Suggested best practice for seismic monitoring and characterization of non-conventional reservoirs

Marco Bohnhoff[1,2*], Peter Malin[1,5], Jan ter Heege[3], Jean-Pierre Deflandre[4] and Charles Sicking[5,6] describe how repeated Seismic Emission Tomography observations can improve reservoir management in addition to regulatory monitoring.

Introduction

General awareness of induced seismicity and gas leakage related to energy reservoir exploitation has been on the rise for several years (McGarr, 2002; Davies et al., 2013). This includes events from short-term fluid injection for reservoir simulation (Giardini, 2009; Atkinson, 2016), Long term hydrocarbon extraction (Van Thienen-Visser and Breuness, 2015), underground storage of natural gas (Cesca et al., 2014), waster water (Ellsworth, 2013), and carbon dioxide (Zoback and Gorelick, 2012). High rates of felt induced events in previously quiet areas are now considered critical for public safety and social licence to operate (Petersen et al, 2016). Concerns about contamination of ground water and climate effects have followed suit (Darrah et al., 2014; Davies et al., 2014).

Prominent injection-induced seismicity that raised concerns are: the Preese Hall-1 frack-related M2.3 in the United Kingdom (de Pater and Baisch, 2011; Clark et al., 2014); an M~3.4 during the Basel, Switzerland, Geothermal project (Häring et al., 2008; Giardini, 2009), increased central-US water-disposal M>3 earthquakes (e.g. Ellsworth, 2013), and M~4 fracking-induced events in Canada (Atkinson et al., 2016).

In the case of gas leakage owing to loss of well integrity, industry long-run estimates range between a few per cent to as much as 50% (Burfatto et al., 2003). For non-conventional resource wells drilled since 2009 in Pennsylvania, well-inspection records suggest that as many as 40% have integrity issues (Davies et al. 2014; Ingraffea et al., 2014) and China (Lei et al., 2017).

The proliferation of microearthquakes many times foreshadows damaging ones and changes in well integrity. Substantial progress has been made in cost-effective, specialized seismic networks that can address these issues (e.g., Van der Baan et al., 2013). We describe these over a ~ 5 x 5 km reservoir in a ~10 x 10 km lease.

As the optimal best practice, we suggest the monitoring scheme be integrated into a reservoir-management plan using Seismic Emission Tomography (SET; e.g. Sicking et al., 2017). In addition to adding value for fracture characterization and production management, only a portion of a permanent SET net is needed for regulatory compliance.

Microseismic reservoir monitoring in a nutshell

With respect to forecasting induced-earthquakes, a lack of prior local earthquake risk studies can be at least partially overcome by determining the background seismicity before operations. Two characteristics of background seismicity make estimates of seismic risks possible: (1) the well-and-long established Gutenberg-Richter (GR) scaling relation (e.g. Richter, 1935), and (2) the less-well and only-recent documented relation between fore- and main-shock magnitudes (e.g. Mignan, 2014). Seismicity generally follows the GR law: a catalogue with 5 to 15 magnitude M '(x)' events in a fixed area and period usually includes 1 M '(x + 1)' event – the *x* being local Richter magnitude recorded by surface seismometers.

A useful view of a 'main shock' earthquake is that it generally emerges from a process that includes a number (yet to be fully determined) of 'foreshocks' (Mignan, 2014). The magnitude needed to track these preceding events seems to be as low as 3 magnitude steps below the main shock: $M_{foreshock} \sim M_{mainshock} - 3$. In other words, monitoring data obtained in the middle of a natural earthquake cycle does not reflect the actual historically cumulative numbers. Following the GR relation, a dozen M=1 could cascade into an existing dozen M=2 that then cascades into an unwanted M=3.

So, at the most basic level, if an M(x + 1) event is potentially damaging, monitoring at M(x – 2) level can give some sense of when a treatment is beginning to exceed natural limits.

Pre-drilling and time-lapse active and passive seismic imaging of hidden features and changes can aid well completion and integrity. While active, cost-intense, seismic profiling is standard, passive imaging using seismic emissions – Seismic Emission Tomography (SET) – is relatively new (Ross et al., 2016; Sicking et al., 2017). SET techniques, as distinct from microearthquake monitoring, can directly map, for example, active permeability pathways and changes in them.

Suggest best practices on sensors and deployments

The best practices seismic monitoring programme presented here is divided into three project phases, each with step-wise options for monitoring system development. The organization of the three phases is shown in Table 1.

