CHAPTER 1

Introduction

The study area is Arthit field, located in the northwestern part of the North Malay Basin, Gulf of Thailand (Figure 1.1). The basin developed during Cenozoic extension, which produced Northwest-Southeast (NW-SE) and North-South (N-S) trending asymmetric half-grabens (Shoup, 2009). The sediments supplied into the basin were both marine and non-marine siliciclastics deposited during the rifting period, marked by Late Eocene to Late Oligocene lacustrine and other continental deposits, of Formation 0 (Shoup, 2009). The Arthit gas field reservoirs (Figure 1.2) consist of Miocene paralic-environment sands (FM1-FM3) (Shoup, 2009).

The reservoir section of Arthit field is dominated by multiple stacked sandstone layers interbedded with shale and coal (Turner et al., 2004). The sandstone thickness varies, but is predominantly relatively thin and in many cases below seismic resolution (approximately 7-10 m) (Turner et al., 2004 and Geologist Team, 2005). Several geophysical studies have been conducted to characterize reservoir and pore fluid distribution in the field, using methods based on seismic attributes, AVO analysis (Kliangglom et al., 2008; Limpornpipat et al., 2008 and Kaewprain and Sognnes, 2013) or deterministic elastic inversion (Kliangglom et al., 2016). These studies had only limited ability to identify thin reservoirs beyond seismic resolution, and provided only a solution that can be considered a most-likely case within the boundaries of the seismic bandwidth (Kliangglom et al., 2016). In an attempt to overcome some of the constraints related to seismic resolution, a pre-stack geostatistical inversion can be carried out to resolve thin reservoir beds and achieve a better understanding of the reservoir distribution away from input well locations (Contreras et al., 2005a). As such methodology allows for multiple solutions that honor the seismic data, well log data, and geostatistical information, sensitivities related to the reservoir distribution can also be accounted for when applying this methodology (Moradi et al., 2015).

Geostatistical inversion allow integration of low-frequency seismic data, high-resolution well log data, and additional statistical information to provide results consisting of spatial distributions of elastic properties with a vertical resolution intermediate between those of seismic data and well logs (Leggett and Chesters, 2005 and McCrank et al., 2009). Moreover, the method provides quantitative estimates of non-uniqueness based on the statistical distribution of inversion products to better understand the range of uncertainty. Simultaneously, geostatistical inversion allows for direct estimation of facies by utilizing the multi-dimensional statistical relationship of elastic properties (McCrank et al., 2009).

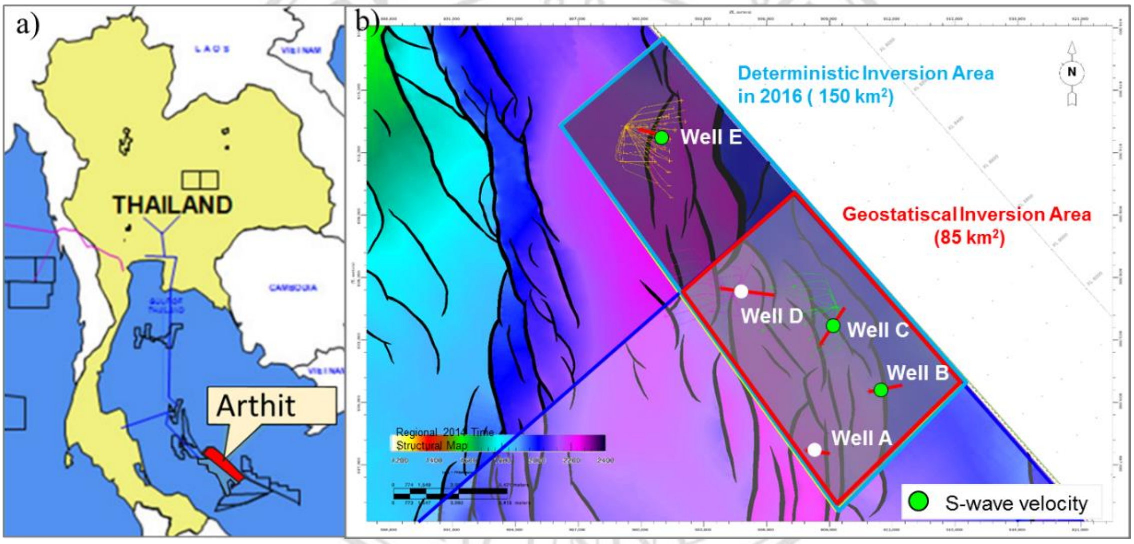

Figure 1.1. a) Map showing the location of Arthit Field in the Gulf of Thailand (Oil and Gas Online, 2000). b) AOI for 3D seismic pre-stack geostatistical inversion study (red polygon) and deterministic inversion study (blue polygon).

