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Advanced sensing and imaging for efficient energy exploration in complex reservoirs

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ABSTRACT

The oil and gas industry continuously struggles to cope with the high cost of production in the context of competitive worldwide market prices. Low oil and gas prices backstop an economic situation where exploration and exploitation of complex reservoirs are hindered. Exploration and production of complex reservoirs face several challenges. Despite having subsurface information from geological models and seismic images, they are prone to uncertainties, and as a consequence, the development and production of such reservoirs are not optimal. Here, we focus on advanced sensing methodologies that are tailored to complex unconventional reservoirs, such as the heavy oil reservoirs in Canada. Further refinement of reservoir extent, hosted oil, and geological properties can potentially increase production rate, decrease the costs and risks of drilling, alleviate well placement issues, and improve the management and monitoring of reservoir – overall leading to lower uncertainty on developing advantage of the seismic-while-drilling imaging approach. The proposed framework provides high-resolution images of the subsurface thanks to new advancements in seismic remote sensing, signal processing, and imaging.

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1. Introduction

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According to the statistics reported by EIA's International Energy Outlook 2017, world energy consumption is expected to increase by 15.3% over the next twenty years (EIA, 2017). However, the oil and gas industry faces a long-term downturn with oil and gas price reduction (dropped \approx 44% from 2014 to 2017) and uncertainties. The financial weakness of operators under low oil and gas prices hinders the exploration and production of complex reservoirs such as the ones encountered in deepwater reservoirs in the Gulf of Mexico or tight heavy oil reservoirs in Canada and Venezuela. For example, difficulties of tight and heavy oil exploration and production have been extensively studied (Butler and Stephens, 1981; Heim et al., 1984; Wehunt et al., 2003; Guo et al., 2016; Montgomery and O'Sullivan, 2017; Dong et al., 2019). Moreover, the demand to reduce environmental impacts of oil and gas production is also important (Dorian et al., 2006). In this paper, we describe a new workflow to optimize drilling, wellplacement, geosteering, and production of complex petroleum reservoirs, which ultimately reduces drilling costs by providing a better subsurface model.

Exploration and exploitation of complex reservoirs face several challenges. These include uncertainties in geological and geophysical models, risks and cost of drilling, and challenges in geosteering and optimal well-placement. Uncertainties inherent in the geological model of the region of interest and subsurface seismic images, provided by processing surface seismic data, should be minimized to increase the performance of drilling, well-placement, geosteering, and production. There have been many new ways to sense and monitor to better capture the structures around wells, locate high pore pressure zones, sweet spots, and barriers, and monitor dynamics of fluid movements in the reservoir during production (Ramakrishnan and Thambynayagam, 1999; Maxwell et al., 2010; Mateeva et al., 2014).

In a complex reservoir, seismic depth images may not pro-34 vide an accurate structure of the reservoir especially for deeper 35 parts of the domain Gray et al. (2001). Accordingly, sensing and 36 monitoring the reservoir is necessary. Additional sensing and 37 monitoring information is required along with seismic images of 38 the subsurface to reduce uncertainties of the reservoir descrip-39 tion (Lines et al., 1988). Multi-offset vertical seismic profiling 40 (MVSP) can provide such information about the structure of the 41 subsurface around the wells (Hardage et al., 1985). MVSP is rich 42 in information and is extensively used for imaging around the 43 wells. MVSP can image below and above the observation point 44

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in the borehole. Moreover, it has shorter raypaths and can provide higher resolution images than surface seismic (Poletto and Miranda, 2004). However, MVSP has several shortcomings. The main issues with MVSP are (1) its acquisition cost is high, (2) to acquire the data drilling must be interrupted which increases the rig time, and (3) to acquire the data, depending on the maximum offset, the drill string should be taken out of the well for one or more days without control of the well pressure which can result in a collapse of the well (Poletto and Miranda, 2004). Logging-while-drilling (LWD) is another way to gather information from around the wells (Godbey, 1967; Tang et al., 2002). LWD provides high-resolution information about the rock properties around the well within a couple of meters. Ironically, in complex reservoirs where the LWD approach can be a vital source of information about the rock properties, logging-while-drilling is not possible (Poletto and Miranda, 2004). This is because in complex areas the drilling process is not stable and it cannot be continued for a couple of meters without casing. Seismicwhile-drilling (SWD) is another sensing mechanism that helps geophysicists image the structure of the subsurface layers around the wells (Rector and Marion, 1991; Poletto and Miranda, 2004). This method sometimes referred to as drillbit VSP or reserve VSP, is of great interest in subsurface imaging, drilling, wellplacement, and geosteering applications (Poletto and Miranda, 2004). The necessity of developing an efficient sensing system that does not interrupt the drilling process and provides highquality images around the wells is the main motivation behind the technique. Since the 1960s, several workflows and sensing mechanisms are proposed and used in the industry (Meehan et al., 1998; Poletto and Miranda, 2004; Anchliya, 2006). SWD has also drawn significant interest in recent years due to increased computational power in the field and improvements in the sensing devices (Meehan et al., 1993; Greenberg, 2008; Rossi et al., 2001; Vasconcelos and Snieder, 2008; Kazemi et al., 2018b). Thanks to new advances in signal processing, high-resolution SWD images of the subsurface is possible. Also, this information is used to improve the performances of drilling and well-placement in challenging reservoirs.

Another concern when dealing with complex reservoirs is the stable and efficient drilling process. Clear understanding and modeling of drill string dynamics and drillbit-rock interaction, appears to be crucial in controlling the drill string vibrations, improving the rate of penetration (ROP) of the drilling system, preventing damages to the system, and finally reducing the safety risks of the drilling operation. Moreover, the cost of drilling is at large dependent on the rig time. Accordingly, it is necessary to reduce non-productive time by increasing the rate of penetration. To do so, knowledge of the bit-rock interaction (and consequently of the underlying formation) is an important factor. Different models of friction due to the contact between the cutting device and drilling surface have been proposed in the literature (Saldivar et al., 2016). These models usually depend on the nature of the drilled rock, such a dependence of the drill string dynamic response on bit-rock interaction and formation properties is studied by Shor et al. (2015). Estimating the characteristics of the formation is not an easy task as downhole sensors are expensive and may raise potential technical risks.

To provide a reliable characterization of the formation (and consequently of the drillbit–rock interaction), SWD could appear of great interest and be the next step towards a formation-aware drilling system. SWD uses the elastic energy radiated by a working bit to determine time-to-depth and look-ahead information while drilling (Anchliya, 2006; Meehan et al., 1998). The radiated energy is recorded at the surface using an accelerometer and conventional seismic sensors (e.g., geophones or hydrophones). The SWD measurements can be used to characterize the formation ahead of the drillbit. In turn, the formation-aware drilling

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system provides an opportunity to update the drilling parameters68in near real-time so that the system experiences a smooth rate of69penetration. It also helps to be aware of hazardous areas before70drilling.71

Another issue is defining the optimal well path when there 72 are uncertainties in the subsurface models. In well placement, 73 74 the objective is to place the well to obtain optimal performance during production. Ideally, the locations are optimized by using 75 a reservoir simulator with a geological model of the reservoir. 76 However, this process is often imperfect due to time constraints 77 and uncertainties of the inputs of the geological and reservoir 78 simulation models. In some approaches, parameters associated 79 with the producible hydrocarbon, such as contacted reservoir 80 quality, is used as a fast and reliable decision proxy. Application of 81 LWD and measurement-while-drilling (MWD) can improve real-82 time geosteering by providing petrophysical information, drilling 83 measurements, and distances to boundaries while drilling (Allen 84 et al., 1989). Reactive geosteering uses LWD measurements while 85 the well is drilled into a given rock. The MWD system provides 86 downhole measurements near the bit while drilling is in progress. 87 It provides accurate and reliable information on the formation be-88 ing drilled and the behavior of the drill string. The frequent data 89 obtained from the sampling of downhole measurements in which 90 the data is collected downhole and telemetered and detected at 91 the surface through either the drilling fluid, electrical conductors, 92 or the drill pipe, are implemented for better control of drilling 93 operations (Arps and Arps, 1964; Gearhart et al., 1981). MWD sys-94 tems provide essentially real-time information generally placed 95 in two categories: (1) drilling variables and hole information, and 96 (2) formation characteristics. Drilling variables and hole informa-97 tion might include hole direction and inclination, tool-face angle, 98 weight on bit and torque, downhole temperature and pressure, 99 mud properties, bit vibration and acceleration, and others. Forma-100 tion characteristics include radioactivity (Gamma-ray), resistivity, 101 annular temperature, and others. 102

SWD method records the seismic energy generated by drillbit-103 rock interaction, processes the data, and provides high-resolution 104 images of the subsurface which allows for steering the well 105 not only on logging data but also on the improved subsurface 106 images. Formation boundaries and main geological uncertainties 107 are identified above, below, and in front of the drill bit. This en-108 hanced subsurface image reduces the uncertainties and provides 109 valuable geological information for placing the well in complex 110 reservoirs. It also provides sufficient time for decision making and 111 drilling optimization through mapping reservoir structures and 112 problematic zones ahead of the drill bit. 113

The paper is organized as follows: First, we introduce a new 114 SWD-based imaging workflow. Then, we integrate SWD with 115 drilling and develop a formation-aware drilling system. Finally, 116 the issues of well placement and the importance of advanced 117 sensing techniques in horizontal drilling are discussed. Each section has its concluding remarks. We also provide a discussion 119 section, in the end, covering final remarks and conclusions. 120

2. Seismic-while-drilling imaging

This section covers the basics of our SWD imaging algorithm.122Detailed and comprehensive formulation and analysis of this123topic are outside of the scope of this writeup. Interested readers124are referred to Kazemi and Sacchi (2014), Kazemi et al. (2018a,b)125for more details.126



Fig. 1. Schematic representation of the geometry of receivers and drillbit sources in vertical and horizontal drilling and the radiation patterns of drillbits.

