

Geothermal Heat Assessment of the Suphan Buri Basin, Thailand, Using Horner-Corrected Bottom-Hole Temperatures

Ba Hein Kyaw ^{1*}, and Sukonmeth Jitmahantakul ²,

¹ M.Sc. Program in Energy Geosciences, Faculty of Science, Chulalongkorn University, Bangkok, Thailand

² Center of Excellence in Applied Mineral and Petrology, Department of Geology, Faculty of Science, Chulalongkorn University, Bangkok 10330, Thailand

* Corresponding author: baheinkyaw1996@gmail.com

Received: 19 Jun 2026

Revised: 14 Jul 2026

Accepted: 19 Jul 2026

Abstract

The Suphan Buri Basin is a Cenozoic half-graben in central Thailand with a mature petroleum history and extensive legacy subsurface dataset that can be re-purposed for geothermal screening. This study presents an integrated geothermal play-fairway assessment that estimates true formation temperature from bottom-hole temperature (BHT) records using the Horner method, rather than a depth-only empirical correction. The complete 67-well study area inventory was screened, and 25 wells were found to record two or more wireline logging-run maximum temperatures at approximately the same depth, together with the elapsed time after the end of mud circulation (EOC). These wells meet the data requirements of a Horner correction. For each well, the static formation temperature (T_f) was obtained by extrapolating the successive logging-run temperatures to infinite shut-in time, from which an apparent geothermal gradient and the depths to target temperatures were derived. Horner-corrected formation temperatures range from about 88 to 154 °C, and apparent gradients from about 39 to 51 °C/km (basin median $\approx$ 44 °C/km), in close agreement with the $\sim$ 42 °C/km previously reported from BP1-well thermal-history modelling. The temperature-depth data define a coherent, near-linear basin trend ($R^2 \approx 0.83$), consistent with a predominantly conduction-dominated regime modified locally by fault-controlled fluid flow. Well BS1 (Ban Don Sa-Nuan) is the strongest thermal anomaly, with $T_f \approx 154$ °C, a gradient of $\sim$ 50 °C/km, and 150 °C at about 2.45 km. Play-fairway mapping that integrates corrected temperature, gradient and depth-to-150 °C with the seismically interpreted structural framework identifies the Ban Don Sa-Nuan–Sang Krajai–U-Thong trend as the most favourable fairway. The workflow provides a transparent, reproducible framework for preliminary geothermal screening of data-rich sedimentary basins in Thailand, and a basis for evaluating reservoir quality, fluid productivity, and development concepts including direct use, binary-cycle power and enhanced geothermal systems (EGS).

Keywords: Horner correction; bottom-hole temperature; formation temperature; Suphan Buri Basin; Sedimentary-basin geothermal; Thailand

1. Introduction

Sedimentary basins are high-potential targets for geothermal exploration because they may contain elevated subsurface temperatures, permeable clastic reservoirs, and structurally controlled fluid pathways (Moeck and Beardsmore, 2014). Compared with volcanic geothermal systems, sedimentary-basin geothermal systems are commonly lower temperature and depend strongly on reservoir continuity, fault transmissivity, and the availability of sufficient fluid volume. Existing petroleum subsurface datasets can therefore be integrated into a geothermal play framework and used for preliminary thermal assessment, provided that the inherent limitations of legacy temperature data are recognized and handled explicitly.

The Suphan Buri Basin in central Thailand has already been investigated for hydrocarbon exploration and production, and the resulting legacy data can be re-evaluated for geothermal purposes through an integrated play assessment rather than by considering isolated temperature anomalies. In a geothermal play framework, prospectivity depends on the coincidence of heat, reservoir, fluid, and pathway (or recharge) elements (Moeck, 2014; Moeck and Beardsmore, 2014).

Regional tectonic and stratigraphic studies of Thailand show that Cenozoic basins developed in response to complex structural processes, including extension and strike-slip-related deformation (Morley et al., 2011). In this setting, faults influence basin subsidence, sediment distribution, and fluid circulation. Stratigraphic variation in the Cenozoic basin fill is also important because sand and conglomerate intervals provide reservoir capacity, whereas shale-rich intervals may act as

seals or thermal-blanketing units (Morley and Racey, 2011)

The Suphan Buri Basin is a Cenozoic, north-south-trending half-graben of approximately 800 km², bounded by a major normal fault along its western flank and filled by a Cenozoic succession of fluvial and lacustrine clastic deposits (Polachan et al., 1991; Ronghe and Surarat, 2002). The basin has a mature petroleum history: light crude is produced from the U-Thong (Sawang) and Sang Krajai fields at a combined rate of approximately 400 barrels per day from Middle–Upper Miocene sandstone reservoirs (Petersen and Mathiesen, 2007). Petersen and Mathiesen (2007) estimated a geothermal gradient of approximately 42 °C/km from temperature-history modelling of the BPI-W2 well in the U-Thong oilfield area, Suphan Buri Basin, central Thailand, using a realistic palaeo-surface temperature of approximately 22 °C. Although this modelling was based on a separate thermal-history dataset, it provides an independent regional benchmark for evaluating the Horner-corrected gradients derived from the 25 qualifying wells in this study.

In hydrocarbon exploration, the play concept provides the geological foundation for resource assessment by defining a stratigraphic or structural setting in terms of source, reservoir, seal, and trap. Play-fairway analysis, originally a petroleum exploration tool, has likewise been adapted to map the spatial coincidence of these favourable elements and to rank exploration risk for geothermal prospects.

Bottom-hole temperatures measured during wireline logging commonly underestimate true static formation temperature because drilling-fluid circulation cools the borehole and surrounding formation. After circulation stops, the borehole gradually

recovers toward thermal equilibrium. The Horner method corrects this effect by using repeated bottom-hole temperature measurements acquired at the same or comparable depth but at different elapsed times after the end of circulation. By extrapolating this thermal-recovery trend to infinite shut-in time, the method provides an estimate of static formation temperature that is more physically based than a simple depth-only empirical correction (Beardsmore and Cull, 2001).

This study addresses the absence of a transparent, basin-scale geothermal play assessment for the Suphan Buri Basin that integrates seismic interpretation, well data, production information, and a physically based bottom-hole temperature correction. Crucially, and in contrast to an earlier screening that relied on a depth-only empirical correction, the present study first screens the entire well inventory to identify wells that record repeated logging-run temperatures suitable for a Horner correction and then uses that correction to estimate true formation temperature. The specific aims are to (1) screen all available wells and select those that provide the data required to construct Horner plots and estimate formation temperature; (2) evaluate the temperature–depth relationship and apparent geothermal gradient across the basin; (3) integrate the thermal results with the seismically interpreted structural and basement framework in a play-fairway map; and (4) rank candidate sectors and outline the technical pathway toward geothermal development, including binary-cycle and enhanced geothermal systems.

