Meadowbrook Carbon Storage Project

Application under Directive 065 for:

Disposal Scheme
Class III Disposal
Carbon Sequestration

Submitted to the
Alberta Energy Regulator

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Acronyms and Abbreviations

ACO	Aboriginal Consultation Office
AER	Alberta Energy Regulator
AFN	Alexander First Nation
AIH	Alberta's Industrial Heartland
BHP	bottom hole pressure
bcf	billion cubic feet
Bison	Bison Low Carbon Ventures
bopd	barrels of oil per day
bwpd	barrels of water per day
CO_2	carbon dioxide
Directive 51	Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements
Directive 56	Directive 056: Energy Development Applications and Schedules
Directive 65	Directive 065: Resources Applications for Oil and Gas Reservoirs
DST	drill stem test
FMI	Formation MicroImager
FVF	formation volume factor
GM	gas migration
IRC	Indian Resource Council of Canada
ISM	Induced seismic movement
ktpa	thousand tonnes per annum
MBHIP	maximum bottomhole injection pressure
mD	millidarcy
MDT	Modular Formation Dynamics Tester
ML	local magnitude
mmbbls	million barrels
MMV	measurement, monitoring and verification
MSHF	multistage hydraulic fracturing
Mtpa	million tonnes per annum
MWHIP	maximum wellhead injection pressure
OOIP	original oil in place
OWA	Orphan Well Association
PVT	pressure, volume and temperature
SAGD	steam assisted gravity drainage
SCVF	surface casing vent flow
the Project	the Meadowbrook Carbon Storage Project
tpd	tonnes per day
TVD	total vertical depth
UWI	unique well identifier

1.0 INTRODUCTION

Bison Low Carbon Ventures (Bison) through this application, is seeking regulatory approval from the Alberta Energy Regulator (AER) under *Directive 065: Resources Applications for Oil and Gas Reservoirs* (Directive 65), for the Meadowbrook Carbon Storage Project (the Project). The Project will be a storage hub for carbon dioxide (CO_2) captured from third party producers from a catchment area expected to include the greater Edmonton area.

1.1 Project Location

The Project is located west of the Town of Legal in Sturgeon County, Alberta (Figure 1-1), with surface facilities to be located within LSD 16, Section 29, Township 057, Range 25, West of the 4th Meridian (Figure 1-2).

1.2 Project Description

Bison is proposing to develop and operate a 0.5 million tonnes per annum (Mtpa) CO_2 storage reservoir in a deep saline Devonian aquifer to serve multiple industrial clients in Alberta's Industrial Heartland (AIH) and Edmonton areas, beginning in mid-2025. The Project will be developed in a phased approach. The first phase (Phase 1) involves a single injection site at 16-29-057-25 W4M with the 103/16-29-057-25W4/0 well completed as a potential injector. A 114 mm production liner will be run from 1,305 mkb to 1,497 mkb with dual inflatable packers set at 1,477 mkb and 1,496 mkb. Injection will be into the Cooking Lake interval from 1,496 mkb to 1,612 mkb. CO_2 will be delivered via tractor trailer. It is expected that a second well will be drilled from the same site (75 m away), within 24 months (i.e. when contracted volumes approach 50% of Phase 1 capacity, or as a second wellbore is deemed necessary for redundancy). The 103/16-29-057-25W4/0 well is required as the initial disposal well in the Meadowbrook Carbon Storage Hub which is designed to serve multiple customer's needs for permanent CO_2 sequestration. This well is also equipped to deliver the observation data of the injection zone, caprock integrity and quiet zone monitoring simultaneously with injection.

This application is proposed as the first phase of a two-phase development. The ultimate objective is to develop a 3Mtpa multi-client carbon storage hub that is pipeline connected to the AIH. The first phase of development, which is the subject of this application, will receive truck delivered CO_2 at rates up to 500 thousand tonnes per annum (ktpa, or 1,370 tonnes per day [tpd]). Bison has a commitment for the delivery of 50 to 75 ktpa beginning as soon as possible upon Project approval, with discussions ongoing for additional volumes. Bison will add additional volumes up to the licensed capacity as demand develops and submit a second application to develop the full tenure and pipeline connection to the anchor customer following establishment of a contract with an anchor tenant.

The stratigraphic interval being requested for use as a sequestration reservoir includes the Devonian Leduc & Cooking Lake formations which combine to form the Woodbend Reef complex, a well understood, very large (>800 km^2), thick (300 m gross), high quality (10% avg. porosity, >100 md avg. permeability), saline aquifer with an excellent top and bottom seal, at a depth of 1,300 m to top of reservoir (1,600 m to base of reservoir). Legacy well risk is low with only three historic penetrations of the sequestration strata within the forecast saturation plume area, all of which appear to have been properly abandoned with no surface flow history (gas migration or surface casing vent flow [SCVF]), based on AER records. The proposed Project will cover 15,600 ha, corresponding to a 21% portion of the 73,000 ha Meadowbrook Evaluation Permit area (Figure 1-2).

Static and dynamic modeling, summarized and schematically depicted in this application, illustrate that the volumes contemplated to be injected over the 15-year forecast would have minimal areal displacement and formation pressure increase. This is owing to the large high-quality nature of the Leduc/Cooking Lake aquifer in the Project area which represents the northern extent of the Rimbey-Meadowbrook reef trend.

1.3 Project Schedule

The proposed plan given in this application is to commence surface facilities installation and commissioning activities for the Project as early as late Q2 2025, pending regulatory approval and finalization of commercial conditions precedent. It is anticipated that the Project will operate for 15 years which is the term of our tenure. Extensions to that term are subject to market demand, reservoir performance, and regulatory approval. Following operation, the Project will enter the post-injection or closure phase. Monitoring will continue post-injection to ensure containment of the stored CO_2.

1.4 Project Proponent

Bison is applying for approval of the Project on behalf of the Meadowbrook Hub Project Consortium, which includes the following partners:

- Bison Low Carbon Ventures Inc. (67.5%)
- PrairieSky Royalty Ltd. (28.5%)
- Indian Resource Council of Canada (IRC, 4%)

Bison will operate the Project on behalf of the Meadowbrook Hub Project Consortium.

Bison is an Alberta based private corporation established in 2020 to develop and operate state of the art CO_2 storage facilities in western Canada and selectively promote natural gas participation along the accelerating energy transition. Bison has executive and technical experience in the upstream oil and gas industry in western Canada, South America, North Africa and the North Sea including the project planning, initiation, development and production operations associated with over 500 facilities and 1,000 wells including applications targeting conventional, unconventional multistage hydraulic fracturing (MSHF), steam assisted gravity drainage (SAGD), offshore and subsea, sour gas, and acid gas injection operations.

1.5 Requested Approvals

Bison is requesting approval for a disposal scheme that allows for carbon sequestration / storage of Class III fluids at their licenced well (Licence 0510240; UWI 103/16-29-057-25W4/0). The following sections of Directive 65 have been addressed in this application:

- Unit 4.1.3 – Application Requirements for a Disposal Scheme
- Unit 4.1.5 – Additional Requirements for Class III Disposal
- Unit 4.1.6 – Application Requirements for CO_2 Sequestration Schemes
- Unit 4.1.7 – Application Requirements for Carbon Sequestration

Concordance tables for these requirements are presented in Appendix A.

The proposed injection well has been licenced under *Directive 056: Energy Development Applications and Schedules* (Directive 56; Licence 0510240 [Appendix B]). The survey plan for the well site is included in Appendix C.

An application for a Single-Well Facility Site is also being applied for under Directive 56.

2.0 PROPOSED STORAGE SCHEME

2.1 Project Site Selection

The planned injection well (03/16-29-057-25W4/0) is located along the western rim of the Meadowbrook reef complex in a location that optimizes reservoir quality, capacity, and isolation of the predicted injection plume from any known alternate pore space uses, or problematic legacy wellbores. The well has demonstrated mechanical isolation, caprock integrity and injection capacity into the Woodbend Group (Leduc and Cooking Lake formations).

2.2 CO_2 Storage Area of Interest

Bison's current area of interest includes the lands identified in Table 2-1 and presented in Figure 2-1 for the storage of CO_2 within the Devonian Leduc and Cooking Lake formations (Woodbend Group).

Table 2-1 Land within CO_2 Storage Area of Interest

Sections	Township-Range-Meridian
1 to 5, 8 to 17, 20 to 29, 32 to 36	057-25 W4M
1 to 5, 8 to 17, 20 to 29, 32 to 36	058-25 W4M

2.3 CO_2 Storage Complex

The disposal interval is the Woodbend Group (Leduc and Cooking Lake formations) and it is entirely water wet on wireline logs at the disposal location and all wells within 4.8 km (3 miles) of the proposed injection well. 102/16-29-057-25W4/0, which is located approximately 140 m northwest of the injection well had a thin hydrocarbon show on logs but tested mud and saltwater and was not completed. Similarly, the 14-32-057-25 W4M well tested a small amount of heavy crude oil from a mid Leduc or Cooking Lake porosity streak but produced saltwater on completion and was abandoned with no commercial recovery.

The confining top seal is provided by the 30 m thick Ireton shale interval. The base of the storage interval is the top of the Beaverhill Lake Group which in this area is a basinal Waterways Formation mix of limestones and shales.

Both the Cooking Lake and Leduc formations are dolomitized at this location and in pressure communication:

- Cooking Lake: (1,486-1,608 m) > 122 m gross thickness (80% net >6% porosity) averaging 9% porosity. Modular Formation Dynamics Tester (MDT) derived permeability indications were between 40 mD and > 1 darcy.
- Lower Leduc/Duvernay interval (1,440-1,486 m) 46 m gross thickness which includes several shale pulses that will locally restrict vertical migration of CO_2 at least in the near wellbore area.
- Leduc: (1,326-1,440 m) 114 m gross thickness (90% net >9% porosity) averaging 11% porosity. MDT indications of permeability were between 40 mD and >1 darcy.

The initial portion of Phase 1 will initially receive liquid CO_2 delivered by tractor trailer at temperatures between -20°C to -25°C. As one measure to mitigate the risk of thermally induced fracture development near the storage complex caprock we will recomplete the 16-29 well to inject early volumes into the Cooking Lake interval approximately 160 m below the base of the Ireton. As volumes increase above initial Phase 1 volumes, and subject to well performance, we will recomplete the well to add perforations to access the upper Leduc interval.

Both intervals demonstrated similar rock quality indications on drilling, wireline logs and MDT tests. A step rate injectivity test over the entire open hole section showed an injection rate >30,000 barrels of water per day (bwpd) at <10% increase in bottom hole pressure (BHP).

The closest hydrocarbon production was from the Ellerslie Formation (Legal Mannville A pool), from two wells located approximately 1 km east of 16-29-057-25 W4M at 7-33 and 10-28-057-25 W4M, the last of which stopped production in 1978. Cumulative production from these wells was 2.4 billion cubic feet (bcf) of gas. The next closest hydrocarbon production is from the Legal Middle Viking A pool located approximately 3 km south of the injector location, which has also been abandoned. The closest hydrocarbon production in the disposal interval is 10.5 km east, from the Fairydell Bon Accord Leduc A field.

2.4 Injection Volumes

The expected life of the Class III disposal scheme is 15 years, with an injection rate of 0.5 Mtpa and a cumulative disposal volume of 7.5 million tonnes.

2.5 Storage Fluid Class

The fluid type currently in the disposal interval within the Woodbend Group is entirely water wet on the wireline logs at the disposal location and at all wells within 4.8 km of the proposed injection well. A thin hydrocarbon layer was observed on logs at the 02/16-29 well 140 m northwest of the injection well; however, it was proven nonproductive, and the well was not completed because of mud and water being recovered on a drill stem test (DST).

3.0 CONSERVATION

3.1 Hydrocarbon Pool and Accumulation

The only hydrocarbon accumulation within 1.6 km of 16-29-057-25 W4M is the Legal Mannville A pool which had produced 2.4 bcf of gas from two wells in the Ellerslie Formation as described in Section 2.3. Both wells are currently reported as abandoned. As these wells are no longer in production, conservation is not an issue.

The closest historic production from within the storage interval is approximately 1.9 km north of the planned injection well, and designated the Legal Leduc A pool at 14-32-057-25 W4M. This well produced a total of 800 barrels of 10 api oil and 14,263 barrels of water over three months in 1984, and has been abandoned. Stratigraphically, this interval would be considered to be in the Cooking Lake Formation.

The closest currently producing well from the storage interval is located approximately 10 km southeast of the planned injection well at 04-21-057-24 W4M, and produces 17 barrels of oil per day (bopd) at 96% watercut. This well produces from the Fairydell Bon Accord Leduc A pool which currently produces 35 bopd at 97% water cut in total, after cumulative production of 11.9 million barrels (mmbbls) of oil and 22.7 mmbbls of water. It is estimated that remaining recoverable reserves are <100k bbls of oil and the pool is downdip from our planned injection.

On this basis, it is not anticipated that the Project will result in negative effects on the economic recovery or conservation of any hydrocarbon resource.

3.2 Hydrocarbon Zones

Disposal is into the Leduc and Cooking Lake formations which are considered a single deep saline aquifer. The closest hydrocarbon production from the storage zone is approximately 10 km southeast at Fairydell Bon Accord (FBA). The FBA pool produces 35 bopd at >97% watercut after cumulative production of 11.9 mmbbls of oil from approximately 20 mmbbls original oil in place (OOIP). The pool has a strong bottom water drive and has shown very little pressure depletion over its 60+ year productive life. Cumulative Phase 1 CO_2 injection at 16-29 will increase aquifer pressure over the tenure area by approximately 10% and will have no effect on remaining hydrocarbon recovery. Formation pressure will be below hydrostatic pressure through Phase 1 injection.

The 16-29 injection well location and forecast plume area have no hydrocarbon zones so there is no oil-water or gas-water contact.

CO_2 injection is along strike with an intervening saddle separating 16-29 from the FBA field and the saturation plume will not extend to the FBA field.

The maximum bottomhole injection pressure (MBHIP) of 18.2 MPaa requested by Bison is based on the approach prescribed in Appendix O of Directive 65. This value of MBHIP was arrived at by using a total vertical depth (TVD) of 1,320 m for top of Leduc and correcting the prescribed pressure of 4.25 MPag using the prescribed gradient of 10.52 kPa/m from Table 1 of Appendix O in Directive 65, as shown below.

$$4.25\ MPag + \frac{1{,}320\ m\ x\ 10.52\ \frac{kPa}{m}}{1000} + 0.1 = 18.2\ MPaa$$

4.0 HYDRAULIC ISOLATION

4.1 Completion Details

4.1.1 Current Completion

The following completion logging and testing requirements were submitted to the AER as required under *Directive 051: Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements* (Directive 51), on November 17, 2023:

- Packer Setting Log
- Radial Bond Log
- Temperature Log

The completion log for 103/16-29-057-25W4/0 is included in Appendix D. A schematic of the injection wellhead is included in Appendix E. The packer schematic is presented in Appendix F.

4.1.2 Proposed Recompletion

Based on continued technical evaluation, Bison plans to recomplete the 16-29 well before commencing injection. The recompletion will case off the interval from the existing base casing level in the Ireton (1,312 m) to 9 m into the Cooking Lake Formation (1,496 m) prior to commencing injection. The recompletion program is attached as Appendix G. This liner will separate the Cooking Lake Formation from the Leduc Formation and the Ireton caprock by way of three sets of external casing packers.

Injecting into the Cooking Lake Formation during the initial low volume portion of Phase 1 (<100 ktpa) will deliver the following benefits;

- put 6 m section of existing open hole Ireton shale behind casing;
- eliminate the risk of thermal effects from the injection of cold CO_2 on the Ireton caprock; and
- confirm the storage capacity and caprock potential of the Cooking Lake (1,487-1,608 m) and potential caprock potential of the Duvernay (1,466-1,487 m) as a locally separated storage interval from the Leduc.

It is still Bison's intention to add Leduc perforations in the 16-29 well at a later date as volumes increase above the initial portion of Phase 1, or as required by well performance, or by way of a second injection well completed in the Leduc, when injection volumes are expanded beyond 100 ktpa.

4.2 Legacy Well Review

A legacy well review was completed for offsetting wells that penetrate the Leduc and Cooking Lake formations in proximity of the injection well and CO_2 storage area of interest, and is presented in Appendix H. This included a review of the AER Tour reports. The wells identified are presented in Figure 4-1, and an overview is presented in Table 4-1, including the identification of any documented surface casing vent flow (SCVF) or gas migration (GM) issues.

Table 4-1 Legacy Well Review

UWI	Well License #	Distance from Injection Well (m)	Total Vertical Depth (m)	Status	Date Abandoned	SCVF / GM Issues
100/15-20-057-25W4/00	0089643	1,746	1,390	Abandoned	1981	-
100/10-28-057-25W4/02	B0002781	1,244	1,309	Cased & Abandoned	2006	-
100/14-28-057-25W4/00	0094847	806	1,445	Abandoned	1982	-
100/16-29-057-25W4/00	0092827	247	1,340	Abandoned	1981	-
100/15-32-057-25W4/00	0174376	1,961	1,505	Abandoned	1995	-
100/14-32-057-25W4/00	0109103	1,987	1,650	Cased & Abandoned	1986	-
100/13-04-058-25W4/00	0044898	3,352	1,295	Cased & Abandoned	1973	-
100/02-05-058-25W4/00	0115789	2,133	1,560	Cased & Abandoned	1986	-
100/06-21-057-25W4/00	0001643	2,464	1,318	Cased & Abandoned	2000	SCVF

5.0 CONTAINMENT

5.1 Geological Setting

The proposed disposal zone for the Project includes the Leduc and Cooking Lake formations which together comprise the Meadowbrook Woodbend Reef complex. Supporting geologic mapping includes:

- top structure map of the Woodbend Reef complex (Figure 5-1);
- isopach map of the Woodbend Reef complex (Leduc and Cooking Lake formations; Figure 5-2);
- isopach map of the Ireton Shale (confinement strata; Figure 5-3);
- schematic cross section in an east-west orientation across the Meadowbrook Reef complex (Figure 5-4); and
- a type well log and cross-sections (Appendix I).

The Meadowbrook reef is the northern extension of the Homeglen-Rimbey Leduc Reef trend (Figure 5-5) that hosts several giant oilfields in the greater Edmonton area, including the well studied Leduc-Woodbend and Golden Spike fields. The 300 m thick reef complex developed where Leduc aged stromatoporoid atolls grew on top of a reef rimmed Cooking Lake platform as sea level rose in the upper Devonian. Although predominantly a regressive sequence, minor transgressive pulses created an overstepping of basinal shales that separate the Cooking Lake platform from the Leduc reef in some areas, but do not extend far enough to limit pressure communication across the entire complex and into the underlying aquifer (Barfoot et al., 1987; Ing, 1985; Figure 5-4). Where well control supports detailed facies analysis, a higher energy reef rim and internal lower energy finer grained lagoonal facies can be differentiated and are well documented in the adjacent Redwater reef complex. But along most of the trend, including at the Project location, those facies are obliterated by extensive dolomitization from the Cooking Lake through to the top of the Leduc which results in a thick (>300 m), highly porous (average porosity = 10.5%), aerially extensive (> 690 km^2 or 275 sq miles) pressure continuous aquifer complex encased in the shales of the Majeau Lake and Duvernay formations, and overlain and sealed by the shales of the Ireton Formation. The extensive dolomitization and connection through the Cooking Lake platform are the key contributors to the massive scale of capacity and injectivity in this candidate reservoir. It is estimated that injection of 3Mtpa for 25 years would occupy <2% of the pore space within the reef complex and any pressure plume would not increase this under pressured reservoir, to even the expected hydrostatic pressure at this depth.

The eastern up dip edge of the reef complex (Figure 5-2) is defined by well control from Township (Twp) 55 to Twp 61, running close to north south along Range 24 W4M. Ing, in her

1985 paper titled "Delineation of the Northern Extension of the Rimbey-Meadowbrook Reef Tract" (Ing, 1985) has interpreted a break in the reef running east west through Twp 62, separating the Meadowbrook reef complex from the northern extension, which Bison has also interpreted. Although the updip edge of the reef complex could serve as an ultimate barrier to long distance migration, modeling shows that the proposed Project volumes are too small for that to be required. It is expected that the effects of CO_2 injection (static model base case CO_2 plume or pressure due to displacement) over a 15-year Project life would extend to a radius of 1.6 to 4.0 km and increase aquifer pressure by approximately 30% or 3,500 kPa, within the saturation plume area and less than 10% on average beyond the plume area and have minimal pressure effect beyond our initial requested tenure boundary.

The Meadowbrook reef is the 'Morinville-Nestow' portion of the schematic section in Figure 5-5. Differential entrapment, where traps fill to spill and then displace hydrocarbons to the next reef up the Homeglen-Rimbey trend, was facilitated by the extensive dolomitization and resulted in an effective migration pathway for over 200 km (125 miles) from Innisfail to Acheson, just south of Bison's Project area. The Acheson Reef does not appear to be filled and little hydrocarbon migration into the Meadowbrook Reef appears to have occurred.

The Ireton shale represents the primary top seal for the storage complex. The Ireton is 31 m thick at our initial 16-29 site and thins to <25 m over the top of the reef but is present over the entire Meadowbrook Reef (Figure 5-3) based on existing well control. The Ireton shale is recognized as an effective seal both regionally where it seals over 1.2 billion barrels in oil accumulation at Redwater and Leduc Woodbend, and locally at oil pools in the Morinville and Fairydell fields. Bison cored the top three of five intervals (12 m) in the Ireton at 16-29 and can confirm that there is no reservoir quality rock or vertical fracturing present in the core. Special core analysis designed to evaluate the caprock showed tight dolomitic shale (dolomicrite) with porosity of 3% and permeability of less than 0.01 mD over the upper two Ireton units. A Formation MicroImager (FMI) borehole imaging log was also completed over the lower three Ireton units. This provides a high-resolution visual image of the fabric, bedding and continuity of these units. Neither analysis gives any indication of fractures, faulting, or any other discontinuities that would suggest increased risk of transmissibility across the caprock. A leak-off test of the Ireton, designed to identify any fracturing in the immediate wellbore area through the caprock did not feed at a pressure of 26 Mpa, signalling it is not fractured (Appendix J).

The secondary top seal is the upper Devonian Winterburn aged Graminia Formation, which is a continuation of the regressive sequence where shales, silty dolomites and thin anhydrites cap the porous Nisku dolomites. The Graminia is a proven top seal regionally (Leduc Woodbend) and locally (Fairydell Bon Accord).

The base seal in a vertical sense is the top Beaverhill Lake Group, where the base of the Cooking Lake platform unit transitions to the first of the upper Waterways shale units. It's important to note that the Cooking Lake platform unit is predominantly dolomite, averages >100 m in thickness, and extends regionally north, south and east (Figure 5-2).

From a geologic perspective, the Project is planned to locate along the high energy windward western rim where the structural reversal will control the updip migration of the buoyant CO_2 plume. The structural control on the plume migration is evidenced in the dynamic model (Appendix K) and honours the interpretation from the structure on top of the Woodbend Reef map (Figure 5-1).

The assessment of quality and continuity of the reservoir comes from a regional geologic understanding, well documented historic performance of analogous pools and Project site specific well penetrations. Table 5-1 summarises the petrophysical interpretation of the 12 well penetrations into the Meadowbrook Reef proximal to the application area, where modern well logs were available. On average, 88% of the logged reef section have porosities >6% (very high net to gross). Within that high percentage of net reservoir, Cooking Lake Formation porosities average 10% and Leduc Formation porosities average 10.5%. Adequate core analyses for wells on the Meadowbrook reef were not available, and regional porosity vs. permeability crossplots for the Acheson Field, just south of Bisons study area, suggest permeabilities above 500 mD for porosities of 10%.

Locating a sequestration project along the western rim of the Meadowbrook Woodbend Reef complex would access a very large, high quality, wet reservoir with excellent top and bottom seals. In this reservoir even very large injection volumes would have minimal areal displacement due to the thickness of the reservoir and minimal pressure effects owing to the size and quality of the aquifer.

Table 5-1 Petrophysical Interpretation of Meadowbrook Reef Penetrations					
Location	**Gross Interval (m)**	**Net to Gross >6% Porosity (%)**	**Average Porosity (%)**	**Formation**	**Lithology**
13-04-057-25W4	33	90	11.5	Leduc	Dolomite
12-21-058-25W4	95	92	11	Leduc	Dolomite
02-17-058-25W4	80	95	11	Leduc	Dolomite
16-17-057-25W4	81	80	11	Leduc	No data
11-32-055-25W4	20	90	10	Leduc	Dolomite
06-22-056-25W4	34	90	9.5	Leduc	Dolomite
16-08-057-24W4	26	75	12	Leduc	Dolomite
16-24-056-26W4	92	87	10.1	Cooking Lake	Dolomite
09-36-055-26W4	92	87	7.7	Cooking Lake	Dolomite
02-17-058-25W4	90	90	10.5	Cooking Lake	Dolomite
12-21-058-25W4	93	95	11.5	Cooking Lake	Dolomite
Average		**88**	**10.5**		

5.2 Base and Caprock

The base of the storage complex (bottom seal) is the top of the Beaverhill Lake Group where tight lower Cooking Lake platform limestones rest conformably on top of basinal Waterways Formation shales. The closest well control that penetrates the base Cooking Lake Formation is 02-17-58-25W4M 5 km north, and in this well 15 m of tight limestone overlays the top Beaverhill Lake (Waterways) shale. The reliance on a bottom seal in this application is not material as injection will occur a minimum of 100 m above this level and there is minimal incremental pressure or CO_2 contact with the base reservoir.

The caprock (Primary or top seal) is the Ireton Formation which is 31 m thick at the proposed 16-29-057-25 W4M injection site and thins to <25 m over the top of the reef but is present over the entire Meadowbrook Reef (Figure 5-3). The Ireton shale is recognized as an effective seal both regionally where it seals over one billion barrels in oilfields at Redwater and Leduc Woodbend, and locally at oil pools in the Morinville and Fairydell fields. Bison cored the top three of five intervals (12 m) in the Ireton at 16-29-057-25 W4M and can confirm that there is no reservoir quality rock or vertical fracturing present in the core. A leak-off test of the Ireton, designed to identify any fracturing in the immediate wellbore area through the caprock did not feed at a pressure of 26 Mpa, signalling it is not fractured.

The secondary top seal is the upper Devonian Winterburn aged Graminia Formation, which is a continuation of the regressive sequence where shales, silty dolomites and thin anhydrites cap the porous Nisku dolomites. The Graminia Formation is a proven top seal regionally (Leduc Woodbend) and locally (Fairydell Bon Accord).

5.3 Area of Influence

The calculated size of the CO_2 plume after 15 years of injection is approximately 2.5 km^2, growing to approximately 5 km^2 after 15 years of shut-in. The larger area of the CO_2 plume after shut-in is the result of a combination of factors, including buoyancy, pressure decline and continued vertical migration. Additional detail on the area of influence is provided in the Reservoir Modelling Report (Appendix K).

6.0 FLUID PROPERTIES

6.1 Reservoir Fluids

Analysis of the native reservoir fluids is presented in Appendix L.

6.2 Gas Properties

Phase 1 of the Project initially involves accepting approximately 200 tpd of trucked CO_2 volumes for injection at the 16-29-57-25 W4M well for sequestration. Bison intends to store the trucked CO_2 at 16-29 in two 55 t capacity mobile storage tanks at approximately 2,100 kPag and -25°C in order to maintain the CO_2 in liquid phase.

Bison has studied the fluid characteristics in the injection reservoir and has determined that injecting fluid at -25°C into the reservoir may result in near wellbore cooling issues that have the potential to effect near well bore stress conditions in the rock matrix. To mitigate this potential risk, Bison has implemented a natural gas fired glycol bath line heater into the design, downstream of the injection pumps, to raise the temperature of the injection fluids to 5°C. In addition, Bison has helped develop and procure a spring-loaded check valve that will be installed in the bottom of the injection tubing that will maintain wellhead pressure at approximately 8,000 kPag. This will maintain the CO_2 in the tubing well above the Critical Pressure to ensure there is no phase change while injection is not occurring. Directing initial Phase 1 injection into the recompleted well 160 m below the caprock will also ensure adequate natural warming of injected fluid before its contacting the caprock.

The reservoir contains saline water at 9,700 kPag at 50°C (top reservoir). As the 5°C fluid enters the pore space it will gradually warm to reservoir temperature and the density difference will result in migration of the CO_2 upwards over time. As the CO_2 plume disperses from the injection well it will be subject to a significant range of in-situ conditions and because of this there will literally be an infinite number of pressure, volume and temperature (PVT) conditions. The reservoir simulator utilizes an internal equation of state module that calculates CO_2 PVT properties depending on the conditions encountered. Chart 6-1 is an example of output from the equation of state module that shows formation volume factor (FVF) over a range of potential operating parameters.

With regards to the PVT characteristics at surface, there will be limited variability in operating conditions and those PVT properties are summarized in Table 6-1.

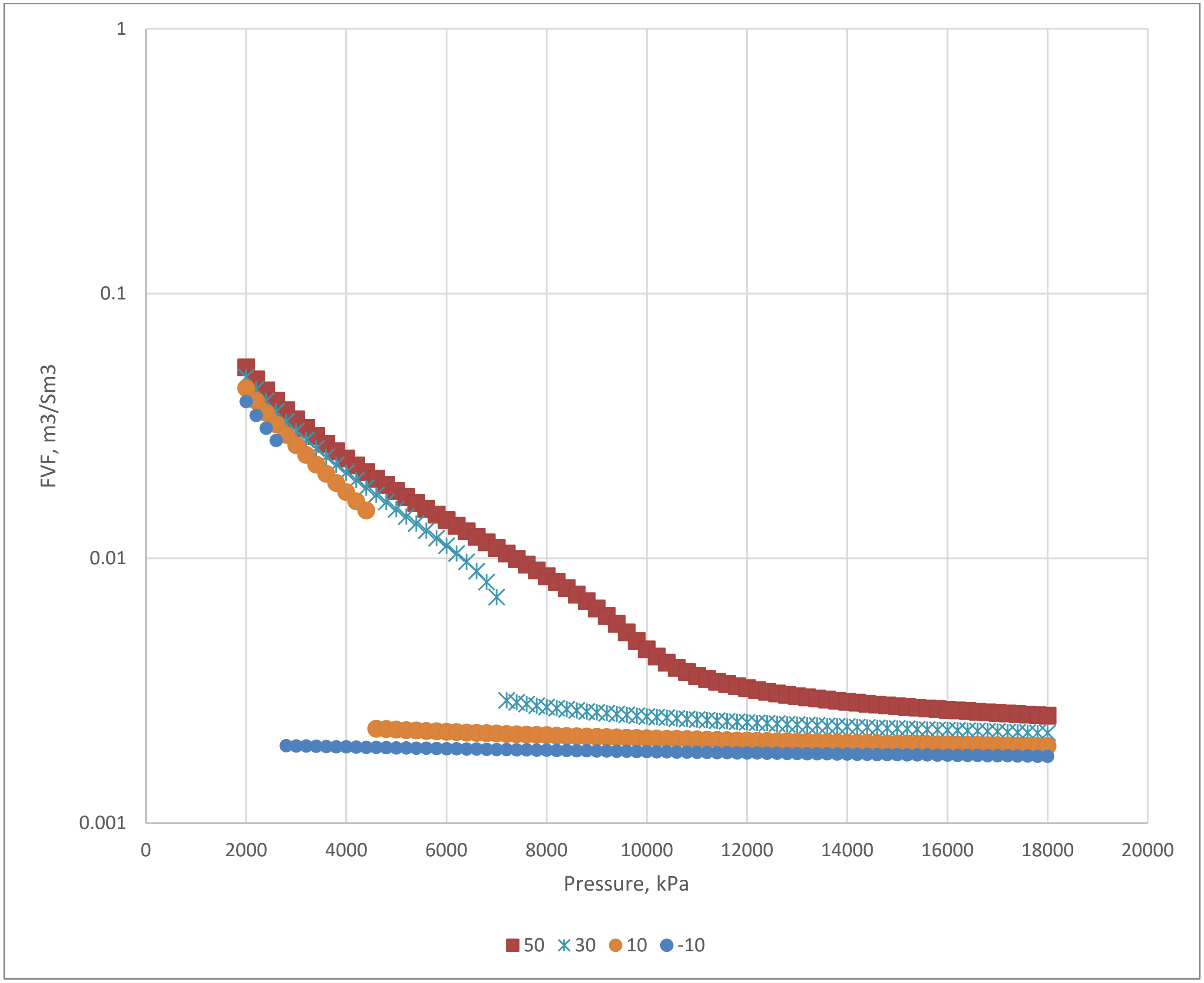


Chart 6-1 Formation Volume Factor as a Function of Pressure

Table 6-1 Gas Properties	
CO2	
Molar Mass	44.01 kg/mol
Critical Temperature	30.97°C
Critical Pressure	7,377 kPaa
Critical Density	467.6 kg/m^3
Site Storage	
Temperature	-25°C
Pressure	2,100 kPag
Density	1,056.00 kg/m^3
Kinematic Viscosity	0.144 mm/sec^2
Wellhead (downstream of injection pump and line heater)	
Temperature	5°C
Pressure	8,000 kPag
Density	934.22 kg/m^3
Kinematic Viscosity	0.108 mm/sec^2

6.3 Radius of Influence

A cylindrical calculation of the radius of influence is summarized in Table 6-2.

Table 6-2 CO_2 Plume Area and Radius	
Parameter	**Best Estimate**
Effective Thickness[1] (m)	120
Net-to-Gross Ratio	0.9
Porosity[2]	0.1
Average Residual Water Saturation	0.5
Formation Temperature (°C)	50
Formation Pressure[3] (MPa)	12
CO_2 density at Formation Conditions (kg/m^3)	580
Injected CO_2 after 15 years (Mt)	7.5
Number of Wells	1
Plume Area (km^2)	2.4
CO_2 Plume Radius[4] (m)	873

[1] Effective thickness refers to the product of reservoir thickness and vertical sweep efficiency.

[2] Porosity represents porosity of that part of the formation into which the CO_2 primarily flows (i.e. the better part of the reservoir.

[3] Formation pressure refers to the pressure within the CO_2 plume area (i.e. within the first 1 to 2 km from the wellbore) and is therefore taken to be larger than the initial reservoir pressure of approximately 11 MPa at the mid-point of the formation.

[4] CO_2 plume radius assumes a circular geometry. The reef edge is expected to be farther than this distance from the wellbore. The plume area of 2.4 km^2 is consistent with the simulation results shown in Appendix K (Figure R-14 and Table R-3).

The migration calculation for the non-circular radius of influence is presented in the Reservoir Modelling Report provided in Appendix K (Figure R-13, Figure R-14, Figure R-15, and Table R-3). All of the results presented in Table R-3 (Appendix K) are based on 15 years of injection at a rate of 0.5 Mtpa.

The numerical simulation approach used in this Reservoir Modelling Report (Appendix K) accounts for various factors affecting the spread of the CO_2 plume, including the effect of gravity and heterogeneity in petrophysical parameters, such as permeability, that may lead to bypassing of the formation fluid.

On the effect of gravity, the results suggest that the CO_2 tends to rise towards the top of the formation. This is especially evidenced in the results after injection is stopped and the pressure effects dissipate (Appendix K; Figure R-15).

Smaller-scale effects such as fingering associated with adverse-mobility ratio are partly taken into account through the use of relative permeability curves. In the "cylindrical" calculation presented in Table 6-2, these effects are incorporated through the use of "effective" thickness and average residual water saturation. Nevertheless, it is expected that the level of heterogeneity is not well understood at this time and could influence the spread of the CO_2 plume. However, the calculations reported here show that the spread of the CO_2 plume is limited to a distance of approximately 1 to 1.5 km from the wellbore after 15 years of injection. Additional fingering or bypassing of the formation fluid could influence the spread of the CO_2 plume. The monitoring methods described in this application will be used to better characterize the factors that could influence the spread of the CO_2 plume. A key advantage to the relatively small-scale initial phase is to confirm the visibility and ability to track the plume.

6.4 Reservoir Injectivity

The simulation results presented in the Reservoir Modelling Report (Appendix K; Figure R-12) indicate that the planned injection well can maintain a proposed annual injection rate of 0.5 Mt for the duration of the Project (15 years). The maximum proposed instantaneous or intermittent injection rate is 1 Mtpa, which equates to 2 m^3/min of liquid CO_2.

7.0 MAXIMUM WELLHEAD INJECTION PRESSURE

To avoid the uncertainties associated with calculation of wellhead pressure, especially in CO_2 injection wells, Bison is not requesting a maximum wellhead injection pressure (MWHIP) but will instead continuously monitor BHP to ensure that it stays below the maximum bottom hole injection pressure (MBHIP). This will be done with permanent pressure gauges run as part of the completion string. There will be high pressure shut down devices connected to both the bottom hole gauges and the wellhead to ensure MBHIP is not exceeded. Given the variations in friction pressure with pumping rates and the changes in CO_2 density as it warms up in the wellbore, Bison believes that measuring BHP and adjusting injection rates based on that will better ensure formation integrity than relying solely on wellhead injection pressure.

8.0 NOTIFICATION

8.1 Storage Rights

Bison has acquired the necessary consents from the Government of Alberta Department of Energy, as provided in Appendix M.

8.2 Offset Operators, Approval Holders and Licensees

A map showing the offset operators, approval holders and licensees in the sections offsetting the planned injection well (103/16-29-057-25W4/0) is presented in Figure 8-1.

The notifications completed for this application according to the section "Resource Applications Notification Guidelines" in Directive 65 are summarized in Table 8-1.

Table 8-1 Notifications

Application Type	Area of Notification	Parties to Notify	Status
Disposal Scheme	A radius of 1.6 km from the proposed disposal well where the proposed disposal zone is known to be present	Unit operator (if applicable)	Not applicable
		Approval holder of scheme (if applicable)	Not applicable – no scheme holders in notification area
		All well licensees, including those of abandoned wells	Notified, as per Table 8-4
CO_2 Sequestration	The maximum calculated injection fluid area plus 1.6 km. Notifications should also cover all zones that overlie the storage zone's maximum calculated injection fluid area plus 1.6 km.	Unit operator (if applicable)	Not applicable
		Approval holders of schemes	Not applicable – no scheme holders in notification area
		All well licensees, including those of abandoned wells	Notified, as per Table 8-4
		All mineral lessees	Notified, as per Table 8-2 and Table 8-3
		All mineral lessors	Not applicable
	Adjacent sequestration agreement or authorization holders within the approved zone from the sequestration boundary	Adjacent Crown agreements or authorizations to sequester CO_2	Not applicable, as there are no adjacent agreements proximal to the carbon storage area of interest.

A copy of the notification letter that was provided to all notified parties, as outlined in Table 8-2, Table 8-3 and Table 8-4, is presented in Appendix N. Notification letters were mailed via registered mail on August 30, 2024, with a requested response date of September 20, 2024. Official sources (e.g. freehold lease titles, AbaData) were used for contact information for notified parties. There are some parties within the notification radius which could not be contacted for notification as indicated in the footnotes in the tables, generally related to companies that no longer exist or individuals that are deceased. Some of the notification letters were returned, due to parties having moved, or issues with the addresses, despite coming from titles, etc. On-line searches were completed to attempt to locate updated addresses, or potential heirs of the freehold lease titles. For those parties where updated addresses were identified, the notification letters were re-sent on September 12, 2024, with a requested response date of October 1, 2024.