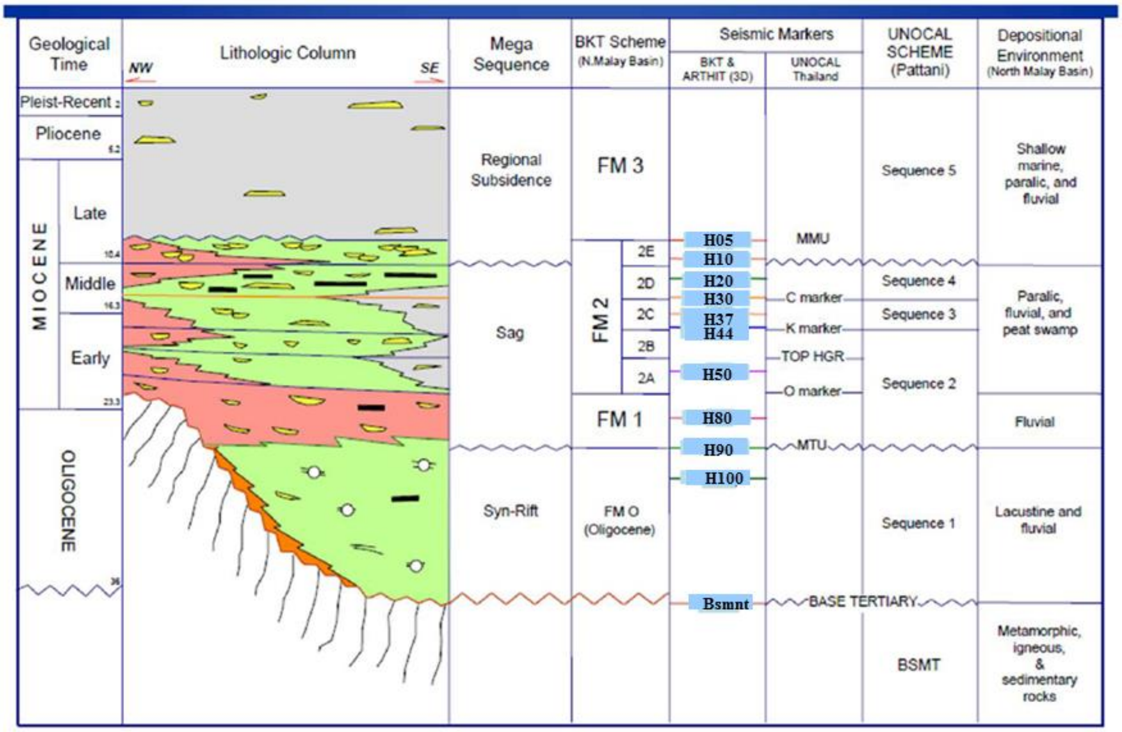

Figure 1.2. Stratigraphic column of the North Malay Basin (Turner et al., 2004).

1.1 Data Availability in Study Area

1.1.1 Seismic data

The Arthit 3D seismic data was acquired by Geco-Prakla in 1998, and covered approximately 4,000 km^2, as shown in Figure 1.3. The study area covered 85 km^2 of 3D seismic data, which was reprocessed by DPC (PTTEP in-house processing center) prior to pre-stack deterministic inversion (150 km^2) in 2016 (Figure 1.3). The seismic acquisition parameters and processing workflow are presented in Appendix A. After migration, angle stack volumes were created using the following angle ranges:

- Angle stack 1: 0-12° (near)
- Angle stack 2: 8-20° (near mid)
- Angle stack 3: 16-28° (mid)
- Angle stack 4: 24-36° (far)

Due to the limited maximum offset of the Arthit 3D seismic survey (3.1 km), the final angle stacks were slightly overlapping to provide sufficient amount of input angles (minimum four), and at the same time considering the level of S/N in these stacks. Examples of angle stack sections can be seen in Figure 1.4.

