KARKAR, ARMENIA – SLIMHOLE DRILLING AND TESTING RESULTS AND REMOTE PROJECT MANAGEMENT OVERVIEW

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ABSTRACT

Two exploration slimhole wells have been completed to ~1600 m depth and tested at the Karkar Geothermal Field in Armenia. Results from the two wells indicate a geothermal resource with temperatures >120°C at ~1500 m depth with conductive bottomhole gradients of ~30°C/km, indicating possible temperatures of >160°C at viable drilling depths. Permeability in the tested lithologic sections is limited, however feasible permeability at commercial temperatures has been discovered to >3000 m depths in analogous fields throughout other geothermal areas in the world. The first exploration well, B-1, was completed and tested in September 2016. The second well, B-2, was completed and tested in November 2016.

The Armenian Renewable Resources and Energy Efficiency Fund (R2E2), an Armenian government affiliated company, is exploring the Karkar Geothermal Field to assess the geothermal energy potential of the site. Multiple companies from various countries collaborated to complete the project successfully. This included the World Bank (financial overseer), ISOR (Iceland, technical overseer), GM Engineering (Turkey, drilling), JRG Energy (New Zealand, well testing and geoscience), Sisian Passenger and Freight (Armenia, rig camp and transport).

The paper summarizes resource data collected from wells B-1 and B-2 and integrates the newly acquired results into the previous conceptual model for the Karkar Geothermal Field as a whole. This paper also summarizes the international project management efforts along with explanation of lessons learned and competitive strategies for future remote projects. Additional conclusions and recommendations are offered for future consideration.

1. BACKGROUND

1.1 Regional Geology

The Karkar Geothermal field is located within the Karkar volcanic field ~3 km north of Mt. Karkar in the Caucus Mountains of southern Armenia, near the town of Sisian (Figure 1). Elevation in the exploration area ranges from ~2500 to 3500 m above sea level (masl).

Armenia is located within a convergent tectonic environment between the Arabian and Eurasian plates. Regional strain is accommodated by east–west trending folds and thrust faults, as well as through block rotation and a complex network of strike-slip faults (White et al, 2015). Basaltic to rhyolitic volcanism is expressed in the region by a number of stratovolcanos in addition to Mt. Karkar, including Mt. Ararat near the Turkey-Armenian border. The dextral Pambak–Sevan–Sunik fault extends nearly 400 km from the border with Iran in the south to the border with Turkey and Georgia in the northwest (White et al, 2015). One section of this fault system - the Sunik section – traverses the Karkar volcanic field and is characterized by multiple small fault strands, and variably dilational and contractional bends and step-overs (Karakhanian et al., 2004). The Karkar volcanic field lies in one of the most prominent stepovers, where the Sunik fault trends northwest and makes a 15 km right step (White et al, 2015).

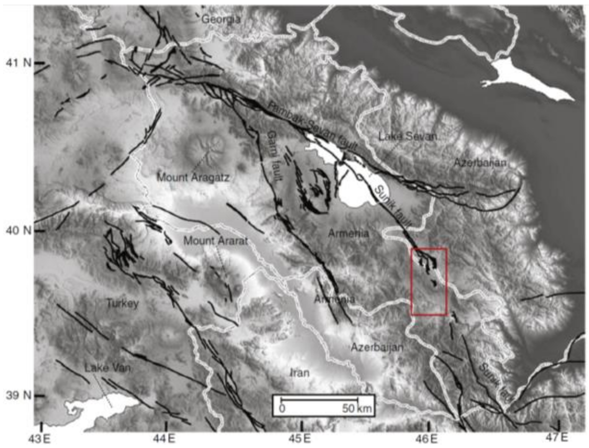

Figure 1. Regional structural map from Georisk (2012). Karkar area outlined in red.

1.2 Karkar Volcanic Field

The Karkar volcanic field contains the youngest volcanism in Armenia, consisting of Pleistocene to Holocene-age basaltic, andesitic, dacitic and rhyolitic flows and domes. Eruptive centers are aligned roughly north-south (Georisk, 2009). The youngest known eruptions in the area have been dated to 5000 +/- 300 years ago (ya) based on lava flows from cinder cones which bury Bronze-age petroglyphs and gravesites dated with archaeological techniques (GVP, 2017).

Structural mapping has identified a narrow 2–3 km wide zone of north-trending oblique right-lateral strike-slip faults with a minimum offset of 700 m bounding a shallow basin overlapping the Karkar volcanic field (Karakhanian et al, 2004; Georisk, 2009).

The only geothermal surface expression in the field is the Jermaghbyur Hot Spring, a ~30°C bicarbonate spring with high CO_2 gas flux located ~2 km west of the exploration area.

Figure 2. Photographs of the Karkar drilling location (left) and Jermaghbyur Hot Spring (right).

1.3 Previous Exploration

An exploration borehole, N-4, was drilled to ~1000 m depth by the Soviet Union in ~1988. This borehole encountered a shallow volcanic and alluvial cover to 123 m, underlain to total depth by an intrusion logged as quartz monzonite (White et al, 2015). The borehole was reportedly impermeable and a conductive thermal gradient was measured of ~100°C/km with a maximum bottomhole temperature of ~92°C.

Between 1988 and 2009 various surface geoscience studies were performed by the government of Armenia including magneto-telluric (MT), gravimetry and magnetometry surveys along two profiles through the area (Georisk, 2009).