Table 8-2 Notified Lease Holders – Crown Leases

Agreement #	Agreement	Location	Status	Agreement Holder
013 1320110050	Coal Lease	SW-06-058-25 W4M	Exploration is permitted under appropriate control, surface and sub-surface mining under restricted development	Mancal Coal Inc

Table 8-3 Notified Lease Holders – Non-Crown Mineral Leases

Owner(s)	Title #	Rights	Location	Area (ha)
772375 Alberta Ltd[1]	982 064 469	All mines and minerals except coal	NE-31-57-25 W4M	129.4
			SE-31-57-25 W4M	
Allan O.[2]; Gerald O.; Arthur O.[2]; Victor B.; and Sheila B.	232 111 130	All mines and minerals except coal	SW-07-58-25 W4M	129.4
			SE-07-58-25 W4M	
Alphonse V. and Margaret V.	772 170 140	All mines and minerals except coal	NE-19-57-25 W4M	64.7
Armande S.; Marie M.; Bernard M.; and Joe M.	032 330 526	All mines and minerals except coal	NE-05-58-25 W4M	64.7
Brookfield Private Equity Inc.	152 003 743 +10	All mines and minerals except petroleum, oil sands & natural gas	SW-31-57-25 W4M	64.7
Brookfield Private Equity Inc.	152 003 743 +12		NW-05-58-25 W4M	64.7
Canadian Natural Resources Limited	992 058 029	All mines and minerals	NW-27-57-25 W4M	194.1
			NE-27-57-25 W4M	
			SE-27-57-25 W4M	
Celina C.[3] executrix for Maglorie C.	125X18	All mines and minerals except coal	SW-03-058-25 W4M	2.02
Charles R.[4]; Louis R.; Roger R.	952 039 692	All mines and minerals except coal	SW-05-58-25 W4M	64.7
Donald B.; Gary B.; Delmar B.[2]	892 030 405	All mines and minerals except coal and petroleum	SW-01-58-26 W4M	64.7
Elaine L.[2]	062 048 050	All mines and minerals except coal	SW-03-058-25 W4M	37.4
Elzeart B.[5]	81c42	All mines and minerals except coal	SW-03-058-25 W4M	0.202
Guy M.	902 029 543	All mines and minerals except coal	SW-03-58-25 W4M	37.4
Hayward Investments Ltd.[6]	842 124 953	All petroleum and natural gas	21-57-25 W4M	258.8
Henri M. Toupin Medical Foundation[1]	862 259 123	All mines and minerals except coal	SE-05-58-25 W4M	64.7

Table 8-3 Notified Lease Holders – Non-Crown Mineral Leases

Owner(s)	Title #	Rights	Location	Area (ha)
Henri M. Toupin Medical Foundation[1]	862 259 124		SW-05-58-25 W4M	64.7
Highvale Power Corporation[6]	972 086 043 +13	All mines and minerals except petroleum and natural gas	21-57-25 W4M	258.8
John M.; Frank O.; Katherine O.; Alexander O.; and Christina O.[1]	962 120 047	All mines and minerals except coal within, upon or under	NW-31-57-25 W4M	64.7
Lucien B.[1, 7]	161X145	All mines and minerals except coal within, upon or under	SW-03-058-25 W4M	0.405
Lucille S.	242 108 130 +1	All mines and minerals except coal within, upon or under	NW-03-58-25 W4M	64.7
Lynda B.[1]	962 331 808	All mines and minerals except coal within, upon or under	SW-05-58-25 W4M	64.7
Norman M.[1,6]	902 029 543 A	All mines and minerals except coal within, upon or under	SW-03-58-25 W4M	37.4
Paul R.[6]; Aurele R.; Cecile T.[2]; Jean T.[6, 8]; and Claire H.	062 293 291	All mines and minerals except coal within, upon or under	SW-05-058-25 W4M	64.7
PrairieSky Royalty Ltd.	142 189 238 +21	All mines and minerals within, upon or under	SW-33-57-25 W4M	64.7
PrairieSky Royalty Ltd.	142 189 853 +8	All mines and minerals and the right to work the same within, upon or under	NW-17-57-25 W4M NE-17-57-25 W4M	129.4
PrairieSky Royalty Ltd.	142 189 913 +7	All mines and minerals and the right to work the same within, upon or under	NW-27-57-25 W4M	64.7
PrairieSky Royalty Ltd.	142 190 313 +6	All mines and minerals within, upon or under	NW-19-57-25 W4M SW-19-57-25 W4M SE-19-57-25 W4M	194.1

Table 8-3 Notified Lease Holders – Non-Crown Mineral Leases

Owner(s)	Title #	Rights	Location	Area (ha)
PrairieSky Royalty Ltd.	142 191 136 +21	All mines and minerals and the right to work the same within, upon or under	NW-33-57-25 W4M NE-33-57-25 W4M	129.4
PrairieSky Royalty Ltd.	142 191 185 +13	All mines and minerals and the right to work the same within, upon or under	SE-33-57-25 W4M	64.7
PrairieSky Royalty Ltd.	142 189 238 +21	All mines and minerals within, upon or under	SW-33-57-25 W4M	64.7
PrairieSky Royalty Ltd.	142 189 853 +8	All mines and minerals and the right to work the same within, upon or under	NW-17-57-25 W4M NE-17-57-25 W4M	129.4
PrairieSky Royalty Ltd.	142 189 913 +7	All mines and minerals and the right to work the same within, upon or under	SW-27-57-25 W4M	64.7
PrairieSky Royalty Ltd.	142 190 313 +6	All mines and minerals and the right to work the same within, upon or under	NW-19-57-25 W4M SW-19-57-25 W4M SE-19-57-25 W4M	194.1
PrairieSky Royalty Ltd.	142 191 136 +21	All mines and minerals and the right to work the same within, upon or under	NW-33-57-25 W4M NE-33-57-25 W4M	129.4
PrairieSky Royalty Ltd.	142 191 185 +13	All mines and minerals and the right to work the same within, upon or under	SE-33-57-25 W4M	64.7
PrairieSky Royalty Ltd.	142 193 648 +14	All mines and minerals and the right to work the same within, upon or under	SW-09-58-25 W4M	64.7
PrairieSky Royalty Ltd.	142 205 324 +18	All coal within upon or under	SW-05-58-25 W4M SE-05-58-25 W4M	129.4

Table 8-3 Notified Lease Holders – Non-Crown Mineral Leases

Owner(s)	Title #	Rights	Location	Area (ha)
PrairieSky Royalty Ltd.	142 205 324 +19	All coal within, upon or under	NW-07-58-25 W4M NE-07-58-25 W4M SW-07-58-25 W4M SE-07-58-25 W4M	258.8
PrairieSky Royalty Ltd.	142 205 368 +10	All coal within, upon or under	NE-19-57-25 W4M	64.7
PrairieSky Royalty Ltd.	142 205 368 +12	All coal within upon or under	NE-31-57-25 W4M SE-31-57-25 W4M NW-31-57-25 W4M	194.1
PrairieSky Royalty Ltd.	142 205 368 +21	All coal which may be found to exist within, upon or under	NW-03-58-25 W4M NE-03-58-25 W4M SW-03-58-25 W4M SE-03-58-25 W4M	258.8
PrairieSky Royalty Ltd.	142 207 149 +9	All coal and petroleum within, upon or under	NE-01-58-26 W4M SW-01-58-26 W4M	129.4
PrairieSky Royalty Ltd.	162 028 346 +6	All petroleum, oil sands and natural gas within upon or under	SW-31-57-25 W4M	64.7
PrairieSky Royalty Ltd.	162 028 346 +8	All petroleum, oil sands and natural gas within upon or under	NW-05-58-25 W4M	64.7
Rachelle P.[1]	992 039 696	All mines and minerals except coal within, upon or under	SW-03-58-25 W4M	37.4

Table 8-3 Notified Lease Holders – Non-Crown Mineral Leases

Owner(s)	Title #	Rights	Location	Area (ha)
Raymond C.	092 246 724	All mines and minerals except coal within, upon or under	NE-31-57-25 W4M SE-31-57-25 W4M	129.4
Raymonde M.[2, 9]	972 114 494	All mines and minerals except coal within, upon or under	SW-03-58-25 W4M	23.9
Roch B.[1, 10]	842 201 939 A	All mines and minerals except coal within, upon or under	SW-03-58-25 W4M	37.4
Ronald B.	892 030 405	All mines and minerals except coal and petroleum within, upon or under	NE-01-58-26 W4M	64.7

[1] Notification returned, no known updated address.

[2] Notification returned, “unclaimed”.

[3] Deceased (1933), based on online search.

[4] Deceased (2021), based on online search.

[5] Assumed deceased – online search indicated individual was aged 54 in 1901 census.

[6] Notification returned, re-sent to updated address.

[7] Deceased (1974), based on online search.

[8] Notification returned, “refused”.

[9] Deceased (2016), based on online search.

[10] Deceased (2003), based on online search.

Table 8-4 Notified Owners of Offset Wells

UWI	Current Licensee	Status
Wells Penetrating the Injection Zone / Storage Complex		
100/06-21-057-25W4/00	Canadian Natural Resources Limited	Cased & Abandoned
100/15-20-057-25W4/00	Ovintiv Canada ULC	Abandoned
100/10-28-057-25W4/02	Excel Valley Petroleum Ltd.[1,2]	Cased & Abandoned
100/14-28-057-25W4/00	ConocoPhillips Canada Resources Corp.	Abandoned
100/16-29-057-25W4/00	ConocoPhillips Canada Resources Corp.	Abandoned
100/15-32-057-25W4/00	ConocoPhillips Canada Resources Corp.	Abandoned
100/14-32-057-25W4/00	Canadian Natural Resources Limited	Cased & Abandoned
100 02-05-058-25W4/00	Canadian Natural Resources Limited	Cased & Abandoned
100/13-04-058-25 W4 / 0	Canadian Reserve Oil and Gas Ltd.	Cased & Abandoned
Wells Not Penetrating the Injection Zone / Storage Complex		
100/11-27-057-25W4/00	ConocoPhillips Canada Resources Corp.	Abandoned
100/06-34-057-25W4/02	2270930 Alberta Ltd.	Abandoned
100/04-21-057-25W4/00	BP Canada Energy Group ULC	Abandoned
100/10-21-057-25W4/00	BP Canada Energy Group ULC	Abandoned
100/11-21-057-25W4/00	BP Canada Energy Group ULC	Abandoned
102/10-21-057-25W4/00	Canadian Natural Resources Limited	Abandoned
100/10-04-058-25W4/00	Canadian Reserve Oil and Gas Ltd.	Abandoned
100/01-05-058-25W4/00	Canadian Reserve Oil and Gas Ltd.	Abandoned
100/07-29-057-25W4/00	ENI Canada Holding Ltd.	Abandoned
100/07-33-057-25W4/03	Excel Valley Petroleum Ltd.[1,2]	Abandoned
102/06-21-057-25W4/00	Legal Oil & Gas Ltd.[1,2]	Abandoned
103/10-21-057-25W4/00	Legal Oil & Gas Ltd.[1,3]	Abandoned
102/16-29-057-25W4/00	Long Run Exploration Ltd.	Abandoned
100/01-36-057-26W4/00	Maga Energy Ltd.	Abandoned
100/02-21-057-25W4/00	Model Oils Limited[4]	Abandoned
102/02-21-057-25W4/00	Model Oils Limited	Abandoned
104/10-21-057-25W4/00	Redwater Energy Corp.[1,2]	Suspended
100/06-04-058-25W4/00	Resman Holdings Ltd.	Abandoned

Table 8-4 Notified Owners of Offset Wells

UWI	Current Licensee	Status
102/10-04-058-25W4/00	Sagres Energy Inc.[1,5]	Abandoned
100/08-21-057-25W4/00	Steen Resources Ltd.	Abandoned
100/14-16-057-25W4/00	Tartan Energy Inc.	Abandoned
100/03-21-057-25W4/00	Tartan Energy Inc.	Abandoned
100/07-21-057-25W4/00	Tartan Energy Inc.	Abandoned
100/09-21-057-25W4/0	Tercero Resources Company[1,6]	Abandoned

[1] Notification returned, no known updated address.

[2] Well is listed with Orphan Well Association (OWA).

[3] Not found on OWA list, but presumed with OWA, consistent with Legal Oil & Gas Ltd.'s 06-21 well.

[4] There has been no record of Model Oils Limited since the 1950s. There is no known address or Alberta Client ID associated with this company.

[5] Sagres Energy Inc.'s notification letter was returned, and they do not appear to be in business any longer. The well is not listed with OWA. The company's listed phone number has a new user.

[6] Tercero Resources Company's notification letter was returned, with an indication that they have moved. There is no new address listed for this company, and their listed phone number did not connect. The well site is reclamation certified.

At the time of filing, the following feedback has been received in response to the notification letters:

- ConocoPhillips Canada Resources Corp. – indicated that they have concerns with the Project, and have requested a copy of the application. This was provided on September 24, 2024. No feedback was received at the time of filing.
- Imperial Oil Ltd. (successor of Canadian Reserve Oil & Gas) - verbally requested a copy of the application. This was provided on September 26, 2024. Feedback was received as a question on the legacy well review, which has been addressed.
- Roger R. (freehold mineral rights holder) – looking for compensation details and impacts on subsurface rights holders through potential water and land contamination. Bison responded to Roger with information on the establishment of protocols for groundwater and soil gas monitoring to generate baseline information prior to commencement of injection, and offered to complete water well testing on property.
- Margaret V. (freehold mineral rights holder) – asked about Bison's plans for the Project and potential compensation. Bison responded to Margaret with information on the Project (e.g. disposal zone and the fact that there will be no impact on hydrocarbon production near the Project), and also discussed her rights as a mineral rights holder and provided information on how royalties are paid on production.

- Paul R. (freehold mineral rights holder) – was not aware that he was a mineral rights holder and not sure why he was being notified. Bison responded to Paul and let him know that there will be no injection wells on the land where he holds mineral rights.

Bison will consult with all concerned parties to understand any outstanding concerns and address them if possible.

8.3 Stakeholder Engagement

In addition to the required notifications, Bison has been engaging local stakeholders to introduce the proposed Project, provide information and to establish and maintain positive relationships in the local community continually since the tenure award in fall 2022.

Bison has engaged early, holding open houses in October 2022, again in September 2023, and on September 9, 2024. Bison has also provided Project information to the Morinville Council (October 2022), Sturgeon Council on multiple occasions, and the Town of Legal and Westlock County councils in August 2024.

Bison submitted a Pre-Consultation Assessment (PCA) request to the Aboriginal Consultation Office (ACO) for the 16-29 well operation and was informed that as the Project is on private land no PCA or further formal consultation via the ACO was required. A follow up request was made regarding the scope and scale of operations being requested under this application and we were again informed that no PCA or additional formal consultation under the ACO was required. Outside of these formal engagements the company has engaged with the local indigenous community, Alexander First Nation (AFN). Engagement with AFN has included introducing the Project and providing updates. Additionally, there were discussions about the possibility of having AFN as a Working Interest partner on the Project, but AFN have been unable to secure funding to-date. Bison has also looked to include AFN-owned companies to provide services on the Project. We have ongoing discussions with the AFN consultation department about providing material in the most useable form for elders and the community in general and remain engaged in progressing that in the timeline requested by AFN. Bison will continue to work with AFN to inform them of opportunities for contracts as the Project moves forward.

Additionally, Bison has engaged directly with local residents and businesses to introduce the Project, provide information on proposed operations, update stakeholders on activity schedules, test local water wells and request placing geophones on stakeholders' properties to monitor seismic activities. This engagement began in the spring and summer of 2023 and has continued through today. Engagement has been conducted in person (including community open houses), through email, regular mail, registered mail, door to door deliveries, and phone calls. Bison has contacted almost 300 Sturgeon County residents, 100 Westlock County residents, 450 Town of Legal residents, and has invited inquiries via local publications.

Water well testing results were provided to stakeholders through follow-up discussions and contact in early 2024. Further discussions on placing geophones on local properties also took place in Q1 2024 and this system is now operational and generating baseline seismicity data.

There have been no major on-going concerns expressed by stakeholders on the Project. Areas of concern raised most often are around groundwater protection, dust and noise. At the recent September 9, 2024 open house held in Legal, AB, community members actively participated in learning more about the Project and discussing their questions and concerns with Bison representatives. Key concerns raised were regarding traffic (specifically the trucking route for CO_2 shipments for this initial phase of the Project), the planned pipeline for future phases of the Project, the Emergency Planning Zone, impacts associated with a potential leak, potential odours, economic benefits for the local community, industrial development in general, and CCS specifically. We can provide an update on contacts and issues raised by stakeholders as our application progresses.

An early concern was expressed by stakeholders in 2022 on the location of a proposed test well. Stakeholders expressed concerns that it was too close to Manawan Lake and could have some impacts to local wildlife. In response to those concerns, Bison moved the location of the test well to 16-29 and no other concerns have been expressed to date.

Bison intends to continue to engage actively in the community as the Project moves through the regulatory application processes and through the various phases.

9.0 SAFETY

9.1 Injectivity

An injectivity and falloff test is included in Appendix O. The results of the test, as anticipated, indicate extremely good permeability and storage capacity in the reservoir. Based on the test results it is believed that the well will be capable of accepting at least 1 Mtpa of liquid CO_2.

9.2 Seismicity

The risk of induced seismicity associated with CO_2 injection into the Leduc Formation at Meadowbrook is believed to be low based the following factors that reduce the risk of induced seismicity:

- The Woodbend Formation is hydraulically separated from the geologic basement and pressure system by approximately 800 m of sedimentary deposits including evaporites. This is evidenced by the Woodbend regional aquifer system being underpresured in part owing to several decades of hydrocarbon production.
- Significant faults which could be reactivated causing ISM activity are not observed within the sedimentary section of the potential plume area, or along the western edge of the Meadowbrook reef north and south of our site, based on seismic data.
- Bottom hole injection pressures will be well below the frac gradient and are expected to be well below the pressures required to cause induced movement.
- The Woodbend aquifer system has considerable industry fluid disposal history at a similar scale as planned in this application in the Edmonton region without recorded induced seismic movements or a material increase in reservoir pressure which would likely preface seismicity.
- The Alberta seismicity network does not recognize any measurable seismicity as a recurring event in the area of our tenure.
- The MMV Plan presented in Appendix Q includes a detailed discussion of seismicity risk and planned mitigation.

The injection well has an associated array of surface geophones configured to detect seismic movements within the potential plume area that have been installed and gathering baseline data since April 2024. The first data batch interpretation (to May 2024) is included in the MMV Plan (Appendix Q). The injection wellbore is also equipped with a fiber digital acoustic cable which can be interrogated for movements if any movements are detected. The cable and geophone array will also be capable of listening for potential thermal events arising from the injection.

In Alberta, well completion operations utilize a 'traffic light' approach where seismicity events >2.0 ML (local magnitude) are reported and events exceeding 4.0 ML require operations to cease. We understand Quest has adopted a similar trigger threshold on a voluntary basis and we would propose to do so as well, subject to discussions with the AER. If any induced seismic events or new hazards are identified once the Project has commenced injection, Bison will contact the AER to propose a response and monitoring plan.

9.3 Risk Mitigation

Bison has implemented a detailed risk mitigation strategy since the inception of the Project. Bison has utilized a 5x5 Likelihood/Severity matrix to score the identified risks to the Project. A detailed Risk Registry (Appendix P) records the identified risks, justifies the matrix score assigned and flags the risk mitigation strategy employed to minimize the risk scoring for each category. The identified project risks have been developed in a collaborative effort by the entire technical and management team at Bison and is based on significant experience of the proponents' executing projects of similar complexity. As the Project progresses and risk mitigation measures are implemented, certain risk scores can be lowered. These changes to the Risk Registry will be recorded in a scheduled monthly review and archived to ensure that the history of the management of risk for the entire Project is captured. Risk mitigation has been ingrained in Bison's execution strategy and it will become an integral aspect of the Project through completion and into operating mode.

10.0 REPORTING

10.1 Measurement, Monitoring and Verification Plan

Bison has developed an MMV Plan and Closure Plan, which is attached as Appendix Q. Baseline MMV reporting, including measurements collected during the pre-injection evaluation period, is included with Appendix Q. Updates to the MMV Plan will be provided to the AER every three years, per Directive 65.

10.2 Schedule

A conceptual schedule throughout all phases of Project development, including renewal periods for MMV plans and closure plans, is presented in Table 10-1.

Table 10-1 Conceptual Project Schedule

Project Phase	Estimated Timeline	
	Start	Completion
PRE-INJECTION		
EVALUATION PERMIT ISSUED	-	01-Oct-22
STAKEHOLDER ENGAGEMENT	11-Oct-22	07-Jun-25
SUBMIT SEQUESTRATION LEASE APPLICATION TO ALBERTA ENERGY	-	20-Feb-24
ALBERTA ENERGY REVIEW - TENURE RECEIVED	20-Feb-24	30-Jul-24
SUBMIT D65 APPLICATION (INCLUDING INITIAL MMV PLAN)	-	21-Oct-24
D65 REVIEW & APPROVAL	21-Oct-24	19-Apr-25
PRE-INJECTION MONITORING	26-Sep-23	07-Jun-25
SURFACE FACILITIES INSTALLATION/ COMMISSIONING (PHS I 75 KTPA)	20-Apr-25	07-Jun-25
INJECTION		
COMMERCIAL OPERATIONS	08-Jun-25	31-Jul-39
STAKEHOLDER ENGAGEMENT	08-Jun-25	31-Jul-39
MODELLING & CALIBRATION AGAINST OBSERVATIONS	08-Jun-25	31-Jul-39
AER REVIEW OF MODELLING	08-Jun-25	31-Jul-39
MONITORING & VERIFICATION (EXECUTION)	08-Jun-25	31-Jul-39
SUBMIT MMV UPDATE / CLOSURE PERIOD PLAN #1	-	18-Apr-28
SUBMIT MMV UPDATE / CLOSURE PERIOD PLAN #2	-	19-Apr-31
SUBMIT MMV UPDATE / CLOSURE PERIOD PLAN #3	-	19-Apr-34
SUBMIT MMV UPDATE / CLOSURE PERIOD PLAN #4	-	19-Apr-37

Table 10-1 Conceptual Project Schedule

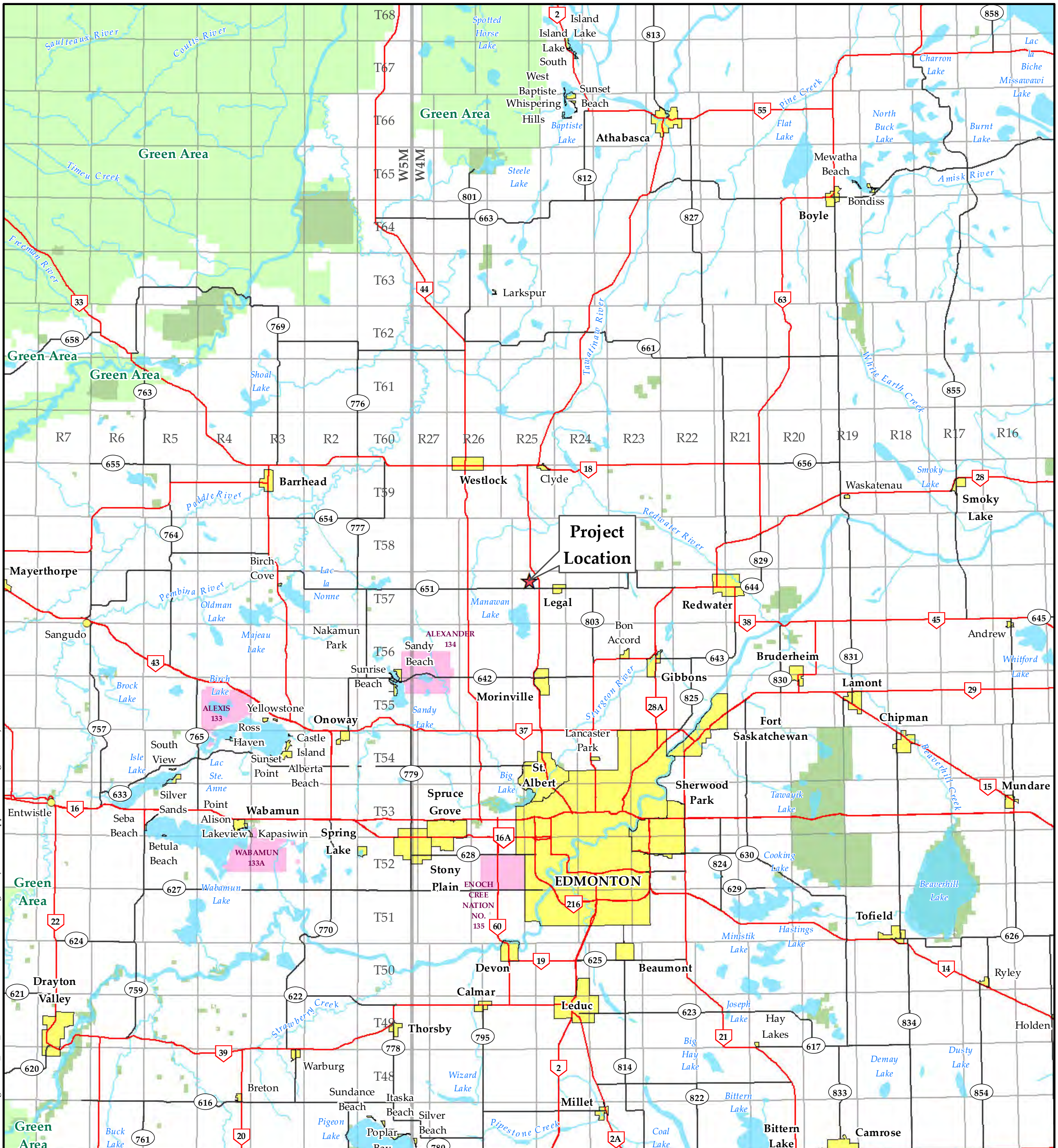
Project Phase	Estimated Timeline	
	Start	Completion
POST-INJECTION		
COMMERCIAL OPERATIONS CEASE	-	31-Jul-39
STAKEHOLDER ENGAGEMENT	31-Jul-39	30-Jul-42
ABANDONMENT & CLOSURE OF INJECTION & MONITORING WELLS	31-Jul-39	30-Aug-39
MODELLING & CALIBRATION AGAINST OBSERVATIONS	31-Jul-39	30-Jul-42
MONITORING & VERIFICATION (EXECUTION)	31-Jul-39	30-Jul-42
SUBMIT MMV UPDATE / CLOSURE PERIOD PLAN #5	-	02-Apr-40
AER REVIEW OF MODELLING (STABLE & PERMANENT)	31-Jul-39	30-Jul-42
ESTIMATED CLOSURE CERTIFICATE	-	30-Jul-42

11.0 REFERENCES

Barfoot, G.L. and Ko, S.C.M. 1987. Assessing, and Compensating for, the Impact of the Leduc D-3A Gas Cap Blowdown on the Other Golden Trend Pools. Journal of Canadian Petroleum Technology 1987.

Ing, A. 1985. Delineation of the Northern Extension of the Rimbey-Meadowbrook Reef Tract, Upper Devonian Northeastern Alberta. Alberta Research Council, ARC/AGS Open File Report 1985-02, 29p.

FIGURES



LEGEND

- Project Location
- Primary Highway
- Secondary Highway
- Park/Protected Area
- Green Area
- First Nations Reserve/Metis Settlement
- Populated Place

BISON LOW CARBON VENTURES

BISON LOW CARBON VENTURES
MEADOWBROOK CARBON STORAGE PROJECT

PROJECT LOCATION

AltaLIS, 2022, 2020; GeoBase, 2015, 2017, 2019; MEMS, 2024;

Coordinate System: NAD 1983 3TM 114

0 20 40
Kilometres

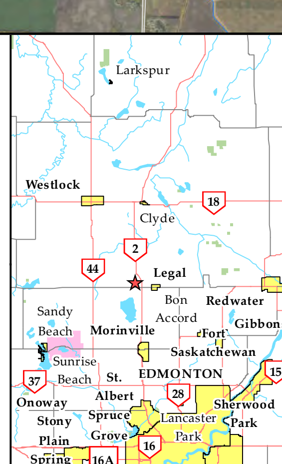
PROJECT: 23-00474
DRAWN BY: EPITTMAN
CHECKED BY: KK
DATE: JUNE 6, 2024

FIGURE
1-1

Document Path: K:\Active Projects 2023\AP 23-00451 to 23-00500\23-00474\Figures\C_and_R\Meadowbrook Carbon Storage Project\D65 Application\Fig 1-1 Project Location 23-00474.mxd

LEGEND

- Planned Injection Well
- Well Lease Boundary
- CO_2 Storage Area of Interest
- Populated Place



BISON LOW CARBON VENTURES
MEADOWBROOK CARBON STORAGE PROJECT

CO_2 STORAGE AREA OF INTEREST

AltaLIS, 2022; MEMS, 2023;
Valtus, 2023 (Image Date: 2017)

Coordinate System: NAD 1983 UTM Zone 12N

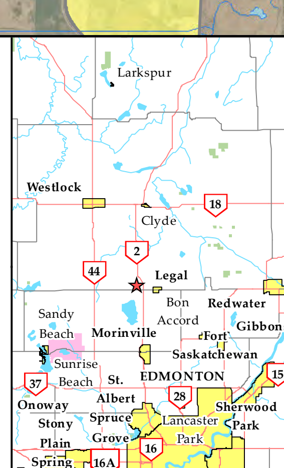
0 2 4
Kilometers

PROJECT: 23-00474	
DRAWN BY: EPITTMAN	
CHECKED BY: KK	
DATE: MAY 31, 2024	
FIGURE	1-2

Document Path: K:\Active Projects 2023\AP 23-00451 to 23-00500\23-00474\Figures\C_and_R\Meadowbrook Carbon Storage Project\D65 Application\Fig 1-2 CO2 Storage Area of Interest 23-00474.mxd

LEGEND

- ★ Planned Injection Well
- Maximum Fluid Injection Area
- CO_2 Storage Area of Interest
- Sequestration Lease Boundary
- Populated Place



BISON LOW CARBON VENTURES

BISON LOW CARBON VENTURES
MEADOWBROOK CARBON STORAGE PROJECT

APPLICATION MAP

AltaLIS, 2022; MEMS, 2023;
Valtus, 2023 (Image Date: 2017)

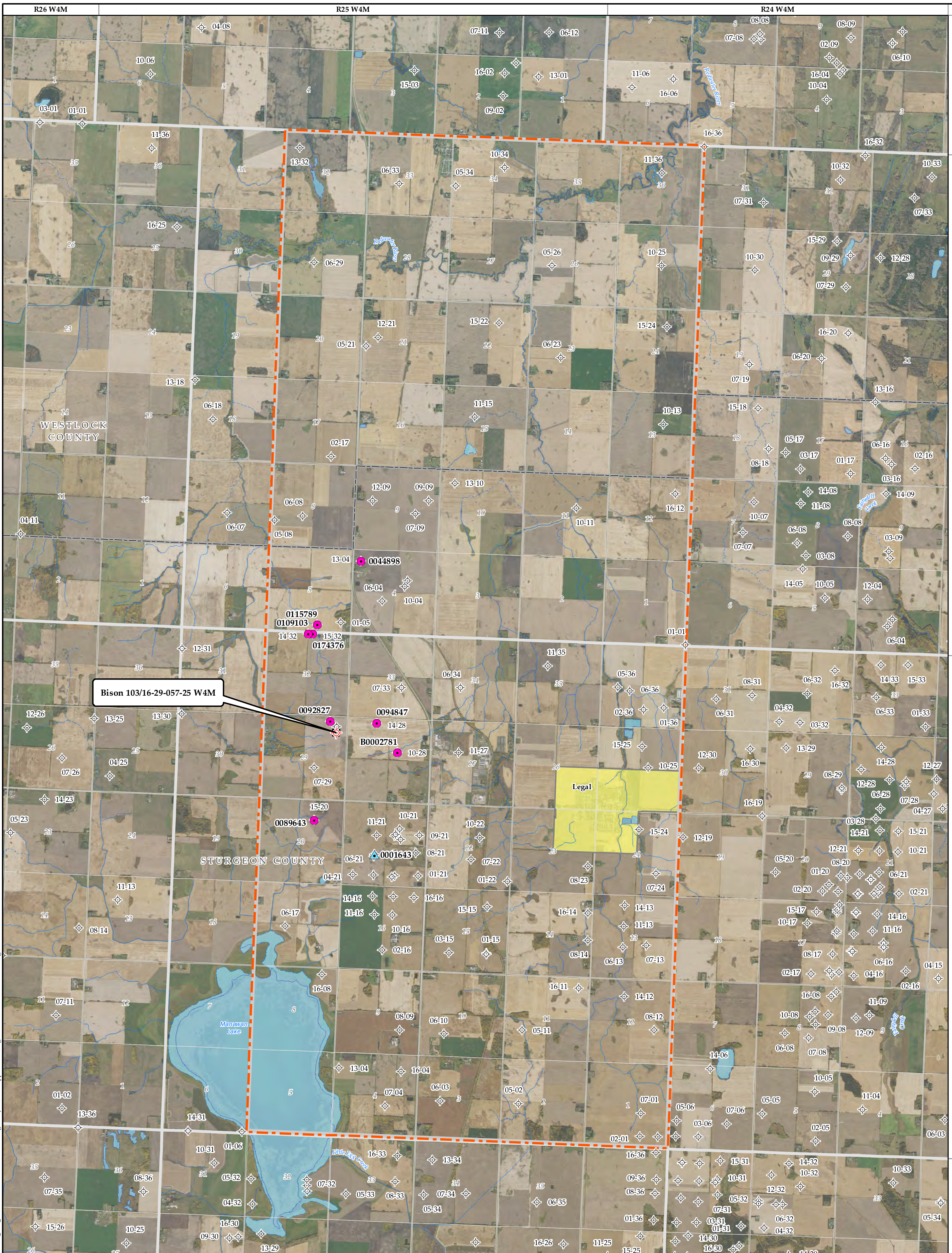
Coordinate System: NAD 1983 UTM Zone 12N

0 5 10
Kilometers

PROJECT: 23-00474
DRAWN BY: EPITTMAN
CHECKED BY: KK
DATE: JUNE 6, 2024

FIGURE
2-1

Document Path: K:\Active Projects 2023\AP 23-00451 to 23-00500\23-00474\Figures\C_and_R\Meadowbrook Carbon Storage Project\D65 Application\Fig 2-1 Application Map 23-00474.mxd

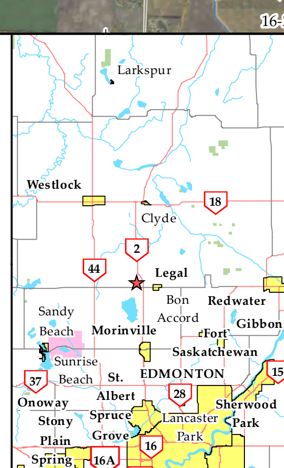


LEGEND

- Planned Injection Well
- Well Centre (AER Surface-Hole Location)

Injection Zone Penetrations

- Abandoned
- Abandoned (SCVF History)
- Well Lease Boundary
- CO_2 Storage Area of Interest
- Populated Place



BISON LOW CARBON VENTURES

BISON LOW CARBON VENTURES
MEADOWBROOK CARBON STORAGE PROJECT

AREA OF INTEREST WITH EXISTING WELLS

AltaLIS, 2022; MEMS, 2023;
Valtus, 2023 (Image Date: 2017)

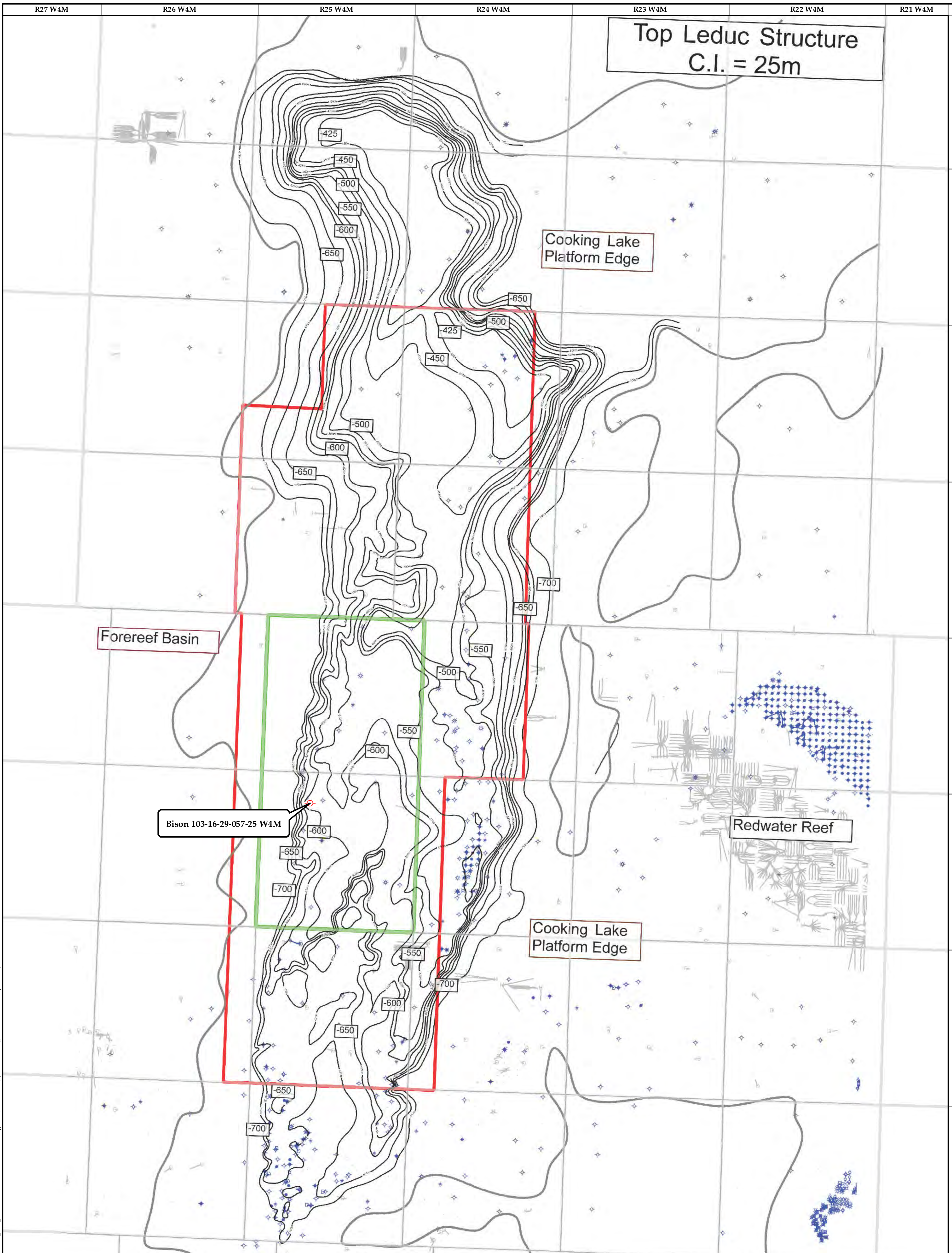
Coordinate System: NAD 1983 UTM Zone 12N

0 2 4
Kilometers

PROJECT: 23-00474
DRAWN BY: EPITTMAN
CHECKED BY: KK
DATE: JUNE 19, 2024

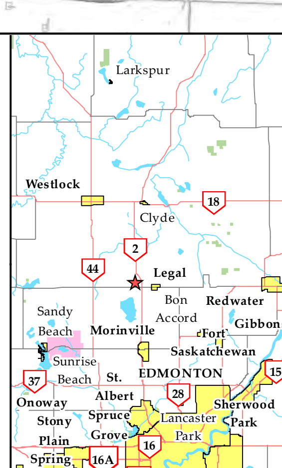
FIGURE
4-1

Document Path: K:\Active Projects 2023\AP 23-00451 to 23-00500\23-00474\Figures\C_and_R\Meadowbrook Carbon Storage Project\D65 Application\Fig 4-1 Area of Interest w Existing Wells 23-00474.mxd



LEGEND

- Planned Injection Well
- CO_2 Storage Area of Interest
- Sequestration Lease Boundary



BISON LOW CARBON VENTURES
MEADOWBROOK CARBON STORAGE PROJECT

STRUCTURE MAP OF DISPOSAL ZONE (TOP LEDUC)

AltaLIS, 2022; MEMS, 2024; S&P Global, 2024;

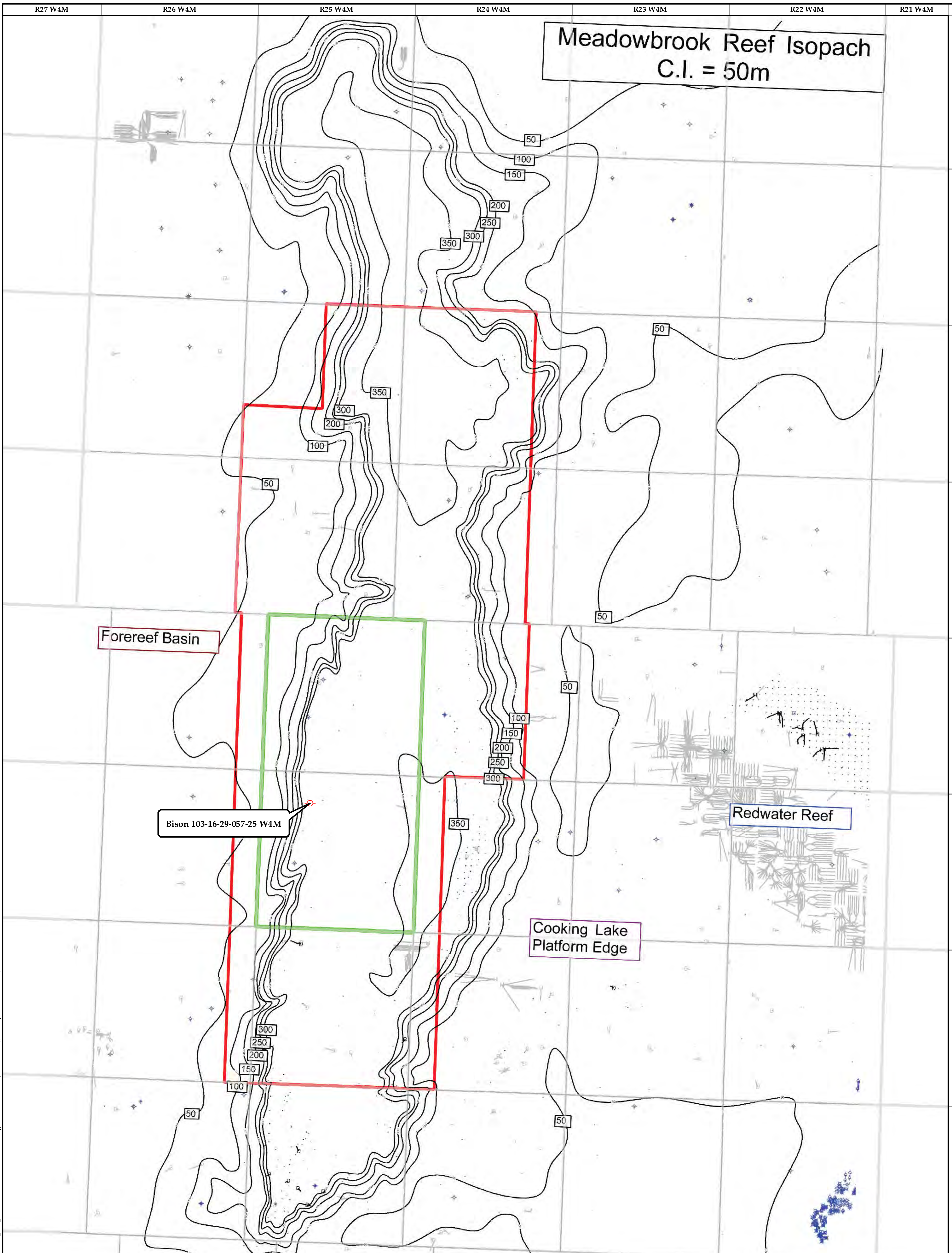
Coordinate System: NAD 1983 UTM Zone 12N

0 5 10
Kilometers

PROJECT: 23-00474
DRAWN BY: EPITTMAN
CHECKED BY: KK
DATE: JUNE 17, 2024

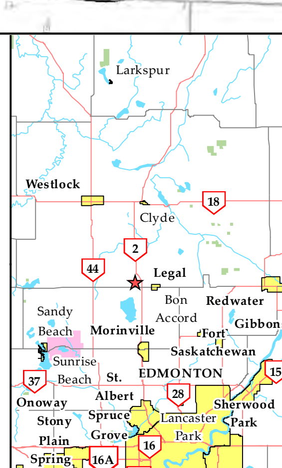
FIGURE
5-1

Document Path: K:\Active Projects 2023\ AP 23-00451 to 23-00500\ 23-00474\ Figures\ C_and_R\ Meadowbrook Carbon Storage Project\ D65 Application\ Fig 5-1 Structure Map of Disposal Zone 23-00474.mxd



LEGEND

- Planned Injection Well
- CO_2 Storage Area of Interest
- Sequestration Lease Boundary



BISON LOW CARBON VENTURES

BISON LOW CARBON VENTURES
MEADOWBROOK CARBON STORAGE PROJECT

ISOPACH MAP OF DISPOSAL ZONE

AltaLIS, 2022; MEMS, 2024; S&P Global, 2024;