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	prior to treatment Steps 1-3	reservoir treatment	post treatment production
monitor period	several months (preferably 1 yr)	days	years
seismicity type	background seismicity	stimulation induced seismicity	production induced seismicity
			disposal/storage induced seismicity
			leakage induced seismicity/noise
instrumentation and deployment	single station surface (detecting M~1)	downhole network (locating M<-1)	surface network (locating M~1)
	single station downhole/behind casing (detecting M~1)	downhole array (locating M<-1)	borehole/behind casing network (locating M~1)
	surface network locating M~1)		production well/behind casing (locating M<-1)
	downhole/behind casing network (detecting M~1)		

Table 1 Overview of proposed monitoring time periods and type of monitoring needed for the 4 Steps as discussed in the text. These are divided into prior, during and post reservoir treatment. The typical minimum magnitudes for detection and location of induced seismicity in a target area, with the potential for M2 to M3 induced-events, are noted.

Phase I: Establishing the background level and locations of seismic emissions.

In Step 1, the baseline seismicity and subsequent sensitivity for inducing earthquakes is observed. Step 2 locates this seismicity, and Step 3 maps subsurface features that might impact drilling, well completion, and resource treatments. While a limited Phase I kit can accomplish mitigation of seismicity and well leakage, if Step 1, 2 or 3 is expanded to include a SET-capable buried network, it can have a direct and significant positive impact on the reservoir exploitation plan.

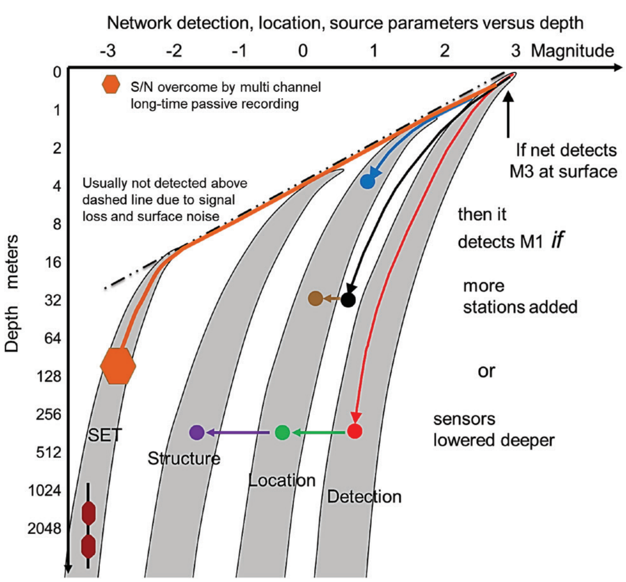

Figure 1 Detection, location, and imaging limits for different combinations of networks as a function of area covered, sensor depth, and event magnitude. (See Table 2 for colour codes.) The coloured lines show that detection thresholds in the target area can be lowered in two ways (1) putting existing stations in deep boreholes (red, 4.5 Hz sensors), or (2) adding shallow stations to reduce inter-station spacing (blue, broadband sensors). Suggested numbers, expected signal-to-noise improvements, and sensor types can be read from Figures 2 and 3 and Table 2. If a SET net is installed (orange sensors), then the resulting increase in instrument depths and numbers covers all the monitoring objectives discussed in this paper.

Phase II. Short-term monitoring of reservoir stimulation operations.

The resource-development aim of this Phase is to image the Stimulated Reservoir Volume (SRV). The environmental aim is to map flow pathways as they relate to potentially active faults, ground water, and resource management. With SET data, it is possible to directly assess SRVs, treatment interferences, and re-fracking operations. (Sicking et al., 2017).

Phase III. Long-term passive monitoring for hazardous earthquakes, gas leakage, and optimal resource recovery.