Georisk performed surface geothermal exploration studies including geologic mapping, geochemistry of the hot spring waters, MT surveys, ground-penetrating radar, and soil gas sampling (Georisk, 2009). A conceptual model of the Karkar geothermal field was developed consisting of either a moderate-temperature reservoir fed by deep circulation along the strike-slip fault zone, or a high-temperature reservoir with a magmatic heat source. Drilling targets were focused on the fault zone and small basin 1 km east of borehole N-4 (Georisk, 2009).

A high-resolution gravity survey of the basin was completed in 2011 and a 3D inversion of the data modeled the basement contact (White et al, 2015). This study included a hydrological model based in part on inferred heat flux form borehole N-4 and concluded that a low-moderate temperature convecting geothermal reservoir was most likely (White et al, 2015).

2. REMOTE PROJECT MANAGEMENT

The project was managed by the Armenia Renewable Resources and Energy Efficiency Fund (R2E2) with an Icelandic Geothermal Consultancy company (ISOR) providing technical oversight. Financial oversight and funding was provided by the World Bank. All aspects of the project bidding process were publicized and made available via a RFP process.

The drilling of the two slim-wells was awarded to GM Engineering, a Turkish drilling and engineering company, with the partnership of Sisian Passenger and Freight (SPAF), an Armenian company providing the rig camp, customs process and transport. The drilling rig itself came from Turkey via the Georgian border for national customs reasons. A camp was constructed and managed by SPAF to accommodate domestic and international workers.

Project Management of the Karkar Slimhole Well Testing and Logging project was awarded to JRG Energy, a New Zealand engineering and consultancy company. The JRG Energy team was made up of personnel from both New Zealand and the United States. An early site visit and final contract negotiation was made by JRG Energy management and project managers of the R2E2 team.

Initial arrangements and preparation of the equipment used for all aspects of the project were made in each respective country. This presented a number of challenges such as language barriers, time differences, technical nomenclature, inability to properly inspect equipment, differences in operational standards, differences in health and safety standards, vast differences in cost structures and political conflicts between countries in this area. These challenges ultimately were overcome but contributed to many delays and frustrations throughout the project.

In regards to the welltest and wireline equipment, it became apparent that it would not be possible to use all domestic equipment as this was the first project of its' kind in Armenia. Thus it was necessary to use imported equipment for most of the wireline and welltest equipment. This provided a series of challenges such as: import taxes and customs requirements, the significant duration required for shipping and the associated costs of importation/exportation. Thus, a number of different suppliers were contacted and asked to provide bids for wireline equipment. A total of six (6) different companies representing four (4) different countries placed bids for the work. Decision for the equipment provider was ultimately made based on equipment specifications, equipment quality, costs of operating, cost of mobilization, cost of importation/exportation and experience of personnel accompanying the equipment. In the end, a Turkish subcontractor was awarded the work to provide a wireline unit and associated operators. Specialized equipment was sourced from the US and New Zealand and hand carried with JRG Energy personnel to the wellsite rather than hassle with international shipping.

International communication was challenging once the team had arrived in Armenia as the connectivity and telecommunications available were limited. Equipment troubleshooting, transport issues and travel requests were communicated via emails when possible but always with delays. A satellite phone was provided to the team to provide communication in case of emergencies while on site.

Site conditions presented unique challenges for the project. The second well was completed during winter months, exposing the team to extreme weather conditions. This created problems from a health and safety point of view and also limited site access due to road conditions. At one stage, the site was inaccessible for several days at a time, stranding members of the GM Drilling team and JRG Energy team at the wellsite until the weather eased.

Cultural differences created unique challenges for all parties involved in the project. Differences in work ethics, HSE practices and historical conflict between different countries made site activities difficult and often hindered progress substantially. Cultural differences and attitudes improved during the drilling of the second well despite adverse weather conditions and technical complications.

Due to the number of contractors and work parties on site, a pragmatic and practical approach was taken to health and safety. Each work party had their own health and safety practices and procedures which they worked under, however when looking at the health and safety of the site overall, a practical stance was taken. This included integration of best work practices for the whole site with very little bureaucracy initiatives, as personal safety was the clear priority on site.

3. EXPLORATORY DRILLING

Well B-1 was spud on 15-July-2016 at a location in the volcanic depression (basin) ~500 m southeast of a volcanic dome (Figure 3). The target of the well was the low-resistivity anomaly in the basin and hot geothermal flowing fluid that may have been located in the N-S fault zone (ISOR, 2012). The well was rotary drilled to a total depth (TD) of 1496.7 m and completed on 21-September-2016.

Well B-2 was spud on 13-October-2016 at a location ~500 m west of B-1 (Figure 3). The target of the well was the low-resistivity anomaly in the basin and hot geothermal flowing fluid that may have been located in the N-S fault zone (ISOR, 2012). The well was rotary drilled to a total depth (TD) of 1684 m and completed on 28-November-2016.