2.1. Background and motivations

The drillbit generates significant elastic wave energy whose raypaths are unique relative to those induced by standard surface seismic. Therefore, if the challenges associated with characterizing the source radiation properties can be adequately addressed. the data arising from SWD are complementary to surface data and have the potential to enhance geophysical evaluation of the subsurface. What the addition of SWD (and its raypaths) to seismic characterization provides is an opportunity to address seismic illumination issues with new measurements. In general, there are two main acquisition geometries for the SWD method. The receivers can be deployed on the surface or in the nearby boreholes, and the drillbit can be associated with vertical wells or horizontal wells. Depending on the type of drilling wells, i.e., vertical or horizontal drilling, the radiation patterns would be different. In vertical drilling, the drillbit radiation patterns in the vertical direction are dominated by the pressure component, i.e., P waves, and in the horizontal direction is mainly shear component, i.e., S waves. Hence, receivers at the surface can record the pressure wave field and provide information-rich SWD data. However, in horizontal drilling the drillbit radiation patterns in the vertical direction are dominated by the shear component, i.e., S waves, and in the horizontal direction is mainly pressure component, i.e., P waves. Accordingly, in a horizontal drilling system receivers at the surface do not record strong pressure components. Moreover, in deep and ultra-deep drilling shear wave field is highly attenuated by the earth and the quality of SWD data is poor. An alternative would be to deploy receivers in the surrounding nearby vertical boreholes and record the P component. Moreover, in downhole recording, as the distance between the drillbit location and borehole receivers are smaller compared to surface receivers, the quality of data is better. The data also contains a broader frequency range which results in providing high-resolution subsurface images. Fig. 1 is a schematic representation of the geometry of receivers, drillbit sources in vertical and horizontal drilling, and the radiation patterns of drillbits.

In complex structures wave energy penetrates weakly into some areas and surface seismic images suffer from nonuniform illumination problems. Nonuniform illumination means that some parts of the subsurface structure will be in the shadow zone of 42 surface seismic acquisition and those regions will not be properly

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imaged. To remedy this shortcoming of surface seismic imaging, 43 the SWD method along with surface seismic data is used to 44 mitigate the nonuniform illumination problem. The idea is to 45 combine the migrated sections of the SWD and surface seismic 46 datasets to achieve a better illumination. To do so, the first step 47 is to understand the seismic characteristics of the drillbit-rock 48 interaction. In other words, we need to estimate the drillbit-rock 49 interaction source signature. This is done by using a multichannel 50 sparse blind deconvolution technique called SMBD (Kazemi and 51 Sacchi, 2014). After estimating the SWD source signature, to 52 migrate the SWD data, we forward propagate the estimated SWD 53 source signature through the background medium and cross-54 correlate it with the backward propagated volume of the recorded 55 SWD data. Finally, we merge the migrated section of the SWD 56 data with the surface seismic image to improve the illumination. 57 The efficiency of the workflow is tested against a benchmark 58 model called the Sigsbee2a model which is designed to mimic 59 the complex reservoir of the Gulf of Mexico. This challenging and 60 complex model is difficult to image since seismic energy tends to 61 bend towards the high-velocity salt body and the sub-salt region 62 is in the shadow zone of the surface seismic acquisition. Hence, imaging the sub-salt region in this model faces challenges in terms of resolution, illumination, and uncertainties.

In the next section, we start by introducing seismic depth imaging methodology and its illumination problem. Then, we argue that SWD data, when used along with surface seismic data, can improve the illumination. Later, we explain the multichannel blind deconvolution algorithm for estimating the SWD source signature. Finally, a workflow presented on merging surface and SWD imaging, and the performance of the workflow is evaluated on a challenging Sigsbee2a model.

2.2. Seismic imaging and nonuniform illumination problem

We start with the description of wave equation in a constant density acoustic and isotropic medium

$$(\omega^2 \mathbf{s}^2 + \nabla^2) \mathbf{P} = f \ \delta(\mathbf{x} - \mathbf{x}_s),\tag{1}$$

78 where *P* is pressure wavefield, **s** is slowness (reciprocal of velocity), ω is temporal frequency, f is the source signature, \mathbf{x}_{s} is source 79 location and ∇^2 is Laplacian operator. To start the analysis, it is 80 assumed that the background smooth velocity (slowness) field is known. We represent the squared slowness and the scalar field in terms of perturbations and backgrounds as

$$\mathbf{s}^2 = \mathbf{s}_0^2 + \mathbf{m}, \quad and \quad P = P_0 + \Delta P,$$
 (2) 8

where \mathbf{s}_0 and P_0 are background slowness and wavefield, respec-85 tively. The parameter **m** is the perturbation in slowness-squared. 86 Similarly, ΔP is the perturbation in the wavefield due to **m**. Now, 87 by using the Green's function G_0 satisfying the wave equation 88 corresponding to the background medium 89

$$(\omega^2 \mathbf{s}_0^2 + \nabla^2) G_0 = \delta(\mathbf{x} - \mathbf{x}_s), \tag{3} \qquad 90$$

the perturbed wavefield can be calculated via

$$\Delta P(\omega, \mathbf{x}) \approx -\sum_{\mathbf{x}'} G_0(\mathbf{x}, \omega; \mathbf{x}') \, \omega^2 \mathbf{m}(\mathbf{x}') \, P_0(\omega, \mathbf{x}'). \tag{4}$$

In general, if the explosive source is at position \mathbf{x}_{s} and the receivers are at spatial coordinates \mathbf{x}_r , Eq. (4) can be written as

$$d(\omega, \mathbf{x}_r, \mathbf{x}_s) = \Delta P(\omega, \mathbf{x}_r, \mathbf{x}_s)$$

$$\approx -\sum_{\mathbf{x}'} G_0(\mathbf{x}_r, \mathbf{x}_s, \omega; \mathbf{x}') \, \omega^2 \mathbf{m}(\mathbf{x}') \, P_0(\omega, \mathbf{x}'), \tag{5}$$

which is the forward modeling operator. In matrix-vector nota-93 94 tion, we have

$$\mathbf{d} = \mathbf{L} \, \mathbf{m},\tag{6} \quad 95$$

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where **d** denotes the seismic measurements represented by a vector and the vector **m** stands for the acoustic potential and **L** is the forward modeling operator. Now, by defining the adjoint of forward operator, migrating the measured data is carried by

$$\mathbf{m}_{mig}(\mathbf{x}) = -\sum_{\omega} \sum_{\mathbf{x}'_{s}} \sum_{\mathbf{x}'_{r}} (\omega^{2} P_{0}^{*}(\mathbf{x},\omega;\mathbf{x}'_{s}) G_{0}^{*}(\mathbf{x}'_{s},\mathbf{x}'_{r},\omega;\mathbf{x})$$
$$\times d(\mathbf{x}'_{r},\mathbf{x}'_{s},\omega)) = \mathbf{L}^{T} \mathbf{d}, \qquad (7)$$

where \mathbf{m}_{mig} is the migrated image of the subsurface and \mathbf{L}^{T} is the adjoint or migration operator.