The first of these tasks – earthquake monitoring – can be accomplished with a limited number of permanent stations, as few as three or four borehole sensors. The second – leakage detection – can follow naturally from well completions that

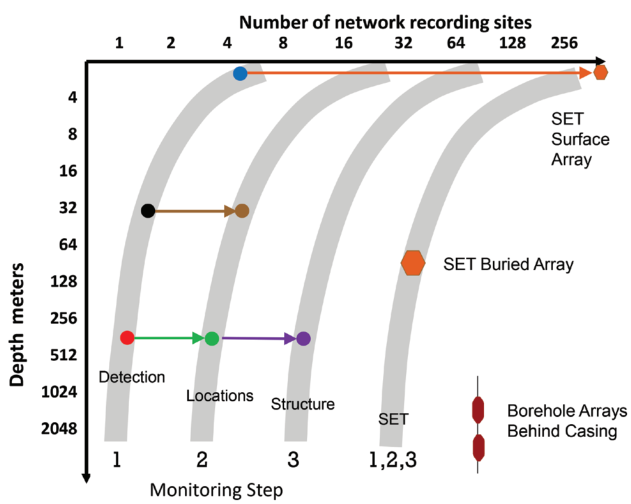

Figure 2 The number versus depth of borehole seismic stations as a function of reservoir seismic monitoring and development needs. (See Table 2 for colour codes.) For Step 1 event detection, while 4 surface stations are needed (blue, broadband sensors), the deep-borehole number is 1 (red, 4.5 Hz sensor). The alternatives instrument choices for Steps 2 and 3 can be selected with the help of Figures 1, 2 and 3 and Table 2.

include behind-casing sensors as standard practice. The third task requires either a large number of permanent, but temporarily recorded, sensors. The selection of instruments and deployments for this phase constitutes Step 4 in our suggested best practice.

Step 1: Establishing the potential for a permit-exceeding induced earthquake

In the absence of any local seismic stations at the respective site, we suggest that the best practice way forward is to make direct field observations with a single borehole sensor or small borehole array.

Few reservoirs have networks that capture events 2-to-3 magnitude units below the regulated maximum allowed magnitude – commonly set around M3 ± 1. if there are only a few small events, Gutenberg-Richter relations suggest that local conditions may be favourable for avoiding creating larger ones. If the rate of small events is high, and reservoir-development activities produce increased numbers, which then spill over into higher magnitudes, there will be fair warning of a permit-exceeding induced-earthquake. Figures 1 to 3 and Table 2 can then be used to find the trade-offs between instruments, deployments, and their relative costs.

Figures 1 to 3 also show the alternative of deploying a SET buried network or borehole array from the beginning of the project. If long-term well leakage monitoring is required, we suggest installing seismometers behind casing (Bohnhoff and Zoback, 2010a; Bohnhoff et al, 2010b). Once the choice of a target magnitude and deployment depth has been made, the number of instruments to be deployed in the target area can be estimated from Figure 2. This can be read from the Step 1 curve at the far left of the figure.

Figures 1 to 3 show that adding more broadband surface stations is not likely to be very cost effective as far as monitoring very small earthquakes is concerned. This is because of near-surface attenuation, scattering, and limited low frequency source energy. Neither the detection nor location capacity for very small earthquakes are dramatically improved by increased sensor depth. Putting aside a buried SET net for the moment, the suggested cost-effective way forward for Step 2

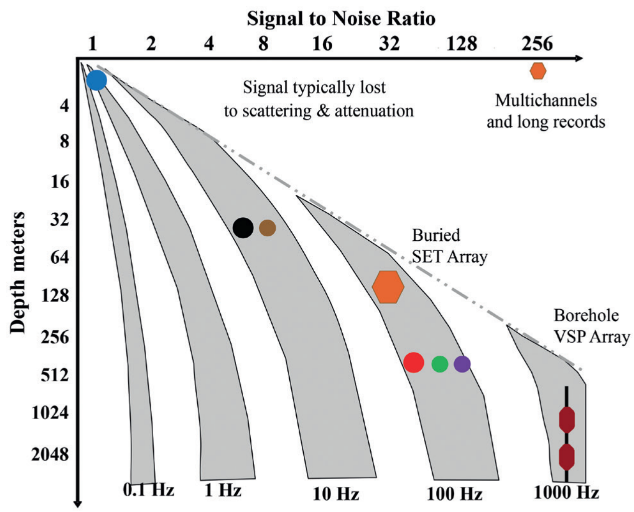

Figure 3 Signal-to-noise improvement versus sensor depth. This plot can be used to judge the advantages of both sensor depth and type on signal improvement with depth. Sensors with natural frequencies above about 4.5 Hz are not recommended for shallow installations. Placing low frequency sensors downhole also only marginally improves signal to noise (modified from Prevedel et al., 2015).