Well	B1	B2
Date Drilled	15-July-2016	28-November-2016
Well Test Date	22-29 September 2016	29-November-2016
Working flange	Recovery tube in BOP	Recovery tube in BOP
Total drilled depth	1496.7 m CHF	1684 m CHF
Production Casing	7”, 0 – 658.5 m CHF	7”: 0 – 716.8 m CHF
Liner	4 ½”; 646.5 – 1493.5 m CHF	4 ½”; 684.8 – 1678.8 m CHF
RKB to CHF	3.55 m	3.55 m
Max deviation	n/a	n/a
Loss zone - TLC	1100 m CHF	1657 m CHF
Loss zone(s) - PLC	1450 m CHF; ≈ 800m - drill string stuck at this depth	n/a

CHF = Casing Head Flange
TLC – Total Loss Circulation
PLC – Partial Loss Circulation

Table 1: Summary of Wells B-1 and B-2

3.1 Lithology

Mudlogging and wellsite geology were provided by Geolog. Interpretation and geologic modeling was provided by JRG Energy and Geologica. Interpreted summary well logs for B-1 and B-2 are provided in Figure 5 and Figure 6.

The lithology of B-1 differs significantly from the reported lithology of N-4, ~1.5 km to the west. N-4 encountered alluvium and volcanics to 123 m and then a quartz monzanite/granosyenite intrusive from 123 m to the TD of 1000 m (Figure 5). The difference in lithologies may be attributed to the highly variable geology of volcanic provinces and the fact that B-1 was drilled in an extensional pull-apart basin which has likely down-dropped relative to the N-4 location and has a deeper basement contact as identified by gravity modeling (Georisk, 2012; White et al, 2015).

Well B-1 encountered young Quaternary volcanic rocks consisting largely of tuffs with occasional interbedded lava flows to a depth of 1075 m where the Paleozoic basement rocks were reached. The interbedded lavas included basalt flows to 205 m, but not below. The basement rocks consist largely of mica-schist occasionally interbedded with other types of meta-sediments including dolomitic marble, greywacke and ophiolites. A granitic body, likely an intrusion, was encountered from 1124 to 1180 m. Below the granitic body and to TD the meta-sediments do not include greywacke. Table 2 below summarizes the lithologies encountered in B-1.

Hydrothermal alteration of the primary lithologies, in general, is of low intensity and low temperature. Smectite alteration was first logged at ~960 m. Higher-grade alteration minerals such as illlite were not observed, however they may exist and could be identified with laboratory analysis of the cuttings. The Paleozoic basement rocks are of course highly altered, but this is due to ancient metamorphism.

Depth (m CFH)	Lithology
60-205	Tuffs interbedded with occasional basalt lava flows, andesites, and diorites
205-1075	Tuffs interbedded with occasional andesites and diorites
1075-1124	Meta-sediments (dolomitic marble, greywacke, ophiolite)
1124-1180	Granite
1180-1500	Meta-sediments (mica-schist, marble)

Table 2: Summary of well B-1 lithology.

Interpretation of cuttings logged by the mud loggers at the wellsite showed well B-2 encountered a quartz monzonite to ~240 m depth underlain by young Quaternary volcanic rocks consisting largely of tuffs with occasional interbedded lava flows to a depth of ~1025 m where the Paleozoic basement rocks were reached (Figure 6). The basement rocks consist largely of mica-schist occasionally interbedded with other types of meta-sediments including dolomitic marble, greywacke, quartzite, serpentinite, and ophiolites. Table 3 below summarizes the lithologies encountered in B-2.

Hydrothermal alteration of the primary lithologies, in general, is of low intensity and the observed minerals indicate low temperature. Smectite alteration was first logged at ~290 m. Higher-grade alteration minerals such as illlite were not observed, however they may exist and could be identified with laboratory analysis of the cuttings. The Paleozoic basement rocks are of course highly altered but this could be due to ancient metamorphism.

Depth (m CFH)	Lithology
0-155	No data
155-241	Quart Monzonite
241-1025	Tuffs interbedded with occasional basalt lava flows, andesites, and diorites
1025-1684	Meta-sediments (dolomitic marble, greywacke, quartzite, serpentinite, ophiolite)

Table 3: Summary of well B-2 lithology.

The lithology of B-2 is similar to B-1 with the exception of the shallow quartz monzonite. This quartz monzonite may be the same unit that dominated the logged lithology of the N-4 well to the west. The difference between B-1 and B-2 lithology reflects the highly variable geology of volcanic provinces. B-1 was drilled in an extensional pull-apart basin which was likely down-dropped relative to the B-2 location and has a deeper basement contact as identified by well lithologic logging and gravity modeling (Georisk, 2012; White et al, 2015).

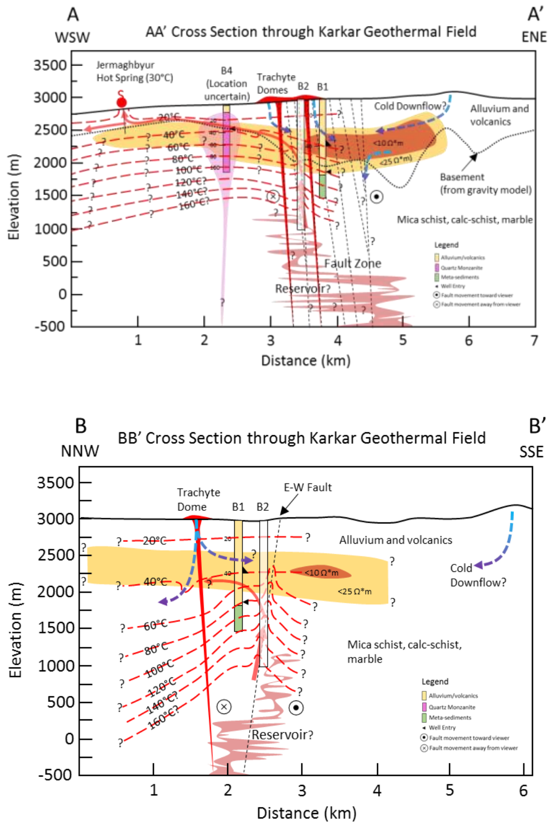

Figure 3: Cross Sections AA' and BB' illustrating the conceptual model of the Karkar geothermal Field.