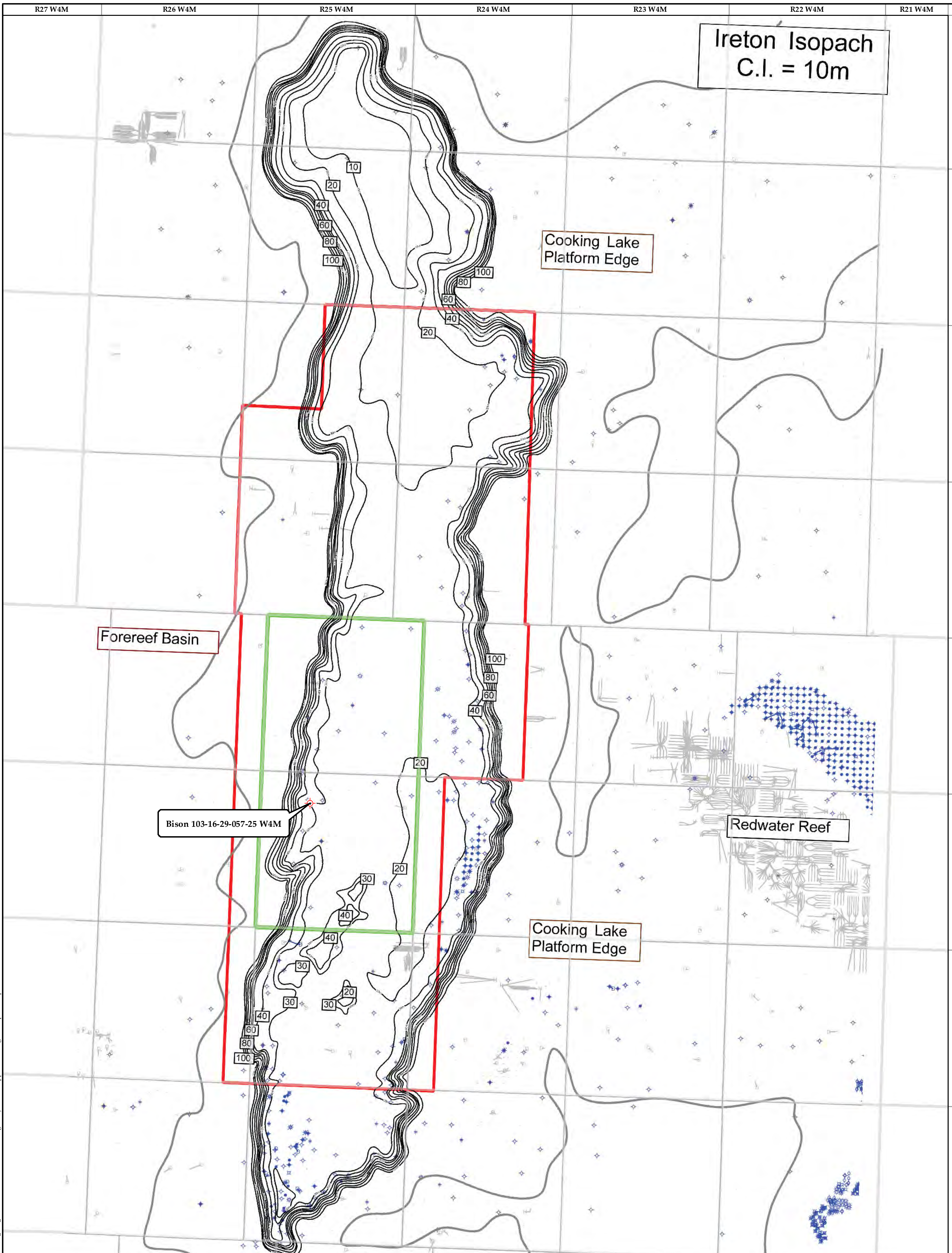
Coordinate System: NAD 1983 UTM Zone 12N

0 5 10
Kilometers

PROJECT: 23-00474
DRAWN BY: EPITTMAN
CHECKED BY: KK
DATE: JUNE 17, 2024

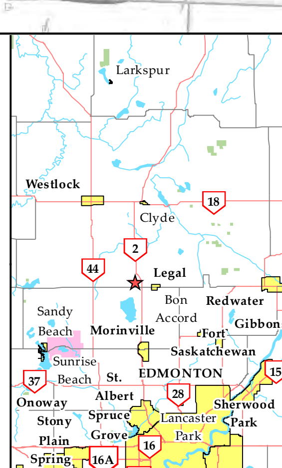
FIGURE
5-2

Document Path: K:\Active Projects 2023\AP 23-00451 to 23-00500\23-00474\Figures\C_and_R\Meadowbrook Carbon Storage Project\D65 Application\Fig 5-2 Isopach Map of Disposal Zone 23-00474.mxd



LEGEND

- Planned Injection Well
- CO_2 Storage Area of Interest
- Sequestration Lease Boundary



BISON LOW CARBON VENTURES

BISON LOW CARBON VENTURES
MEADOWBROOK CARBON STORAGE PROJECT

ISOPACH MAP OF CONFINEMENT STRATA

AltaLIS, 2022; MEMS, 2024; S&P Global, 2024;

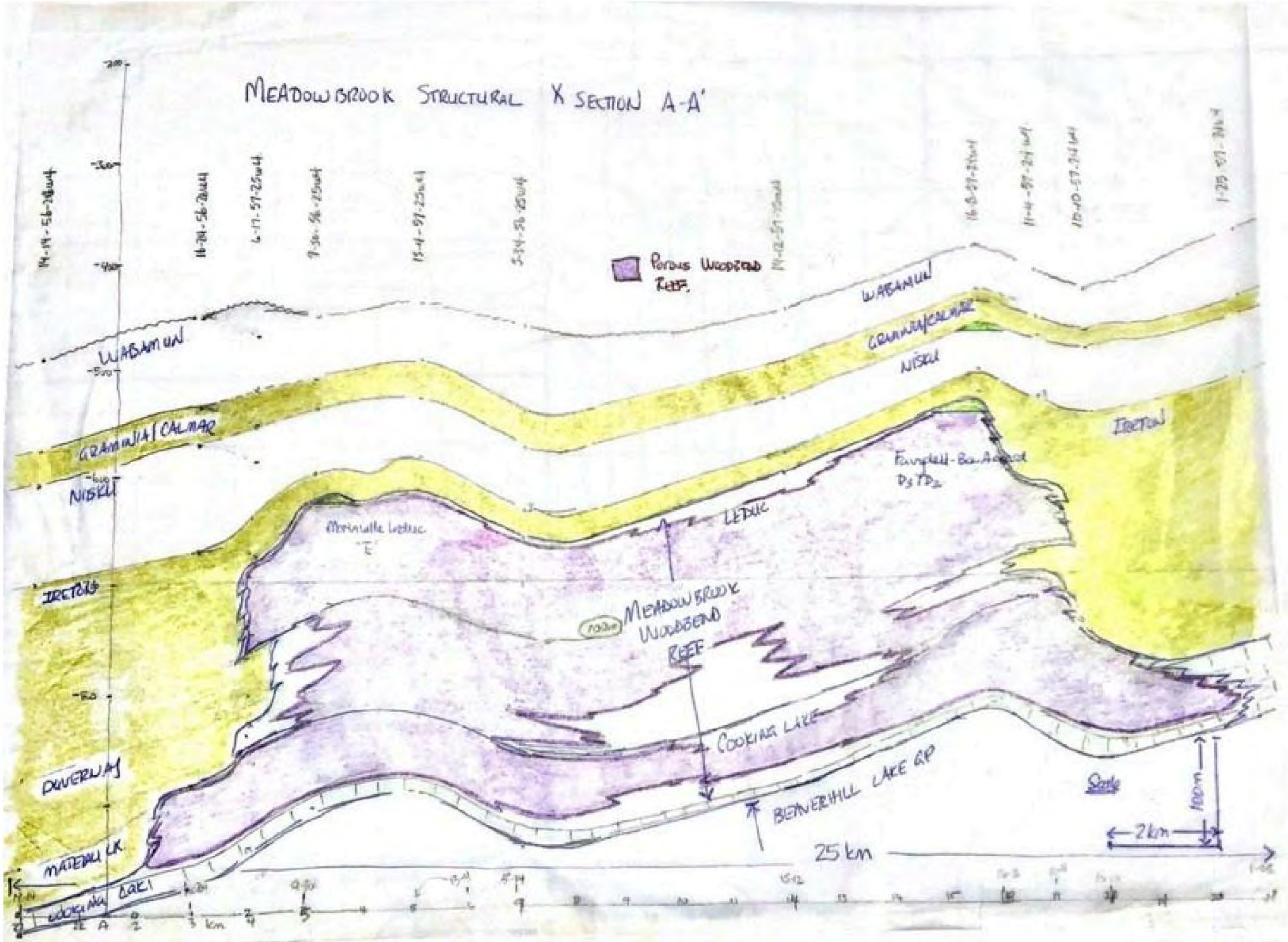
Coordinate System: NAD 1983 UTM Zone 12N

0 5 10
Kilometers

PROJECT: 23-00474
DRAWN BY: EPITTMAN
CHECKED BY: KK
DATE: JUNE 17, 2024

FIGURE
5-3

Document Path: K:\Active Projects 2023\AP 23-00451 to 23-00500\23-00474\Figures\C_and_R\Meadowbrook Carbon Storage Project\D65 Application\Fig 5-3 Isopach Map of Confinement Strata 23-00474.mxd



LEGEND

BISON LOW CARBON VENTURES
MEADOWBROOK CARBON STORAGE PROJECT

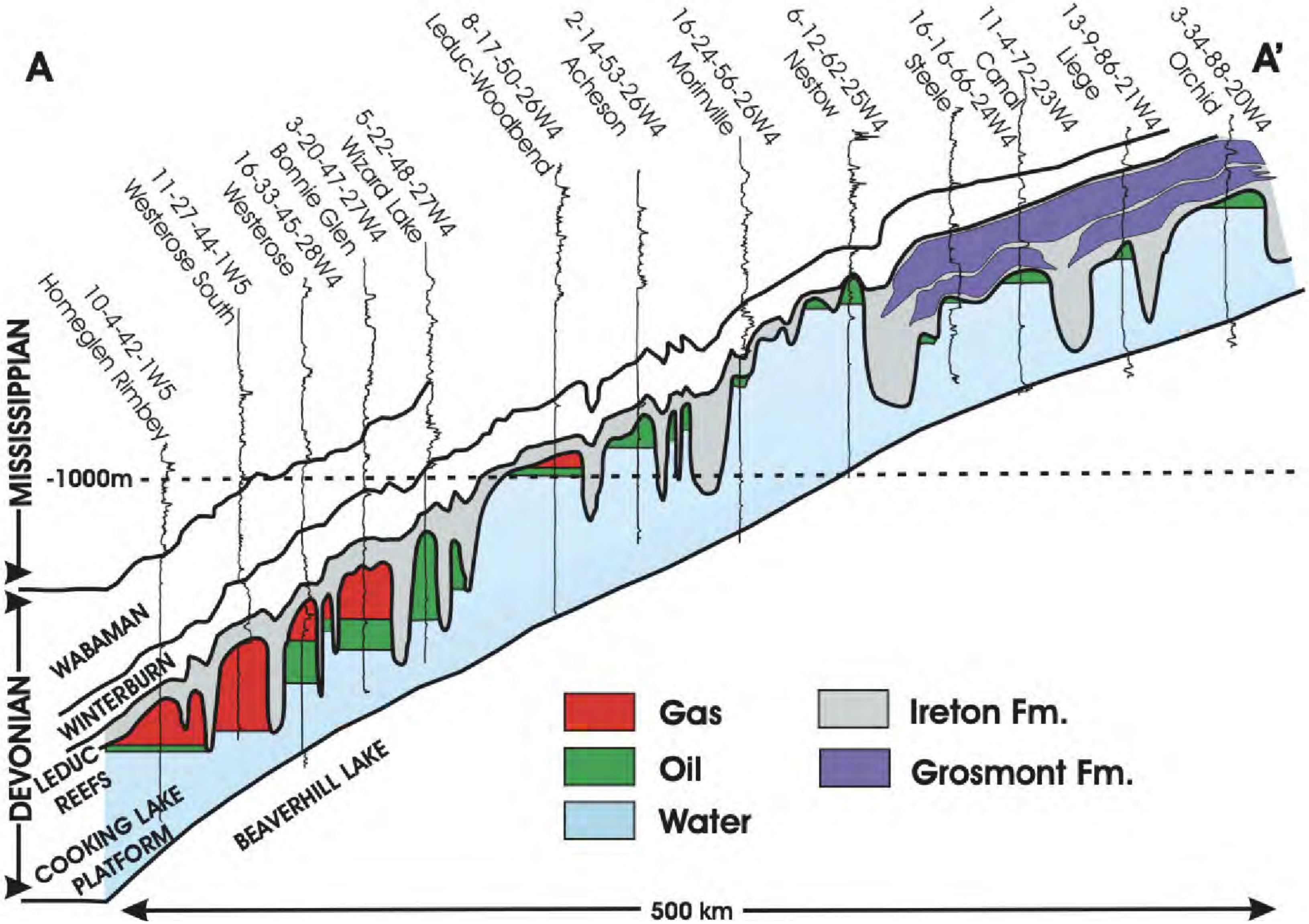
MEADOWBROOK STRUCTURAL CROSS-SECTION

PROJECT: 23-00474
DRAWN BY: EPITTMAN
CHECKED BY: KK
DATE: JUNE 19, 2024

AltaLIS, 2022; MEMS, 2024;S&P Global, 2024;

N/A

FIGURE
5-4



LEGEND

BISON LOW CARBON VENTURES

BISON LOW CARBON VENTURES
MEADOWBROOK CARBON STORAGE PROJECT

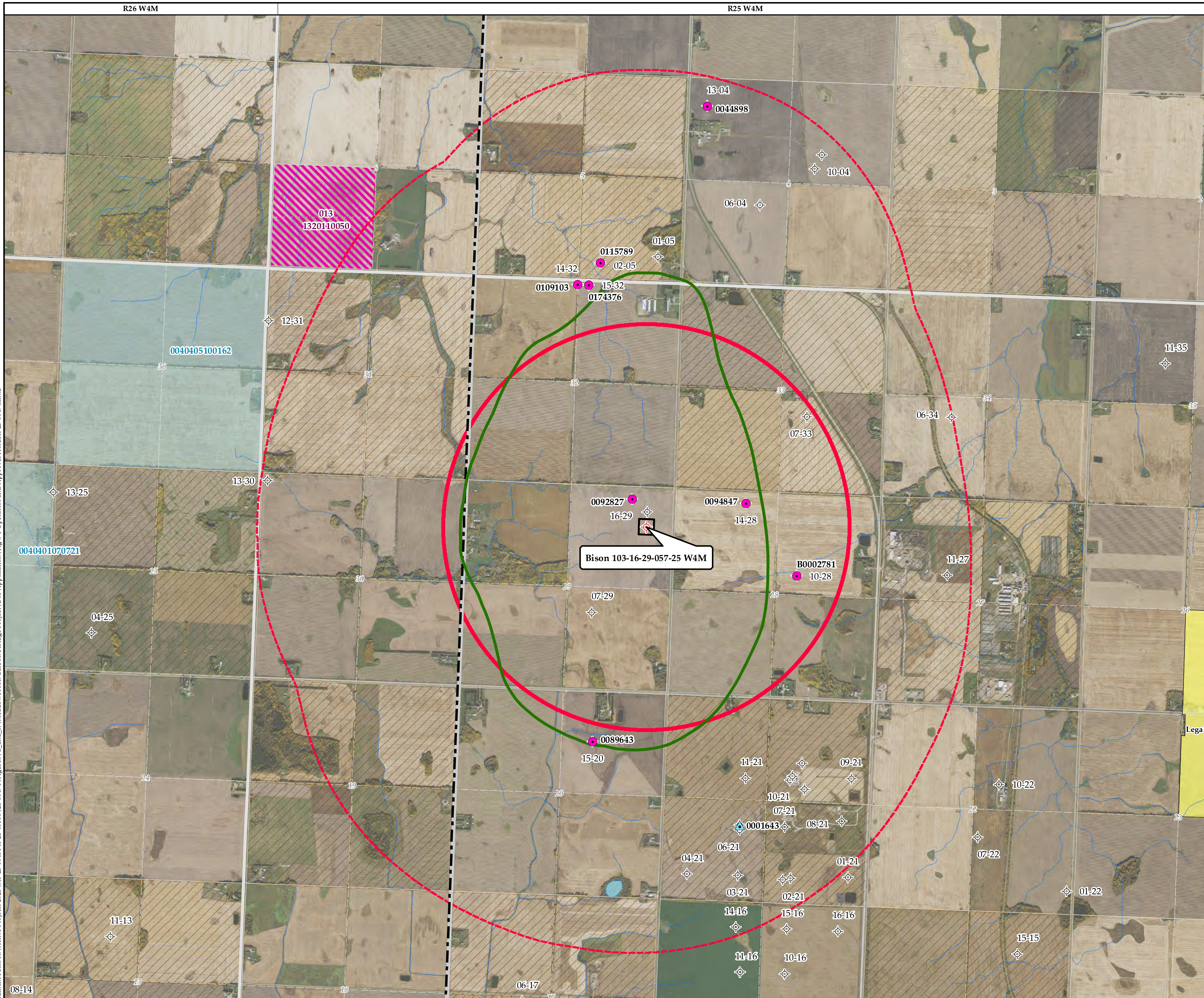
SCHEMATIC SECTION OF THE RIMBEY / MEADOWBROOK TREND

PROJECT: 23-00474
DRAWN BY: EPITTMAN
CHECKED BY: KK
DATE: JUNE 19, 2024

AltaLIS, 2022; MEMS, 2024;S&P Global, 2024;

N/A

FIGURE
5-5



BISON LOW CARBON VENTURES
MEADOWBROOK CARBON STORAGE PROJECT

OPERATORS AND APPROVAL HOLDERS WITHIN 1.6 km OF 103/16-29-057-25W4

LEGEND

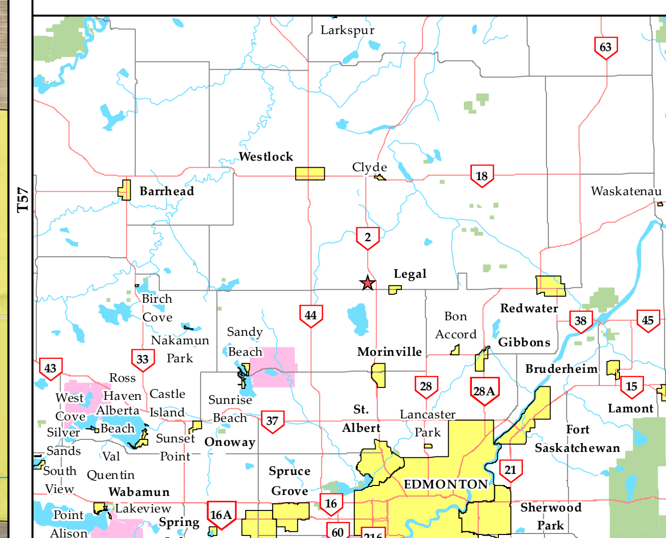
- Planned Injection Well
- Well Centre (AER Surface-Hole Location)

Injection Zone Penetrations

- Abandoned
- Abandoned (SCVF History)
- Well Lease Boundary
- Maximum Fluid Injection Area
- CO_2 Storage Area of Interest
- Operators and Approval Holders within Offsetting Sections of Planned Injection Well
- Operators and Approval Holders within 1.6 km of Maximum Fluid Injection Area
- Populated Place

Lease Agreements

- Coal Lease Agreement
- Petroleum & Natural Gas Lease Agreement
- Non-Crown Agreement



0 0.5 1
Kilometers

Coordinate System: NAD 1983 UTM Zone 12N

AltaLIS, 2022; Government of Alberta, Energy, 2024; MEMS, 2024; Valtus, 2023 (Image Date: 2017)

PROJECT: 23-00474
DRAWN BY: EPITTMAN
CHECKED BY: KK
DATE: SEPTEMBER 18, 2024

FIGURE

8-1

Document Path: K:\Active Projects 2023\AP 23-00451 to 23-00500\23-00474\Figures\C_and_R\Meadowbrook Carbon Storage Project\D65 Application\Fig 8-1 Operators and Approval Holders 23-00474.mxd

APPENDIX A: CONCORDANCE TABLES

Table A-1 Disposal Scheme

Requirement	Section(s)	Supporting Document(s)
4.1.3 Application Requirements for a Disposal Scheme		
General Requirements		
1) A description of the proposed disposal scheme, including:		
a) unique well identifiers,	Section 1.2	-
b) disposal zone with zone top and base,	Section 1.2	-
c) disposal perforations,	Section 1.2	-
d) disposal fluid class,	Section 1.5	-
e) anticipated daily disposal volumes, and	Section 1.2	-
f) depth of the production packer.	Section 1.2	
2) A statement on why the proposed well is suitable for disposal.	Section 2.1	-
3) A statement on why the proposed disposal is required.	Section 1.2	-
4) An indication of whether you have applied for or obtained approval for related surface facilities.	Section 1.5	Appendix B Appendix C
5) An indication of whether you have applied for or obtained approval for the related geothermal well in accordance with *Directive 089*.	N/A	N/A
6) Identification of the following:		
a) fluid type currently in the disposal interval (*i.e.*, water, gas, or oil),	Section 2.5	-
b) confinement strata,	Section 2.3	-
c) porosity and permeability of the disposal zone, and	Section 2.3	-
d) the distance between the proposed disposal wells and any hydrocarbon pool or accumulation.	Section 2.3	-
Conservation		
1) A discussion on hydrocarbon pools or accumulations within 1.6 km of the disposal well.	Section 3.1	-
2) If disposal is into a hydrocarbon zone or associated aquifer:		
a) A discussion on the stage of depletion of the recipient hydrocarbon zone.	Section 3.2	-
b) A statement on whether the hydrocarbon zone contains an oil-water (o/w) or gas-water (g/w) contact. Provide the depths of all contacts in relation to the proposed injection interval.	Section 3.2	-

Table A-1 Disposal Scheme

Requirement	Section(s)	Supporting Document(s)
4.1.3 Application Requirements for a Disposal Scheme		
c) An explanation of why the proposed disposal would not be detrimental to ultimate hydrocarbon recovery.	Section 3.2	-
d) A net pay isopach map of the zone, including both oil and gas if there is an associated gas pool.	N/A	N/A
e) A discussion on the proposed maximum operating pressure for disposal into the receiving hydrocarbon zone or the associated aquifer.	Section 3.2	-
Hydraulic Isolation		
1) For disposal wells injecting hydrogen sulphide (H2S), Class I and Class III fluids, all completion logging, testing requirements, and associated discussion required by *Directive 051*.	Section 4	Appendix D
2) In order to prove hydraulic isolation for Class II and Class IV disposal, the wellbore integrity logs must be submitted to demonstrate hydraulic isolation of the disposal zones in accordance with *Directive 051*.	N/A	N/A
3) If three months is not sufficient time to meet *Directive 051* requirements, request an extension, providing the following information:	N/A	N/A
a) the proposed submission date, and	N/A	N/A
b) the reasons for needing the submission date extension.	N/A	N/A
4) When submitting *Directive 051* information after the approval has been issued, you should provide the field and pool name, the disposal scheme approval number, and the well locations.	N/A	N/A
5) Provide the following information for either (1) all the wells in the pool if disposal is into a depleted hydrocarbon pool or (2) all the wells within the disposal well section and adjoining sections if disposal is into an aquifer system:		-
a) well location,	Section 4.2 Table 4-1 Figure 4-1	Appendix H
b) status of well,	Section 4.2 Table 4-1 Figure 4-1	Appendix H
c) completion intervals, and	Section 4.2 Table 4-1	Appendix H
d) all casing information.	-	Appendix H

Table A-1 Disposal Scheme

Requirement	Section(s)	Supporting Document(s)
4.1.3 Application Requirements for a Disposal Scheme		
Containment		
1) A discussion of the geological setting of the proposed disposal zone, base, and caprock.	Section 5.1	-
2) The following maps:		
a) structure and isopach maps of the proposed disposal zone, and	Figure 5-1 Figure 5-2	-
b) an isopach map of the confinement strata.	Figure 5-3	-
3) An interpreted and annotated log cross section or representative well logs showing:		
a) stratigraphic interpretation of the zones of interest and	Section 5.1	Appendix I
b) interpretation of the fluid interfaces present.	Section 3.2	-
4) Confirmation that all wells within the area of influence have been completed or abandoned in a manner that prevents the migration of the injected fluid or substance to another formation.	-	Appendix H
Maximum Wellhead Injection Pressure		
1) A statement of the proposed MWHIP and what it is based on.	Section 7	-
2) If requesting an MWHIP other than that prescribed in Appendix O, Table 1:	Section 7	-
a) Technical justification of the proposed MWHIP, including the complete test data and all analyses.	N/A	N/A
b) A discussion on the appropriate safety factor to ensure fluid containment.	N/A	N/A
Notification, Equity, and Safety		
1) Evidence of your right to dispose into the proposed zone. (For CO_2 sequestration schemes, see Section 4.1.6.)	Section 8.1	Appendix M
2) Provide		
a) a map showing the boundaries of the disposal pool or the area within the disposal section and the offset section up to a 1.6 km radius with the requisite parties listed below displayed, and	Figure 8-1	-

Table A-1 Disposal Scheme		
Requirement	**Section(s)**	**Supporting Document(s)**
4.1.3 Application Requirements for a Disposal Scheme		
b) a statement as to whether the parties shown on the map referred to in 2(a) have been notified about the application and, if so, include any statements of concerns received. Notification requirements for disposal scheme applicants are outlined in the section “Resources Applications Notification Guidelines.”	Section 8.2	Appendix N
3) All sour fluid injection operations must meet the requirements of *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*.	N/A	N/A
4) For Class I wells, a statement as to whether the landowners/occupants within a 0.5 km radius of the proposed disposal well have been notified about the application and, if so, include any statements of concerns received.	N/A	N/A

Table A-2 Class III Disposal		
Requirement	**Section(s)**	**Supporting Document(s)**
4.1.5 Application Requirements for Class III Disposal		
Containment		
1) For bounding formations, information including:		
a) continuity and thickness of base and caprock,	Section 5.2 Figure 5-3	-
b) lithology,	Section 5.2	-
c) integrity of the base and caprock,	Section 5.2	-
d) if fracturing is evident, explanation of how containment can be assured, and	Section 5.2	-
e) a comment on the stratigraphic, structural, or combination reservoir trap type and its containment features.	Section 5.2	-
2) A discussion on the maximum expected area of influence surrounding the proposed well over the life of the scheme, including any pressure gradients that exist as a result of past or current production or injection operations.	Section 5.3	Appendix K

Table A-2 Class III Disposal		
Requirement	**Section(s)**	**Supporting Document(s)**
4.1.5 Application Requirements for Class III Disposal		
3) An area review to ensure fluid containment. Offsetting wells must be investigated for hydraulic isolation of the disposal zone within the maximum expected area of influence surrounding the proposed well or a 1.6 km radius, whichever is greatest.	Section 4.2	Appendix H
Fluid Properties		
1) Analysis of the native reservoir fluids.	Section 6.1	Appendix L
2) Gas properties, including:		-
a) composition,	Section 6.2	-
b) viscosity, density, gas injection formation volume factor, and compressibility factors, and	Section 6.2	-
c) phase behaviour through the range of pressures and temperatures to which the injected fluid will be subjected.	Section 6.2	-
3) Migration calculation showing radius of influence, as well as a discussion if migration could occur due to displacement, gravity, fingering, *etc.* (not required for depleted reservoirs less than two sections in areal extent).	Section 6.3	Appendix K
4) Complete pressure history of the pool, with material balance calculations if proposed disposal zone is a depleted hydrocarbon pool.	N/A	N/A
5) Injectivity of the reservoir, proposed daily maximum injection rate, cumulative disposal volume, and expected life of the scheme.	Section 6.4 Section 2.3	-

Table A-3 Carbon Sequestration		
Requirement	**Section(s)**	**Supporting Document(s)**
4.1.7 Application Requirements for Carbon Sequestration		
Notification and Equity		
1) Evidence that you have the right to inject captured CO_2 for sequestration into the proposed zone. This right must be secured prior to application submission.	Section 8.1	Appendix M

Table A-3 Carbon Sequestration

Requirement	Section(s)	Supporting Document(s)
4.1.7 Application Requirements for Carbon Sequestration		
2) For the purposes of notification, the maximum injection fluid area must be calculated for each injection well.	Section 6.3 Section 8.2 Section 8.3 Figure 8-1	Appendix K
3) When calculating maximum injection fluid area for dense-phase CO_2 injection, the estimation must presume that stratigraphic, structural, and hydrodynamic trapping will be the dominant trapping mechanisms.	Section 6.3	Appendix K
Application Map		
4) In addition to maps required in section 4.1.3, provide maps showing:		
a) the sequestration lease boundary and	Figure 2-1	-
b) the calculated maximum fluid injection area per well.	Figure 2-1	-
Containment		
5) Evidence that the proposed formation depth within the sequestration agreement boundary is greater than or equal to 1000 metres true vertical depth from the surface of the land.	-	Appendix D
6) A discussion of the maximum expected CO_2 fluid plume and pressure plume area surrounding the proposed wells over the life of the scheme, including any pressure gradients that exist because of past or current production or injection operations.	Section 6.3 Figure 2-1	Appendix K
Safety		
7) For any CO_2 sequestration scheme approvals injection wells requesting an MWHIP, a recent injectivity test that is representative of the reservoir conditions prior to the commencement of the CO_2 injection, with	Section 9.1	Appendix O
a) the safety factor applied at the bottomhole formation fracture pressure, and		
b) any analogous offset data supported with a brief geological assessment that indicates its suitability.		
8) A hazard assessment evaluating potential for induced seismicity within the maximum CO_2 plume extent.	Section 9.2	-

Table A-3 Carbon Sequestration		
Requirement	**Section(s)**	**Supporting Document(s)**
4.1.7 Application Requirements for Carbon Sequestration		
9) If induced seismic events or new hazards are identified once a CO_2 sequestration scheme has commenced injection, the scheme operator must immediately contact the AER at Resources.Applications@aer.ca to propose a response and monitoring plan, and the AER may amend scheme approval conditions with mitigations as needed.	Section 9.2	-
Reporting		
10) The initial application submission to the AER after obtaining a valid Crown agreement or authorization to sequester CO_2 must include the MMV and closure plan.	Section 10.1	Appendix Q
11) The scheme operator must provide a complete baseline MMV, including a full set of baseline measurements collected during the pre-injection evaluation period.	Section 10.1	Appendix Q
12) Updates to MMV plans and closure plans, including duration and renewal of the plans, must be provided to the AER.	Section 10.1	-
13) A timeline chart with planned and issued dates and duration of all the evaluation permits and sequestration leases and the renewal periods of MMV plans and closure plans within the sequestration lease boundary.	Section 10.2 Table 10-1	-
14) An annual progress report, including scheme operation, containment, and performance.	N/A	N/A

APPENDIX B: WELL LICENCE

WELL LICENCE AMENDMENT

Licence No	0510240		
Well Name	BLCV LEGAL 16-29-57-25		
Licensee	BISON LOW CARBON VENTURES INC.		
Well Type	DISPOSAL (CCS)		
	Substance Name	**Formation Name**	
	CARBON DIOXIDE	WOODBEND GRP	
Surface Location	16-29-57-25W4	**Bottomhole Location**	16-29-57-25W4
Surface Co-ordinates	315.0 metres South	205.0 metres West	
Surface Location	**Surface Latitude**	**Surface Longitude**	
(NAD83 ATS 4.1)	53.960834	-113.672775	

Unique Well Identifier	103/16-29-057-25W4/0	**Surface Rights**	FREEHOLD
AER Classification/	OTH (C)	**Mineral Rights**	ALBERTA CROWN
Confidentiality Status		**Terminating Zone**	WOODBEND GRP
Surface Casing Depth	420.0 metres	**Projected Depth**	1650.0 metres
Ground Elevation	710.5 metres		

Drill Cutting Samples

Interval (m)	From Formation	Depth (m)	To Formation	Depth (m)
10.0	GRAMINIA FM	1150	TOTAL DEPTH	1650

Emergency Planning Zone 0.14 km

Number of Occupied Dwellings, Public Facilities and/or Places of Business inside the EPZ 0

AER Emergency 24-Hour Response Line 1-800-222-6514 (toll free)

This licence expires on August 14, 2025 if the well has not been spudded.

Dated at Calgary, Alberta this

21st day of August 2023

Application Number 32475452

Activity ID 32475454

For Alberta Energy Regulator

WELL LICENCE AMENDMENT

The approval amends Licence No. 0510240 issued to BISON LOW CARBON VENTURES INC.

By striking out the following;

Drill Cutting Samples:	Graminia Fm 1150.0 m to Beaverhill Lake Grp 1650.0 m
Terminating Zone:	Beaverhill Lake Grp

And by substituting the following;

Drill Cutting Samples:	Graminia Fm 1150.0 m to Total Depth 1650.0 m
Terminating Zone:	Woodbend Grp

APPENDIX C: SURVEY PLAN

BISON 103 LEGAL 16-29-57-25

Well Site and Access Road
to be Drilled from Surface Location in
L.S.16-SEC.29-TWP.57-RGE.25-W.4M.
Sturgeon County

THIS WELL IS TO BE DRILLED VERTICALLY

AER INFORMATION

THE PROPOSED WELL CENTRE:

	YES	NO
• is at least 200m from a water well.	■	□
• is at least 100m from a water body. (Low Area & Draw)	■	□
• is at least 100m from any surface improvements. - if "NO" see Table of Proximities	■	□
• is at least 40m from any surveyed road.	■	□
• is at least 5.0km from a lighted airport.	■	□
• is at least 1.6km from a unlighted airport.	■	□
• is at least 3.0km from a subsurface coal mine.	■	□
• requires the approval of Historic Resources Management Branch, Alberta Culture and Community Spirit re: Historical Resources Act. (Fall, 2022)	□	■
• meets the land reclamation guidelines with respect to drainage and elevation; Alberta Environment criteria. (Low Area on Pad Site or elevation change across Pad Site)	■	□

- the nearest urban centre is Legal, located ±4.5km east of wellsite. (Sec.26-57-25-W4M.)
- Owners: Skyhawk Farms Ltd.
- C. of T.: 142 078 112 +3

The location of the Well Site and Access Road is agreed to this _____ day of _______________ , ________ . I/We have no objection to the Alberta Energy Regulator issuing a Well license for the same.

Skyhawk Farms Ltd. ____________________ Witness ____________________

ELEVATIONS

DATUM (CGVD28): Precise Point Positioning (PPP)

708.32	Well Center 710.51	708.66
710.89		709.27

AREAS

Well Site	1.440ha.	3.56acres
Access Road	0.324ha.	0.80acres
Total	1.764ha.	4.36acres

LEGEND

Survey Monuments Found	●
Survey Spikes Found	▲
Survey Iron Bars Found	■
Survey Hubs Planted	□
Temporary Point	△
Existing Well Heads	⌖
Proposed New Well Centre	◉
Proposed Drilling Location	○ ○
Portions referred to bounded thus:	

Distances are in metres and decimals thereof.

UTM projection UTM NAD 83(CSRS)

Bearings are UTM. Convergence angle: -2°09'43"

Distances shown are ground using combined scale factor : 0.999869

I, Dagen Deslauriers, Alberta Land Surveyor, of Sherwood Park, Alberta, certify that the field survey represented by this plan is true and correct to the best of my knowledge, was carried out in accordance with the Alberta Land Surveyors' Association Manual of Standard Practice, and the field survey was performed on the 29th day of November, 2022.

ALBERTA LAND SURVEYORS' ASSOCIATION PERMIT NUMBER P123 MERIDIAN SURVEYS LTD.

Alberta Land Surveyor

Witness(D. Skish)

Date Signed: December 5, 2022

BISON LOW CARBON VENTURES

No.	Revision	Date

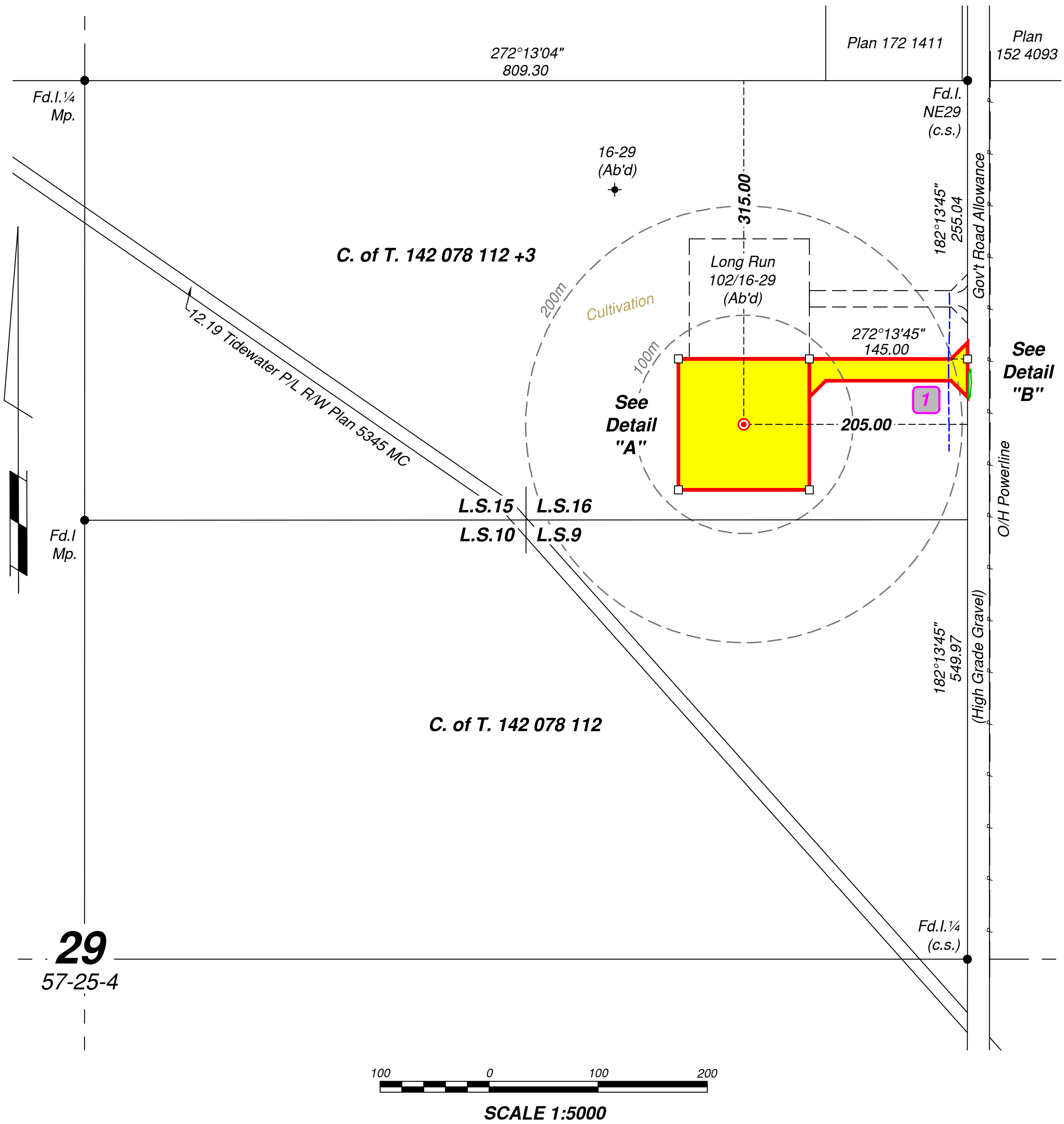
Meridian Surveys Ltd.
#152, 2301 PREMIER WAY SHERWOOD PARK, AB T8H 2K8 P:(780)665-4929

OUR FILE: ED224050 MC / JRL

LAND FILE: ______ Page 1 of 4

REVISIONS 0 2022 / __ / __

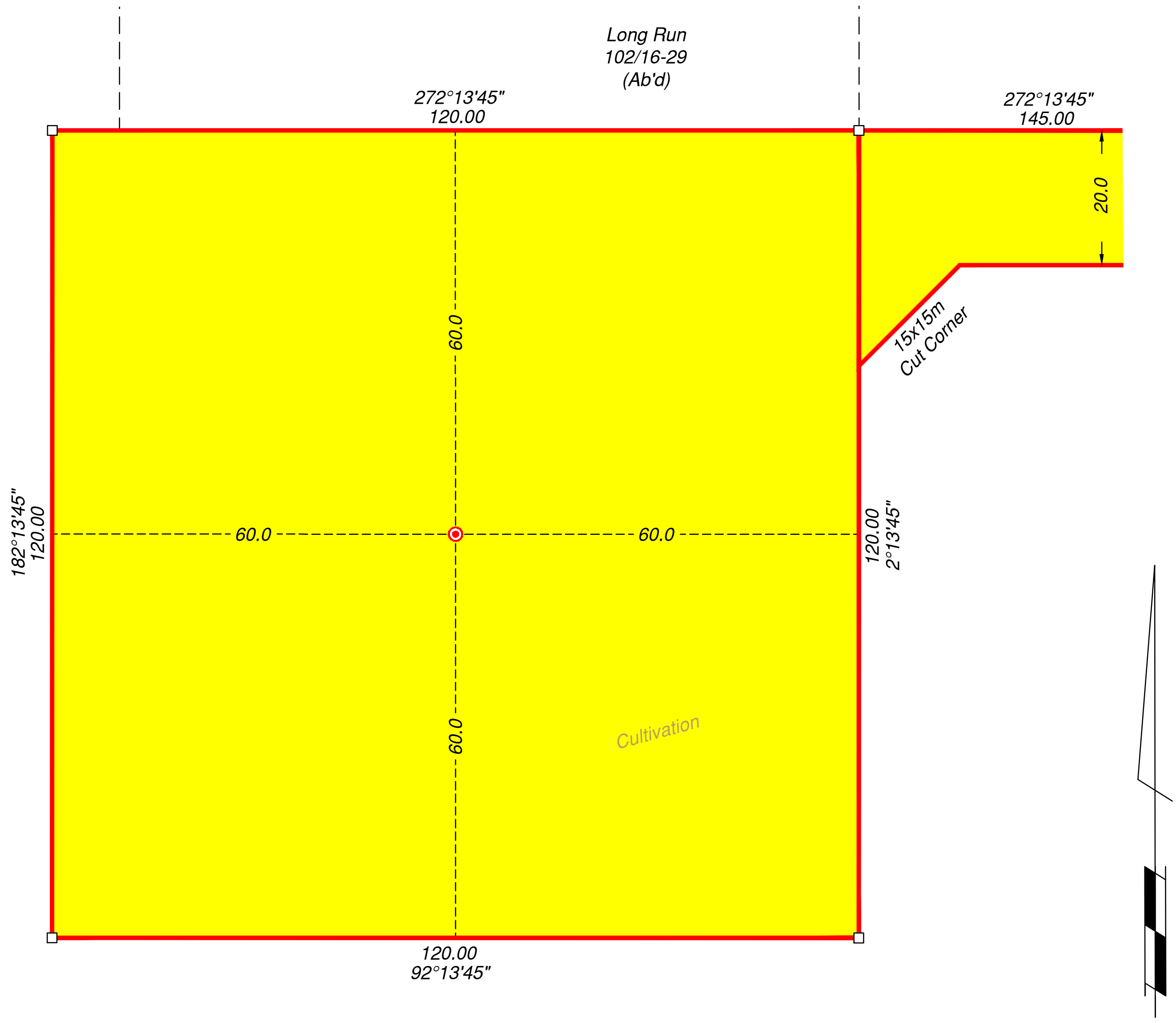
CLIENT FILE: ________



Meridian Surveys Ltd. makes no guarantee as to the underground facilities shown, actual locations must be verified independently prior to any construction activities.

