Design of the Monitoring Program for AOSTRA's Underground Test Facility, Phase B Pilot

P.M. COLLINS
Consultant

Abstract

A monitoring program for an oil sands thermal recovery pilot project is described. New methods of monitoring were used to monitor the steam-assisted gravity drainage process, and to observe the reservoir's geomechanical response. In addition, the performance of the access tunnels and of the production wells' surface casings were also monitored. The types, quantities, and locations of instrumentation are described. Rationale for the selection of instrumentation is presented, and approximate costs are provided.

Background

The Alberta Oil Sands Technology and Research Authority's Underground Test Facility (AOSTRA UTF) is located 20 km west of Syncrude in the Athabasca oil sands deposit of north-eastern Alberta. The reservoir bottom is at a depth of 160 m and the pay is 20 m thick. At the reservoir temperature of 7°C, the viscosity of this 1.014 kg/l (8° gravity) bitumen is 5 Pa·s. The underburden consists of massive, undeformed Waterways Formation limestone. Open pit mining of this reservoir is uneconomic because of the low pay to overburden ratio, and the relatively thin pay is uneconomic to recover with in situ processes from vertical wells. Instead, the UTF project uses the Shaft And Tunnel Access Concept (SATAC) to gain access to the reservoir from tunnels within the limestone underburden. Horizontal well pairs were drilled into the oil sands from the tunnels.

Steam injection is concurrent with the bitumen and water production. The process operates at a constant pressure (below fracture pressure) and relies on gravity drainage to deplete the reservoir[1]. The Phase A "laboratory scale" pilot consisted of three pairs of 160 m wells, each with 55 m of completion, and was successful[2]. The subsequent Phase B pilot is operating, and consists of three pairs of 600 m wells, with 500 m completions.

Purpose

The intent of the monitoring program was to ensure the safety of the tunnels and wells, to quantify the success of the process, to confirm the geomechanical observations made during the Phase A laboratory scale pilot, and to assess methods of monitoring a commercial-scale project.

The SATAC approach to bitumen recovery was novel enough to warrant extensive instrumentation of the shaft and tunnels. The Phase A tunnels, which provide access to the underground wellheads, had to be safe for personnel, isolate them from the pressurized steam chamber, and allow for the continuous flow of steam and produced fluids between the wells and the surface. Given the observed integrity of the Phase A tunnels and the extremely consistent geology of the limestone underlying the UTF lease, the new Phase B tunnels have a reduced number of instrumented stations[3]. The program is sufficiently flexible to allow for supplementary instrumentation if warranted.

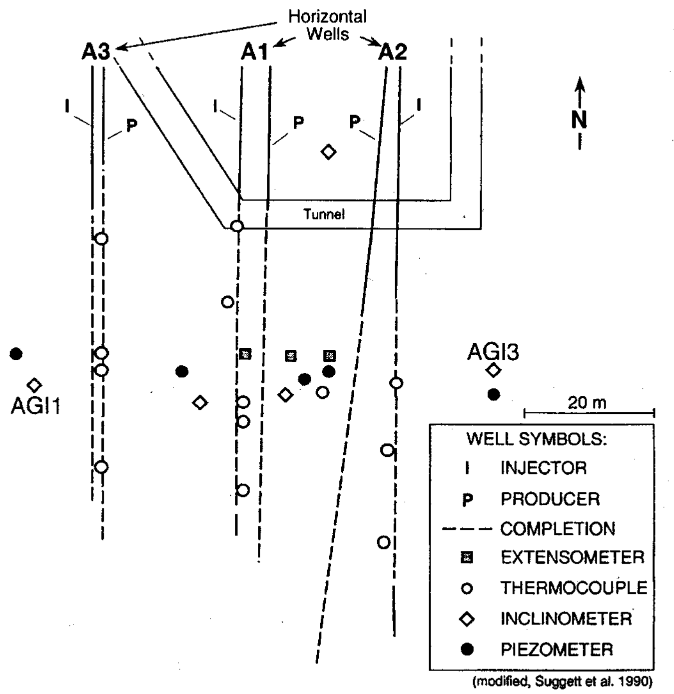


FIGURE 1: Plan of Phase A wells.

For interpretting the process results, the data obtained from surface instrumentation in the Phase A pilot was extremely useful. It was expected that the behaviour observed in the Phase A pilot would be applicable to the Phase B pilot and would therefore avoid the costs of using closely-spaced wells for monitoring small-scale phenomena. The challenge in Phase B was to choose monitoring techniques which could interpolate between isolated wells exhibiting known behaviour.

Geomechanical data collected from the Phase A pilot were unique in their completeness and density. Numerical models allowed a back-analysis of observed Phase A behaviour using results of laboratory tests[4] on the oil sands, the limestone underburden, and the capping mudstones at various temperatures and pressures. Trends observed in this analysis were extrapolated to those expected in Phase B and resulted in modifications to the

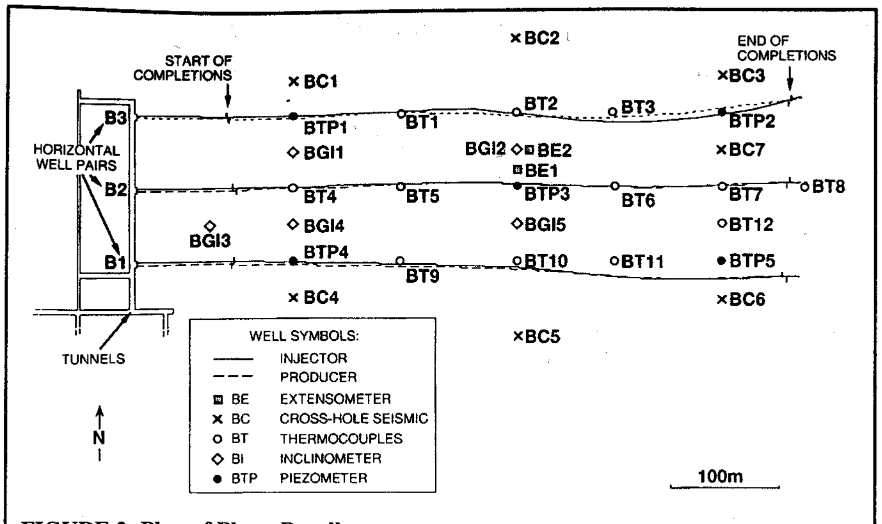


FIGURE 2: Plan of Phase B wells.

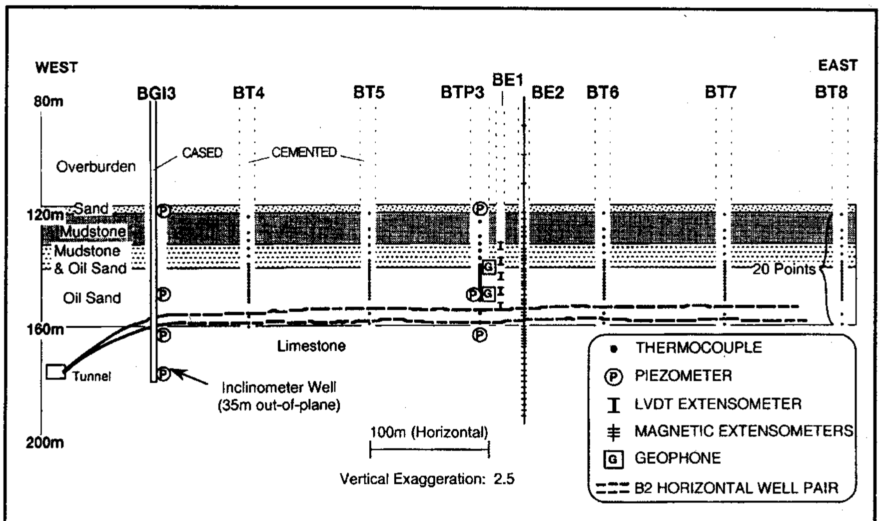


FIGURE 3: Phase B West-East cross-section.