3.2 Drilling Observations

3.2.1 Loss Zones

Well B-1 encountered several zones of permeability during drilling where drilling fluids were partially or totally lost to formation. Table 4 below summarizes the loss zones encountered during drilling. The loss zone at 850 m resulted in a stuck pipe situation and was later cemented.

All of the total loss zones occurred in the Quaternary volcanic overlying the Paleozoic basement rocks, except for the zone at 1106 m which produced H2S gas and black water. This zone is located within the package of meta-sediments containing dolomitic marble, greywacke and ophiolite. Both the H2S gas and black water may be related to hydrothermally-altered sulfur-bearing rocks and/or organic material within the buried sediments.

Depth (m CFH)	Losses
152-155	Total Losses
550-554	Total Losses
850	Total Losses, zone cemented, stuck pipe observed
1000-1006	Total Losses
1057	Total Losses
1106	Total Losses, H2S and black water produced on subsequent bit trips

Table 4: Summary of well B-1 loss zones.

Well B-2 did not encounter the intermediate depth mud loss zones encountered in B-1. The only losses occurred during drilling near TD, where drilling fluids were partially or totally lost to the formation. Table 5 below summarizes the loss zones encountered during drilling.

Depth (m CFH)	Losses
1576	Partial Losses
1660-1665	Total Losses, CO_2=20%
1670-1675	Partial Losses, CO_2=23%

Table 5: Summary of well B-2 loss zones.

4. WELL LOGGING AND TESTING

4.1 B-1 Well Testing

JRG Energy began completion testing of well B-1 on 23-September-2016. A dummy tool was run initially to verify the maximum open depth of the well for safe logging. This depth was found to be ~1490 m CHF, indicating ~10 m of fill material had accumulated on bottom. An initial static pressure-temperature-spinner (PTS) log was completed on slick line with a Kuster Quantum memory logging tool. Flowing PTS logs were completed on 24-September-2016 during the injectivity testing consisting of a three flow rate injection test followed by a pressure fall off test during which the Kuster tool was hung ~10 m off bottom at ~1480 m.

Additional dummy tool runs and heat-up static surveys were completed at approximately the 24 hour mark after injection ceased, at the 48 hour mark, at the 4-day mark and at the 6-day mark. Material, possibly cuttings, continued to fill the bottom of the well between each survey, resulting in progressively shallower maximum logging depths. The 48 hour, 4-day, and 6-day surveys logged to ~1460 m depth.

4.1.1 B-1: Temperature and Pressure

Logging after the 96 hour survey indicates that the maximum temperature is ~116°C at ~1460 m. The small isothermal anomalies in the first and third static surveys are likely due to the Kuster tool being buried in the muddy fill material at the bottom of the well. The anomalously high bottom hole temperature in the second static survey, when a temperature of ~118°C was measured, may be due to transient temperature effects.

The temperature gradient in the bottom ~150 m of the well is up to 100°C/km and similar to the bottom hole gradient in well B-4 at ~850 m (~120°C/km), although somewhat lower. The final natural state bottom hole gradient is not yet clear, but temperature gradients of this magnitude are indicative of high heat flow and are typical of geothermal systems around the world.

The maximum static pressures were logged during the fifth static survey (5 day survey) with ~130 bar measured at ~1460 m. This corresponds to a static water level at a depth of ~113 m. The static water levels have progressively shallowed between the five static surveys, indicating the well is filling with fluid.

4.1.2 B-1: Permeability

The completion test produced a good pressure falloff test (PFO), indicating an injectivity of 7 tons per hour per bar (t/h.b.). This is considered to be low to moderate permeability by conventional geothermal standards.

Analysis of the spinner logs and temperature transients allows identification of permeable intervals. The dominant entry appears to be the zone at ~795 m where spinner data indicates the well is inflowing with intra-wellbore flow down the well to an outflow zone at ~1075 m. The flow is around 80 litres per minute (lpm). This dominant feed zone appears to be less than 90°C (and probably closer to 70°C) and is not the zone of interest for geothermal electricity production; although it could be utilized in a direct use/district heating application.

Secondary feed zones appear to exist at 1195 m and 1263 m. This correlates with lithology changes around the granite body and a package of meta-sediments including dolomitic marble, greywacke and ophiolites. These lithologies may be in place or they may represent an exotic block of rock moved to this location by fault displacement.

4.2 B-2 Well Testing

JRG Energy began completion testing of well B-2 on 29-November-2016, approximately 28 hours after the end of circulation. A dummy tool was run initially to verify the maximum open depth of the well and to verify safe logging conditions. This depth was found to be ~1630 m, indicating ~50 m of fill material had accumulated on bottom.

