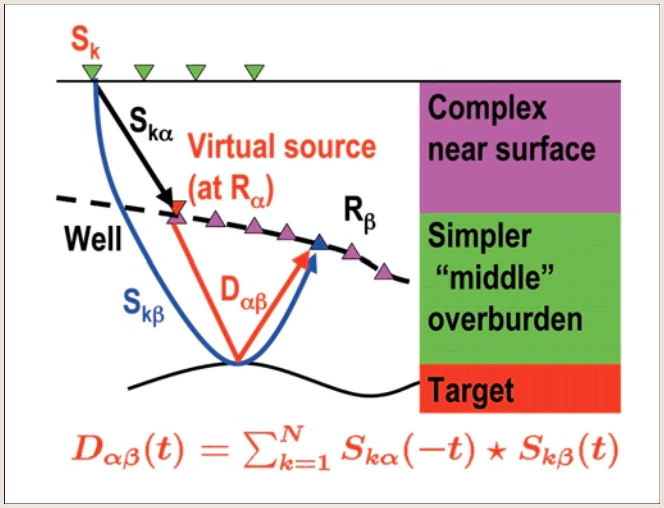


Figure 1. Schematic of virtual source method.

From a processing standpoint it suffices to visualize the technique as a cross-correlation of direct-arrival energy at one buried geophone (the virtual source) with the trace recorded at a second geophone (the receiver). The result, once summed over a suitable set of illuminating physical sources, approximates the response of a buried source-receiver pair in the subsurface. This data-driven virtual source redatuming process does not require any velocity information.

A word on artifacts and unwanted arrivals. In theory, extracting the exact response between a virtual source and a receiver requires illumination by physical sources that completely surround the area of interest. In practice, we have a limited aperture from surface-source acquisition. In addition, we may want to limit the type and directionality of the arrivals that fuel the virtual source in order to make it emit a preferred mode (P or S) in a desired direction (e.g., downward). In either case, limiting the input to the virtual source computation creates some artifacts in the virtual source data—namely, spurious events that would have been canceled if we had sources all around. Given that we cannot cancel them, we may try to avoid exciting them by further limiting the input to the virtual source by wavefield separation combined with gating. This strategy can be also employed to suppress other unwanted events such as interbed multiples.

Here is an example with an ocean-bottom cable (OBC) survey from Mars Field in the Gulf of Mexico. Virtual source redatuming to the seabed at Mars is aimed at improving repeatability of time-lapse surveys by eliminating the effects of varying water depth and velocity, and imperfect acquisition. Figure 2 shows the result of turning the middle OBC receiver into a virtual source in three slightly different ways. Correlating the total wavefields at the virtual source and receiver locations, as is a common practice in seismic inter-

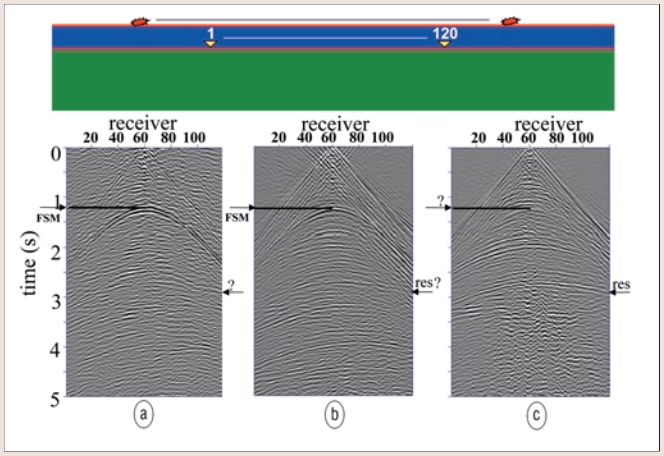


Figure 2. Suppressing noise in the redatumed Mars OBC survey; common virtual shot gathers created by cross-correlating: (a) total wavefields at virtual source and receiver locations; (b) total wavefields but with the time-reversed wavefield gated on first arrivals; (c) downgoing waves at the virtual source location (gated on first arrivals) with the upgoing waves at the receiver.

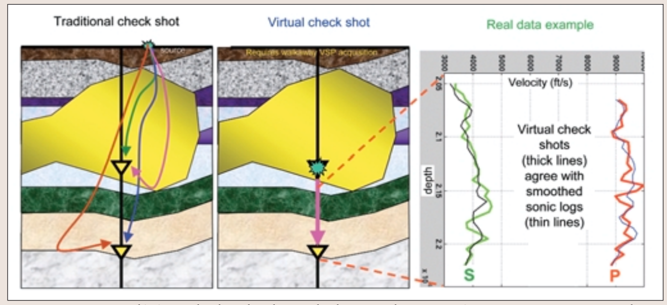


Figure 3. Traditional check shots below salt can give erroneous results because of complex raypaths and distorted waveforms. A virtual check shot with a virtual source location in the borehole avoids these complications. It gives accurate results below massive salt, as seen in the example on the right.

ferometry, we observe a strong free-surface multiple (FSM) and unwanted artificial events caused by incomplete aperture (Figure 2a). Doing the same but with a gate on the first arrival on the time-reversed wavefield cleans up the virtual source data and diminishes the amplitude of free-surface multiples (Figure 2b). This is our current most used practice. An even better practice is to correlate the downgoing waves at the virtual source (gated to first arrivals) with the upgoing waves at the receiver. One can see much better suppression of free-surface multiples, cleaner shallow reflections and enhanced reservoir response (Figure 2c).

Such adaptations of the virtual source construction make it very usable for seismic prospecting. They allow us great control on the radiation pattern and properties of the virtual source wavefield—an area that deserves additional study. Here we advocate an experimental approach and explore a number of applications based on physical intuition and business needs. Perhaps our results will inspire further efforts into understanding the theoretical underpinnings of these practical applications.