2. Data and Methods

2.1 Study Area and Datasets

The study area covers the central and southern Suphan Buri Basin and includes seven petroleum field areas: Nong Phak Chi, Hua Mai Sung, Ban Don Sa-Nuan, Ban Don Talai, Bung Kratiam, Sang Krajai, and U-Thong (Figure 1). The datasets comprise: (i) three-dimensional seismic volumes acquired in 2011 and 2013; (ii) well data for the 67-well inventory, including well headers and bottom-hole coordinates, deviation and check-shot surveys, wireline and logging-while-drilling (LWD) logs, formation tops, and final well reports; (iii) wireline formation-testing records (pressure, temperature, mobility, and fluid type); and (iv) oil- and water-production histories used qualitatively as proxies for reservoir connectivity. All coordinates are reported in the Indian 1975 / UTM Zone 47N system, and depths are referenced to true vertical depth sub-sea (m TVDSS) unless otherwise stated.

2.2. Well Screening and Selection of Horner-qualifying wells

A central methodological decision in this study is that formation temperature is estimated by the Horner method wherever the data permit, rather than by applying a depth-only empirical correction uniformly to all wells. The Horner method was originally developed for pressure build-up analysis but has been widely adapted for correcting bottom-hole temperature measurements affected by drilling-fluid circulation and borehole thermal recovery (Beardsmore and Cull, 2001). The method requires, at a given or closely comparable depth interval, two or more temperature measurements acquired at different elapsed times after the end of circulation (EOC), because the correction is

based on extrapolating the borehole thermal recovery trend toward static formation temperature.

Accordingly, the complete 67-well inventory was screened systematically. For every well, the final well report was examined and all logging-run maximum temperatures, their recording depths, and their times after EOC were extracted. A well was retained as Horner-qualifying when it satisfied all of the following: (1) valid bottom-hole UTM coordinates; (2) two or more logging-run temperatures recorded at

approximately the same depth (within ± 60 m TVDSS) at different times after EOC; (3) consistent depth referencing between runs; and (4) a physically reasonable temperature build-up with increasing shut-in time. Twenty-five wells satisfied these criteria and form the analysis set; the remaining wells were retained in the inventory but lacked repeated same-depth measurements and so could not support a Horner correction.

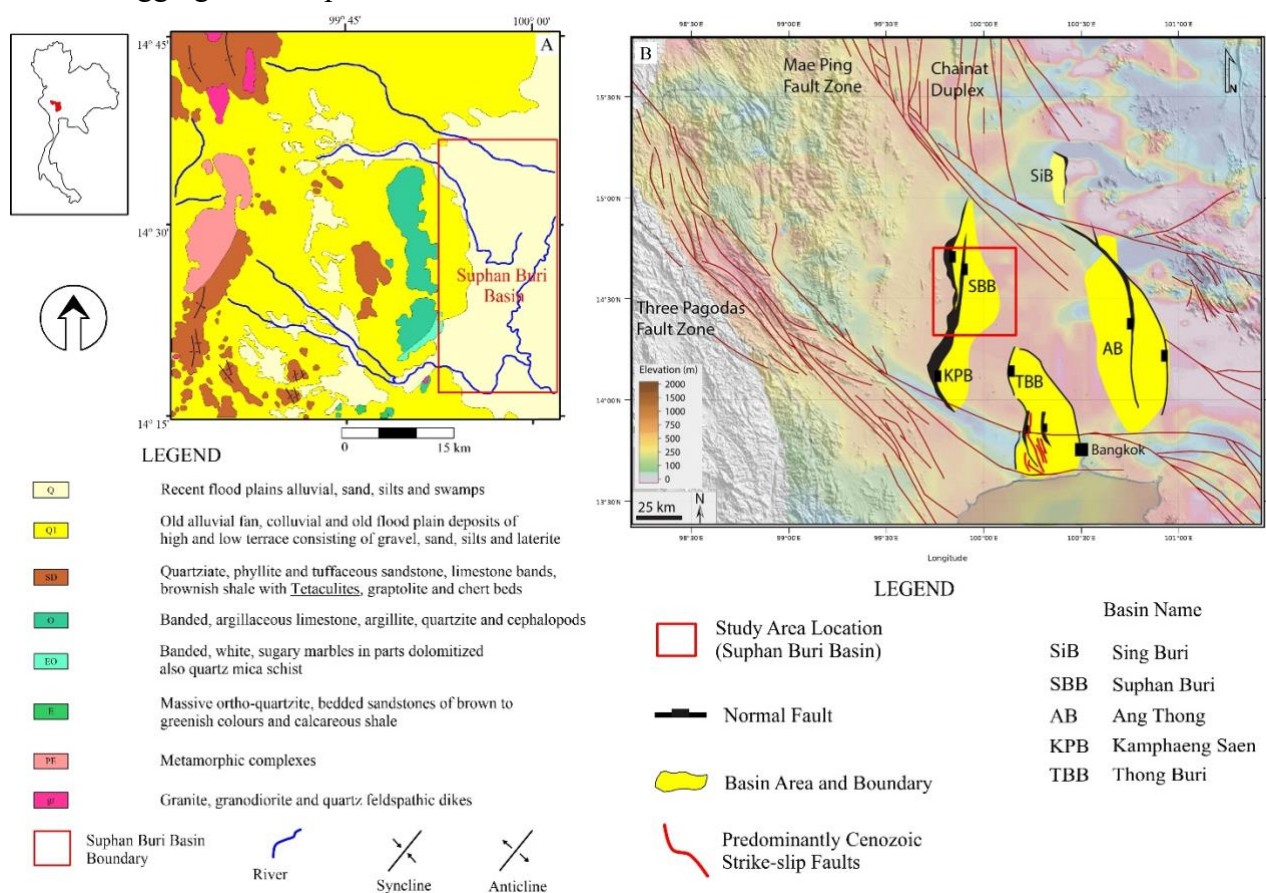


Figure 1. Location of the study area in the Suphan Buri Basin, central Thailand: (A) Simplified Geological Map of Suphan Buri Province; (B) Regional Tectonic Setting of the Basin