Unfortunately, \mathbf{m}_{mig} is the approximated version of \mathbf{m} . This can be inferred by combining Eqs. (6) and (7)

5
$$\mathbf{m}_{mig} = \mathbf{L}^T \, \mathbf{d} = \mathbf{L}^T \mathbf{L} \, \mathbf{m},$$
 (8)

where $\mathbf{L}^T \mathbf{L} \neq \mathbf{I}$. Least squares migration aims at improving the illumination by applying the inverse of the Hessian on the migrated image. Nonetheless, in the case of least squares migration, if there is no illumination (i.e., null space of the migration operator) then there is no way that least squares can recover the information. To remedy this shortcoming, more information is added about the subsurface by including the SWD dataset into the imaging problem. In other words, we aim at solving

$$\mathbf{h}_{merged} = \mathbf{L}^{T} \mathbf{d} + \mathbf{L}_{SWD}^{T} \mathbf{d}_{SWD}$$
$$= [\mathbf{L}^{T} \quad \mathbf{L}_{SWD}^{T}] [\mathbf{d}^{T} \quad \mathbf{d}_{SWD}^{T}]^{T} = \mathbf{L}_{merged}^{T} \mathbf{d}_{merged},$$
(9)

and we are hoping that \mathbf{L}_{merged}^{T} $\mathbf{L}_{merged} \approx \mathbf{I}$. To build the \mathbf{L}_{SWD}^{T} operator, the SWD source signature is required. Next section 6 7 8 describes the SWD source signature estimation algorithm.

9 2.3. SWD source signature estimation

10 Seismic while drilling data can be modeled as

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$$\mathbf{d}_{i} = \mathbf{W} \mathbf{r}_{i} + \mathbf{n}_{i} \qquad j = 1, \dots J, \tag{10}$$

12 where **W** is the convolution matrix of SWD source signature, **r** is reflectivity series and **n** is the noise term. After some algebraic 13 14 manipulations, it is easy to show that,

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$$\mathbf{D}_p \mathbf{r}_q - \mathbf{D}_q \mathbf{r}_p = \mathbf{N}_p \mathbf{r}_q - \mathbf{N}_q \mathbf{r}_p, \qquad (11)$$

16 where \mathbf{D}_p and \mathbf{D}_q in Eq. (11) represent the convolution matrices 17 of channels p and q, respectively. N_p and N_q are convolution 18 matrices of noise components. The combination of all possi-19 ble equations leads to the following inhomogeneous system of 20 equations

$$\mathbf{A}\mathbf{x} = \mathbf{e},\tag{12}$$

23
$$\mathbf{A} = \begin{pmatrix} \mathbf{D}_{2} & -\mathbf{D}_{1} & & & \\ \mathbf{D}_{3} & & -\mathbf{D}_{1} & & & \\ \mathbf{D}_{4} & & & -\mathbf{D}_{1} & & \\ \vdots & & & & \ddots & & \\ \mathbf{D}_{3} & -\mathbf{D}_{2} & & & & \\ \mathbf{D}_{4} & & -\mathbf{D}_{2} & & & \\ \vdots & & & \ddots & & \\ & & & & \mathbf{D}_{J} & & -\mathbf{D}_{J-2} \\ & & & & & \mathbf{D}_{J} & -\mathbf{D}_{J-1} \end{pmatrix}$$
(13)

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25 and
$$\mathbf{x} = [\mathbf{r}_1, \mathbf{r}_2, \mathbf{r}_3, \dots, \mathbf{r}_J]^T$$
. (14)

26 To find the reflectivity, SMBD minimizes the following cost func-27 tion



Fig. 2. Seismic-while-drilling acquisition.



Fig. 3. Imaging result of SWD data over Sigsbee2a model.

$$\hat{\mathbf{x}} = \underset{\mathbf{x}}{\operatorname{argmin}} \quad \frac{1}{2} \|\mathbf{A}\mathbf{x}\|_{2}^{2} + \lambda \sum_{i} (\sqrt{x_{i}^{2} + \epsilon^{2}} - \epsilon),$$

subject to $\mathbf{x}^{T}\mathbf{x} = 1$ (15)

where ϵ is a small number to mimic the L_1 norm behavior and 28 λ is a regularization parameter. As a by-product, after solving for 29 the reflectivity, SWD source signature can be estimated using the 30 frequency-domain least squares estimator. 31

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2.4. Numerical examples

To test the performance of the combined SWD and surface 33 seismic imaging in improving the subsurface illumination, we 34 35 simulated both surface and SWD data over the Sigsbee2a model. In the case of SWD data, we used drillbit-rock interaction as 36 sources in the deeper part of the well and we put receivers near 37 the surface with 9 km offset from the well's location (Fig. 2). 38 In the case of surface seismic, sources are fired near the surface 39 and receivers were listening to all of the shots. To generate the 40 data, we used a second-order acoustic finite-difference modeling 41 engine and in the case of SWD data, later we convolved the 42 data with a drillbit source signature. To mimic the drillbit-rock 43 signature, we assumed that every tooth of the drillbit generates 44 a harmonic waveform (Poletto, 2005). Nonetheless, the source 45 signature has harmonic and non-harmonic components due to 46 the resonances between the drill string and rocks at the source 47 locations. Moreover, to make the source signature broadband, we 48 added a band-limited white Gaussian noise to the signature (see 49

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Fig. 4. Windowed version of SWD data. (a) SWD shot gather. (b) True drillbit source removed data. (c) Estimated drillbit source removed data. (d) True and (e) Estimated source signatures.

1 Fig. 4d). To image the SWD data, we estimated the source signa-2 ture by applying the SMBD algorithm on one of the shot gathers. A 3 windowed version of the data is depicted in Fig. 4a. True drillbit-4 signature-removed data and the estimated version of it are shown 5 in Figs. 4b and c, respectively. Later, we use the estimated drillbit-6 signature-removed data and drillbit data to estimate the drillbit 7 waveform. The estimated waveform is shown in Fig. 4e. Then, we 8 feed the drillbit signature into the pre-stack reverse time migra-9 tion algorithm to image the subsurface (Fig. 3). The algorithm is 10 able to successfully image the subsurface. Comparing the SWD image with the surface seismic image, shown in Fig. 5a, we notice 11 12 that under the salt region is nicely imaged by the SWD technique. 13 On the other hand, the surface seismic image suffers from poor 14 illumination. Finally, in Fig. 5b, by combining SWD and surface 15 seismic data images, we can improve the subsurface image and 16 provide a reliable and clear image of the subsurface that can 17 be used to optimize the drilling parameters and guarantee an 18 efficient rate of penetration. The blue square rectangle in Fig. 5b 19 shows the common image region between the SWD and surface 20 seismic images and arrows show the sub-salt regions where the 21 combined image did a better job than that of the surface seismic 22 image in improving the illumination. In the combined image, the 23 lower boundary of the salt and the point diffractor under it are 24 accurately imaged. Imaging and merging workflow of the surface 25 seismic and SWD data is presented in Fig. 6. 26 2.5. Remarks 27 The drillbit generates significant elastic wave energy whose 28

ray paths are unique relative to those induced by standard surface 29 seismic. Provided that we understand the challenges associated 30 with characterizing the source radiation properties of the drillbit-31 rock interaction, the data arising from SWD are complementary 32 to surface data and have the potential to enhance geophysical 33 evaluation of the subsurface. Hence, it brings an opportunity to 34 address the seismic illumination issue by adding new measure-35 ments into the imaging problem. We used the SWD method to 36 mitigate the illumination problem in imaging. Source signature 37 estimation of the drillbit-rock interaction is a necessary step for 38 pre-stack migration of the SWD dataset. To do so, we applied a 39 multichannel sparse blind deconvolution technique to estimate 40 the signature, and later, we fed the signature into the SWD imaging workflow. Finally, we merged the SWD image with the 41 42 surface seismic migrated section to improve the illumination of 43 the subsurface features. The efficiency of the workflow is tested 44 against the Sigsbee2a model.

3. Formation-aware drilling system

This section reports a Formation-aware drilling system method46based on the SWD measurements and drill string dynamics mod-47eling. For a detailed explanation of the algorithm and its applica-48tion for estimating the velocity of the formation while drilling49and further development of the approach for improving the50drill string dynamics estimation, interested readers are refereed51to Kazemi et al. (2018a,b), Auriol et al. (2020b,a).52

3.1. Drilling systems and challenges

The drilling of an oil well consists of creating a borehole up to several thousand meters deep into the ground until an oil reservoir is reached. If the first (onshore) wells only ran tens of meters deep, due to the evolution of the drilling techniques, deeper and thinner reservoirs can now be reached and the corresponding wells run several thousand meters deep under the seabed. The drilling rig can be located on an onshore or offshore platform, but also a drilling ship.

61 A drilling system mainly consists of a mechanical part and a 62 hydraulic part. The mechanical part is made of three components: 63 the rotating mechanism (usually a rotary table or a top drive), 64 the drill string, and the Bottom Hole Assembly (BHA); while 65 the hydraulic part consists of the main pump, the inner part of 66 the drill string, the annulus and the outlet valve. Regarding the 67 mechanical part, the rotating mechanism (located at the top of 68 the drill string) provides the necessary torque to put the system 69 into a rotary motion. This rotary motion, applied at the surface, 70 is transferred to the drill string and the BHA. The drill string is 71 mainly built from drill pipes which usually are steel tubes with a 72 length of typically 10 m. These pipes are usually run in tension to 73 avoid the effect of fatigue due to a potential helical buckling. They 74 are hollow so that drilling fluid can be injected by a mud pump. 75 This fluid has, among others, the function of cleaning, cooling and 76 lubricating the bit, thus evacuating the rock cuttings. The BHA 77 comprises the bit (a rock cutting device), a series of relatively 78 heavy pipe sections, known as drill collars (much thicker pipes 79 which provide the necessary weight to perform the perforation), 80 stabilizers (at least two spaced apart) which prevent the drill 81 string from unbalancing, and "shock subs" that absorb vibrations 82 between the bit and the drill-collars. While the length of the BHA 83 remains constant, the total length of the drill pipes may increase 84

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Fig. 5. Prestack RTM images of the Sigsbee2a model. (a) Surface seismic imaging. (b) Combined SWD and surface seismic imaging.