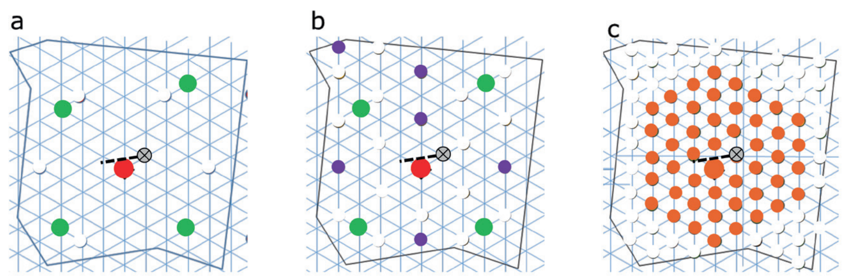

Figure 4 A notional stepwise development plan for a seismic monitoring network and alternative SET buried net. The resource is assumed to be at a depth of ~1.5-2 km, the target area to be monitored ~ 5 x 5 km, and the exploration/lease area equal to be ~ 10 x 10 km. A well with a ~1 km long lateral has been planned as shown by the grey circle. A dense face-centered hexagonal station grid was used so a densified SET buried array could easily be accommodated. (a) Step 1 event detection – red circle: the initial seismicity-detection station, preferably as deep as possible in a borehole. Step 2 event location – green circles: four additional borehole stations. (b) Step 3 tomography – purple circles. (c) A SET buried array – orange circles: an alternative monitoring development strategy, comprised of a ~48 stations in 100 m deep boreholes, a density of ~2 stations/km².

Type	Usable bandwidth	Instrument OD	Sensor cost	Relative sensor + deployment cost			Step 1	Step 2	Step 3
				surface	posthole	deep well	suggested deployment		
BB ●	40 s - 20 Hz	~250 mm	high	moderate	moderate		~ 4 @ 1 m		
1 Hz ● ●	4 s - 100 Hz	~200 mm	moderate	low	low	high	~ 2 @ 30 m	~ 6 @ 30 m	
4.5 Hz ● ● ●	1-500 Hz	70 mm	Low	low	low	moderate	~ 1 @ 300 m	~ 4 @ 300 m	~ 12 @ 300 m
15 Hz VSP	4-2000 Hz	50 mm	lowest			high	< 3000 m VSP array		
4.5 Hz SET ⬢	1-500 Hz	70 mm	Low		moderate	high	~ 36 @ 100 m buried SET array		

Table 2 Common instruments, deployments, and relative costs for 5 x 5 km target area.

is through downhole sensors – preferably in relatively deep deployments.

The relative trade-offs between sensor types, natural frequencies, deployments, and costs are summarized in Table 2.

Step 2: Establishing the locations of seismic activity

Assuming the Step 1 survey picked up a significant number of smaller events, in Step 2 their locations need to be determined to avoid potential fault reactivation and hazardous seismicity during reservoir development. This brings us back to Table 2 and Figures 1 to 3, which suggest that, depending on cultural noise and geological conditions, a location network can require a set of four 4.5 Hz stations buried at ~ 300-1000 m. A flexible station layout map for Step 2 makes use of a SET-type face centered hexagonal grid, as shown in Figure. 4a. This grid should be fine enough to leave open the option of deploying a SET buried net.

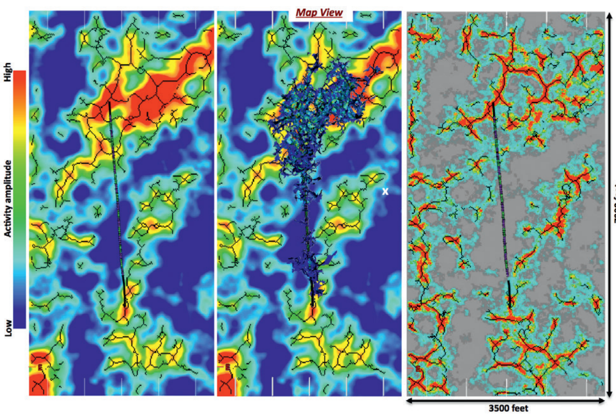

Figure 5 a) A SET map of the ambient seismic-activity volume of fractures before fracking. The brighter colours are interpreted as locations of greater permeability and fluid movement. b) Shows the fractures activated during a hydraulic treatment overlaid on the ambient background in a). c) A forecast of major production permeability pathways from the combination of pre-treatment and treatment-time SET (Figure from Sicking et al., 2017).

