Regina Geothermal Project

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Abstract

In sedimentary basins, the temperature increases downward at an average rate of 30°C per kilometre of depth. Where large volumes of water occur at temperatures above 50°C, immense amounts of energy are available. Sedimentary basin geothermal energy is, utilized in France where installed capacity in 2005 was 308 MW.

In winter 1978, a 2226 m deep geothermal test well, funded by Energy, Mines and Resources Canada (EMR, the predecessor of Natural Resources Canada), was completed on the University of Regina campus. The project was to supply heating for a sports complex and to serve as a demonstration of sedimentary basin geothermal energy. The proposed project involved production of hot water from the geothermal reservoir, passing the hot water through a heat exchanger, and transferring the heat to a fresh-water circuit that would carry the heated fresh water to the point of utilization. The cooled geothermal brine would be injected into the producing reservoir through a disposal well about a kilometre distant. Plans for the sports complex were shelved. This, coupled with decreasing energy prices, resulted in the termination of the project. The knowledge acquired from the test well will be useful in designing geothermal projects proposed for the Regina area or elsewhere.

The well was completed in Winnipeg-Deadwood strata with open hole from 2034 to 2226 m. The open section has 111 m of net effective sandstone reservoir with an average porosity of 13.2%; two six-hour pump tests indicate average permeability of 350 mD. With long-term pumping at 100 m^3*/h, it is considered that drawdown will stabilize 150 m below ground surface. Bottom-hole temperature is 61°C and, when pumped at 100* m^3*/h (440 usgpm), it is expected that the surface temperature of produced water will be 59°C. The fluid is sodium-chloride-sulphate brine with approximately 108 500* g/m^3 *of total dissolved solids. Estimated content of* CO_2 *and* H_2S *are 56* g/m^3 *and 26* g/m^3 *respectively. On a short-term (103 hours) test, corrosion rates with ferrous metals were low and fall into an acceptable range. Caution is advised, and oxygenation of the water must be avoided.*

Two options are presented for completion of a geothermal project at Regina; both assume one vertical well and one directional well (slant hole). Option One will satisfy a heating load of 2.0 MW (6.7 million Btu/h) by direct heat transfer and 2.7 MW (9.2 million Btu/h) with added heat pumps. For this option, the hole size on both producing well and disposal well is 222 mm (8.75 inches) and casing size 178 mm (7.00 inches). Approximate cost for the primary (salt-water) circuit is $3.7 million. Using the present well at the University of Regina would reduce the cost to approximately $2.1 million. Option Two, for a heating load of 3.5 MW (12.0 million Btu/h) by direct transfer and 4.8 MW (16.3 million Btu/h) with heat pumps, requires a larger hole and casing size; the estimated cost for the primary circuit is $4.9 million.

A large area in southern Saskatchewan has geothermal potential with temperatures above 50°C. At Estevan reservoirs hotter than 100°C are present, and around Swift Current the maximum reservoir temperature could be above 70°C.

Keywords: *Regina geothermal, sedimentary basin geothermal, geothermal gradient, water chemistry, minor elements, trace elements, geothermal corrosion.*

1. Introduction

Since antiquity, humankind has been aware that the deeper parts of the earth are hotter than the surface. Heat is flowing from depth to the surface resulting in a temperature gradient (geothermal gradient). A portion of this heat flow originates below the crust and is attributed to the origin of the earth as a planet. A significant portion originates

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from the radioactive decay of uranium, thorium, and potassium within the crust and outer mantle. The geothermal gradient varies greatly from place to place, but, on a worldwide basis, is considered to average about 25°C per kilometre of depth.

In restricted areas of the globe, magma has moved upward to relatively shallow depths, commonly 1 to 10 km below the surface. If the intrusion is geologically young (two million years or less), the geothermal gradient above the intrusion is very high, generally in the range of 100°C/km to 600°C/km. These localities are potential sites for magmatic-type geothermal development, lending themselves to electrical power generation. All of the magmatic-type sites exploited to the present have associated water reservoirs (Figure 1); depending on temperature, depth, and pressure, the reservoir fluid may be liquid water, water and steam, or steam alone. Most high-grade geothermal areas are found along divergent or convergent plate boundaries. Examples are Llarderello in Italy, The Geysers in California, and Cerro Prieto in Mexico.

In sedimentary basins remote from plate boundaries, the temperature increases downward at an average rate of about 30°C/km. Despite the moderate geothermal gradient, immense amounts of heat energy are available where large volumes of water can be produced at temperatures above 50°C. This lower grade of heat energy has been used extensively for space heating, greenhouses, aquiculture, and industrial processes, especially in France, Hungary, and parts of eastern Europe.

The goal of the Regina Geothermal Project was to supply the space and hot water heating needs of a large sports complex to be built on the University of Regina campus. The intent also was to demonstrate the recovery of heat energy from a sedimentary basin in Canada. Unfortunately the sports building was not built at the requisite time so that the 2200 m well, drilled and completed in the winter of 1978-79, has never been used for its intended purpose. Decreasing petroleum costs in the early 1980s was a factor in terminating the project. A program of research, however, was conducted and is reported on here. The work has shown that water available at the wellhead would have a temperature of 58° to 59°C when pumped at a rate of between 60 and 100 m^3/h. The water contains little hydrogen sulphide and carbon dioxide and, if kept free of dissolved oxygen, is not aggressively corrosive. At the higher pumping rate and with a base temperature of 30°C, the heating load available would be 3.5 MW (thermal) (12 million Btu/h). With heat pumps, the available energy would be increased by 37% (*i.e.*, to 4.8 MW), estimated to be sufficient for the well duplex to provide the heating needs at peak load of 500 residential units each having an average floor space of 1470 square feet (136.6 m^2). The geothermal resource is widespread and extremely large, but varies in quality within southern Saskatchewan.

Currently, the cased well is plugged and abandoned. We are confident that it could be rehabilitated and utilized as a production or disposal well for a geothermal well doublet. We have indicated how a fully developed program at the University of Regina and, alternatively, a newly developed project in a new area could be put in place. We have shown the amounts of energy available from such projects and have included some estimates of infrastructure costs for the projects.

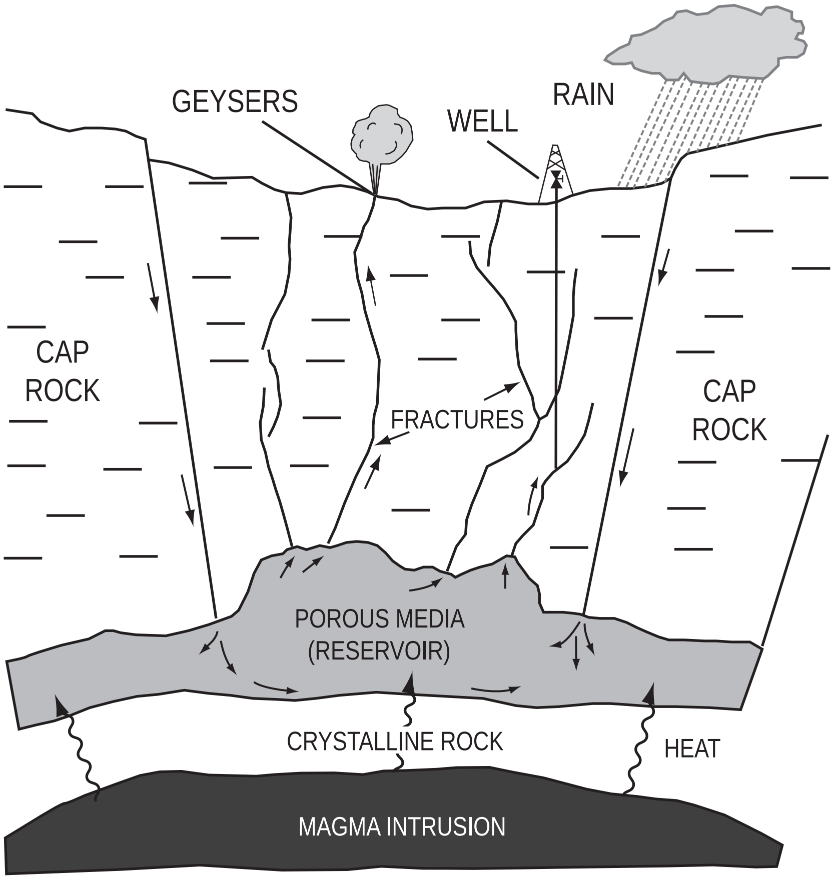

Figure 1 - Hypothetical example of a geothermal reservoir of the magmatic type showing hot magma, the associated reservoir containing water, and recharge of the reservoir through fractures (after DiPippo, 1980, Figure 1.3).

2. French Experience and Origin of the Regina Project

Use of sedimentary basin geothermal energy is well established in France. The first successful geothermal doublet was completed in the Paris Basin in 1969. By 1990, 66 geothermal projects were operational in the country (Harrison *et al.*, 1990, p385-430), saving about 1.4 million barrels of oil per year. By 2005, the total installed capacity in the country was 308 MW (thermal) with 34 district heating projects utilizing 243 MW (79%) with the remainder used in fish farming (7%), geothermal heat pumps (5%), bathing and swimming (5%), and greenhouse heating (4%) (Lund *et al*., 2005).

The standard mode of direct use of geothermal energy in France consists of a production and a disposal well (the well doublet). Hot fluid from the geothermal reservoir is passed through a heat exchanger, transferring the heat to a fresh-water counter-current. The cooled geothermal fluid, high in dissolved salts, is injected into the source reservoir by means of the disposal well, generally about one kilometre distant. Fluid in the primary circuit is completely enclosed and is kept at sufficient pressure that dissolved gases, such as carbon dioxide and hydrogen sulphide, remain in solution. The cooled geothermal water injected into the disposal well eventually makes its way back to the producing well, but the spacing between the wells is chosen so that the cold water front reaches the producer after 20 to 40 years. The secondary circuit carries the heated fresh water to the point of utilization where it is circulated and returned to the heat exchanger. A simplified diagram of this scheme applicable to the Regina geothermal well is shown in Figure 2.

In an ideal situation, the geothermal doublet supplies the base heating load to district heating schemes, large apartment buildings or groups of buildings. In colder weather, the direct heat transfer is supplemented by heat pumps incorporated into the system. During periods of peak demand, these sources are augmented by oil-fired boilers that also act as backups for the geothermal system.