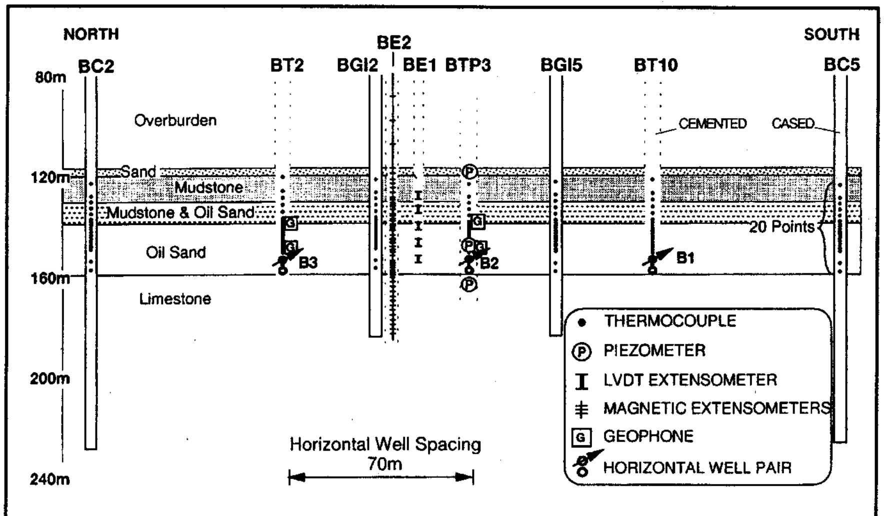


FIGURE 4: Phase B North-South cross-section.

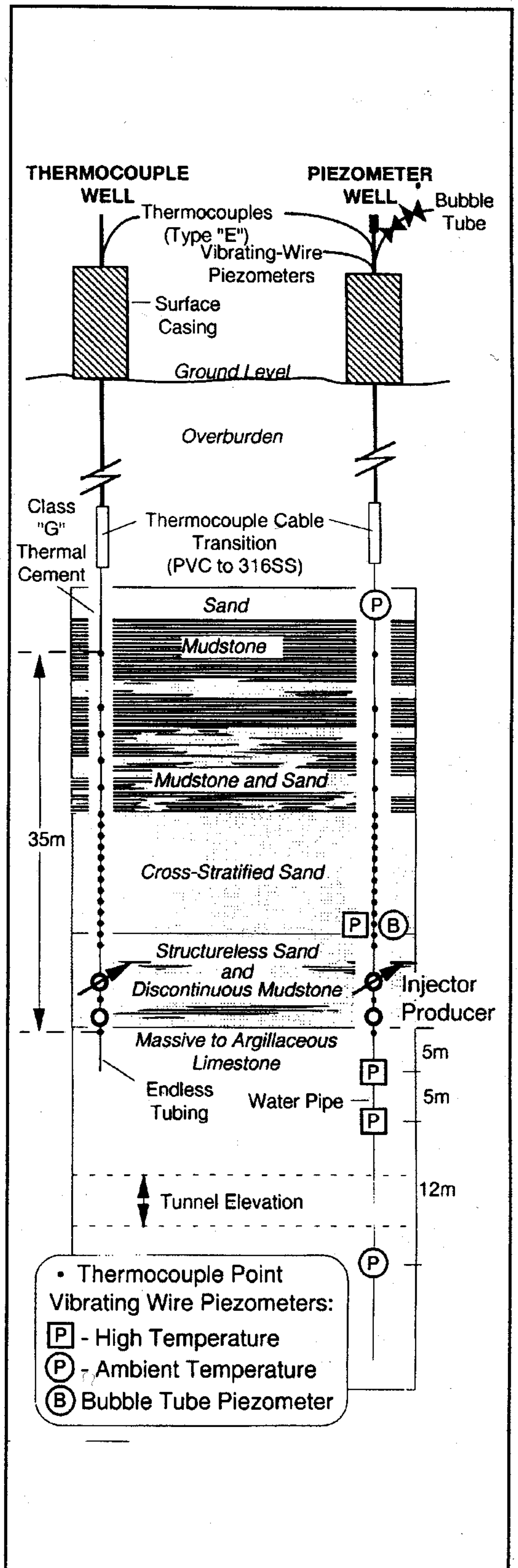


FIGURE 5: Thermocouple and piezometer distributions as related to geology.

instrumentation installed. Some instrumentation was intended to confirm the findings from the Phase A pilot.

The scaling-up of the UTF pilot from Phase A (Figure 1) to Phase B (Figure 2) resulted in a twenty-fold increase in area. The dense coverage of observation wells installed in Phase A[5,6] could not be justified for Phase B. Instead, the phenomena observed in the Phase A pattern were used to choose the optimal type and spacing of instrumentation for the Phase B pattern, with the dual purpose of quantifying the progress of the steam assisted gravity drainage (SAGD), and evaluating monitoring techniques for the commercial expansion of UTF. It was also recognized that some types of instrumentation provide very precise data from an extremely local portion of the reservoir (e.g. temperatures) while others provide more general information about an extended area of reservoir (e.g. surface heave analyses). Furthermore, some instrumentation could be read continuously while others only seasonally or annually due to their comparatively high survey costs. As a result, methods of monitoring the general behaviour of the entire pattern were pursued, and combined with some confirmatory specific instrumentation at one or two selected locations within the reservoir. Thus, the general behaviour could be correlated with the specific observations to infer the behaviour of the entire reservoir.

Well Layout

The Phase B well layout (Figure 2) was designed to detect both early steam chamber development and longer-term performance. The layout provides data along each well pair, and along three north-south cross-sections (Figures 3 and 4).

All wells include thermocouple strings for a precise measurement of thermal advance. The BT-series wells mostly lie along the intended alignment of the horizontal well pairs (Figure 2) and include a thermocouple point below the reservoir for underburden heat loss calculations, as well as a point between the injector and producer for monitoring breakthrough due to conductive heating of the interwell region, as seen in Figure 5. A dense spacing of thermocouple points above the well provides excellent data on steam chamber rise. The deteriorating quality of the reservoir above the basal 20 m will result in a reduction in the rate of steam chamber rise, therefore the points are more dispersed. Thermocouple points for the cased wells, a nominal 35 m from the injector/producer well pairs, are concentrated at the top of the 20 m pay since the lateral growth of the steam chamber will initially be seen at the top of the reservoir.

Well BT8 (Figure 3) is located to monitor end effects, as can be done with BGI3. Well BT12 was cemented instead of cased because it was believed that there was adequate inclinometer coverage throughout, and to seismically isolate its two cemented-in geophones from potential interference from tube waves.

The BTP-series piezometer wells criss-cross the Phase B pattern with piezometers. Vibrating-wire piezometers were installed in the sands of the Wabiskaw Formation above the capping mudstones, within the reservoir, and in the limestone underburden (Figure 5). Bubble tube piezometers were installed beside the piezometers within the reservoir, and one pneumatic piezometer is in the Wabiskaw Formation. These will serve as independent checks on the long-term stability of the vibrating-wire units. Additional piezometers were installed in the limestone in wells BTP1 and BTP4 because of their proximity to the tunnels. One vibrating-wire piezometer within the reservoir has already failed at ambient temperatures, and another is being examined to assess its reliability.

Piezometers were installed in Well BGI3 because of its close proximity to the tunnels. Piezometers were placed on the outside of the 114 mm (4.5 in.) casing, which may have resulted in a layer of cement between the piezometer sandpacks and the sandface. Pressure readings from this well appear reasonable. The continued performance of these units will be monitored to assess the necessity of any device to push the piezometer sandpack against the sandface.