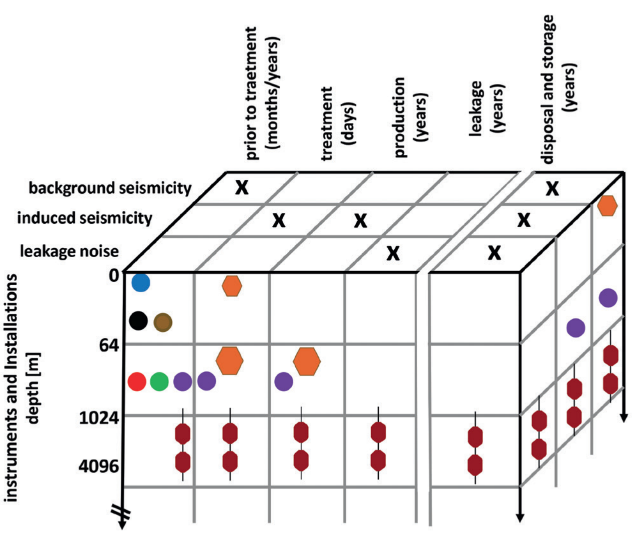

Table 3 A matrix of monitoring Phases, Steps, and suggested Best Practices for sensors, deployments, and objectives. Combined with Figures 1-3 and Tables 1 and 2, this matrix provides a key to cost-effective regulatory and reservoir characterization and monitoring.

Step 3: Short-term monitoring of reservoir stimulation

This monitoring tasks currently divides along two lines: (1) regulatory mandates and (2) cost-effective reservoir development and management. If monitored by a local network, the spatial resolution of the 'seismic cloud' of induced seismicity is mostly used as an approximation of the Stimulated Rock Volume. Only in a very limited number of existing cases is this seismicity information used to feed a regulatory system.

A deep borehole Step 1 monitoring system near the treatment well would certainly establish event distance and magnitude, and this might be all that is needed to stay within permitted earthquake limits. The uncertainty would then be in accurate locations. If well-resolved event location is also required by regulations, then a Step 2 system should suffice.

Step 4: Long-term monitoring of production, disposal, storage and leakage

Phase III requires that both the equipment and costs of a monitoring net need to be maintained for many years. This includes detecting well interferences and 'frack hits' in areas with increasing densities of wells (U.S. EPA 2016).

Practical long-term monitoring solutions are especially important for seismic detection of well barrier failures. In fact, a significant fraction of all production wells do show barrier failure within two or three decades of well abandonment (see the compilation by Davies et al., 2014 for a general inventory).

In terms of decadal-scale seismicity from production or waste water disposal, automated versions of Step 1 and 2 type-networks should suffice (Figure 4a). Signals that trigger automatic flags from such systems could include: (1) rapid increases in event magnitudes (Häring et al., 2008; De Pater and Baisch, 2011), (2) increased frequency of events with reservoir operation changes (Farahbod et al. 2015; Schultz et al., 2015), (3) alignment of hypocentres along pre-existing faults (Wolhart et al. 2006; Norton et al., 2010), (4) changes in GR relationships (Maxwell et al.,

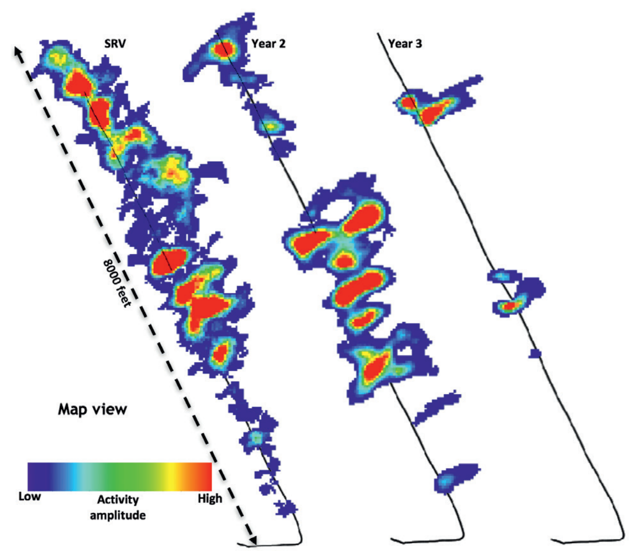

Figure 6 Changes in SET-signal-generating fractures over the producing life of a well. The treatment Stimulated Resource Volume is shown in the left panel. The middle shows the volume after two years of exploitation. The right panel shows the volume after three years (Figure from Sicking et al., 2017).