Several processing steps were applied to the migrated CDP gathers to improve the seismic quality, such as automated hi-resolution velocity picking, Radon demultiple, trim statics, and Q-compensation. Additional seismic pre-conditioning applied to angle stacks consisted of residual Q-compensation (Q-Wave) and time misalignment corrections (Chansane et al., 2016). Q-wave amplitude correction was used to compensate amplitude distortion caused by shallow gas by balancing background amplitude laterally (Chansane et al., 2016) as shown in Figure 1.5. A time-misalignment correction was applied to further flatten events in the angle-gather domain with mild time shifts, using angle stack 2 as a reference (see Figure 1.6) (Kliangglom et al., 2016).

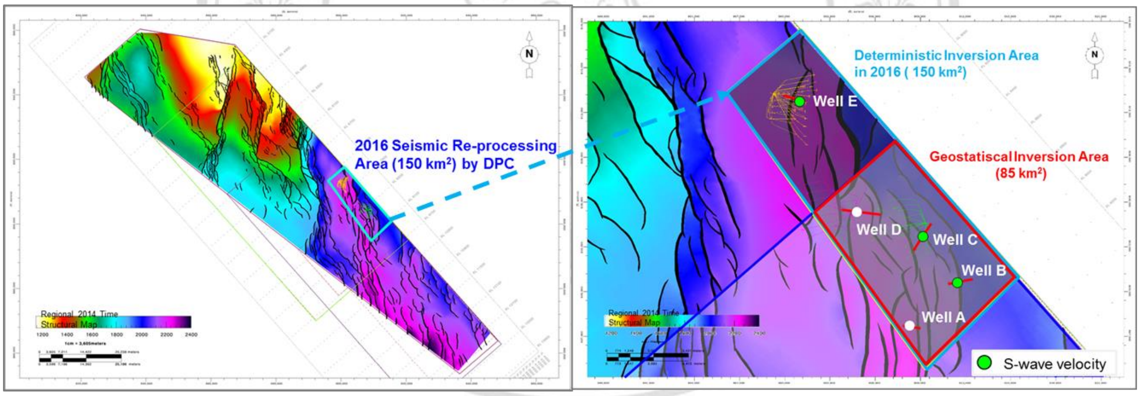

Figure 1.3. The left picture shows a regional time map across the Arthit Field, covered by 4000 km^2 of 3D seismic data. The blue boundary indicates the area included in seismic preconditioning and deterministic inversion in 2016 (150 km^2). The right picture shows a detailed map of areas input to a deterministic inversion study in 2016 (blue), the geostatistical inversion study area considered in this thesis (red), and locations of key input wells (A to E) in the area.