All BC-series and BGI-series wells are surveyed and used for inclinometer wells to detect horizontal movements. The regular, wide spacing of these 12 wells allow a complete reconstruction of the lateral deformations within the reservoir as the process advances. Well BGI3 is particularly well-positioned as it will monitor movements affecting the shear movements of the horizontal well pairs as they enter the pay from the limestone below (Figure 3).

The seven BC-series wells are at spacings of 70 m, 140 m, 210 m, and 280 m (Figure 2). Seismic analyses of panels at these various spacings allow for an assessment of the ultimate range of the piezoelectric source and receiver. Interpolating between panels should permit a more accurate interpretation of the supposed local geology and subsequent process performance. The results of a preliminary analysis of the pre-steam cross-hole seismic data are good for the 70 m and 140 m panels, fair for the 210 m panel, and poor for the 280 m panel.

Cemented-in geophones were installed in wells BT2, BT12, and BTP3 as part of the seismic measurement-while-drilling (MWD) tests. These could also be used for microseismic monitoring.

All electrical instrumentation at surface is hard-wired into a central computer for report generation and archiving with a supervisory control and data acquisition (SCADA) system. Data gathered manually is entered separately. Data are recorded by the SCADA system every week. These are automatically supplemented by subsequent readings during significant changes in data in order to record events within the reservoir.

TABLE 1: Instrumentation locations and quantities.

Thermocouple	Reservoir	630
	Horizontal Wells	6
	Surface Casing	10
	Tunnels	99
	Heave Monuments	6
Vibrating Wire Piezometer	Reservoir	23
	Surface Casing	2
Pneumatic Piezometer	Reservoir	1
Bubble Tube Piezometer	Reservoir	6
	Horizontal Wells	2
Standpipe Piezometer	Tunnels	8
LVDT Extensometer	Reservoir	6
Magnetic Extensometer	Reservoir	80
Rod Extensometer	Tunnels	65
Heave Monument	Ground Surface	131
	Surface Casing	30
Convergence Pin	Tunnels	56
	Wellheads	6

Instrumentation

The nature of the information desired determined the type, quantity and quality of the instrumentation for Phase B. A summary of the instrumentation is presented in Table 1.

Thermocouples

From our Phase A experience, it was found that temperatures were the single most useful set of data for interpretting reservoir performance. In Phase A, temperature data were collected from the 26 observation wells drilled from surface with thermocouples either cemented into the open holes or hung within wells cased with 114 mm (4.5 in.) casing but with no completion to the reservoir. The wells were drilled subsequent to the placement of the horizontal wells and there was a concern that their cementing would result in a cement breakthrough to the horizontal wells, which would necessitate an acidizing treatment to remove the unwanted cement from the completion screens. To prevent this, the Phase A wells contiguous to the horizontal wells were shallow and did not extend through the full depth of the reservoir. An improvement used in Phase B was to install uncased vertical observation wells prior to horizontal drilling to allow for the instrumentation of the full depth of the reservoir. The possibility of drilling through an uncased vertical well during horizontal drilling was an accepted improbability.

In Phase A, temperatures were obtained from thermocouple bundles consisting of 8 to 12 strands of Type "E" thermocouples, each insulated with magnesium-oxide (MgO) and sheathed in 316 stainless steel (316SS). Each bundle had a transition to less expensive ambient-temperature thermocouple cable at a point above the expected heated zone. In Phase B, the number of points was increased to 20 because the incremental cost was insignificant compared to the total cost of the well and the value of the data, and because cementing the strings in place would prevent any repositioning of the points. These units are robust and can withstand installation, and Type E gives a fairly high signal-to-stimulus ratio. An alternate design consisting of a transition from Type E to copper wire at depth, with two reference temperature points at the

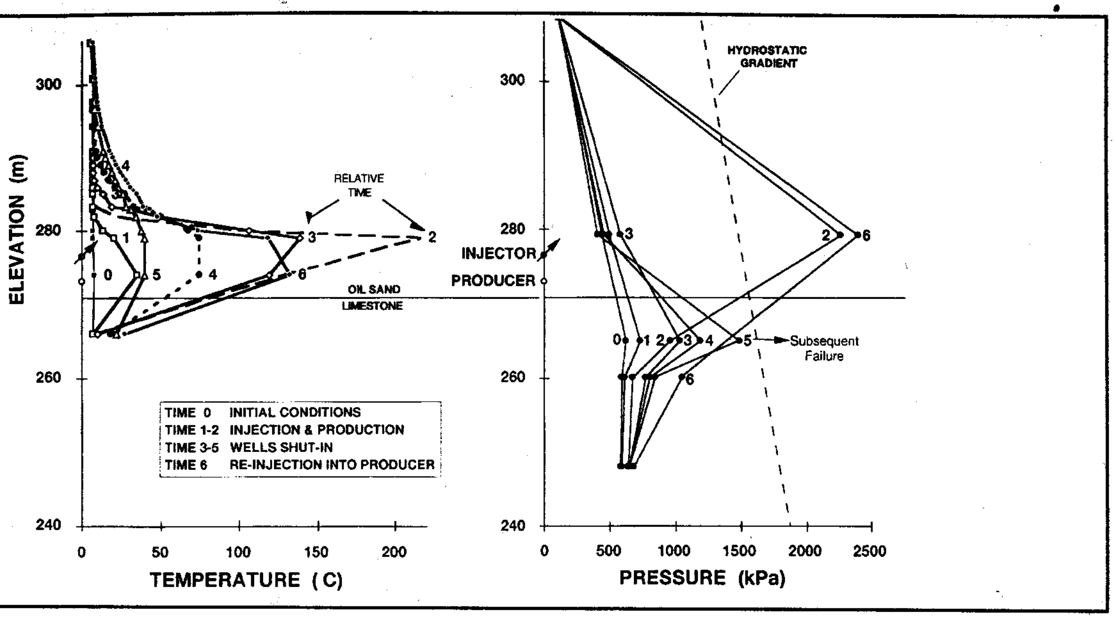


FIGURE 6: Temperature and pressure profiles, Well BTP1.

transition, was rejected since UTF's shallow depth would only result in a small cost savings and the cumulative precision errors in calibrating all readings to the reference readings would be too high. Deeper projects may consider such a cost-saving alternative.

The temperature data was extremely useful in the SAGD process since the mechanism is largely that of localized heating with the associated drainage of the bitumen and condensed water. The depleted volume of reservoir or "steam chamber" exhibits a sharp gas saturation boundary, with contiguous thermal gradients in the order of 50°C/m. In projects where the recovery mechanism is less dependent upon the placement of heat in the reservoir, temperature data would be less useful. The Phase A data allowed for a very precise determination of steam rise rates and lateral spread of the steam chamber, therefore the sparse Phase B layout will only allow for a confirmation of known behaviour. Should the Phase B thermal advance differ greatly from expectations, there are only limited opportunities to measure frontal advance. Produced bitumen volumes from Phase A correlated closely with the volume of the steam chamber as determined by the thermocouple data, and this relationship could be used to infer chamber growth between Phase B wells. The record of the Phase B steam rise rates will be more precise because of the increased density of points within each well, and the increased frequency of data collection that the SCADA system permits.

Some preliminary temperature profiles for Well BTP1 are presented in Figure 6. At Time 0, the well is at a uniform temperature, with a small residual temperature increase between the injector and producer well pair because of the warming effect of the drilling mud used for drilling the horizontal wells. During the SAGD process (Times 1 and 2), the temperatures at the elevation of the well pair have increased sharply, with the temperatures at the injector being highest. After these wells were shut-in during facilities expansion, Times 3 to 5 show the drop in reservoir temperature at the wellpair and the movement of heat into the underburden and overburden. Note the vertical temperature profile straddling the injector well, which indicates the presence of a steam chamber in that interval. Time 6 shows the effect of re-injecting steam into the production well in preparation for recommencing the SAGD process.