In the Western Canada Sedimentary Basin, the presence of hot water in deep reservoirs was well known from petroleum exploration wells at least as early as 1950. By 1976, personnel of the Earth Physics Branch of EMR were quite aware of the geothermal projects in France, and the branch had commissioned a study of geothermal resources in sedimentary strata of western Canada. At about the same time, David Surjik, a Regina geophysicist, suggested to Lloyd Barber, then president of the University of Regina, the use of hot water from deeply buried aquifers for heating. A feasibility study of the Regina–Moose Jaw area, proposed by the University of Regina's Energy Research Unit to the Earth Physics Branch, was conducted (Vigrass *et al.*, 1978). It directly led to the drilling of the Regina geothermal well in 1978-79. The feasibility study, the drilling and completion of the well, and most of the attendant research were funded by EMR.

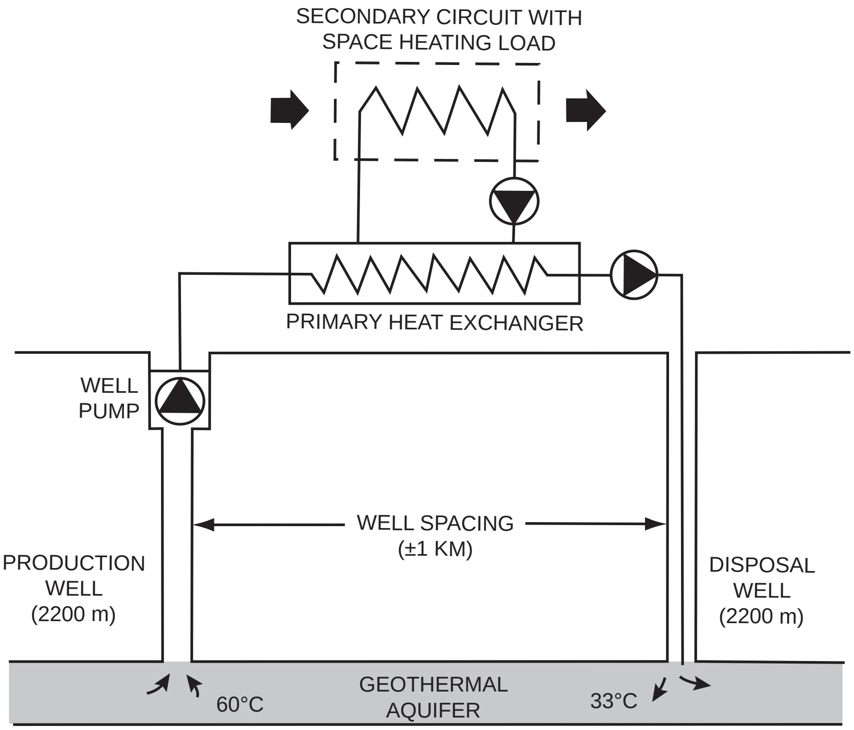

Figure 2 - Diagram of the French geothermal doublet system as applied to the Regina geothermal well. In the practical case, a heat pump and auxiliary back-up would be added.

3. Geological Framework of the Regina Area

a) Stratigraphy

The southern two-thirds of Saskatchewan lies within the Western Canada Sedimentary Basin where, toward its eastern margin, Precambrian crystalline rocks are covered by nearly flat-lying Phanerozoic sedimentary rocks. The sedimentary section in the province thickens from its zero edge on the Canadian Shield to a maximum thickness of about 3300 m in the Williston Basin at the International Border south of Weyburn.

In the Regina area, the Phanerozoic strata can be grouped into three gross geological subdivisions: a Basal Clastic Unit of sandstone and shale; a Carbonate-Evaporite Unit of dolostone, limestone, salt

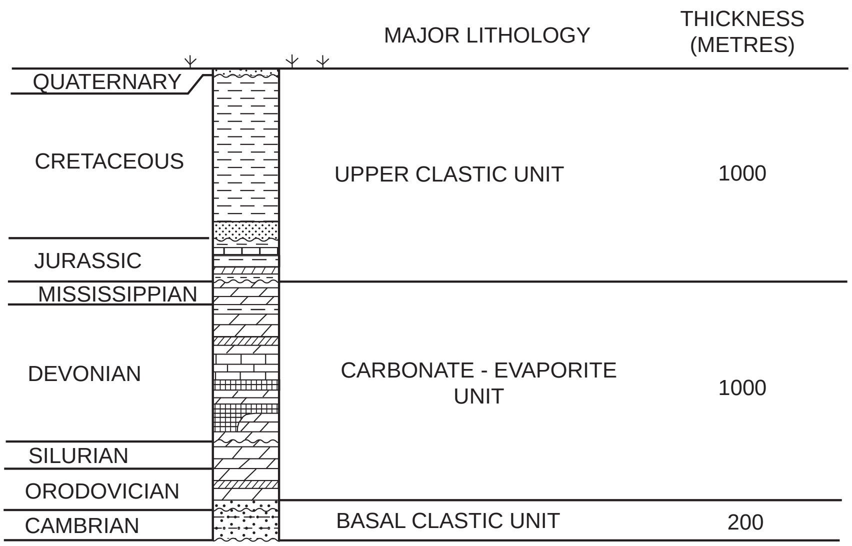

Figure 3 - Major sedimentary units in the vicinity of Regina. Patterns show lithologies: stippling, sandstone; dashes, shale; vertical brickwork, limestone; diagonal brickwork, dolostone; squared, halite (salt); diagonal slashing, anhydrite; and wavy contact, unconformity.

(halite and potassium salts), and anhydrite; and an Upper Clastic Unit composed predominantly of shale and sandstone (Figure 3).

The Basal Clastic Unit consists of the Cambrian Deadwood Formation, which unconformably lies on eroded and weathered Precambrian crystalline rocks, and the overlying Ordovician Winnipeg Formation.

The Carbonate-Evaporite Unit extends upward from Ordovician dolostones of the Red River to the limestone and dolostone of the Mississippian Souris Valley Formation. Bedded salt up to 115 m thick occurs in the lower part of the Devonian section, and one, two, or three layers of evaporite are locally present higher in the Devonian section.

The lower part of the Upper Clastic Unit is Jurassic in age and consists of shale and sandstone with beds of limestone and minor anhydrite. The Jurassic strata are overlain by up to 90 m of sandstone and shale of the Mannville Group (sometimes referred to as the Blairmore). Cretaceous strata above the Mannville largely consist of claystone, typically 600 to 900 m thick; these beds are the youngest consolidated rocks of the area. The overlying unconsolidated Quaternary deposits are mainly Pleistocene glacial drift.

b) Structure

Strata on the northern flank of the Williston Basin dip gently toward the basin centre with an average slope of about 5 m/km. Some local structural anomalies in the sedimentary rocks reflect deep-seated basement features. Many other structures in Devonian and younger strata are related to the solution of salt in the subsurface, a process that occurred episodically from Late Devonian to Recent times. A large salt-free tract extends northward into the Regina area, 13 to 22 km west of the city. Smaller solution-related depressions occur in the northern part of Regina and near the southwestern city limits. A seismic profile that was shot as part of the feasibility study did not show noticeable salt solution and collapse at the site of the Regina geothermal well.

c) Hydrogeology

Many Paleozoic aquifers in the northern Williston Basin area are widespread, and water is moving through them as part of a regional flow system. In general, water is flowing from elevated recharge areas in the southwest to low-lying discharge areas in the northeast. Total dissolved solids in the waters vary and are dependent on their proximity to evaporite deposits. Most reservoir waters are very saline where salt beds are preserved and are less saline in salt-free areas.

4. Regina Well

a) General Results

The U of R Regina 3-8-17-19W2 well was drilled at the southern edge of the campus in the winter of 1978-79. A summary of well completion data is reported in Table 1. More detailed data are available in the well files stored at the repository of Saskatchewan Industry and Resources. Core and samples are available for examination at the Saskatchewan Subsurface Geological Laboratory.

A full section of Prairie salt (112 m) and a thick Davidson salt (53 m) were encountered (Table 1). Aquifers with a net reservoir thickness in excess of seven metres are listed in Table 2. Drillstem tests, cores, and logs showed that thick aquifers with good reservoir occur in the Winnipeg and Deadwood formations; these zones are the deepest so

Table 1 - Regina geothermal well.

1a - General completion data.

Well Name	U of R Regina 3-8-17-19
Location	Lsd 3 Sec 8 Tp 17 Rge 19 W2M
Latitude and longitude	50.41434N, 104.58184W
Kelly bushing (KB) elevation	581 m
Ground Elevation	576 m
Spudded	28 Dec 1978
Rig Release	7 Feb 1979
Final Depth (log)	2215 m; deepened to 2226 m in subsequent operation
Operator	University of Regina
Contractor	Mustang Drilling (Rig No. 1)
Surface casing	273 mm landed at 228 m KB
Production casing	178 mm landed at 228 m KB Cemented in two stage to 201 m KB Possilbe free pipe or cement poor from 608 to 1145 m KB
Open hole	222 mm from 2034 to 2226 m KB

1b - Main geological markers (the stratigraphic sequence is shown in detail in Figure 8).

Marker	KB Depth (m)	Elevation (m)
Cretaceous (Montana Group)	14	+567
Mannville	703	-122
Jurassic (Vanguard)	790	-209
Mississippian (Souris Valley)	989	-408
Bakken	1097	-516
Devonian (Big Valley)	1104	-523
Birdbear	1164	-583
Davidson Salt	1454	-873
Base of Davidson Salt	1507	-926
Dawson Bay	1538	-957
Prairie Salt	1586	-1005
Winnipegosis	1698	-1117
Ashern	1751	-1170
Silurian (Interlake)	1763	-1182
Ordovician (Stonewall)	1885	-1304
Red River (Herald)	1950	-1369
Yeoman	1968	-1387
Winnipeg (Icebox)	2034	-1453
Black Island	2045	-1464
Cambrian (Deadwood)	2083	-1502
Precambrian (Basement)	2209	-1628
Total Depth	2215	-1634

1c - Cores.

Core No.	Depth (m)	Formation	Recovery (m)
1	1987 to 2002	Red River	15.2
2	2045 to 2063	Winnipeg	18
3	2067 to 2085	Winnipeg-Deadwood	18
4	2095 to 2105	Deadwood	9.4
5	2201 to 2212	Deadwood-Basement	9

1d - Main logs.

	Depth (m)
Dual induction laterolog	229 to 2215
BHC sonic gamma	229 to 2211
Comp. density sidewall-neutron	229 to 2214
Temperature log	213 to 2211
Bond log-casing inspection	100 to 2034

1e - Drillstem tests.

DST #	Depth (m)	Formation	Recovery Salt water	Shut-in Pressure (Mpa)	Depth (Elev) (m) of pressure gauge
1	2042 to 2067	Winnipeg	1975 m	21.484	2045 (-1464)
2	2067 to 2088	Winnipeg	2034 m	21.562	2069 (-1488)
3	2190 to 2214	Deadwood	2017 m	22.334	2193 (-1612)
4	2152 to 2183	Deadwood	2095 m	Not recorded	2140 (-1559)
5	2034 to 2215	Winnipeg-Basement	to surface	Not recorded	2014 (-1433)

Table 2 - Aquifers over seven metres thick encountered in the Regina well.