Fig. 6. Imaging and merging workflow of the surface seismic and SWD data. Note that the conditioning of datasets are necessary depending on the requirements of the migration operators.

as the borehole depth does, which explains why some pipe sections (drill pipes) are added, leaving the bit coupled at the bottom part of the set. Apart from providing the rotary motion of the drillbit, the drill string transfers necessary axial force, known as Weight On Bit (WOB), to facilitate the deep hole drilling process. Drill strings can reach lengths of several kilometers, which make them very slender structures (Kapitaniak et al., 2015). Note that to avoid the collapse of the well or damage of the formation, it is crucial to maintain the Bottom-Hole Circulating Pressure (BHCP) between pre-specified constraints.

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The dynamical behavior of drill strings is complex as many dynamic phenomena are involved, such as vibrations, bending and twisting quasi-static motion, and bit-rock interactions (Kapitaniak et al., 2015; Spanos et al., 2003). Different drilling models have been proposed through the literature. The dynamics of interest (axial and torsional vibrations) can be derived by assuming elastic deformations and using equations of continuity of the state and the momentum balance. These different models can be classified into two main categories (Saldivar et al., 2016).

• Lumped parameter models. In this class of models, the drilling system is represented by a simple mass-spring model, abstracting the BHA inertia as a lumped mass while the drill string stiffness is represented by a torsional stiffness. Such a system can consequently be simplified in an ordinary differential equation. This finite-dimensional system representation (whose motivation relies on the need to define a simple description of drilling dynamics) provides a 27 rough description of the dynamics taking place at different 28 levels of the string. Although such models do not capture all the system dynamics and have a reduced accuracy, they are accurate enough to properly describe the drill string behavior and are easy enough to make the analysis simple and straightforward (Christoforou and Yigit, 2003).

 Distributed parameter models. In this class of models, the drill string is considered as a beam subject to axial and torsional efforts. Then, it can be modeled by a set of hyperbolic partial differential equations (namely wave equations) (Di Meglio and Aarsnes, 2015). This class of models, although much accurate compared to lumped parameter models, makes the analysis harder and may involve a higher computation cost when dealing with simulations. If the damping can be neglected, these wave equations can be reduced to neutral-type time-delay models, offering a good trade-off between the accuracy of the model and its complexity, allowing to exploit techniques from delay systems theory. Finally, one must be aware that if the dynamics of the drill string can be modeled by a set of PDEs, these equations may be different for the upper part of the drill string and the BHA as they have different inertia, Young's modulus, etc. 50

For both classes of representations, model inputs include drill 51 string and BHA composition, well survey data, surface equipment, 52

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Fig. 7. Illustration of the stick-slip phenomenon by representing the top-drive and downhole velocity obtained with a simulated example.

and drilling parameters. Special attention has to be paid to the boundary conditions. More precisely, for the distributed parameter models, the wave equations describing the drilling system dynamics are uncoupled through the domain and the coupling between the axial and torsional dynamics appears through the bit-rock interaction law at the downhole boundary. Several equations describing the couplings between the torsional and axial dynamics at the boundaries of the drill string can be found in the literature (Boussaada et al., 2012; Germay et al., 2009a; Richard et al., 2004). An extensive review of drilling models and the most suitable modeling approach depending on the pursued research objective can be found in Saldivar et al. (2016).

Understanding the drill string vibrations is a crucial step as these vibrations can cause instability in the system. The drill string interaction with the borehole gives rise to a wide variety of non-desired oscillations (Dunayevsky and Abbassian, 1998; Jansen, 1993; Saldivar et al., 2011) which can be classified depending on the direction they appear

- Longitudinal or axial vibrations. They are produced in a vertical direction, causing a bit-bouncing effect that is rebounds of the bit at the bottom of the oil well.
- Lateral vibrations. These vibrations are produced when the drill string's mass center is displaced from the rotation axis. They cause a whirling phenomenon, which is whirl-like movements and rebounds within the oil well walls.
- **Torsional vibrations.** These vibrations can appear due to downhole conditions, such as significant drag, tight, hole or formation characteristics (even though as explained below, these are not the only causes). They are known as stickslip and are considered to be one of the most prevalent vibrations. These stick-slip oscillations are characterized by a series of stopping - "sticking" - and releasing - "slipping" - events of the bit. More precisely, under certain conditions, the system enters a limit cycle. In other words, it oscillates between a stick phase, in which the velocity of the bit is equal to zero (there is an accumulation of energy) and a slip phase that consists of a sudden release of the bit that starts rotating at very high velocities (around twice the velocity of the rotary table). These oscillations are pictured in Fig. 7.

40 All these vibrations may lead to a reduction of the Rate of 41 Penetration (ROP) as they deteriorate the performance of the 42 process, cause fatigue on the equipment and wellbore instability. 43 These vibrations can also lead to premature failure of the bit.

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Thus, they may cause catastrophic failures or at least wear the 44 expensive components of the drill string (Kriesels et al., 1999). 45 Among these different types of vibrations, numerous contribu-46 tions have focused on the stick-slip phenomenon (Navarro-Lopez 47 and Cort, 2007; Sagert et al., 2013; Bekiaris-Liberis and Krstic, 48 49 2014; Di Meglio and Aarsnes, 2015) as the torsional vibrations are considered to be the most prevalent. As mentioned above, 50 such oscillations can be the consequence of specific downhole 51 conditions (rock composition or small diameter of the borehole), 52 53 and therefore, numerous models assume that stick-slip is a consequence of the non-linear frictional force actuating at the bit by contact with the rock formation (Leine et al., 2002; Nandakumar and Wiercigroch, 2013). More precisely, in these models, the 56 stick-slip phenomenon is considered to be related to the velocity-57 weakening effect (Stribeck-like effect) of the frictional force at 58 the bit and is insofar associated to typical dry friction profiles 59 (static friction and dynamic friction) (Brett, 1992; Kapitaniak 60 et al., 2015). However, one must be aware that the bit-rock inter-61 action is not the only cause of stick-slip. Otherwise, this would 62 63 not explain the occurrence of such stick-slip oscillations in the case of the off-bottom bit. This off-bottom stick-slip phenomenon 64 is well known from the field, and is often assumed to be caused 65 by a negative difference between static and kinematic along-66 string Coulomb-type friction (Brett et al., 1989; Halsey et al., 67 1986; Zhao et al., 2016). It emphasizes the action of non-linear 68 forces along the drill string (which are combined with the bit 69 70 rock interaction) in the torsional oscillatory behavior of drilling systems (Aarsnes and Shor, 2018). This is of particular importance 71 in modern wellbores which are rarely straight and must follow 72 73 preplanned well plans, ranging from simpler horizontal or devi-74 ated wells to complex three-dimensional paths, thus increasing the effect of torque and drag. 75

3.2. Methodology for a formation-aware drilling system

During the drilling process, the operator wants to control the 77 downhole behavior of the drill string (e.g. reach a given rpm, 78 a given orientation, etc.) and optimize the ROP, while avoiding 79 undesired oscillations. To do so, it is usually possible to impose 80 (using the rotary table) the weight on the drill string and the 81 torque at the surface. Automated control laws have been de-82 83 signed to solve such control problems (Serrarens et al., 1998). Recent control laws (which are not simple PID controllers) are 84 usually based on the previously mentioned lumped or distributed 85 parameter models. The accuracy of these models (and therefore 86 87 the performance of the associated control laws) depends on the 88 knowledge of the drilled rock, as the downhole boundary condition depends on the bit-rock interaction. Thus, developing a 89 formation-aware system that estimates in real-time the nature 90 of the formation may be of prime interest as it would provide 91 92 precious information about this bit-rock interaction. This knowledge of the drilled rock nature can then be used to reinforce or 93 adjust in real-time the model (and in particular the downhole 94 boundary condition) on which the control law is designed. This 95 section gives some insights about a novel approach for the char-96 acterization of the formation using SWD sensing methodology. 97 The proposed approach could lead to a formation-aware drilling 98 system. More precisely, we propose in a simplified framework 99 (vertical weight without any angular rotation and in the absence 100 of damping) an algorithm that estimates the compressional and 101 shear velocities of the formation ahead of a roller-cone drill-bit. 102 This algorithm uses the amplitude variations of the first arrivals 103 of the P and S-waves, in the processed seismic-while-drilling 104 records at the surface, combined with topside hook speed and 105 106 hook load measurements.