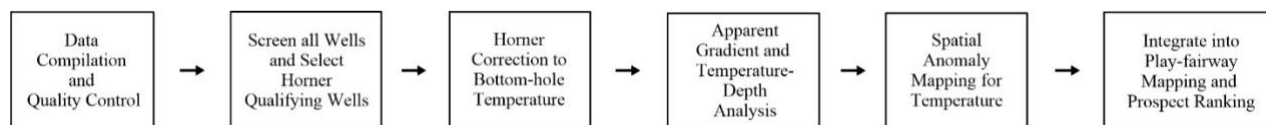


Figure 2. Workflow of the integrated geothermal play-fairway assessment

2.3. How temperature was measured and temperature data quality control

Because the reliability of the entire study depends on the temperature data, the origin of each measurement was examined explicitly. Two classes of downhole temperature are present in the dataset. The first is the station temperature recorded by wireline formation testers during pressure pre-tests (Schlumberger XPT, MDT and RFT tools), and Weatherford MFT tools, which provide a temperature reading at each test depth. The second, and the basis of the Horner correction, is the maximum recorded temperature of each wireline logging run, registered by the temperature sensor of the logging string and reported in the final well report together with the run depth and the time after EOC. The logging-run maximum temperatures were used as the input for Horner correction because successive wireline runs commonly re-occupy the near-bottom interval after progressively longer shut-in times, allowing the borehole thermal recovery trend to be reconstructed. This approach follows standard bottom-hole temperature correction practice, in which repeated logging temperatures are used to estimate static formation temperature from transient post-circulation recovery (Beardsmore and Cull, 2001).

2.4. Horner bottom-hole temperature correction

Bottom-hole temperatures measured during and shortly after drilling are systematically lower than the true static formation temperature because circulation of relatively cool drilling fluid cools the near-borehole rock; the formation then recovers toward equilibrium during the shut-in period (Beardsmore and Cull, 2001). The Horner method (Horner, 1951), adapted from pressure build-up analysis, models this thermal recovery. For a set of temperatures $T(\Delta t)$ measured at a fixed depth at increasing times Δt after the end of circulation, the static formation temperature T_f is obtained from:

$$T(\Delta t) = T_f - m \cdot \ln[(t_c + \Delta t) / \Delta t] \quad (1)$$

where t_c is the mud-circulation time at that depth and m is the slope of the build-up. When the measured temperatures are plotted against the dimensionless Horner time $\ln[(t_c + \Delta t)/\Delta t]$, they fall on an approximately straight line whose intercept at infinite shut-in time (where the Horner ratio tends to unity and the logarithm to zero) gives T_f . In this study a linear regression of the logging-run temperatures against the Horner time was fitted for each qualifying well, and T_f was taken as the regression intercept (Figure 3). Wells with three or more runs yield an over-determined fit and a coefficient of determination (R^2); wells with exactly two runs yield an exact two-point estimate.

Three assumptions are made explicit. First, because circulation time (t_c) is not

reported in any of the well reports. Only the time after the end of circulation (Δt) is recorded. t_c was assumed to be 4 hours. The sensitivity of T_f to this assumption was tested by recomputing T_f for $t_c = 1$ to 12 hours. The resulting change is at most 5.1 °C and on average 1.5 °C across the 25 wells, and no more than 1.5 °C over the realistic 3-6 hour range, so the assumption is not a material source of uncertainty. Second, only runs at essentially the same depth (within ± 60 m TVDSS) were combined, so that the build-up reflects a single near-bottom interval rather than a depth gradient. Third, each Horner-qualifying well was assigned a confidence class using quantitative and reproducible criteria. All qualifying wells first had to satisfy the minimum screening requirements of two or more logging-run maximum temperatures recorded at comparable depths within ± 60 m TVDSS and at different elapsed times after the end of circulation. For wells with three or more logging runs, the quality of the Horner fit was evaluated using the coefficient of determination (R^2) of the linear regression between bottom-hole temperature and Horner time.

A Good confidence class was assigned where three or more logging runs were available, the same-depth criterion was satisfied, the Horner fit showed a clear linear recovery trend with $R^2 \geq 0.60$, and the correction was physically reasonable, meaning that the extrapolated formation temperature was equal to or higher than the latest measured temperature and not anomalously large relative to the observed temperature build-up. A Fair class was assigned to wells with only two logging runs, for which R^2 is not diagnostic because a two-point fit is mathematically exact, or to wells with three or more runs showing moderate scatter, defined

here as $0.30 \leq R^2 < 0.60$, but still producing a geologically reasonable corrected temperature.

A Poor class was assigned where the recovery trend was weak or non-physical, defined by $R^2 < 0.30$ for wells with three or more runs, decreasing temperature with increasing shut-in time, an extrapolated formation temperature lower than the latest measured temperature, a very short shut-in-time range, or an anomalously large correction that could not be justified from the observed data. These confidence classes were used to weight the interpretation, with the main conclusions based primarily on Good- and Fair-confidence wells. This classification is carried through the interpretation so that the most heavily weighted conclusions rest on the best-constrained wells.

Confidence Class	Interpretation
Good	Main interpretation and candidate ranking
Fair	Used for basin trend and screening, but with lower weight
Poor	Retained for transparency but not used as primary evidence

