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DESIGN OF THE MONITORING PROGRAM FOR AOSTRA'S UNDERGROUND TEST FACILITY, PHASE B PILOT

BY
Patrick M. Collins
AOSTRA

SUMMARY

A monitoring program for an oil sands thermal recovery pilot project is described. It covers the steam-assisted gravity drainage process, the reservoir's geomechanical response, tunnel safety and surface casing performance. The types and quantities of instrumentation are described, as is their distribution within the lease. Rationale for the instrumentation is presented, and approximate costs are provided. The writer advocates the use of instrumentation of pilot and commercial projects to substantiate the forecast reservoir behaviour.

BACKGROUND

The Alberta Oil Sands Technology and Research Authority's Underground Test Facility (AOSTRA UTF) is located in the Athabasca deposit of north-eastern Alberta and is 10km west of Syncrude. The reservoir is at a depth of 150m and the pay is 20m thick. Viscosity of this 8° gravity bitumen at the reservoir temperature of 7°C is 5E+06mPa·s. The underburden consists of a massive, undeformed limestone. This reservoir is uneconomic using open pit mining technology because of the low pay to overburden ratio, and the relatively thin pay is presently uneconomic to recover with in situ processes drilled with vertical wells. Instead, the UTF project uses the Shaft And Tunnel Access Concept (SATAC) to gain access to the pay from tunnels within the underlying limestone. Horizontal well pairs drilled into the oil sands are injected with steam, with concurrent bitumen and water production.

The process operates at a constant pressure below fracture pressure and relies on gravity drainage to deplete the reservoir (Edmunds, et al., 1988). The Phase A "laboratory scale" pilot consisted of 3 pairs of 160m wells with 55m of completion. The project was extremely successful (Edmunds, et al., 1991), prompting the Phase B pilot of three well pairs, 600m long, with 500m of completion. At the time of writing, drilling of the Phase B horizontal wells was ongoing, with three wells drilled and completed. Steam injection will begin in July, 1991.

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.

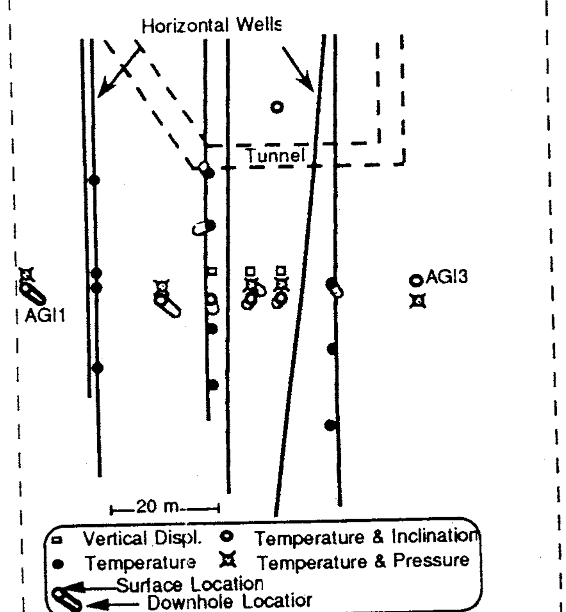
The SATAC approach to bitumen recovery was novel enough to warrant extensive instrumentation of the shaft and tunnels. The Phase A tunnels, which provide access to the underground wellheads, had to be safe for personnel, isolate them from the pressurized steam chamber, and allow the continuous flow through mine piping of produced fluids and steam to and from the surface. Given the long-term integrity of these tunnels and the extremely consistent geology of the Waterways Formation limestone underlying the UTF lease, the new Phase B tunnels will have a reduced number of instrumented stations. Many details are unavailable at the time of writing since instrumentation will be installed after all three horizontal well pairs are drilled and completed.

The data obtained from surface instrumentation in the Phase A pilot was extremely useful in interpretting the process results. It was expected that the behaviour observed in the Phase A pilot would be applicable to the Phase B pilot and would therefore void 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 (Chalaturnyk, et al., 1990) using results of laboratory tests on the McMurray Formation oil sands, the limestone underburden and the capping shales at various temperatures and pressures (Scott and Chalaturnyk, 1990). Trends observed in this analysis were extrapolated to those expected in Phase B and resulted in modifications to the instrumentation installed. Some instrumentation was intended to confirm the findings from the Phase A pilot.

The scaling-up of the UTF pilot from three horizontal well pairs with a 55m completion length spaced at 24m in Phase A (Figure 1), to three pairs completed for 500m at a 70m spacing in Phase B (Figure 2)resulted in a twenty-fold increase in area. Clearly the dense coverage of observation wells installed in Phase A (Laing, et al., 1988; Suggett, et al., 1990)could not be justified for this larger project, nor was that ever the intention. 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. inclinometer results). Furthermore, some instrumentation could be read continuously while others only seasonally or annually due to their comparatively high survey costs. The axiom for designing the instrumentation program for the Phase B pilot became "you can monitor all of the pilot some of the time, and some of the pilot all of the time, ...".

Figure 1 PHASE A OBSERVATION WELLS



(modified, after Suggett, et al. 1990)

The logical extrapolation of this concept of going from specific to general information about the reservoir is the applicability of instrumentation to a commercial project. Assuming that sufficient data from a pilot are available to understand the mechanisms at work in the reservoir, and that the reservoir and process within the commercial pattern are similar to that of the pilot, it is unnecessary to duplicate the type and density of instrumentation for the commercial project. Instead, methods of monitoring the general behaviour of the entire pattern should be pursued, and combined with some confirmatory specific instrumentation at one or two selected locations within the reservoir. Thus, the general behaviour can be correlated with the specific observations to infer the behaviour of the entire reservoir. This allows for a minimum of instrumentation. However, It must be remembered that this instrumentation can only be justified if analyses of the data collected will result in a more economic or safe operation.

LAYOUT

The Phase B well layout (Figure 2) allows for early indications of steam chamber development and longer-term performance. The layout provides data along each well pair as well as along three north-south cross-sections.

All wells include thermocouple strings for a precise measurement of thermal advance at the wells. The BT-series wells mostly lie along the intended alignment of the horizontal well pairs (Figure 3) 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. A dense spacing of thermocouple points above the well (Figure 4) will provide excellent data on steam chamber rise. The deteriorating quality of the reservoir above the basal 20m 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 35m away (Figure 5), are concentrated at the top of the 20m pay since the lateral growth of the steam chamber will likely be detected there first. These strings could be raised or lowered, however it is advisable to eliminate the need for this by using an ample distribution of points. The marginal savings in using fewer points and periodically adjusting the string are more than offset by increased operating costs and the chance of errors or damage.