Virtual check shot. A simple application of virtual source technology involves propagation from one geophone to another (along the geophone string), a configuration that can be used to accurately estimate velocities along the borehole. Compared to conventional check shots with a single source at the surface, virtual check shots have virtual sources in the borehole and are immune to raypath distortions in the overburden. By appropriate gating on VSP traces, one can create virtual sources that emit predominantly compressional (P) or shear (S) waves that are detected on the vertical or horizontal components in the geophones below. A walkaway VSP in the deepwater Gulf of Mexico with geophones in and below salt was used to test this concept. The resulting velocity profiles for P- and S-waves were in very good agreement with sonic logs below salt at a depth of about 22 000 ft (Figure 3). Velocity estimates in salt were also in excellent agreement with well velocities.

Virtual check shots may be used where traditional check shots are expected to be inaccurate (e.g., because of complex overlying salt geometry) or unavailable (e.g., shear check shot), or where sonic logs are not feasible or desirable (e.g., in large boreholes or nonreservoir sections). These may be repeated over time to identify velocity variations due to geomechanical effects in producing fields, as measured at seismic frequencies. If downhole sensors are installed permanently, anomalies in virtual check shots may provide early warning of potential casing integrity problems.

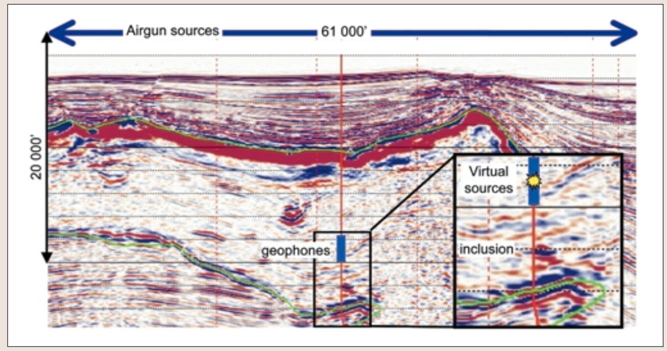


Figure 4. Seismic cross-section showing acquisition geometry for walkaway VSP in deepwater Gulf of Mexico prospect. The VSP was acquired in 40 geophones spanning a 2000-ft interval in the borehole. The inset shows the main objective of the virtual source analysis: high-resolution characterization of the in-salt inclusion and the base of salt interface.

Look-ahead VSP. Virtual sources can be synthesized underneath massively distorting features (such as salt, basalt, or ice) and processed to obtain high-resolution images of the reflectors below, regardless of the overlying complexities. For a single instrumented well bore drilled along geologic dip, the lateral extent of the resulting 2D image is ultimately limited by sensor coverage, and otherwise depends critically on the relative inclination of the well to reflectors. The image dimension is maximized for wells parallel to reflectors—e.g., horizontal wells over flat geology or vertical wells next to steeply dipping beds. This dimension is reduced proportionally as the angle between well and reflector increases, and shrinks to a single trace for wells perpendicular to reflectors, as in the case of a look-ahead VSP that we discuss next.

The look-ahead VSP with virtual sources was tested on a walkaway VSP data set acquired while a well was being drilled through thick salt in the Gulf of Mexico. The objective was to obtain a high-resolution image of the path ahead, which surface seismic suggested was plagued with intrasalt hazards, and of a complex base of salt interface with a potential for highly overpressured sands immediately below salt (Figure 4).

The VSP data set consisted of 40 geophones at 50-ft spacing, which were transformed into 40 virtual sources, giving a total of 1600 source-receiver pairs illuminating a narrow path ahead of the well. This high-fold data set confirmed that a prominent seismic feature in the salt was indeed an intrasalt reflection and not a multiple from the surface seismic. Careful study of the virtual source gathers allowed one to estimate the dip, attitude, and time of the intrasalt reflector. A salt velocity estimate from the corresponding virtual check shot yielded a prediction to the depth of the reflector 2000 ft ahead of the well with 50-ft uncertainty; the prediction was communicated to the rig, which soon thereafter encountered the inclusion within 2 ft of prognosis (Figure 5).

A similar analysis yielded a prediction for the depth to base of salt 4000 ft ahead of the well with 70-ft uncertainty. This prediction was also validated by the well results. Further dissection of the base salt reflection on the virtual source data revealed a bright event just 350 ft below salt, suggestive of hydrocarbons, which the well also validated (Figure 5).

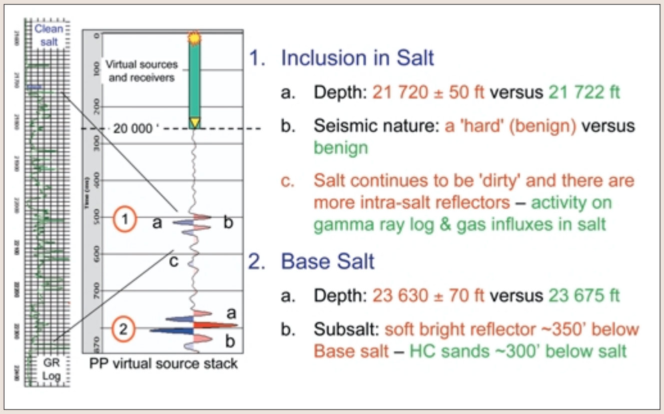


Figure 5. Stack of virtual source P-wave traces illuminating a 4000-ft interval ahead of the well. Comparison of high-resolution predrill predictions (red) with postdrill results (green) validates the remarkable accuracy of the virtual source data.

Imaging under complex overburden. Next, we illustrate the advantages of virtual source technology to generate useful images with some lateral extent, in a model inspired by the Peace River field in Canada (Figure 6a). A very heterogeneous near-surface layer creates large distortions of the seismic wavefield recorded on downhole receivers in a horizontal well above the reservoir (Figure 6b). These distortions cannot be handled by conventional imaging methods, as the requisite high-resolution near-surface velocity field cannot be recovered from the data itself. However, by applying the virtual source method, we immediately remove most of these distortions and obtain a virtual source gather (Figure 6c, in black) which is kinematically simple and closely resembles the ground truth response of an actual buried source (Figure 6c, in red) that we wanted to replicate. The virtual source data can then be easily migrated with a 1D velocity model beneath the horizontal well (Figure 6d). The virtual source image is of excellent quality and compares favorably to the idealized case of a conventional VSP image obtained with the exact velocity model (Figure 6e).