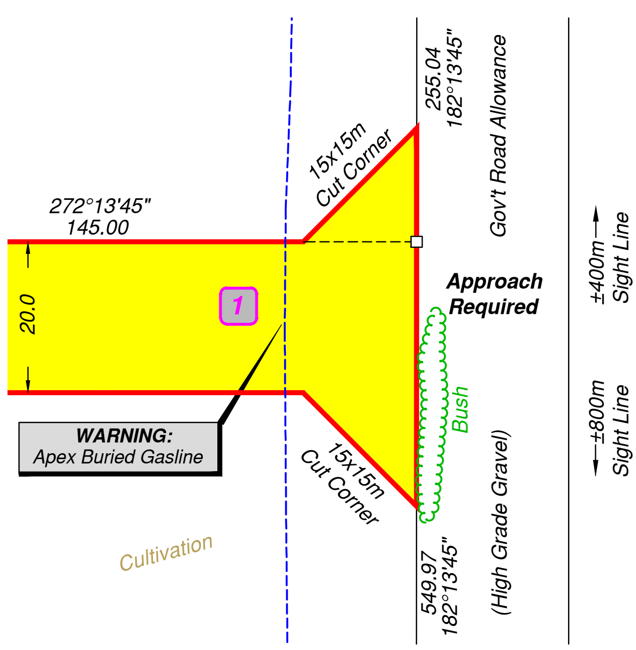
CO-ORDINATE TABLE

	REFERRED TO SECTION BOUNDARY	CARTESIAN (N.E. Sec.29)	GEOGRAPHICAL NAD '27(CSRS)	GEOGRAPHICAL NAD '83(CSRS)	UTM NAD '27(CSRS)	UTM NAD '83(CSRS)
SURFACE	(Sec.29-57-25-4) 315.00 S. of N. 205.00 W. of E.	314.80 South 205.37 West	53°57'38.70"N. 53.960751°N. 113°40'18.28"W. 113.671744°W.	53°57'38.97"N. 53.960825°N. 113°40'21.95"W. 113.672764°W.	5982243.98 N. 324717.04 E.	5982471.09 N. 324656.66 E.



DETAIL "A"

SCALE 1:1000



DETAIL "B"

SCALE 1:1000

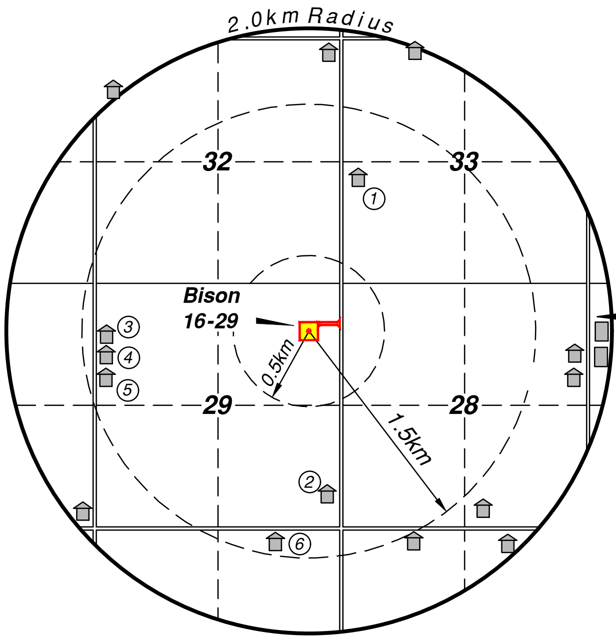
TABLE OF PROXIMITIES

OPERATOR	DESCRIPTION	DISTANCE FROM WELL CENTRE
Long Run	102/16-29 Lease	60.0m

Crossing numbers indicated: 1

TABLE OF CROSSINGS

No.	OPERATOR	DESCRIPTION	LOCATION
1	Apex Utilities	Buried Gasline	N.E.¼ Sec.29-57-25-W4M.



RESIDENCE SKETCH

Scale 1:50,000

Occupied Residence shown thus . . .
Abandoned Residence shown thus . . .
Public Facilities . . . .

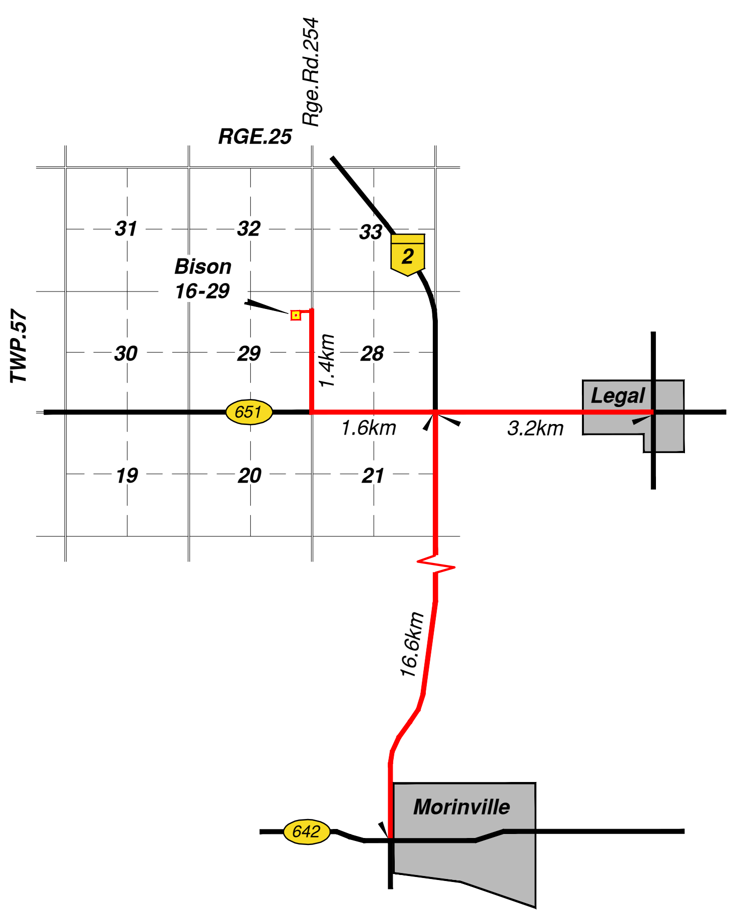
Surface Developments within 1.5km of Well Centre

1 1070m	3 1300m	5 1360m
2 1100m	4 1350m	6 1440m

Nearest Surface Development: *Residence: 1070m*

Nearest Urban Centre: *Legal: 4.5km*

ROAD USE AGREEMENT DATA
No other access required



ROUTE MAP

Scale 1:100,000

PHOTO MOSAIC PLAN

SHOWING

BISON 103 LEGAL 16-29-57-25

IN THE

N.E.¼ SEC.29-TWP.57-RGE.25-W.4M.

SCALE 1:10 000

Imagery Source:
© 2022 Airbus Defense and Space, Licensed by Planet Labs Geomatics Corp.,
www.blackbridge.com/geomatics

CLIENT FILE: ________	OUR FILE: ED224050

APPENDIX D: 103/16-29-057-25W4/0 COMPLETION LOG

BLCV Legal 16-29-57-25

BISON LOW CARBON VENTURES

Confidential: *Yes*

Licence #: *0510240* | ***Surface:*** *16-29-57-25W4M* | ***Lahee:*** *Other*

Drilling Rig: *Excalibur 14* | ***UWI:*** *103/16-29-057-25W4/0* | ***Objective:*** *Disposal*

Casing Bowl

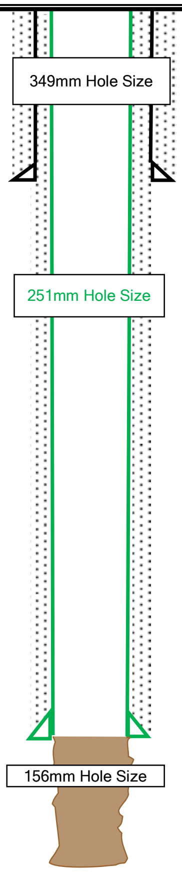
279mm x 273.1mm x 21MPa
SOW 2 x 2" LPSO

General Info

Working Interest:	100.0%	**Ground Level:**	710.51
Est. Days (Spud to RR):	12.0 days	**KB to GRND (est.):**	4.80 m
AFE #:	23DR001	**KB Elevation (est):**	715.31
AFE (est):	$2,305,200	**Total Depth (KB):**	1,612 mKB

H_2S Information

H_2S: 5.92%
Release Rate: 0.0140 m3/s
EPZ: 120 m
Last Checked: August 8, 2023



Formation Tops

MD (m KB)	TVD (m KB)	Formation Tops		Depth (m SS)	Expected Pressure	EMD	H_2S	Potential Problems
368.3	368.3	Lea Park		347.0	3,613 kPa	1000.0 kg/m³	0.0% H2S	
411.1	**411.1**	**BGWP (AER)**		**304.2**				**WG**
425.3	**425.3**	**SURFACE HOLE TD**		**290.0**				
455.3	455.3	Milk River		260.0	4,467 kPa	1000.0 kg/m³	0.0% H2S	**WG**
527.3	527.3	Colorado Grp		188.0	5,173 kPa	1000.0 kg/m³	0.0% H2S	WG
703.3	703.3	Second White Specs		12.0	4,818 kPa	698.3 kg/m³	0.0% H2S	
795.3	795.3	BFS		-80.0	7,802 kPa	1000.0 kg/m³	0.0% H2S	**WG**
838.3	838.3	Viking		-123.0	7,042 kPa	856.3 kg/m³	0.0% H2S	
866.3	866.3	Joli Fou		-151.0	6,671 kPa	784.9 kg/m³	0.0% H2S	
878.3	878.3	Mannville		-163.0	7,378 kPa	856.3 kg/m³	0.0% H2S	
1,018.3	1,018.3	Glauc		-303.0	8,656 kPa	866.5 kg/m³	0.0% H2S	
1,038.3	1,038.3	Ostracod		-323.0	10,186 kPa	1000.0 kg/m³	0.0% H2S	**WG**
1,053.3	1,053.3	Ellerslie		-338.0	7,584 kPa	733.9 kg/m³	0.0% H2S	
1,120.3	1,120.3	Wabamun		-405.0	7,842 kPa	713.6 kg/m³	0.0% H2S	
1,169.3	1,169.3	Graminia		-454.0	11,471 kPa	1000.0 kg/m³	0.0% H2S	**WG**
1,171.3	1,171.3	Blueridge		-456.0	7,496 kPa	652.4 kg/m³	0.0% H2S	
1,195.3	1,195.3	Calmar		-480.0	7,889 kPa	672.8 kg/m³	0.0% H2S	
1,197.5	**1,197.5**	**Stage Tool**		**-482.2**				
1,199.3	1,199.3	Nisku		**-484.0**	8,875 kPa	754.3 kg/m³	**5.92% H2S**	**S**
1,281.3	1,281.3	Ireton	1,286 - 1,304m MD (18m)	**-566.0**	9,738 kPa	774.7 kg/m³	0.0% H2S	
1,308.3	**1,308.3**	**ICP (Confirm depth with on-site geo)**		**-593.0**	11,644 kPa	907.2 kg/m³	**4.96% H2S**	**S**
1,309.3	1,309.3	Leak-off Test, approx 1m outside ICP		-594.0	11,653 kPa	907.2 kg/m³	**4.96% H2S**	**S**
1,311.3	1,311.3	Leduc		-596.0	11,671 kPa	907.2 kg/m³	**4.96% H2S**	**S**
1,457.3	1,457.3	Cooking Lake		-742.0	11,658 kPa	815.5 kg/m³	0.0% H2S	
1,612.0	**1,612.0**	**TD**		**-921.0**	15,814 kPa	1000.0 kg/m³	0.0% H2S	**WG**

Legend: LC = Lost Circulation, AP = Abnormal Pressure, S = Sour, WG = Water Gradient (9.81 kg/m^3)

WEST ROCK ENERGY CONSULTANTS LTD.

Geological Evaluation

AER Samples Surf Csg to TD, 10m intervals
Operator's Samples: 50m above Nisku to TD, 5m intervals
Gas Detection: Surface casing shoe to HZ TD
Logging: Array Induction/SP 1:600 & 1:240 Intermed - TD CNL-LDT-GR-CAL, Sonic-GR-CAL, MicroLog SP, LST Matric on Main Pass, Dipole Sonic, MDT
H_2S Detection: Yes, Required
Cores or DST: 18m Ireton Core

Additional Information

GENERAL WELL
Potential mud rings, preventative measures to be taken.
Multi well pad potential, monitor deviation.
Wiper trip at TD or whenever hole dictates.

SURFACE HOLE
Drill to surface TD or 1st competent formation below.
Raise vis @ TD to ensure hole is clean.

INTERMEDIATE HOLE
Above Mannville
Keep mud weight ALAP
Below Mannville
Mud up at Basal Colorado top, ensure fluid loss is 6-8 ml/30min, Pretreat with U-Scav for H_2S

OPEN HOLE

Drilling Fluids (refer to Drill Fluids Program for full details)

SURFACE: 0 - 425.31 m MD | Floc Water | Density: As Low As Possible
Spud w/ H_2O allowing native clays to build vis. Increase vis w/ gel & lime for hole.

INTERMEDIATE:
Above MNVL 0 - 868.31 m MD | PHPA Floc Water | Density: As Low As Possible
Below MNVL 868.31 - 1308.31 m MD | Polymer | Density: As Low As Possible

OPEN HOLE: 1308.31 - 1612 m MD | Clay Free Polymer | Density: < 1,050 kg/m^3
Displace with Fresh Water + 5 kg/m^3 ArkBreak EN-1090 + bioci

Casing & Casing Attachments

SURFACE: 0 - 425.31 m MD **273.1mm, 60.27kg/m, J-55, BT&C**
Float shoe, 2x bow spring, float collar, bow spring every 3rd joint to surface

INTERMEDIATE: 0 - 1287.31 m MD **177.8mm, 39.14 kg/m, L-80, LT&C**
1287.31 - 1308.31 m MD **177.8mm, 38.69 kg/m, 13CR-80, Tenaris Wedge 513**

OPEN HOLE: 1308.31 - 1612 m MD **Not cased**

Cement (refer to Cement Program for full details)

ALL CEMENT JOBS: Plug loading head to be utilized. Adjust flow rate to allow constant reciprocation. Do not exceed drilling annular velocity (drill pipe).

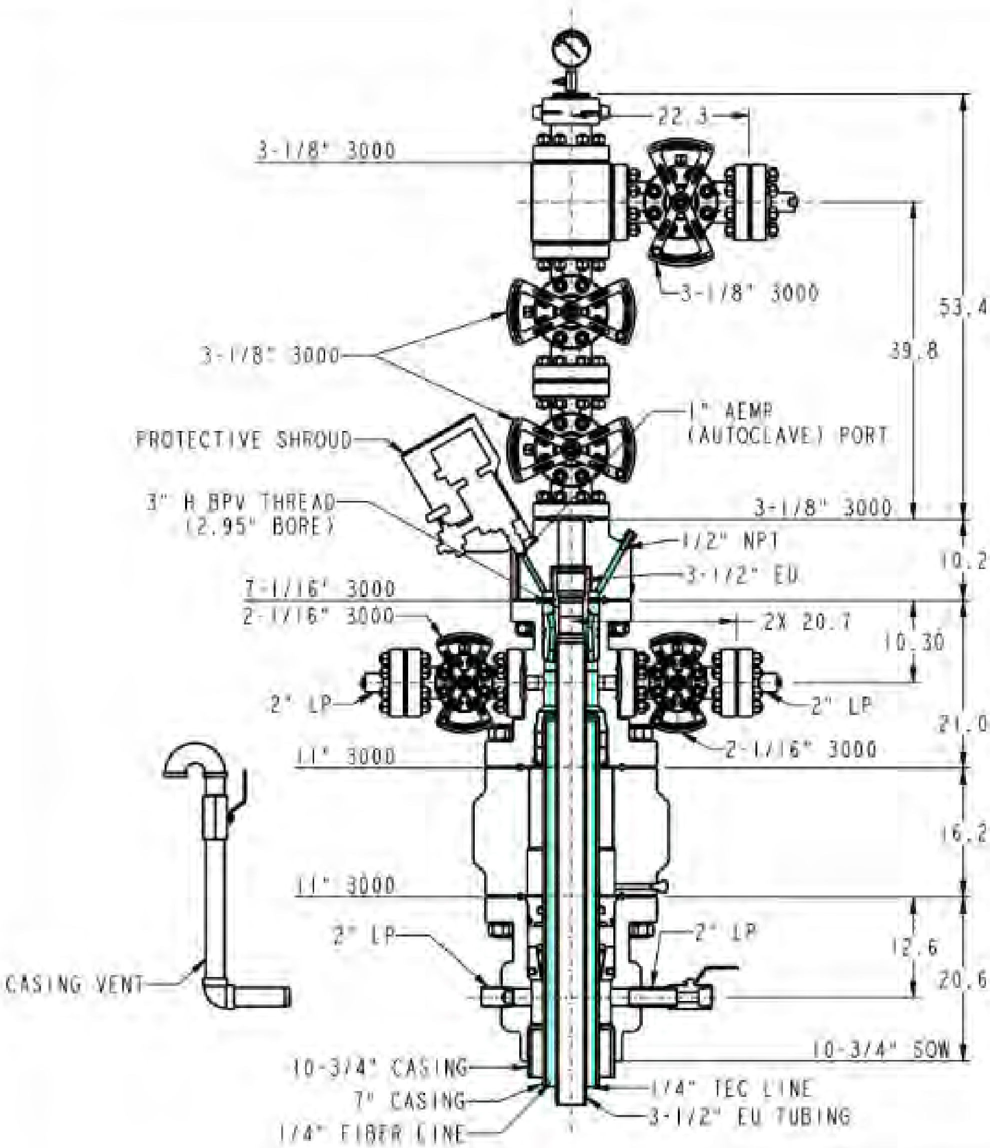
SURFACE:
0 - 425.31 m MD
75% Excess
Pre-Flush: 4.0 m³ Fresh Water
Tail: TSC 1700 + 0.2% AFA-7 + 1.0% $CaCl_2$

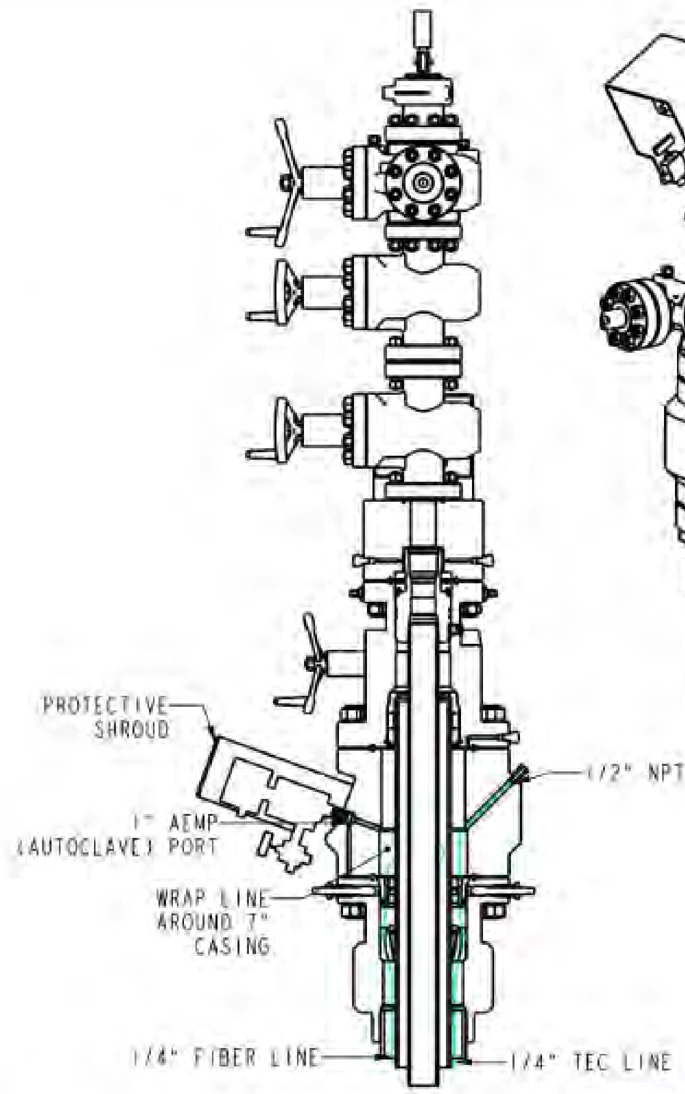
INTERMEDIATE: Pre-Flush: 5.0 m³ Optimum Flush
0 - 1197.51 m MD — Stage 1: Thermolite 1650 HT + 0.4% TLA + 1.5% TA-4 + 0.6% AFA-7 + 0.8% TLF-HT + 1.5% TA-1
1197.51 - 1308.31 m MD — Stage 2: Thermolite 1650 HT + 0.4% TLA + 1.5% TA-4 + 0.6% AFA-7 + 0.8% TLF-HT + 1.5% TA-1

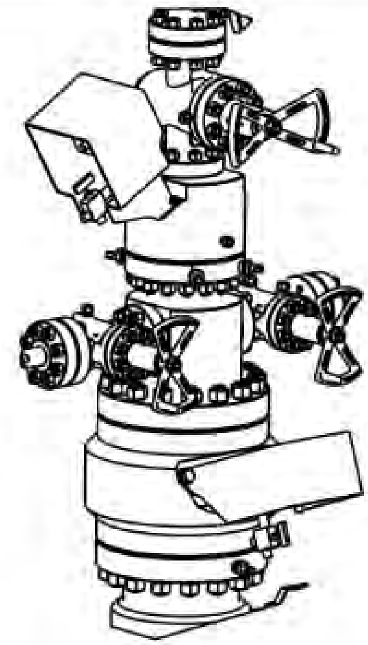
OPEN HOLE: Not Cemented **Displace with Fresh Water + 5 kg/m3 ArkBreak EN-1090 + biocides**
1308.31 - 1612 m MD

Prepared by: Mike Johnson September 28, 2023 :Date

APPENDIX E: WELLHEAD SCHEMATIC







3D VIEW
PROTECTIVE
SHROUD

BISON LOW CARBON VENTURES INJECTION WELLHEAD 10-3/4" X 7" X 3-1/2"				StreamFlo	DRAWING No.
	DWN.	VJL	05-01-23		WH-24754
	CHK.	RM	05-01-23		REV. 1
	APPD.				SHEET 1 OF 1
		BY	DATE		

APPENDIX F: PACKER SCHEMATIC

HALLIBURTON
Completion Tools

Bison Low Carbon Ventures

PLT Packer and Gauges Install - Monitoring CCS Injector

Prepared for Terry Sharkey / Grant Wierzba

Ryan Bartko - (780) 832-6539

Account Representative

FORMATION INFORMATION

Open Hole MD	**1,310.790 - 1,612.000 m**	Reservoir MD	**1,310.790 - 1,612.000 m**
Open Hole TVD	**1,310.790 - 1,612.000 m**	Reservoir TVD	**1,310.790 - 1,612.000 m**

ADDITIONAL NOTES

Equipment Suppliers:
Pressure Temperature Gauges and Paker BHA Supplied by Halliburton Completions
Fiber Optic Cable Supplied by Halliburton Pinnacle.

Clamp Details (Installed on Tubing):
- 1 cross coupling clamp on the middle of the pup joint on top on the Gauge Mandrel.
- Cross coupling clamp on every joint for the first 15 connections. Clamp on every other connection to surface after that.
- 1 cross coupling clamp below the tubing hanger.

Totals: 177 Cross Coupling Clamps

Clamp Details (Installed on Intermediate Casing):
- First 5 Joint have centralizers, 2 w/ Mid joint clamps
- 2 stop collars above and below the bottom Array gauge w/ 1 cross coupling clamp covering the gauge.
- 2 stop collars above and below the Top Array gauge w/ 1 cross coupling clamp covering the gauge.
- 2 centralizers on the pup joints above and below the stage tool.
- 1 Long clamp across the stage tool.
- 112 cross coupling clamps on every joint to surface.
- 23 centralizers w/ mid joint clamp on every 3rd joint to Joint # 74.
- 9 centralizers w/ mid joint clamp on every 4th joint from Joint # 74 to Joint # 110.

Totals: 146 Cross Coupling/ Mid Joint Clamps, 39 Centralizers, 4 Stop Rings, 1 Long Clamp.

Downhole Opsis Gauge (Installed on Tubing):
SAP# 102815210 SN# OPS-002869 Address: 165
Gauge: Opsis 150C 10K
Cable: 11mm O.D, 0.250'' x 0.035'', 16AWG, S/N 134553-1
Gauge Ported to Tubing: 1295.68mKB
Final Gauge Readings: 9433.66kPa, 47.69°C Wellhead Outlet Completed.

Downhole Array Gauges (Installed on Intermediate Casing):
DataSphere Array Sensors, 150°C , 10,000 psi, SAP# 103170698
Array Sensor #1 SN: 296850
Array Sensor #2 SN: 296910
Cable: 11mm O.D, 0.250'' x 0.035'', 16AWG, S/N DMS-00110
Array Sensor #1 Installed **@ 1275.79 mKB**
Array Sensor #2 Installed **@ 1235.79 mKB**
Final Gauge Readings (Wellhead Outlet Completed):
Array Sensor #1: 9203.75kPa, 36.65°C
Array Sensor #2: 8804.55kPa, 36.79°C

Fiber Optic Line:
"FiberSight" P/N: 103164245 SN: 7020296234-10
- 2 x Fibercore GIMM CMTDA 50/125 Graded Index Fiber; Colored Blue & Orange
- 2 x Fibercore SM1250 CMTDA Single Mode Fiber; Colored Red & Black
- FIMT: 3.2 mm x 2.8 mm Stainless Steel 316L, Filled with LA4000 EFL > 0.30%
- Natural Polypropylene; O.D.: 4.57mm (0.180") Nominal – Belt OD run larger for CCS Application
- 825 Alloy Tube; Wall Thickness: 0.89 mm (0.035"); O.D.: 6.35 mm (0.250") Nom

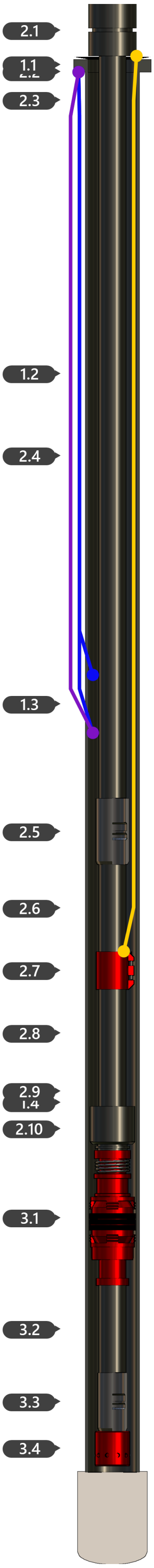
Fiber End Termination **@ 1275.79mKB**

Directions:
From St. Albert:
-North on HWY 2 to State HWY 651.
-Left onto 651 to RR 254.
-Right on RR 254 for 1.3km.
-Left on access road into Location.

FOC Service Specialist:
Rob Lauzon, James Walsh

IC Service Specialists:
Nathan Argue, Amir Naeem
SO#90877710, 908903626

Job Complete Date:
October 28 2023



CONTROL LINE LEGEND

Individual Control Lines

- Array Casing Deployed TEC - 1/4" x 0.049" WT INC-825 TEC c/w 11mm Encapsulation
- Tubing Deployed TEC - 1/4" x 0.035" WT 316SS TEC c/w 11mm Encapsulation
- Fiber Optic - 1/4" x 0.035" WT Fiber Optic Cable

TOOL INFORMATION

Index	Description	ID (mm)	OD (mm)	Length (m)	Depth (m)
177.8mm Intermediate Casing					
1.1	KB to CHF	159.41	255.27	4.800	0.000
1.2	177.8mm 38.69kg/m L-80 LT&C Casing	157.07	177.80	1,230.990	4.800
1.3	177.8mm 38.69kg/m L-80 LT&C Casing (Top Array Gauge @ 1235.79mKB)	157.07	177.80	40.000	1,235.790
1.4	177.8mm 38.69kg/m L-80 LT&C Casing (Bottom Array Gauge & Fiber End Termination @ 1275.79mKB)	157.07	177.80	35.000	1,275.790
Note:	End of Assembly | Bottom depth: **1,310.790 m**				
88.9mm Tie-Back String					
	KB Diff			4.550	
2.1	Tubing Hanger w/ 88.9mm EUE to NSCT Crossover	76.00	157.07	0.460	4.550
2.2	1 Jts- 88.9mm 13.69kg/m L-80 NSCT Tubing Joints	76.00	88.90	9.830	5.010
2.3	4 Pups- 88.9mm 13.69kg/m L-80 NSCT Space Out Pups (Top-Bottom: 2.41m,	76.00	88.90	8.430	14.840
	10 kdAN Compression			0.500	
	Wireline Tally Correction			-1.030	
2.4	126 Jts- 88.9mm 13.69kg/m L-80 NSCT Tubing Joints	76.00	88.90	1,270.770	22.740
2.5	69.85mm X nipple L-80 ENC coated threaded 88.9mm 13.69Kg/m NSCT Box x Pin	69.85	107.97	0.360	1,293.510
2.6	88.9mm 13.69kg/m L-80 NSCT Pup Joint - ENC Coated	76.00	88.90	1.810	1,293.870
2.7	88.9mm L-80 Halliburton Opsis Gauge Mandrel Assy.Threaded NSCT - ENC Coated c/w Internally Ported 150C 10,000PSI Rated Gauge	76.00	124.22	0.830	1,295.680
2.8	88.9mm 13.69kg/m L-80 NSCT Pup Joint - 3.1m ENC Coated	76.00	88.90	3.020	1,296.510
2.9	88.9mm 13.69kg/m L-80 NSCT Pup Joint - 3.1m ENC Coated	76.00	88.90	3.020	1,299.530
2.10	177.8mm x 88.9mm Halliburton L-80 On/Off Assembly c/w 69.85mm "X" Profile in SlickJoint (NSCT Box) - ENC Coated	69.85	146.05	0.650	1,302.550
Note:	End of Assembly | Bottom depth: **1,303.200 m**				
177.8mm Packer BHA (Set on Wireline)					
3.1	177.8mm x 88.9mm 34.23kg/m-43.16kg/m Halliburton Versa-Set Packer L-80 EUE 10K H2S/CO2 - ENC Coated (CE @ 1304mKB)	72.80	151.89	2.130	1,303.200
3.2	88.9mm 13.84kg/m L-80 EUE Pup Joint - ENC Coated	76.00	88.90	3.100	1,305.330
3.3	88.9mm Halliburton "Otis" 2.75'' "XN" Landing Nipple c/w 68.95mm Profile and 66.93mm No-Go - ENC Coated	66.93	95.45	0.390	1,308.430
3.4	88.9mm L-80 EUE Pump Out Plug Re-Entry Guide - ENC Coated	N/A	114.39	0.170	1,308.820
Note:	End of Assembly | Bottom depth: **1,308.990 m**				
Note:	Open Hole 1310.79mKB - 1612mKB				

APPENDIX G: PROPOSED RECOMPLETION OF 16-29 INJECTION WELL

HALLIBURTON
Completion Tools

Bison Low Carbon Ventures

"Work-Over" Permanent Packer and Open Hole Packers

Prepared for Terry Sharkey / Grant Wierzba

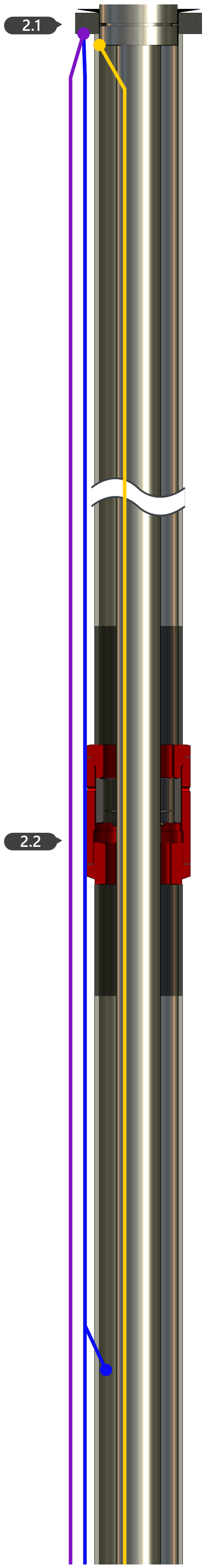
Ryan Bartko - (780) 832-6539

Account Representative

FORMATION INFORMATION

Open Hole MD	**1,310.790 - 1,612.000 m**	Reservoir MD	**1,310.790 - 1,612.000 m**
Open Hole TVD	**1,310.790 - 1,612.000 m**	Reservoir TVD	**1,310.790 - 1,612.000 m**

Note: A positive pressure injection valve will be installed in 2.3 Otis 2.75" "X" NSCT Landing Nipple at 1285.13m and a Halliburton MC Injection Valve will be installed in 2.5 Otis 2.75" "X" Nipple at 1295.09m



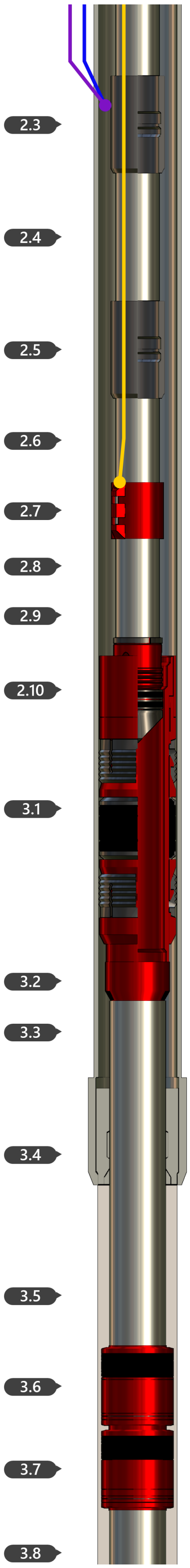
CONTROL LINE LEGEND

Individual Control Lines

- Array Casing Deployed TEC - 1/4" x 0.049" WT INC-825 TEC c/w 11mm Encapsulation
- Tubing Deployed TEC - 1/4" x 0.035" WT 316SS TEC c/w 11mm Encapsulation
- Fiber Optic - 1/4" x 0.035" WT Fiber Optic Cable

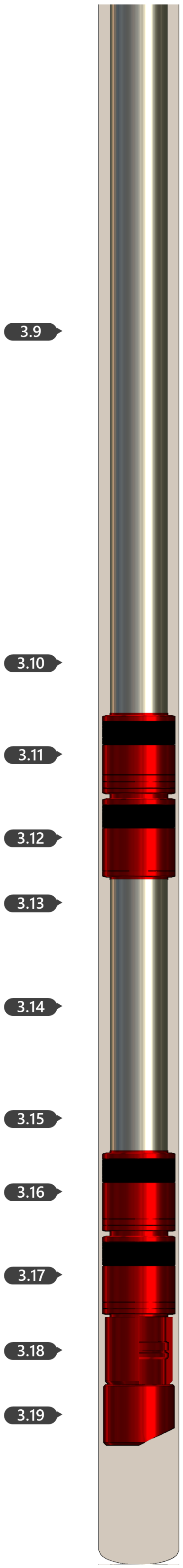
TOOL INFORMATION

Index	Description	ID (mm)	OD (mm)	Length (m)	Top Depth (m)	Supplier
88.9mm Tie-Back String						
	KB to Tubing Hanger Flange			4.550		
2.1	Tubing Hanger w/ 88.9mm EUE to NSCT Crossover	76.00	157.07	0.460	4.550	Bison LCV
	10 kdaN Compression			0.500		
	Wireline Tally Correction			-1.030		
2.2	88.9mm 13.69kg/m L-80 NSCT Tubing Joints	76.00	88.90	1,280.650	4.480	Bison LCV



TOOL INFORMATION

Index	Description	ID (mm)	OD (mm)	Length (m)	Top Depth (m)	Supplier
88.9mm Tie-Back String						
2.3	88.9mm Halliburton "Otis" 2.75'' "X" NSCT Landing Nipple c/w 68.95mm Profile ENC Coated	69.85	107.97	0.360	1,285.130	Halliburton
2.4	88.9mm 13.69kg/m L-80 NSCT Tubing Joint	76.00	88.90	9.600	1,285.490	Bison LCV
Note:	***The current Tie Back Assy. will be re-used on the next run. We will ship back to the Halliburton Facility for Overshot removal and torque into Ratch Latch Assy and full Inspection and Pressure Test.***					
Note:	**Sub Assembly 5 (Gauge Mandrel) - To be Shipped out from Nisku Facility.** **Length: +/- 6m (19.6ft)**					
2.5	88.9mm Halliburton "Otis" 2.75'' "X" NSCT Landing Nipple c/w 68.95mm Profile ENC Coated	69.85	107.97	0.360	1,295.090	Halliburton
2.6	88.9mm 13.69kg/m L-80 NSCT Pup Joint ENC Coated	76.00	88.90	1.810	1,295.450	Bison LCV
2.7	88.9mm L-80 Halliburton Opsis Gauge Mandrel Assy.Threaded NSCT - ENC Coated c/w Internally Ported 150C 10,000PSI Rated Gauge	76.00	124.22	0.830	1,297.260	Halliburton
2.8	88.9mm 13.69kg/m L-80 NSCT Pup Joint - 3.1m ENC Coated	76.00	88.90	3.020	1,298.090	Bison LCV
Note:	**Pup Joints to be split at the Halliburton Facility**					
Note:	**Sub Assembly 4 (Liner Hanger Packer) - To be Shipped out from Nisku Facility.** **Length: +/- 8m (26.2ft)**					
2.9	88.9mm 13.69kg/m L-80 NSCT Pup Joint - 3.1m ENC Coated	76.00	88.90	3.020	1,301.110	Bison LCV
2.10	127mm Bore Ratch Latch Seal Assy. c/w HNBR Moulded Seals for CO2 Compatibility. **Threading: *TBD*** ENC Coated	100.03	134.37	0.871	1,304.130	Halliburton
Halliburton 'MHR' Hydraulic Set Permanent Packer Liner Hanger						
3.1	177.8mm x 127mm 38.69kg/m Halliburton "MHR" Permanent Packer Assy. - COE:1305m c/w HNBR Elastomers for CO2 Compatibility. c/w 127mm Upper Seal Bore ENC Coated	98.77	149.06	2.040	1,305.000	Halliburton
3.2	Packer to Tubing Adapter - ENC Coated c/w 114.3mm BTC Box Connection	101.60	145.00	0.500	1,307.040	Halliburton
3.3	114.3mm 22.47kg/m T-95 VaRoughneck Box x Pin **- 4' Pup Joint - 1.24m for handling purposes - *Customer Supplied***	97.18	114.30	1.240	1,307.540	Bison LCV
3.4	114.3mm 22.47kg/m VA-XP-SS95 VA-Roughneck Casing Joints - **Estimated 2Joints of Casing**	97.18	114.30	26.000	1,308.780	Bison LCV
Note:	**Sub Assembly 3 (Zone Guards) - To be Shipped out from Nisku Facility.** **Length: +/- 5.1m (16.73ft)**					
3.5	114.3mm 22.47kg/m VA-XP-SS95 VA-Roughneck **6' Pup Joint - 1.86m** - ***Customer Supplied***	97.18	114.30	1.860	1,334.780	Bison LCV
3.6	Halliburton ZoneGuard Open Hole Packer Threaded 114.3mm 22.47kg/m BTC Box x Pin ENC Coated	99.06	146.18	0.984	1,336.640	Halliburton
3.7	Halliburton ZoneGuard Open Hole Packer Threaded 114.3mm 22.47kg/m BTC Box x Pin ENC Coated	99.06	146.18	0.984	1,337.624	Halliburton



TOOL INFORMATION

Index	Description	ID (mm)	OD (mm)	Length (m)	Top Depth (m)	Supplier
Halliburton 'MHR' Hydraulic Set Permanent Packer Liner Hanger						
3.8	114.3mm 22.47kg/m VA-XP-SS95 VA-Roughneck **4' Pup Joint - 1.24m** - ***Customer Supplied***	97.18	114.30	1.240	1,338.608	Bison LCV
3.9	114.3mm 22.47kg/m VA-XP-SS95 VA-Roughneck Casing Joints - **Length - TBD, To place lower ZoneGuards on depth**. - **Estimated 10Joints of Casing**	97.18	114.30	135.000	1,339.848	Bison LCV
Note:	**Sub Assembly 2 (Zone Guards) - To be Shipped out from Nisku Facility.** **Length: +/- 5.1m (16.73ft)**					
3.10	114.3mm 22.47kg/m VA-XP-SS95 VA-Roughneck **6' Pup Joint - 1.86m** - ***Customer Supplied***	97.18	114.30	1.860	1,474.848	Bison LCV
3.11	Halliburton ZoneGuard Open Hole Packer Threaded 114.3mm 22.47kg/m BTC Box x Pin ENC Coated	99.06	146.18	0.984	1,476.708	Halliburton
3.12	Halliburton ZoneGuard Open Hole Packer Threaded 114.3mm 22.47kg/m BTC Box x Pin ENC Coated	99.06	146.18	0.984	1,477.692	Halliburton
3.13	114.3mm 22.47kg/m VA-XP-SS95 VA-Roughneck **4' Pup Joint - 1.24m** - ***Customer Supplied***	97.18	114.30	1.240	1,478.676	Bison LCV
3.14	114.3mm 22.47kg/m VA-XP-SS95 VA-Roughneck Casing Joints - **Length - TBD, To place lower ZoneGuards on depth**. - **Qty 1 Casing Joint**	97.18	114.30	13.000	1,479.916	Bison LCV
Note:	**Sub Assembly 1 (Zone Guards) - To be Shipped out from Nisku Facility.** **Length: +/- 4.5m (14.8ft)**					
3.15	114.3mm 22.47kg/m VA-XP-SS95 VA-Roughneck **6' Pup Joint - 1.86m** - ***Customer Supplied***	97.18	114.30	1.860	1,492.916	Bison LCV
3.16	Halliburton ZoneGuard Open Hole Packer Threaded 114.3mm 22.47kg/m BTC Box x Pin ENC Coated	99.06	146.18	0.984	1,494.776	Halliburton
3.17	Halliburton ZoneGuard Open Hole Packer Threaded 114.3mm 22.47kg/m BTC Box x Pin ENC Coated	99.06	146.18	0.984	1,495.760	Halliburton
3.18	114.3mm Halliburton 2.75'' "XN" Profile Nipple c/w 69.85mm "X" Profile & 66.93mm No-Go Threaded BTC Box x Pin - ENC Coated ***Used to set Open Hole Packers and MHR Packer***	66.93	139.00	0.500	1,496.744	Halliburton
3.19	114.3mm Bullet-Style Wireline Re-Entry Guide Threaded BTC Box - ENC Coated	101.60	146.05	0.150	1,497.244	Halliburton
Note:	End of Assembly | Bottom depth: **1,497.394 m**					
Note:	**CO2 Storage Complex**					