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 crisscross the Phase B pattern with piezometers. Vibrating-wire piezometers are installed in the Wabasca sand, within the reservoir and in the limestone below (Figure 4). All piezometers at the reservoir elevation are backed-up with a bubble tube. One pneumatic piezometer is in the Wabasca (Rottenfusser, et al., 1990) in the middle of the pattern as an independent check on the long-term stability of the vibrating-wire units. Additional, deeper piezometers are in BTP1 and BTP4 because of their proximity to the tunnels.

Well BGI3 has 4.5" casing and was equipped with piezometers on the outside of the casing which were installed without actuation. This test showed that pressure readings could be taken through a thin cement covering on these units before the approach of steam. The continued performance of these units will

Figure 2 PHASE B SURFACE WELL LAYOUT

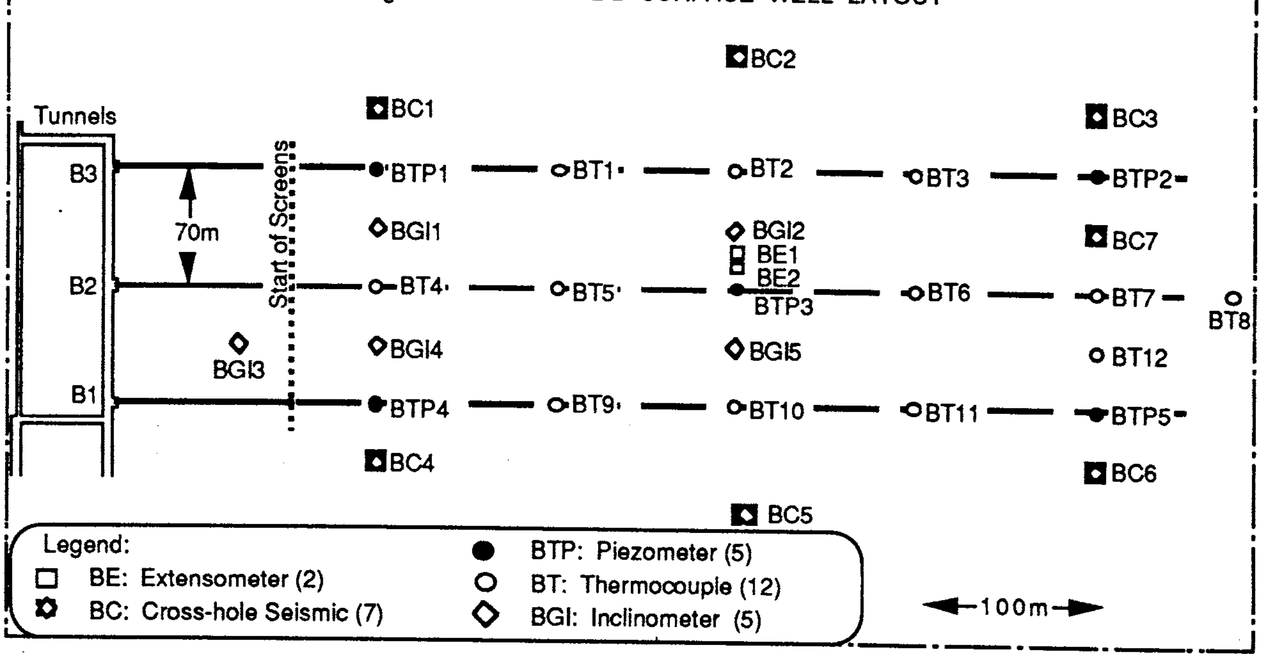
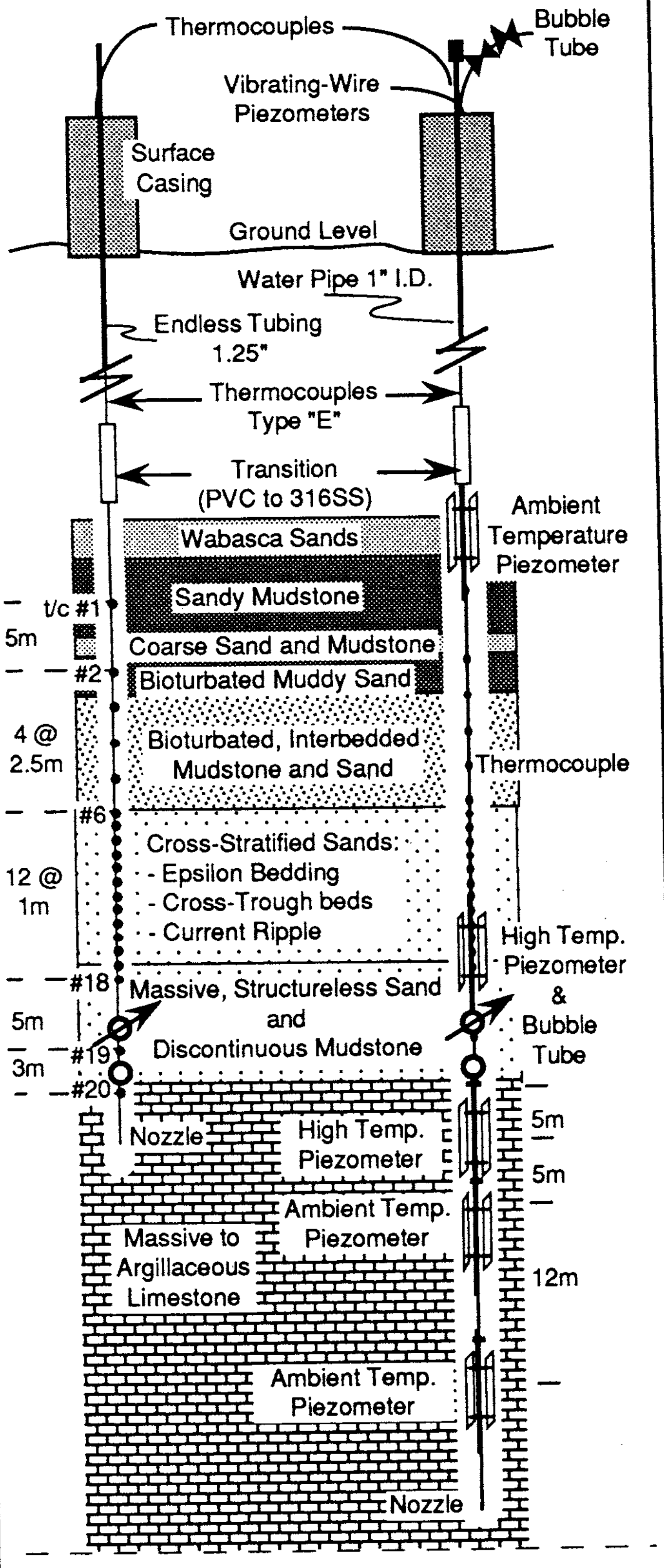


Figure 4: TYPICAL THERMOCOUPLE AND PIEZOMETER DISTRIBUTION



be closely monitored to assess the necessity of any device to push the piezometer sandpack against the sandface. Piezometers were recommended for this well because of its depth (185m) and its proximity to the tunnels.