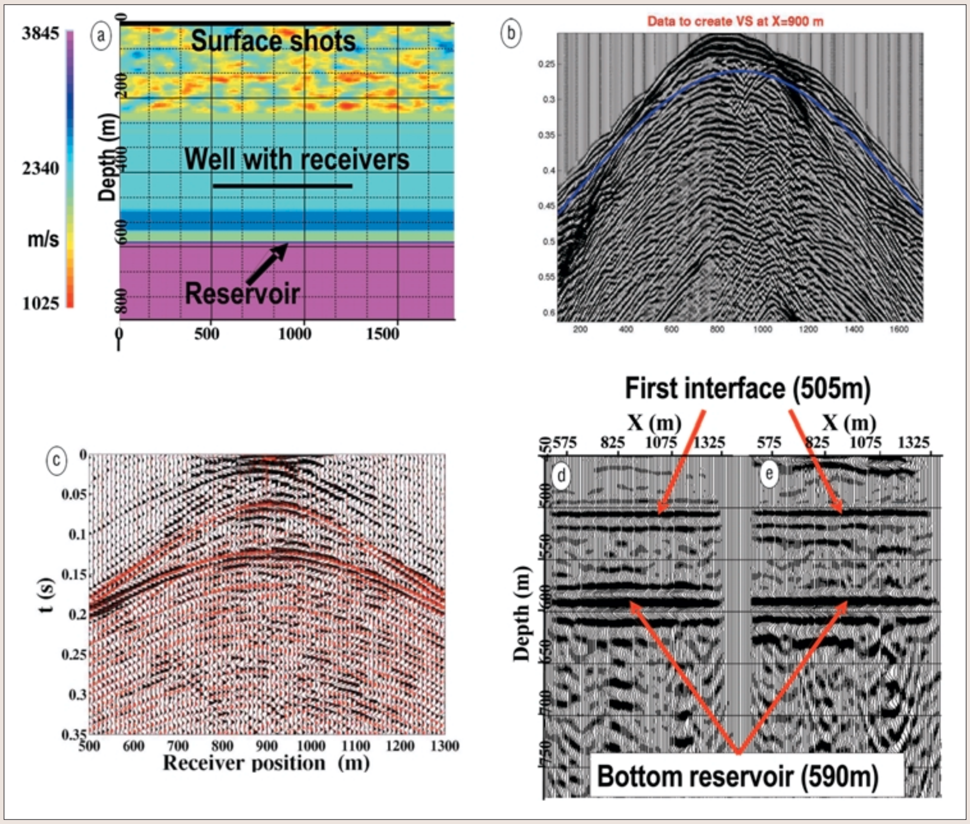


Figure 6. Synthetic Peace River model to image through complex overburden with virtual source technology: (a) P-wave velocity model with very heterogeneous near-surface layer; (b) common-receiver gather showing great distortions of the VSP wavefield; (c) common virtual source gather (red) compared to ground truth response of buried source (black); (d) VS image obtained with 1D velocity model beneath the well; (e) image of VSP data assuming unrealistic scenario where exact near-surface velocity model is known.

Not needing velocity information about the overburden is useful not only in permafrost areas and rugged terrains, but also near the edges of salt, where complex geometries and rapid changes in sediment velocity and anisotropy are difficult to model and leave imprints on the target images below. Even if such model inaccuracies could be overcome, the complicated scattering from strong heterogeneities in the overburden becomes noise that degrades the images in conventional processing. In contrast, overlying model errors are irrelevant for virtual source synthesis and complex scattering can be a beneficial fuel for the virtual source wavefield. Indeed, scattered high frequencies that get stacked out in conventional processing are not lost in the virtual source creation, and therefore, are available for high-resolution imaging of the medium below the virtual source locations.

To image with virtual sources we need velocity information for the relatively small region between them and the target. This velocity can be estimated from sonic logs or virtual check shots and, even if uncertain, it can lead to useful images because the target is relatively close. This idea has been exploited in the literature for imaging salt flanks with real and synthetic data and is being explored by Shell operating units for subsalt imaging (Figure 7).

With suitable acquisition, one may image salt flank recumbencies, which are very difficult to define from surface seismic data. The key to success is presurvey modeling, as physical sources need to be far from the well bore, and a complex 3D salt flank may not be amenable to this type of 2D imaging.

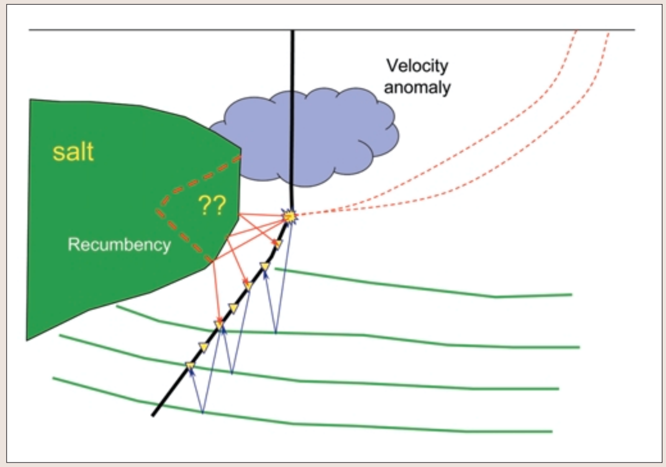


Figure 7. Conceptual example of virtual sources placed next to or under salt to image reflectors below without regard to overlying velocity complexities. Illuminating receivers at virtual source locations from the side (dashed raypaths) can resolve possible salt flank recumbencies hard to image from surface.