APPENDIX H: LEGACY WELL REVIEW

Legacy Well Report for Bison Meadowbrook CCS Hub Phase 1 application area. (TWP57/58-Rg 25W4M)

100/11-15-58-25W4M
This well has a SCVF history.
Drilled into Leduc from 1227 to FTD at 1234.4m (1954). Plugged back and cased to 814m (1954). Completed in Viking formation (1972). Bridge plug set over Viking perforations at 779m (2003). A bridge plug capped with cement added at 752m (2017). AER well status as of 2017: Abandoned. Status: Yellow

Surface Casing Vent Flow Report Date

2017-04-05 Classification
Non Serious Ground Water Base (kb) 334

Current License Status Abandoned Flow Substance Gas Resolution Date 2017-04-12

Licensee at Reporting Coastal Resources Limited (0PR1) Flow Rate m3/day
29

Status Closed

Pressure (kpa) 262

100/6-21-57-25w4
This well has a SCVF history.
Drilled into the Leduc from 1316.7m to 1318.3m (1950). Cased from 1096.4m and completed in the Mannville formation 1056.1m – 1070.8m (1961). Cement plugs set in casing 1023.5m-1078.4m (1966). Bridge plug in casing at 1000m (1998). Remedial casing cement job (1988). Remedial casing cement job (2000). This well appears to be properly abandoned. Status: Yellow

Surface Casing Vent Flow
Report Date Current License Status

2000-05-29 RecCertified Resolution Date

2000-03-10

Licensee at Reporting
Canadian Natural Resources Limited (0HE9)

Status Closed

100/2-5-58-25W4M

Drilled into the Leduc from 1319m to 1560m (1985). Plugged back and cased from 1102m to surface and completed in the Mannville. Never completed below the Mannville and plugs set in casing from 1039-1047 (1986) and 1052-1054 (1985). This well appears properly abandoned. Status: Green

100/6-17-57-25w4

Drilled into the Leduc from 1363m to 1600m (1998). No production casing run and well was abandoned during drilling operation on 1998-10-01. This well appears to be properly abandoned. Status: Green

1000/9-9-58-25w4

Drilled to TD at 1261.3m and well was abandoned during drilling operation (1948). This well appears properly abandoned. Status: Green

100/10-11-58-25w4

Drilled into the Leduc from 1248m to 1284m (1981). No production casing run and well was abandoned during drilling operation (1981). This well appears to be properly abandoned. Status: Green

100/10-28-57-25w4

Drilled into Leduc formation from 1305.2m to 1309.1m (1949). Production casing was run to 1082m. Completed in Ellerslie 1053.1m – 1054.6m (1949) and abandoned with cement squeeze (1949) Completed in the Upper Viking 832.9 – 834.1m (1994). Abandoned with bridge pug capped with cement (2006). Remedial casing cement job (2006) and well abandoned (2006). This well appears to be properly abandoned. Status: Yellow

100/11-35-57-25w4

Well drilled into the Leduc formation 1283m to 1393m (1981). Well plugged back and casing run to 1306.4m. Completed in Nisku 1234 -1240.5m (1981) and abandoned with bridge plug capped with cement (1981). Completed in Viking 816m -817m (1981) and abandoned with bridge plug capped with cement (1996). This well appears to be properly abandoned. Status: Green

100/13-04-57-25w4

Well drilled into Leduc from 1312.4m to 1350m (1986) Production casing run to 1350m. Completed in Leduc 1312m -1312.8m (1987) and abandoned with bridge plug capped with cement (1987). Completed in Mannville 1000.5m -1004.5m (1987) and abandoned with bridge plug caped with cement (1995) Remedial casing cement job (1995). This well appears to be properly abandoned. Status: Green

100/13-04-58-25w4

Well drilled into Leduc 1286.6m to 1295.4m (1973) and production casing run to 1294.8m. Completed in Leduc 1270.1m – 1271m and abandoned with bridge plug capped with cement (1973). Completed in Ellerslie 1026.6m -1027.8m (1973) and abandoned with bridge plug capped with cement (1973). Cement plug in casing from 774.2m – 493.8m and second cement plug from 204.2m -161.5m (1973). This well appears to be properly abandoned. Status: Green

100/14-12-57-25w4
Well drilled into Leduc from 1297m to 1325m (1989). No production casing run and well was abandoned during drilling operation (1989). This well appears to be properly abandoned. Status: Green

100/14-28-57-25w4
Well drilled into Leduc to1445m (1982). No production casing run and well was abandoned during drilling operation (1982). This well appears to be properly abandoned. Status: Green

100/14-32-57-25w4
Well drilled int Leduc from 1321.3 to 1650m (1984). Production casing run to 1650m. Completed in Leduc 1457m -1457.5m (1984) and abandoned with bridge plug capped with cement (1986). This well appears to be properly abandoned. Status: Yellow

100/15-20-57-25w4
Well drilled into Leduc from 1333.4m to 1390m (1981). No production casing run and well was abandoned during drilling operation (1981). This well appears to be properly abandoned. Status: Green

100/15-22-58-25w4
Well drilled into Leduc from 1226m to 1260.1m (1990). Well was plugged back and production casing run to 850m. Completed in Viking 774.5 – 779m (1993) Well is still Active. Status: Green

100/15-32-57-25w4
Well drilled into Leduc from 1318.9m to 1505m (1995) No production casing run and well was abandoned during drilling operation (1995). This well appears to be properly abandoned. Status: Green

100/16-11-57-25w4
Well drilled into Leduc from 1311.9m to 1321.3m (1952). Production casing run to 1306.1m and Liner run to 1245m. Completed in Nisku 1248.8m to 1291.1m (1954) Packer installed at 1242m (2016). Currently Active Injection well. Status: Green

100/16-29-57-25w4
Well drilled into Leduc from 1309.4m to 1340m (1981). No production casing run and well was abandoned during drilling operation (1981). This well appears to be properly abandoned. Status: Green

Methodology in Dealing with potential for Legacy well risk.

Legacy well risk refers to the potential for a containment breach from 'historic' wellbore penetrations through a casing failure, poorly cemented casing or incomplete aquifer isolation on abandonment of the sequestration reservoir, that could provide an avenue for leakage by migration along a pathway that may not be fully contained by the top seal. This risk already exists with every suspended and abandoned wellbore in the province where cross formational flow of fluid, or the potential for a gas migration or vent flow of natural gas, is managed to within an acceptable tolerance with the application of good oilfield practice and adherence to license conditions. The unique aspect of this risk in a CCS project is an incremental fiscal risk resulting from a credit reversal, as the potential for this to evolve into either a safety or environmental risk is extremely low both from a released volume and concentration perspective. Notwithstanding the likely low impact of a legacy well related leak we recognize this as having a higher likelihood of occurrence owing to poor cement jobs resulting from lost circulation due to the underbalanced pressure and exceptional permeabilities in the Nisku, Leduc and Cooking Lake intervals.

We have completed a legacy well risk assessment based on a well by well review of AER wellbore records of wells that have penetrated the storage complex and ranked them as to what risk they may represent depending on the age of the well, the original and current status, the amount and quality of information available on the original wellbore condition and configuration, and whether there is a record of any well integrity issue (known gas migration or SCVF occurrence). A well that did not penetrate the storage complex cannot provide a pathway for loss of containment. Historically, D&A wells that have plugs set properly represent a lower legacy leak risk than cased wells that are subsequently abandoned.

This analysis resulted in a 'traffic light' ranking where a red or amber ranking would result in **baseline and subsequent periodic** monitoring incorporated into our MMV plan, based on assessment of the following criteria,

a) penetration of the storage complex
b) any recognized migration or flow that remains unresolved.
c) well having been cased to the storage complex.
d) confirmation of proper abandonment (age and data dependent)

Every well that penetrated the storage complex (a) was reviewed in detail. It is given a **green** ranking if it has no flow history AND records show it was abandoned as per AER regs (**no further review planned)**. It is flagged as **yellow** if it has been recognized as having, or having had, a migration issue (b), or the well was cased to the storage complex and sits within a forecast saturation plume area (c+), or the well file review is unavailable or inconclusive as to proper abandonment having been completed (d+). A **yellow ranking requires further investigation;**

- A **yellow** ranking requires further review to designate it as green (no recognized risk) or red (high risk), based in part on its proximity to active development of the tenure,
- Subject to licensee and landowner support if/as required, All yellow designated wells within 1.5km of a forecast CO_2 plume fairway (3km from 16-29) will require a surface inspection, an initial season's photogrammetry survey, and a 30 day air monitoring test to determine a pre injection baseline.

A **red** ranking would be attached to any yellow ranking that upon further investigation demonstrates recognizable surface flow of gas. We would commit to reporting this to both the AER and the well operator for further monitoring as deemed appropriate by those parties. There have been no red ratings identified by our work to date.

If an initial surface site inspection shows no sign of migration/flow or leak, the ranking shifts to **green**.

The area of application has been assessed and three wells with yellow rankings have been flagged. All yellow rankings will be downgraded to green, or upgraded to red, prior to the commencement of injection.

Further Mitigation of legacy well risk on our project is achieved by:

- avoiding areas with pre-project penetration within areas identified as the likely sequestration plume area, and minimizing the required penetrations to only those needed to manage the project. There are NO producing wells that penetrate the sequestration strata within the forecast plume area. We estimate that there are 7 historic penetrations through the top of the sequestration interval strata (top Leduc Formation) and 3 of those that fully penetrate the section (Cooking Lake Formation or deeper) within the forecast CO_2 plume area. One well, 15-32-57-25W4M, is 1 mile from the 16-29 well cluster site and had a reported gas migration issue that was reported as resolved in 2000. That site has been flagged and will be monitored and reported as part of the MMV phase application.
- integrate any wells that penetrate the sequestration reservoir (future Legacy wells) but are NOT abandoned, into the observation/monitoring scheme to enhance the MMV program. We have identified 2 existing wellbores that could possibly be integrated into the observation/monitoring scheme for subsequent phases, if they can be acquired (one is an orphan well). Neither of these wells is within, or relevant to this initial phase application.

In our selection of the 16-29 injector location, consideration was given to the number of penetrations of the Woodbend Reef within the expected plume area, the status of those wellbores as to whether they have/had casing or cement plugs to ensure isolation, the age of the wells, whether there is any AER record of leakage or cross flow, and whether a surface inspection shows any evidence of flow.

WELL DETAILS			
UWI	100/06-21-057-25W4/00	KB Elevation	709 m
Licensee	Canadian Natural Resources Limited	C.F. Elevation	0 m
Operator		G.L. Elevation	705.9 m
License Number	0001643	Max T.V.D	1,318.3 m
Surface Location	06-21-057-25W4	Total Depth	1,318.3 m
Well Name	M.w. gas legal 6-21-57-25	H2S Analysis	No analysis
Rig No.		H2S Content	
Fluid	Oil		
Status	Abandoned	License Date	1950-06-22
Type	Production	Spud Date	1950-08-26
Trajectory	Vertical	Rig Release Date	
		On Production Date	1963-06-18
Province	AB	Last Status Date	1966-06-21
Field	Legal		
Pool	MANNVILLE B		
Producing Formation	Mannville		
Projected Formation			
Terminating Formation			

CASING					
Type	Outer Diameter (mm)	Top (m)	Bottom (m)	Grade	Weight (kg/m)
Surface	273	0	180.7		0
Surface	273	0	180.7		0
Production	177.8	0	1,096.4		0
Production	177.8	0	1,096.4		0

PRODUCTION		
Fluid	Most Recent Month	Cumulative
Oil	45.1 m3	1,022.7 m3
Gas	89.3 e3m3	723 e3m3
Water	151.2 m3	3,114.4 m3
Injection	None	None
Water Cut		
Gas Oil Ratio		

FORMATION TOPS	
Formation	Interval (m)
Lea park fm	368.8 - 524.3
Lea park fm	368.8 - 524.3
Colorado grp	524.3 - 690.4
Colorado grp	524.3 - 690.4
Second white specks	690.4 - 794.3
Second white specks	690.4 - 794.3
Base fish scales marker	794.3 - 838.2
Base fish scales marker	794.3 - 838.2
Viking sandstone	838.2 - 879.3
Viking sandstone	838.2 - 879.3
Blairmore grp	879.3 - 1,018.6
Blairmore grp	879.3 - 1,018.6
Glauconitic ss	1,018.6 - 1,047.6
Glauconitic ss	1,018.6 - 1,047.6
Ostracod member	1,047.6 - 1,053.4
Ostracod member	1,047.6 - 1,053.4
Ellerslie mbr	1,053.4 - 1,138.4
Ellerslie mbr	1,053.4 - 1,138.4
Wabamun grp	1,138.4 - 1,217.7
Wabamun grp	1,138.4 - 1,217.7
Calmar fm	1,217.7 - 1,231.4
Calmar fm	1,217.7 - 1,231.4
Nisku fm	1,231.4 - 1,289.3
Nisku fm	1,231.4 - 1,289.3
Ireton fm	1,289.3 - 1,316.7
Ireton fm	1,289.3 - 1,316.7
Leduc fm	1,316.7 - 1,000,000
Leduc fm	1,316.7 - 1,000,000

COMPLETIONS		
Date	Interval (m)	Treatment
1961-01-09	1,069.8 - 1,070.8	Jet perforation
1961-01-09	1,069.8 - 1,070.8	Jet perforation
1961-01-10	1,056.1 - 1,059.2	Jet perforation

1961-01-10	1,056.1 - 1,059.2	Jet perforation
1964-03-10	1,056.1 - 1,059.2	Cement squeeze
1964-03-10	1,056.1 - 1,059.2	Cement squeeze
1964-03-16	1,069.8 - 1,070.8	Acid squeeze - press used
1964-03-16	1,069.8 - 1,070.8	Acid squeeze - press used
1964-03-18	1,069.8 - 1,071.4	Acid squeeze - press used
1964-03-18	1,069.8 - 1,071.4	Acid squeeze - press used
1964-03-19	1,070.8 - 1,071.4	Jet perforation
1964-03-19	1,070.8 - 1,071.4	Jet perforation
1964-03-21	1,070.5 - 1,071.7	Jet perforation
1964-03-21	1,070.5 - 1,071.7	Jet perforation
1966-06-18	1,023.5 - 1,078.4	Cement plug
1966-06-18	1,023.5 - 1,078.4	Cement plug
1998-08-10	1,000 - 0	Bridge plug
1998-08-10	800 - 0	Cement retainer
1998-08-10	1,000 - 0	Bridge plug
1998-08-10	800 - 0	Cement retainer
1998-08-10	847 - 848	Remedial casing
1998-08-10	847 - 848	Jet perforation
1998-08-10	420 - 848	Cement plug
1998-08-10	847 - 848	Jet perforation
1998-08-10	847 - 848	Remedial casing
1998-08-10	420 - 848	Cement plug
2000-03-07	721 - 0	Cement retainer
2000-03-07	721 - 0	Cement retainer
2000-03-07	689.5 - 690.5	Jet perforation
2000-03-07	689.5 - 690.5	Jet perforation
2000-03-07	847 - 848	Remedial casing
2000-03-07	847 - 848	Remedial casing
2000-03-08	672.5 - 0	Cement retainer
2000-03-08	672.5 - 0	Cement retainer
2000-03-08	689.5 - 690.5	Remedial casing
2000-03-08	689.5 - 690.5	Remedial casing
2000-03-10	219 - 220	Remedial casing
2000-03-10	219 - 220	Remedial casing
2000-03-10	219 - 220	Jet perforation
2000-03-10	219 - 220	Jet perforation

2000-03-10	392 - 397	Remedial casing
2000-03-10	392 - 397	Remedial casing

Petro Ninja MAPS

100/02-05-058-25W4/00
Canadian Natural Resources Limited
https://petroninja.com/wells/100020505825W400

WELL DETAILS			
UWI	100/02-05-058-25W4/00	KB Elevation	686 m
Licensee	Canadian Natural Resources Limited	C.F. Elevation	0 m
Operator		G.L. Elevation	682 m
License Number	0115789	Max T.V.D	1,560 m
Surface Location	02-05-058-25W4	Total Depth	1,560 m
Well Name	Andex et al legal 2-5-58-25	H2S Analysis	No analysis
Rig No.	21	H2S Content	
Fluid	Gas		
Status	Abandoned	License Date	1985-07-02
Type	Production	Spud Date	1985-07-03
Trajectory	Vertical	Rig Release Date	1985-07-18
		On Production Date	1985-10-01
Province	AB	Last Status Date	1986-09-08
Field	Legal		
Pool	MANNVILLE D		
Producing Formation	Mannville		
Projected Formation	Leduc fm		
Terminating Formation			

CASING					
Type	Outer Diameter (mm)	Top (m)	Bottom (m)	Grade	Weight (kg/m)
Surface	219.1	0	277	J 055	35.7
Production	139.7	0	1,102	J 055	23.1

PRODUCTION		
Fluid	Most Recent Month	Cumulative
Oil	None	None
Gas	189.1 e3m3	934.7 e3m3
Water	0.2 m3	0.9 m3
Injection	None	None
Water Cut		
Gas Oil Ratio		

FORMATION TOPS	
Formation	Interval (m)
Colorado grp	499 - 673.4
Second white specks	673.4 - 767.2
Base fish scales marker	767.2 - 810
Viking fm	810 - 813.2
Viking sandstone	813.2 - 839.5
Joli fou fm	839.5 - 851.5
Mannville grp	851.5 - 989.6
Glauconitic ss	989.6 - 1,013
Ostracod member	1,013 - 1,042
Ellerslie mbr	1,042 - 1,095
Wabamun grp	1,095 - 1,167
Graminia fm	1,167 - 1,171.5
Blueridge mbr	1,171.5 - 1,200
Calmar fm	1,200 - 1,206
Nisku fm	1,206 - 1,283
Ireton fm	1,283 - 1,319
Leduc fm	1,319 - 1,466
Basal reef	1,466 - 1,000,000

COMPLETIONS		
Date	Interval (m)	Treatment
1985-07-25	1,052 - 1,054	Jet perforation
1986-09-08	1,039 - 1,047	Bridge plug capped w/cement

Petro Ninja MAPS

100/10-28-057-25W4/02
Excel Valley Petroleum Ltd.
https://petroninja.com/wells/100102805725W402

WELL DETAILS			
UWI	100/10-28-057-25W4/02	KB Elevation	711.1 m
Licensee	Excel Valley Petroleum Ltd.	C.F. Elevation	0 m
Operator		G.L. Elevation	708.1 m
License Number	B0002781	Max T.V.D	1,309.1 m
Surface Location	10-28-057-25W4	Total Depth	1,309.1 m
Well Name	Cigol legal 10-28-57-25	H2S Analysis	No analysis
Rig No.		H2S Content	
Fluid	Gas		
Status	Abandoned	License Date	1949-04-22
Type	Production	Spud Date	1949-04-18
Trajectory	Vertical	Rig Release Date	
		On Production Date	2002-12-06
Province	AB	Last Status Date	2006-10-12
Field	Legal		
Pool	UPPER VIKING B		
Producing Formation	Upper viking		
Projected Formation			
Terminating Formation			

CASING					
Type	Outer Diameter (mm)	Top (m)	Bottom (m)	Grade	Weight (kg/m)
Surface	273	0	183.2		0
Surface	273	0	183.2		0
Production	177.8	0	1,082		0
Production	177.8	0	1,082		0

PRODUCTION		
Fluid	Most Recent Month	Cumulative
Oil	None	None
Gas	25.4 e3m3	350.1 e3m3
Water	None	None
Injection	None	None
Water Cut		
Gas Oil Ratio		

FORMATION TOPS	
Formation	Interval (m)
Lea park fm	362.7 - 518.2
Lea park fm	362.7 - 518.2
Colorado grp	518.2 - 696.5
Colorado grp	518.2 - 696.5
Second white specks	696.5 - 790
Second white specks	696.5 - 790
Base fish scales marker	790 - 832.1
Base fish scales marker	790 - 832.1
Viking sandstone	832.1 - 871.7
Viking sandstone	832.1 - 871.7
Blairmore grp	871.7 - 1,015.6
Blairmore grp	871.7 - 1,015.6
Glauconitic ss	1,015.6 - 1,043
Glauconitic ss	1,015.6 - 1,043
Ostracod member	1,043 - 1,049.4
Ostracod member	1,043 - 1,049.4
Ellerslie mbr	1,049.4 - 1,126.2
Ellerslie mbr	1,049.4 - 1,126.2
Devonian system	1,126.2 - 1,202.4
Devonian system	1,126.2 - 1,202.4
Calmar fm	1,202.4 - 1,209.4
Calmar fm	1,202.4 - 1,209.4
Nisku fm	1,209.4 - 1,275.6
Nisku fm	1,209.4 - 1,275.6
Ireton fm	1,275.6 - 1,305.2
Ireton fm	1,275.6 - 1,305.2
Leduc fm	1,305.2 - 1,000,000
Leduc fm	1,305.2 - 1,000,000

COMPLETIONS		
Date	Interval (m)	Treatment
1949-05-14	1,053.1 - 1,055.2	Bullet perforation
1949-05-14	1,053.1 - 1,055.2	Bullet perforation
1949-05-15	1,053.1 - 1,055.2	Cement squeeze

1949-05-15	1,053.1 - 1,055.2	Cement squeeze
1963-03-14	1,053.4 - 1,054.6	Jet perforation
1963-03-14	1,053.4 - 1,054.6	Acid squeeze - press used
1963-03-14	1,053.4 - 1,054.6	Acid squeeze - press used
1963-03-14	1,053.4 - 1,054.6	Jet perforation
1994-10-25	832.9 - 834.1	Jet perforation
1994-10-25	832.9 - 834.1	Jet perforation
2006-09-06	812 - 820	Bridge plug capped w/cement
2006-09-06	812 - 820	Bridge plug capped w/cement
2006-09-09	789 - 790	Abrasa-jet perforation
2006-09-09	789 - 790	Abrasa-jet perforation
2006-09-09	791 - 792	Abrasa-jet perforation
2006-09-09	791 - 792	Abrasa-jet perforation
2006-09-10	774 - 784	Bridge plug capped w/cement
2006-09-10	774 - 784	Bridge plug capped w/cement
2006-09-10	789 - 792	Remedial casing
2006-09-10	789 - 792	Remedial casing

Petro Ninja MAPS

100/13-04-058-25W4/00
Canadian Reserve Oil And Gas Ltd.
https://petroninja.com/wells/100130405825W400

WELL DETAILS			
UWI	100/13-04-058-25W4/00	KB Elevation	694 m
Licensee	Canadian Reserve Oil And Gas Ltd.	C.F. Elevation	0 m
Operator		G.L. Elevation	690.4 m
License Number	0044898	Max T.V.D	1,295.4 m
Surface Location	13-04-058-25W4	Total Depth	1,295.4 m
Well Name	Cdn res et al legal 13-4-58-25	H2S Analysis	No analysis
Rig No.		H2S Content	
Fluid	None		
Status	Abandoned	License Date	1973-01-23
Type	Production	Spud Date	1973-02-01
Trajectory	Vertical	Rig Release Date	
		On Production Date	
Province	AB	Last Status Date	1973-11-07
Field	Legal		
Pool			
Producing Formation			
Projected Formation			
Terminating Formation			

CASING					
Type	Outer Diameter (mm)	Top (m)	Bottom (m)	Grade	Weight (kg/m)
Surface	219.1	0	189		0
Production	139.7	0	1,294.8		0

PRODUCTION		
Fluid	Most Recent Month	Cumulative
Oil	None	None
Gas	None	None
Water	None	None
Injection	None	None
Water Cut		
Gas Oil Ratio		

FORMATION TOPS	
Formation	Interval (m)
Lea park fm	341.4 - 498.3
Colorado grp	498.3 - 672.7
Second white specks	672.7 - 765
Base fish scales marker	765 - 793.7
Viking fm	793.7 - 848.9
Mannville grp	848.9 - 985.1
Glauconitic ss	985.1 - 1,014.1
Lower mannville fm	1,014.1 - 1,021.7
Ellerslie mbr	1,021.7 - 1,096.7
Wabamun grp	1,096.7 - 1,131.4
Winterburn grp	1,131.4 - 1,154
Calmar fm	1,154 - 1,157.6
Nisku fm	1,157.6 - 1,239.9
Ireton fm	1,239.9 - 1,268.6
Leduc fm	1,268.6 - 1,000,000

COMPLETIONS		
Date	Interval (m)	Treatment
1973-03-08	1,270.1 - 1,271	Jet perforation
1973-03-11	1,072.3 - 1,072.9	Jet perforation
1973-03-11	1,249.1 - 1,249.1	Bridge plug capped w/cement
1973-03-12	1,026.6 - 1,027.8	Jet perforation
1973-03-12	1,062.2 - 1,062.2	Bridge plug capped w/cement
1973-03-14	1,040 - 1,040.6	Jet perforation
1973-03-15	1,026.6 - 1,040.6	Cement squeeze
1973-03-16	1,026.6 - 1,027.8	Jet perforation
1973-03-20	1,026.6 - 1,027.8	Cement squeeze
1973-03-21	1,022.3 - 1,023.5	Jet perforation
1973-03-22	1,022.3 - 1,023.5	Acid squeeze - press used
1973-11-07	1,025 - 1,025	Bridge plug capped w/cement
1973-11-17	493.8 - 774.2	Cement plug
1973-11-20	161.5 - 204.2	Cement plug

WELL DETAILS			
UWI	100/14-28-057-25W4/00	KB Elevation	713.5 m
Licensee	ConocoPhillips Canada Resources Corp.	C.F. Elevation	0 m
Operator		G.L. Elevation	709.4 m
License Number	0094847	Max T.V.D	1,445 m
Surface Location	14-28-057-25W4	Total Depth	1,445 m
Well Name	Arl et al legal 14-28-57-25	H2S Analysis	No analysis
Rig No.		H2S Content	
Fluid	None		
Status	Abandoned	License Date	1982-02-01
Type	Production	Spud Date	1982-02-12
Trajectory	Vertical	Rig Release Date	
		On Production Date	
Province	AB	Last Status Date	1982-02-27
Field	Legal		
Pool			
Producing Formation			
Projected Formation			
Terminating Formation			

CASING					
Type	Outer Diameter (mm)	Top (m)	Bottom (m)	Grade	Weight (kg/m)
Surface	244.5	0	206		0

PRODUCTION		
Fluid	Most Recent Month	Cumulative
Oil	None	None
Gas	None	None
Water	None	None
Injection	None	None
Water Cut		
Gas Oil Ratio		

FORMATION TOPS	
Formation	Interval (m)
Colorado grp	522.5 - 698.8
Second white specks	698.8 - 787.7
Base fish scales marker	787.7 - 835
Viking sandstone	835 - 852.5
Joli fou fm	852.5 - 874
Mannville grp	874 - 1,015
Glauconitic ss	1,015 - 1,032.2
Ostracod member	1,032.2 - 1,050.1
Ellerslie mbr	1,050.1 - 1,128.2
Wabamun grp	1,128.2 - 1,000,000

COMPLETIONS		
Date	Interval (m)	Treatment

Petro Ninja MAPS

100/14-32-057-25W4/00
Canadian Natural Resources Limited
https://petroninja.com/wells/100143205725W400

WELL DETAILS			
UWI	100/14-32-057-25W4/00	KB Elevation	687.5 m
Licensee	Canadian Natural Resources Limited	C.F. Elevation	0 m
Operator		G.L. Elevation	682.8 m
License Number	0109103	Max T.V.D	1,649.78 m
Surface Location	14-32-057-25W4	Total Depth	1,650 m
Well Name	Cnrl legal 14-32-57-25	H2S Analysis	No analysis
Rig No.	8	H2S Content	
Fluid	Oil		
Status	Abandoned	License Date	1984-09-04
Type	Production	Spud Date	1984-09-06
Trajectory	Vertical	Rig Release Date	1984-09-16
		On Production Date	1984-10-15
Province	AB	Last Status Date	1986-11-20
Field	Legal		
Pool	LEDUC A		
Producing Formation	Leduc		
Projected Formation	Beaverhill lake grp		
Terminating Formation			

CASING					
Type	Outer Diameter (mm)	Top (m)	Bottom (m)	Grade	Weight (kg/m)
Surface	244.5	0	276	K 055	53.6
Production	139.7	0	1,650	K 055	23.1

PRODUCTION		
Fluid	Most Recent Month	Cumulative
Oil	22.9 m3	127.5 m3
Gas	1.2 e3m3	6 e3m3
Water	596.5 m3	2,266.6 m3
Injection	None	None
Water Cut		
Gas Oil Ratio		

FORMATION TOPS	
Formation	Interval (m)
Colorado grp	503.15 - 675.54
Second white specks	675.54 - 766.94
Base fish scales marker	766.94 - 812.64
Viking sandstone	812.64 - 842.94
Joli fou fm	842.94 - 854.54
Mannville grp	854.54 - 992.42
Glauconitic ss	992.42 - 1,019.92
Lower mannville fm	1,019.92 - 1,020.92
Ostracod member	1,020.92 - 1,028.92
Ellerslie mbr	1,028.92 - 1,083.92
Detrital =cret=	1,083.92 - 1,095.32
Wabamun grp	1,095.32 - 1,170.92
Graminia fm	1,170.92 - 1,177.92
Blueridge mbr	1,177.92 - 1,205.91
Calmar fm	1,205.91 - 1,211.41
Nisku fm	1,211.41 - 1,284.91
Ireton fm	1,284.91 - 1,321.31
Leduc fm	1,321.31 - 1,644.78
Beaverhill lake grp	1,644.78 - 1,000,000

COMPLETIONS		
Date	Interval (m)	Treatment
1984-10-01	1,457 - 1,457.5	Jet perforation
1984-10-05	1,457 - 1,457.5	Acid squeeze - press used
1986-11-20	1,453 - 1,453	Bridge plug capped w/cement

Petro Ninja MAPS

100/15-20-057-25W4/00
Ovintiv Canada ULC
https://petroninja.com/wells/100152005725W400

WELL DETAILS			
UWI	100/15-20-057-25W4/00	KB Elevation	706.5 m
Licensee	Ovintiv Canada ULC	C.F. Elevation	0 m
Operator		G.L. Elevation	702.4 m
License Number	0089643	Max T.V.D	1,390 m
Surface Location	15-20-057-25W4	Total Depth	1,390 m
Well Name	Pcp legal 15-20-57-25	H2S Analysis	No analysis
Rig No.		H2S Content	
Fluid	None		
Status	Abandoned	License Date	1981-03-24
Type	Production	Spud Date	1981-03-31
Trajectory	Vertical	Rig Release Date	
		On Production Date	
Province	AB	Last Status Date	1981-04-17
Field	Legal		
Pool			
Producing Formation			
Projected Formation			
Terminating Formation			

CASING					
Type	Outer Diameter (mm)	Top (m)	Bottom (m)	Grade	Weight (kg/m)
Surface	219.1	0	190		0

PRODUCTION		
Fluid	Most Recent Month	Cumulative
Oil	None	None
Gas	None	None
Water	None	None
Injection	None	None
Water Cut		
Gas Oil Ratio		

FORMATION TOPS	
Formation	Interval (m)
Lea park fm	389 - 532
Colorado grp	532 - 709.7
Second white specks	709.7 - 800.2
Base fish scales marker	800.2 - 843.5
Viking sandstone	843.5 - 872.8
Joli fou fm	872.8 - 884
Mannville grp	884 - 1,027
Glauconitic ss	1,027 - 1,044
Ostracod member	1,044 - 1,061.2
Ellerslie mbr	1,061.2 - 1,143.2
Wabamun grp	1,143.2 - 1,184.5
Graminia fm	1,184.5 - 1,216
Calmar fm	1,216 - 1,221
Nisku fm	1,221 - 1,300
Ireton fm	1,300 - 1,333.4
Leduc fm	1,333.4 - 1,000,000

COMPLETIONS		
Date	Interval (m)	Treatment

Petro Ninja MAPS

100/15-32-057-25W4/00
ConocoPhillips Canada Resources Corp.
https://petroninja.com/wells/100153205725W400

WELL DETAILS			
UWI	100/15-32-057-25W4/00	KB Elevation	688.3 m
Licensee	ConocoPhillips Canada Resources Corp.	C.F. Elevation	0 m
Operator		G.L. Elevation	683.8 m
License Number	0174376	Max T.V.D	1,504.8 m
Surface Location	15-32-057-25W4	Total Depth	1,505 m
Well Name	Trax et al legal 15-32-57-25	H2S Analysis	No analysis
Rig No.	34	H2S Content	
Fluid	None		
Status	Abandoned	License Date	1994-12-19
Type	Production	Spud Date	1995-02-04
Trajectory	Vertical	Rig Release Date	1995-02-14
		On Production Date	
Province	AB	Last Status Date	1995-02-14
Field	Legal		
Pool			
Producing Formation			
Projected Formation	Leduc fm		
Terminating Formation			

CASING					
Type	Outer Diameter (mm)	Top (m)	Bottom (m)	Grade	Weight (kg/m)
Surface	219.1	0	312.5	J 055	35.7

PRODUCTION		
Fluid	Most Recent Month	Cumulative
Oil	None	None
Gas	None	None
Water	None	None
Injection	None	None
Water Cut		
Gas Oil Ratio		

FORMATION TOPS	
Formation	Interval (m)
Lea park fm	344 - 504
Colorado grp	504 - 676
Second white specks	676 - 770
Base fish scales marker	770 - 812.5
Viking sandstone	812.5 - 843
Joli fou fm	843 - 854.5
Mannville grp	854.5 - 992.5
Glauconitic ss	992.5 - 1,024.5
Ostracod member	1,024.5 - 1,030
Ellerslie mbr	1,030 - 1,084
Detrital =cret=	1,084 - 1,096.5
Wabamun grp	1,096.5 - 1,171.5
Graminia fm	1,171.5 - 1,181
Blueridge mbr	1,181 - 1,203.5
Calmar fm	1,203.5 - 1,210
Nisku fm	1,210 - 1,284.9
Ireton fm	1,284.9 - 1,318.9
Leduc fm	1,318.9 - 1,000,000

COMPLETIONS		
Date	Interval (m)	Treatment

Petro Ninja MAPS

100/16-29-057-25W4/00
ConocoPhillips Canada Resources Corp.
https://petroninja.com/wells/100162905725W400

WELL DETAILS			
UWI	100/16-29-057-25W4/00	KB Elevation	711.8 m
Licensee	ConocoPhillips Canada Resources Corp.	C.F. Elevation	0 m
Operator		G.L. Elevation	707.8 m
License Number	0092827	Max T.V.D	1,340 m
Surface Location	16-29-057-25W4	Total Depth	1,340 m
Well Name	Arl et al legal 16-29-57-25	H2S Analysis	No analysis
Rig No.	1	H2S Content	
Fluid	None		
Status	Abandoned	License Date	1981-10-20
Type	Production	Spud Date	1981-10-21
Trajectory	Vertical	Rig Release Date	
		On Production Date	
Province	AB	Last Status Date	1981-11-02
Field	Legal		
Pool			
Producing Formation			
Projected Formation			
Terminating Formation			

CASING					
Type	Outer Diameter (mm)	Top (m)	Bottom (m)	Grade	Weight (kg/m)
Surface	244.5	0	207		0

PRODUCTION		
Fluid	Most Recent Month	Cumulative
Oil	None	None
Gas	None	None
Water	None	None
Injection	None	None
Water Cut		
Gas Oil Ratio		

FORMATION TOPS	
Formation	Interval (m)
Lea park fm	383.4 - 524.2
Colorado grp	524.2 - 700
Second white specks	700 - 791.4
Base fish scales marker	791.4 - 835.2
Viking sandstone	835.2 - 863.5
Joli fou fm	863.5 - 875
Mannville grp	875 - 1,015.5
Glauconitic ss	1,015.5 - 1,033.4
Ostracod member	1,033.4 - 1,050.3
Ellerslie mbr	1,050.3 - 1,117.5
Wabamun grp	1,117.5 - 1,166
Graminia fm	1,166 - 1,168.5
Blueridge mbr	1,168.5 - 1,196
Nisku fm	1,196 - 1,278.3
Ireton fm	1,278.3 - 1,309.4
Leduc fm	1,309.4 - 1,000,000

COMPLETIONS		
Date	Interval (m)	Treatment

APPENDIX I: TYPE WELL LOG AND CROSS-SECTIONS

LAYOUT

Well(s): **BLCV LEGAL 16-29-57-25**

Techlog

Project: **CCS**
Dataset(s): **Merged_Set**
Scale: 1:**500**

Author: **Sviat IURAS**
(ID: **BisonTower**)
Date: **March 18, 2024**

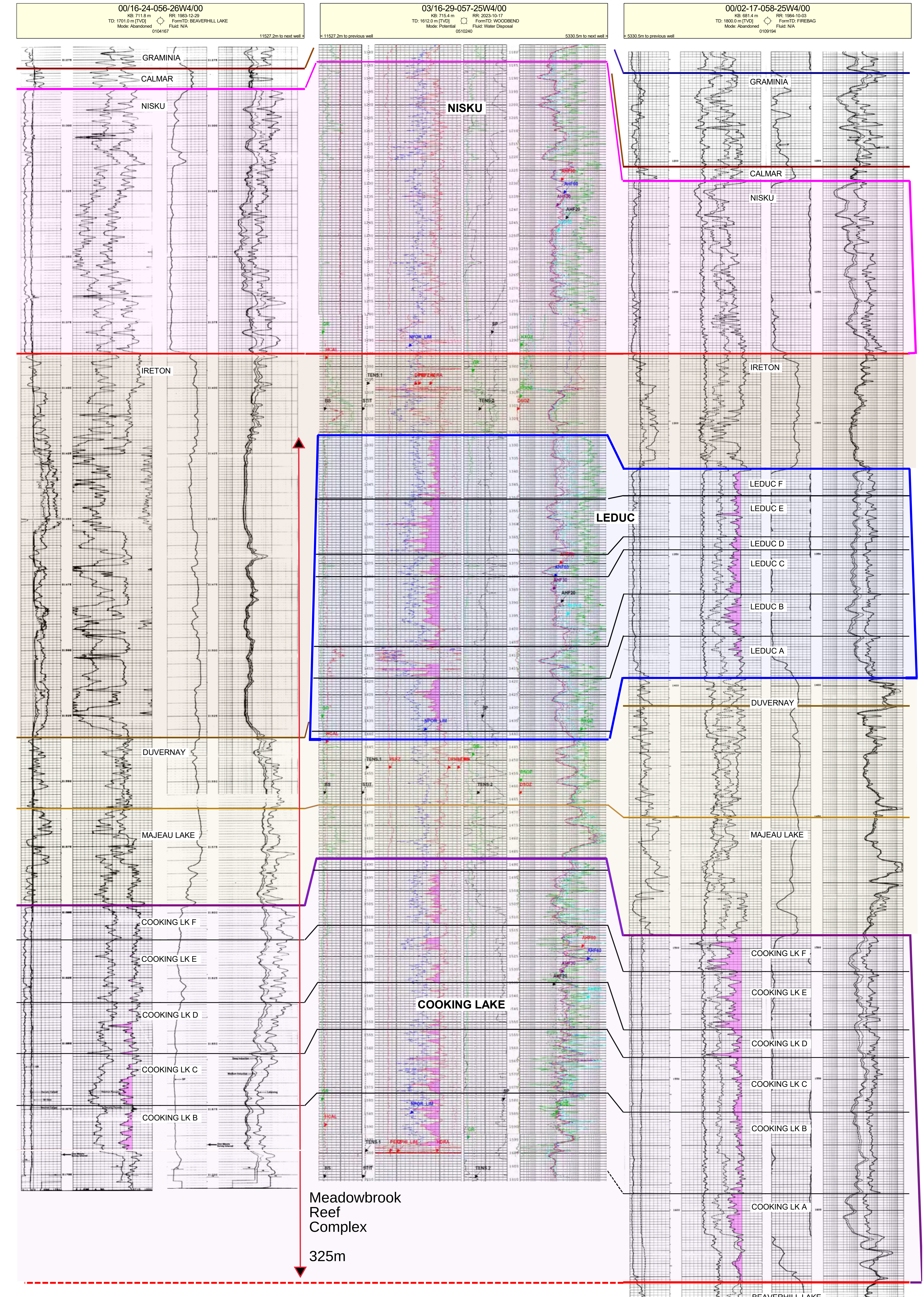
LAYOUT

Well(s): **BLCV LEGAL 16-29-57-25,CNRL LEGAL 14-32-57-25,TRAX ET AL LEGAL 15-32-57-25**

Project: **CCS**
Dataset(s): **Merged_Set,Log,Log**
Scale: 1:**500**

Author: **Sviat IURAS**
(ID: **BisonTower**)
Date: **March 15, 2024**

BISON LCV LEGAL 03/16-29-57-25W4



STRATIGRAPHIC CROSS SECTION

MORINVILLE A - A'

MEADOWBROOK REEF COMPLEX

APPENDIX J: LEAK-OFF TEST

Leakoff Test of October 13, 2023

Background and Objectives: Once the intermediate casing was set and cemented, within the Ireton caprock, the hole was deepened to 1313 mkB and a leakoff test was conducted to test the integrity of the casing shoe. A secondary objective was to initiate a *small* fracture if possible and to determine the fracture and closure pressures. If fracturing was detected, it were to be repeated two or three times to ascertain closure pressure. The latter then could be used to estimate S_{hmin}. Creating a large fracture was to be avoided not to jeopardize the caprock integrity, since the well is intended as an injector.

Figure 1 shows the log signature over the tested interval beneath the casing shoe.