All BC-series and BGI-series wells will be surveyed and used for inclinometer wells. The regular, wide spacing of these 12 wells will 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 70m, 140m, 210m, and 280m (Figure 2). Seismic work across these various spacings will allow for an assessment of the ultimate range of the piezoelectric source and receiver. Interpolating between panels should permit a more elegant interpretation of the supposed local geology and subsequent process performance.

Cemented-in geophones were installed in wells BT2 and BT12 as part of the seismic MWD tests, and in BTP3 for possible future use in MWD and microseismic monitoring.

A decision was made to adapt the instrumentation and facilities operation to a SCADA system (supervisory control and data acquisition system). All electrical instrumentation at surface will be hard-wired into a central computer for report generation and archiving. Data from manually operated equipment will be entered separately. In Phase A, all instruments were read periodically (generally weekly) and the data manually entered into a database. With the increased number of wells, data points and the more remote access, a cost analysis supported connecting these wells to the automated system.

INSTRUMENTATION

The types of information required determined the type, quantity and quality of the instrumentation for Phase B. An instrumentation summary is presented in Table 1. The instrumentation installation was not complete at the time of writing therefore all quantities have not been finalized.

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 4.5" casing but 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, resulting in 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 instrumentation of the full depth of the reservoir. The added benefit was that a temperature point could be located mid-way between the injector and producer wells, thereby providing a quantitative estimate of the development of breakthrough due to conductive heating of the oil sands between the wells. The possibility of drilling through an uncased vertical well during horizontal drilling was an accepted improbability.

TABLE 1: INSTRUMENTATION

INSTRUMENT	PURPOSE	LOCATION	QUANTITY
Thermocouple	Temperature	Reservoir	630
		Horizontal Wells	6
		Surface Casing	10
		Tunnels	99
		Heave Monuments	6
Vibrating Wire Piezometer	Pressure & Temperature	Reservoir	23
		Surface Casing	2
		Tunnels	2
Pneumatic Piezometer	Pressure	Reservoir	1
Bubble Tube Piezometer	Pressure	Reservoir	6
		Horizontal Wells	2
LVDT Extensometer	Vertical Displacement & Temperature	Reservoir	6
Magnetic Extensometer	Vertical Displacement	Reservoir	80
Rod Extensometer	Axial Diispl.	Tunnels	65
Strain Gauge	Axial Strain & Hoop Strain	Surface Casing	15
Monument	Heave	Ground Surface	125
Convergence Pin	Relative Displ.	Tunnels	56
	Axial Displ.	Wellheads	6

In Phase A, temperatures were obtained from thermocouple bundles consisting of 8 to 12 strands of type "E" thermocouples, insulated with magnesium-oxide (MgO) and sheathed in 316 stainless steel (316SS). The strands were of various lengths and were silver-soldered together into a single bundle, with a transition to less-expensive ambient-temperature thermocouple wire 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 re-positioning of the points. Thermocouples were selected because of their excellent survival rate compared with the thermistors installed within the tunnels. The units are robust and can withstand installation, and the 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, was rejected since UTF's shallow depth would 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 an 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 boundary of increased gas saturation with 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, and this relationship could be used to infer chamber growth between Phase B wells. The record of steam rise rates will, of course, be more precise because of the increased density of points within each well.

Additional temperature data will also be available from other instruments. Within both the vibrating-wire piezometers and the linearly-varying displacement transducer (LVDT) extensometers there are thermistors used for calibrating those instruments. The thermistors were not commonly used for analyses since they were sparsely distributed and generally overlapped coverage by the thermocouple strings. In addition, the relative positioning of the thermocouple points was fixed, whereas there could be a small error in including the temperature from another instrument of uncertain relative position. Field engineers will recognize the errors associated with installing instrumentation under adverse conditions. Every effort was made to land instrumentation at the desired elevation and a complete record was made of the installation as it progressed. AOSTRA strapped each thermocouple string to obtain the as-built lengths. Future designs will emphasize the adherence to specified lengths, use uniform lengths wherever possible, and include a secondary method of ensuring that the thermocouple points are landed correctly.