Salt cavern modeling study. One may also image salt flanks from within salt. This novel idea is being tested in a salt dome in The Netherlands, where a Shell operating unit is assisting the salt mining company Akzo Nobel in the evacuation of salt caverns for underground gas storage by the Dutch gas companies Gassunie and NUON. The caverns will be 300 m in height with a diameter of 60 m, starting at depths of 1 km. They must be at least 100 m from the salt flank (Figure 8). The Zuidwending salt dome is an upward lobe of the Zechstein salt formation, which tightly seals the huge, underlying Groningen gas field. The geometry of the salt dome has been derived from surface seismic, but it remains rather uncertain (+/- 200 m) along the vertical flanks (Figure 8). A salt proximity survey would require very distant sources to image a useful portion of the salt flank, and would be very uncertain. On the other hand, generating virtual sources in the salt, we could image the salt flank needing only the salt velocity for accurate lateral positioning.

The acquisition will be a conventional walkaway VSP with receivers in the salt cavern pilot holes. Shot locations were initially chosen based on ray tracing to image the desired portion of the salt flank (Figure 9, top). We also generated a full waveform 2D elastic synthetic data set with a free surface. The salt flank reflection is discernible on the raw common receiver gathers but is obscured by top salt multiples. After application of virtual source technology, the salt flank reflection becomes clean and easy to pick, especially on the zero-offset gather (Figure 9, bottom). Picking the times on the synthetic data we reproduced the model interface with better than 25-m precision, which was sufficient to justify acquisition.

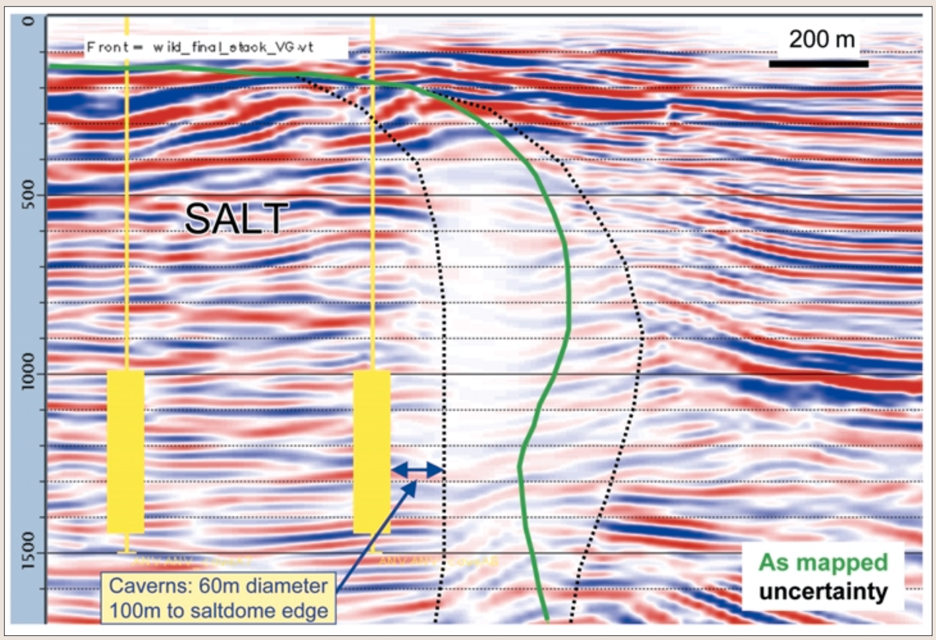


Figure 8. Planned salt caverns for underground gas storage in The Netherlands. Uncertainty of lateral positioning of salt flank from surface seismic needs to be reduced for safe placement of salt cavern.

High-fidelity and in-situ time-lapse seismic. Virtual source monitoring has emerged as a complementary tool to conventional time-lapse seismic to address the following challenges:

- Inability to repeat the acquisition geometry (e.g., source and receiver locations)
- False 4D responses due to seasonal changes in the near surface between time-lapse surveys which can be completely overwhelming in certain areas (e.g., Arctic, Siberia).
- Difficulty in tracking small time-lapse signals under complex near surface (typical for Middle East reservoirs)

Seismovie experiments by CGG have demonstrated that high repeatability can be achieved and very small time-lapse signals observed when sources and receivers are placed at fixed locations beneath the layer subject to seasonal changes. While such in-situ 4D seismic is attractive, it requires both sources and receivers to be permanently buried. In contrast, the virtual source method offers essentially the same advantages but requires that only the receivers be permanently buried. Indeed, it has been demonstrated before that, with permanent receivers in the well, virtual source technology corrects for typical geometry nonrepeatability of surface acquisition. We show next that seasonal changes can also be handled, thus enabling sensitive monitoring of small signals. Such high-fidelity time-lapse seismic technology will be key to the success of the Shell Group's next generation Smart Fields in increasingly complex areas.

To demonstrate the ability of this technique to mitigate near-surface seasonal changes, we use the same Peace River model and VSP acquisition in Figure 6. In the baseline survey the upper 5 m of the near-surface layer are assumed to transition from unfrozen wet soil to frozen conditions; in the