Thermocouples were installed into two of the injection wells and all three production wells. In each case, a single thermocouple point was pumped down the inner 89 mm (3.5 in.) tubing, attached to a wax-filled pig that latched to the end of the tubing. Once steaming began, the paraffin wax melted, allowing unrestricted flow through the tubing. The temperature at the end of the well indicates whether steam is reaching the far end. Heat losses down the well are important as this determines the optimum size of completion casing. On the centre well pair, an additional thermocouple point was installed in the producer well at the oil sands/limestone contact to quantify the heat loss to the underburden for the uncompleted segment of the casing.

Temperatures within the tunnel walls are monitored and correlated with movements of the rock around the tunnel to determine what percentage of these movements are due to thermal effects. Strings parallel to the injector and producer wells quantify the heat losses to the limestone. In Phase A, these temperatures were measured with strings of resistance temperature device (RTD) thermistors, however they failed when exposed to moisture. Phase B strings consist of 316SS-sheathed, Type E thermocouples which have proved to be more robust.

With the steam chamber being relatively close to the tunnels, there was a need to examine the integrity of the cement holding the surface casing in place. Samples were taken of the cement during cementing for subsequent curing and strength testing. One well pair was instrumented with thermocouple strings on the outside of the casing to obtain temperatures within the cement for future numerical modelling of the cement-casing performance. This diligence stems from minor leaks observed in Phase A: modifications to the surface casing design and cementing program have reduced the potential for leakage in Phase B.

Piezometers

In Phase A, there were 37 piezometers installed in piezometer wells across the main instrumented cross-section through the pattern (Figure 1). The density of these units allowed for a small-scale examination of the pressure transmissibility in the reservoir. Initial mobility appeared to be limited to the finer-grained lenses with lower bitumen saturations. After some steaming, the pressures were less dependent on geology and more dependent upon the process, and on geomechanical effects away from the steam chamber.

The piezometers installed in Phase B quantify the fluid pressure within the reservoir and the surrounding formations. Their distribution allows for trending of the pressures within the reservoir but the relatively sparse spacing would not allow for any small-scale examination of initial transmissibility. However, one major expectation is that the piezometers in the reservoir and in one injection well will provide data for optimizing the size of future wells.

In addition to the reservoir piezometers, additional units were placed in the Wabiskaw Formation sands above the capping mudstones (Figure 5). This underpressured aquifer is monitored for changes in pressure as a result of the process. Piezometers were also installed in the limestone underburden to assess the amount of leak-off to this formation and quantify the pressurization of argillaceous strata within. Other piezometers installed into the limestone from the tunnel ensure the safety and integrity of the facility's access. Wells BTP1 and BTP4 were drilled deeper to obtain core through to the tunnel elevation, and to allow for the instrumentation of more permeable strata at that elevation. For landing the piezometers within the target strata, field estimates of the permeability were inferred from the geolograph's record of increased drillability of these argillaceous units as compared to that of the massive, tight limestone units. It was determined that a fracture network within the argillaceous limestone resulted in the increased secondary permeability of this unit.

Vibrating-wire piezometers were used for Phase B. In Phase A, both vibrating wire and pneumatic piezometers were used with similar accuracies and longevities, however the pneumatic devices were uneconomic to automate, and they required two tubes to extend from the reservoir to surface. Unfortunately, the Viton O-rings used in both models were susceptible to failure under the high temperatures and pressures within this bituminous, sour environment and it was felt that the possible hazard inherent in the tubing of the pneumatic devices was unwarranted. One pneumatic device was installed in the Wabiskaw Formation above the reservoir to correct for any long-term drift in the calibration of the vibrating wire piezometers.

Before the instrumentation was installed, a laboratory test was conducted on one vibrating-wire piezometer. The device was subjected to increasing temperatures and pressures over three days to simulate field conditions. Upon depressuring, it was found that a significant non-recoverable strain had caused the pressure readings to drift by 300 kPa. This was unacceptable; therefore, the number of piezometers was reduced. Instead of having three piezometers stacked within the 20 m pay along the well, a single unit was located at the mid-point.

Preliminary pressure results are shown for Well BTP1 in Figure 6. Note that the initial gradient is parallel to the hydrostatic gradient, but that the reservoir is underpressured due to the influence of the low-pressured Wabiskaw Formation at the 309 m elevation. The pressure at the 248 m elevation shows the depressuring effect of the access tunnels on local hydrodynamics. During steam injection (Times 1 and 2), the pressure increase above the injector is rapid, with a delayed response in the limestone. During shut-in (Times 3 to 5) the pressure response in the reservoir is rapid. It is likely that the pressure response in the limestone at the 265 m elevation is due to a deteriorating instrument since the pressures monotonically increased before the unit failed prior to Time 6. At Time 6, the response to reinjection is immediate. The water pressure in the underburden has slowly increased due to the effect of the high pressure steam injection. There is no pressure change seen in the Wabiskaw Formation.

To provide an occasional check on the remaining vibrating wire piezometers within the reservoir, a bubble tube device was included at the same location. These consisted of a continuous length of 6.35 mm (0.25 in.) stainless steel tubing extending from the reservoir to surface. At the reservoir end was a check valve to prevent backflow. Below the check valve was a 3 m length of 10 mm stainless steel tube with a slotted tip imbedded in a 20/40 fracsand sandpack with a resin binder. In the unlikely event of a backflow into the device, the viscous bitumen can be more easily displaced in the larger 10 mm tube than in the 6.35 mm tubing by connecting a pressurized gas bomb at surface. The reservoir pressure is calculated using the shut-in pressure after pressurizing the tubing with nitrogen.

All vibrating-wire piezometers in the five piezometer wells were installed with a piezometer actuator device (Suggett, et al., 1990). This ensured excellent contact with the sandface and limited the chance of cement plugging of the sandpacks. Bubble tubes were similarly installed.

One 114 mm cased well, BGI3 (Figure 3), was also instrumented with piezometers on the outside of the casing. This well is the closest to the Phase B tunnels and would provide the best estimate of any pressure transmittal to the strata overlying the tunnels themselves. These were not installed with the actuator device because of the limited space, but were welded onto the casing instead. Approximately 20 mm of cement could coat the outside of the sandpack which could possibly plug every piezometer. Every sandpack was saturated with water prior to installation to reduce the influx of drilling mud and cement. Pressure readings indicated hydrostatic conditions at installation, falling to reservoir conditions within two days. This confirmed previous behaviour observed during the Phase A piezometer installation using the actuated devices.

Within the tunnels, two stand-pipe piezometers were installed in the tunnel ceiling. The tunnels lie beneath a competent limestone stratum, however above this there is a fractured argillaceous stratum. Movements observed from Phase A were not fully explainable in terms of elastic deformation or thermal effects and it was suspected that some movement was due to a parting of this weaker layer, perhaps due to pressurizing from the reservoir. The two Phase B devices provided conclusive proof of this, and an additional six piezometers were installed into the roof for continued monitoring.

Two vibrating-wire piezometers were installed along the surface casing of the B2 well pair. These devices provide the fluid pressures along the surface casing which can be used to assess any leakoff through the cement job either due to bleeding, improper curing or damage due to the thermal conditions imposed by injection and production.

To monitor the process, injection well B3I was equipped with bubble tubes. One tube was pumped down the inner tubing and latched in place at the far end of the completion screens. The other was strapped onto the exterior of the tubing at the near end of the completion screens. This configuration will allow for a measure of the pressure loss over the length of the screens, a useful number for calibrating wellbore simulation models and optimizing well design.