Let us consider a vertical well with a roller-cone drillbit. A distributed model proposed in Di Meglio and Aarsnes (2015), Germay et al. (2009b) is used to describe the evolution of the axial displacement $\xi(t, x)$ of the drill string. Let us denote A the cross-sectional area of the drill string and E as Young's modulus. To simplify the model, it is assumed that these parameters are constant along the drill string (usually steel). Let us also denote t the temporal variable (which is positive) and x the spatial variable that belongs to [0, L] (with L being the total length of the drilling system). The point x = 0 corresponds to the surface and x = L corresponds to the drill-bit. The axial motion satisfies the following wave PDE

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$$\frac{\partial^2 \xi}{\partial t^2}(t,x) - c_{\xi}^2 \frac{\partial^2 \xi}{\partial x^2}(t,\xi) = -k_a \frac{\partial \xi}{\partial t}(t,x), \qquad (16)$$

where $c_{\xi} = \sqrt{\frac{E}{\rho}}$, ρ being the pipe mass density, and k_a is a damping coefficient representing the viscous shear stresses acting on the pipe. A similar wave equation could be obtained for the angular displacement if there was an angular motion. The axial force can be found from the strain, given as the local relative compression: $w(t, x) = AE(\xi(t, x) - \xi(t, x + dx))/dx$, $dx \to 0$ being the infinitesimal axial position increment. The velocity can be expressed as $v(t, x) = \frac{\partial \xi(x)}{\partial t}$. It can be shown that the axial motion is described by the following set of PDEs

$$\frac{\partial w(t,x)}{\partial t} + AE \frac{\partial v(t,x)}{\partial x} = 0, \qquad (17)$$

$$\frac{\partial v(t,x)}{\partial t} + \frac{1}{A\rho} \frac{\partial w(t,x)}{\partial x} = -k_a v(t,x).$$
(18)

15 At the topside boundary, we assume that the weight on the drill 16 string is imposed by the operator, which yields

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$$-EA\frac{\partial\xi(t,x)}{\partial x} = w_0(t)$$

To derive the downhole boundary condition, one can use a force 18 19 balance on the lumped BHA. As the BHA is made of different 20 pipes from those of the drill string (with different inertia, Young's 21 modulus, etc.), a new set of wave PDEs for the BHA are required. 22 However, as the length of the BHA is much smaller than the one 23 of the drill string, its effect can be lumped into an ODE coupled 24 with the drill string (Di Meglio and Aarsnes, 2015). As mentioned 25 above, different expressions can be found in the literature to 26 express this boundary condition. However, they usually use the 27 *intrinsic specific energy* of the rock that depends on the formation. 28 A simplified (but still accurate) expression of this bottom-hole 29 boundary condition is given by

$$M_b \frac{\partial^2 \xi}{\partial t^2}(t,L) = -\frac{a\zeta \epsilon}{\omega_{\text{bit}}} \frac{\partial \xi(t,L)}{\partial t} - w_f - EA \frac{\partial \xi(t,L)}{\partial x},$$
(19)

31 where M_b is the mass of the lumped BHA, ω_{bit} the bit angular 32 velocity (assumed constant here), w_f the friction weight, *a* the 33 bit radius, ζ a number characterizing the inclination the cutting 34 angle and ϵ the *intrinsic specific energy* of the rock.

35 Due to the complexity of this boundary condition, control-36 ling the weight on the drill string to achieve optimal drilling 37 performance is not an easy task. This weight on the bit has 38 to be updated in real-time to adapt to the changing operating 39 conditions (different types of rocks for instance). To do so, clas-40 sical control procedures rely on topside drilling data and either 41 assume the nature of the drilled rock is known or use simple PID 42 controllers. This explains why the knowledge of the nature of the 43 formation could lead to an improvement in the performance of 44 the control mechanism and thus optimize ROP while drilling.

The *intrinsic specific energy* of rock is related to its compressional and shear velocities. While drilling, the drill-bit rock

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interaction radiates significant elastic, P- and S-wave, energy. In 47 isotropic and homogeneous media, these radiations are functions 48 of the drill-bit point force and the seismic velocities of rocks. It 49 has been shown in Rector and Hardage (1992), that for a roller-50 cone drill bit, the seismic radiation pattern proceeding from the 51 axial component drill-bit impacts can be modeled as a transient, 52 monopolar point force acting along the axis of the borehole. Let 53 us denote U_r the P-wave radiation and U_{ϕ} the S-wave radia-54 tion. These radiations can be measured at the surface using the 55 SWD method described above. More precisely, the far-field radial 56 57 displacement resulting from a point force, w(t, L) satisfies the following relation 58

$$U_r(r,\phi,t) = \frac{A_1 \cos(\phi)}{\rho_f \alpha^2 r} w(t - \frac{r}{\alpha}, L),$$
(20)

and the far-field angular displacement satisfies

$$U_{\phi}(r,\phi,t) = \frac{A_1 \sin(\phi)}{\rho_f \beta^2 r} w(t - \frac{r}{\beta}, L),$$
(21) 61

where r is the straight line distance from the source to the wave-62 front, ρ_f is the formation density, α is the formation compres-63 sional velocity, β the formation shear velocity, A_1 is a constant, 64 and the angle ϕ is measured relative to the direction of the point 65 force (i.e. relative to the direction of axial drill-tooth impacts 66 at the bottom of the borehole). Note that ρ_f can be expressed 67 as functions of α (e.g. $\rho_f = 1.74\alpha^{0.25}$, see Brocher (2005) for 68 details). Expressions (20)–(21) provide a relation between seismic 69 waves and the force exerted at the bit. Each of them involves an 70 unknown parameter (α and β) that depends on the formation. 71 However, if the functions U_r , U_ϕ and $w(\cdot, L)$ are known, simple 72 optimization techniques can be used to give an estimation of 73 these parameters. The seismic time series U_r and U_{ϕ} can be 74 measured using surface seismic sensors, but this is not the case 75 for the force on the bit $w(\cdot, L)$. Nevertheless, as w is the solution 76 of a wave equation, the function $w(\cdot, L)$ can be expressed as a 77 (delayed) function of drill string topside hook speed and hook 78 load, which are usually measured. For a simplified case, in which 79 the damping term (k_a) is neglected (if this is not the case, the 80 proof is much more technical and out of the scope of this con-81 tribution). Denoting the Riemann invariants $u(t, x) = \frac{\partial}{\partial t}\xi(t, x) - c_{\xi}\frac{\partial}{\partial x}\xi(t, x)$ and $z(t, x) = \frac{\partial}{\partial t}\xi(t, x) + c_{\xi}\frac{\partial}{\partial x}\xi(t, x)$, we immediately have using (16) 82 83 84

$$\frac{\partial}{\partial t}u(t,x) + c_{\xi}\frac{\partial}{\partial x}u(t,x) = \frac{\partial}{\partial t}z(t,x) - c_{\xi}\frac{\partial}{\partial x}z(t,x) = 0.$$
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As u and z satisfy transport equations, we can write

$$u(t, L) = u(t - \frac{L}{c_{\xi}}, 0), \quad z(t, L) = z(t + \frac{L}{c_{\xi}}, 0).$$
 87

Thus, we have

$$\begin{aligned} \frac{\partial}{\partial x}\xi(t,L) &= \frac{1}{2c_{\xi}}(z(t,L) - u(t,L)) \\ &= \frac{1}{2c_{\xi}}(z(t+\frac{L}{c_{\xi}},0) - u(t-\frac{L}{c_{\xi}},0)) \\ &= \frac{1}{2c_{\xi}}(\frac{\partial}{\partial t}\xi(t+\frac{L}{c_{\xi}},0) + c_{\xi}\frac{\partial}{\partial x}\xi(t+\frac{L}{c_{\xi}},0) \\ &- \frac{\partial}{\partial t}\xi(t-\frac{L}{c_{\xi}},0) - c_{\xi}\frac{\partial}{\partial x}\xi(t-\frac{L}{c_{\xi}},0)). \end{aligned}$$

Using the fact that $v(t, x) = \frac{\partial}{\partial t}\xi(t, x)$ and $w(t, x) = -EA\frac{\partial}{\partial x}\xi(t, x)$, we immediately obtain

$$w(t, L) = -\frac{EA}{2c_{\xi}}v(t + \frac{L}{c_{\xi}}, 0) + \frac{1}{2}w(t + \frac{L}{c_{\xi}}, 0) + \frac{EA}{2c_{\xi}}v(t - \frac{L}{c_{\xi}}, 0) - \frac{1}{2}w(t - \frac{L}{c_{\xi}}, 0).$$
(22)

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Finally, using Eq. (20) and the fact that $r \ge L$ (as the well is 1 2 vertical), we get

$$\frac{\partial}{\partial t}U_r(r,\phi,t) = \frac{A_1\cos(\phi)}{\rho_f \alpha^2 r} f(t-\frac{r}{\alpha}),\tag{23}$$

where f is a function obtained from (22) that only depends 4 on $w(\cdot, 0)$ and $v(\cdot, 0)$ (which are measured). A similar result can 5 6 be obtained for U_{ϕ} . Thus, using this latter expression and classical 7 parameter estimation techniques, it becomes possible to provide 8 in real time a reliable estimation of α (and of β using U_{ϕ}). Actu-9 ally, from this relation, it is possible (using parameter estimation 10 techniques) to distinguish the effect of α (that acts as a delay) and of the scaling coefficient $\frac{A_1}{\rho_f \alpha^2}$. In the general case (for which the 11 12 damping term cannot be neglected), a similar relation can still be 13 obtained, after more complex computations. It is of remarkable 14 interest that, using the wave equation (16), we can explicitly 15 express the state w(t, x) at each point of the drill string as a function of the drill string topside hook speed and hook load, 16 17 without using the downhole boundary condition.