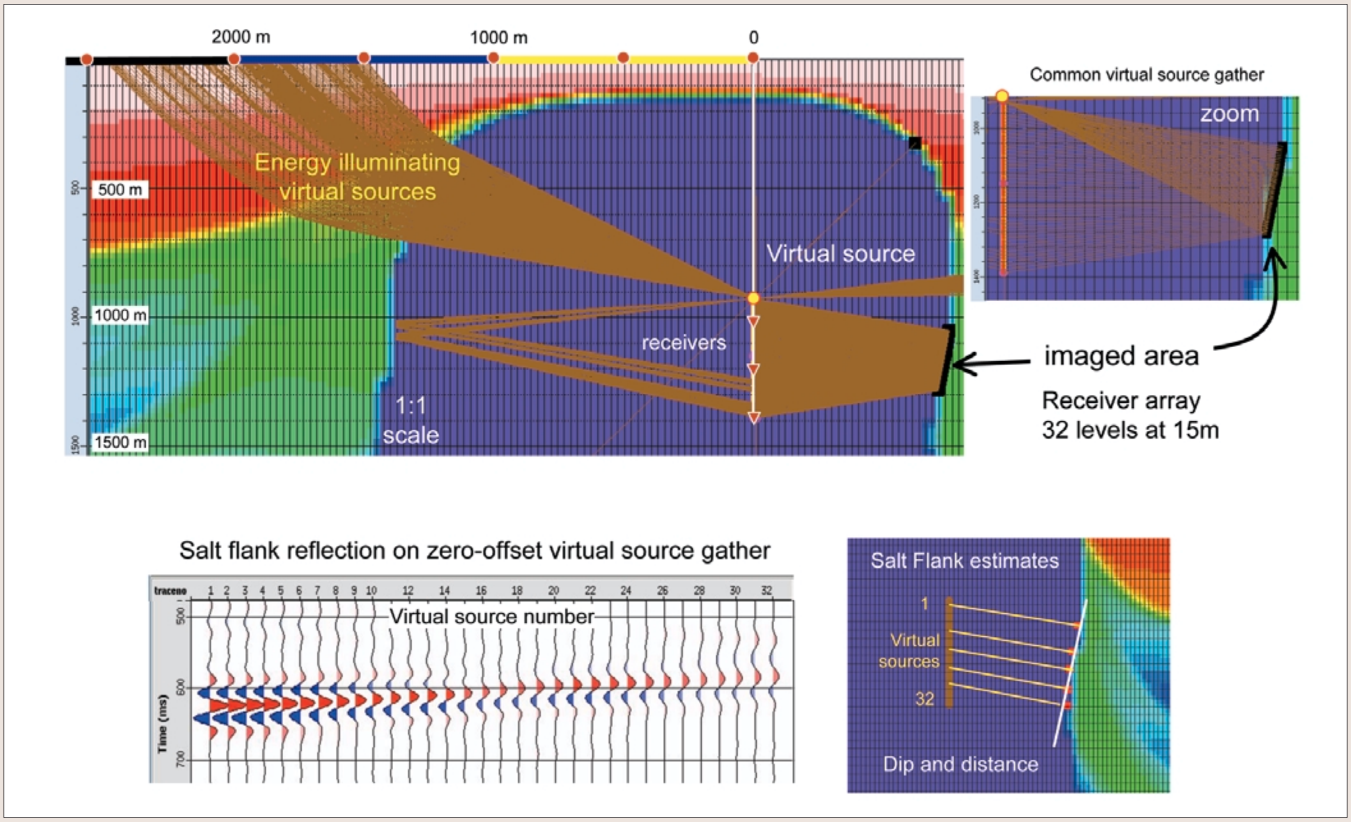


Figure 9. Raytrace modeling to locate surface shots that illuminate receivers at virtual sources locations to image salt flank at desired depth (top). Zero-offset virtual source traces can be used to estimate distance to salt flank in a simple way (bottom).