Zone	Aggregate Net Thickness (m)
Mannville	22
Souris Valley (upper)	9
Birdbear (lower)	8
Duperow (lower)	26
Interlake	11
Stonewall	8
Yeoman	16
Winnipeg	31
Deadwood	80

they contain the hottest water. The well was completed as a Basal Clastic Unit geothermal test well with open hole below the casing shoe at 2034 m.

b) Basal Clastic Unit

Lithology

The Deadwood Formation comprises 126 m of sandstone, siltstone, and mudstone (Figure 4). The basal member, 19 m thick, consists of quartzose sandstone with accessory feldspar and biotite. The sandstone is medium to coarse grained with occasional pebbles, strongly cross-bedded, and moderately cemented with silica; porosity is good at 15 to 20%. Gamma-log spikes reflect potassium feldspar or granitic pebbles rather than claystone. Deadwood sandstones above the basal member are quartzose and slightly micaceous, are fine to medium grained, and contain a green mineral commonly referred to as glauconite. Sporadic sandstone cement is generally siliceous but, in the upper part of the formation, the cement locally consists of calcite or anhydrite. Many sandstone layers have poor to fair porosity (5 to 15%). Interbedded mudstone in the lower Deadwood (Figure 3) is green to grey shale which grades upward into green, grey, white, and red claystone and silty claystone. The uppermost 6 m of the Deadwood are micaceous, glauconitic or chloritic green mudstones with thin interlayers of quartzose siltstone.

The Winnipeg Formation, unconformably overlying the Deadwood, comprises the lower sandy Black Island Member (38 m) and the overlying muddy Icebox Member (11 m). The Black Island is a fining-upward sequence, medium grained and well sorted in the lower part becoming very fine grained and slightly muddy above. Most of the sandstone is lightly cemented with calcite and has fair to good porosity (10 to 20%). The Icebox Member is largely light grey to green, silty to sandy dolomitic mudstone and is in abrupt contact with the overlying sandy dolomitic limestone of the Yeoman Formation.

Definition of Aquifers

Well control near Regina, though sparse, suggests that a mudstone aquitard several metres thick occurs at the top of the Deadwood Formation. The position of this mudstone layer below the sub-Winnipeg unconformity suggests that it may be a paleosol or regolith and that, over a large area, the Winnipeg and Deadwood can justifiably be considered as separate aquifers. In addition, in the Regina 3-8 well, mudstone zones occur at 2110 m and 2150 m. The basal 19 m of the Deadwood lithologically differ from the overlying beds. For analysis and description, the Basal Clastic Unit is sub-divided into the five aquifers shown in Figure 4.

Aquifer Properties from Core, Logs, and Drillstem Tests

Aquifer properties are assessed in order to predict hydraulic-head drawdown at the well and to determine pumping power required under various utilization schemes. Knowing the properties also allows us to determine pressure drawdown over a wide area.

Net effective sandstone thickness, average porosity, and average permeability for the defined aquifers were determined from core and logs (Table 3). For the entire Basal Clastic Unit, the total net thickness of sandstone capable of significant fluid flow is 111 m, and the weighted average porosity is 13.2%. The middle and lower Deadwood aquifers were not cored, so their average permeability (104 mD) is based on core from the upper Deadwood, a zone of somewhat lesser porosity. The weighted average permeability for the entire unit is 115 mD. Using values of bulk modulus reported for Winnipeg sandstones by Roegiers and McLennan (1980), storativity of the entire Basal Clastic Unit was approximated as 5×10^{-4}.

Drillstem tests 1, 2, and 3 were used to assess permeability capacities and permeabilities (Table 4). A range of permeabilities is given because the determination is sensitive to plotting of the final shut-in pressure build up (Horner, 1967); the slope of this curve is steep where the tested interval is thick or the reservoir has high permeability. For the total Winnipeg, the DST permeability is at least four times as great as that estimated from core. It is concluded that the flow properties are much better than those indicated by the core determinations.

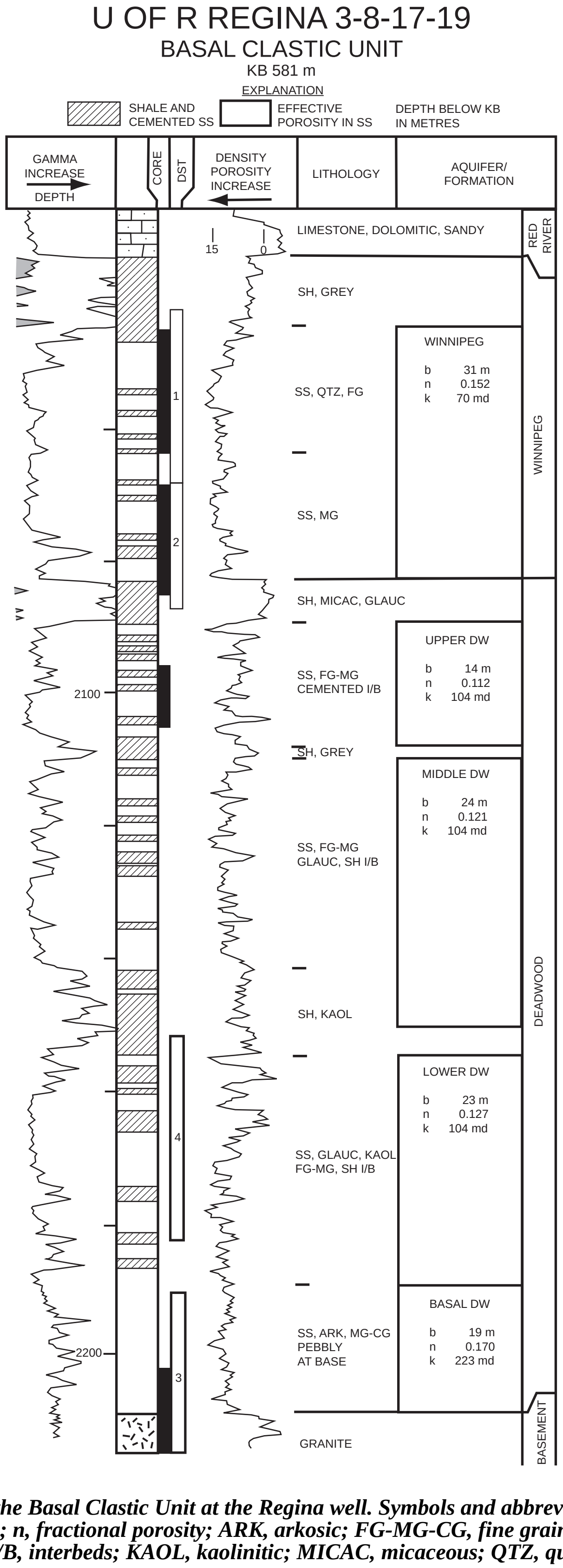

Figure 4 - Columnar section of the Basal Clastic Unit at the Regina well. Symbols and abbreviations: b, net effective thickness; k, permeability in mD; n, fractional porosity; ARK, arkosic; FG-MG-CG, fine grained-medium grained-coarse grained; GLAUC, glauconitic; I/B, interbeds; KAOL, kaolinitic; MICAC, micaceous; QTZ, quartzose; SH, shale and mudstone; and SS, sandstone.

Table 3 - Net effective thickness, porosity, and permeability from cores and logs.

Aquifer (Depth in m)	Net Effective Thickness (m)	Average Porosity (%)	Average Permeability (mD)
Winnipeg (2045 to 2083)	31	15.2	70
Upper Deadwood (2089 to 2108)	14	11.2	104
Middle Deadwood (2110 to 2150)	24	12.1	104
Lower Deadwood (2150 to 2190)	23	12.7	104
Basal Deadwood (2190 to 2209)	19	17	223
Basal Clastic Unit (2045 to 2209)	**111**	**13.2**	**115**

Note: Average porosity and permeability for the Basal Clastic Unit are weighted arithmetic averages of the component aquifers.

Table 4 - Permeability capacities and permeabilities from drillstem tests, Basal Clastic Unit.

Aquifer	DST #	Permeability Capacity Range (mD.m)	Net Thickness (m)	Permeability Range (mD)
Upper Winnipeg	1	3250 to 4330	19.8	160 to 220
Lower Winnipeg	2	6310 to 12 620	11.4	550 to 1110
Total Winnipeg	1 and 2	9560 to 16 950	31.2	310 to 540
Basal Deadwood	3	2700 to 5600	19.0	140 to 290

Pump Tests

To assess well performance and reservoir parameters, high-volume pump tests were conducted between June 12 and 14, 1979. A 60 horsepower, 22-stage Reda submersible pump hung on 90 mm tubing was set with intake at 196 m KB. A trial test of 45 minutes was followed by Test No. 2 (370 minutes) and Test No. 3 (360 minutes). The tests were run on separate days at a constant rate of 57.5 m^3/h (253 usgpm) with time between tests sufficient to allow at least 95% recovery of head. Drawdown was measured by a Telrite sonolog which measures water levels by a sonic method with a precision of five metres. Recording pressure transducers were attached to the tubing at various depths, but only the transducer at 35 m recorded successfully.

Elevation of the surface of the water during the production-drawdown cycles for Tests No. 2 and No. 3 is plotted against the logarithm of time (Figure 5). During the early part of Test No. 2, the observed drawdown was 66 m but this decreased to 56 m later in the test; the change may have occurred as a result of expansion of the water column with warming or it may have resulted from improved transmissibility of the aquifer with the inflow of water. Upon initiation of pumping for Test No. 3, the water level fell rapidly by 50 m and the drawdown remained at about 50 m for the duration of pumping (Figure 5). During recovery of each pumping cycle, the water level rose rapidly during the first 90 seconds and reached a maximum level 30 to 36 minutes after pump shut-down. During the next 12 to 16 hours, the water level declined by 0.5 to 3.5 m as a result of contraction of the water column with cooling in excess of recovery from the pumping cycle. The maximum temperature of produced water was 53°C during Pump Test No. 2 and 53.8°C during Pump Test No. 3.

To assess aquifer characteristics with precision, pressure measurements at the face of the producing zone are required. In Test No. 3, the decrease of head due to pipe friction is estimated to be about 7 m, and the increase of head due to a temperature rise in the 2000 m fluid column approximates 10 m. The drawdown of water with density of 1075 kg/m^3 was approximately 50 m (525 kPa) after six hours of pumping at 57.5 m^3/h. The Theis solution (Freeze and Cherry, 1979, p317-18) results in an aquifer permeability capacity of 39 300 mD.m and average permeability of 350 mD.