Table 1. Confidence criteria used for Horner-corrected temperature estimates

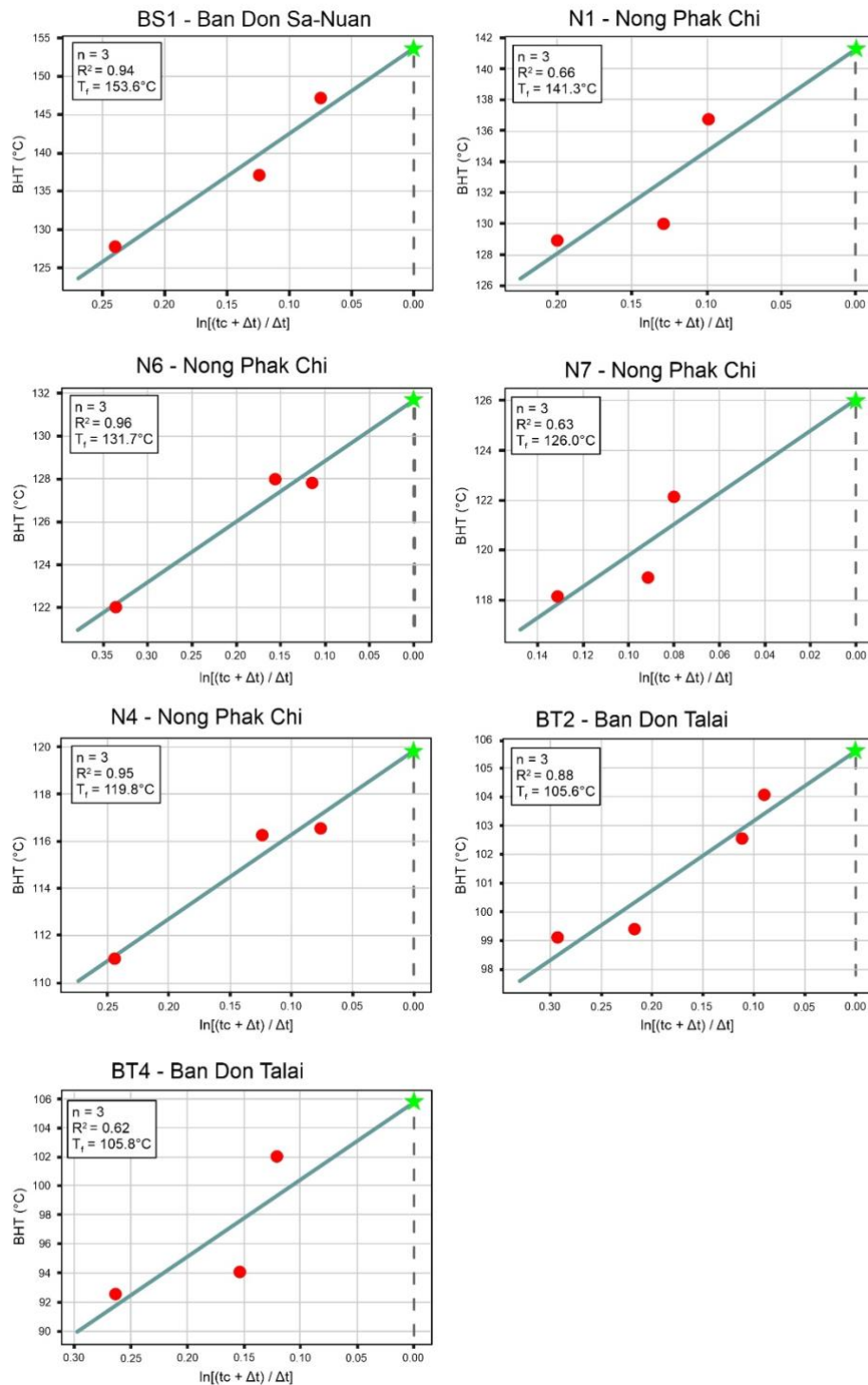


Figure 3. Horner plots for the seven good-confidence wells. For each well the logging-run maximum temperatures (BHT) are plotted against the Horner time $\ln[(tc + \Delta t) / \Delta t]$ ($tc = 4$ h); the linear fit (with R^2) extrapolates to the static formation temperature T_f at the intercept (star).

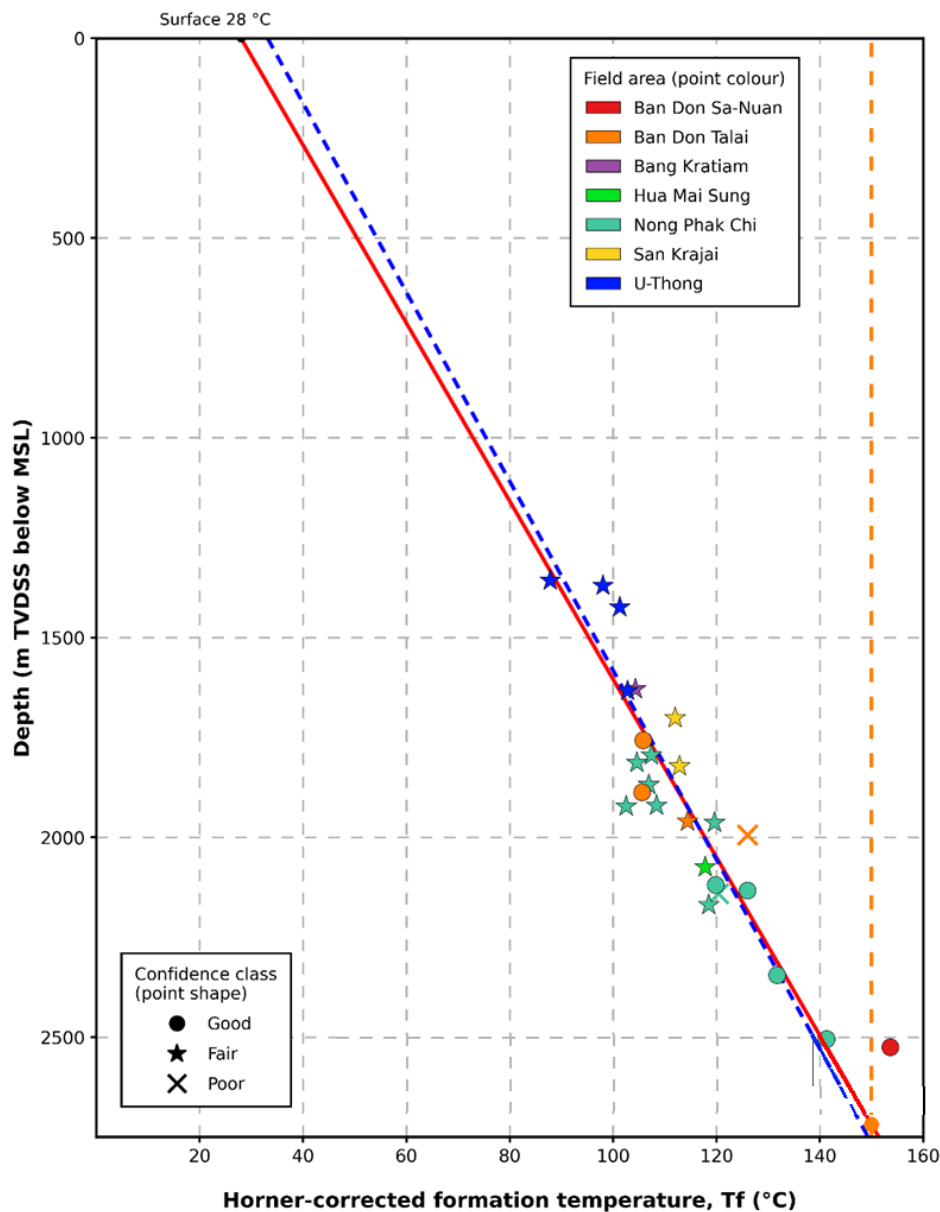


Figure 4. Horner-corrected formation temperature (T_f) plotted against true vertical depth below mean sea level (TVDSS) for the qualified wells in the Suphan Buri Basin. Point colours represent the different field areas. Point shapes represent the assigned confidence classes: circles indicate Good, stars indicate Fair, and crosses indicate Poor confidence. The red solid line is the surface-anchored linear fit using a mean surface temperature of 28 °C, corresponding to an apparent geothermal gradient of 44.9 °C/km ($R^2 = 0.827$). The blue dashed line is the unconstrained linear regression, corresponding to an apparent geothermal gradient of 42.3 °C/km ($R^2 = 0.830$). The orange vertical dashed line marks the 150 °C geothermal screening target; its intersection with the surface-anchored fit occurs at approximately 2,719 m TVDSS.