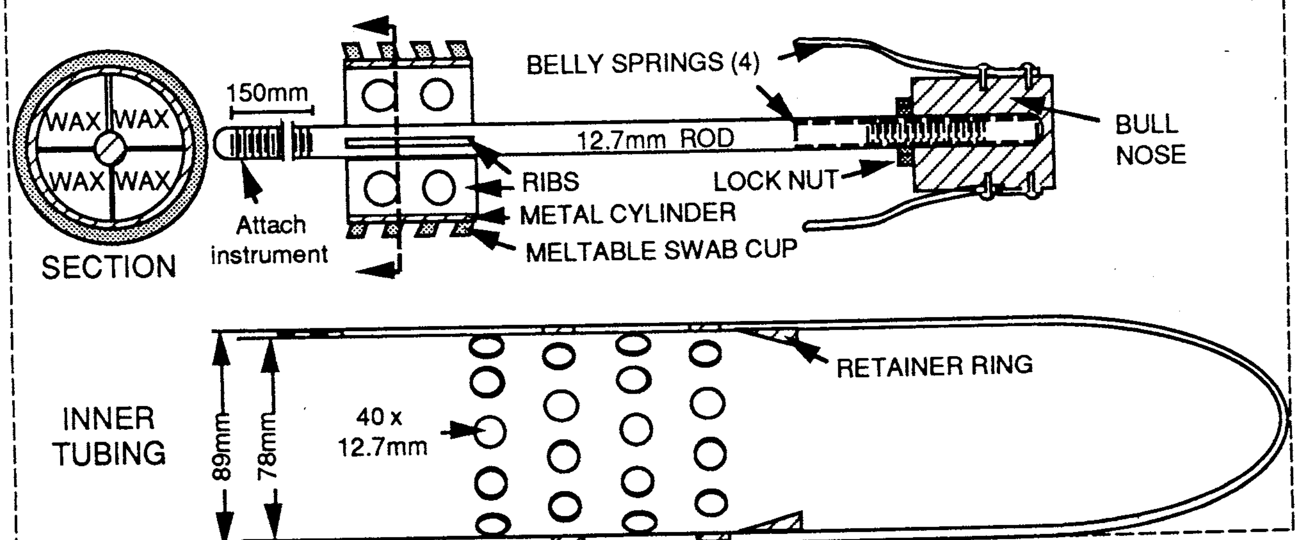
Thermocouples were installed into five of the injection and production wells from the tunnels. Four of the wells have a single thermocouple point pumped down the inner 3.5" tubing, attached to a wax-impregnated screen pig that latched to the end of the tubing Figure 6). Once steaming begins, the paraffin wax will melt, exposing the screens to allow steam to exit or fluids to enter. Knowing the saturation temperature and pressure of the injected steam, this will provide a measure of the cooling along the well which will indicate whether steam is travelling to 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 is planned for the producer well at the expected oil sands:limestone contact. When combined with the temperature of the produced fluids at the wellhead, this will quantify the heat loss to the underburden for the uncompleted segment of the casing.

Temperature-measuring devices will be installed into the tunnel walls as was done in Phase A. In Phase A, these devices consisted of a string of resistance temperature device (RTD) thermistors, however they failed when exposed to moisture. Phase B strings will consist of 316SS-sheathed, type "E" thermocouples. Temperatures obtained from these strings will be compared with movements of the rock around the tunnel to determine what percentage of the movements are due to thermal effects. Strings parallel to the injector and producer wells quantify the conductive heat losses to the limestone.

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 with the intention of subsequent curing and strength testing. At the same time, one well pair will be

Figure 6 INNER TUBING INSTRUMENTATION PIG

(modified, after C.G. Bohme, 1990)



instrumented with thermocouple strings on the outside of the casing to obtain temperatures along the cement for future numerical modelling of the cement-casing performance. This diligence stems from leaks observed in Phase A: subsequent modifications to the surface casing design and cementing program have minimized the potential for leakage in Phase B.

Piezometers

The piezometers installed in Phase B will quantify the fluid pressure within the reservoir and the surrounding formations.

In Phase A, there were 37 piezometers installed across the main instrumented cross-section through the pattern. 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, as well as small geomechanical effects away from the steam chamber.

For Phase B, the original intention was to instrument a few wells above, within, and below the reservoir. The distribution of these wells would allow for trending of the pressures within the reservoir but the relatively sparse spacing would not allow for any in-depth examination of initial transmissibility. One major expectation is that the piezometers in the reservoir and the 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 Wabasca sands above the capping shales (Figure 4). This regional underpressured aquifer could then be monitored for changes in pressure as a result of the process. Piezometers were also installed in the limestone underburden to assess the amount of leakoff to this formation and quantify the pressurization of argillaceous strata within. Wells BTP1 and BTP4 were drilled deeper to obtain core through to the tunnel elevation, and to allow for the instrumentation of permeable strata at that elevation. For landing the piezometers at the more permeable target strata, field estimates of the permeability were inferred from the geolograph's record of increased drillability of these argillaceous units as compared with the massive, tight limestone units.

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 difficult to automate and they require 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 pneumatic device was unwarranted. One pneumatic device was installed in the Wabasca above the reservoir to calibrate on any long-term drift in 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 300kPa. This was unacceptable therefore the number of piezometers was reduced. Instead of having three piezometers stacked within the 20m pay along the well , a single unit was located at the mid-point, the rationale being that less data was preferable to erroneous data. To ensure that the remaining vibrating wire piezometers within the reservoir were accurate, a bubble tube device was included at the same location. Each device consisted of a continuous length of 0.25" 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 3m length of 10mm stainless steel tube with a slotted tip imbedded in a 20/40 fracsand sandpack and a resin binder. At the surface, the 0.25" tubing was finished with two needle valves (one for redundancy). After pressurizing the device, the shut-in pressure is recorded and corrected for the check valve's cracking pressure minus the static head of pressurized gas in the tubing. The vibrating wire unit, which may creep during the five year life of this pilot, can then be calibrated and all recent readings adjusted.

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, with the exception of one bubble tube that, due to the 24hr set-up time required for the sandpack, was imbedded in a ball of paraffin wax to prevent cement from plugging the slotted tip. This soft wax should melt at 55°C allowing the device to become operable.

One 4.5" 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 20mm of cement would coat the outside of the sandpack which could possibly plug every piezometer. To reduce this possibility, every sandpack was saturated with water prior to installation to minimize the influx of drilling mud. Some invasion of mud probably protected the sandpacks from the subsequent cementing, thereby allowing the piezometers to work. As insurance, one piezometer was soaked with a sugar solution prior to installation to inhibit cement hydration. Pressure readings taken before, during, and after the installation showed that the devices worked well, indicating hydrostatic conditions at installation falling to reservoir conditions within two days. This confirmed previous behaviour observed at the Phase A installation using the actuator devices.

Within the tunnels, two vibrating-wire piezometers were planned for the tunnel ceiling. The tunnels lie beneath a competent limestone facies, however above this there is an 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 should provide conclusive proof.

Two vibrating-wire piezometers were installed along the surface casing of the middle well pair. These devices will provide the pressure regime along the surface casing which can then 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, one injector well (B3I) will be equipped with bubble tubes. One tube will be pumped down the inner tubing and latch in place at the far end of the completion screens. The other will be 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 figure for calibrating wellbore simulation models and optimizing well design.