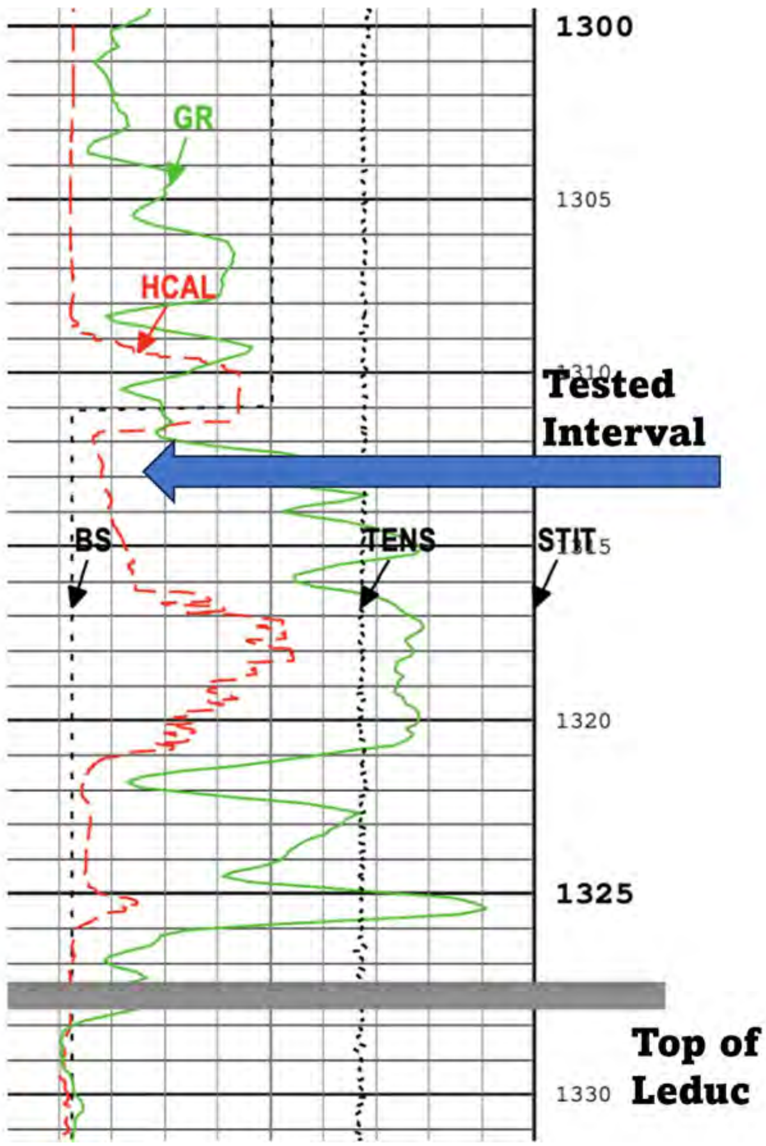


Figure 1: Log signature of the tested interval.

Leakoff Test Operations: The operations were conducted between 4 and 5 am on October 13th 2023. The bottomhole gauge was run to a depth of 1305 m, the wellbore was filled with water and the wellhead was connected to the pumping unit. At approximately 4 am injection was initiated at a low rate of 1 L/min. (The black symbols in Figure 3 below). Soon after injection rate was increased to 10 L/min, however no increase in pressure was detected (The blue line in Figure 2)[1]. Ten minutes in, it was recognized the bypass valve at the pump truck is open and the injected volumes were being diverted from the wellbore. At approximately 4:12 am the bypass valve was closed resulting in an immediate response in pressure. The rate of pressure increase reflects the compressibility of the water in the casing[2].

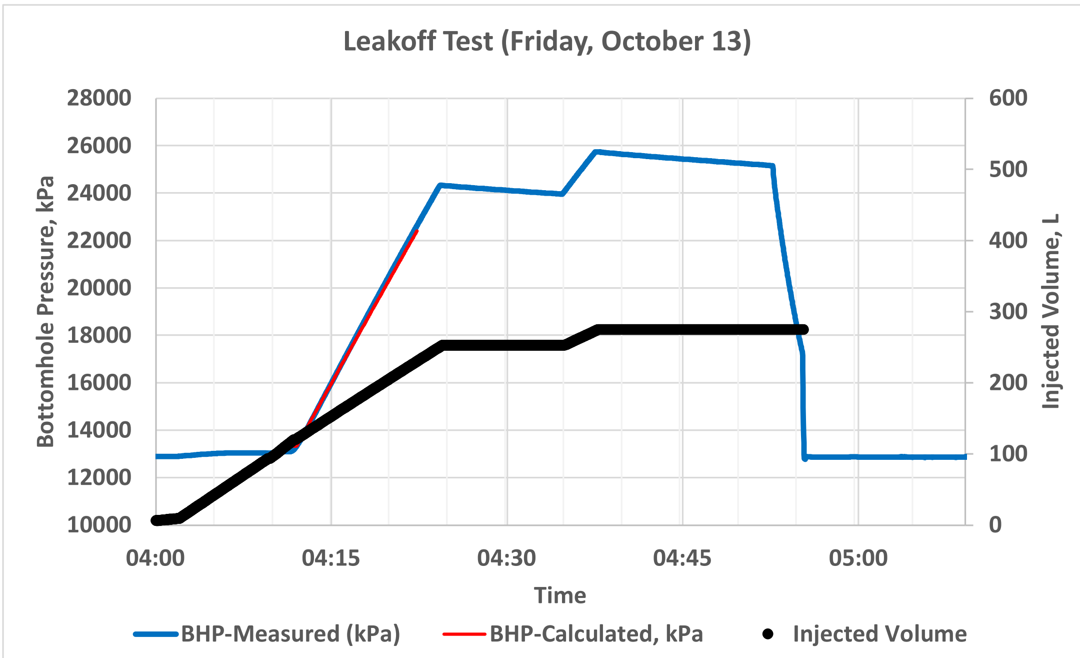


Figure 2: Bottomhole pressure during the leakoff test. The black symbol the injected volume includes the first ~12 minutes when the fluid was not going into the wellbore.

Data from the literature had suggested a fracture gradient of less than 17 kPa, corresponding to a pressure of approximately 22000 kPa. As the data in Figure 2 shows, no change in the trend line of pressure vs. time was observed, suggesting that the formation remained intact. Injection was paused at a pressure of approximately 24000 kPa to consult about the next action and observe the leakoff. Little decline in pressure was observed. (see below for the MDT testing of a similar interval, which indicated "dry".)

After about 10 minutes, it was decided to proceed until a pressure gradient of 20 kPa/m. This gradient would be sufficiently higher than what was required for injection. (Earlier reservoir

[1] Figure 2 shows the bottomhole pressures, which were not available during the test. However, wellhead pressures were available which were used to monitor the test and make decisions.

[2] Using the volume of wellbore, the rate of injection and a water compressibility of 3.3×10^{-6} psi^{-1}, I calculated pressures, which closely matched the measured pressures (See the red line in Figure 2)

modelling studies had indicated that an injection-pressure gradients of less than 14 kPa/m would be sufficient for 1 Mtpa injection.)

At approximately 4:30 am injection was resumed at the same rate of 10 L/min. Pressure inclined at a slope similar to before (indicating no fracturing) until the operations were stopped at maximum BHP of approximately 26000 kPa, corresponding to a pressure gradient of ~ 20 kPa/m. After monitoring the pressure for about 15 minutes, being concerned that increasing the pressure further may damage the cap-rock, the test was terminated and the pressure was released.

What did we expect? What did we get?

Figure 3 (left) below shows an idealized pressure curve during a mini-frac test, and that to the right shows an example of three cycles of mini-frac test at a single station. Under ideal circumstances we would have liked to experience something similar to the Figure on the right; to allow determination of a repeatable closure pressure. The following points are note-worthy:

1. The pressure response that we observed is similar to the A-B section of the ideal curve. We did not detect the onset of fracture formation or the breakdown pressure.
2. The closure pressure can be smaller than the breakdown pressure, due to stress concentration around the wellbore and the tensile strength of the rock.
3. It is the closure pressure that is used for estimating of S_{hmin}. The maximum allowable bottomhole pressure is generally set at 90% of the closure pressure or lower.

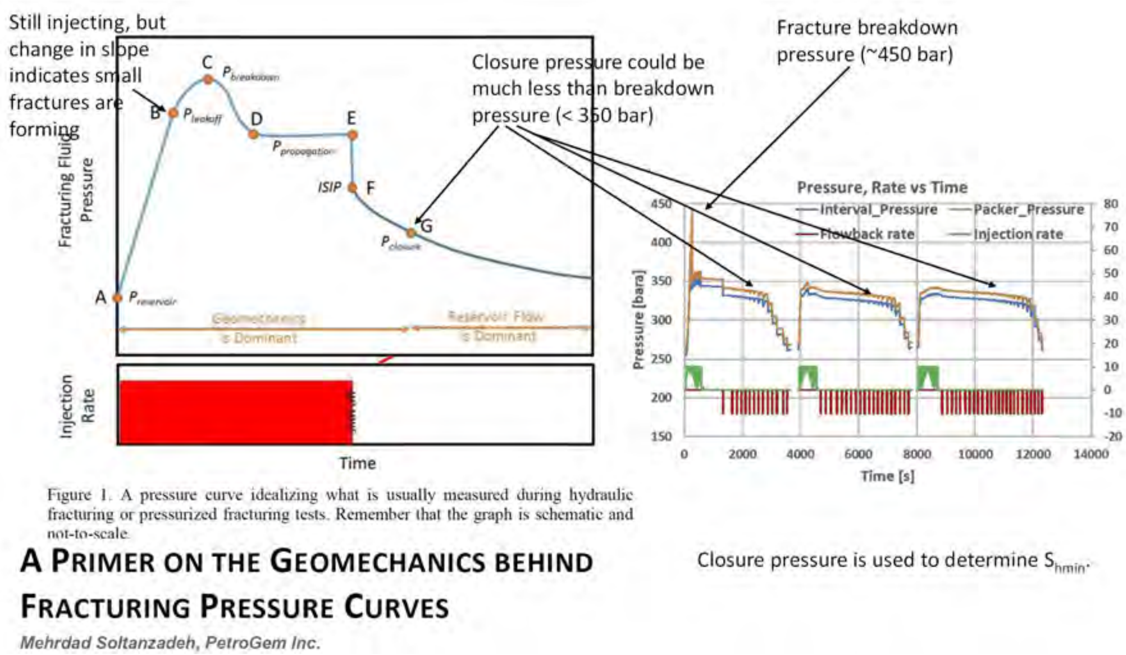


Figure 3: Idealized pressure curve during a frac test (left), and an example of three cycles of mini-frac test at a single station (right). (The Figure on the left is adapted from Soltanzadeh, 2018)

Overall, we could say that where the caprock was tested was intact (had no fractures) and was capable of withholding a pressure gradient of 20 kPa/m. However, S_{hmin} was not determined.

Other information:

(1) Figure 4 shows the MDT test that was run at a depth of 1321.5 m approximately 8 meters beneath where the leakoff test was performed. As seen in Figure 1, the log signature of the interval that was examined using the MDT tool is very similar to where the leakoff test was performed on.

Also included in Figure 4 is an MDT test that was run in the casing. (This one was done to ensure the MDT seals are working properly). Both tests indicate that pressure declines to approximately 1000 kPa and barely builds up, suggesting that the tested interval is nearly as tight as the casing.

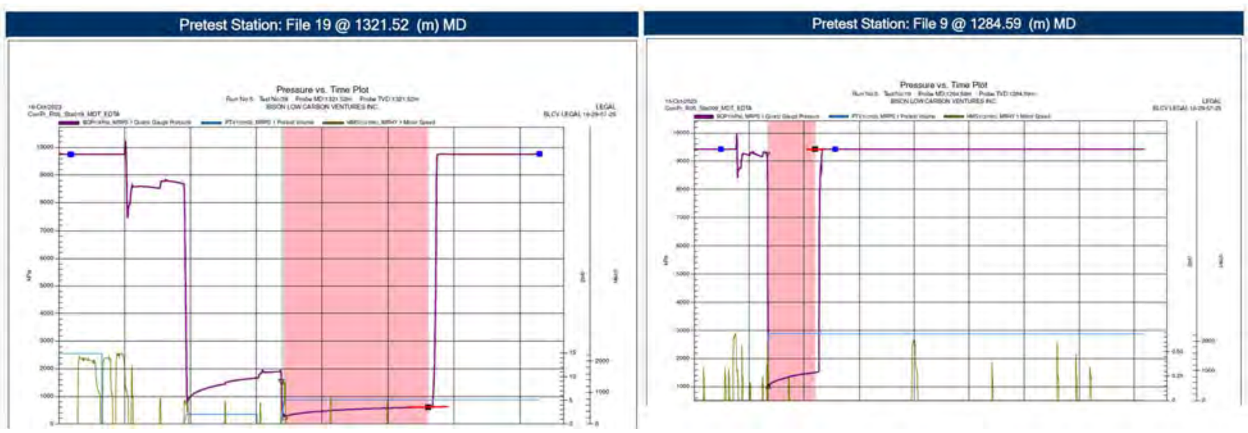


Figure 4: MDT in the caprock (left) and in the Casing (right): In both cases pressure declined to 1000 kPa and built up only a few hundred kPa suggesting that the tested interval is nearly as tight as the casing.

(2) During the operation of the leak-off test, where pressure was increased by approximately 16 MPa, the pressure gauge (behind the casing) in the Nisku detected little/no pressure change, indicating vertical isolation. Any direct communication across the Ireton (caprock) would have led to loss of pressure when the pump was stopped.

APPENDIX K: RESERVOIR MODELLING

Reservoir Modelling

A reservoir modelling study was conducted to investigate storage capacity, the CO2 plume size and the pressure effects as a result of injection in the Meadowbrook reef. This is described in two sections below. First the building of the static reservoir model is described, followed by the dynamic simulations and the results.

The Static Model

The following geological information and maps were used for building of the static model.

- A 2D E-W cross-section of porosity shown in Figure R-1, which honors the main features of the stratigraphic understanding including the difference in reservoir quality between the reef margins and the reef interior. Furthermore, the three main units of the reef (i.e. Upper Leduc, Lower Leduc and Cooking Lake) are represented with their internal features. Each of the units in Figure R-1 represent 20 m in height and 1 km in length, consistent with the size of the grid blocks used in the simulation study[1].

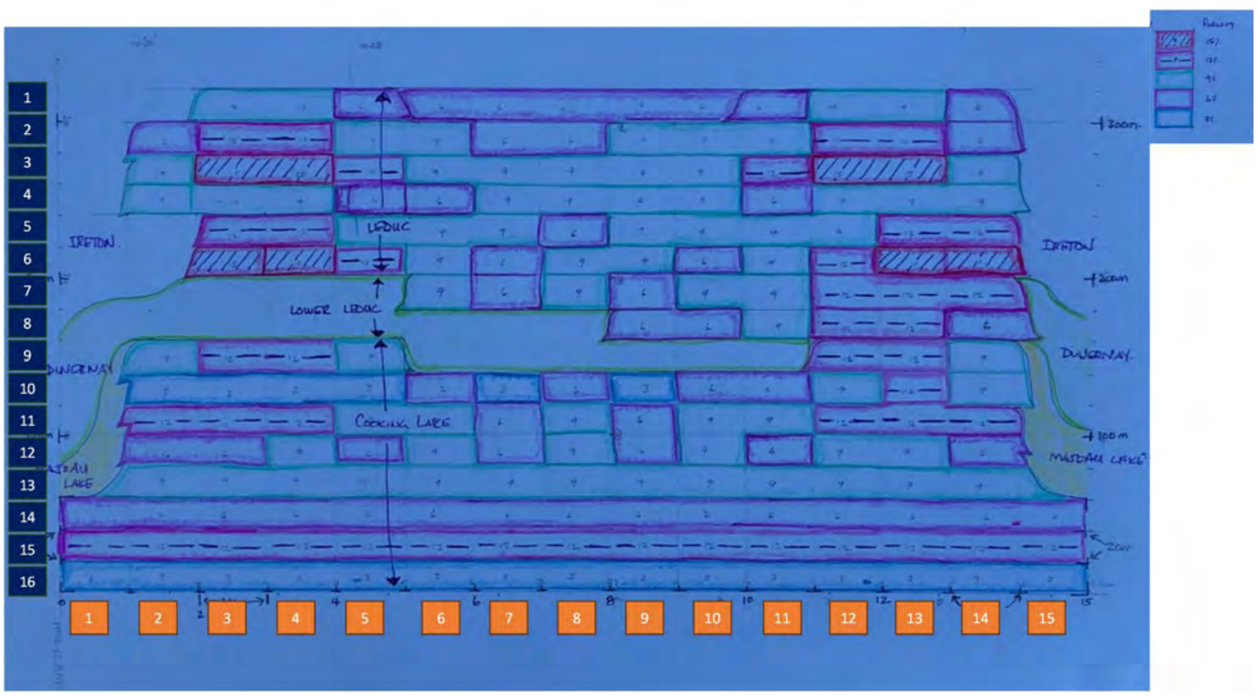


Figure R-1. E-W cross-section of porosity

[1] As discussed in under Dynamic Modelling, fine-gridding is used in the vicinity of the injector.

- A 2D map showing the two outlines, one for the reef (i.e. 300 m isopach of Leduc and Cooking Lake) and one for the Cooking Lake (i.e. 60 m isopach of Cooking Lake), as shown in Figure R-2 (left). On the east, north and south of the Reef, the continuation of Cooking Lake formation beyond the mapped interval (shown by the dashed brown line) is accommodated by connecting the grids to an analytical aquifer. This is further discussed under Dynamic Modelling.
- The structure map of top of Leduc, exhibiting the regional dip to the north and east, as well as internal features including a structural roll on the west side of the reef, as shown in Figure R-2 (right).

Further information about the above is given under Geology.

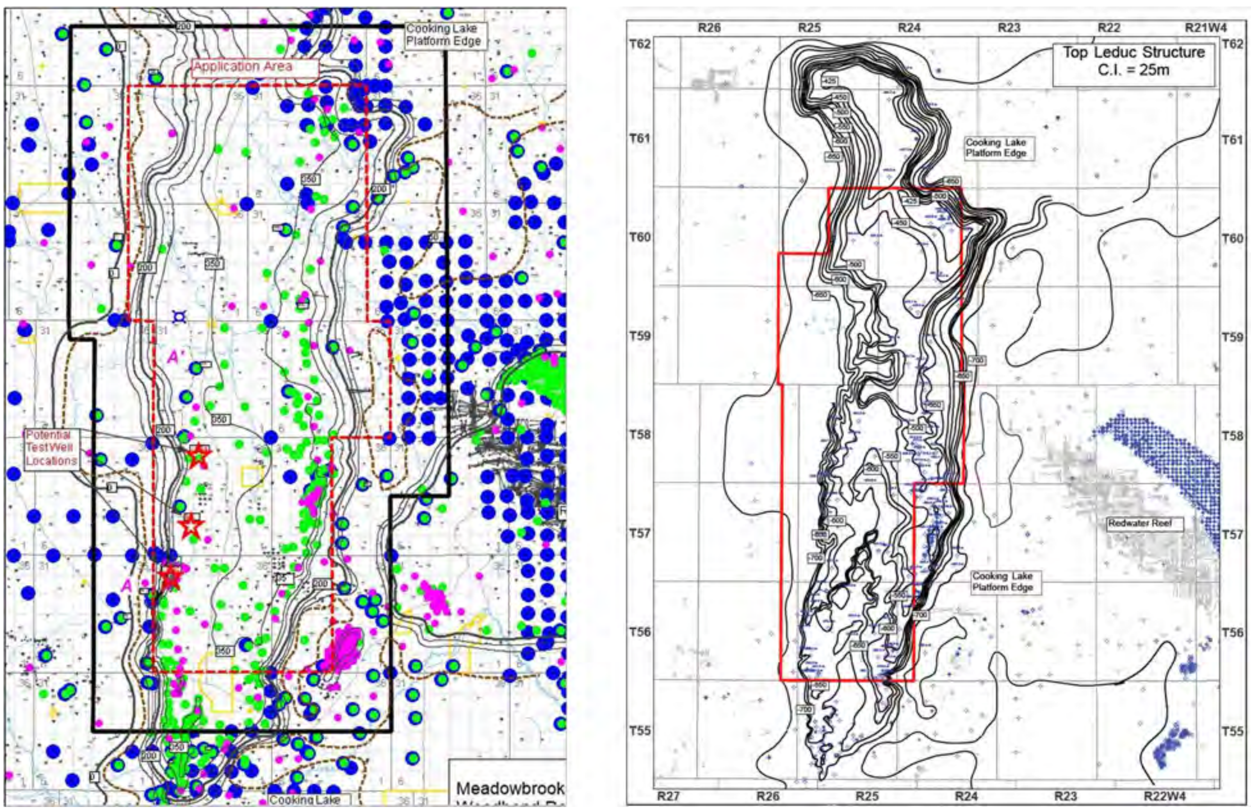


Figure R-2: Isopach map of Leduc + Cooking Lake (left), and map of structure on top of Leduc + Cooking Lake Platform Edge (right)

To build the geological model, the E-W cross-section of porosity (Figure R-1) was used to build a slice of the reef where its width is approximately 15 km. Other slices were created by replicating the same slice, with the following modifications. (i) cells that represent the reef interior were either removed or added to accommodate the change in the E-W width of the reef. (ii) the porosity of an interior cell was randomly chosen from among the porosity values of all interior cells within that layer. This was done to introduce additional heterogeneity.

Next, between the two outlines (320 and 60 m contour lines) a number of the grids were removed from the top. This was done to build the reef front. And finally, the structure map at top of Leduc (Figure R-2, right) was assigned to the top of the upper most grids. Figure R-3. Shows the 3D structure of the reef, where the colour scheme represents the subsea elevation of the grid top. Location of the 16-29 injector is also shown.

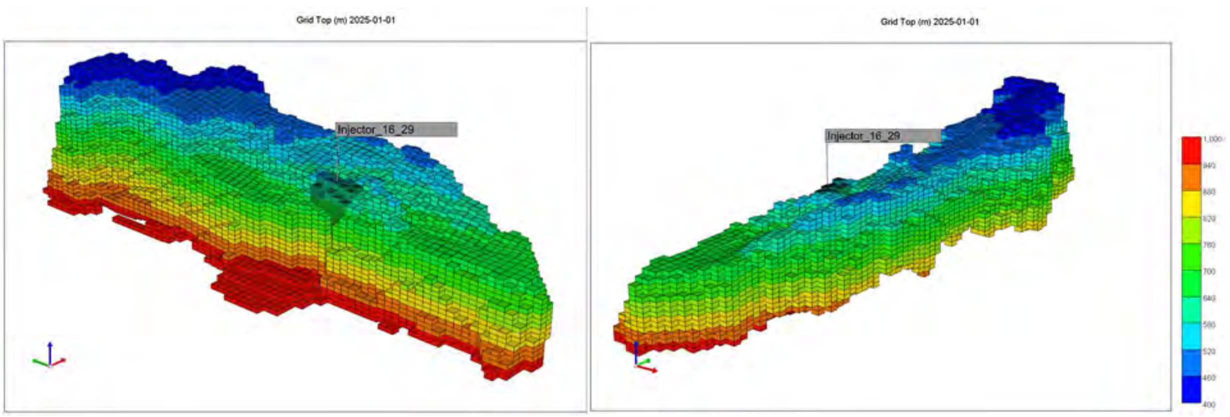


Figure R-3: Two views of the 3D structure of the reef showing the sub-sea elevation of the grids. Grid blocks are 1000 m x 1000 m x 20 m.

The total pore-volume of the reef was calculated, and this was found to be approximately 25% more than the corresponding pore volume of the model used for the evaluation permit. Without any independent way to calibrate the pore volume, and just for consistency, all porosity values were reduced by two porosity-units resulting in a total pore-volume of 17.2×10^9 m^3 (closer to 18.7×10^9 m^3 in the model used for evaluation permit) which we feel is a conservative estimate.

Figure R-4 shows three E-W cross-sections where the colour scheme demonstrates the final grid porosity. The cross-sections from left to right are 10 km north of the 16-29 well, at the 16-29 well, and 10 km south of the well. Figure R-5 shows the 3D arrangement of the porosity in the model.

The sequestration permit being applied for here, is for injecting CO2 into the 16-29 well for a period of 15 years at a rate of 0.5 Mtpa. As we shall see in the next section, this CO2 will occupy significantly less than 1% of the pore volume of the reef, suggesting sufficient static capacity. The injection scenarios are studied in the next section.

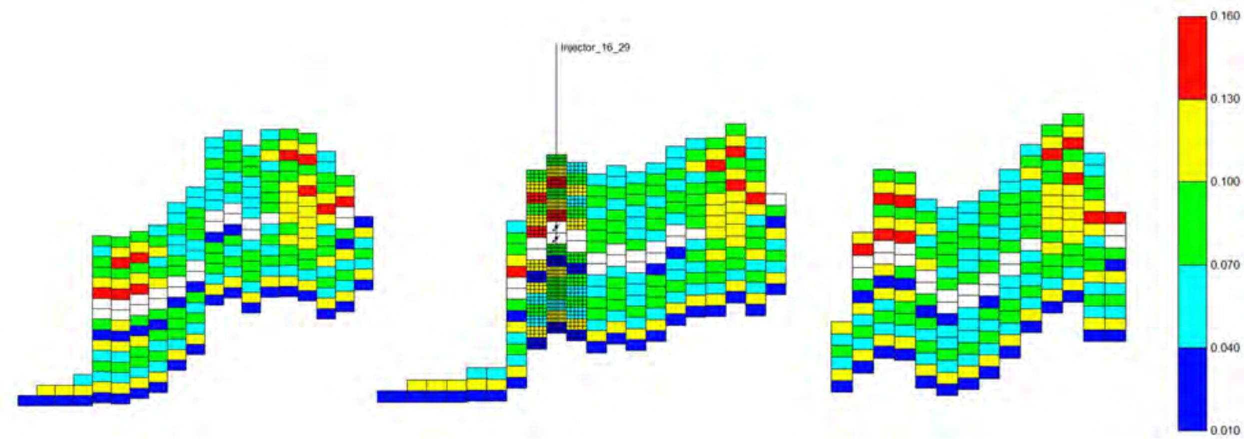


Figure R-4. three E-W cross-sections where the colour scheme demonstrates the grid porosity as follows: Dark blue: 1%, Light blue: 4%, Green: 7%, Yellow: 10%, Red: 13%, white cells have a porosity of zero and represent non-reservoir rock e.g. "Lower Leduc". The cross-sections from left to right are 10 km north of the 16-29 well, at the 16-29 well, and 10 km south of the well. The bottom three grids are connected to the "regional" Cooking Lake aquifer from the East as well as North and South, not shown here.

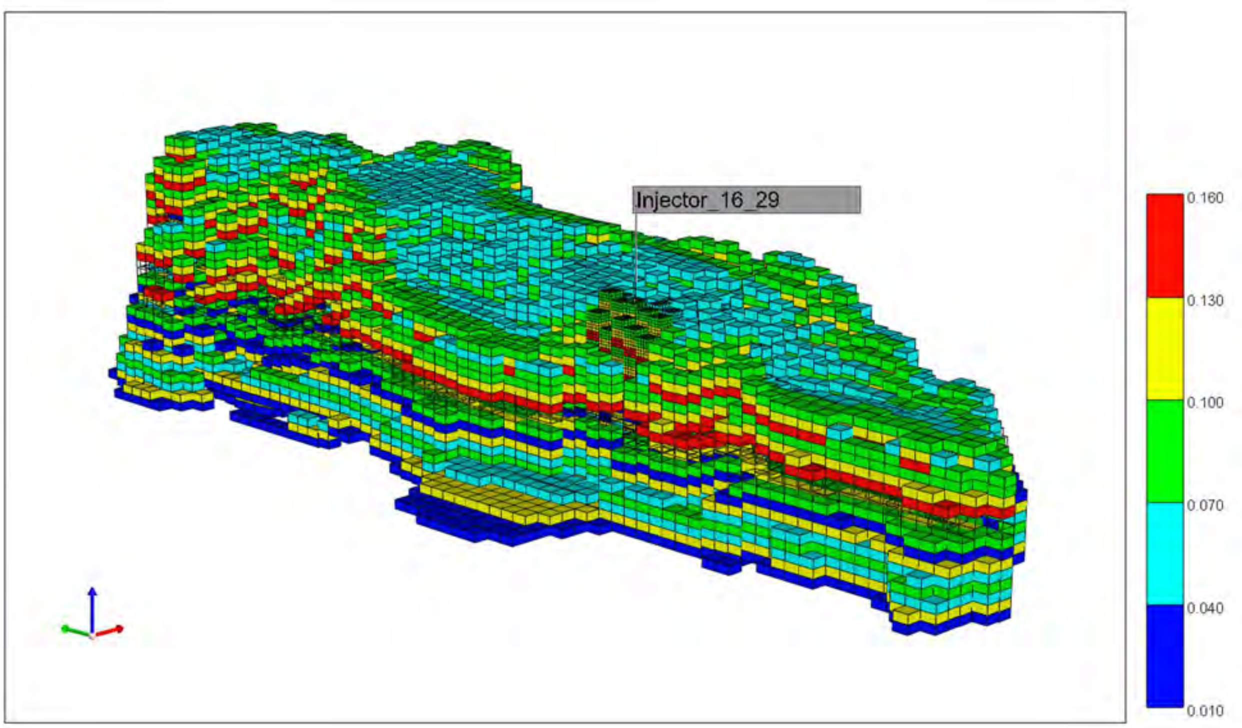


Figure R-5: 3D arrangement of porosity. The colour scheme is the same as Figure R-4, except that the cells with porosity of zero (e.g. Lower Leduc) appear transparent.

The Dynamic Model

The 3D static model built above was incorporated into GEM; the compositional simulator of the CMG and a dynamic model was built to study the evolution of the CO2 and pressure plumes. For this purpose, the pressure and temperature conditions were set according to that described previously, and the fluid model was defined for the in-situ brine and the CO2 that will be injected. Additional important parameters include the relative permeability curves, the reservoir compressibility, the connections to the regional Cooking Lake aquifer, and quite importantly the permeability. Each of these is described below, followed by the results.

Pressure and Temperature: As described previously, formation pressure was measured throughout the Leduc and Cooking Lake using the MDT tool. Correspondingly, the dynamic model was initialized with a pressure of 9.7 MPa at top of Leduc at a depth of 1320 m TVD. Correspondingly, this pressure was set at the top of the uppermost grid block at the location of the 16-29 well in the model (- 586 mSS). The initial pressure gradient in the formation is determined using the brine density of 1060 kg/m^3. Simulation studies were conducted under isothermal conditions using a temperature of 52 °C.

Fluid Properties: To model fluid properties of the CO2 under reservoir conditions including density, viscosity, and compressibility, the Peng-Robinson EOS was chosen with the default parameters of GEM. Solubility was modelled using the Henry's law, with parameters found from the experimental work reported in Pooladi-Darvish et al. (2009), after adjusting them to reservoir temperature and salinity. Table R-1 gives some of the important fluid properties at the initial reservoir conditions.

Table R-1. Fluid Properties in the Dynamic Model at the reference conditions of 9700 kPa and 52 C.

CO_2 Density, kg/m^3	CO_2 Viscosity, cp	Brine density, kg/m^3	Brine Viscosity, cp	CO_2 solubility in Brine, m^3/m^3
328	0.027	1060	0.66	17

Relative Permeability Curves: To model two-phase flow properties, Corey-type relative permeability functions with the relative permeability parameters measured by Bennion and Bachu (2010) were considered. These authors and others find that the resistance associated with two-phase flow could be significant, represented by a wide range of end-point relative permeability curves and exponents. Through a series of modelling studies, using the range of relative permeability curves found by Bennion and Bachu (2010), Burton et al. (2009) found that the uncertainty in the relative permeability could have a significant effect (up to a factor of four) in estimation of injectivity. This wide range of uncertainty might have been a reason for the original application of Quest have concluded that the project might require between 3 and 11 wells for injection of 1 Mtpa. One of the objectives of this project with the lower rate of 0.5 Mtpa is to determine CO_2 injectivity and to use it for determining the relative-permeability parameters in the Meadowbrook reservoir before applying for the Phase II project at 3 Mtpa.

The base values of relative permeability parameters are end-point relative permeability to CO_2, $k_{rg0}=0.17$, CO_2 exponent, $n_g=4$, and residual brine saturation, $S_{wr}=0.5$. Hysteresis in relative permeability, which is responsible for residual trapping was not included.

The effect of the uncertainty in the relative permeability function on the results is investigated using a sensitivity study.

Formation Compressibility: Much has been made of the issue of low compressibility of water and formation and its potential effect on storage capacity (Ehlig-Economides and Economides, 2010). The concern is that because of the low compressibility of the water and rock, CO_2 injection could lead to significant increase in formation pressure, at least in closed systems. There is previous experience with an acid gas injection project in one of the oil pools of the Zama field, where the injection permit rescinded by the regulator because of over-pressurization (Pooladi-Darvish et al. 2011). While in that case, the cause of over-pressurization was determined to be water injection in an adjacent pool that was connected through a permeable carbonate platform beneath the reef, that and similar studies have highlighted the effect of low compressibility and importance of large-scale connectivity.

Overpressurization is not expected to be an issue for the Meadowbrook Woodbend Reef complex. Experience with other dolomitized reefs of the Homglen-Rimbey trend indicate an open system, where effective communication with the Cooking Lake aquifer is expected to allow for pressure dissipation. Nevertheless, compressibility can play a large role on how much does the pressure rise. To assign formation compressibility, we used data and correlations gathered in the literature for carbonates (Hall 1953, Newman 1973, Horne 1990, Jallah 2006). These provided a range. Considering the range of porosity in the Meadowbrook, a base value of 1×10^{-6} 1/kPa was chosen. The effect of the uncertainty in this parameter is investigated using a sensitivity study, where the formation compressibility is lowered to 0.4×10^{-6} 1/kPa.

Connection to the Cooking Lake Aquifer: As mentioned above the dolomitized Cooking Lake aquifer is expected to allow for dissipation of formation pressure associated with CO_2 injection. In reservoir simulation studies, this is modelled by characterizing the aquifer through parameters including porosity, permeability, thickness, and size. The most important parameters among these are probably permeability and size. To determine these parameters, we consulted two studies which characterized the regional Cooking Lake aquifer in the Homglen-Rimbey trend. The study by Barfoot and Ko (1987) assessed the impact of the Leduc D-3A gas cap blowdown on the other Golden Trend pools. For this purpose, the authors modeled the 10 dolomitized pools of the Golden Trend, between Homglen-Rimbey in the south and St. Albert in the north (See Figure R-6 for pools studied. The Meadowbrook reef is just north of St. Albert.) The authors found that in order to match the effects of production and injection on pressure of the neighbouring pools, an important parameter is permeability within the Cooking Lake. The initial permeability trend that was used in the simulation study is shown (Figure R-6, right). Also shown is the final fit where the authors needed to increase the permeability to better model inter-pool communication and thereby match the pool pressures. As shown in Figure R-6 (right) the values of permeability used are between 100 and 1000 md. Furthermore, they found a positive correlation between the permeability and the thickness. To be conservative, the Base value of permeability that we chose for the Cooking Lake permeability is 100 md.

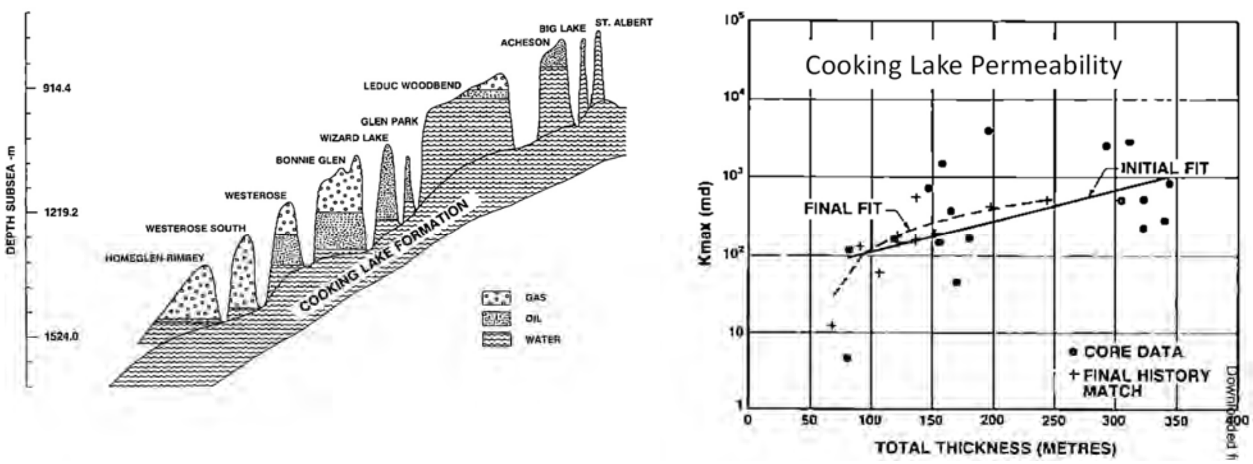


Figure R-6. The Golden Trend Pools studied by Barfoot and Ko, 1987 (left) and the Cooking Lake permeability used to obtain the history match (right)

The other important study is that of Amthor, Mountjoy, and Machel, (1994), where the authors used core data from approximately 30 wells to study regional-scale porosity and permeability Upper Devonian Leduc Buildups within the trend. The location of the approximately 20 pools that was studied is shown in Figure R-7, along with the map of the dolomitized portion of the Cooking Lake platform. The location of the Meadowbrook reef is identified. One of the strongest factors that the authors find is an improvement of reservoir quality with lower depth, with the quality improving from the south to the north. Extrapolation of the trend lines to township 55 – 58, suggest p50 porosity of ~11-12% and permeability of 100’s of md.

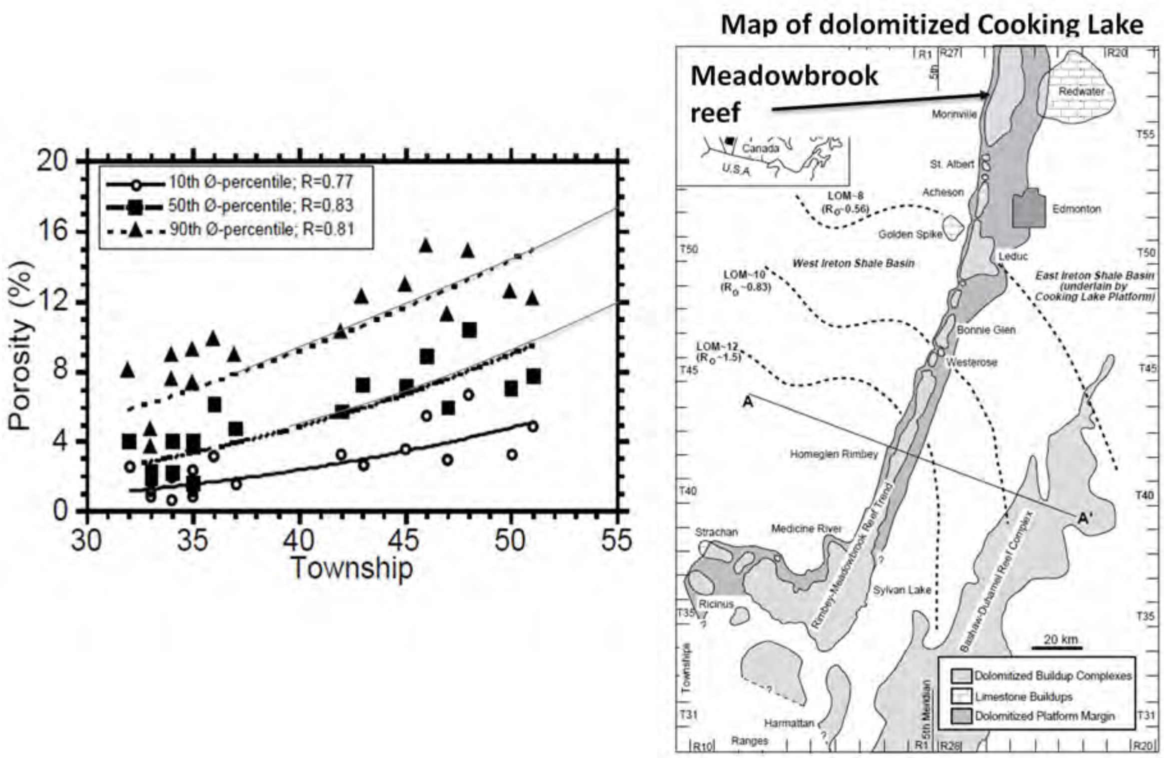


Figure R-7. The study area (right) and the correlation found between porosity and location (left). Modified after Amthor et al. (1994)

The third study that we considered is that conducted by Bachu et al. (2010), where the Red Water reef was considered for large scale CO2 storage, i.e. the Harp Project. This multi-disciplinary study included detailed core work, where the extent of the dolomitized portion of the Cooking Lake was mapped to be with the Western portion of the reef, consistent with that shown in the work of Amthor et al. (1994) in Figure R-7. Red Water reef is among the largest oil pool in Canada, and the volumes of fluid injected and produced from the field are significantly larger than what is being considered in this project. Field experience and the pressure history of the reservoir indicates that there has been significant pressure support from the Cooking Lake aquifer (presumably its dolomitized region). Another part of the project included a stochastic material balance study to characterize the permeability of the Cooking Lake aquifer. The results of this study suggested that the strong aquifer communication between the reef and the underlying carbonate platform, is most likely through the western high permeability dolomitized portion of the reef with permeability of 100’s of md.

All of these studies suggest that the permeability of the Cooking Lake in the Meadobrook reef and its vicinity is in the 100’s of md. To be conservative, the base value of permeability that we chose for the Cooking Lake permeability is 100 md, and for the sensitivity study we removed the connections to the aquifer. As will be shown, the pressure increase in the reef was not significantly affected by the presence (or properties) of the Cooking Lake. This is because of the relatively small size of the project being considered in this phase. It is expected that connectivity to the Cooking Lake aquifer will play a significant role, for the larger scale project (of 25 years of injection of up to 3 Mtpa).

Permeability

One of the important attributes of a good storage site is good injectivity requiring a smaller number of injection wells. Field experience in dolomitized Leduc reefs indicate very high injectivity. For example, injection history of the 1-35-52-26 well in the Acheson field demonstrates injection capability of many thousands of m3/day over many decades (see Figure R-8). An injection rate of 0.5 Mtpa of CO2 is equivalent to just a fraction on injection rates in this well in volumetric terms. Cumulative water injected over a 30-year period was close to 30 Mt (30 e6m3).