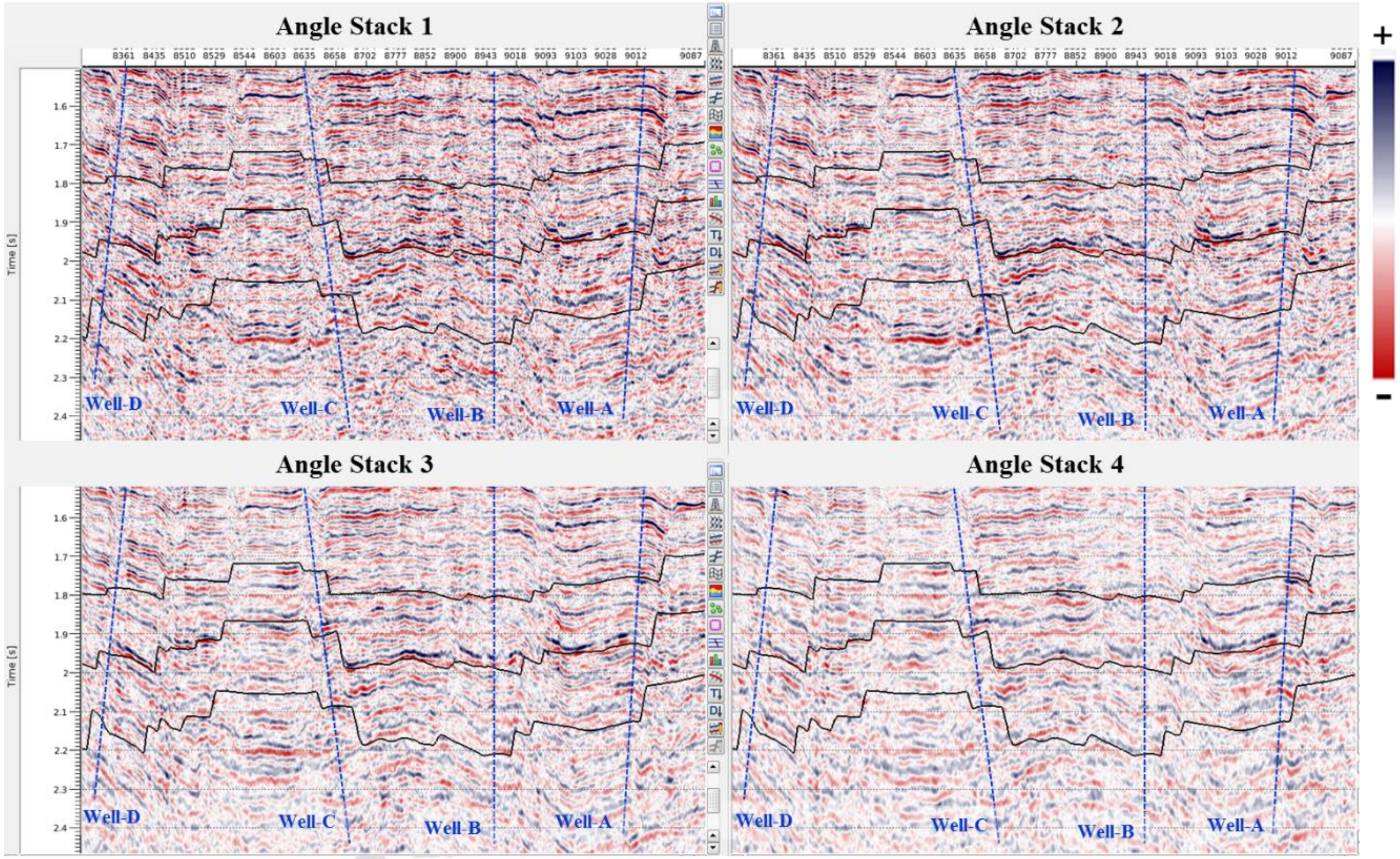

Figure 1.4. Seismic arbitrary line passing through all input wells for angle stack 1 (near), angle stack 2 (near mid), angle stack 3 (mid) and angle stack 4 (far).