2.5. Apparent Geothermal Gradient and Depth to target temperature

For each qualifying well, an apparent geothermal gradient was calculated as the difference between the Horner-corrected formation temperature and an assumed mean surface temperature of 28 °C (representative of central Thailand), divided by the corresponding TVDSS depth. This first-order approach follows standard regional geothermal-screening practice, in which corrected subsurface temperatures are used with a surface-temperature boundary condition to estimate conductive temperature gradients where detailed thermal-conductivity profiles are not yet available (Beardsmore and Cull, 2001). The depth to selected target temperatures (120, and 150 °C) was then estimated by linear extrapolation of this gradient. The 120–150 °C window is relevant because binary-cycle (organic Rankine) systems are commonly viable in this range in sedimentary-basin settings. These gradients are termed apparent gradients to acknowledge that they assume a linear, conduction-dominated profile between the surface and the measurement depth and do not account for vertical variation in thermal conductivity.

3. Results

3.1. Qualifying wells and data quality

Of the 67 wells screened, 25 satisfied the Horner data requirements and form the analysis set (Table 1). They are distributed across all seven field areas: twelve in Nong Phak Chi (N1–N12), four in Ban Don Talai (BT1–BT4), four in U-Thong (U1–U4), two in Sang Krajai (S1–S2), and one each in Ban Don Sa-Nuan (BS1), Bung Kratiem (BK1) and Hua Mai Sung (H1). Under the confidence scheme, seven wells are

classified as Good, sixteen as Fair, and two as Poor. Each well contributed between two and five logging runs, with shut-in times after EOC of roughly 7 to 51 hours, providing the temperature build-up needed for the extrapolation.

3.2 Horner-corrected Formation Temperatures

Horner-corrected formation temperatures range from about 88 °C to 154 °C, with a median of approximately 112 °C. The corrections relative to the maximum measured temperature are positive in nearly all wells, as expected for a borehole recovering from circulation cooling, and are typically in the range +2 to +7 °C, reaching about +16 °C where the shut-in interval is short and the extrapolation correspondingly larger. The seven Good-confidence wells (Figure 3) provide the most reliable estimates: BS1 ($T_f \approx 154$ °C), N1 (≈ 141 °C), N6 (≈ 132 °C), N7 (≈ 126 °C), N4 (≈ 120 °C), and BT2 and BT4 (each ≈ 106 °C). For these wells, the linear Horner fits are well defined (R^2 between 0.61 and 0.96), confirming a coherent thermal build-up and supporting the corrected temperatures as robust screening values.

3.3. Temperature-Depth Relationship and Apparent Gradient

The corrected formation temperatures define a clear, near-linear increase with depth across the basin (Figure 4). A free linear regression of T_f on TVDSS yields a basin-scale apparent gradient of about 42 °C/km ($R^2 \approx 0.83$); anchoring the fit to the assumed 28 °C surface temperature gives about 45 °C/km. Individual-well apparent gradients range from about 39 to 51 °C/km, with a median near 44 °C/km. The

tightness of the basin trend indicates that, at the scale of the dataset, depth is the first-order control on temperature and that the wells sample a single, coherent regional thermal regime rather than isolated, unrelated anomalies. The 150 °C isotherm is reached at about 2.7 km on the basin trend, and between roughly 2.4 and 3.1 km in individual wells, depending on their gradient.

3.4. Spatial Distribution and Play Fairway

When the corrected gradient and formation temperature are mapped and draped on the main reservoir (D7) structural surface (Figure 5), the warmest, highest-gradient wells define a fairway along the western and southern parts of the study area. Ban Don Sa-Nuan (BS1) has the highest apparent gradient (~50 °C/km), and the shallowest depth to 150 °C (~2.45 km), and the Sang Krajai and U-Thong areas also show comparatively high gradients (~48–49 °C/km) at shallower control depths. Nong Phak Chi and Hua Mai Sung have slightly lower gradients (~43 °C/km) but reach the highest absolute corrected temperatures (up to ~141 °C in N1) by virtue of greater drilled depth. The coincidence of the highest gradients with structural highs and fault intersections on the D7 structural map supports a structurally influenced fairway rather than a purely stratigraphic one.

3.5. Candidate Ranking and Target Depths

Combining corrected temperature, apparent gradient, and depth-to-150 °C, well BS1 is the strongest temperature-led candidate:

it has the highest corrected formation temperature, the highest apparent gradient, and the shallowest estimated depth to 150 °C (~2.45 km). The next-ranked candidates are the deep Nong Phak Chi wells (N1, N6, N7) and the high-gradient Sang Krajai and U-Thong wells. For the high and moderate candidates, the 150 °C threshold is estimated to lie at roughly 2.45–2.9 km, defining a preliminary target window; the 120–130 °C range relevant to many direct-use and small binary applications is reached at correspondingly shallower depths. These target depths are screening estimates and must be revised once reservoir permeability, fluid productivity, and equilibrium-temperature logs are available.

The clearest result is a temperature-led anomaly at well BS1 in the Ban Don Sa-Nuan area. BS1 in the Ban Don Sa-Nuan area is the highest-ranked temperature-led candidate in the dataset. It has the highest Horner-corrected formation temperature. $T_f \approx 153.6$ °C, the highest apparent geothermal gradient, approximately 49.7 °C/km, and the shallowest estimated depth to 150 °C, approximately 2.45 km. The next-ranked candidates are the deeper Nong Phak Chi wells, especially N1, N6 and N7, together with high-gradient wells in the Sang Krajai and U-Thong areas.