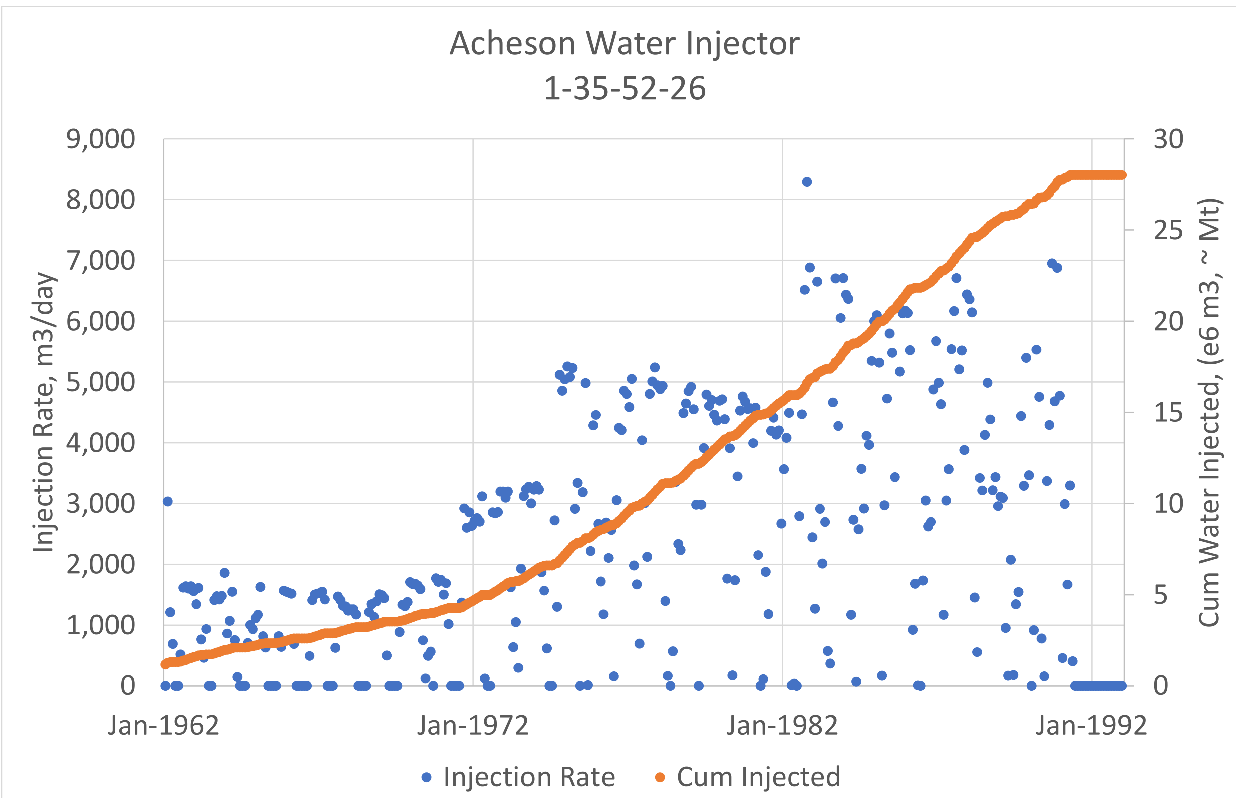


Figure R-8. Water injection history of the 1-35-52-26 well in the Acheson field

To determine the injectivity of the 16-29 well, a step-rate test was conducted where injection rate was increased from 0.5 m3/min to more than 3.5 m3/min (equivalent to 720 to more than 5000 m3/day). The bottomhole pressures shown in Figure R-9 indicate that bottomhole pressure increased by less than 3 MPa (and remained sub-hydrostatic) hence confirming excellent injectivity.

Unfortunately, the interpretation of the fall-off test after the step-rate test was complicated by first the well going on vacuum that had significant effect on the interpretability of the results, and second the use of friction reducer for the final rates that not only reduced the wellhead injection pressure as intended, but also led to a reduction in bottomhole pressure as seen in Figure R-9. Because of these, it was decided to also analyze two shorter periods of injection one approximately a day before the step-rate test and the other one a day after.

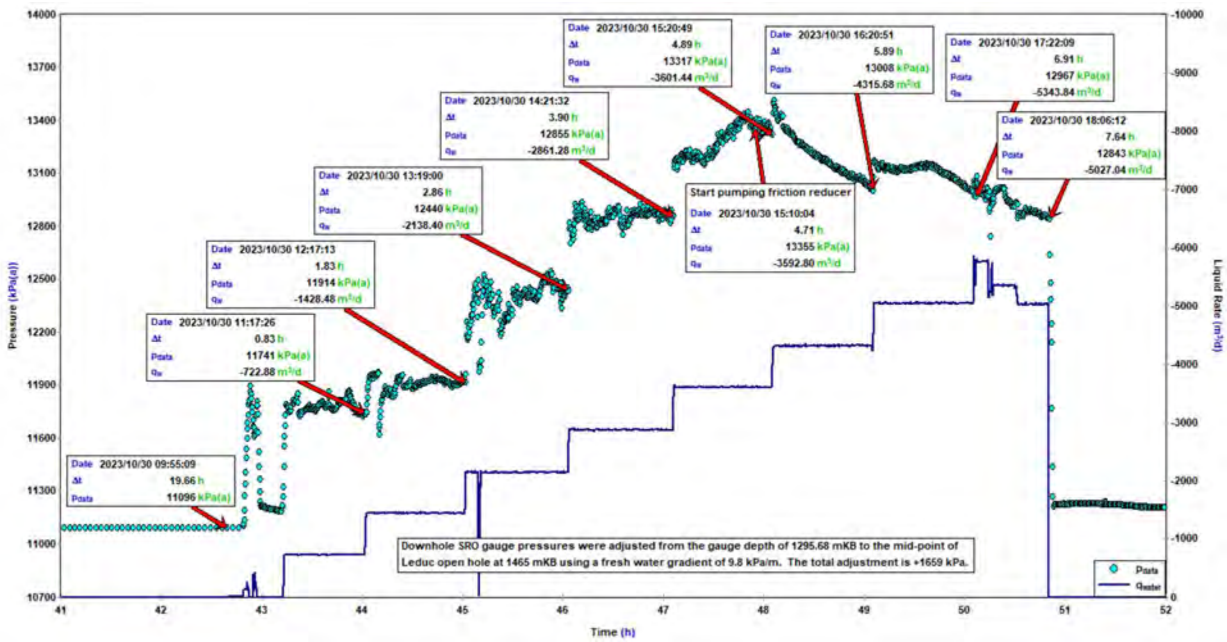


Figure R-9: Injection rate and bottomhole pressure during the step-rate test. The start of pumping friction reducer at 4.7 hrs after start of the test is marked on the graph. (Note that the bottomhole pressures shown here are corrected to the mid-point of the open interval at 1465 mKB, by adding 1660 kPa to the measured pressures).

Figure 10 shows the derivative plots of the three fall-offs. Significant scatter is present during the first few hours, as a result of the well going on vacuum. Because the quality of all tests is significantly affected by this wellbore effect, by the debris in the wellbore during the first injection (requiring a clean-out before the step-rate test), and the short period of injection and the low rate of injection in injection periods 1 and 3 it was decided that the results obtained from interpretation of the fall-off tests are used in a semi-quantitative way i.e. only for developing a range of models (i.e. low- and high-k.h. cases).

The interpretation of these fall-offs leads to a range of permeability-thickness product (k.h.) of between ~7100 and 25,000 md.m, corresponding to kh/μ of between 11,000 and 39,400 md.m/cp seen in Figure R-10. The radius of investigation associated with this interpretation is between 0.5 and 2 km, which corresponds reasonably well with the size of grid blocks used in the model (of 1 km).

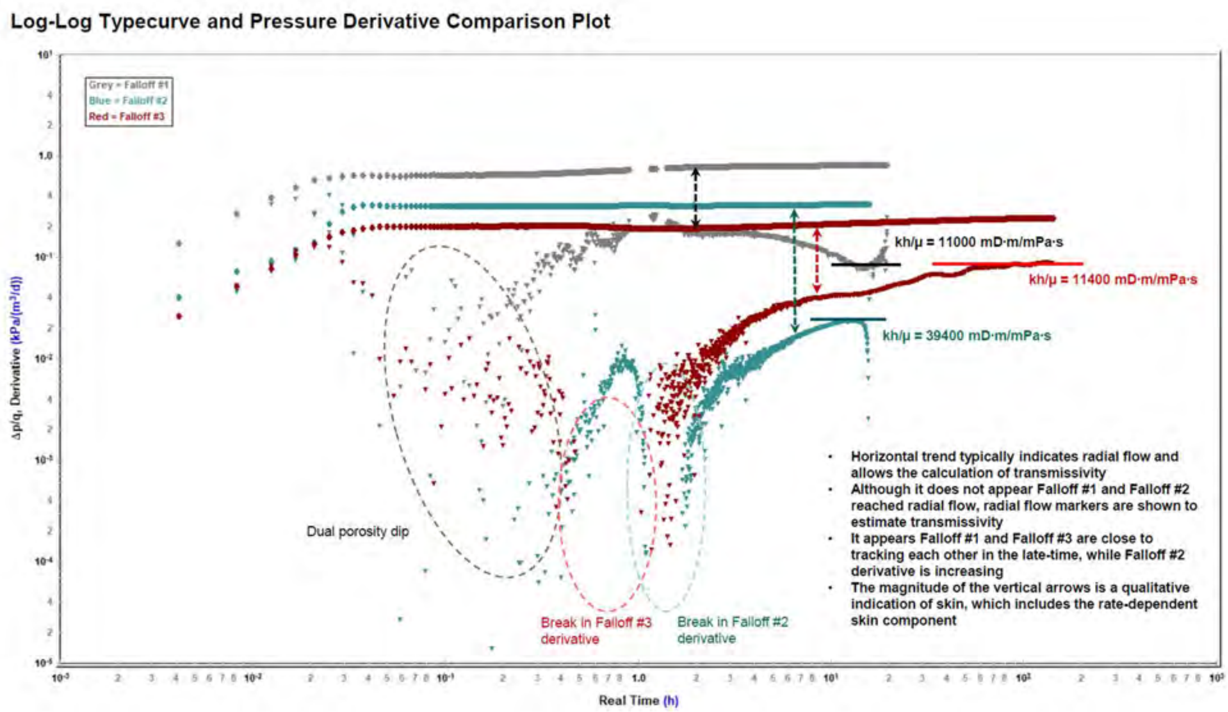


Figure R-10 Log-Log type curve and derivative plots for the fall-off after the step-rate test (Fall-off #2) and the fall-offs before and after.

Because of the early-time data were not interpretable, and the wide range of k.h., four different models were developed each consistent with some of the data. Since these were to be used to calibrate the numerical reservoir simulation model for large-scale CO2 injection, they were used to model water injection at a rate up to 5000 m3/day. After a period of injection of one month, three of them exhibited a pressure increase of ~ 3 MPa and one model exhibited a pressure increase of ~7 MPa. These will be used as additional consistency check as explained below.

To develop a permeability-porosity relation for the reservoir simulation model the following steps are taken:

- Core data of an analogue well (00/15-23-052-26W4) from the Acheson field was used (see Figure R-11).
- A straight-line correlation was drawn through the data that as compared with the original correlation shown on the data (shown in blue) exhibited a lower permeability at low porosity values (see the back-solid line, which I call “Core”)
- This correlation when applied to the porosity in the model exhibits too high of a k.h. The poro-perm correlation was lowered uniformly (by a factor of 5) until the total k.h. of the injector in the model corresponded to the higher k.h. identified from the fall-off analysis. The total k.h. at the 16-29 location in this k.h. model is 24,300 md.m.

- This correlation is shown as a dashed-black line in the figure (Core/5). Using this correlation, the range of permeability is between 0.1 and 450 md, for porosity between 1 and 13%.
- This correlation (Core/5) was applied to the reservoir model, and a water injection test was simulated. The bottomhole pressure response is shown in Figure R-11 (Top-Right). This exhibits a pressure rise of approximately 3 MPa, consistent with three of the four welltest models. In the simulation studies that are reported next, this correlation is used for the Base Case.
- To model the case with the lower k.h., the pore-perm correlation was further lowered by a factor of three, shown with dotted line in Figure R-11, called Core/15.
- When this correlation (Core/15) was applied to the numerical simulation model, and water was injected for a period of one month, the bottomhole pressure exhibited a pressure increase of approximately 8 MPa (see Figure R-11, Bottom-Right). This was consistent with one of the four welltest models. In the simulation studies that are reported next, this correlation is used for the k_Low Case.

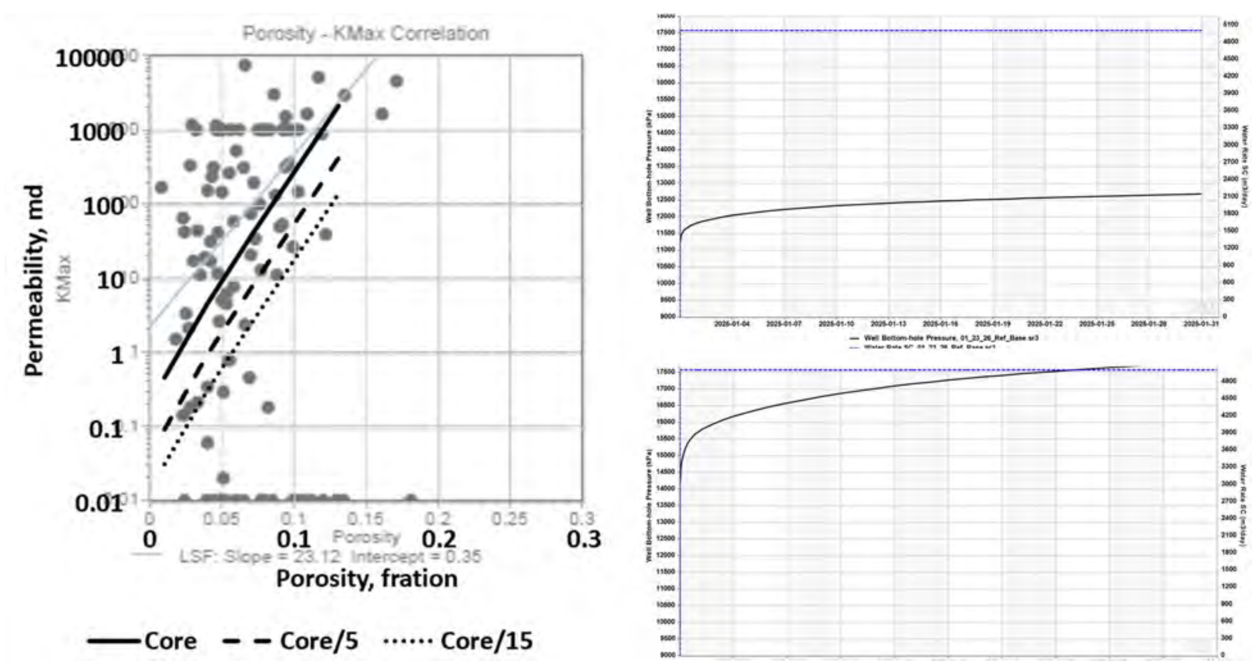


Figure R-11 Pore-Perm data from the 15-23-052-26W4 well, with three pore-perm correlations named Core, Core/5 and Core/15 (left). Simulation results of water injection in the Dynamic Model when Core/5 is used (Top-Right) and Core/15 is used (Top-Left). The pressure increases after a month of injection are consistent with three and one of the well-test models, respectively.

Results

Once the above input data were incorporated into the simulation model, a number of simulation cases were run to study the evolution of the CO2 and pressure plumes and the effect of uncertainty in parameters was studied. The results of the base case are presented in detail below, followed by a summary of the sensitivity studies.

Base Case

All simulation results are presented using a coarse grid (1 km x 1 km x 20 m) away from the injector. Fine-grid simulations were conducted to determine the area that requires fine-gridding and how fine they need to be. These studies suggested that two forms of fine-gridding are needed; one for the column of the grids that contains the wellbore and another one for the area beyond. In the horizontal plane, the fine-gridding in grids that contain the wellbore consisted of 10 grids in the radial direction and four grids in the angular direction. For grids beyond, each larger grid was divided into 25 smaller grids. It was found that for accurate results, the fine-gridded area should be large enough to contain the CO2 plume. Therefore, an area of 5 by 3 km around the wellbore was finely gridded. In the vertical direction, each 20 m grid in this area is divided into 3 finer grids.

The Base Case represents injection at a constant rate of 0.5 Mtpa (730,000 m3/day) for 15 years, where the wellbore is fully open from the base Ireton to TD. This is followed by 15 years of shut-in. All simulations have a start date of first of January 2025.

This and all sensitivity cases are constrained against the maximum injection pressure of 18.2 MPa. Other properties are given in Table R-2.

The simulation results shown in Figure R-12 indicate that the well can maintain the injection rate of 0.5 Mt/a for the duration of the project, equivalent to approximately 730×10^3 m^3/day at surface conditions of 15 °C and 1 atm (see the solid black line). The cumulative mass of the CO_2 injected in 15 years is 7.5 Mt, shown by the dotted grey line.

Also shown in Figure R-12 are the bottomhole pressure at the injection well, shown by the dashed blue line. The pressure is reported at the top of Leduc, i.e. ~ 1320 m TVD. The results show that the injection pressure rises to approximately 13.2 MPa by the end of injection, and then it dissipates during the shut-in time, first sharply because of near-wellbore drop in pressure at the time of shut-in and then more slowly as the elevated pressures dissipate through the formation and because of the connectivity to the Cooking-Lake aquifer.

Table R-2. Base Case Properties

Parameter	Value
Porosity	Cross-section shown in Figure R-1, minus two units (1, 4, 7, 10, 13%) *
Pore-Perm cross-plot	Core/5** (see Figure R-11)
Kv/kh	0.1
Skin	0
NTG	1
Rock Compressibility, 1/kPa	1 e-6
Regional Cooking Lake Aquifer	H=60 m, phi=0.08, k=100 md, Carter Tracy-infinite
Relative Permeability to CO2	Krg0=0.17, ng=4
Injection Interval	Leduc and Cooking Lake
Maximum BH Injection Pressure Constraint	18.2 MPa
Injection Rate, Mtpa	0.5
Duration of Injection, years	15
Duration of shut, years	15
Grid refinement	The wellbore grid is divided into 10 radial grids and 4 in the angular direction. The grids around the wellbore grid are divided into 25 grid blocks (5 by 5) within an area of approximately 4 km by 5 km. In the vertical direction, all these grids are divided into 3 grids.

* Total PV=17.3 x 10^9 m^3

** Total permeability-thickness product=24,300 md.m

As the results in Figure R-12 shows injection pressure barely reach the hydrostatic pressure by the end of injection period.

Also shown in Figure R-12 is the average pressure. This is volumetric average of pressure in the reservoir and its datum depth is the average reservoir depth. Results in Figure R-12 show that starting at an average pressure of 11,180 kPa, average reservoir pressure rises by less than 400 kPa to 11,575 kPa at the end of injection, before it declines slightly as formation brine effluxes into the regional Cooking Lake aquifer.

The relatively small increase in bottomhole injection pressure of 3.5 MPa and in average reservoir pressure of 0.4 MPa are indicative of high injectivity and dynamic capacity of the Meadowbrook reef, respectively, and are consistent with experience in other large, dolomitized Leduc reefs on the trend.

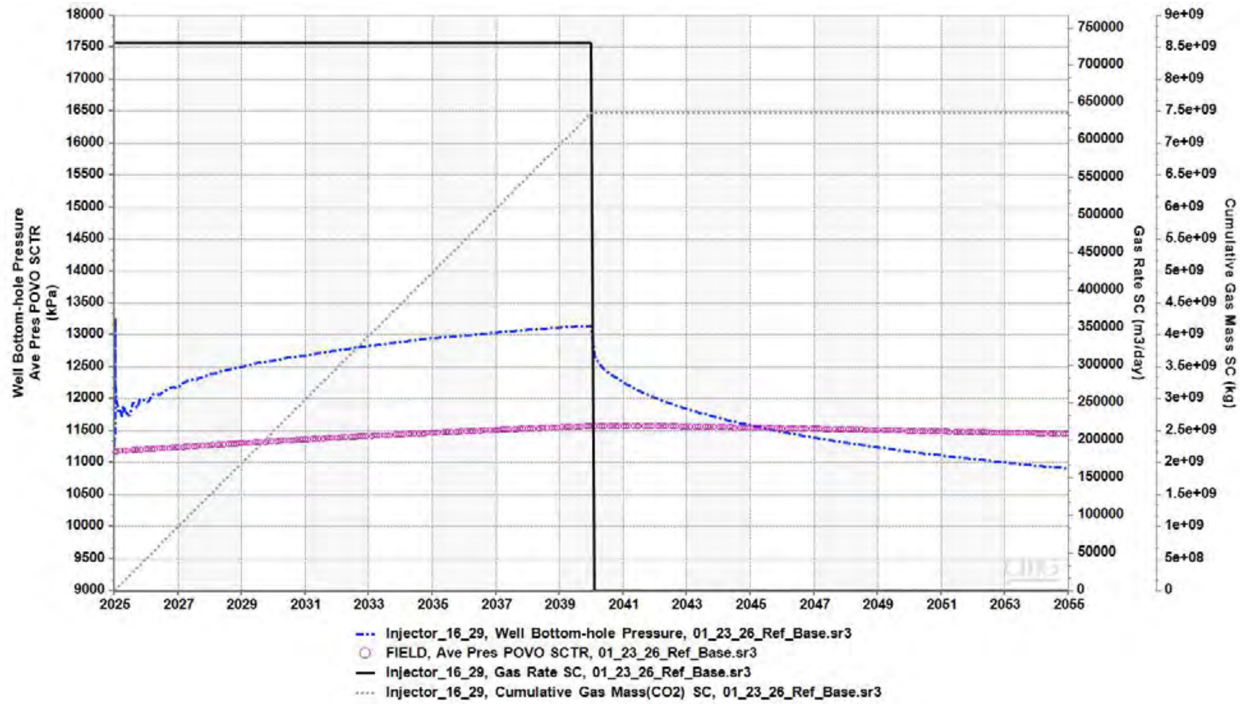


Figure R-12: Injection rate and cumulative stored mass, with bottomhole injection and average reservoir pressure for 15 years of injection @ 0.5 Mtpa followed by 15 years of shut-in. Base Case

Another view of the pressure plume is depicted in Figure R-13, where the change in reservoir pressure from its initial value is shown. The results are for the top of Leduc (upper most layer in the simulation model) where the increase in pressure is the greatest. Here, and in subsequent figures the results are shown at the end of 15 years of injection, i.e. Year 2040, and also after the well has been such-in for an additional 15 years, i.e. year 2055.

Using the results depicted in Figure R-13, the following observations could be made. At the end of injection, the maximum increase in pore pressure is approximately 3.5 MPa. At this time, approximately half of the reservoir area is experiencing a pressure increase of less than 0.5 MPa. The area associate with a pressure-increase of more than 1 MPa ($\Delta p > 1$ MPa), is approximately two townships.

After 15 years of shut-in most of this pressure increase dissipates, such that the area with pressure increase of $\Delta p > 1$ MPa is limited to a few square-kilometres around the injector.

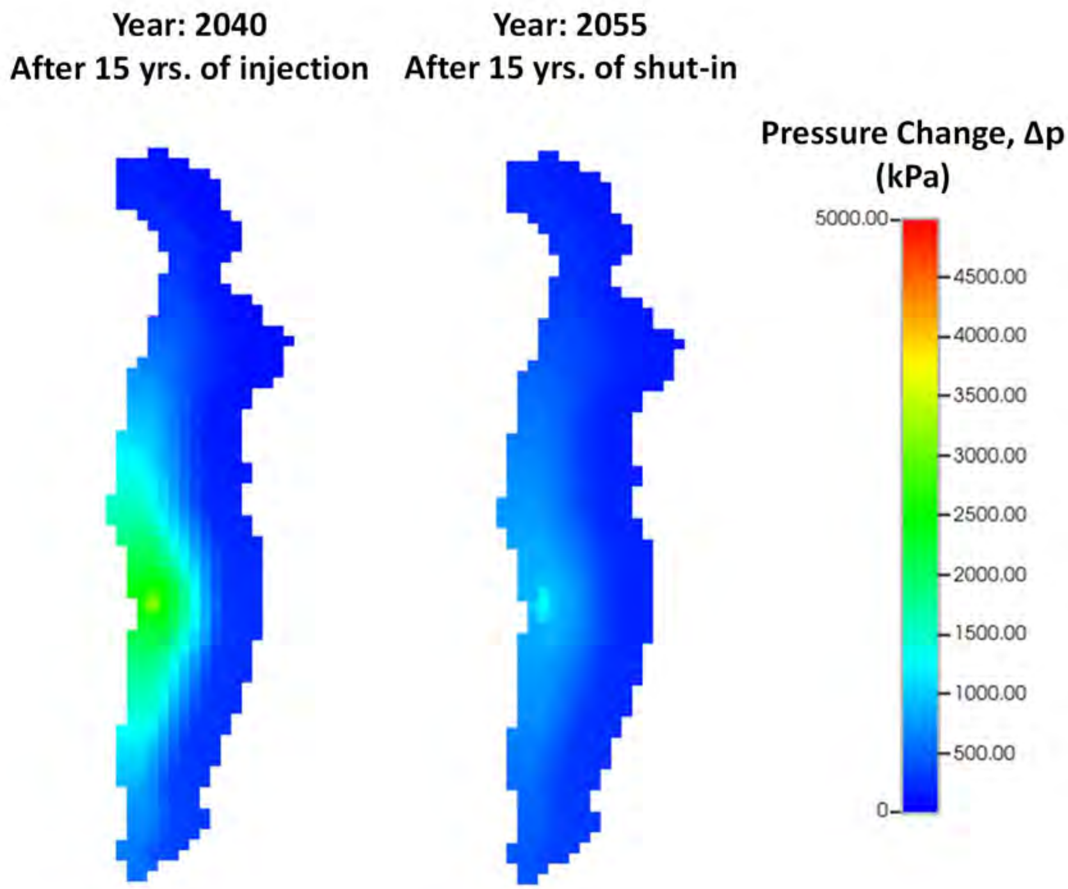


Figure R-13. Map of increase in reservoir pressure (Δp) after 15 years of injection (left), and after 15 years of shut-in (right)

In addition to pressure, the areal and vertical distribution of the CO2 plume was investigated. This is particularly important for designing monitoring activities.

Figure R-14 shows the shape and size of the CO2 plume at the end of 15 years of injection (left) and after 15 years of shut-in (right). The CO2 plume is preferentially elongated in the North-South direction affected by the reef edge on the west and lower structure to the east of the injector as seen in EW cross-section in Figure R-4. The flow is mostly towards to the north following the dip of the structure. The effect of this is more apparent after the injection has stopped and viscous forces have dissipated.

As the results show, the size of the CO2 plume after 15 years of injection is approximately 2.5 square-kilometers, growing to approximately 5 square-kilometers after 15 years of shut-in. The larger area of the CO2 plume in year 2055 is result of combination of factors including pressure decline and continued vertical segregation. It is expected that with more time, the CO2 would continue to move northwards along the structure dip driven by buoyancy. With continued flow of the plume more of the CO2 would dissolve into the formation brine, and some would get trapped by the mechanism of residual trapping[2].

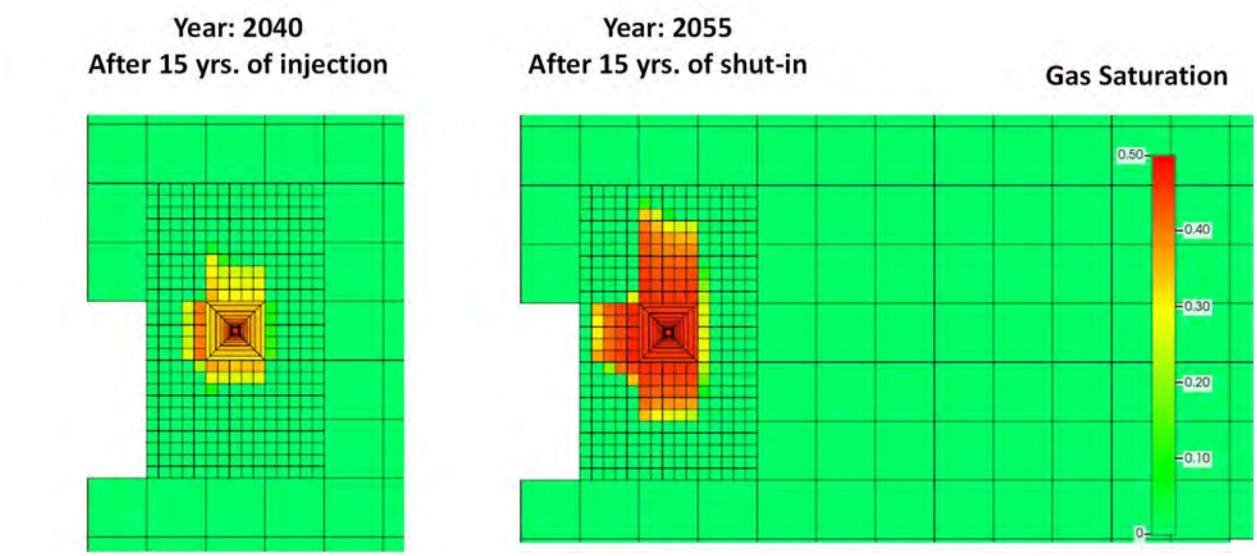


Figure R-14. Map of CO2 plume after 15 years of injection (left), and after 15 years of shut-in (right)

Figure R-15 presents a cross-sectional view of the plume shape. The following observations can be made: CO2 enters both the Upper Leduc and the Cooking Lake, with the Upper Leduc exhibiting a larger plume size dues to its higher permeability. Furthermore, CO2 moves upwards, where this upward rise is affected by layering and vertical permeability. Also shown in Figure R-15 is the influence of the structure roll on the plume. The results suggests that the CO2 has been mostly contained by the high-structural feature on the western rim of the reef.

[2] As mentioned under Fluid Properties and Relative Permeability Curves, solubility is included in the model, but residual trapping is not.

Figure R-15. E-W cross-sectional view of CO2 plume after 15 years of injection (left), and after 15 years of shut-in (right)

In a high injectivity reservoir such as the Meadowbrook reef, it is expected that viscous forces be small, and the distribution of the CO2 would be affected by the forces of gravity and capillary. These in turn are affected by heterogeneities in permeability and capillary pressure. High permeability streaks and thin layers are expected to affect horizontal and vertical flow of the CO2 plume. Furthermore, the local structure at top of the formation over the CO2 plume area is expected to affect buoyancy-driven flow of the CO2. We do not expect to have a precise knowledge of the small-scale heterogeneities. Previous experience such as that in Sleipner (Chadwick et al. 2010) suggests that only after injection and with use of various monitoring programs, the factors that control the distribution of the CO2 are characterized. Bison's operations envision starting at volumes significantly less than 0.5 Mtpa. This could provide the opportunity for calibrating the reservoir model and its input parameters.

As the colour scale shown to the right of Figures R-14 and R-15 shows the maximum gas saturation in the CO2 plume is 50%. The remaining fluid in the pores is the formation brine that is now saturated with CO2 according to its solubility parameters. For the residual water saturation considered here (50% for the base case) and solubility parameters considered here, by the end of the injection period (year 2040) approximately 13% of the injected CO2 is dissolved in the formation brine within the CO2 plume volume. This is shown in Figure R-16 below, where the mass of the CO2 in the reservoir is depicted. The results in Figure R-16 show that after the well is shut-in more of the CO2 dissolves as the CO2 plume moves through the reservoir and comes across unsaturated brine. By the year 2055, approximately 17% of the total CO2 is dissolved.

Also shown in Figure R-16 is the fraction of CO2 that is trapped by residual trapping, which remains at zero. If residual trapping were included the size of the CO2 plume would have been smaller (everything else being the same).

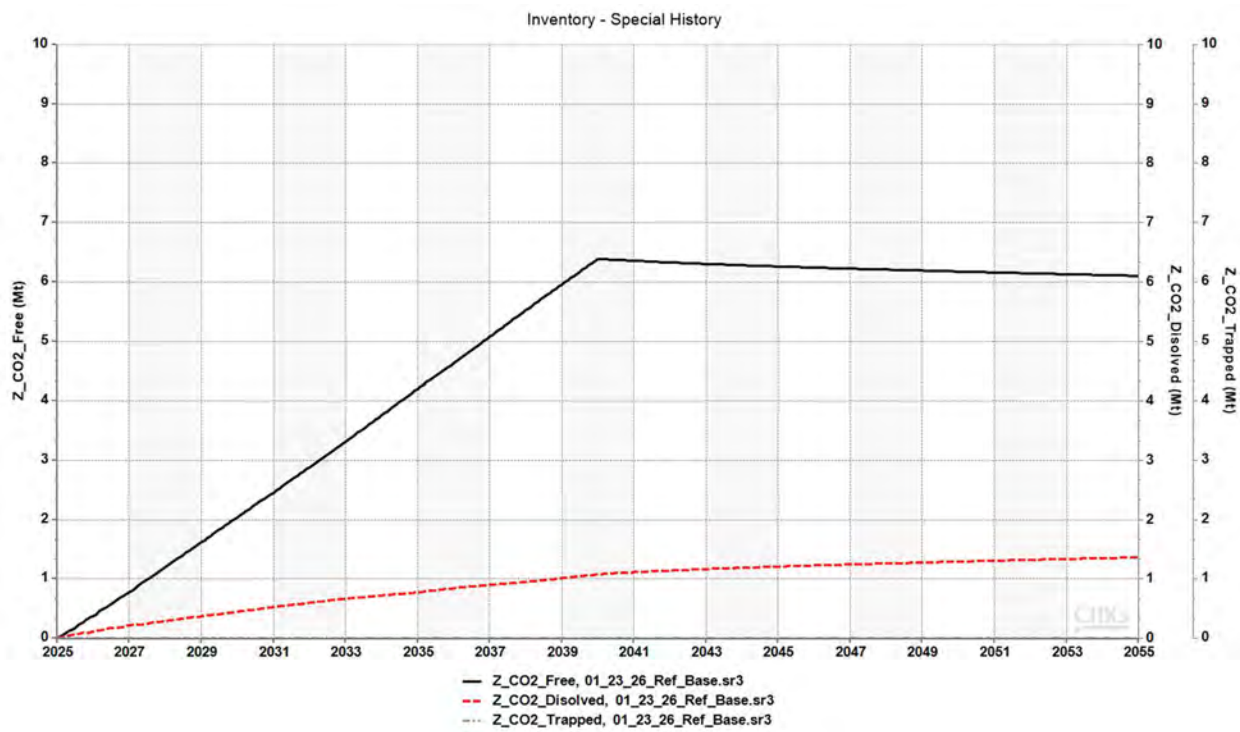


Figure R-16: Total mass of the CO2 in the reservoir in three states of "free", "dissolved" and "trapped" by the mechanism of residual trapping. Base Case.

Sensitivity Studies

The results of the sensitivity cases are reported in this section. Two groups of sensitivity studies are conducted. In the first group, one of the reservoir parameters such as permeability is varied, while in the second group, the operational conditions such as injection rate is varied.

Table R-3 lists the cases and provides a brief description of the parameter that is changed. Table R-4 gives a summary of the results, where the following four parameters are listed:

Injection pressure at the end of injection, total mass of CO2 injected, increase in average aquifer pressure, and the approximate size of the CO2 plume at the end of injection.

These sensitivity cases and their results are briefly discussed below.

Table R-3. Sensitivity Cases

Case Name	Description	Value
Ref_Base	As described in Table 1	
Sensitivity to Reservoir Parameters		
Ref_Base_Comp	Reduce rock compressibility, 1/kPa	0.4 e-6
Ref_Base_RP	Increase relative permeability to CO2	Krg0=0.3, ng=2
Ref_Base_NoAquif	Remove the connections to the regional aquifer	0
Ref_Base_Skin_Low	Stimulate (Reduce skin)	-3
Ref_ase_Skin_High	Damage (Increase skin)	2
Ref_Base_NTG	Reduce NTG to 0.85 (resulting in reduction in PV and k.h.)	0.85
Ref_Base_kv_High	Increase kv/kh to 0.3	0.3
Ref_Base_k_Low	Reduce permeability by a factor of 3 (see Core/15 in Figure 1)	Core/15
Sensitivity to Operational Parameters		
Ref_Base_Rate_High	Increase injection rate and duration to 1 Mtpa and 25 years, followed by 25 years of shut-in	1 Mtpa

Table R-4. Summary of results

Name	Injection Pressure @ end of inj., MPa	Total CO2 stored, Mt	Plume area @ end of inj., km^2	Change in average pressure @ end of inj., MPa
Ref_Base	13.1	7.5	2.5	0.4
Sensitivity to Reservoir Parameters				
Ref_Base_Comp	13.4	7.5	2.5	0.5
Ref_Base_RP	12.9	7.5	3.5	0.4
Ref_Base_NoAquif	13.2	7.5	2.5	0.5
Ref_Base_Skin_Low	13.0	7.5	2.5	0.4
Ref_ase_Skin_High	13.4	7.5	2.5	0.4
Ref_Base_NTG	13.6	7.5	3	0.4
Ref_Base_kv_High	13.1	7.5	3	0.4
Ref_Base_k_Low	16.5	7.5	1.5	0.4
Sensitivity to Operational Parameters				
Ref_Base_Rate_High	16.0	25	6	1.0

In the first group of sensitivity studies, the sensitivity of the results to the following reservoir parameters is investigated: reservoir compressibility, relative permeability, connection to the regional Cooking Lake aquifer, wellbore skin, net-to-gross ratio, vertical permeability, and reservoir permeability. As the summary of results in Table R-4 indicates, with the exception of reservoir permeability, the effect of all other parameters is small. In all cases, the bottomhole injection pressure remained below 18.2 MPa. Therefore, the well was not constrained, and injection rate was maintained at 0.5 Mt throughout the 15 years. In all cases the increase in the average reservoir pressure remained small (in the range of 0.4 to 0.5 MPa).

The case of no connection to aquifer is of particular interest. While for the case studied here (0.5 Mtpa for 15 years), presence of the aquifer makes little difference, it is expected that the situation be different for the larger case of 3 Mtpa and injection period of 25 years. This is because, for this larger case, the total CO2 injected is 10 times more than what is simulated here. Should there be no connection to the aquifer, this will result in an increase in reservoir pressure that is roughly one order of magnitude more (i.e. of the order of 4 to 5 MPa). Under these conditions, there will be a significant driving force between the reservoir and the Cooking Lake aquifer, with the resulting outflow of formation fluid into the regional Cooking Lake aquifer. This suggest that the results of the sensitivity cases are only valid with the range of parameters considered and should not be extrapolated o other scenarios. One more observation about this case is worth mentioning: Because the presence or absence of the connection to the regional aquifer made little difference in the results, it is unclear if field experience at these lower rates (0.5 Mtpa) could help in characterizing the regional Cooking Lake aquifer and its connectivity to the Meadowbrook reef.

As mentioned, the reservoir parameter that had the largest impact on the results was reservoir permeability. When the reservoir permeability was reduced by a factor of three (i.e. total kh=8,100 md.m), wellbore pressure increased to 16.5 MPa. The results of this case are shown in Figure R-17 and can be compared with those in Figure R-12. Still at this level of permeability, injection was not constrained by the maximum injection pressure of 18.2 MPa, and the total stored mass of CO2 at the end of 15 years remained at 7.5. Should the wellbore exhibit a lower injectivity than what is modelled here and the bottomhole injection pressure reaches 18.2 MPa, the injection rate will have to be reduced accordingly. The size of the CO2 at the end of injection is also smaller than the base case, reflecting the higher pressures close to the wellbore.

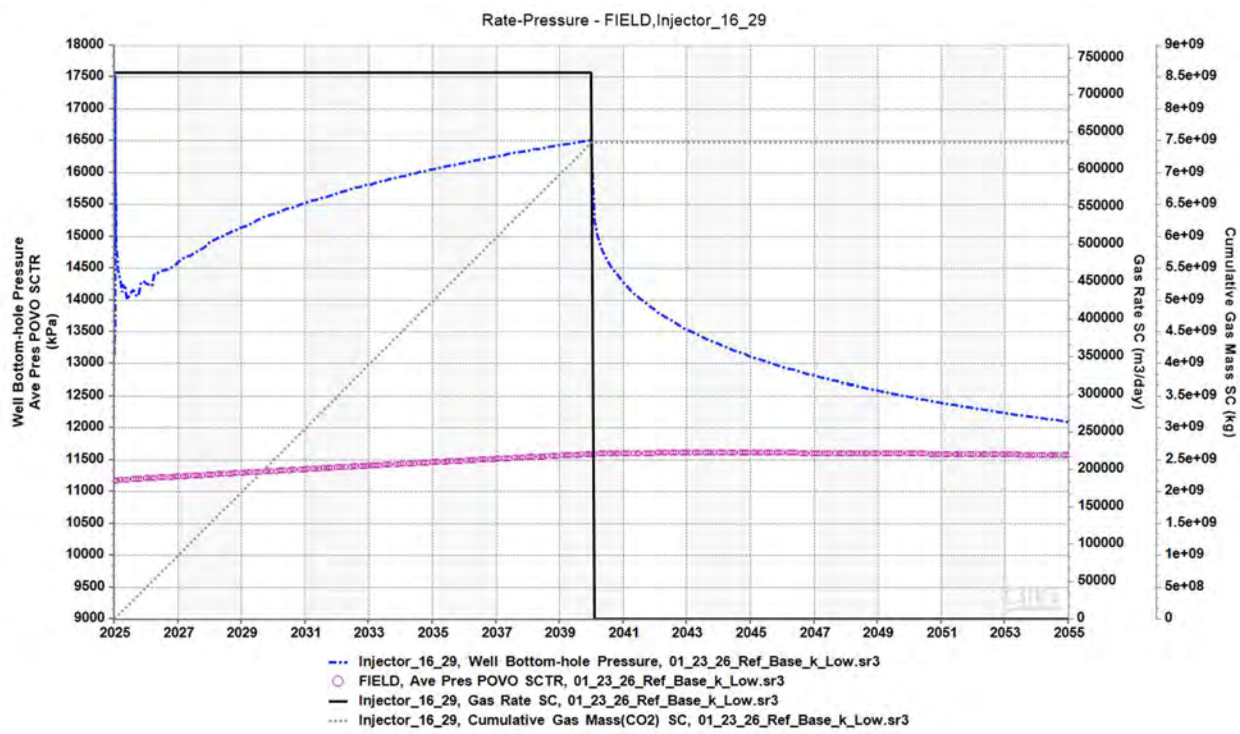


Figure R-17: Injection rate and cumulative stored mass, with bottomhole injection and average reservoir pressure for 15 years of injection @ 0.5 Mtpa followed by 15 years of shut-in. Case of low permeability (Ref_Base_k_Low)

In addition to the above, the effect of increasing injection rate and duration to 1 Mtpa and 25 years is studied. The injection pressure increases to 16 MPa, and the average reservoir pressure increase by 1 MPa. Once again, the maximum injection pressure remains below the maximum limit of 18.2 MPa and the injection rate (of 1 Mtpa) is maintained. The increase in average reservoir pressure was 2.5 times of the base case; it did not increase proportional to the total injection amount (25:7.5), suggesting an increased contribution of the aquifer.

Discussion

Simulation studies presented here were conducted at isothermal conditions. It is expected that in practice, CO2 would arrive at the sandface at temperatures lower than the reservoir pressure. Because the density of the CO2 is higher at colder temperatures, it is expected that the volumetric rate of the CO2 injection into the reservoir would be less than those modelled here, suggesting that if injection of cold CO2 were modelled, the injection pressure and potentially plumes size would tend to be lower.