Summary of Aquifer Properties

A net effective thickness of 111 m, average porosity of 13.8%, and storativity of 5×10^{-4} are accepted as working values. Permeabilities obtained from drillstem tests and the pump tests are much higher than those obtained from cores and are possibly an indication of fracturing within the producing zone. An average permeability of 350 mD for the open interval at the Regina well is accepted as a working value. The indicated productivity index is estimated at 0.11 m^3/h per kPa of drawdown.

Predicted Drawdown During Production

At a production rate of 57.5 m^3/h and using the working values of properties described above, the Theis solution (Freeze and Cherry, 1979, p317-18) indicates an estimated drawdown at the well of 71 m after 100 days of continuous pumping. If the production rate is 100 m^3/h, the drawdown after six hours is predicted to be

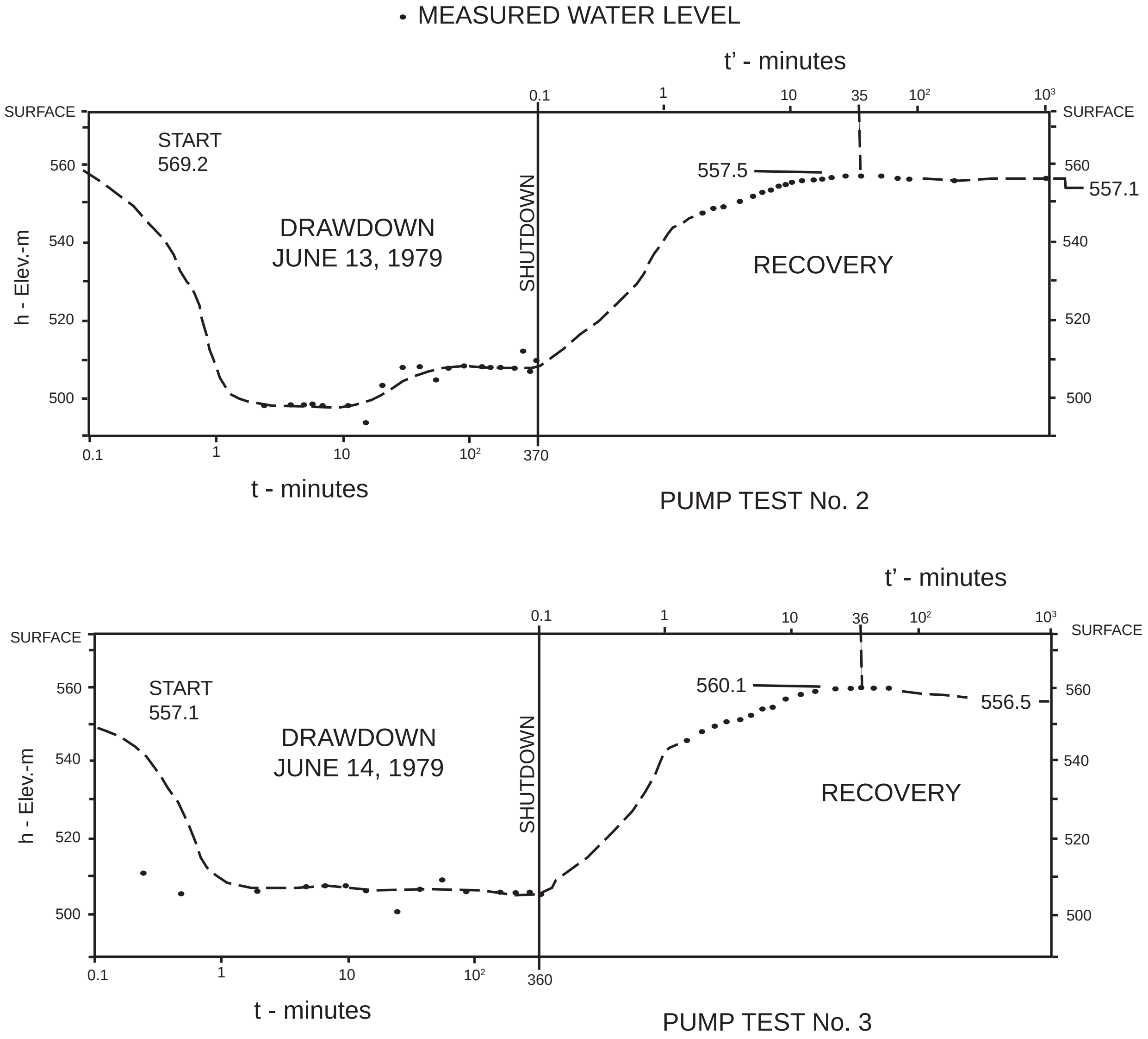

Figure 5 - Drawdown-recovery diagrams for Pump Tests No. 2 and No. 3. Symbols: t, time after start of pumping and t', time after start of recovery.

approximately 100 m; this includes an additional 10 m of lost head due to pipe friction. Following 100 days of continuous pumping at 100 m^3/h, the estimated drawdown is predicted at 135 m. After 100 days of steady pumping, the radius of the cone of depression of pressure exceeds eight kilometres and the area of the zone affected is greater than 200 km^2. It is unlikely that the overlying aquitards are completely impermeable and it is expected that leakage into the aquifer will limit the drawdown at the well to about 140 m and the depth below surface will stabilize at about 150 m. The lifting power required to bring the water to the surface is estimated at 60 horsepower or 45 kW.

Formation Fluid Pressures

Extrapolated shut-in virgin fluid pressures were obtained on DSTs 1, 2, and 3 and a virgin formation pressure was estimated from the flow pressure of DST 4 (Table 5). Instrumental and other error limits are estimated at ±100 kPa for DSTs 1 to 3 and ±150 kPa for DST 4. Standing hydraulic heads corresponding to the pressures are based on formation water having a density of 1058 kg/m^3 at a reservoir temperature of 60°C. Evidence is strong that the Winnipeg aquifer has a significantly higher fluid potential than the basal Deadwood. Within the Basal Clastic Unit, systematic decrease of fluid potential with increasing depth is indicated; this would result in a downward flow of fluid through the open borehole. The relationship of the pressures to the static gradient of formation fluid at 60°C (Figure 6) emphasizes a potential downward flow of fluid in the well bore from the Winnipeg to the lower part of the Deadwood.

Table 5 - Formation fluid pressures, Basal Clastic Unit.

Aquifer	DST No.	Gauge Elevation (m)	Pressure (kPa)	Hydraulic Head (Elevation in m)
Upper Winnipeg	1	-1464	21 484	+606
Lower Winnipeg	2	-1488	21 562	+589
Lower Deadwood	4	-1559	21 958*	+557
Basal Deadwood	3	-1612	22 334	+540

Note: * Shut -in pressure estimated from final flowing pressure.

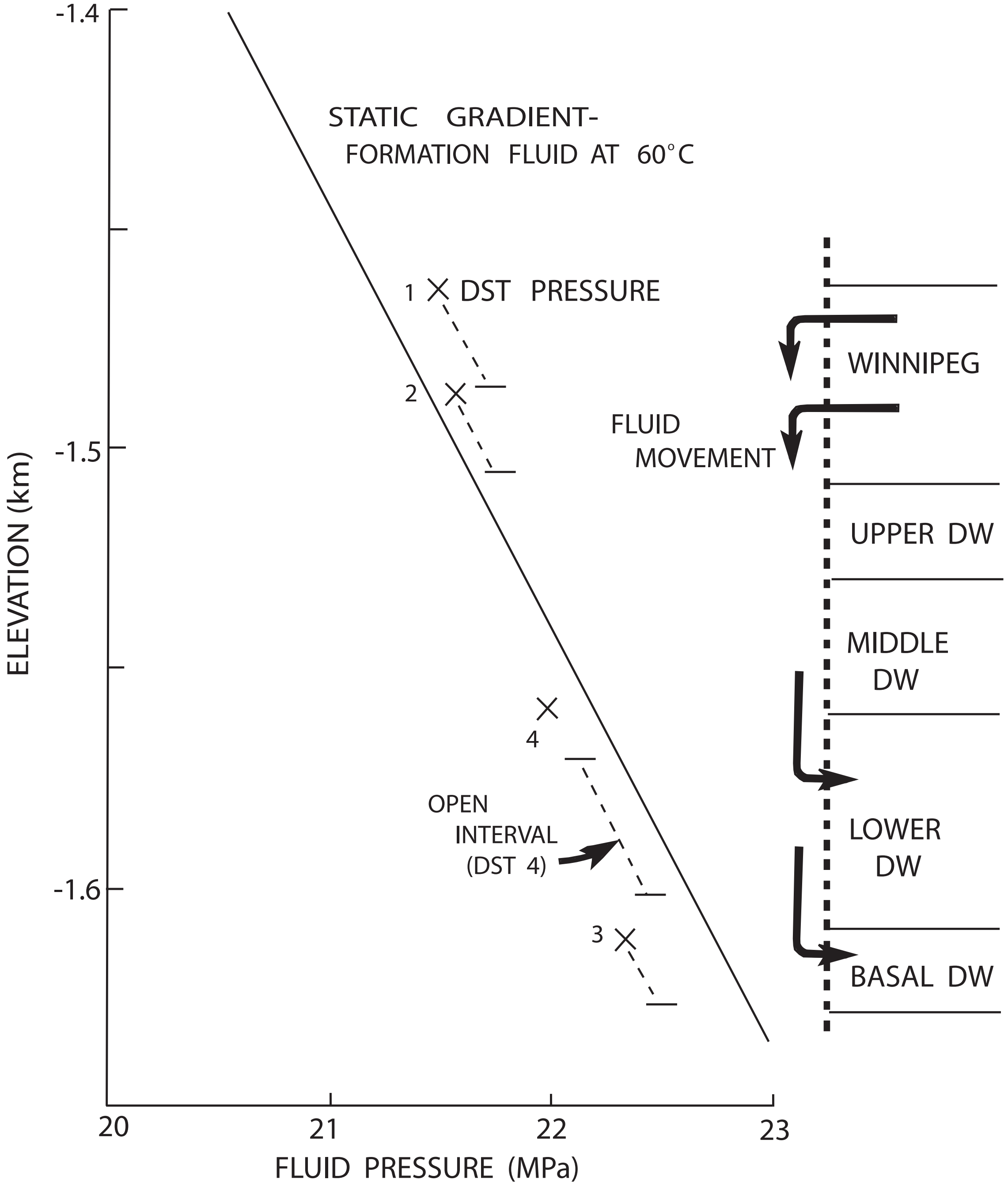

Figure 6 - Virgin fluid pressures in the Basal Clastic Unit, as measured in drillstem tests, plotted against elevation. Symbols: DW, Deadwood; dashed line, open interval during drillstem test; and x, extrapolated shut-in pressure at point of measurement.