The testing plan for B-2 was somewhat abbreviated relative to B-1 due to water supply issues related to frozen lines and the onset of winter weather. Despite these challenges good testing data was collected. An initial static pressure-temperature-spinner (PTS) log was completed on slick line with a Kuster Quantum memory logging tool. A 6-hour heat-up run was completed in the afternoon of 29-November-2016. A 24-hour heat up run completed in the morning of 30-November-2016 during which the fill was observed to have shallowed to ~1607 m. The material on bottom may be sloughing native formation, cuttings falling into the hole, settling drilling mud, or a combination of these things. Dynamic PTS logs were completed on 30-November-2016 during injectivity testing consisting of a two flow rate injection test followed by a pressure fall off test during which the Kuster tool was hung ~10 m off bottom at ~1600 m.

An attempt was made on 2-December-2016 to airlift the well with the drill string hung at ~600 m (~200 m below the static water depth) but the well did not flow. This is likely due to a number of factors including: the fact that the total loss zone at ~1660 m was covered with debris/sloughing material, the drill string in this situation could not be taken further into the well to displace fluid, and the permeability of the existing wellbore was very poor.

4.2.1 B-2: Temperature and Pressure

After the initial static survey, subsequent static surveys indicated that the maximum temperature of B-2 was ~124°C at ~1600 m. The temperatures were increasing up to the last survey, and may eventually stabilize at ~130-135°C at TD. The temperature profile of well B-2 may eventually be hotter than well N-4 after it fully heats up, as can be seen in the temperature-elevation profiles for wells B-2 and N-4 in Based on the evolution of the temperature in well B-2 between the three static surveys, the well may heat up another ~10°C. This prediction is supported by the Horner plot in Figure 4.

The temperature gradient in the bottom ~150 m of the well is ~30°C/km and lower than the bottom hole gradient in well B-1 at ~1450 m (~50-100°C/km). The gradient near the bottom of the well is lower than the gradient at more shallow depths, which is ~60°C/km. This falling gradient with depth may be indicative of proximity to a potential isothermal geothermal reservoir, which may have been encountered at the zone of total losses at ~1660 m.

The maximum static pressures were logged during the third static PTS survey with ~118 bar measured at ~1606 m. This corresponds to a static water level at a depth of ~382 m. The static water levels have progressively shallowed between the static PTS surveys, indicating the well is filling with fluid. This rise in water level is also partially due to the thermal expansion of the water in the wellbore as it heats up.

Note that the static water level in well B-1 was measured at ~113 m. This significant difference between the water levels of the two wells (>250 m) is indicative of very poor hydrological communication between the two wells over the open (uncased) depth interval. This suggests that well B-2 may have crossed a hydrological barrier such as an impermeable strand of the N-S fault zone. It should also be noted that, unlike well B-1, the basement contact in well B-2 does not appear to be permeable.

4.2.2 B2: Permeability

The injection test was carried out on 30 November. A PTS tool was placed at 690 m initially and held until the pumping stabilized. After stabilization occurred, two passes were performed and the tool was left at TD for the pressure fall-off.

A rough injectivity index (II) ~0.7 tph/bar was calculated during the multi-rate injection test. This is a very low II, but as stated above, does not represent the permeability likely present below ~1660 m.

Further analysis of the spinner logs and temperature transients allows identification of permeable intervals. There are no significant feed zones recognized in the logs, but a minor feed zone appears to exist at ~1576 m, which correlates with a zone of partial losses. Horner Plot analysis suggests the temperature of this zone is >120°C and may eventually heat up to >130°C (Figure 4). It must be noted that Horner temperature buildups are generally indicative rather than precise, being prone to inaccuracies. They are affected by drilling losses, and so are best in wells of low permeability, as is the case with B2. The plots do generate good straight lines, and indicate final temperatures a few degrees higher than the last log, with a maximum temperature of around 130°C. These plots do confirm that there are no markedly higher reservoir temperatures present near B-2.

The bottom of the well below 1576 m appears to be completely impermeable, however, the total losses at ~1660 m likely represented a zone of significant permeability. The temperature of this zone may be >130°C. Unfortunately, this zone could not be tested due to cuttings sloughing into the hole and filling the bottom of the well from 1684 to 1607 m.

There is small but significant flow from the casing shoe down to 800 m. This flow is then largely lost by 900 m, but the noise in the data is too great to specify losses within this interval. It may be that most of the loss is near 800 m, but this is not definite. Below 900 m there is only minor flow, so the zone 800-900 m is identified as the major permeable zone, with only minor permeability elsewhere in the well.

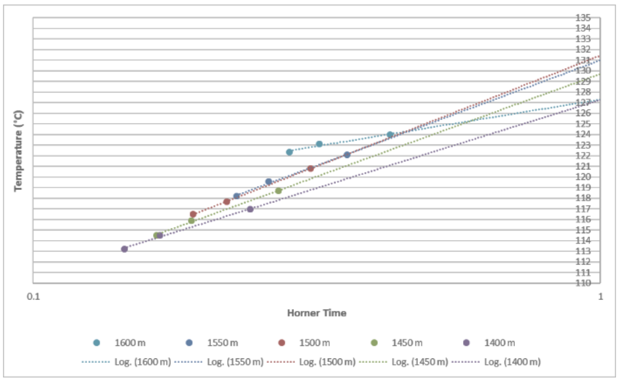

Figure 4: Horner Plot of temperatures at depths near the bottom of well B-2.

There is a pressure differential between the two wells of over 25 bar, indicating generally poor permeability – if there were some highly permeable structure elsewhere, but not intersected by the wells, it would still tend to equalize pressures across the area. This suggests overall low reservoir permeability between the two wells over the depth interval of the open hole sections, i.e. ~600 to 1700 m depth.