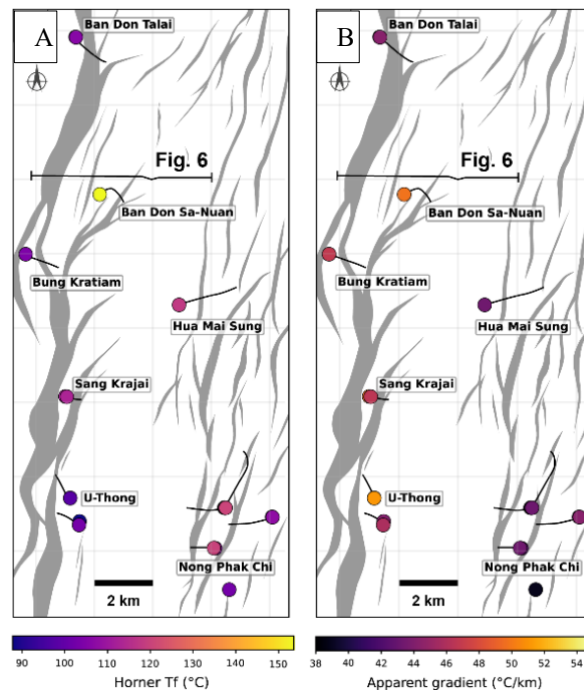


Figure 5. Geothermal play-fairway maps showing (A) Horner-corrected formation temperature (Tf) and (B) apparent geothermal gradient. Fault polygons in grey are based on the D7 depth structural map.

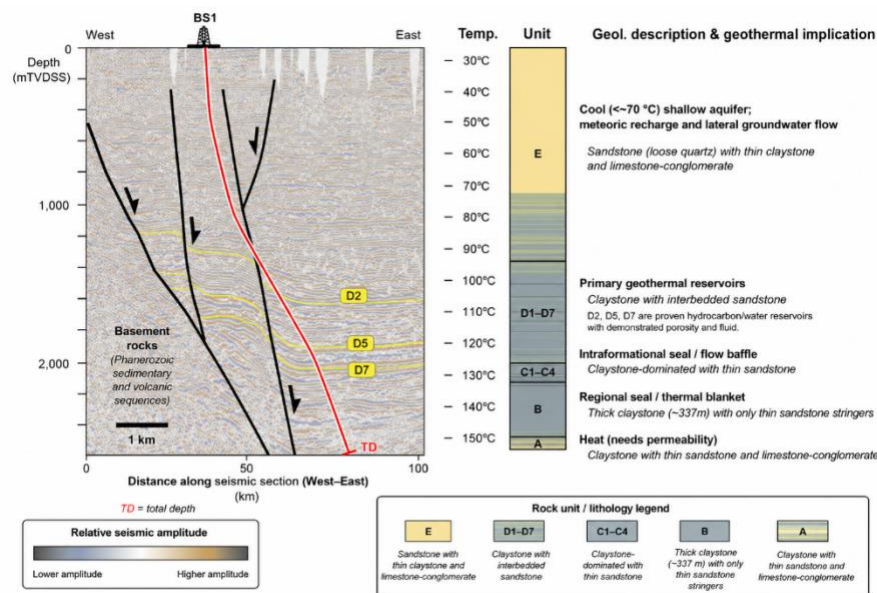


Figure 6. Interpreted west-east seismic section across well BS1, with the simplified lithology log shown alongside in mTVDSS. Red line = BS well track, black lines with arrows = interpreted normal faults defining the half-graben; yellow horizons = reservoir markers D2, D5 and D7. The temperature scale gives the Horner-corrected profile along the well (~150 °C near TD). Faults are interpreted as vertical fluid/heat pathways linking the deep hot section to shallower reservoir

Well	Area	Max BHT (°C)	Tf depth (mTVDSS)	Horner Tf (°C)	App. gradient (°C/km)	Depth to 120 °C (m)	Depth to 150 °C (m)	Confidence
BS1	Ban Don Sa-Nuan	147.1	2,525	153.6	49.7	1,851	2,455	Good
N1	Nong Phak Chi	136.7	2,505	141.3	45.2	2,035	2,699	Good
N6	Nong Phak Chi	128.0	2,345	131.7	44.2	2,081	2,760	Good
BT1	Ban Don Talai	110.0	1,994	126.0	49.1	1,874	2,485	Poor
N7	Nong Phak Chi	122.1	2,133	126.0	46.0	2,000	2,652	Good
N9	Nong Phak Chi	122.0	2,141	120.4	43.2	2,130	2,824	Poor
N4	Nong Phak Chi	116.5	2,119	119.8	43.3	2,125	2,818	Good
N10	Nong Phak Chi	113.0	1,963	119.6	46.6	1,974	2,618	Fair
N8	Nong Phak Chi	118.3	2,169	118.5	41.7	2,206	2,926	Fair
H1	Hua Mai Sung	114.7	2,074	117.8	43.3	2,125	2,818	Fair
BT3	Ban Don Talai	107.1	1,960	114.4	44.1	2,086	2,766	Fair
S2	Sang Krajai	108.9	1,822	112.8	46.5	1,978	2,624	Fair
S1	Sang Krajai	106.7	1,701	112.0	49.4	1,862	2,470	Fair
N2	Nong Phak Chi	104.8	1,920	108.4	41.9	2,196	2,912	Fair
N12	Nong Phak Chi	105.1	1,794	107.4	44.3	2,077	2,754	Fair
N3	Nong Phak Chi	103.5	1,868	106.9	42.2	2,180	2,891	Fair
BT4	Ban Don Talai	102.0	1,757	105.8	44.3	2,077	2,754	Good
BT2	Ban Don Talai	104.1	1,887	105.6	41.1	2,238	2,968	Good
N11	Nong Phak Chi	103.8	1,813	104.6	42.3	2,175	2,884	Fair
BK1	Bung Kratiem	97.8	1,629	104.3	46.8	1,966	2,607	Fair
U2	U-Thong	100.0	1,633	102.8	45.8	2,009	2,664	Fair
N5	Nong Phak Chi	100.7	1,922	102.5	38.8	2,371	3,144	Fair
U3	U-Thong	94.2	1,424	101.3	51.5	1,786	2,369	Fair
U4	U-Thong	91.4	1,370	98.0	51.1	1,800	2,387	Fair
U1	U-Thong	87.8	1,357	87.8	44.1	2,086	2,766	Fair

Table 2. Summary of the 25 Horner-qualifying wells, corrected formation temperatures, apparent geothermal gradients, target depths, and confidence classes. Colour indicates Horner-confidence class: green = Good, yellow = Fair, and red/pink = Poor.

4. Discussion

4.1. Significance of the BS1 Thermal Anomaly

The BS1 anomaly is significant because it combines both high corrected formation temperature and high apparent geothermal gradient. A high formation temperature alone may partly reflect greater drilling depth, whereas a high apparent gradient indicates that the well is anomalously warm relative to its depth. This makes BS1 the strongest temperature-led screening target in the present dataset. The anomaly is also relatively robust because BS1 is classified as a Good-confidence Horner well, with three logging runs and a well-defined linear Horner fit ($R^2 \approx 0.94$). However, BS1 should not yet be interpreted as a confirmed geothermal reservoir. The current evidence demonstrates a strong thermal anomaly, but reservoir permeability, fluid productivity, water

chemistry, pressure support, and an equilibrium-temperature log are still required before geothermal development potential can be confirmed.