Fluid Level Behaviour in the Standing Well

Fluid levels of the Regina well were observed sporadically over a period of 2.7 years after the well was pumped for corrosion testing (Table 6). Observations during the first eight days show that the fluid column was still cooling following the pumping event. In the subsequent 1.2 to 2.7 years, the surface of the water ranged from a high level of 9.2 m below ground surface to a low of 14.6 m below the ground. The exact reason for this variation is unknown.

More precise fluctuations in fluid level were monitored continuously from February 23, 1983 to March 15, 1985 using a float-type recorder provided by the Saskatchewan Research Council. Depth of the water surface was within the range noted above. The well responded to changes in atmospheric pressure with a barometric efficiency of about 0.75 and to earth tides with peak-to-peak displacement of about 20 mm. In addition, the records show numerous "spikes" that have a general rise time of less than one hour and a decay time that ranged from hours to days (Figure 7a). The spikes had average amplitude of 40 to 60 mm with a maximum of 154 mm (Figure 7b). Both frequency and size of the spikes decreased during the recording period (all information from Garth van der Kamp of Saskatchewan Research Corporation, pers. comm., 1985). The spikes may be related to fluid movement that was taking place in the well bore between the Winnipeg and the basal Deadwood. Alternatively, as suggested by the shape of the spikes, they may have resulted from slip-stick stress relief events on fractures that could have been created in the small volume hydrofracturing treatments conducted in May and June 1979.

Well Behaviour During the Deepening Attempt

In March 1985, an attempt was made to deepen the Regina well by 60 m to a depth of 2275 m KB. The major objectives were to measure the temperature gradient in the basement rock and to take two cores in order to measure conductive heat flow from the Precambrian granitic rock. A large service rig was used with brine as the drilling fluid. Major problems arose as a result of high permeability near the Deadwood-Precambrian basement contact and the flow pattern within the open Basal Clastic Unit; no core was cut and drilling was abandoned after penetrating only 11 m of granitic rock.

During this drilling operation, the lower 30 m of the Basal Clastic Unit (and possibly the open Precambrian basement) took fluid with extreme ease and circulation was lost under low pump pressure. In order to remedy this situation, the drilling fluid was lightened up with fresh water and this resulted in a flow of brine to the surface at rates as high as 19 m^3/h. This brine flow presumably came from the Winnipeg Formation. The rocks near the Deadwood-Precambrian basement contact have high permeability, are presumably fractured, and have a lower hydraulic potential than the aquifers higher in the section. The delicate balance between lost circulation in the vicinity of the Deadwood-Precambrian basement contact and the brine flow from, possibly, the Winnipeg appeared to amount to about 200 kPa or 20 m of fresh-water head (Ruse and Vigrass, 1985).

The deepening attempt was finally defeated by differential sticking of the drill pipe below a depth of 2178 m KB. This situation resulted when the "thief" zone near the Deadwood-Precambrian basement contact took on water rapidly. This behaviour confirms the high permeability zone in the basal Deadwood-Precambrian basement section with an "under-pressured" basal Deadwood and an "over-pressured" Winnipeg.

Table 6 - Water-level measurements in the Regina well following low-rate pumping for chemical and corrosion testing.

Date (y-m-d)	Days After End of Pumping	Water Level Elevation (m)	Depth (m) Below Surface at Elevation +576m
80-04-08	6.7	+567.6	8.4
80-04-09	7.7	+567.5	8.5
81-06-11	436	+565.4	10.6
81-06-18	443	+564.4	11.6
81-06-22	447	+564.1	11.9
81-06-23	448	+564.1	11.9
81-06-26	451	+563.6	12.4
81-06-29	454	+563.3	12.7
81-06-30	455	+563.2	12.8
81-07-02	457	+563.0	13.0
81-07-03	458	+562.9	13.1
81-09-15	532	+561.4	14.6
81-10-05	552	+561.7	14.3
82-12-14	987	+566.8	9.2

c) Downhole Temperatures and Temperature Gradients

A high-precision temperature log (Figure 8) was run by Alan Jessop of the Geological Survey of Canada on October 26, 1983; the thermal disturbance resulting from well operations was minimal because measurements were made 1,729 days after drilling. Stationary readings were taken at a spacing of 25 m except for the interval from 950 to 1225 m where the measurement points were spaced at 10 m. Accuracy of depth was one metre and accuracy of temperature was within five milli-kelvin (mK) or five one-thousandths of a degree

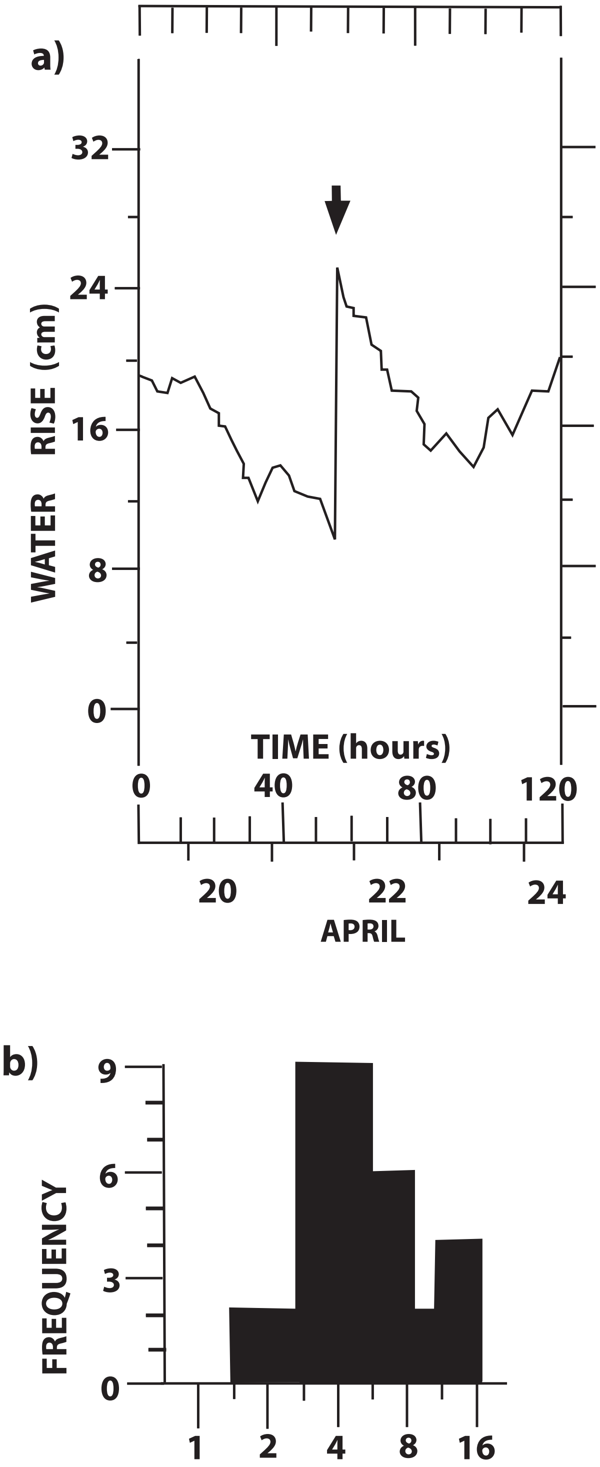

Figure 7 - Water-level "spikes" in the standing Regina well: a) prominent water-level rise (arrow) and slow decay on April 21 to 22, 1983 (barometric and earth tidal effects have not been removed); b) frequency histogram of 34 detectable "spikes" recorded in 83 days from February 23 to May17, 1983.

Celsius. The temperature increases downward from 10°C at 200 m to close to 59°C in the lower part of the Deadwood.

The temperature gradient, calculated from the difference between readings, shows a decreasing trend from 40 to 20 mK/m in the Upper Clastic Unit, a variation about 18 mK/m in the Carbonate Evaporite Unit and anomalously low values in the Basal Clastic Unit. An anomalously high temperature gradient is prominent across the Bakken, a formation largely composed of organic shale with high insulating value. Equally prominent are the effects of highly conductive halite in the Davidson and Prairie evaporites where the temperature gradient is about 15 mK/m (Figure 8).

For the uncased Winnipeg and Deadwood, the temperature gradient falls to1 mK/m and is lower than 5 mK/m in the interval 2060 to 2175 m. This is much too low to be the result of conductivity alone. Little doubt exists that the isothermal effect is the result of water movement in the open borehole from the Winnipeg Formation to the region of the Deadwood-Precambrian basement contact. The *in situ* rock temperature at the top of Precambrian basement is probably 61°C (Jessop and Vigrass, 1989, p164).

d) Chemistry of Water and Corrosion Tests

Major Ions

Routine chemical analyses for major ions were conducted by Chemical and Geological Laboratories, Calgary, on water recovered from pump and drillstem tests. The water sample considered the least contaminated by the salt-saturated drilling fluid was recovered after pumping for a total of 13 hours and a total production of 749 m^3 of brine. Reported total dissolved solids content for this water, shown as Basal Clastic Unit in Table 7, is 108 534 g/m^3 with a reported density of 1075 kg/m^3 at 25°C. Samples from DSTs 1 and 3 were considered to be contaminated by 5 to 10% drilling fluid, which was rich in sodium, chloride, potassium, and sulphate, but low in calcium and magnesium. When adjusted for this contamination, the ionic ratios of the drillstem test waters are similar to those of the water obtained on the pump test. The sodium-chloride-sulphate water in the Basal Clastic Unit is characteristic of the deep groundwaters of the northern Williston Basin where bedded halite is present and natural groundwater movement is sluggish.

Minor and Trace Ions

Analyses were conducted by Chemical and Geological Laboratories Limited, University of Regina Geochemical Laboratory, and Barringer Magenta Limited. Most cations were determined by argon plasma absorption. Anions and uranium, rubidium, arsenic, mercury, and selenium were determined by a variety of methods. The University of Regina Chemistry Department determined iodine by the ceric-arsenium method.