Inclinometers

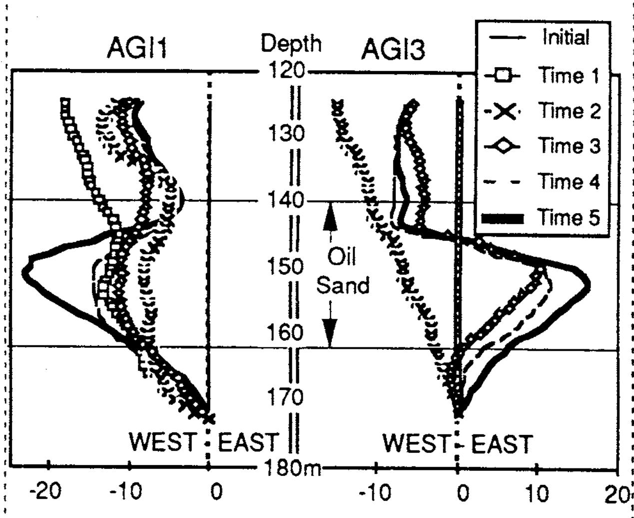
In oil sands, particularly when operating with injection pressures approaching overburden pressures, there is likely to be considerable deformation of the rock matrix (as distinct from the compressibility of its composite mineralogy) which has an enormous effect on the porosity and permeability of the formation. In addition, associated with these deformations is a significant loss in strength. Furthermore, these strains are cumulative and may result in deformations that may compromise the integrity of the wells by inducing shear failures.

Strains were measured in Phase A by gyrocompassing the inclinometer wells, obtaining a reading every 1m over the interval of interest. The assumption was made that the bottom 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. The method of surveying the Phase B wells has yet to be determined.

To examine the lateral deformations within the reservoir, a total of twelve cased wells were included in the Phase B pattern. Since no well was completed, each is a closed tube within the reservoir. Wellheads were installed in the event of any leakage into the wells. Seven wells have 7" casing, allowing access for cross-hole seismic tools, and extend 70m beneath the pay. The other five are 4.5" in diameter and extend 25m beneath the pay. All are distributed throughout the pattern for complete coverage. These wells will be surveyed prior to steaming to determine their present position. As the process gets underway, the reservoir deforms due to a combination of reduced effective stresses (total stresses minus the fluid pressure),and increased horizontal stress due to thermal expansion against fixed boundary conditions. Subsequent surveys will 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 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 and within shaley lenses within the reservoir and its cap rock. Monitoring these deformations at the critical locations will not prevent the problems, but will provide early warning of potential 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 inclinometer wells straddling the Phase A pattern are shown, and are remarkably symmetric. The general westerly drift up each well may be a residual effect from 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 shales above. No problems are seen at the limestone interface.

Figure 7 HORIZONTAL DISPLACEMENTS



Extensometers

The only means of determining vertical deformations within the reservoir is to measure them directly. In Phase A, fifteen linearly varying displacement transducer (LVDT) extensometers were used. These were cemented in place from surface and consisted of a stack of modules with 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 will consist 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 will be coarse but allow for more complete coverage of the reservoir. Six conventional LVDT units will also be used to confirm these results. The LVDT devices are more precise, can be automated and are useable if the casing must be abandoned due to a casing leak.

Preliminary analyses of the Phase A data showed that the reservoir was increasing in volume due to the upward dilation of the oil sands. This implied that shear strains in general may have a significant effect on the process, any casing, and the integrity of cap rock. These results are currently being analyzed and compared with results of numerical modelling of the same phenomenon.

Within the mine, rod extensometers will be 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 are occurring and that most correspond to thermal effects and the presence of the argillaceous strata 3m above the tunnels.

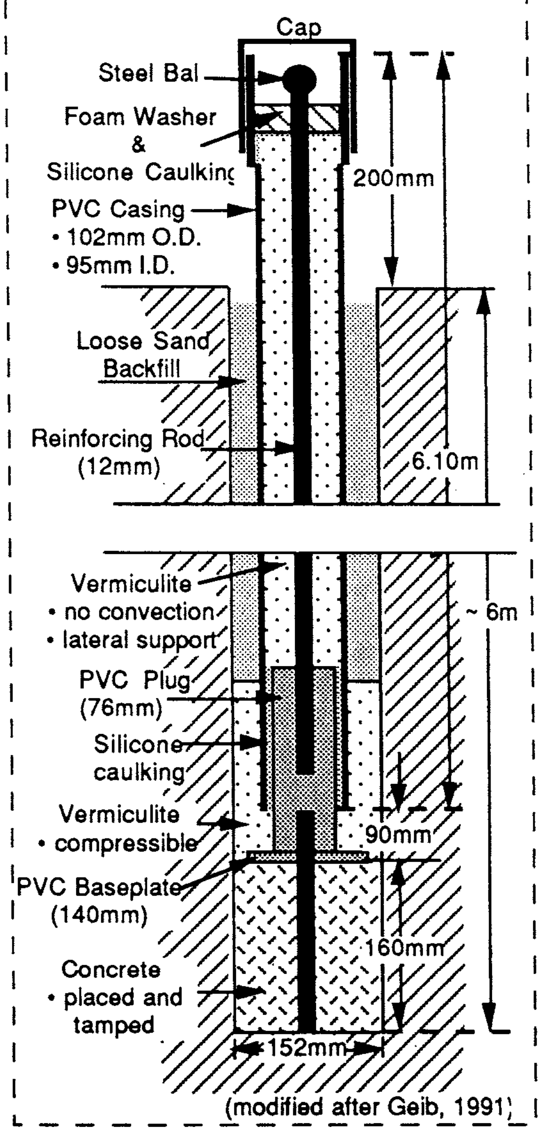
Strain Gauges

The centre well pair (B2) will begin steaming before the other pairs because of short-term limitations on steam capacity. To assess the effect of thermal shock on the integrity of the surface casing-cement-limestone seal, two pairs of strain gauges will be installed on both the injector and producer surface casings and oriented in the axial and circumferential (hoop) directions since these are expected to be the directions of principal strains. The duplication of these devices on each casing is for redundancy. One additional pair of gauges will be bonded to a scrap portion of surface casing within the cement. This segment will be coated to prevent any mechanical constraint from the surrounding cement and will be used to measure the thermal strains as distinct from the constrained thermal strains monitored by the gauges on the casing.

Surface Heave Monuments

The surface of the Phase B pattern was instrumented with 125 survey monuments to monitor uplift. The number and distribution of monuments were designed to optimize the quality of the resultant data (Figure 8). Monuments extend 6m below surface, and were built on site. Their purpose was to allow for a fixed anchored foundation for a rod extending to surface. Vermiculite internal backfill allowed for lateral stability and prevented thermal convection along the rod (Figure 9). The outer sleeve of the unit was attached to the base with flexible caulking to allow downdrag or frost jacking of the sleeve without bearing on the rod's foundation. 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. There is a commercially-available monument that would likely prove to be less expensive once installation costs are factored in.