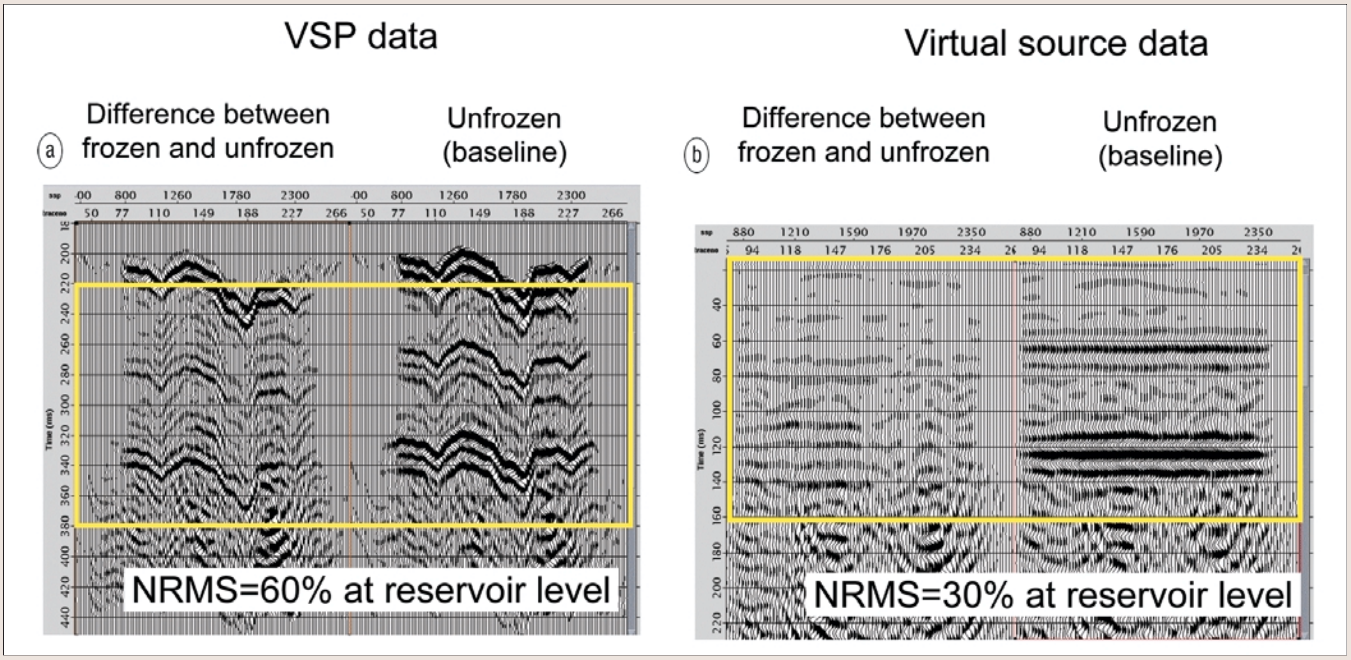


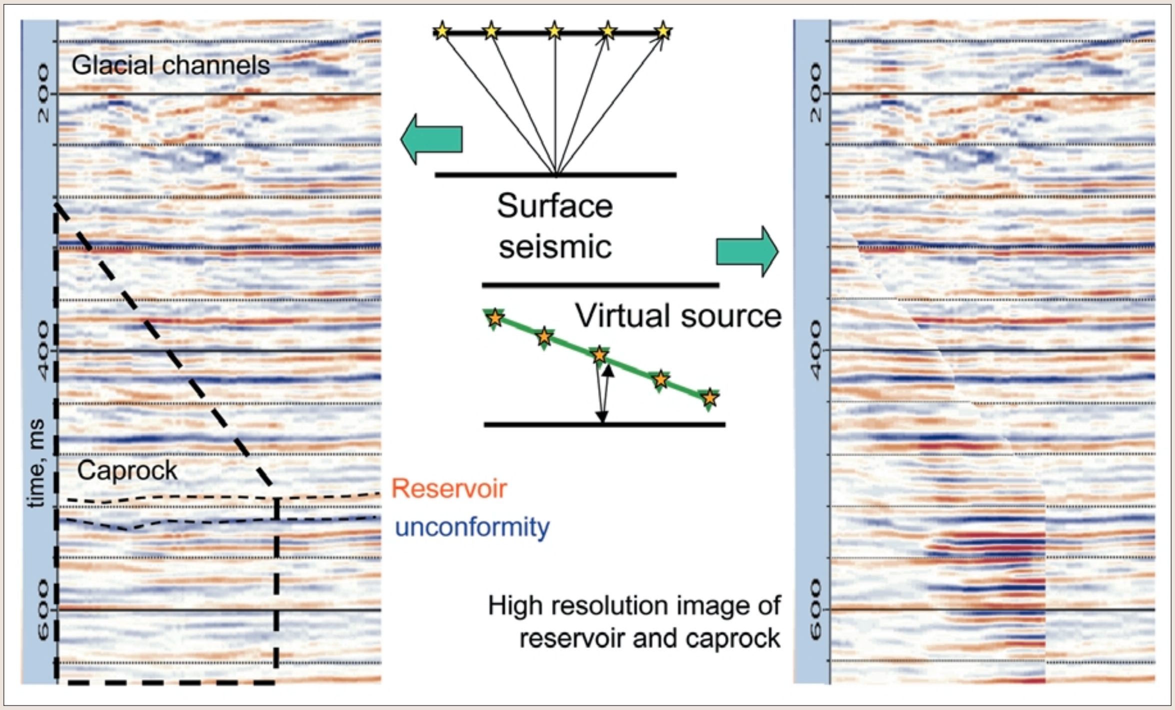
Figure 10. Modeled images from two surveys recorded under wet (baseline) and frozen (monitor) conditions when no reservoir changes take place. (a) VSP data time-migrated with baseline velocity model. Note strong jiggling of traveltimes due to heterogeneous near-surface and poor repeatability around reservoir zone. (b) VS data time-migrated with 1D velocity model below the well. Note that all time jiggling in the overburden is removed and much better repeatability is achieved without additional acquisition effort.

repeat survey the entire near surface is assumed frozen. The Voronkov equation

$$\frac{(V_{Pf} - V_{Pw})}{V_{Pf}} = 0.73 - 0.11\, V_{Pw}$$

was used to convert P and S velocities (km/s) of wet soil (V_{Pw}) to corresponding values in frozen soil (V_{Pf}). This very heterogeneous speed-up of up to 100% of the original velocities causes large nonrepeatability even though the reservoir zone remains unchanged. Migrating both baseline and repeat VSP data sets with the same baseline velocity model (wet/frozen) gives a poor repeatability estimate of 60% in

Figure 11. Comparison of surface seismic (left) with zero-offset virtual source image (right) as acquired in a deviated well in Peace River Field in Canada. Application of virtual source technology shows improved resolution of the cap rock and reservoir sections.



normalized rms units and an artifact-ridden baseline image (Figure 10a). In contrast, the corresponding virtual source data give a much improved repeatability estimate of 30% rms and a clear baseline image (Figure 10b). Thus, with application of virtual source technology we have a much better chance of observing production-related time-lapse signals. While our modeled heterogeneities and seasonal velocity changes may be exaggerated, they illustrate the stable performance of this method under conditions unmanageable by other methods.

Our real data example also pertains to Peace River, where massive heavy oil resources are being exploited by cyclic steam stimulation. Studies show that the steam paths in the reservoir are hard to model and must be measured to be able to alter the steam injection patterns to increase recovery from each square-kilometer development pad. Glacial channels overlying the field and seasonal changes in the immediate near surface compromise data quality and repeatability of surface seismic and make us seek downhole solutions with virtual source monitoring. At Pad 40, a well was drilled above the reservoir at an inclination of 45° and instrumented with 50 permanent 3-C geophones. The seismic data sets include a baseline and four repeats of a 2D source line at various stages of the steam injection cycle, with simultaneous surface and downhole recording. We have processed the downhole data to synthesize virtual sources at each receiver location and focused our attention on the upgoing, zero-offset virtual source reflections. This basic single-fold data set ties the corresponding surface seismic and shows increased resolution of the 75-m seal section, the 25-m reservoir, and the unconformity below (Figure 11).

The single-fold virtual source time-lapse images (Figure 12) show very good repeatability above the reservoir and distinct changes in the reservoir and the section below (presumably due to absorption in the heated reservoir). A quantitative evaluation of the changes over time will be attempted, although the results will be of limited use given the small imaged area and an apparent shadow zone near the edge of the survey. Nonetheless, these encouraging results justify a test of areal monitoring, as we discuss below.