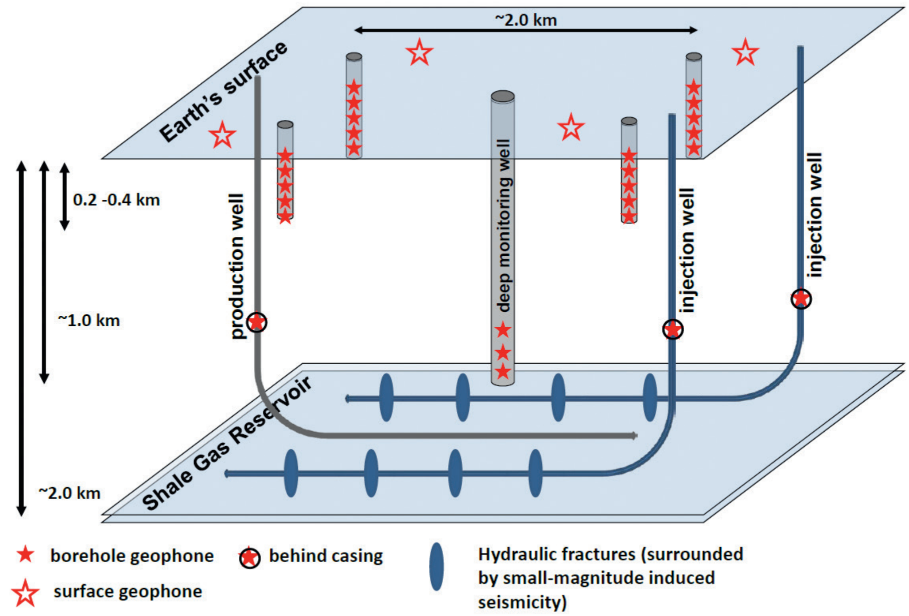

Figure 7 A selection of the regulatory best practices seismic kits and deployments discussed in this paper.

2009; Kratz et al., 2012), and (5) rotations of stresses with flow rates during stimulation (Martinez-Garzon et al., 2013b).

Leaky well detection requires detecting complex signals that can occur during gas rise to the surface (Bohnhoff et al., 2010b; Martinez-Garzon et al., 2013a). For new wells, to achieve the high sensitivities needed, our suggested approach is to install short arrays – say four or more levels – of behind-casing seismometers at strategic depths.

SET: The best practice (regulatory and reservoir exploitation) combined

Passive recordings of what has been thought of as incoherent seismic noise have now been shown to contain information on subsurface fractures and fluids (e.g. see Ross et al., 2016; Sicking et al., 2017, and the references therein.) The SET method can, for example, be used to directly map the Stimulated Rock Volume resulting from a well treatment. It also provides a potential method of advanced seismicity control and regulation for operators and regulators.

SET data can reveal the locations of the highest density of natural fractures with active fluid flow (e.g. Geiser et al., 2012). If mapped before well completion, they show the locations where treatments can best target natural fractures (Figure 5a). Treatment-time SET can reveal the extent and location of the best SRV (Figure 5 b and c). By taking repeated SET recordings a few times a year changes, in the production and SRV can be tracked (Ross et al., 2016; Figure 6).

A SET buried network can be used as both a stimulation-seismicity control system and a regulatory monitor. Because of its sensitivity, any rapid build-up of very small events can be used to guide injection-volumes-and-rates, avoiding larger or well interfering events.

Summary and Conclusions

We provide step-by-step workflows to organize these reservoir monitoring technologies, starting with the minimum needed to establish background seismicity. Each Step in the workflow is then used to help decide on the most cost-effective way to proceed during reservoir treatments and production.

We have collected our suggested best practices into a final summary table and figure showing the various phase, steps, and deployments we have described here (Table 3 and Figure 7).

The instruments and deployments shown in Figure 7 are primarily aimed at monitoring for regulatory purposes. It includes long-term detection of well seal failures by making well completions that include behind-casing seismometers as a standard practice (see also Deflandre, 2016 and the reference therein.)

We suggest that optimum seismic monitoring is achieved if Step 1-4 systems are planned with the potential of including them as part of a SET-based reservoir development and exploitation programme. For life-time monitoring of a reservoir, we suggest a buried SET network as the optimal solution. We conclude that, with carefully separated regulatory and proprietary reservoir-management data streams (if desired or necessary), both the public and field operators benefit most from this monitoring approach.

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