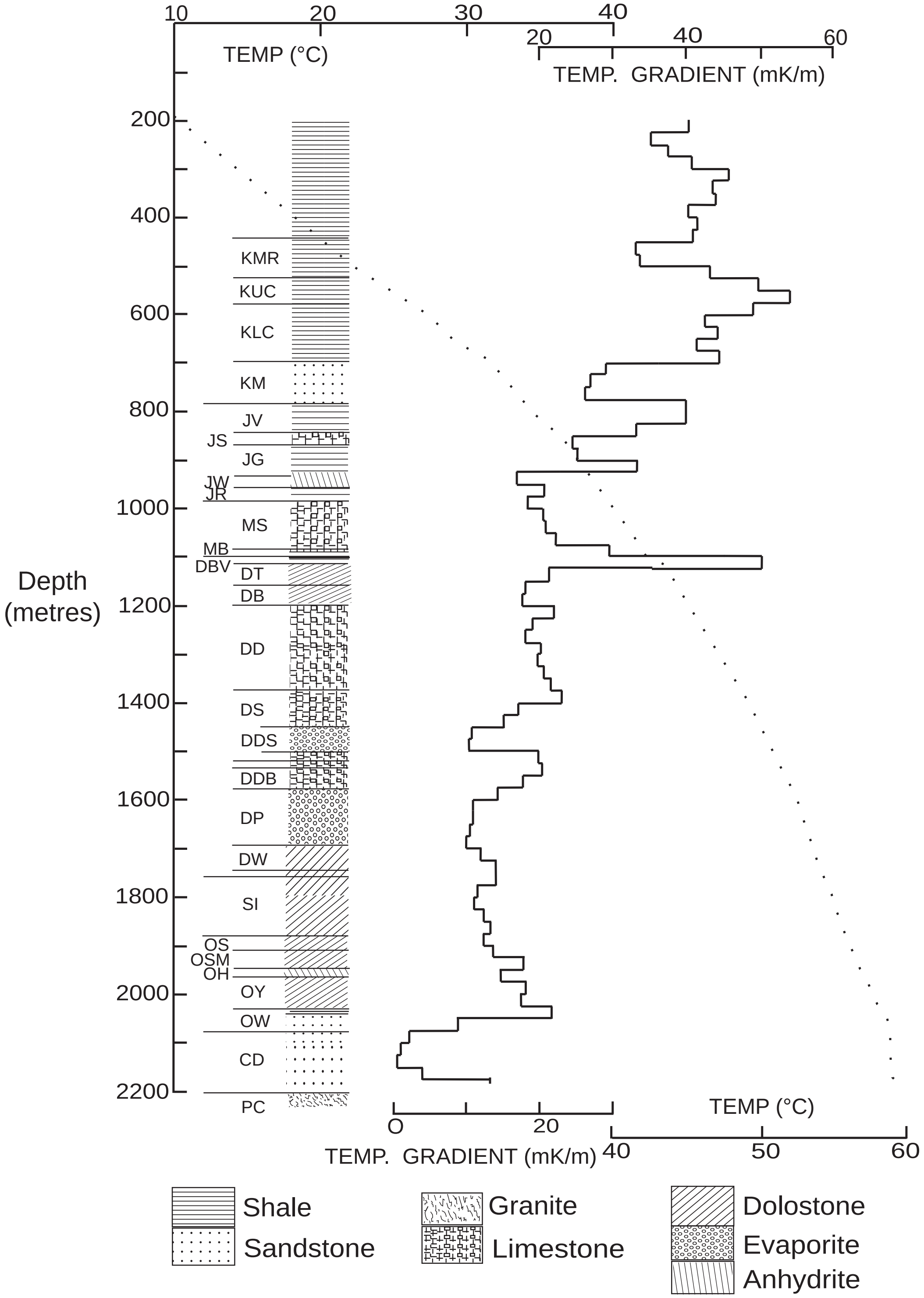

Figure 8 - Temperature, temperature gradient, and lithological section for the Regina well. Temperature shown by points and gradient (solid line) is calculated over 25 m intervals (after Jessop and Vigrass, 1989, Figure 3). Abbreviations for the lithological units: KMR, Milk River; KUC, Upper Colorado; KLC, Lower Colorado; KM, Mannville; JV, Vanguard; JS, Shaunavon; JG, Gravelbourg; JW, Watrous Anhydrite; JR, Watrous Redbeds; MS, Souris Valley; MB, Bakken; DBV, Big Valley; DT, Torquay; DB, Birdbear; DD, Duperow; DS, Souris River; DDS, Davidson Salt; DDB, Dawson Bay; DP, Prairie Evaporite; DW, Winnipegosis; SI, Interlake; OS, Stonewall; OSM, Stony Mountain; OH, Herald; OY, Yeoman; OW, Winnipeg; CD, Deadwood; and PC, Precambrian basement. The first letter of each abbreviation designates the geological system: K, Cretaceous; J, Jurassic; M, Mississippian; D, Devonian; S, Silurian; O, Ordovician; and C, Cambrian.

Table 7 - Major ion analyses of waters from the Basal Clastic Unit, Regina well.

Formation	Constituents in g/m³ TDS	Na + K	Ca	Mg	Cl	HCO_3	SO_4	Density (kg/m³ at 25°C)
Basal Clastic Unit	108 534	39 608	1942	365	62 200	312	4107	1075
Lower Winnipeg	117 426	43 569	1477	333	67 500	403	4144	1077
Basal Deadwood	129 605	47 916	1806	411	75 250	366	3856	1084

Main results for the minor elements strontium, lithium, silicon, boron, bromine, and zinc are reported in Table 8. The modal value for strontium is 37.5 g/m^3 but higher values of 45 to 55 g/m^3 are reported for the basal Deadwood, just above weathered Precambrian basement. Water from the basal Deadwood is also slightly enriched in lithium. Boron values fall into two definite groups: 4.5 to 6.5 g/m^3 analyzed by one laboratory at an early date and a second group at 7.0 to 9.5 g/m^3 analyzed at a later date; contamination of the samples analyzed later is a possibility. Zinc values showed considerable scatter from below the detection limit of 0.5 g/m^3 (5 of 20 samples) to a maximum of 6 g/m^3.

Trace elements reported as having concentrations of less than 1.0 g/m^3 are rubidium, barium, uranium, mercury, arsenic, selenium, iodine, cobalt, and copper (Table 9). Modal values are not given in the table because of the small numbers of analyses, but a representative value for rubidium is 850 mg/m^3. Some water samples have barium below the detection limit of 250 mg/m^3 and, where this element was detectable, it generally had a concentration of less than 500 mg/m^3. Special analyses of six samples for uranium indicated very low values at 2.2 to 3.4 mg/m^3; samples of water taken during the pump test showed activity of radon as high as 1.48 x 10^5 Bq/m^3. Mercury has very low concentration with two out of four analyses below the detection limit of 0.02 mg/m^3. Values for arsenic range from below the detection limit of 5 mg/m^3 to a high value of 73 mg/m^3 in the basal Deadwood above Precambrian basement. Selenium ranges from below the detection limit of 1 to 19 mg/m^3. Iodine, at less than 1.0 g/m^3, is low compared to brines in other sedimentary basins.

Dissolved Gases, pH, and Redox Potential

For the majority of the dissolved gases, the most reliable results were obtained during a pump test conducted specifically to measure pH and the amount of gases, and to measure corrosion rates by direct testing (Postlethwaite *et al*., 1980a, 1980b). During the test, conducted from March 26 to April 1, 1980, water was pumped from the well at 8.6 m^3/h and passed through a test section fitted with various chemical and physical test sensors. Pressure was maintained at 269 kPa so that dissolved gas did not come out of solution within the confines of the test section. The water then passed into a separator where dissolved gases came out of solution at a pressure of 123 kPa, as close to atmospheric as practical. Dissolved oxygen and pH were measured directly in the test section and the water and gases were taken from the separator for immediate analysis. Temperature of both sections was 40°C.

The main results are reported in Table 10. Probable carbon dioxide and nitrogen content in the downhole water are the amounts present in the evolved gas stream plus the amounts present in the water stream based on Henry's Gas Law. Evidence is strong that the gas-liquid separation is incomplete and that the carbon dioxide and nitrogen content may be two to five times higher than indicated (Postlethwaite *et al.*, 1980b). Hydrogen sulphide content of 20 to 26 g/m^3 is based on direct

Table 8 - Minor element analyses of waters from the Basal Clastic Unit.

Minor Elements	Range of Values (g/m³)	Modal Value (g/m³)	No. of Analyses
Strontium	30 to 55	37.5	22
Lithium	7 to 11	9	12
Silicon	4 to 21	10	17
Boron	4.5 to 9.5	5.5 and 8.5	20
Bromine	23 to 29	25	10
Zinc	<0.5 to 6	3.5	20

Table 9 - Trace element analyses of waters from Basal Clastic Unit.

Trace Elements	Range of Values (mg/m³)	No. of Analyses
Rubidium	700 to 1000	4
Barium	250 to 2250	7
Uranium	2.2 to 3.4	6
Mercury	0.02 to 0.09	4
Arsenic	5 to 73	4
Selenium	1 to 19	4
Iodine	560 to 820	6

Table 10 - Gas analysis, pH, and Eh of water from pump test, Basal Clastic Unit.

	Gas Evolved in Separator Volume of Gas : Volume of Water = 0.016 m^3 Gas : 1.0 m^3 Water) (40°C and 123 kPa)			
Component	Volume (%)	Moles/m^3	g/m^3	Interpreted Probable Downhole Composition (g/m^3)
CO_2	4.03	0.0293	1.3	56
N_2	95.31	0.687	19.2	38
H_2S	0.29	0.00216	0.07	20 to 26
O_2	0.37	0.0026	0.08	1.0 to 1.3

pH before gas separation (40°C and 269 kPa): 5.2 to 5.3

Eh of DST waters (15.4°C): -20 to -95 mV

measurement of the component in the gas and water streams from the separator. Based on gas samples forwarded to Chemical and Geological Laboratories Limited, Calgary, the evolved nitrogen contains 4 to 5% helium and 1 to 2% hydrocarbons, mostly methane.

During the pump test, the pump inlet was about 38 m below the maximum drawdown level and precautions were taken to avoid air leakage into the system. After pumping for 100 hours, dissolved oxygen in the water stream was still about 1.0 g/m^3. The dissolved oxygen reported is not in equilibrium with the water as shown by the presence of dissolved hydrogen sulphide and hydrocarbons plus the reported redox potential (Eh) of -20 to -95 mV. The presence of a segregated aquifer free of hydrogen sulphide and hydrocarbons is highly improbable. The reported oxygen likely reflects an undetected leak.

The reported pH before gas came out of solution in the test section was 5.2 to 5.3. At 40°C and 269 kPa pressure, neutral pH for water is approximately 6.77 so the water is slightly acid, presumably due to the dissolved carbon dioxide and hydrogen sulphide. Most chemical analyses of oilfield waters report a pH of 7 or higher (routine determinations of pH are often made when the dissolved acid gases have come out of solution).

Corrosion Tests

Corrosion rates for steel were determined using both weight loss and electrochemical measurements over a period of 103 hours during the period from March 26 to April 1, 1980; corrosion rates were also determined for solder and brass/solder coupons (Postlethwaite *et al*., 1980a, 1980b). The rates determined by weight loss of the mild steel, more realistic than those determined by the electrochemical method, amounted to 0.20 to 0.25 mm/year. The weight loss of the solder and brass/solder coupons was not significant.