5. DISCUSSION

Data from wells B-1 and B-2 support the high temperature gradients and elevated temperatures of the Karkar Geothermal Field first discovered in well N-4. While the precise location of N-4 is unconfirmed (to within several hundred meters), wells B-1 and B-2 extend the area of this heat anomaly south into the pull-apart basin. The elevated conductive gradient at the bottom of B-2 has proven temperatures >120°C at less than 2000 m, and possibly >160°C at drillable depths. By analogy to commercial geothermal fields in similar basement rocks in, temperature gradients could decrease near intermediate aquifers and then increase again with greater depth.

The operating geothermal field at Gumuskoy in Turkey has lower temperature gradients than the Karkar wells (Kuyumcu et al, 2010). Well ORT-4 reached a max temp of 130°C at 2350 m. However elsewhere in the field there are commercial wells such as GK-1, drilled to 2100 m, which has a temperature of 178°C and flows 230 tph.

Similarly, in the Basin and Range in Nevada, the operating filed of Patua, has similar temperature profiles to Karkar at similar depths (Garg et al, 2015).

Based on analogy to these fields, deeper drilling could possibly encounter commercial permeability and temperatures at drillable depths.

CONCLUSION

The exploration drilling and testing completed by R2E2 has produced the following conclusions about the Karkar Geothermal Field:

- The main feed zone of well B-1 has a temperature <100°C. Therefore, it is not the zone of interest for commercial geothermal energy production. However, it may be useful for a direct use/district heating project.
- The bottom of well B-1 is >110°C, however there are no definitive feed zones at this temperature and therefore, cannot be utilized in B-1 production.
- The basement contact in B-1 is permeable but contains a mixture of hot outflowing and cold downflowing waters. It is not the zone of interest for geothermal production but could be useful for injection or direct use.
- No significant feed zones were able to be tested in well B-2. A zone of total lost circulation was encountered at ~1660 m but was covered in sloughing cuttings before it could be tested. If this zone could be tested it may have a temperature >130°C.
- If B-2 is deepened to 2000-3000 m it may encounter permeable zones at higher temperature within the basement rocks. This situation would be analogous to commercial geothermal fields in western Anatolia and in the western United States.
- Unlike well B-1, the basement contact in well B-2 is not permeable.
- As evidenced by the large difference in static water levels between wells B-1 and B-2, the two wells are not in good hydraulic communication. This may be due to B-2 crossing a hydrological barrier such as impermeable fault.

- The lateral extent of the Karkar Geothermal Field is unbounded in all directions. Deep temperatures in the basement rocks may fall of rapidly to the east of well B-1. B-2 may be the hottest well in the field after it fully heats up, but the upflow may also be located elsewhere.

- The temperatures and geothermometry of the Jermaghbyur Hot Spring are consistent with outflow of a geothermal system located to the east near wells B-1 and B-2.

LEARNINGS AND RECCOMENDATIONS

Remote project management introduced a number of complexities to the project, and thus, produced many valuable learnings upon completion. The following is a summary of some of these lessons along with technical recommendations for future success in Armenia:

- Equipment specifications on paper can be different than the actual status of the equipment when it arrives for a specific project. Discussions and decisions were made based on physical descriptions, photos, and diagrams. However, complications still arose from miscommunication and discrepancies with documentation. It is recommended for international operations to perform a visit to the equipment providers. If cost of travel is to deer, third party inspectors can be hired in the respective country or at minimal, a video conference call to inspect the equipment is advised.

- Cost of personnel and equipment for drilling and well test operations are fairly standardised in the oil and gas industry. This is mainly due to the high level of standards inflicted on all operating procedures. However, these international standards are not universally accepted across the geothermal industry. Thus, multiple quotations for equipment and personnel should be obtained from the respective countries of operation and weighed against other geothermal operating countries for direct comparison. However, additional consideration should be given to other factors such as operational standards and HSE standards of the operating company and equipment provider before making any decisions.

- Cultural differences and historical relations cannot be solved during the duration of a project. These obstacles should be planned for and dealt with accordingly before arriving on the project site. Separation of cultures and specific tasks seems unethical and backwards to some western civilisations, however is a necessity in certain areas of the world. The age old expression applies, “when in Rome”.