Figure 9: HEAVE MONUMENT DESIGN



(modified after Geib, 1991)

A single string of thermocouples was installed along one surface heave monument to record the seasonal variations in monument temperatures. Precisions of the order of 0.5mm are required for the interpretation of UTF's surface heaves therefore thermal effects can significantly affect those readings. Type "E" thermocouples were chosen to be compatible with all other thermocouples from the surface. The six thermocouples within the one heave monument were spaced further apart with depth, reflecting the increased thermal activity at shallow depths.

After the initial survey, subsequent surveys will reveal the changing surface profile, which will then be devolved to provide estimates of the locations of volumetric change within the reservoir. This analysis will benefit from the extensometers at reservoir level and previous geomechanical data on overburden compressibilities. The algorithm for analyzing the heaves is described in Bilak, (1989) and Bilak, et al., (1991). For Phase B, it is anticipated that such 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. If this technique works, it will be commercially viable, particularly for shallow deposits with a good surface expression of underground expansion.

Cross-Hole Seismic Tomography

At the time of writing the University of Toronto, under AOSTRA and Natural Sciences and Engineering Research Council (NSERC) funding, was conducting cross-hole seismic tomography on site. Seven wells (BC series) were drilled deeper, to a depth of 230m and wider (7" casing) to accommodate their piezoelectric source and receiver. A pseudo-random signal was stacked to improve the signal-to-noise ratio. Expected frequencies were in the order of 250Hz which, when combined with typical P-wave velocities of 2500 m/s, should allow for resolutions of 2m 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 them between wells.

This technique will be repeated after steaming. It is hoped that the significant reduction (~25%) in seismic velocities associated with the presence of a gas phase and high temperature (Wang and Nur, 1988) will allow for an exact determination of the extent of the steam chamber through the three north-south panels

(Figure 2, wells BC1-BC4, BC2-BC5, BC3-BC7-BC6). Current laboratory work on the effect of anisotropic stresses on seismic velocities will be used to aid in the interpretation.

Micro-Seismic Monitoring

This technique is analogous to tectonic seismicity monitoring in that the source is "naturally" occurring at depth and the differing arrival times are used to triangulate the location of the source. From preliminary analyses of data collected from the Phase A pattern, the sources tend to be highly localized shear displacements within the reservoir, a finding that is consistent with our understanding of the geomechanical response of the reservoir to the SAGD process. Unfortunately a complete analysis of the data was unavailable and precluded the inclusion of such monitoring for Phase B at present. Geophones may be installed later, without the benefit of early data generated near the horizontal well pairs that could be used to calibrate the seismic model used for subsequent analyses. Orientation of the phones could be obtained by triggering an event at a known location, as was done by Vandamme (1990).

This method has the benefit of being non-intrusive and allows for complete coverage of the reservoir. Its downside is that it is subject to the quality of the overburden (although geophones may be installed at depth in an observation well) and that the results require significant processing and are subject to interpretation. Being able to correlate the results with observed behaviour at observation wells would increase the confidence in the results.

Seismic Monitoring of Horizontal Well Locations

Rudimentary tests performed from the Phase A tunnels proved that high quality seismic transmission was possible from percussive drilling in the limestone through the oil sands and overburden to shallow (40m deep) geophones. Additional testing was conducted during the drilling of the Phase B surface observation wells: three wells were equipped with two three-component geophones cemented within the reservoir while hydrophones were be installed from surface in nearby cased wells. While drilling additional observation wells, data were collected and analyzed with the intention of developing a seismic measurement-while-drilling device for the steering of the three horizontal well pairs.

Unfortunately, the ease of drilling within the oil sands did not generate sufficient seismic signal to be used in such an application. An artificial source was designed for the down-hole assembly, and after a necessary re-design, did not generate enough signal to be detected from any appreciable distance.

A seismic check was obtained by detonating a cap within the completed well and the event recorded using a combination of hydrophones, surface geophone strings and the geophones cemented at depth from the previous testing. The results were excellent and confirmed the azimuth of the downhole surveys to within 1.5m at the 600m depth. This provided an independent check on the absolute location of the charge, regardless of assumptions of initial casing alignment and cumulative survey errors inherent in downhole methods.

COSTS

This observation program was expensive, however the quality and usefulness of the results are hoped to justify the costs. A preliminary cost breakdown is as follows (1990 CDN$):

TABLE 2: PROJECT COSTS

	Quantity	Unit Cost $(000's)	Total Cost $(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
	31		$1700
Other:			
Heave Monuments	125	$0.6	$75
SCADA Hook-up	all	-	$200
Tunnel Stations	7	$15	$105
Horizontal Well Instr.	6	$10	$60
TOTAL			$2140

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

Because of the shallow (160m) depth, water well rigs were used for drilling a 158mm hole, with reaming to 245mm for the placement of the 178mm casing. One advantage of these rigs is that the core can be wirelined to surface rather than having to trip out the entire string. This feature was extremely useful in previous drilling programs, when obtaining geomechanical core with a modified core barrel, because of the time-dependent nature of gas exsolution.

Significant savings were realized by using endless tubing to install the thermocouples in 12 cemented wells. Blow-out preventers were not needed for this project therefore immediately after drilling, the rig was moved off. After logging, thermocouples were strapped and taped to the tubing as it was lowered into the hole. The tubing was cut at the wellhead and cement injected through the tubing. The 5 piezometer wells required the rig since the instruments were pre-assembled on 25mm i.d. water pipe.

Costs for the underground monitoring (Table 2) are approximate since that program has not yet been finalized. A combined geological and geomechanical visual core analysis of limestone recovered from the vertical wells will be used to best position the tunnels instrumentation.

APPLICATIONS

The best evidence of applicability is that experience gained from Phase A and Phase B is currently being applied by our participants to their own projects in Alberta. They have seen how AOSTRA applied the monitoring results to improve the understanding of the recovery process and numerical forecasts, and they have justified the incremental costs of instrumentation for own projects.

Any project relying on uncertain technology must be able to quantify the success (or failure) of that process in order to optimize the design of future projects. The UTF monitoring has provided ample information with which to plan a number of recovery strategies in the Athabasca. Unfortunately, some results of this research is limited to the Athabasca deposit: other oil sands, exhibitting different mechanical properties, may perform differently under similar operating schemes. The recovery process and monitoring program, however, are generally applicable.