The corrosion rates as determined were low and fall within an acceptable range. Postlethwaite cautioned, however, that, when using brine solutions in the presence of H_2S and CO_2, that the corrosion rates are reported to accelerate after about one week. The tests conducted were too short for this effect to appear. Brines containing H_2S and CO_2 must be handled with caution, especially when oxygen is present. High strength steel must be avoided and stress corrosion cracking may occur (Postlethwaite *et al*., 1980a, p6-7).

Postlethwaite indicates that corrosion problems are most severe where dissolved O_2 is present along with H_2S and CO_2. We have stated that dissolved oxygen is highly unlikely to be present in the water in the reservoir, and the oxygen detected during the corrosion test was probably due to an undetected leak. Atmospheric oxygen must be kept out of the produced water and a closed system is mandatory. None-the-less, the cautions expressed by Postlethwaite (1980a) should be observed, and the assumption made that corrosion will occur. Experience over a period of more than 50 years has been gained in handling similar waters in the oilfields, and corrosion problems have been successfully handled by the petroleum industry.

e) Well Spacing in Proposed Doublet

Definition of well spacing is required for a two-well system in a sedimentary basin such as that proposed at Regina. Cooled water injected into the disposal well will eventually reach the producing well through the underground aquifer and the useful life of the system will be ended when the temperature at the producing well drops to a level that makes further production impractical. Factors to be taken into account include: 1) if the well spacing is increased, the life of the system is greater; 2) if the well spacing is decreased, the pressure effect at the producing well will be enhanced with a saving of producer pumping costs. In addition, savings in terms of the cost of connecting pipeline, if any, or length of a slanted borehole need to be considered. A computer-mathematical model was developed to appraise the Regina situation and to provide answers about a suitable well spacing (Hutchence *et al.*, 1986).

The basal Deadwood zone has the largest permeability of the aquifers open in the Basal Clastic Unit at the Regina well and it will accept a relatively high proportion of injected water. For several models, it was assumed that this aquifer, which has a net thickness of 19 m (along with an unknown thickness of fractured Precambrian basement), accepts 33 m^3/h of injected water, amounting to one-third of the water from the total Basal Clastic Unit when it is produced at 100 m^3/h. Assumptions were that the temperature of the injected water is 33°C, the original temperature of the aquifer is 62.5°C and the inter-well spacing is one kilometre. Isotherm plots after continuous pumping for several periods of time are shown in Figure 9. The cooling front with a temperature of 62.0°C (0.5°C below the original reservoir temperature) reaches the producing well after 35 years of continuous pumping. The temperature will decline slowly for some time after it reaches 62.0°C because the 60°C isotherm is some distance away (Figure 9). Based on the limited hydrogeological data available, a well spacing of about one kilometre appears to be reasonable when the Regina well is utilized in a production-disposal doublet.

5. Geothermal Resource in Saskatchewan

In the vicinity of Regina, the total fill of sedimentary rocks above Precambrian basement has a thickness of about two kilometres, increasing southward to about 3.3 km at the International Boundary south of Weyburn (Figure 10). Within the sedimentary fill, the temperature increases downward with depth so that, in general, the temperature at the base of the fill (*i.e.*, at the top of the Precambrian basement) is higher in areas of thick sedimentary rock. This general principle is modified by other factors including the magnitude of the heat flow from depth and the heat conductivity of the overlying sedimentary column. In addition, several authors have presented evidence that the regional flow of water in subsurface formations has a significant effect on temperature distribution within the strata of the basin; the hydrodynamic effect has been reported to be especially important within the Upper Clastic Unit (Majorowicz and Jessop, 1981, 1993; Hitchon, 1984; Majorowicz *et al.*, 1986; Jessop and Vigrass, 1989; Jones, 1991). A contrary view has been expressed (Bachu and Burwash, 1991).

An approximation of the temperature at the Precambrian basement surface across southern Saskatchewan is shown in Figure 11. The basement temperature has been estimated from place to place by obtaining the downhole temperatures measured during logging and testing operations in oil, gas, and potash wells and extending the value downward to the Precambrian surface by estimating the thickness and the geothermal gradient in the beds below the temperature measuring point. The map is generalized from the temperature distribution map of Majorowicz *et al.* (1986, Figure 17, p775) supplemented by additional data. The map is only an indication of the basement temperature, and better definition of the expected temperature can be obtained only by examination of data from the surrounding wells.

The top of the Precambrian basement is hottest, probably exceeding 100°C, in an area surrounding and south of Estevan (Figure 11). This basement-temperature high is situated outside of the area with thickest sedimentary fill, which is located due south of Weyburn (Figure 10) in a region of anomalously high heat flow probably related to a crustal feature known as the North American Central Plains conductivity anomaly (Jones and Craven, 1990).

A second area of high temperature, not related to thickness of sedimentary cover, is around Swift Current (Figure 11) where the expected temperature at the base of the sedimentary column is in excess of 70°C. This high-temperature area is probably related to anomalously high heat generation in basement rocks (Majorowicz *et al.*, 1986, p776). Wells at Wilhelm, 15 km northwest of Swift Current, produced commercial helium from Deadwood reservoirs resting on Precambrian rocks. The high heat flow may result from uraniferous Precambrian rocks from which the helium at Wilhelm was generated.

One might reasonably expect that the geothermal resource will be recoverable from waters having a temperature in excess of 50°C. Such waters are present in aquifers covering a very large area in southern Saskatchewan (Figure 11). The total amount of low-temperature geothermal energy available in the southern part of the province is very large indeed.

6. Development of Projects

Two options are outlined based on the size of the heat load. Option One utilizes direct transfer of heat from geothermal water produced at about 60 m^3/h (264 usgpm); this would satisfy a heating load of about 2.0 MW (thermal) (6.7 million Btu/h). Option Two, suitable for a very large heating load, utilizes direct transfer of heat from geothermal water produced at 104 m^3/h (458 usgpm); this option would satisfy a heating load of 3.5 MW (thermal) (12.0 million Btu/h). With the addition of electrically driven heat pumps, heat production for Option One could be

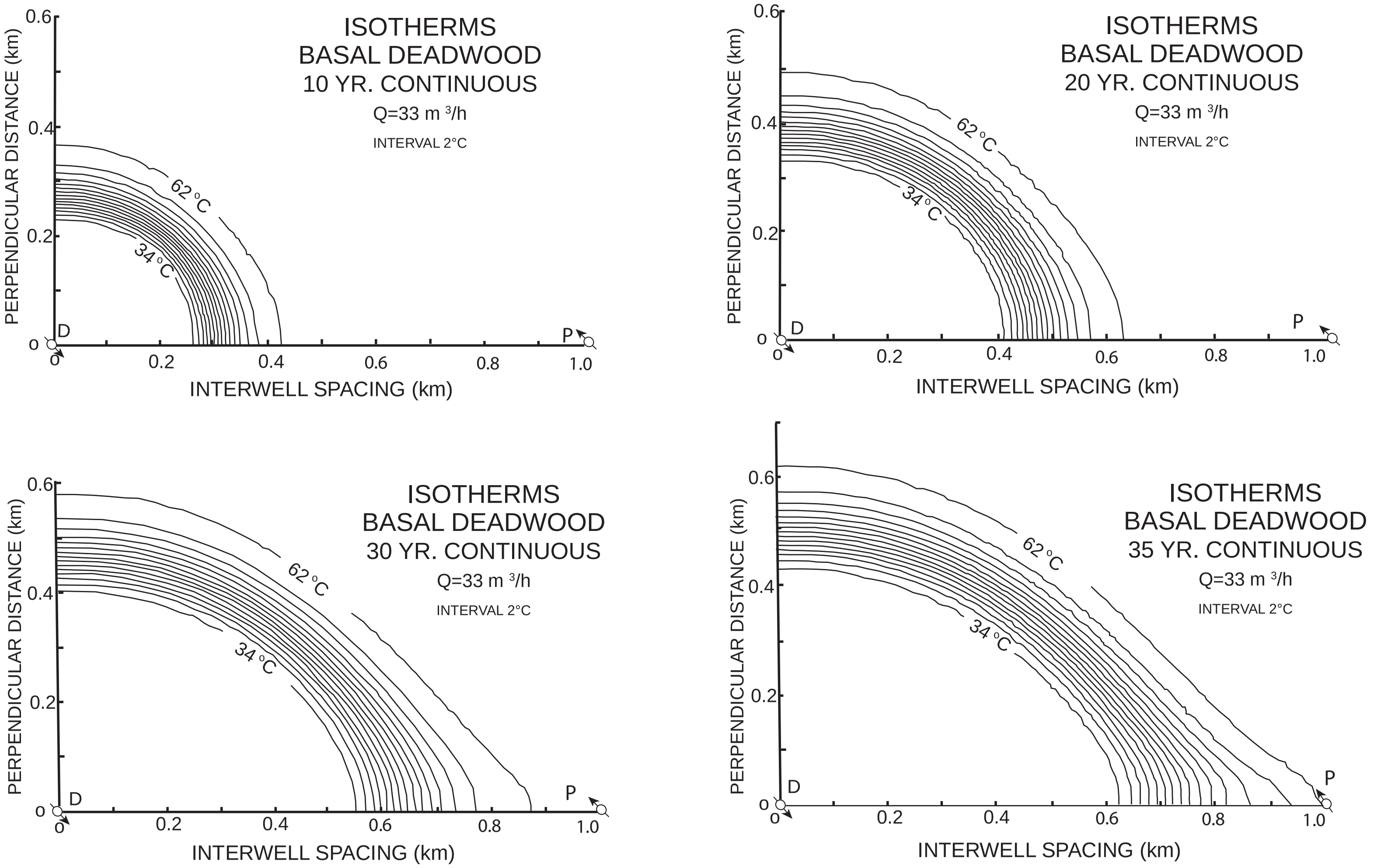

Figure 9 - Model isotherm plots of the basal Deadwood aquifer after 10, 20, 30, and 35 years of continuous injection at 33 m^3/h. Original aquifer temperature is 62.5°C and temperature of the disposal water is 33°C.