Inclinometers

In oil sands, particularly when operating with injection pressures approaching overburden pressures, there is likely to be considerable deformation of the rock matrix (as distinct from the individual grain compressibility). This has an enormous effect on the porosity and permeability of the formation. Furthermore, the deformations are cumulative and may compromise the integrity of the wells by inducing shear failures. In Phase A, inclinometer well displacements were early indicators of the growth of the steam chamber since these wells would deflect away from the expanding depleted zones. In addition, associated with these deformations is a significant loss in rock strength. For these reasons, inclinometer wells were incorporated into Phase B.

Strains are calculated from the horizontal deformations measured between successive gyrocompass surveys of the inclinometer wells. These wells consist of uncompleted 114 mm or 178 mm casing cemented into the reservoir. An alternative was to install grooved aluminum casing within casing cemented into the reservoir, with uncompacted sand backfill in the annular space between the two for the mechanical coupling[7]. Measurements would be taken with an accelerometer tool that would travel within the grooves. However, the expected reservoir deformations would be significantly attenuated within the two coaxial casings when using a deformable material as mechanical coupling. Cementing the grooved casing was also rejected because the resultant structure would be considerably stiffer than the surrounding rock mass and therefore would not deform as much as the surrounding reservoir. Tiltmeters were also proposed as alternative monitoring devices but were cancelled due to budgetary constraints.

The well azimuths are determined using a rate gyroscope that measures the horizontal component of the earth's spin vector. Inclinations are obtained with an accelerometer. All measurements are taken with the tool rotated in 90° stops to obtain a bias correction, and an offset-centre correction is performed to account for the misalignment of the tool in the casing. A coarse survey of data every 5 m is done on the entire well, with a reading every 1 m over the interval of interest.

In interpretting these inclinometer data, the assumption was made that the bottomhole position in the limestone was fixed, and that every point above was free to move with the reservoir. Subsequent surveys were presented relative to the initial survey.

To examine the lateral deformations within the reservoir, 12 cased, uncompleted wells were used. Wellheads were installed in the event of any leakage into these wells. Seven wells have

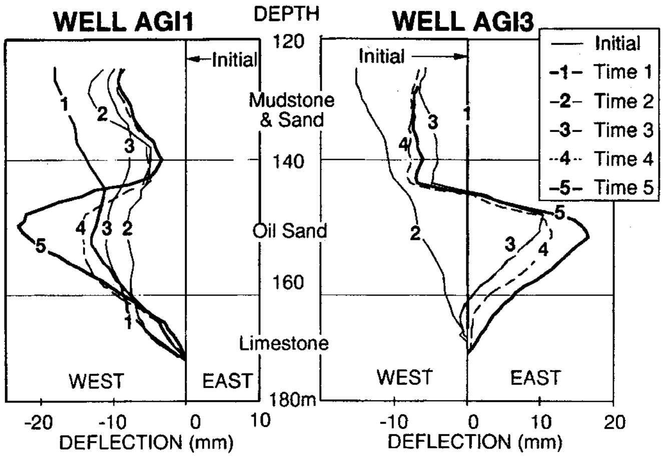


FIGURE 7: Phase A horizontal displacements.

178 mm (7 in.) casing, allowing access for cross-hole seismic tools, and these extend 70 m beneath the pay. The other five are 114 mm in diameter and extend 25 m beneath the pay. All are distributed throughout the pattern for complete coverage. These wells were surveyed prior to steaming to determine their initial position. As the process proceeds, the reservoir deforms due to a combination of reduced effective stresses, and increased horizontal stress due to thermal expansion against fixed boundary conditions. Subsequent surveys should show these wells deflecting away from depleted zones. Cumulative strains should result in the largest deformations being seen furthest away from the centre of the pattern, assuming symmetry of recovery. Departures from this expected behaviour will indicate anomalies in the process's effect on the reservoir and in the local in situ stress state.

To monitor potential shearing of the production wells, Well BGI3 (Figure 3) was located in line with the points where the horizontal wells enter the oil sands from the limestone. The limestone, being relatively massive, competent and therefore stiff, is unlikely to deflect as a result of reservoir heating. The oil sand, however, due to its much lower strengths and stiffnesses under reservoir conditions, can deform significantly. Such differential movements are expected to be accentuated at the limestone-oil sand unconformity, within discontinuous mudstone lenses within the reservoir, and at the contact with the cap rock. Monitoring deformations at these critical locations provides early warning of problems, and data for subsequent analyses of alternate well completion designs or spacings.

An example of the importance of such deformations is shown in Figure 7, in which the deformations from two Phase A inclinometer wells straddling the pattern (Figure 1) are shown. The lateral deformations are symmetrical, indicating radial growth of the steam chamber. The general westerly drift up each well may be a residual effect of the survey method. Maximum shear strains correspond to both a sharp change in temperature and a change in facies from clean sands below to interbedded sands and mudstones above. No excessive shear strains are seen at the limestone interface. The north-south deformations (not shown) were relatively small.

Extensometers

The only accurate means of determining vertical deformations within the reservoir is to measure them directly. In Phase A, 15 linearly varying displacement transducer (LVDT) extensometers were cemented in place from surface. These were a stack of modules consisting of an anchor at each end and the LVDT between, housed in tubing that was debonded from the cement. As the formation deformed vertically, the anchors would move and displace the sensor within the housing. Due to their high cost, and the fact that data had been available from Phase A, only two extensometer wells were planned for Phase B. These would consist of a few LVDT-type units plus a new design based on existing extensometers used in tunnels and elsewhere. The new design consists of a series of magnets around non-magnetic casing, into which a magnetic probe is inserted. As the reservoir deforms, the magnets will move up and down the casing, changing the inter-magnet spacings which will be recorded periodically. These readings are less precise but allow for more complete coverage of the reservoir. Five conventional LVDT units were used in the second extensometer well. These LVDT devices are more precise, can be automated and do not have to be abandoned due to a casing leak. The alternative of determining vertical strains from a multi-anchor system of cemented casing with expansion joints[7] was not used because of the high cost for relatively few data points. However, that system

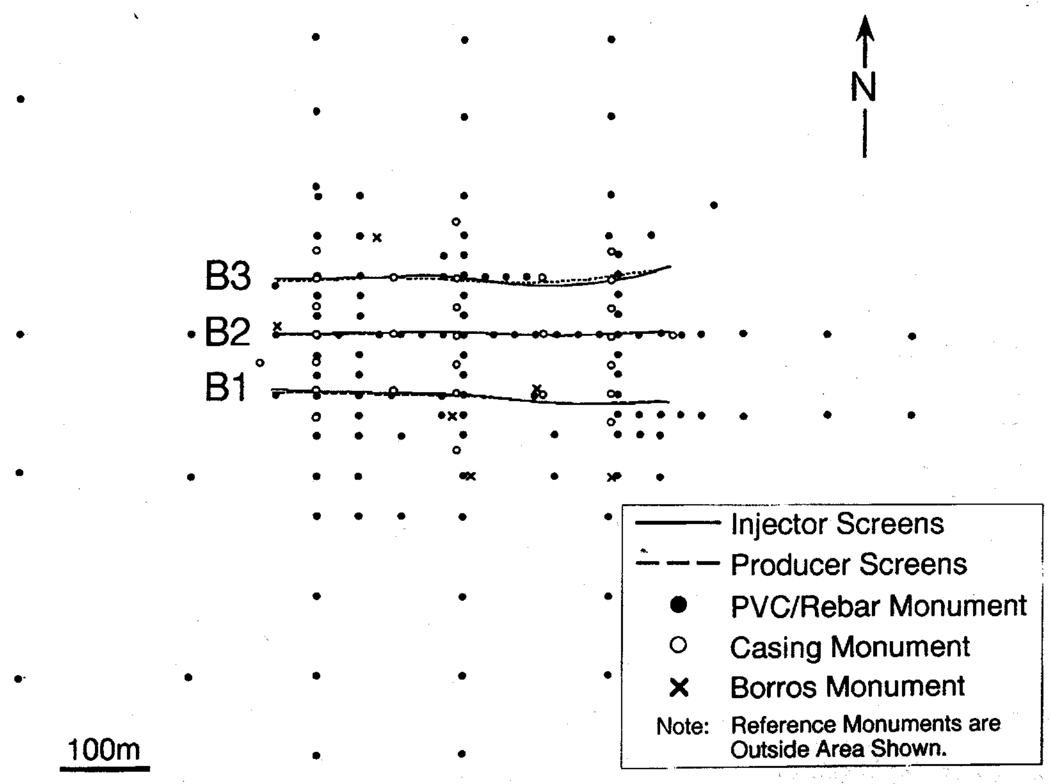


FIGURE 8: Plan of surface heave monuments.