CONCLUSIONS

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, and both will be extrapolated to a commercial pilot.

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 and not prone to calibration errors (e.g. bubble tubes). 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 is not intended to serve as a model of how a pilot should be instrumented. Many competing forms of process monitoring (e.g. heave analysis, cross-hole seismic, micro-seismic) have been used and are being evaluated for their applicability to commercial projects and it not recommended that others repeat the same diversity of monitoring evaluation. Rather, the intention was to sufficiently monitor the process to evaluate the success of various operating strategies, and to examine promising technologies for commercial application.

Greater errors result from inadequately instrumenting a pilot project. The purpose of a pilot is to prove that a process is viable for a particular reservoir. Enormous amounts of money are invested in producing wells and surface facilities based on geological and numerical models, and it requires adequate instrumentation to monitor the process to conclusively confirm or revise those models. Without such confirmation, extrapolation to a commercial venture would be risky and defeat the purpose of the pilot.

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Figure 3 PHASE B WEST-EAST CROSS-SECTION

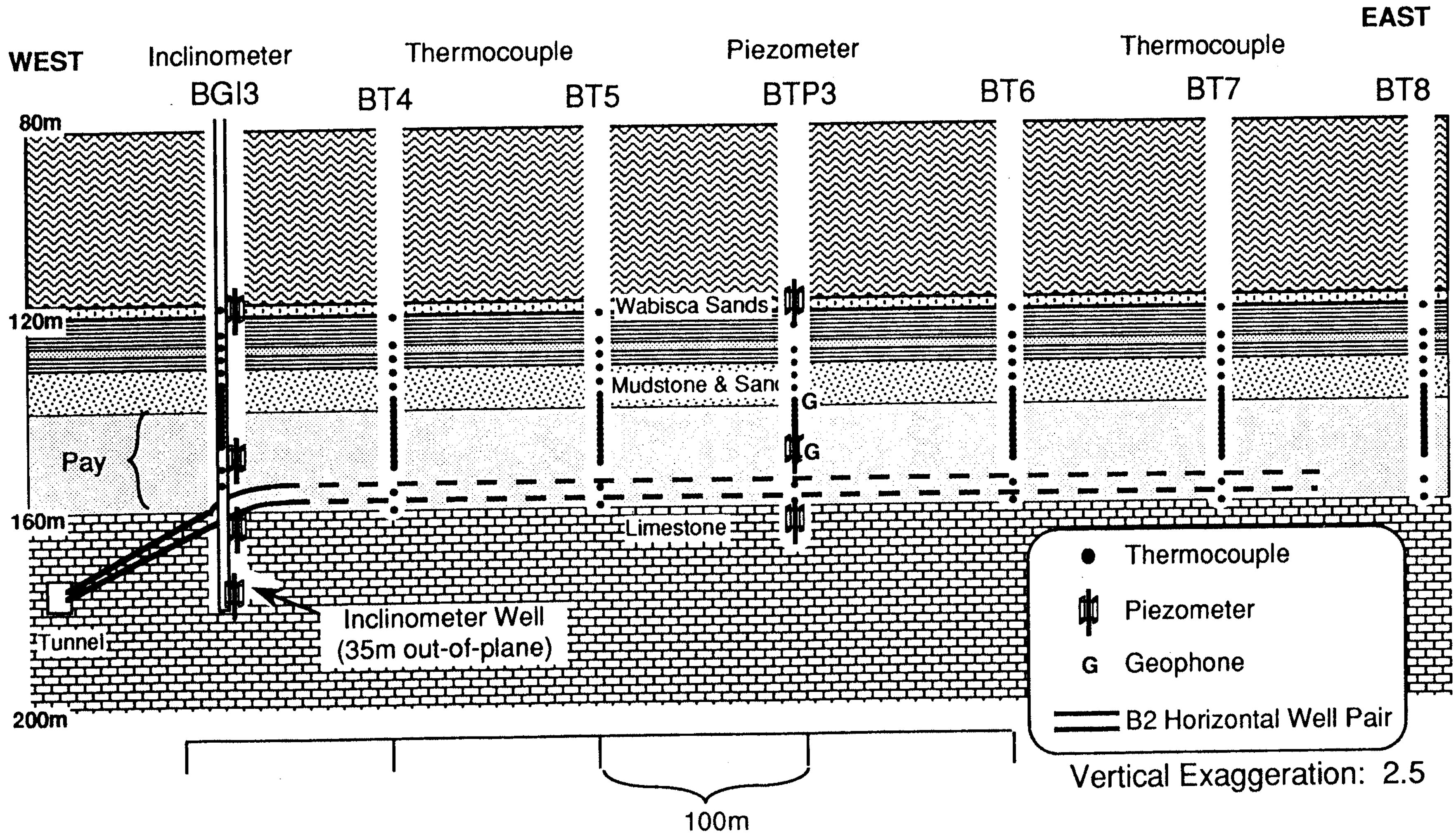
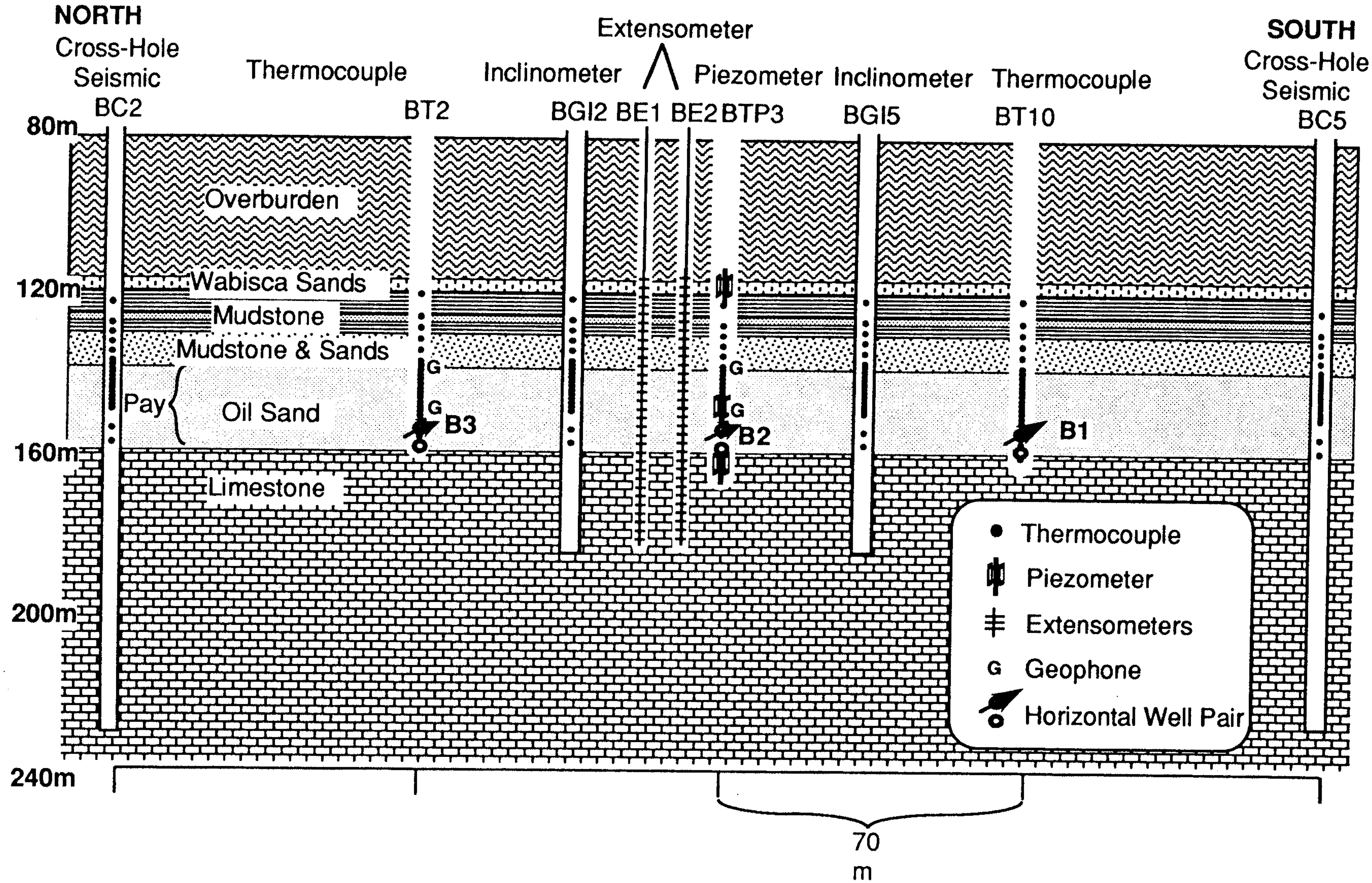