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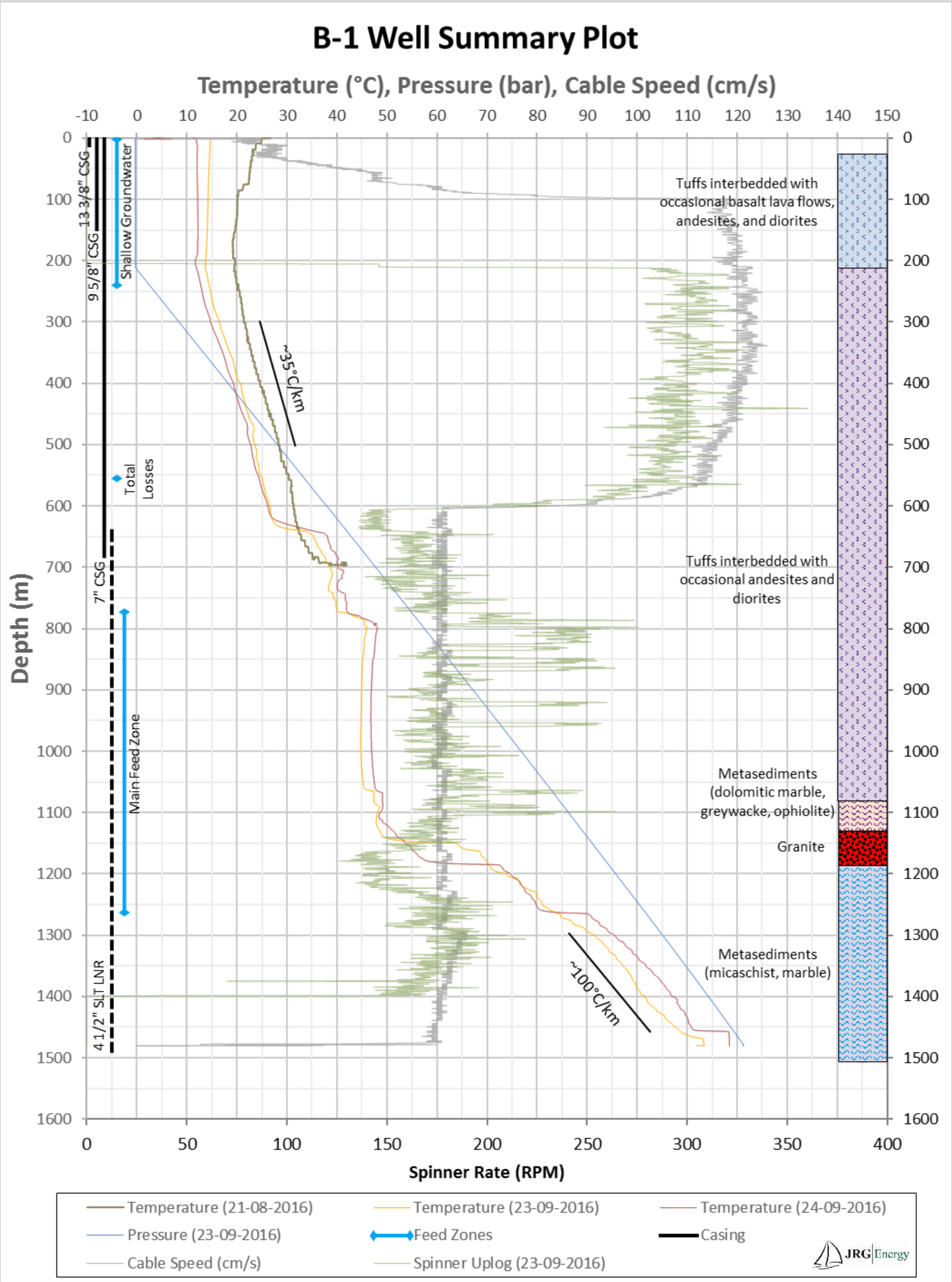

Figure 5: Summary plot of well B-1.