4.2. Conduction versus Convection, and the role of Groundwater

Whether the basin thermal regime is dominated by conduction or convection has direct consequences for exploration strategy. The near-linear temperature–depth trend and the comparatively narrow range of apparent gradients ($\approx 39\text{--}51$ °C/km, $R^2 \approx 0.83$) are most consistent with a predominantly conduction-dominated regime, in which heat is transferred vertically through the sedimentary column and temperature increases approximately linearly with depth. Pronounced convection would instead produce strongly non-linear profiles (Bredehoeft and Papadopoulos, 1965; Anderson et al., 1979), isothermal intervals, or large lateral

temperature contrasts at constant depth, which are not observed at the basin scale. Nevertheless, the modest scatter about the trend, and the association of the highest gradients with fault-bounded structural highs, suggest that fault-controlled fluid movement modifies the conductive background locally (Smith and Chapman, 1983; Bense et al., 2013). Such localised convection, where permeable faults connect deeper, hotter intervals to shallower reservoirs, is exactly the mechanism that can elevate the gradient at sites such as BS1.

Groundwater flow is a related control that should be considered explicitly in future work. Regional meteoric recharge along basin margins and topographically driven flow can depress gradients in recharge areas and elevate them in discharge areas (Garven, 1995). In the Suphan Buri Basin, lateral aquifer flow within the laterally continuous Miocene sandstones could redistribute heat and partly explain the scatter in apparent gradients between adjacent fields. Incorporating produced-water chemistry, formation-pressure gradients, and hydraulic-head data would help to distinguish conductive from advective contributions and to test whether any field lies in a thermally favourable discharge setting.

4.3. Toward Geothermal Development, Direct Use, Binary Power, and EGS

The corrected formation temperatures of approximately 88–154 °C and apparent gradients of about 39–51 °C/km indicate low- to moderate-enthalpy geothermal conditions in the Suphan Buri Basin. These values are suitable for temperature-led screening of direct-use applications and, in the highest-temperature sectors, potential binary-cycle power generation. Direct-use applications commonly

operate across low to moderate temperature ranges, whereas binary-cycle systems are commonly considered for lower-temperature geothermal fluids, including water-dominated resources in the 110–160 °C range. The BS1 anomaly is therefore practically significant because it reaches approximately 154 °C and has an estimated 150 °C target depth of about 2.45 km, but it remains a screening target until permeability, flow rate, water chemistry, and pressure support are confirmed. The present basin-scale gradient of approximately 42–45 °C/km is consistent with the ~42 °C/km gradient reported by Petersen and Mathiesen (2007) for the U-Thong oilfield area, supporting the reliability of the Horner-corrected temperature trend.

The corrected temperatures place the Suphan Buri Basin in the low- to moderate-enthalpy range, which is appropriate for direct-use geothermal applications and may support binary-cycle power generation where temperatures approach or exceed the 120–150 °C range. Direct-use applications are commonly developed from low- to moderate-temperature geothermal resources, whereas binary-cycle systems are widely used for lower-temperature geothermal fluids because a secondary working fluid with a low boiling point can be vaporized to drive a turbine (Lund and Boyd, 2016; DiPippo, 2012). The 120–150 °C target interval used in this study is therefore a reasonable screening threshold for evaluating potential direct-use and small binary-cycle applications, although reservoir permeability, sustainable flow rate, water chemistry, and production performance must be confirmed before development decisions are made (Franco and Villani, 2009; DiPippo, 2012).

In the near term, the most attractive concept is the re-use of existing wellbores and co-produced water from the U-Thong and Sang Krajai oil fields, where warm water is already produced with the oil. Such co-produced-fluid geothermal schemes can supply direct heat for agricultural drying, food processing, or district-scale heating with minimal additional drilling. Where temperatures approach or exceed 150 °C, as projected near 2.4–2.9 km in the best sectors, small binary (organic Rankine cycle) units become feasible, albeit at the modest conversion efficiencies noted above.

Looking further ahead, the deeper, hotter, structurally controlled sectors (particularly the Ban Don Sa-Nuan block) are candidates for EGS, in which permeability is engineered by hydraulic stimulation of low-permeability rock to create a circulation system between an injector and a producer (Tester et al., 2006; Olasolo et al., 2016). EGS is most relevant where heat is present but natural permeability is insufficient, which may apply to the claystone-dominated deep section that hosts the BS1 anomaly. A staged development pathway is therefore suggested: (i) confirm permeability and fluid productivity in existing wells; (ii) pilot direct use of co-produced water in producing fields; (iii) appraise binary-power potential in the highest-gradient sectors; and (iv) evaluate EGS feasibility in the deep, hot, low-permeability blocks. Each stage reduces resource uncertainty before committing to deeper, higher-cost drilling.

4.4 Limitations and Next Work

The principal limitation remains the absence of fully equilibrated temperature logs. The Horner correction substantially improves on uncorrected or depth-only-corrected BHT,

but extended shut-in or dedicated temperature logs would refine T_f further. A second limitation is reservoir characterization. Permeability, porosity, net-pay thickness, water chemistry, and pressure behaviour must be integrated before any drilling decision, since a hot but impermeable interval has limited value. A third is spatial coverage and structural resolution: although 25 wells provide a useful basin-scale screen, a refined and better-integrated top-basement map, together with fault-seal and fault-permeability analysis, is needed to convert the thermal fairway into drillable prospects. These items define the immediate next phase of the study.

The apparent-gradient approach used in this study is appropriate for first-order geothermal screening, but it does not resolve vertical variation in thermal conductivity between sand-rich and shale-rich intervals. A conductivity-weighted thermal model should therefore be developed once core-derived or log-derived thermal-conductivity data are available. Future volumetric resource assessment will also require explicit justification of the recovery factor. Conservative values of approximately 0.10–0.25 are more appropriate for unstimulated clastic reservoirs, whereas higher values in the range of 0.50–0.60 should only be applied where fractured reservoirs, EGS stimulation, or reservoir-specific production evidence can be demonstrated (Williams et al., 2008). In addition, binary-cycle conversion efficiencies in the 120–150 °C temperature range are commonly modest, approximately 10–13%, which should be considered when translating thermal anomalies into realistic power-generation potential (DiPippo, 2012).