Figure 5 PHASE B NORTH-SOUTH CROSS-SECTION



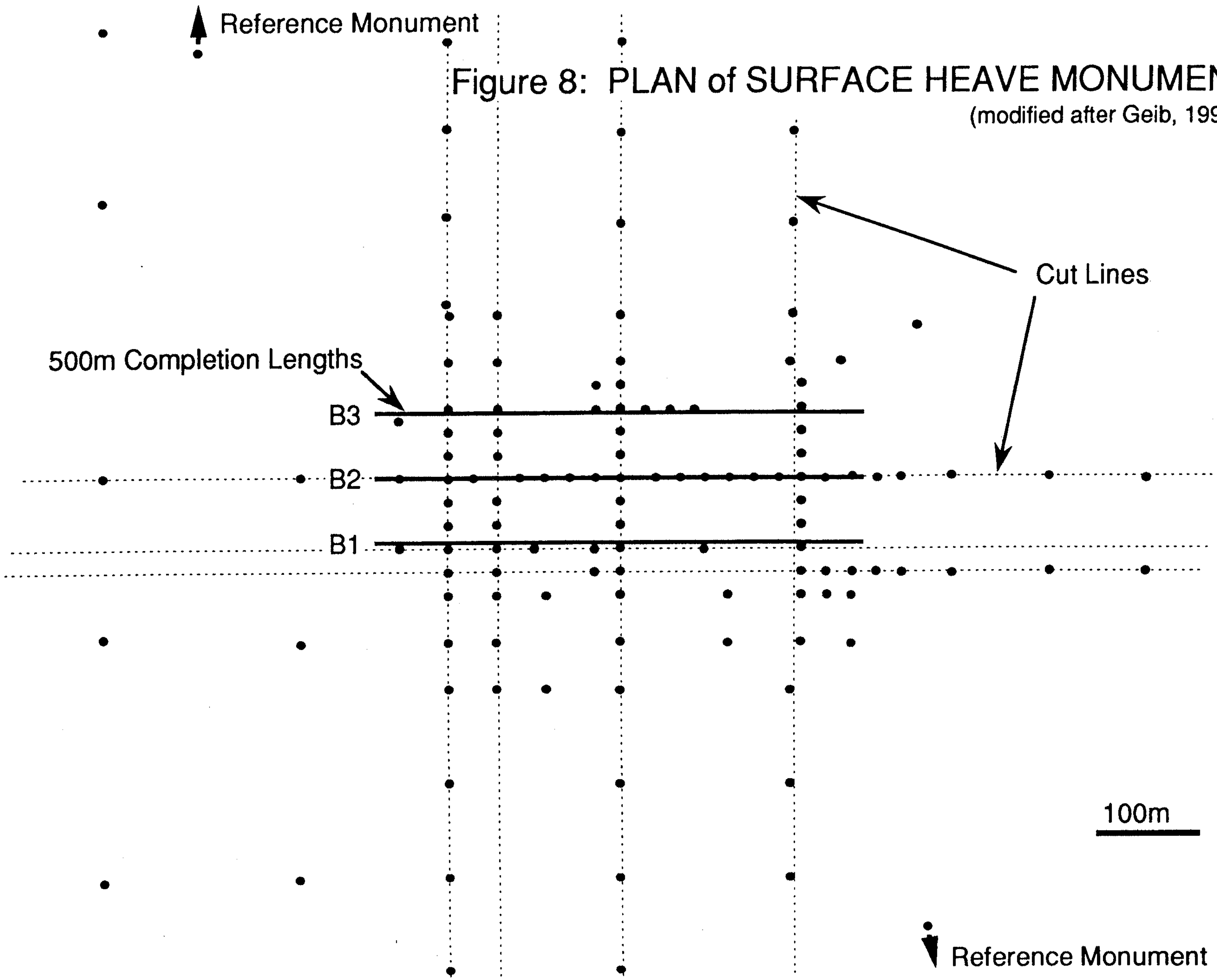


Figure 8: PLAN of SURFACE HEAVE MONUMENTS
(modified after Geib, 1991)