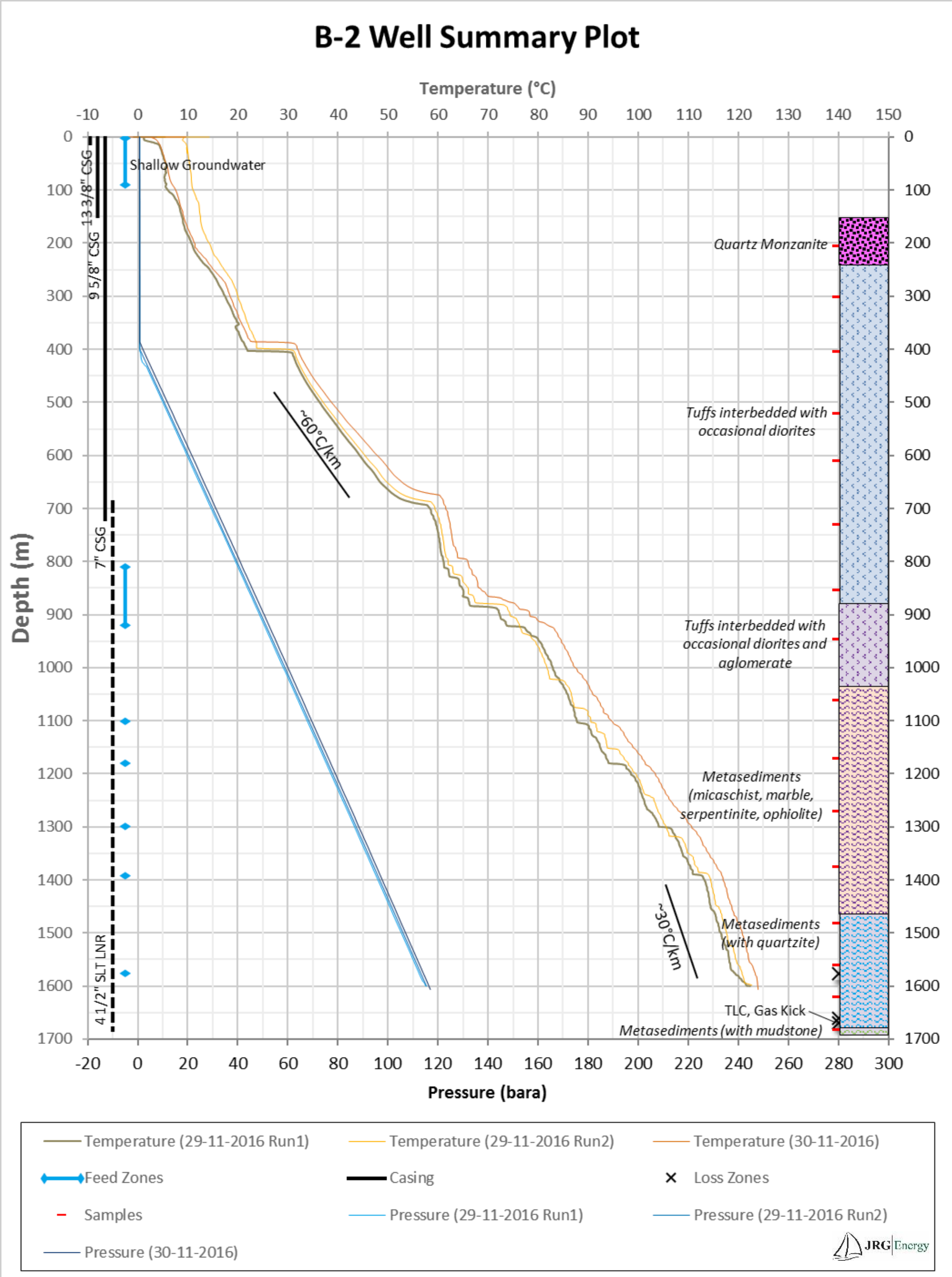

Figure 6: Summary plot of well B-2.

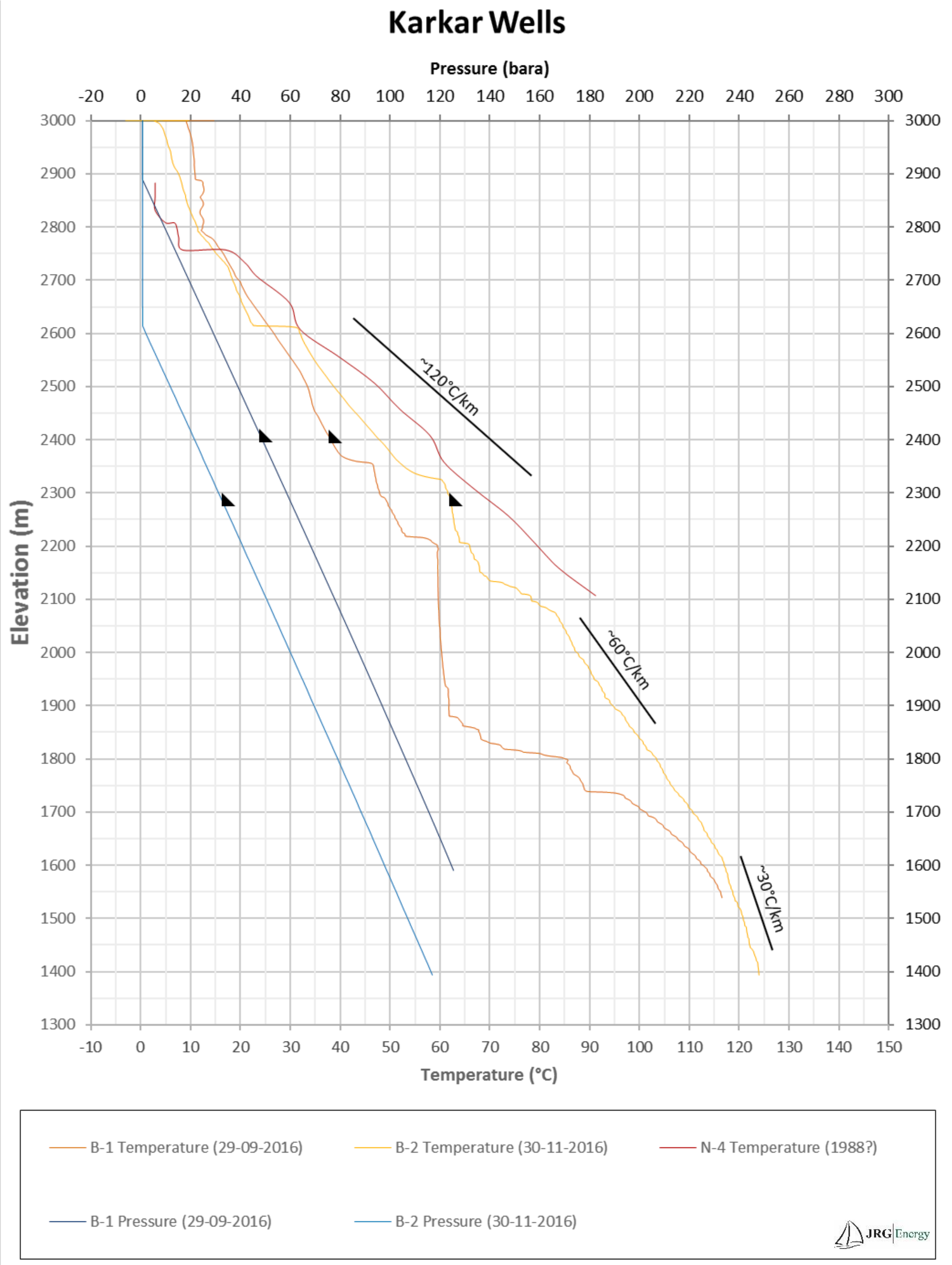

Figure 7: Summary temperature and pressure plots of the three Karkar wells.