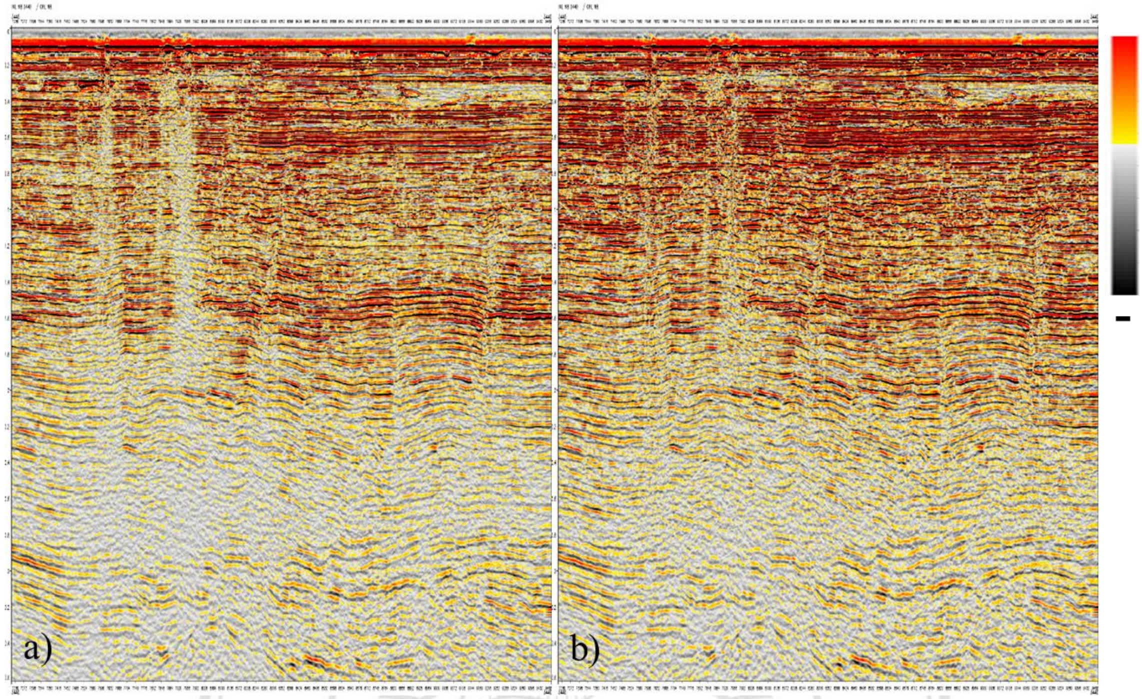

Figure 1.5. a) Before Q-Wave amplitude correction. b) After Q-Wave amplitude correction. The application of Q-Wave reduced the effect of unwanted lateral amplitude variations caused by near-surface amplitude anomalies in this area (Chansane et al., 2016).

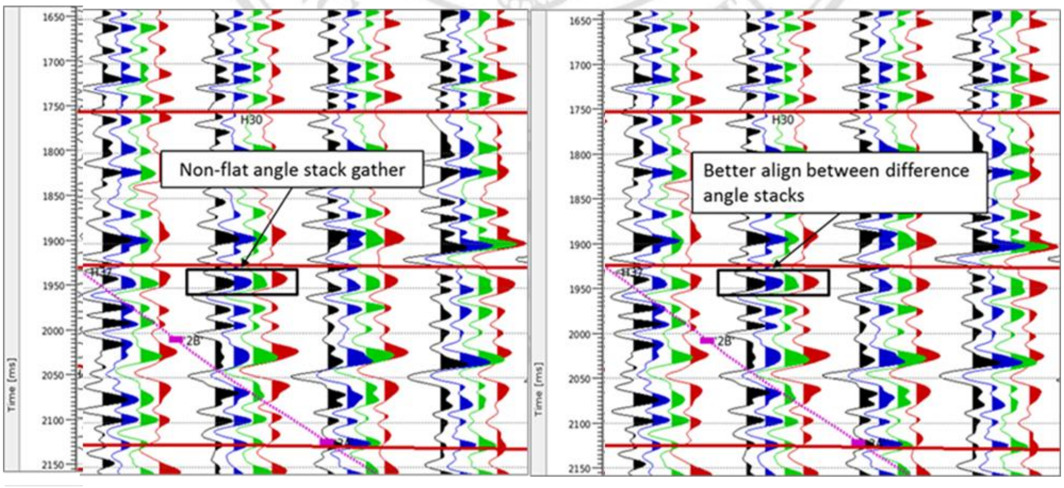

Figure 1.6. A time misalignment correction was applied to the near, mid and far angle stacks, using the near-mid angle stack as a reference, resulting in improved angle-gather flatness (Kliangglom et al., 2016).

1.1.2 Deterministic Pre-Stack Inversion

A deterministic seismic inversion project was carried out within Arthit Field, using 150 km^2 of pre-stack 3D seismic data and five input wells (Figure 1.3). The primary targets were gas sandstone reservoirs from Formation 2E to Formation 1. Simultaneous seismic inversion was carried out to generate elastic property volumes for P-impedance (AI), Vp/Vs and density. The results showed very good correlation with well log data for AI (81%-85% R^2) and moderate correlation for Vp/Vs (44%-49% R^2); while the density showed poor correlation due to the relatively short maximum angle available in the seismic data (Kliangglom et al., 2016).

Following inversion, lithofacies were classified using a Bayesian classification, which was limited to lithology identification of sand and shale in the area. Accurate classification of pore-fluid variations could not be detected, and this was also in agreement with an initial rock physics study carried out prior to the seismic inversion. The sand probability cube highlighted most of the thicker sand reservoir units (greater than 7-10 m), considering both individual sands and stacked sands (Kliangglom et al., 2016).