TABLE 2: Instrumentation costs.

	Quantity	Unit Cost (000's)	Total (000's)
WELLS:			
Thermocouple	12	$35	$420
Piezometer	5	50	250
Inclinometer	5	60	300
Extensometer	2	85	170
Cross-Hole Seismic	7	80	560
Sub-Total:	**31**		**$1700**
OTHER:			
Heave Monuments	131	$0.6	$80
SCADA Hook-up	all	—	200
Tunnel Stations	10	13	130
Horizontal Well Instr.	6	10	60
TOTAL:			**$2170**

(Costs in 1990 CDN$)

is simple, can be automated, and is free from calibration changes.

Preliminary analyses of the Phase A data showed that the reservoir was increasing in volume due to the dilation of the oil sands. This implied that shear strains have a significant effect on the well casing, the integrity of cap rock, and on the physical properties of the reservoir which, in turn, would affect the process.

Within the tunnels, rod extensometers were installed into the roof, the floor and into the wall adjacent to the injector and producer well pairs. Data from Phase A have shown that no significant movements occurred and that most correspond to thermal effects and the presence of the fractured argillaceous stratum 3 m above the tunnels.

Surface Heave Monuments

The Phase B pilot was the first petroleum reservoir to have the number and distribution of surface monuments pre-engineered, based on geomechanical and process data, for a quantitative assessment of the process. Previously, projects installed monuments on an intuitive basis and used the resulting data in a qualitative manner.

Analyses of levelling survey data will determine the distribution of depleted zones within the reservoir. Surface heaves are expected during the steam injection due to the low effective stress state in the reservoir which results in shearing and dilatant volume change. Some compaction is expected upon depressurization, however, since the SAGD process works at a constant pressure, compactive drive and its related subsidence are relatively unimportant.

The Phase B pattern was initially instrumented with 125 survey monuments to monitor uplift. The number and distribution of monuments (Figure 8) were designed to optimize the quality of the resultant data. Monuments extend 6 m below surface, to allow for a fixed anchored foundation for a rod extending to surface. The outer sleeve of the unit was mechanically isolated from the base to allow for downdrag or frost jacking of the sleeve without bearing on the rod's foundation. Vermiculite internal backfill allowed for lateral stability and prevented thermal convection within the monument. Some field modifications were necessary in order to install the units into sands with a high water table; questionable data from these units will be discarded. A commercially available monument was used for six subsequent monuments since they proved to be far easier to install.

A string of Type E thermocouples was installed along one surface heave monument to record the seasonal variations in monument temperatures. Since precisions of the order of 0.5 mm are required for the interpretation of surface heaves at the UTF, the thermal effects can significantly affect those readings.

After the initial first-order levelling survey, subsequent surveys will reveal the changing surface profile, which will then be deconvolved to provide estimates of the locations of volumetric change within the reservoir[8]. This analysis will benefit from the extensometer data and previous geomechanical data on overburden compressibilities. For Phase B, it is anticipated that these analyses will provide a general distribution of steam within the reservoir, although there may be complicating influences such as dilation outside of the steam chamber.

Cross-hole Seismic Tomography

Seven wells (BC series) were drilled deeper, to a depth of 230 m and with larger 178 mm casing to accommodate the cross-hole seismic piezoelectric source and receiver. A pseudo-random signal was stacked to improve the signal-to-noise ratio to obtain resolutions of 2 m or better. Such definitive resolution within the reservoir, regardless of the quality or thickness of the overburden, offers a better understanding of the continuity of reservoir facies and may provide a basis for interpolating between wells.

This technique will be repeated during steaming. The reduction in seismic velocities associated with the presence of a gas phase and high temperature will allow for a determination of the extent of the steam chamber through the three north-south panels (Figure 2, wells BC1-BC4, BC2-BC5, BC3-BC7-BC6).

Seismic Monitoring of Horizontal Well Locations

The observation wells were used to determine the absolute locations of the horizontal wells. Blasting caps were detonated within the horizontal wells and the seismic events were recorded using a combination of hydrophones in cased wells, surface geophone strings, and geophones cemented at depth in 3 observation wells. The results confirmed the results of the downhole surveys to within 1.5 m at the 600 m depth. The technique provided an independent check on the absolute location of the blasting cap, regardless of assumptions of initial casing alignment and cumulative survey errors inherent in downhole methods.

Costs

The costs (Table 2) were low as a result of the use of water well drilling rigs and favourable weather. Costs include the camp, clearing, access, pads, drilling, logging, instrumentation, casing or tubing, power tongs, cementing, core analyses, shipping and road construction.

Significant savings were realized by using endless tubing to install the thermocouples in 12 cemented wells. Since blow-out preventers were not needed for this project, the rig was moved off immediately after drilling. After logging, thermocouples were fixed to the tubing as it was lowered into the hole. The tubing was cut at the wellhead and cement injected through the tubing. The five piezometer wells required the rig since the instruments were pre-assembled on 25 mm water pipe.

Conclusions

Installation of monitoring equipment must be meticulously documented and checked to ensure proper positioning of the instruments. Backup instruments should be installed to prevent over-reliance on one type. Preferably, the backup, or the sole primary instrument, should be simple in design, operation and interpretation, and not prone to calibration errors. Instrument design should be as uniform as possible to prevent manufacturing errors. If dimensions and tolerances are critical, these must be pointed out to the vendors, who may have a different perspective. Likewise, drillers and other support staff should be made aware that the purpose of the drilling is to carefully install the instruments at known locations.

The UTF project has a unique data set of reservoir, process, geological, geophysical and geomechanical performance. Coordinated research in the geomechanical laboratory testing of core, geophysical studies, reservoir studies, reservoir and geomechanical numerical modelling and geological interpretation have provided a diverse, cooperative environment for optimizing the performance of the project. The monitoring program will continue to be a major contribution to that end.

Experience gained from the operation of the Phase A pilot was applied to the design of the Phase B monitoring. It is expected that the experience gained from Phases A and B will be extrapolated to a commercial phase at UTF. Many competing forms of process monitoring (e.g. heave analysis, cross-hole seismic) were used in Phase B and are being evaluated for their applicability to a commercial project. The experience gained from the instrumentation of the Phase A and Phase B pilots is currently being applied by some of the partners of the UTF project to their projects in Alberta.

Enormous amounts of money are invested in producing wells and surface facilities based on geological and numerical models. Adequate instrumentation is required to monitor the process to conclusively confirm or revise those models. It is necessary to quantify the success (or failure) of a recovery process in order to optimize the design of future projects. The UTF monitoring program described above will provide ample information with which to plan a number of recovery strategies in the Athabasca oil sands.

Acknowledgements

The UTF is funded by the Province of Alberta through the Alberta Oil Sands Technology and Research Authority, and by its participants: Amoco Canada Petroleum Company Ltd., Chevron Resources Canada Ltd., CNPC Canada, Conoco Canada Ltd, Imperial Oil Resources Canada Ltd., Japex Oilsands, Petro-Canada Resources Inc., Shell Canada Ltd., and Suncor Inc. A significant proponent and supporter of the monitoring program was the Canadian government through CANMET. Support for the surface and underground instrumentation was received from Thurber Engineering (Edmonton) and Golder Associates (Vancouver), respectively.