Deployment issues and opportunities for monitoring. Monitoring with virtual sources in observation wells is technically feasible with current technology for single instrumented well bores. For field-wide areal monitoring, multiple instrumented well bores are required and several technical and operational challenges need to be overcome.

First, we need to develop inexpensive and reliable methods for drilling horizontal wells in the shallow and deep overburden. A recent U.S. Department of Energy initiative fostered the development of a set of low-cost drilling technologies for vertical, instrumented, very small diameter "microholes." A similar effort seems required for horizontal wells to fully leverage the virtual source method. U-shaped wells (with two surface exits) are particularly attractive for shallow horizontal wells, because they provide great flexibility for sensor deployment.

Second, fit-for-purpose seismic sensor arrays need to become available for this new geophysical market niche. Conventional VSP sensors are designed for very harsh pressure and temperature conditions, and provide good borehole coupling. Their specs are well above those needed for shallow overburden wells, and their cost is not attractive for permanent deployment. Typical surface seismic arrays may have the right specs but are not suitable for deployment in horizontal wells. OBC cables may be the easiest to adapt to borehole conditions, and the presence of a hydrophone sensor would allow routine application of dual-sensor (vertical geophone + hydrophone) wavefield separation for improvement of the virtual source data. Alternatively, repackaging of surface seismic arrays (a la OBC) may allow them to adapt to borehole coupling conditions. Long sensor arrays would also require digital recording and transmission systems.

Third, conveyance methods need to be developed to deploy long seismic arrays in horizontal or deviated wells. While some methods exist and are practiced for wireline VSP and crosswell seismic, the jury is still out on the most effective way of emplacing long arrays with well-coupled permanent sensors in such wells.

For areal monitoring we require repeated application of

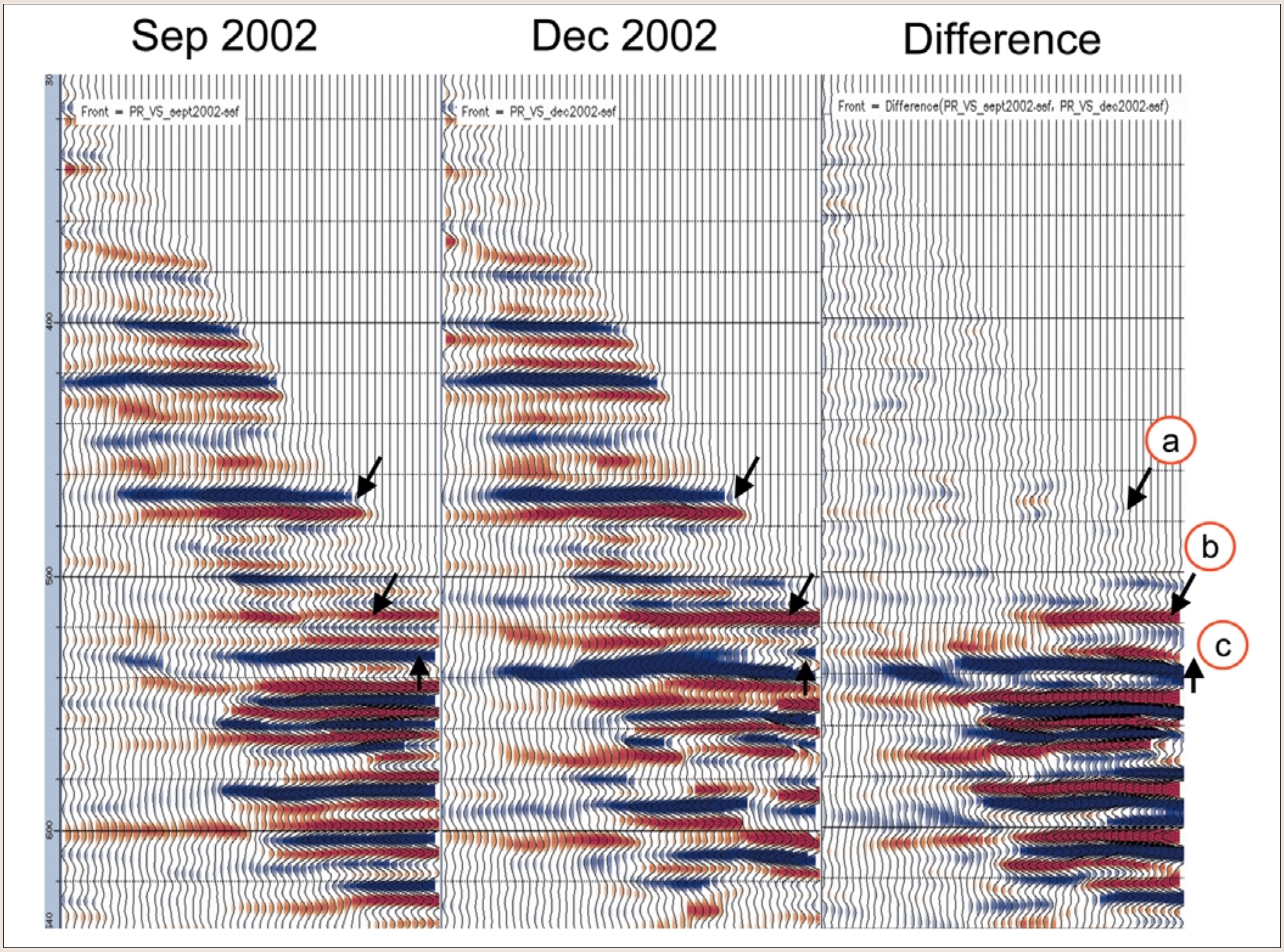


Figure 12. *Zero-offset virtual source image for the baseline (September 2002) and monitor survey (December 2002) after steam injection at Peace River. The arrows on the time-lapse changes on the zero-offset virtual source data point to characteristic events—top seal (a), reservoir (b), and underlying regional unconformity (c). Note the very good repeatability above the reservoir and the marked changes in and below the reservoir.*