Four additional wells (“blind wells”) were added to validate the results obtained from the deterministic elastic-impedance inversion. Analysis of the validation wells showed that lithology and sand probability volumes provided good quality predictions down to about 2200-2300 ms (TWT), while the predictions were moderate to poor quality towards the deeper target (below 2300 ms TWT). Several factors could contribute to the decreasing lithology predictability with depth, such as reduced seismic resolution, short streamer length not providing sufficient AVA information, and Vp/Vs values converging (Kliangglomet al., 2016).

1.1.3 Well data

To be consistent with the input dataset used in the 2016 deterministic seismic inversion study, a similar set of input wells was used in this study, consisting of Wells A, B, C, and D. An additional well (Well E) was used during the deterministic inversion study, but is not considered in this study as it is located outside the study area for geostatistical inversion. All input wells included the following information:

- Location and deviation survey.
- Sonic, shear-sonic*, density, gamma-ray logs, and borehole calliper.
- Petrophysical logs (Sw, Phie, and Vsh).
- Lithology logs.
- Geological picks/tops.
- Checkshot-data/VSP and T/D relationship based on final well-tie.

  *: Shear-sonic was measured in wells B and C, but predicted in A and D.

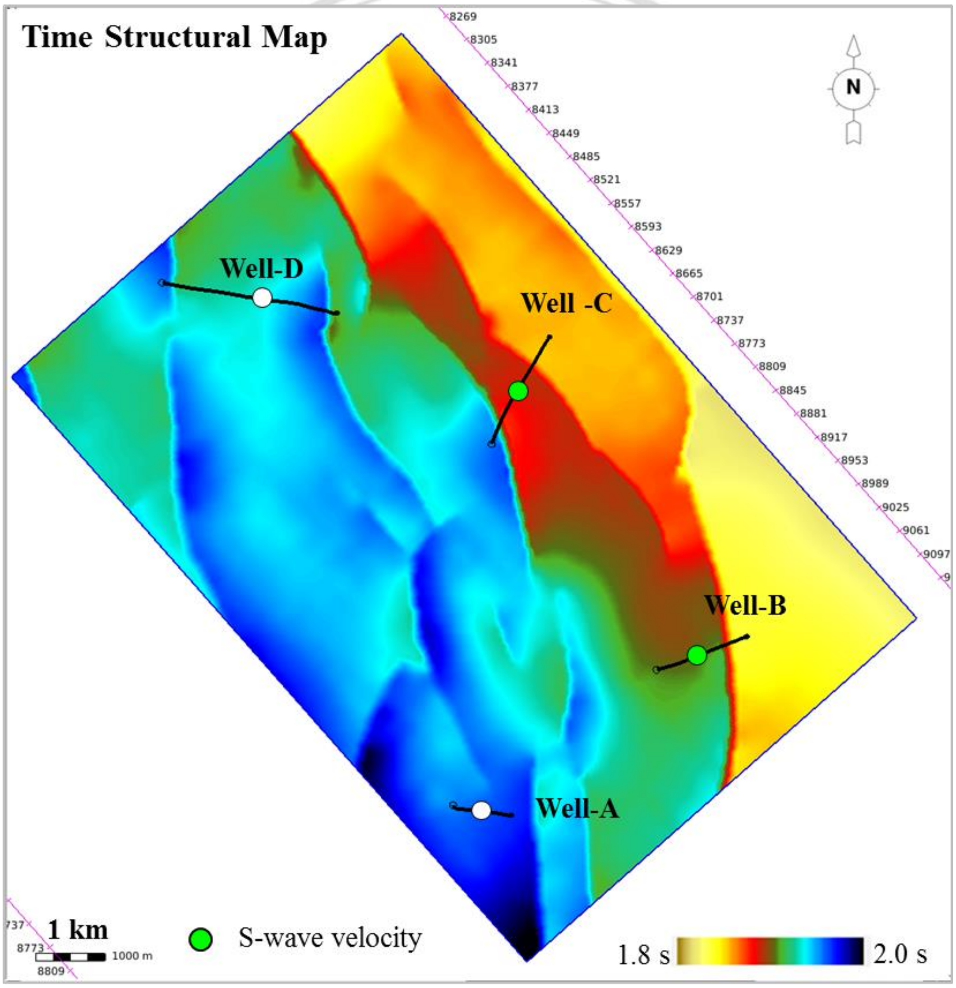

Figure 1.7. Time structural map overlaid with all input wells considered in this study.