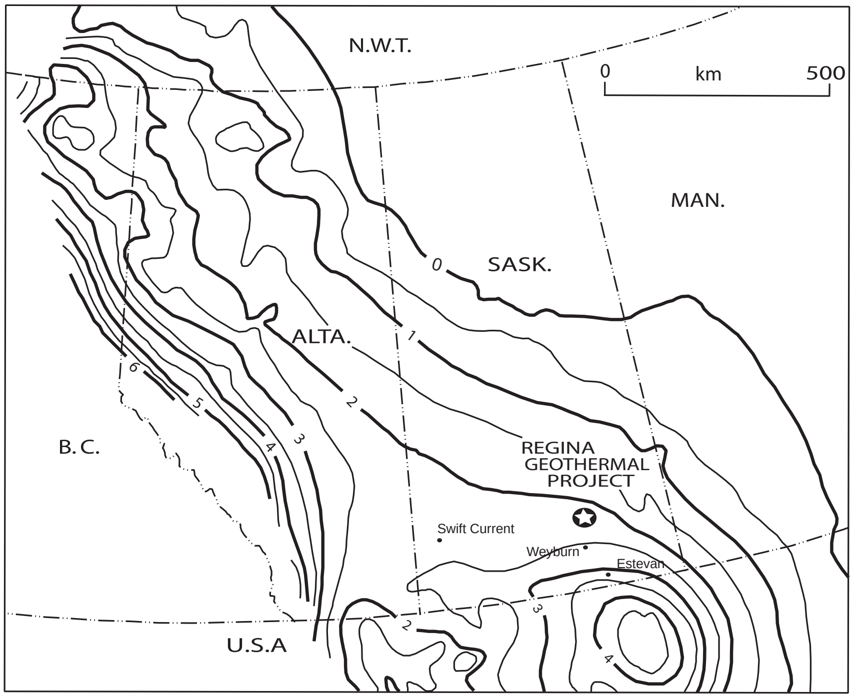

Figure 10 - Thickness in kilometres of the strata above Precambrian basement in the southern part of the Western Canada Sedimentary Basin.

increased to about 2.7 MW (9.2 million Btu/h) and with a similar addition the second option would satisfy a heating load of about 4.8 MW (16.3 million Btu/h) (Table 11).

a) Primary Salt-water Circuit

By using directional drilling, the wells of a geothermal doublet can be situated a few metres apart, close to where the energy will be used. After setting surface casing, the main hole would be drilled, either vertically or as a directional (slant) hole as required, using a drilling bit of the required diameter, to the Precambrian basement surface at a true depth of approximately 2200 m. Production casing of suitable size (with a packoff shoe) would be run to the top of the Basal Clastic Unit reservoir at an approximate true depth of 2030 m and cemented. This would result in an open-hole (barefoot) completion similar to that at the current Regina geothermal well. The length (apparent depth) of the slant hole would be 250 to 500 m more than the length (depth) of a vertical hole. Separation of the points where the wells intersect the top of the aquifer will be about 1000 m. Because of the information gained from the current well, a minimum of coring and drillstem testing will be required for new wells drilled in the vicinity.

The main differences in the primary circuits of Options One and Two are the diameter of hole and casing for the production well, pump requirements, and cost. Data on these are shown in Table 11. For Option One, the hole and casing diameters for both production and disposal well are the same as for the current Regina geothermal well. The Reda pump would be hung on 90 mm (3.5 inches) tubing at a depth of 200 m or more. It is estimated that the brine would enter the exchanger at a temperature of 58°C and exit at a temperature of 30°C. The estimated total cost of $3.7 million includes a directional well, a vertical well, Reda submersible pump, heat exchanger, and injection pump. Using the present geothermal well at the University of Regina would reduce project costs about $1.6 million for a total cost of about $2.1 million. In order to accommodate the higher flow rate and large diameter submersible pump of Option Two, the main hole of a production well and the production casing would be larger (Table 11). The disposal well would be sized the same as the current Regina geothermal well. The brine would enter the exchanger at somewhat higher temperature (59°C) because of the higher flow rate and would exit at 30°C. The submersible pump would be hung on 114 mm (4.5 inches) tubing set at 550 m. Total cost is estimated as close to $4.9 million; the increase compared to Option One results from larger hole size, casing, and pumps. The Reda pump would operate at variable speed, adjusting to seasonal needs. Electrical demand of the pump is 225 kW and the heat generated from the pump will raise the temperature of the water stream by an estimated 1.5°C.

b) Secondary Fresh-water Circuit

Plate and frame heat exchangers will transfer heat from the salt-water circuit to the secondary fresh-water circuit. Three exchanger units will be utilized with one unit on standby or for replacement during maintenance. Estimated temperature of water in the secondary circuit leaving the exchanger is 55°C (131°F), providing heat through radiant panels, for fan coils and for ventilation air. The estimated temperature of water returning to the heat exchanger is 26°C (79°F). At these assumed temperatures, the flow rate in the secondary circuit would be equal to the flow rate in the primary circuit.

Geothermal energy is utilized most efficiently when it is used to provide the base heating load to a large area. During colder periods, the energy supplied by simple exchange is supplemented by heat pumps that extract energy from the secondary circuit return water. It is reasonable to assume that the temperature of the return water could be

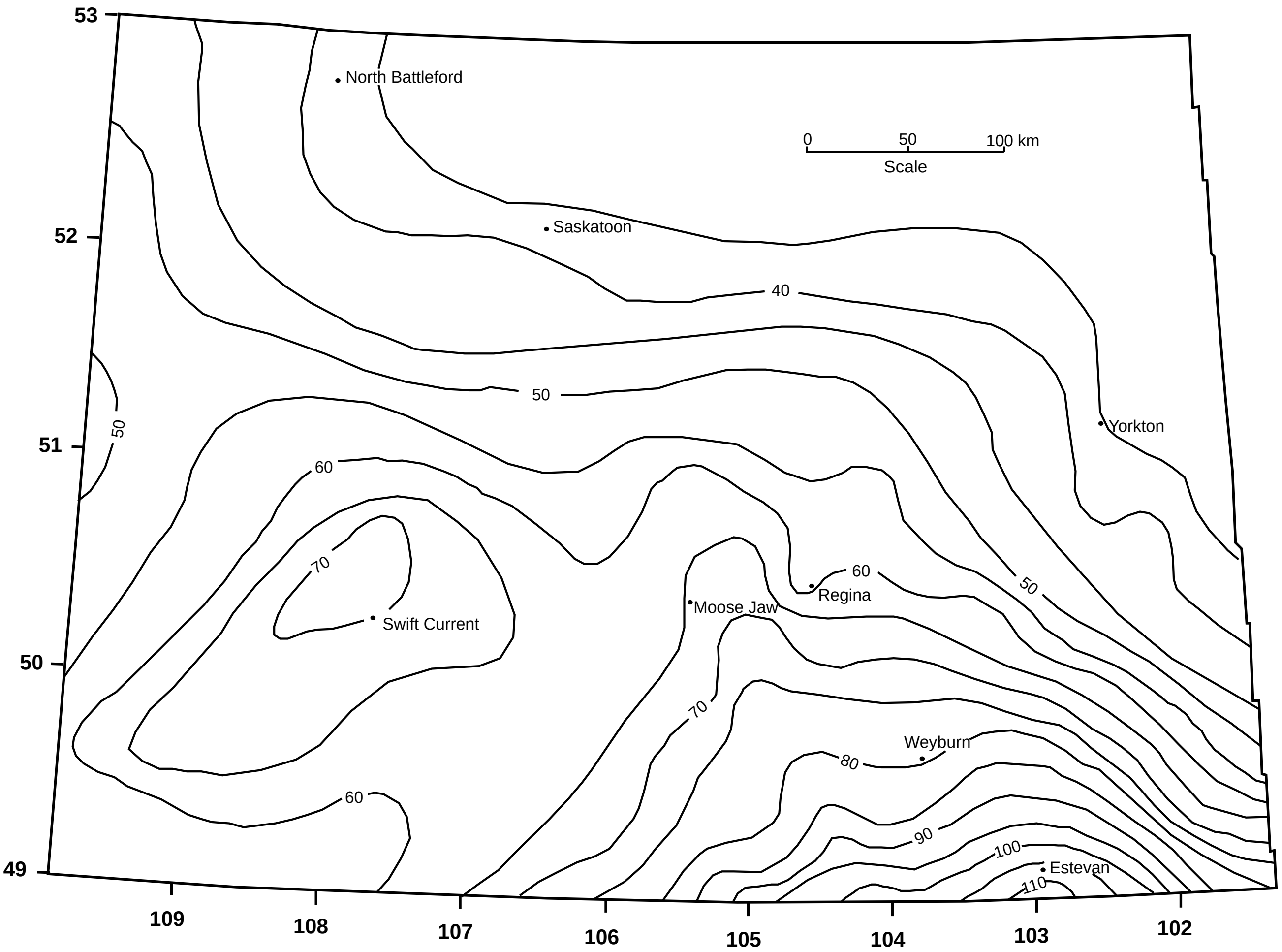

Figure 11 - Approximate temperature at the base of the sedimentary section in Saskatchewan south of latitude 53°N. Interval is 5°C.

reduced to 15.5°C (60°F). This would increase the heat extracted for both options (Table 11). In addition, a gas-fired or oil-fired boiler might be required to satisfy peak loads during the coldest weather and to serve as backup.

Heating industry representatives report that one million Btu/h are sufficient to meet the designed peak load of 45,000 ft^2 (4181 m^2) of energy-efficient commercial buildings. With heat pumps, Option One would provide heating for approximately 450,000 ft^2 (41 810 m^2) of commercial space and Option Two would heat about 735,000 ft^2 (68 280 m^2) of space, which, for district heating, would provide the peak heating load to at least 500 dwellings having average floor space of 1,470 ft^2 (136.7 m^2).

Table 11 - Primary circuit options for Regina area geothermal projects.

	Pumping Rate (usgpm)	Energy Production (Million Btu/h)	Exchanger Inlet Temp.	Exchanger Outlet Temp.	Surface Casing Diameter	Main Hole Diameter	Production Casing Diameter	Reda Pump Size	Injection Pump Size	Estimated Cost
Option One	264	6.7 (9.2)*	58°C	30°C	273 mm	222 mm	178 mm	60 hp	20 hp	$3,700,000
Option Two	458	12.0 (16.3)*	59°C	30°C	340 mm	311 mm	244 mm	300 hp	100 hp	$4,900,000

* Energy production in million Btu/h when heat pumps in secondary circuit are included.
Estimated cost includes one vertical well, one directional (slant) hole, submersible pump, heat exchanger, and injection pump.

7. Acknowledgments

Jessop and Vigrass acknowledge the contributions made by many co-workers in geothermal energy over the years. These workers include, but are not limited to, Keith Hutchence, Walter Jones, Jacik Majorowicz, and Doug Ruse. Special thanks go to Lloyd Barber, president-emeritus of the University of Regina, who provided support while the project was active. The authors acknowledge the assistance provided by Craig Nelson, District Manager of Trane Canada, for providing information on the secondary circuit and Doug Ruse of Cavern Engineering for information on drilling and completion.

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