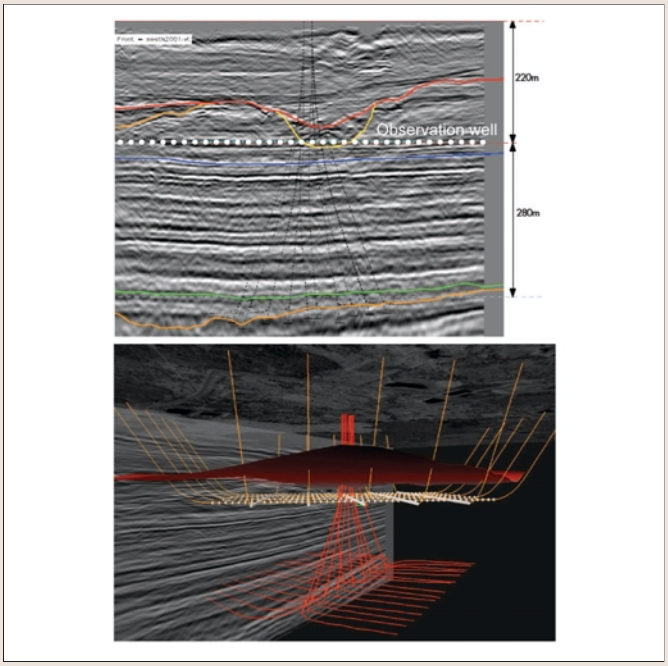


Figure 13. *Conceptual design for areal field monitoring with a grid of instrumented observation wells drilled immediately below the shallow glacial channels at Peace River.*

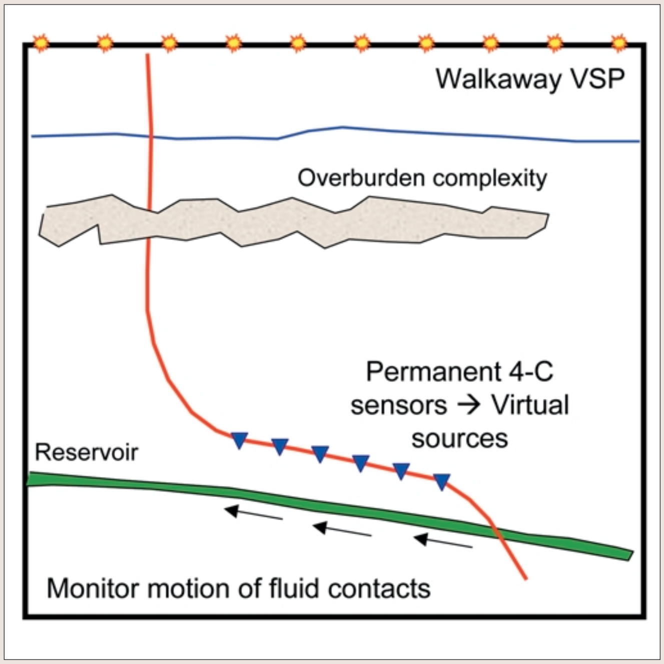


Figure 14. *Conceptual design to monitor a fluid contact with a permanent sensor installation in an injector well.*

these technologies. The simplest configuration is a virtual cross-spread, where an orthogonal pair of instrumented wells is illuminated by an areal surface acquisition, to simulate a buried cross-spread in the subsurface. Field-wide monitoring requires a grid of horizontal wells to image the reservoir with overlapping cross-spreads—e.g., a grid of 5+5 wells to monitor the square-kilometer pads at Peace River (Figure 13). This eventual goal requires the advances in drilling and instrumentation discussed above, although field trials over small areas are being planned for the near future. Besides the operational issues, a challenge remains on the processing of such sparse and possibly irregular data sets.

One may also consider placing permanent sensors in production or injection wells, which by their nature could be highly deviated, for instance when surface obstructions require drilling of extended reach wells from a few drilling centers. A particularly favorable example would be a water injector that has a nearly horizontal section over and along the reservoir from the original fluid contact up to the crest of the structure (Figure 14). If this well section is permanently instrumented and acquired periodically (by shooting a walkaway VSP line over the sensor array), one could monitor the progress of the OWC as the field depletes.

Summary and outlook. Virtual source technology has the potential to revolutionize the ability to probe, image, and monitor the subsurface, especially in areas overlain by very complex overburden. The Shell Group is planning and executing small-scale field trials onshore and offshore, while advances in theory, instrumentation, and drilling technology proceed in parallel. Market forces suggest that a convergence of technical feasibility and cost-effective deployment should occur in the not-too-distant future.

Suggested reading. "Virtual source: new method for imaging and 4D below complex overburden" by Bakulin and Calvert (*SEG 2004 Expanded Abstracts*). "The virtual source method: Theory and case study" by Bakulin and Calvert (GEOPHYSICS, 2006). "Virtual shear source makes shear waves with air guns" by Bakulin et al. (GEOPHYSICS, 2007). "Seismic imaging a subsurface formation" by Calvert (US Patent 6 747 915). "Acoustic time-reversal mirrors" by Fink and Prada (*Inverse Problems*, 2001). "Gas storage in salt caverns" by Hoelen et al. (23rd World Gas Conference, 2006). "VSP: Beyond time-to-depth" by Hornby et al. (*TLE*, 2006). "On the fundamentals of the virtual source method" by Korneev and Bakulin (GEOPHYSICS, 2006). "Integrated reservoir surveillance of a heavy oil field in Peace River, Canada" by Maron et al. (*EAGE 2005 Extended Abstracts*). "Reservoir monitoring using permanent sources and vertical receiver antennae: the Cere-la-Ronde case study" by Meunier et al. (*TLE*, 2001). "A theoretical overview of model-based and correlation-based redatuming methods" by Schuster and Zhou (GEOPHYSICS, 2006). "A novel application of time-reversed acoustics: Salt-dome flank imaging using walkaway VSP surveys" by Willis et al. (GEOPHYSICS, 2006). TLE

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