1.2 Literature Review

Torres-Verdin et al. (1999) applied geostatistical inversion to estimate density distribution away from wells by simultaneously honoring both seismic and wellbore data. The implementation was based on a random-walk stochastic simulation of acoustic impedances with an acceptance/rejection gate based on the actual seismic data. A stochastic co-simulation was implemented to yield independent realizations of both lithology and density. Tens of realizations were computed to describe the distribution of both lithology and density. The geostatistical inversion result provided four times the vertical resolution obtained with seismic data alone, and helped assess individual sand units away from wells. The use of this technology significantly improved reservoir evaluation for field development planning and optimized placement of infill wells in San Jorge Basin, Argentina.

Contreras et al. (2005b) described the application of an AVA stochastic-inversion algorithm to quantitatively integrate pre-stack seismic data and well logs. The stochastic inversion algorithm was used to characterize Miocene deep-water sand deposits located in the central Gulf of Mexico. Fluid/lithology sensitivity analysis indicated that the shale/sand interface (top of the hydrocarbon-bearing sand) was represented by Class III AVA responses. Moreover, the Biot-Gassmann fluid substitution demonstrated that P-wave velocity and density were very sensitive to pore-fluid variations. Subsequently, AVA stochastic inversion provided high-resolution (1 ms) 3D distribution of lithotypes (sand/shale), P-velocity, S-velocity and density. The AVA stochastic-inversion algorithm combined the advantages of AVA analysis with those of geostatistical inversion. This inversion algorithm was based on the Markov Chain Monte Carlo (MCMC) method and was combined with a Gaussian random field conceptual model. Finally, 3D spatial distributions of petrophysical properties (porosity, permeability, and water saturation) were constructed by co-simulating the AVA stochastic inversion using multivariate statistics. The pre-stack stochastic inversion provided improved vertical resolution and more realistic results than those achieved by the deterministic inversion. Moreover, the combination of AVA sensitivity analysis techniques and pre-stack stochastic inversion can significantly help reduce risks related to field development.

McCrank et al. (2009) applied geostatistical inversion to identify thinly-bedded Ardley coal in west-central Alberta. The gross thickness of coal in the area of interest varied from 3-10 m, thinner than seismic resolution. The inverted acoustic impedance from a previous deterministic inversion overestimated the coal thickness and did not detect thinner coal beds. Geostatistical inversion was therefore carried out to improve the inversion resolution and assess model uncertainty. The inversion combined the information of seismic data, well data and geostatistics. The inversion provided high-resolution acoustic impedance volumes that were used for facies estimation. As a result, geostatiscal inversion provided more accurate coal thickness estimates and captured the range of uncertainty of coal thickness variations away from well control points in the area.

Contreras et al. (2014) described the joint stochastic inversion of well logs and 3D pre-stack seismic data using a Bayesian search criterion implemented with fast Markov-Chain Monte Carlo (MCMC). The inversion algorithm was successfully applied to a deep-water reservoir at Marco Polo Field, located in Green Canyon Block 608, Gulf of Mexico. The reservoir consisted of sandy turbidite packages inter-bedded with muddy debris flows. Pre-stack stochastic inversion was applied to generate elastic properties (Vp, Vs, density) and lithotypes. This was followed by petrophysical co-simulation based on the elastic inversion results and well log data. Finally, multiple co-simulation realizations provided a statistical tool to assess the non-uniqueness and uncertainty of the results.

1.3 Objectives of the current study

1.3.1 To produce multiple highly-detailed elastic property and litho-facies models that are consistent with well log data and AVA responses from pre-stack seismic data.

1.3.2 To combine available subsurface information to obtain the uncertainty range of reservoir distribution and elastic properties in the study area.

1.3.3 To compare the results obtained with geostatistical inversion to standard inversion techniques (deterministic inversion).