18 Note that the measurements of the functions U_r and U_{ϕ} can 19 be done in different locations at the surface, thus enabling an 20 improvement of the estimated compressional and shear velocities 21 using the redundancy of the available data.

22 3.3. Simulation results

This section illustrates our approach through simulation results. The drill string made of steel whose parameters are chosen as follows:

 $L = 2000 \text{ m}, \quad A = 3.5 * 10^{-3} \text{ m}^2, \quad E = 2 * 10^{11} \text{ Pa},$ $M_b = 12000 \text{ kg}, \quad \rho = 8000 \text{ kg m}^{-3}, \quad a = 0.1 \text{ m},$ $\zeta = 0.6, \quad w_f = 71280 \text{ N}, \quad \omega_{bit} = 1.05 \text{ s}^{-1}.$

23 We consider three different types of formation which have dif-24 ferent hardness (and consequently different compressional/shear 25 velocities):

- Unconsolidated sand (i.e. water saturated) for which α = 1750 m s⁻¹, $\rho_f = 2$ g cm⁻³ and $\epsilon = 11$ J cm⁻³.
- Sedimentary rocks (e.g. sandstone) for which $\alpha = 3500$ m s⁻¹, $\rho_f = 2.4$ g cm⁻³ and $\epsilon = 57$ J cm⁻³.
- Igneous or metamorphic rocks (e.g. granite) for which $\alpha =$ 5750 m s⁻¹, $\rho_f = 2.7$ g cm⁻³ and $\epsilon = 151$ J cm⁻³.

32 Using a Poisson ratio of 0.25, the shear velocities satisfy for each 33 rock $\beta = \frac{\alpha}{\sqrt{3}}$. We want to estimate these velocities using the seismic measurements (20)-(21) and topside hook speed and 34 35 hook load measurements. The model, which is use to simulate 36 the drilling system, is given by (16)–(19). This section only con-37 siders an axial movement of the drill string in the absence of 38 damping $(k_a = 0)$. Even if the new methodology proposed in the 39 previous section does not require the expression of the downhole 40 boundary condition, this condition is necessary for simulation 41 purposes. We have pictured in Fig. 8 the functions $U_r(r, \phi, t)$ for 42 the three different rocks. A single seismic sensor located at the 43 top of the well (i.e. r = L and $\phi = 0$). Note that this example is 44 only for illustration purposes as the initial condition of the drill 45 string and the control law have been arbitrarily chosen (constant 46 initial condition and pulse).

47 Expression (23) is used to estimate the formation compres-48 sional velocity α , in the case of sedimentary rocks, where $\hat{\alpha}$ 49 denotes the estimation of α . We measure the functions $U_r(L, 0, \cdot)$, 50 $w(\cdot, 0)$, and $v(\cdot, 0)$, and consequently the function f defined



Fig. 8. Evolution of U_r (normalized) with respect to time for different rocks. The seismic sensor is located at the top of the drill string.

in (23). A set of N measurements is recorded at N different mo-51 ments: t_1, \ldots, t_N . The goal is to find $\hat{\alpha}$ that solves the following 52 least squares optimization problem 53

$$\min_{\hat{\alpha}} \sum_{i=1}^{N} (U_r(L, 0, t_i) - \frac{A_1}{\rho_f(\hat{\alpha})\hat{\alpha}^2 L} f(t_i - \frac{L}{\hat{\alpha}}))^2.$$
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This optimization problem can easily be solved using classical 55 algorithms. In the presence of white Gaussian noise in the measurements, we obtain the estimation $\hat{\alpha} = 3717 \text{ m s}^{-1}$, which is 57 close to the real value. Note that we only give here some insights 58 for this new approach and that the proposed methodology can be 59 easily improved: 60

- either by increasing the number of seismic sensors (redundancy of the information and robustness);
- or by pre-filtering the data.

Moreover, rather than using a finite number of points, one could 64 use a sliding window to update the estimation in real time. The 65 next steps consist in proving that (23) still holds in presence of 66 67 damping (with some adjustments in the expression of f) and to test the proposed approach against real data. 68

3.4. Remarks

The cost of drilling a well is related to the time it takes 70 to drill it. Thus, during drilling processes, specific attention is 71 paid to reducing non-productive time and increasing the rate of 72 penetration. Moreover, from a security point of view, the drill 73 string interaction with the borehole gives rise to a wide variety 74 of non-desired oscillations that may lead to a reduction of the 75 ROP, but also cause fatigue on the equipment, create wellbore 76 instability or lead to premature failure of the bit. In this con-77 text, several control techniques have been developed towards the 78 goal of optimizing ROP and avoiding these undesired oscillations. 79 Such techniques may be limited in the field situation due to 80 the large uncertainty and significant complexity of the downhole 81 dynamics of the drilling system. To increase the efficiency of 82 existing control methods (and insofar reducing cost and time of 83 operation), drill bit seismic can be of specific interest. More pre-84 cisely, measuring P and S-waves at the surface, we have shown 85 in a simplified case that combining these seismic-while-drilling 86 measurements with a wave equation representation of the drill 87 string dynamics could lead to efficient and reliable estimation of 88

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the seismic velocities of rocks ahead of the drill bit, enabling a more precise characterization of the formation. Combining the estimation stage with existing and efficient control laws could then lead to the improvement of the drilling performances. This new methodology is the first step towards a formation-aware drilling system.

7 **4. Optimal well placement in tight oil sand reservoirs**

This section reports the application of the SWD imaging algorithm for optimal well placement in tight oil sand reservoirs. To better understand the potential and challenges of using SWD imaging for optimizing the well placement and improving the production rate, interested readers are referred to Kazemi et al. (2018a,b), Nejadi et al. (2020).

14 *4.1. Background and motivations*

15 Not only will detailed mapping of the underlying deposits 16 allow more predictive reservoir modeling to occur but also, in 17 turn, it leads to a better well placement. However, depending on 18 the area of interest, the poor vertical well spacing may still not be ideal to develop a geological or reservoir model with confidence. 19 20 For example, if the vertical well spacing is limited, small mud 21 packages that will still have an effect on reservoir development 22 may not be captured. Because of this, horizontal wells drilled 23 in the area may encounter unexpected hindrances even with 24 a proper geological model according to mapping using vertical 25 wells. SWD can be employed in such areas to guide the drillbit 26 towards more favorable areas and to avoid low permeability 27 layers. Moreover, drilling decisions such as identification of coring 28 and casing points, hazardous areas and overpressured zones are 29 enhanced with the use of SWD (Cornish et al., 2007). While tra-30 ditional LWD and MWD techniques help to further the accuracy 31 of geological models by providing petrophysical measurements 32 along a horizontal well, these parameters can only be analyzed 33 once the drillbit has already passed through a potentially haz-34 ardous zone. The advantage of SWD is the real-time feedback 35 as the tool is placed directly at the drillbit, rather than slightly 36 behind it (Esmersoy et al., 2001). This section analyzes the opti-37 mal well placement issues in terms of cost and net present value 38 (NPV) over McMurray Formation (Carrigy, 1959). In McMurray 39 Formation, steam-assisted gravity drainage (SAGD) approach is 40 used to produce the viscous bitumen from oil sands. To do so, 41 we first start with the geology model of the area. Then explain the reservoir model and its NPV for each well pad in the SAGD 42 43 setting. Next, we connect the NPV values to the uncertainties in 44 well placement and lack of high-resolution images of the subsur-45 face. Last, we show the possibility of acquiring a high-resolution 46 SWD image of the subsurface over a realistic model, which is 47 representative of McMurray Formation; and argue that such an 48 image could have had improved the horizontal well placement.