Special thanks to the other members of the UTF Geotechnical Sub-Committee: Dr. A.W. Stokes (CANMET), Dr. J.D. Scott (U. of Alberta) and Mr. R.J. Chalaturnyk (C-FER) for their invigorating input. Within AOSTRA, Messrs. Jack Suggett and Neil Edmunds provided valuable technical advice.

REFERENCES

1. EDMUNDS, N.R., HASTON, J.A. and BEST, D.A., Analysis and Implementation of the Steam-assisted Gravity Drainage Process at the AOSTRA UTF; *Proc. UNITAR Fourth International Conference on Heavy Crude and Tar Sands, Edmonton, Alberta, August 1988.*

2. EDMUNDS, N.R., KOVALSKY, J.A., GITTINS, S.D. and PENNACCHIOLI, E.D., Review of the Phase A Steam-assisted Gravity Drainage Test: An Underground Test Facility; *SPE 21529, Proc. International Thermal Operations Symposium, Society for Petroleum Engineering, Bakersfield, California, Feb.7-9, 1991.*

3. MADSEN, D.H., HAMMETT, R.H., and COLLINS, P.M., Geotechnical Monitoring of the AOSTRA Underground Test Facility; *Proc. 94th CIM Ann. Gen. Mtg., Montreal, Quebec, April 26-30, 1992.*

4. SCOTT, J.D. and CHALATURNYK, R.J.; Phase A Geomechanical Testing Program, Final Report; *Dept. of Civil Engineering, Univ. of Alberta; Edmonton, Alberta, March 1, 1990.*

5. LAING, J.M., SCOTT, J.D., STOKES, A.W., SUGGETT, J.C. and WOOD, D.F., Geotechnical Instrumentation of the AOSTRA Mine-assisted Underground Steaming Trial; International Conf. on Heavy Crude and Tar Sands Proc.; *UNITAR/UNDP Information Centre for Heavy Crude and Tar Sands, Edmonton, Alberta, August 1988.*

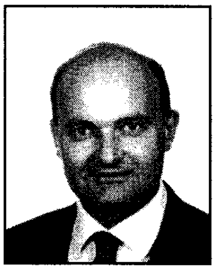
6. SUGGETT, J.C., COLLINS, P.M. and STOKES, A.W., In Situ Monitoring at AOSTRA's Underground Test Facility; *The Second China-Canada Heavy Oil Technical Symposium, Proc., Beijing, People's Republic of China, October 29 - November 1, 1990.*

7. GRONSETH, J.M., Geomechanics Monitoring of Cyclic Steam Stimulation Operations in the Clearwater Formation; *Proc. ISRM-SPE International Symposium, Rock at Great Depth, Pau, France, August 28-31, 1989; eds. V. Maury and D. Fourmaintraux, publ. A.A.Balkema, Rotterdam, pp.1393-1398.*

8. BILAK, R.A., ROTHENBURG, L. and DUSSEAULT, M.B., Use of Surface Displacements to Monitor EOR Projects; *5th International Conf. on Heavy Crude and Tar Sands Proc., UNITAR/UNDP Information Centre for Heavy Crude and Tar Sands, Caracus, 4-9, August 1991, V3, pp. 257-277.*

Paper reviewed and accepted for publication by the Editorial Board of The Journal of Canadian Petroleum Technology.

Author's Biography



Patrick Collins consults in the area of geomechanics as applied to petroleum engineering. He received engineering degrees from the University of Toronto (B.A.Sc.) and the University of Alberta (M.Sc.). Since managing the geomechanical aspects for the UTF reservoir engineering team, he has worked internationally (Italy) on wellbore stability studies, predicting formation overpressures while drilling, and optimizing drilling performance.