5. Conclusions

1. Systematic screening of the 67-well inventory identified 25 wells with repeated logging-run temperatures recorded at comparable depths and different shut-in times, satisfying the data requirements for Horner correction. This allows static formation temperature to be estimated using a physically based borehole thermal-recovery method rather than a depth-only empirical correction.

2. Horner-corrected formation temperatures range from about 88 to 154 °C, and apparent geothermal gradients from about 39 to 51 °C/km (basin median $\approx$ 44 °C/km), defining a coherent, near-linear basin temperature-depth trend ($R^2 \approx 0.83$).

3. Well BS1 (Ban Don Sa-Nuan) is the strongest temperature-led candidate, with $T_f \approx 154$ °C, a gradient of ~ 50 °C/km, and an estimated depth to 150 °C of about 2.45 km. The Ban Don Sa-Nuan–Sang Krajai-U-Thong trend defines the most favourable fairway.

4. A preliminary target window of about 2.4–2.9 km is suggested for 150 °C objectives in the high and moderate candidates, pending confirmation of reservoir permeability, fluid productivity, and equilibrium temperature.

Acknowledgement

The authors gratefully acknowledge PTTEP for providing the subsurface data used in this study. The authors also acknowledge SLB for providing an academic license of Petrel software.

References

Bachu, S., 2003. Screening and ranking of sedimentary basins for sequestration of CO₂ in geological media in response to climate change. *Environmental Geology*, 44(3), 277–289.

- Beardsmore, G.R. and Cull, J.P., 2001. *Crustal Heat Flow: A Guide to Measurement and Modelling*. Cambridge University Press, Cambridge.
- Bradshaw, J., Bachu, S., Bonijoly, D., Burruss, R., Holloway, S., Christensen, N.P. and Mathiassen, O.M., 2007. CO₂ storage capacity estimation: issues and development of standards. *International Journal of Greenhouse Gas Control*, 1(1), 62–68.
- Bredehoeft, J.D. and Papadopoulos, I.S., 1965. Rates of vertical groundwater movement estimated from the earth's thermal profile. *Water Resources Research*, 1(2), 325–328.
- Climate Analytics, 2019. Country profile Thailand: Decarbonising south and southeast asia. Available at: <https://climateanalytics.org/media/decarbonisingasia2019-profile-thailand-climateanalytics.pdf>
- DiPippo, R., 2012. *Geothermal Power Plants: Principles, Applications, Case Studies and Environmental Impact*, 3rd ed. Butterworth-Heinemann, Oxford.
- Dowdle, W.L. and Cobb, W.M., 1975. Static formation temperature from well logs — an empirical method. *Journal of Petroleum Technology*, 27(11), 1326–1330.
- Fertl, W.H. and Wichmann, P.A., 1977. How to determine static bottom-hole temperature from well log data. *World Oil*, 184(1), 105–106.
- Franco, A. and Villani, M., 2009. Optimal design of binary cycle power plants for water-dominated, medium-temperature geothermal fields. *Geothermics*, 38(4), 379–391.
- Garven, G., 1995. Continental-scale groundwater flow and geologic processes. *Annual Review of Earth and Planetary Sciences*, 23, 89–117.
- Horner, D.R., 1951. Pressure build-up in wells. *Proceedings of the 3rd World Petroleum Congress, The Hague, Section II*, 503–521.
- Lun, J.W. and Boyd, T.L., 2006. Direct utilization of geothermal energy 2015 worldwide review. *Geothermics*, 60, 66–93.
- Metz, B., Davidson, O., De Coninck, H.C., Loos, M. and Meyer, L., 2005. *IPCC special report on carbon dioxide capture and storage*. Cambridge: Cambridge University Press.
- Moeck, I.S., 2014. Catalog of geothermal play types based on geologic controls. *Renewable and Sustainable Energy Reviews*, 37, 867–882.
- Moeck, I.S. and Beardsmore, G.R., 2014. A new "geothermal play type" catalog: streamlining exploration decision making. *Proceedings of the 39th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California*.

- Morley, C.K. and Racey, A., 2011. Tertiary stratigraphy. In: Ridd, M.F., Barber, A.J. and Crow, M.J. (eds.), *The Geology of Thailand*. Geological Society of London, 223–271.
- Morley, C.K., Charusiri, P. and Watkinson, I.M., 2011. Structural geology of Thailand during the Cenozoic. In: Ridd, M.F., Barber, A.J. and Crow, M.J. (eds.), *The Geology of Thailand*. Geological Society of London, 273–334.
- Muffler, P. and Cataldi, R., 1978. Methods for regional assessment of geothermal resources. *Geothermics*, 7(2–4), 53–89.
- Olasolo, P., Juárez, M.C., Morales, M.P., D’Amico, S. and Liarte, I.A., 2016. Enhanced geothermal systems (EGS): A review. *Renewable and Sustainable Energy Reviews*, 56, 133–144.
- Petersen, H.I. and Mathiesen, A., 2007. Determination of the temperature history for the U Thong oilfield area (Suphan Buri Basin, central Thailand) using a realistic surface temperature. *Journal of Petroleum Geology*, 30(3), 289–296.
- Polachan, S., Praditjan, S., Tongtaow, C., Janmaha, S., Intarawijitr, K. and Sangsuwan, C., 1991. Development of Cenozoic basins in Thailand. *Marine and Petroleum Geology*, 8(1), 84–97.
- Ratanasthien, B., Chompoosri, S., and Mathatthanachai, T., 1997. Deposition environment of Mae Moh Basin as indicated by coal petrography. In *Proceedings of the International Conference on Stratigraphy and Tectonic Evolution of Southeast Asia and the South Pacific*. Department of Mineral Resources, Thailand, 605–176.
- Ronghe, S. and Surarat, K., 2002. Acoustic impedance interpretation for sand distribution adjacent to a rift boundary fault, Suphan Basin, Thailand. *AAPG Bulletin*, 86(10), 1753–1771.
- Smith, L., and Chapman, D.S., 1983. On the thermal effects of groundwater flow: 1. Regional scale systems. *Journal of Geophysical Research: Solid Earth*, 88(B1), 593–608.
- Tester, J.W., Anderson, B.J., Batchelor, A.S., et al., 2006. *The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century*. Massachusetts Institute of Technology / Idaho National Laboratory, INL/EXT-06-11746.
- Williams, C.F., Reed, M.J. and Mariner, R.H., 2008. A review of methods applied by the U.S. Geological Survey in the assessment of identified geothermal resources. U.S. Geological Survey Open-File Report 2008-1296.