49 4.2. Geology of the McMurray formation

50 The Lower Cretaceous McMurray Formation is part of the 51 Athabasca Oil Sands in northeastern Alberta, where primary 52 hydrocarbon-bearing units are found within ancient fluvial de-53 posits of the Middle McMurray Formation (Carrigy, 1959). The 54 McMurray Formation was deposited on top of underlying Pale-55 ozoic carbonates, creating a sub-Cretaceous unconformity. De-56 posited of the McMurray Formation ended with a major sea 57 level rise and deposition of the transgressive Clearwater Formation (Leckie and Smith, 1992; Flach and Mossop, 1985). An-58 cient channels of the McMurray Formation flow towards the 59

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north, following the main paleo-valley heading towards the Bo-60 real Sea (Fustic, 2007; Patruyo, 2010). The Middle McMurray 61 Formation is composed of thick (sometimes upwards of 50 m) 62 fining-upward point bar successions. These point bar deposits 63 often exhibit thick packages of massive to cross-stratified sand-64 stones near their base and have interbedded sandstones and 65 siltstones referred to as inclined heterolithic strata (IHS) near 66 their tops (Thomas et al., 1987; Labrecque et al., 2011). These 67 thick sands are the main target for hydrocarbon exploitation, 68 and adjacent sand bodies can increase the reservoir volume even 69 further. Bitumen is recovered from the McMurray Formation by 70 either surface mining or by in-situ methods, depending on the 71 depth of the reserve. Because eighty percent of Alberta's Oil Sands 72 are recovered using in-situ methods, understanding the associ-73 ated challenges is important. One of the main in-situ methods 74 is steam-assisted gravity drainage (SAGD), where two horizontal 75 wells placed 5 m apart vertically. The upper well injects steam, 76 heating the viscous bitumen and allowing it to flow downwards 77 78 to the production well (Butler and Stephens, 1981; Strobl et al., 1997). It is therefore vital to understand where there may be 79 any barriers to both steam and bitumen flow. Heterogeneities 80 within the reservoir zone can hinder the development of the 81 resulting steam chamber (Zhang et al., 2007; Chen et al., 2008; 82 Gates et al., 2008: Gotawala and Gates, 2010: Peacock, 2010) and 83 production performance is shown to be heavily affected by these 84 internal heterogeneities (Su et al., 2013, 2014). Fluvial processes 85 related to meander-belt evolution such as point bar formation, 86 intra-point bar erosion, counter-point bar formation, and channel 87 abandonment contribute to major heterogeneities within these 88 deposits that have a major impact on reservoir connectivity (Jack-89 son, 1976; Thomas et al., 1987; Smith et al., 2009; Willis and Tang, 90 2010; Hubbard et al., 2011; Durkin et al., 2015). The youngest, 91 best-preserved meander-belts of the McMurray Formation have 92 been extensively studied using 3D seismic data, well logs and core 93 and heterogeneities within reservoirs in this interval can be esti-94 mated with some confidence (Hubbard et al., 2011; Su et al., 2013, 95 2014; Durkin et al., 2017). Often horizontal SAGD well pairs are 96 placed below the well-characterized youngest meander deposit, 97 so it is also important to have an understanding of the underlying 98 units. However, the older deposits are often overlooked due to 99 the lack of lithologic contrast and resolution of seismic data at 100 these depths. Geological models that incorporate the underlying 101 units often do not consider the geology at the same level of detail 102 as meander-belts that are imaged with seismic. For example, Su 103 et al. (2013, 2014) refer to the underlying units as remnant chan-104 nel successions, with no emphasis on the specific architecture. 105 To begin to understand the distribution of channel elements in 106 the underlying deposits without the use of seismic data, core 107 descriptions and stratigraphic dip analysis are used (Fustic, 2007). 108 Incision by the overlying meander-belt makes correlations dif-109 ficult and adds to the complexity of reservoir characterization 110 when vertically stacked meander-belts are considered. 111

4.3. Reservoir model of McMurray formation

A detailed geological model and the corresponding reservoir 113 models of the well pads are constructed from the Surmont Phase 114 1 SAGD project located approximately 70 km southeast of the city 115 of Fort McMurray, AB, Canada. The formation under development 116 is the Cretaceous McMurray. A typical vertical profile of the Mc-117 Murray Formation in the area used for this study shows an overall 118 fining upward sequence composed of a series of upward fining 119 cycles. It consists of a meander-belt deposit in the uppermost part 120 of the McMurray Formation and underlying older deposits. Thin, 121 regionally deposited fine-grained sandstone and mudstone cover 122 the meander-belt deposit in the study area. The top of the reser-123 voir (cap rock) is defined by a marine flooding surface at the base 124

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Fig. 9. Seismic depth slice of the area under study showing the abandoned channel fill and associated depositional elements of the point bar. *Source:* Adapted from Durkin et al. (2017).

1 of the Wabiskaw Member. To enhance the predictive capabilities of the modeling, detailed geological features of the meandering 2 3 channel belt deposits are considered in the model construction. 4 The geological model not only reflects the complex rock proper-5 ties in three-dimensional (3D) space but also includes spatial dis-6 tribution characteristics of inner structural elements. Durkin et al. 7 (2017) have used 3D seismic data of the uppermost part of the 8 McMurray Formation and identified depositional elements com-9 prising the fill of channel bodies. Fig. 9 shows the seismic depth 10 slice of the area. Meander-belt and point bars can be tracked in 11 this seismic section. The depositional elements in Durkin et al. 12 model include point bars, counter point bars, side bars, and 13 abandoned channel fills (Fig. 10). Each depositional element is 14 constructed as a separate zone in the model, which captures the 3D representation of the geobody. Then, each zone internally 15 16 layered based on bedding characteristics (e.g., dipping lateral-17 accretion surfaces in point-bar deposits). Five main lithofacies, 18 i.e., Sandstone, Siltstone-clast Breccia, Sandstone-dominated IHS, 19 Siltstone-dominated IHS, and Siltstone, comprise the depositional 20 elements in the study region as described in Durkin et al. (2017), 21 Hubbard et al. (2011). Facies distributions (histogram) are con-22 strained to the depositional elements and the proportions are 23 derived from petrophysical interpretations at the well locations. 24 For instance, in the Abandoned Channel, the dominant facies 25 is Siltstone and the proportions of other facies are negligible, 26 whereas, in a Point-Bar, all rock types are present. In model-27 ing facies, local facies observations (conditioning hard data at 28 the well locations), as well as facies variability from secondary 29 trend information, are considered in geological modeling. Ta-30 ble 1 summarizes the reservoir parameters and constraints of the 31 model.

32 4.4. Well placement and production issues in McMurray formation

33 Drilling operations through complex fluvial meander-belt deposits can be extremely challenging. The geological models are of-34 35 ten limited to the resolution of the seismic data and the sampling 36 from drilled wells is poor. To optimize production performance 37 and maximize NPV from SAGD reservoirs, optimal horizontal oil 38 producer and steam injection well placement requires advanced 39 geosteering. Well planning and the location of horizontal sections 40 of SAGD well pairs within the reservoir is a challenge to field development. The notion of optimal well placement in SAGD is 41 42 (1) drilling in the most favorable and productive reservoir rock Energy Reports xxx (xxxx) xxx



Fig. 10. Zone model of the reservoir under study for the uppermost part of the McMurray Formation.

Source: Adapted from Durkin et al. (2017).

Table 1

Reservoir parameters and constraints for the Surmont Phase 1 SAGD project.

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Reservoir properties	Values
Reservoir Depth	400 m
Average Porosity	35%
Average Horizontal Permeability	3500 mD
Average Vertical Permeability	2100 mD
Average Oil Saturation (Reservoir Facies)	80%
Initial Reservoir Temperature	7 °
Circulation period	80 days
Relative Permeability End Points – Reservoir Facies	
Oil–Water System	$S_{orw} = 0.40, S_{wc} = 0.12$
Oil-Gas System	$S_{gc} = 0.05, S_{org} = 0.40$

(highest permeability), (2) placing the producer near the base 43 of the reservoir (approximately 2 meters above the base) to 44 45 maximize draining the liquids, (3) maintain sufficient distance with the base rock and possible underlying high water saturation 46 zones, (4) avoid drilling into non-reservoir rocks (IHS, Lower 47 early McMurray mudstones (paleosols), or abandoned channel 48 deposits). In this work, optimal well placement is defined in terms 49 of well pair performance that is evaluated by drilling in the most 50 favorable reservoir rock. Fig. 11 displays the well deviation survey 51 and gamma-ray (GR) well logs for two different well pairs in a 52 well pad. The average vertical separation distance between the 53 injector (upper well) and producer (lower well) are 5 m and 54 the approximate length of the wells is 850 m (except well pair 55 A - injector). The vertical exaggeration is 12 times. The colored 56 curves show the Gamma Ray log along with the drilled horizontal 57 sections of the wells. A GR cut off value of 75 API is used to 58 differentiate reservoir and non-reservoir rock types. Low GR (red 59 to yellow) represents reservoir facies (Sandstone, Siltstone-clast 60 Breccia, and Sandstone-dominated IHS) and a GR greater than 61 75 API (cyan, light and dark blue) shows non-reservoir rocks, 62 i.e. Siltstone-dominated IHS, and Siltstone. Generally speaking, 63 the geological features of the reservoir and rock types in the 64 region of the well pad are identical. However, due to poor well 65 placement, approximately 140 meters of production well in well 66 pair A has been drilled in low permeability non-reservoir rocks. 67 As shown in Fig. 11 - Well Pair A, only 709 m of the total 846 m 68 of the producer is exposed to reservoir rock and can effectively 69 produce fluids. The horizontal section length of the corresponding 70 injection well - Well Pair A, has been drilled according to the 71 producible length of the production well and is 714 m, which 72 is 136 m shorter than the pad average. The length of horizontal 73 sections for a typical well pair design in this pad is 850 m. Table 2 74 summarizes the total length of the horizontals compared to the 75

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Fig. 11. Well deviation survey and gamma ray (GR) logs for two different well pairs. Well pair A has low production performance, whereas, Well pair B has a superior performance compared to the pad average.