Figure 2 PLAN OF PHASE B WELLS

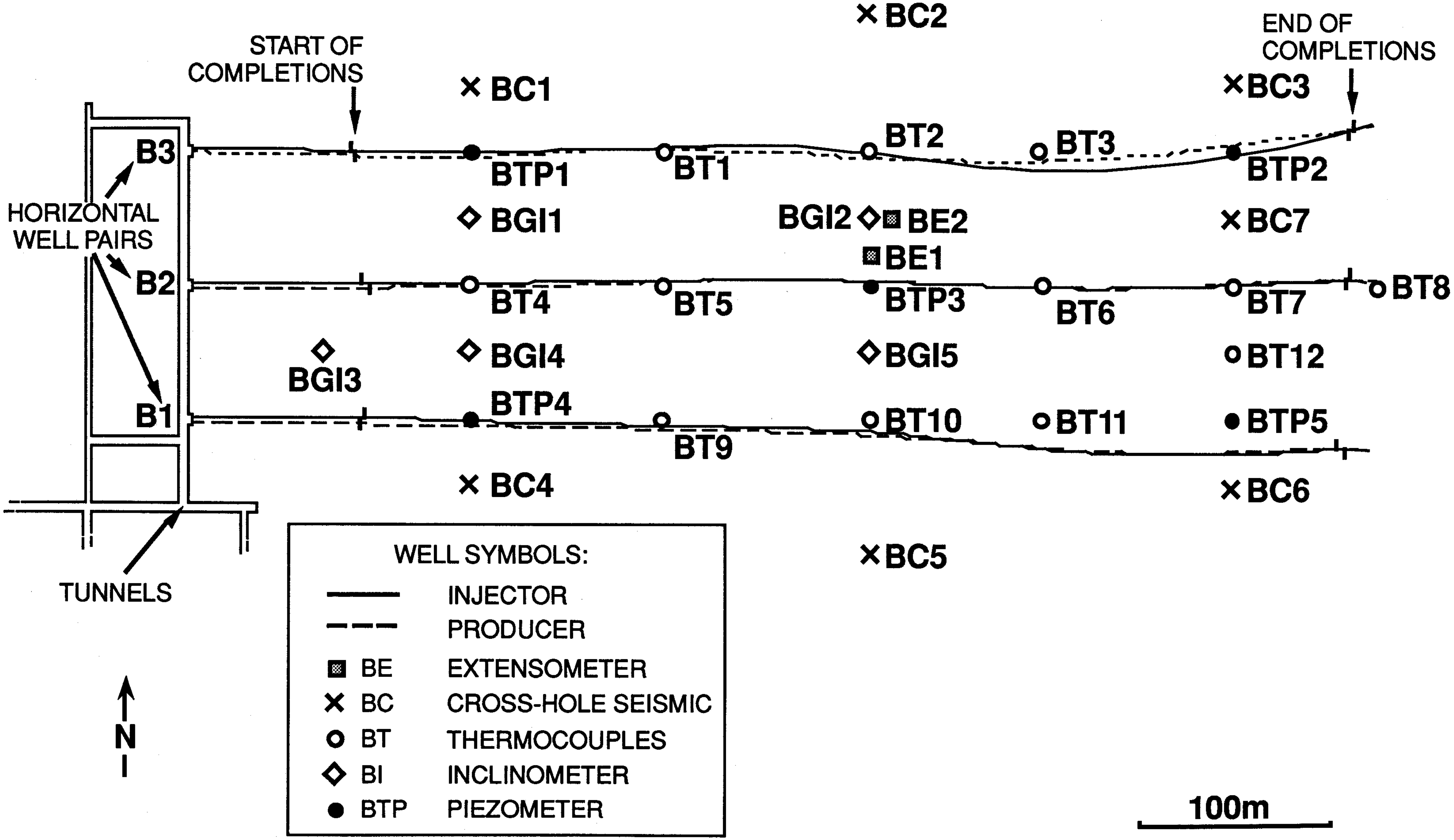


Figure 3 PHASE B WEST-EAST CROSS-SECTION

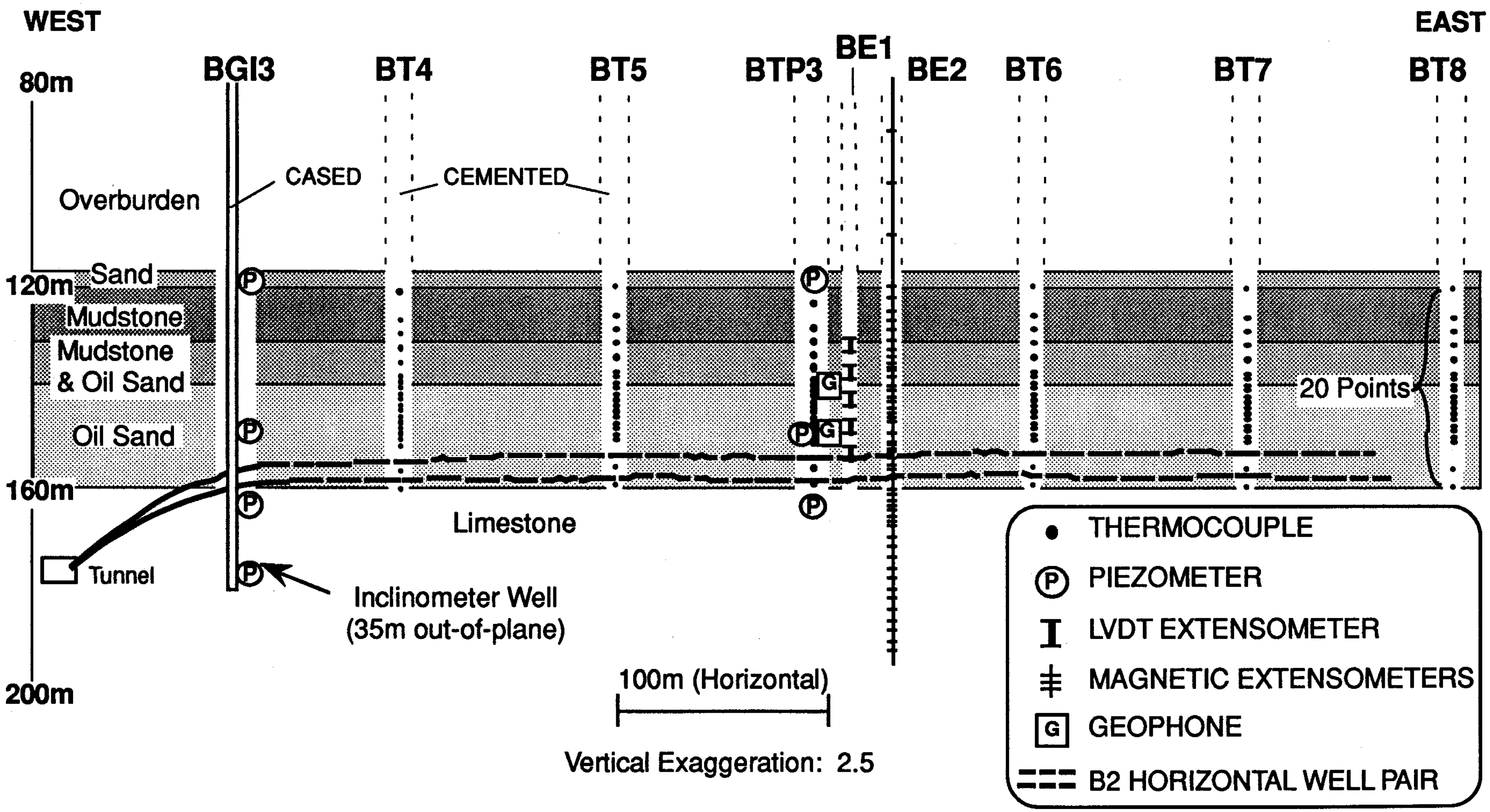


Figure 4 PHASE B NORTH-SOUTH CROSS-SECTION

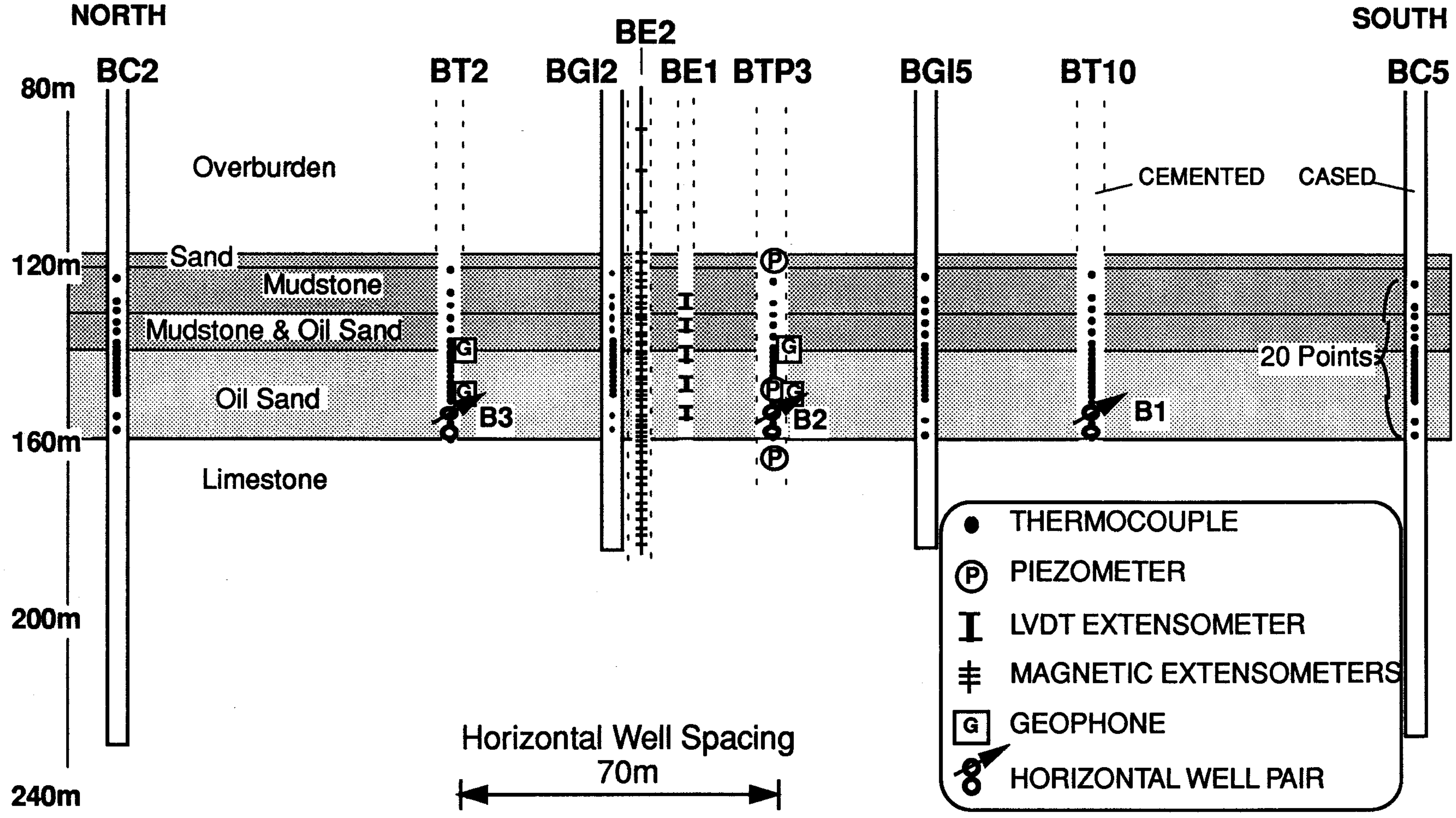


Figure 8 PLAN OF SURFACE HEAVE MONUMENTS