Table 2	
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Total length of the horizontal sections compared to their effective lengths drilled in reservoir facies.

	Horizontal Section (m)	Reservoir Facies (%)	Actual Production length (m)
Well Pair A - Injector	714	99	714
Well Pair A - Producer	846	81	709
Well Pair B - Injector	860	97	860
Well Pair B - Producer	850	99	850
Pad average	850	97	850

effective lengths (drilled in the reservoir and permeable facies) of the wells.

The deficiencies in geosteering and drilling into low permeability rock types directly affect the production efficiency of the well pairs. The average oil production rate of the well pair A is approximately half of the pad and the cumulative steam-oil ratio (cSOR) is 3.6 m³/m³. The average cSOR of the pad is 3.4 m³/m³. Well pair B, which is one of the good pairs in this pad has a cSOR of 2.8 m³/m³. Table 3 presents the average normalized steam injection rate, and the normalized oil production rate of the well pairs compared to the pad average. Normalized injection and production rates are characterized by a wells injection or production rates relative to the whole pad rates.

The geosteering and well placement practices in McMurray Formation could be improved if the advanced sensing and imaging of the subsurface were implemented in the process. To provide more insight into the application and usefulness of SWDbased imaging techniques in the well placement of tight oil sand reservoirs, we generated a realistic model of subsurface geology that is representative of the complexities encountered in McMurray Formation. Fig. 12a is the 2D velocity model that shows a tight oil sand reservoir around 400 m with an average thickness of 20 m. We simulated a surface seismic acquisition over the model with sources and receivers deployed at the surface. We used 35 equally spaced shots at the surface, and the receivers were densely deployed with 2 m intervals from left to right of the mode covering the whole region. Fig. 12b shows the depth 27 migrated image of the surface seismic data around the reservoir. 28 As clear, seismic depth image could reveal the main structures 29 of the subsurface, however, it struggles to provide the high-30 resolution image with details. The regions with uncertainties 31 and illumination problems are marked with arrows. To further 32 improve the resolution of subsurface images and lower the depth 33 34 uncertainties, we also simulated an SWD-based acquisition ge-35 ometry. The geometry of production and injection SAGD well pairs are borrowed from the real data. We simulated five SWD 36 shot gathers by recording the pressure component of the seismic 37 energy radiated from drillbit-rock interaction in the horizontal 38 section of the production well. The geometry of SWD acquisition 39 is represented in Fig. 13a. The SWD shots are equally spaced with 40 horizontal locations varving from 1400 m to 1550 m. In hori-41 zontal drilling, pressure wavefields, i.e., P waves, are dominant 42 in the horizontal direction, hence we deployed the receivers in 43 downhole inside the vertical well around 3100 m. Fig. 13b shows 44 the SWD-based image around the reservoir interval between the 45 SWD sources and the vertical well. Rectangle regions on the SWD-46 based depth image show the regions where surface seismic image 47 suffered from low resolution and had uncertainties in depth. 48 Contrary, the SWD-based image, thanks to the unique ray paths of 49 SWD acquisition, provided a high-resolution image of the target 50 region. The use of SWD in the McMurray formation could reduce 51 the issues encountered in well placement and improve the rate 52 of production. For example, if an SWD-based image was available 53 at the time of well placement the production well in well pair A 54 (Fig. 11) should be stopped before drilling into the mud package. 55 56

4.5. Remarks

The issues and challenges of well placement in the presence 58 of uncertainty in the geological model and seismic depth im-59 ages are discussed. The tight heavy oil reservoirs are prone to 60 inefficient well placement, as the surface seismic images usually 61 do not provide accurate images of the subsurface, especially in 62 the deeper part of the model. We used McMurray Formation 63 to evaluate the production rate of SAGD well pairs and relate 64 the rate of production to uncertainties in the subsurface models. 65

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Fig. 12. Surface seismic image over a synthetic model representative of McMurray Formation. (a) Velocity model. (b) Surface seismic image. Arrows show the regions where surface seismic image has low resolution.

Table 3

Normalized steam injection rate, oil production rate, and cumulative steam-oil ratio of the well pairs compared to the pad average.

Well Pair	Normalized Steam Injection Rate	Normalized Oil Production Rate	$cSOR \ \frac{m^3}{m^3}$
Α	0.59	0.51	3.6
В	1.14	1.28	2.8
Pad average	1	1	3.4

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We showed that due to the lack of resolution of the models the production well in well pair A is drilled into the low permeable laver. If high-resolution images of the subsurface were available the drilling of the production well should be stopped, or the well path is updated to void drilling into the non-reservoir rocks. Using a realistic model of the McMurray Formation we showed that the SWD approach has the potential of providing such an image.

5. Conclusions

We have developed advanced sensing workflows that are tailored to complex reservoirs such as the tight heavy oil reservoirs in Canada. Our methodologies started with introducing a new SWD-based imaging algorithm. We showed that the drillbit follows ray paths that are unique relative to those induced by standard surface seismic and the data arising from SWD have the potential to enhance geophysical evaluation of the subsurface. We used the SWD method to mitigate the illumination problem in the imaging of complex reservoirs. Two realistic models that are representative of challenging Gulf of Mexico deep-water and tight oil sand reservoirs in McMurray Formation are generated. SWD image in both cases provided high-resolution images of the



Fig. 13. Seismic-while-drilling acquisition and image over a synthetic model representative of McMurray Formation. (a) Velocity model and geometry of SAGD well pairs. Downhole receivers is used to record the drillbit seismic energy. (b) SWD image. Rectangle regions show the locations where SWD image has superior resolution compared to surface seismic image shown in Fig. 12b.

subsurface and improved the illumination problem inherent in surface-only seismic imaging.

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Next, we introduced a smart drilling mechanism that takes 23 advantage of SWD-based sensing. The smart drilling system com-24 bined the SWD measurements with a wave equation represen-25 tation of the drill string dynamics and provided an efficient and 26 reliable estimation of the seismic velocities of rocks ahead of the 27 drill bit, enabling a more precise characterization of the forma-28 tion. The formation characteristics can be further used to design 29 efficient control laws for improving the drilling performances.

Finally, we discussed the well placement issues in the context 31 of McMurray Formation. McMurray Formation is a challenging 32 tight oil sand reservoir in Canada. We analyzed the performances 33 of well pairs in this region, and draw interesting relationships 34 between the uncertainties of the subsurface model and rate of 35 production. We showed that the surface seismic images suffer 36 from non-uniform illumination, resulting in the inefficient placing 37 of wells. Our SWD-based images on the realistic model of McMur-38 ray Formation revealed high-resolution images of the subsurface 39 comparing to that of the surface seismic. Accordingly, the use of 40 the SWD image in this region could add value to the placement 41 of the wells and provide higher production rates. 42

CRediT authorship contribution statement

Nasser Kazemi: Conceptualization, Methodology, Software, 44 Validation, Formal analysis, Writing - original draft, Writing -45 review & editing. Siavash Nejadi: Conceptualization, Methodol-46 ogy, Software, Validation, Formal analysis, Writing - original draft. 47

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Jean Auriol: Conceptualization, Methodology, Software, Validation, Formal analysis, Writing - original draft. Jordan Curkan: Formal analysis, Writing - original draft. Roman J. Shor: Conceptualization, Project administration, Writing - review & editing. Kristopher A. Innanen: Conceptualization, Writing - review & editing. Stephen M. Hubbard: Conceptualization, Writing - review & editing. Ian D. Gates: Conceptualization, Writing - review & editing, Funding acquisition.

9 **Declaration of competing interest**

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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