The effect of (low) temperature of CO2 on stresses are accounted for in the geomechanical part of this application.

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APPENDIX L: RESERVOIR FLUID ANALYSIS

Fluid Information as of 2024-09-06 UWI 00/02-05-058-25W4/00

Header

UWI:	00/02-05-058-25W4/00	Ground Elevation:	682.0 m
Well Name:	ANDEX ET AL LEGAL 2-5-58-25	Total Depth:	1560.5 m
Field:	LEGAL	BH Latitude:	53.979393
Status:	Gas, Abandoned	BH Longitude:	-113.679462
KB Elevation:	686.0 m	Producing Formation:	ELRL

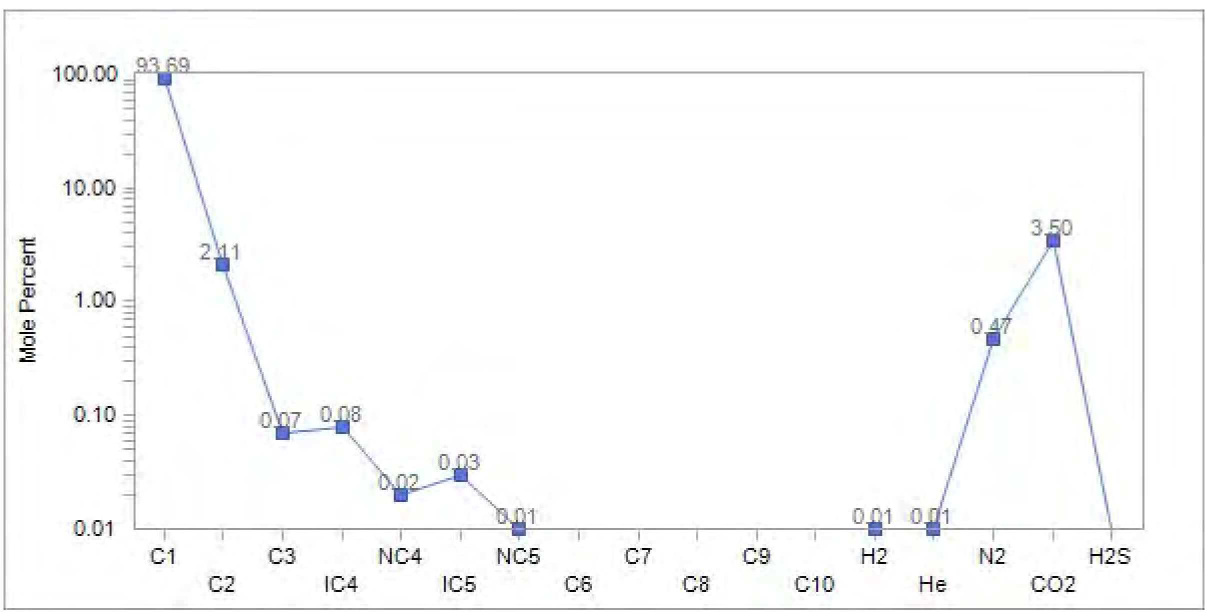
Gas Analysis Mole Fraction

	As Received		Acid Gas Free
C1:	0.9369	C1:	0.9709
C2:	0.0211	C2:	0.0219
C3:	0.0007	C3:	0.0007
IC4:	0.0008	IC4:	0.0008
NC4:	0.0002	NC4:	0.0002
IC5:	0.0003	IC5:	0.0003
NC5:	0.0001	NC5:	0.0001
C6:	-	C6:	-
C7:	-	C7:	-
C8:	-	C8:	-
C9:	-	C9:	-
C10:	-	C10:	-
H2:	0.0001	H2:	0.0001
He:	0.0001	He:	0.0001
N2:	0.0047	N2:	0.0049
CO2:	0.0350		
H2S:	-		
Total:	1.0000	Total:	0.9650

Gas Analysis Remarks

A LYNES UNITED SERVICES LTD. DOWNHOLE SAMPLER WAS RECEIVED AT5515 KPA. IT CONTAI
NED GAS ONLY.

Gas Analysis Log Chart



Fluid Information as of 2024-09-06 UWI 00/02-05-058-25W4/00

Header

UWI:	00/02-05-058-25W4/00	Ground Elevation:	682.0 m
Well Name:	ANDEX ET AL LEGAL 2-5-58-25	Total Depth:	1560.5 m
Field:	LEGAL	BH Latitude:	53.979393
Status:	Gas, Abandoned	BH Longitude:	-113.679462
KB Elevation:	686.0 m	Producing Formation:	ELRL

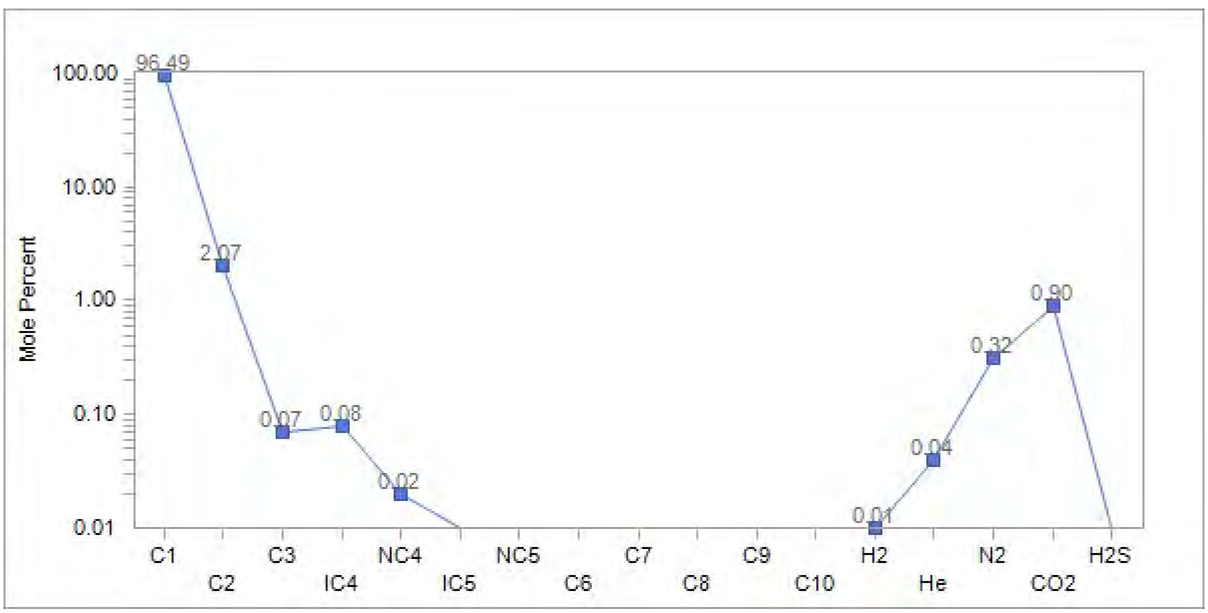
Gas Analysis Mole Fraction

	As Received		Acid Gas Free
C1:	0.9649	C1:	0.9737
C2:	0.0207	C2:	0.0209
C3:	0.0007	C3:	0.0007
IC4:	0.0008	IC4:	0.0008
NC4:	0.0002	NC4:	0.0002
IC5:	-	IC5:	-
NC5:	-	NC5:	-
C6:	-	C6:	-
C7:	-	C7:	-
C8:	-	C8:	-
C9:	-	C9:	-
C10:	-	C10:	-
H2:	0.0001	H2:	0.0001
He:	0.0004	He:	0.0004
N2:	0.0032	N2:	0.0032
CO2:	0.0090		
H2S:	-		
Total:	1.0000	Total:	0.9910

Gas Analysis Remarks

SAMPLING POINT TRUNCATE.

Gas Analysis Log Chart



Fluid Information as of 2024-09-06 UWI 00/02-05-058-25W4/00 Obs.No.1

Header

UWI:	00/02-05-058-25W4/00	Ground Elevation:	682.0 m
Well Name:	ANDEX ET AL LEGAL 2-5-58-25	Total Depth:	1560.5 m
Field:	LEGAL	BH Latitude:	53.979393
Status:	Gas, Abandoned	BH Longitude:	-113.679462
KB Elevation:	686.0 m	Producing Formation:	ELRL

Oil Analysis Header

Obs. No.:	1	Top Depth:	52.0 m
Test Type:	-	Top Formation:	LEA PARK
Test Number:	-	Bottom Depth:	1054.0 m
Sampled Date:	-	Bottom Formation:	ELLERSLIE
Received Date:	1985-10-11	Primary Formation:	LEA PARK
Analyzed Date:	1985-10-17	Sample Location:	OTHER
		Laboratory:	-

Oil Analysis Details

	Sample Properties
Color:	BLACK-BROWN
Water Fraction:	0.011
Sediment Fraction:	0.001
Total:	0.012

	Received		Clean
Relative Density:	-	Relative Density:	0.864
Absolute Density:	-	Absolute Density:	863.0 kg/m³

API Gravity:	32.29	Total Sulphur:	10.400 g/kg
API Gravity Temp.:	15.00 °C	Salt:	-

	Pour Point
USBM:	-
ASTM:	-

	Distillation
Pressure:	-
Room Temperature:	-
Naptha:	-
GOR:	0.220
Kerosene:	0.370
Recovered:	-
Distillate Loss:	-
Residue:	-
Characterization:	11.7

Oil Analysis Volume Fraction Distilled

Fraction	Temperature (°C)
-	110.00
0.05	124.00
0.10	140.00
0.15	154.00
0.20	169.00
0.25	181.00
0.30	192.00
0.35	197.00
0.40	209.00
0.45	221.00
0.50	239.00
0.55	258.00
0.60	277.00
0.65	293.00
-	-
-	-
-	-
-	-
-	-

Fluid Information as of 2024-09-06 UWI 00/02-05-058-25W4/00 Obs.No.1

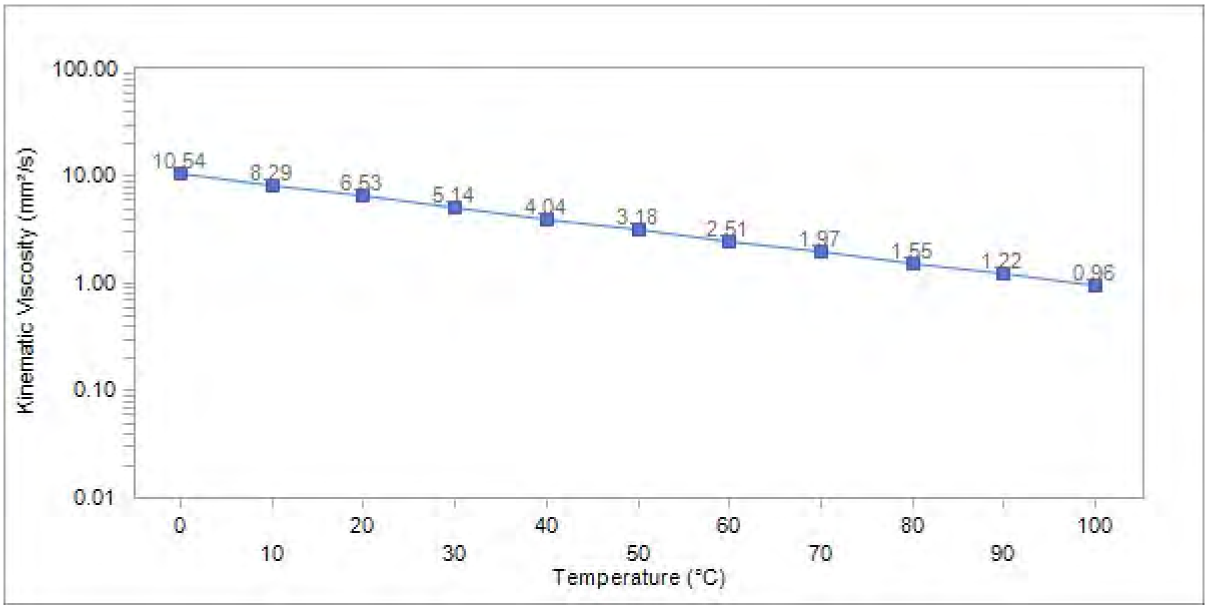
-	-
-	-
-	-
-	-
-	303.00

Oil Analysis Viscosity

Temperature (°C)	Absolute (mPa·s)	Kinematic (mm²/s)
10.00	7.25	8.36
20.00	5.55	6.45
40.00	3.44	4.06

Oil Analysis Remarks - No Data

Oil Analysis Log Chart



Fluid Information as of 2024-09-06 UWI 00/02-05-058-25W4/00 Obs.No.1

Header

UWI:	00/02-05-058-25W4/00	Ground Elevation:	682.0 m
Well Name:	ANDEX ET AL LEGAL 2-5-58-25	Total Depth:	1560.5 m
Field:	LEGAL	BH Latitude:	53.979393
Status:	Gas, Abandoned	BH Longitude:	-113.679462
KB Elevation:	686.0 m	Producing Formation:	ELRL

Water Analysis Header

Obs. No.:	1	Top Depth:	1048.5 m
Test Type:	DRILL STEM TEST	Top Formation:	ELLERSLIE
Test Number:	3	Bottom Depth:	1056.0 m
Sampled Date:	1985-07-15	Bottom Formation:	ELLERSLIE
Received Date:	1985-07-16	Primary Formation:	MANNVILLE
Analyzed Date:	1985-07-19	Sample Location:	OTHER
		Laboratory:	-

Water Analysis Details

Water Type:	-	Salinity:	-
TDS@110C:	20270.00 mg/L	TDS@180C:	-
TDS@Ignition:	19120.00 mg/L	TDS Calculated:	20628.00 mg/L
Relative Density:	1.01	Density Temp.:	25.00 °C
Observed pH:	7.70	pH Temp.:	25.00 °C
Refractive Index:	1.34	RI Temp.:	25.00 °C
Resistivity:	0.33 ohm·m	Resistivity Temp.:	25.00 °C

Water Analysis Composition

Cation	Concentration (mg/L)	Normality (meq/L)
Na	6690.00	291.00
K	137.00	3.50
Ca	448.00	22.36
Mg	209.00	17.20
Ba	-	-
Sr	-	-
Fe	-	-
Mn	-	-
B	-	-

Anion	Concentration (mg/L)	Normality (meq/L)
Cl	11040.00	311.40
Br	-	-
I	-	-
HCO3	1779.00	29.16
SO4	325.00	6.77
CO3	0.00	0.00
OH	0.00	0.00
H2S	-	-

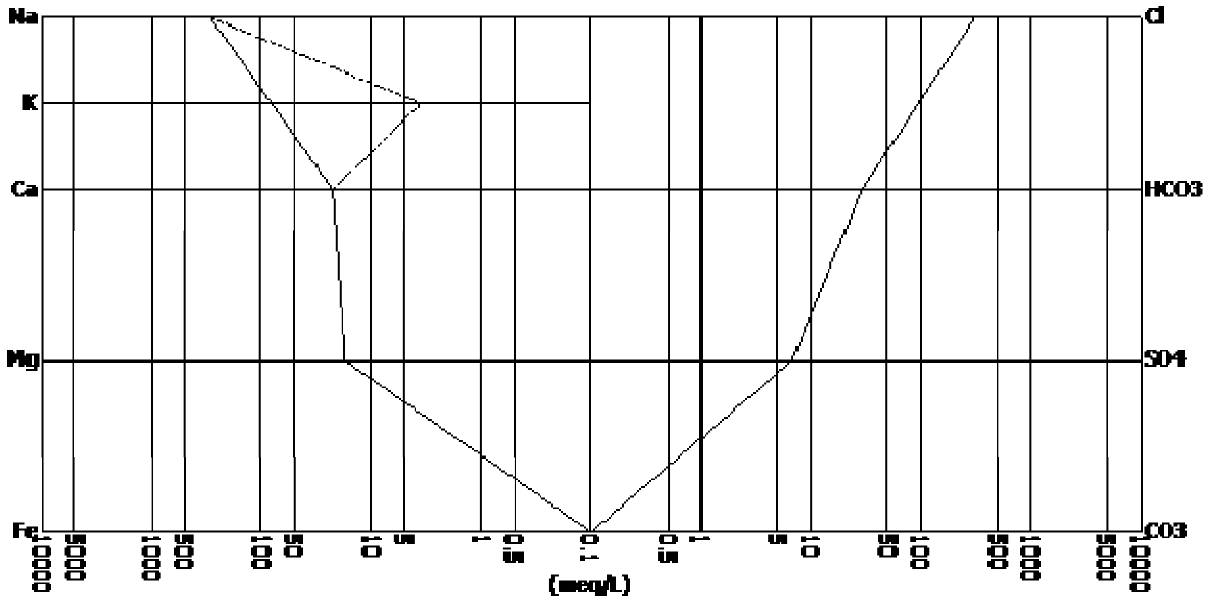
Water Analysis Remarks

THE SAMPLE CONSISTED OF VERY SLIGHTLY OIL STAINED MUDDY WATER.

27 M G/SALT WATER

Fluid Information as of 2024-09-06 UWI 00/02-05-058-25W4/00 Obs.No.1

Water Analysis Stiff Chart



Fluid Information as of 2024-09-06 UWI 00/02-05-058-25W4/00 Obs.No.3

Header

UWI:	00/02-05-058-25W4/00	Ground Elevation:	682.0 m
Well Name:	ANDEX ET AL LEGAL 2-5-58-25	Total Depth:	1560.5 m
Field:	LEGAL	BH Latitude:	53.979393
Status:	Gas, Abandoned	BH Longitude:	-113.679462
KB Elevation:	686.0 m	Producing Formation:	ELRL

Water Analysis Header

Obs. No.:	3	Top Depth:	1495.0 m
Test Type:	DRILL STEM TEST	Top Formation:	COOKING LAKE
Test Number:	1	Bottom Depth:	1507.0 m
Sampled Date:	1985-07-14	Bottom Formation:	COOKING LAKE
Received Date:	1985-07-15	Primary Formation:	COOKING LAKE
Analyzed Date:	1985-07-25	Sample Location:	DOWNHOLE SAMPLE
		Laboratory:	-

Water Analysis Details

Water Type:	POSSIBLE FORMATION WATER, ACCEPTABLE TDS	Salinity:	-
TDS@110C:	153100.00 mg/L	TDS@180C:	-
TDS@Ignition:	115800.00 mg/L	TDS Calculated:	116571.00 mg/L
Relative Density:	1.07	Density Temp.:	25.00 °C
Observed pH:	7.10	pH Temp.:	26.00 °C
Refractive Index:	1.35	RI Temp.:	25.00 °C
Resistivity:	0.07 ohm·m	Resistivity Temp.:	25.00 °C

Water Analysis Composition

Cation	Concentration (mg/L)	Normality (meq/L)
Na	32700.00	1422.37
K	1777.00	45.45
Ca	6967.00	347.67
Mg	1968.00	161.95
Ba	-	-
Sr	-	-
Fe	-	-
Mn	-	-
B	-	-

Anion	Concentration (mg/L)	Normality (meq/L)
Cl	71050.00	2004.06
Br	-	-
I	-	-
HCO3	800.00	13.11
SO4	1309.00	27.25
CO3	-	-
OH	-	-
H2S	-	-

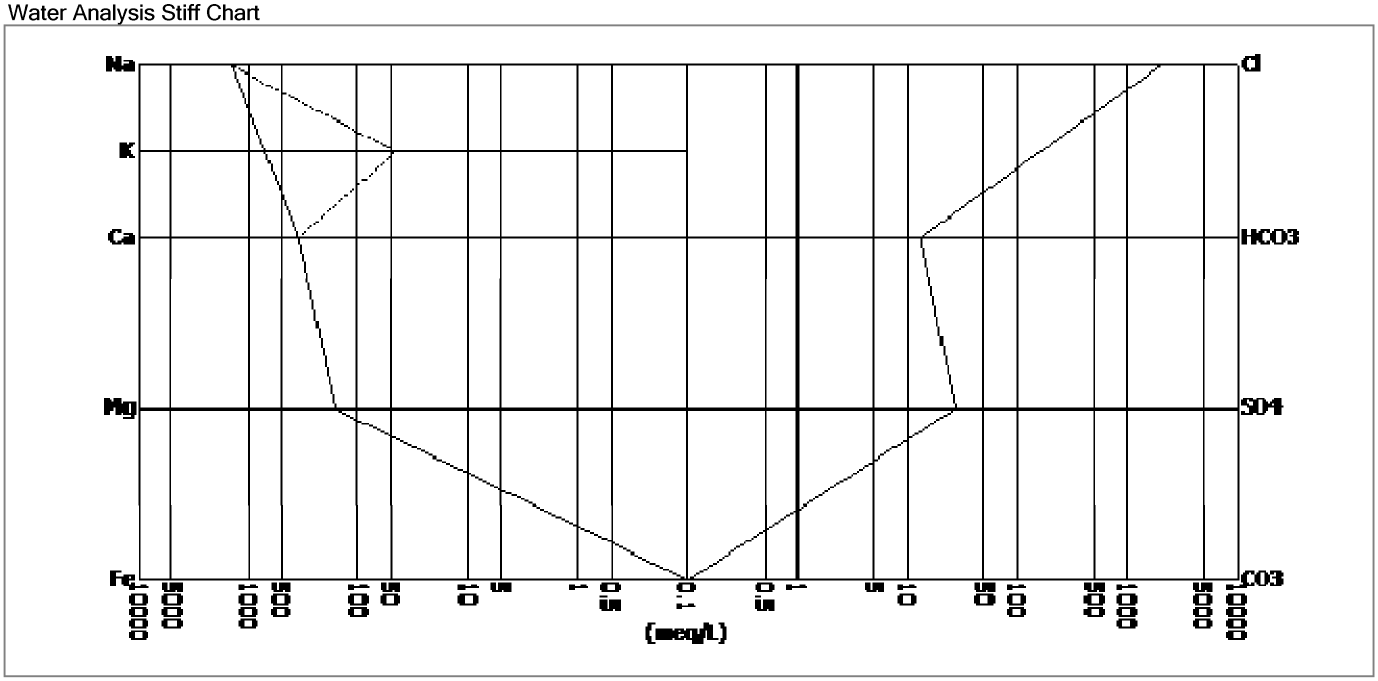
Water Analysis Remarks

A LYNES UNITED DHS REC'D AT. ATM. PRESSURE AND CONTAINED 2.4 L OFMUDDY SALT WATE
R.

200.0M GAS- AND WATER-CUT MUD:906.0M SALT WATER

Fluid Information as of 2024-09-06 UWI 00/02-05-058-25W4/00 Obs.No.3

Water Analysis Stiff Chart



Fluid Information as of 2024-09-06 UWI 00/02-05-058-25W4/00 Obs.No.4

Header

UWI:	00/02-05-058-25W4/00	Ground Elevation:	682.0 m
Well Name:	ANDEX ET AL LEGAL 2-5-58-25	Total Depth:	1560.5 m
Field:	LEGAL	BH Latitude:	53.979393
Status:	Gas, Abandoned	BH Longitude:	-113.679462
KB Elevation:	686.0 m	Producing Formation:	ELRL

Water Analysis Header

Obs. No.:	4	Top Depth:	1402.5 m
Test Type:	DRILL STEM TEST	Top Formation:	LEDUC
Test Number:	2	Bottom Depth:	1415.5 m
Sampled Date:	1985-07-14	Bottom Formation:	LEDUC
Received Date:	1985-07-16	Primary Formation:	LEDUC
Analyzed Date:	1985-07-19	Sample Location:	DOWNHOLE SAMPLE
		Laboratory:	-

Water Analysis Details

Water Type:	POSSIBLE FORMATION WATER, ACCEPTABLE TDS	Salinity:	-
TDS@110C:	139100.00 mg/L	TDS@180C:	-
TDS@Ignition:	121400.00 mg/L	TDS Calculated:	122237.00 mg/L
Relative Density:	1.08	Density Temp.:	25.00 °C
Observed pH:	6.40	pH Temp.:	27.00 °C
Refractive Index:	1.35	RI Temp.:	25.00 °C
Resistivity:	0.07 ohm·m	Resistivity Temp.:	25.00 °C

Water Analysis Composition

Cation	Concentration (mg/L)	Normality (meq/L)
Na	35530.00	1545.47
K	1875.00	47.96
Ca	7231.00	360.85
Mg	1886.00	155.20
Ba	-	-
Sr	-	-
Fe	-	-
Mn	-	-
B	-	-

Anion	Concentration (mg/L)	Normality (meq/L)
Cl	73600.00	2075.99
Br	-	-
I	-	-
HCO3	852.00	13.96
SO4	1263.00	26.30
CO3	-	-
OH	-	-
H2S	-	-

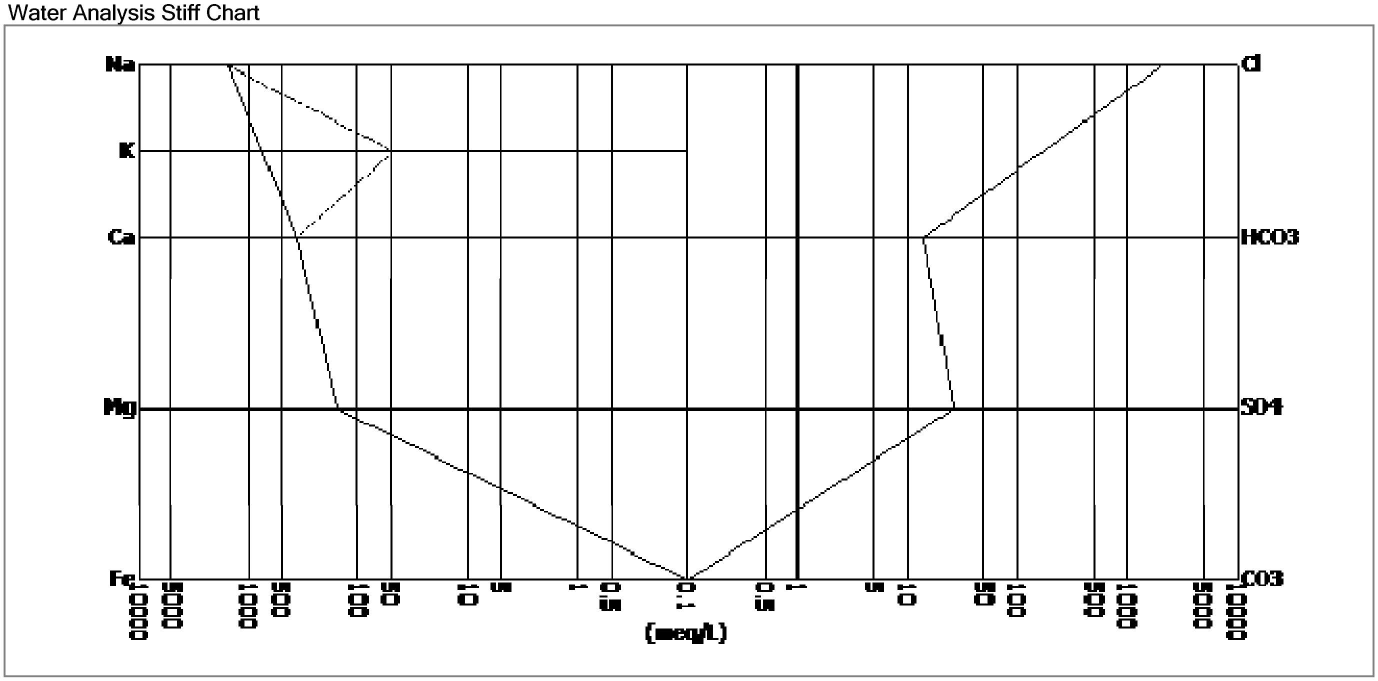
Water Analysis Remarks

LYNES DHS REC'D @ATM PRESSURE; 2L OF SALT WATER.

20.0M MUD:991.0M SALT WATER

Fluid Information as of 2024-09-06 UWI 00/02-05-058-25W4/00 Obs.No.4

Water Analysis Stiff Chart



Fluid Information as of 2024-09-06 UWI 00/02-05-058-25W4/00 Obs.No.5

Header

UWI:	00/02-05-058-25W4/00	Ground Elevation:	682.0 m
Well Name:	ANDEX ET AL LEGAL 2-5-58-25	Total Depth:	1560.5 m
Field:	LEGAL	BH Latitude:	53.979393
Status:	Gas, Abandoned	BH Longitude:	-113.679462
KB Elevation:	686.0 m	Producing Formation:	ELRL

Water Analysis Header

Obs. No.:	5	Top Depth:	-
Test Type:	-	Top Formation:	TD UNDEFINED
Test Number:	-	Bottom Depth:	-
Sampled Date:	-	Bottom Formation:	TD UNDEFINED
Received Date:	-	Primary Formation:	TD UNDEFINED
Analyzed Date:	-	Sample Location:	OTHER
		Laboratory:	-

Water Analysis Details

Water Type:	INCOMPLETE	Salinity:	-
TDS@110C:	-	TDS@180C:	-
TDS@Ignition:	-	TDS Calculated:	-
Relative Density:	-	Density Temp.:	-
Observed pH:	-	pH Temp.:	-
Refractive Index:	-	RI Temp.:	-
Resistivity:	-	Resistivity Temp.:	-

Water Analysis Composition

Cation	Concentration (mg/L)	Normality (meq/L)
Na	-	-
K	-	-
Ca	-	-
Mg	-	-
Ba	-	-
Sr	-	-
Fe	-	-
Mn	-	-
B	-	-

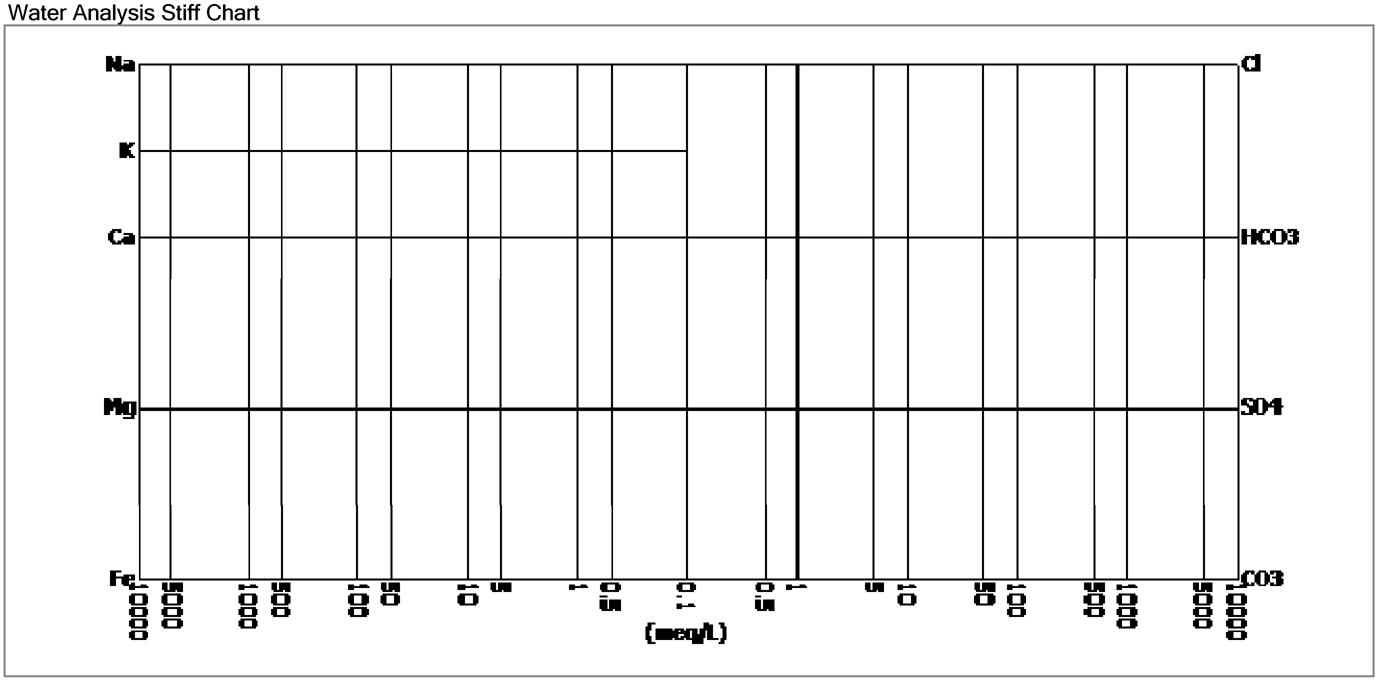
Anion	Concentration (mg/L)	Normality (meq/L)
Cl	-	-
Br	-	-
I	-	-
HCO3	-	-
SO4	-	-
CO3	-	-
OH	-	-
H2S	-	-

Water Analysis Remarks

SUMMARY OR METHODOLOGY PAGE

Fluid Information as of 2024-09-06 UWI 00/02-05-058-25W4/00 Obs.No.5

Water Analysis Stiff Chart



APPENDIX M: ALBERTA ENERGY – RIGHTS TO DISPOSE CO_2

CARBON SEQUESTRATION AGREEMENT

NO. 5924070002

Effective Date: July 30, 2024

Agreement Holder:

Bison Low Carbon Ventures Inc	**100.00%**

CARBON SEQUESTRATION AGREEMENT NO. 5924070002

THIS AGREEMENT made effective as of the 30th day of July, 2024 (the "**Effective Date**")

BETWEEN:

HIS MAJESTY IN RIGHT OF ALBERTA, as represented by the Minister of Energy and Minerals ("**Alberta**")

- and -

BISON LOW CARBON VENTURES INC. ("**Agreement Holder**")

Hereinafter, each a '**Party**' and collectively the "**Parties**"

WHEREAS:

A. Alberta posted two rounds of Requests For Full Project Proposals For Carbon Sequestration Hubs dated December 2, 2021 & March 3, 2022 (each, an "**RFPP**" and collectively, the "**RFPPs**") for the purpose of engaging with companies to develop and operate a carbon sequestration hub in Alberta.

B. The Agreement Holder and Alberta entered into a carbon sequestration evaluation agreement on October 1, 2022 ("**Evaluation Agreement**") to evaluate, define and establish the suitability and capacity of the identified area of interest for a future carbon sequestration hub.

C. Alberta has accepted the Agreement Holder's application under an Evaluation Agreement to enter into a sequestration agreement. Alberta and the Agreement Holder agree that the Agreement Holder shall commence the process to develop, and operate a carbon sequestration hub that will enable sequestration of commercial volumes of captured carbon dioxide in accordance with the plan set out as part of the Agreement Holder's application (the "**Hub Development Plan**") and attached hereto as Schedule "B".

D. The Agreement Holder and Alberta have agreed that this carbon sequestration hub will enable and govern open access to the hub, and payment of just and reasonable charges for the hub by Clients seeking to sequester captured carbon dioxide within the subsurface pore space in accordance with the design described in the Agreement Holder's Hub Development Plan.

E. The Agreement Holder and Alberta further acknowledge and agree that 'open access' is a fundamental requirement of the carbon sequestration hub and as such, it is imperative that the Agreement Holder's project be designed and constructed to optimize utilization of the subsurface pore space, to support any infrastructure interconnection that may be necessary to permit the Alberta emissions market access to the Agreement Holder's sequestration facilities, and to ensure that there is a mechanism for the fair and timely resolution of disputes between the Agreement Holder, its Clients, and its prospective Clients.

F. This agreement is entered into under the authority of section 9 and section 116 of the *Mines and Minerals Act*.

NOW THEREFORE in consideration of the following, the Parties agree as follows:

ARTICLE 1 DEFINITIONS

1. Except as defined in this Article, in this agreement, all Capitalized Terms shall have the meanings ascribed to them under the *Mines and Minerals Act*, RSA 2000, c. M-17, the *Pipeline Act*, RSA 2000, c P-15, the *Oil and Gas Conservation Act*, RSA 2000, c O-6, *Interpretation Act*, RSA 2003 and the *Responsible Energy Development Act*, SA 2012, c R-17.3, as each may be amended, substituted or replaced from time to time, including regulations and rules thereunder, unless otherwise defined herein:

   (a) "**Additional Term**" or "**Additional Terms**" is defined in Article 4;

   (b) "**Business Day**" means 8:15 am to 4:30 pm in the Province of Alberta from Monday through Friday excluding holidays observed by Alberta;

   (c) "**Client**" means any legal entity other than the Agreement Holder who wishes to sequester captured carbon dioxide within the Location and who seeks to enter into a commercial arrangement with the Agreement Holder for that purpose;

   (d) "**CSTR**" means the *Carbon Sequestration Tenure Regulation* (A.R. 68/2011), as amended, substituted or replaced from time to time;

   (e) "**Enactments**" means any relevant legislation, including any acts, regulations, rules, directives, guidelines and by-laws as amended, substituted or replaced from time to time;

   (f) "**Hub Development Plan**" means the development plan submitted by the Agreement Holder in its application to obtain this Sequestration Agreement, dated February 19, 2024, as may be amended, substituted or replaced from time to time;

   (g) "**Initial Term**" is defined in Article 4;

   (h) "**Location**" means, pursuant to Article 6, the subsurface area or areas underlying the surface area of the lands described in Schedule A, and as amended, substituted or replaced from time to time;

   (i) "**Minister**" means the Minister of Energy and Minerals of the Province of Alberta, or his successor;

   (j) "**MMA**" means the *Mines and Minerals Act*, RSA 2000, c. M-17, as amended, substituted or replaced from time to time;

   (k) "**MMAR**" means the *Mines and Minerals Administration Regulation* (A.R. 262/1997), as amended, substituted or replaced from time to time;

   (l) "**Regulator**" means the Alberta Energy Regulator or AER;

ARTICLE 2: INTERPRETATION

1. The headings of the Articles of this agreement are for convenience of reference only and do not affect the meaning or construction of this agreement.

2. In this agreement, a reference to the MMA or to any other Act of the Legislature of Alberta shall be construed as a reference to:

   (a) that Act, as amended from time to time;

   (b) any replacement of all or part of the Act from time to time enacted by the Legislature, as amended from time to time; and,

   (c) any regulations, orders, directives, by-laws or other subordinate legislation from time to time made under any enactment referred to in clause (a) or (b), as amended, substituted or replaced from time to time.

3. Terms defined in the MMA, whether or not capitalized, have the same meaning in this agreement, unless otherwise required by the context in which they have been used, or unless otherwise defined in this agreement.

4. For clarity, this agreement is an agreement as defined in section 1(1)(a) and under Part 9 of the MMA.

5. Whenever the singular, masculine or neuter is used in this agreement, the same will be construed as meaning plural or body politic or corporate and vice versa where the context so requires.

6. Unless otherwise specified, all references to money in this agreement are in Canadian dollars.

7. The following Schedules are attached to and form part of this agreement:

   Schedule A Location
   Schedule B Hub Development Plan

8. In the case of conflicts or inconsistencies between this agreement and the Schedules, the documents shall take precedence and govern in the following order:

   The body of this agreement
   Schedule A
   Schedule B

9. This agreement is not intended to and does not: (a) contemplate either Party acting as the agent of the other for any purpose, or create any relationship of agency; (b) constitute or create any joint venture; (c) constitute or create any partnership; or (d) constitute the relationship of landlord and tenant; and neither Party shall allege or assert for any purpose that this agreement constitutes or creates a relationship of agency, joint venture, partnership, or landlord and tenant.

ARTICLE 3: APPLICATION OF AND COMPLIANCE WITH LEGISLATION

1. This agreement is made and entered into pursuant to section 9 and section 116 of the MMA.

2. The Agreement Holder acknowledges that it is obligated to comply with all relevant Enactments and any applicable Orders, Directives and Rules of the Regulator.

3. The Agreement Holder agrees to obtain and maintain all necessary licences, permits, approvals, or other consents required pursuant to the legislation applicable to activities contemplated pursuant to the rights granted under this agreement, prior to commencing and during such activities, and regarding surface access to the Location, as such legislation may be amended from time to time. The Parties agree and acknowledge that obtaining all such licences, permits, approvals, or other consents constitutes a condition precedent to the exercise of rights granted to the Agreement Holder under this agreement and that any failure to maintain these represents a fundamental breach of this agreement.

4. The Agreement Holder further acknowledges and agrees that it shall be obligated, at its sole expense, to undertake any and all closure, abandonment and post-injection activities as may be required by any applicable Enactments, or as may be stipulated to be conditions or requirements of any approvals, authorizations, licenses or permits issued by the Regulator.

ARTICLE 4: INITIAL TERM AND ADDITIONAL TERMS

1. The term of this agreement is fifteen (15) years from the Effective Date of this agreement ("**Initial Term**").

2. The Initial Term of this agreement may be renewed for additional fifteen (15) year periods (such further periods being each an "**Additional Term**" and collectively, the "**Additional Terms**") subject to the submission of the following within three (3) years prior to the expiry of the Initial Term or any subsequent Additional Term:

   (a) an application for extension in accordance with Section 11 of the CSTR and any applicable Enactments, or which is in a form that is otherwise satisfactory to the Minister;

   (b) evidence satisfactory to the Minister that the Agreement Holder holds all approvals, permits, and licences required to be issued by the Regulator to authorize the Agreement Holder's ongoing activities in the Location; and,

   (c) any other additional information as required by the Minister.

3. Upon provision by the Agreement Holder of the information and evidence set out in Article 4(2) above, and upon demonstration to the satisfaction of the Minister that the Agreement Holder and this Agreement remain in good standing, that the Agreement Holder is in compliance with its obligations under this Agreement and its Hub Development Plan, and that sequestration activities have commenced and are ongoing within the Location, the Minister's consent to the application for Additional Terms shall not be unreasonably

withheld. The Minister shall utilize best efforts to render its decision on consent to the Agreement Holder's application for Additional Terms within six (6) months of receipt of the information set out in Article 4(2).

4. Notwithstanding the fact that lands may be added or removed at different times pursuant to Article 6 below, this agreement shall have a single anniversary date (whether Initial Term or Additional Term) and such anniversary shall apply to all areas in the Location (as defined in Article 6 below) which may form part of this agreement from time to time.

ARTICLE 5: GRANT

1. Subject to the terms and conditions of this agreement, and any restrictions identified in Schedule A, Alberta grants the Agreement Holder the right to drill wells, conduct evaluation and testing and inject captured carbon dioxide into deep subsurface reservoirs within the Location for the purposes of sequestration.

2. This agreement does not grant the right to win, work or recover any minerals or geothermal resources found within the Location, and the Agreement Holder shall take reasonable steps to conserve minerals and geothermal resource found within the location by ensuring recovery of the minerals and geothermal resource is impaired only to the extent necessary to conduct approved sequestration activities.

ARTICLE 6: LOCATION

1. The Agreement Holder may apply to the Minister to modify the area of the Location if the Minister receives from the Agreement Holder:

   (a) an application in the form that is satisfactory to the Minister;

   (b) in the case of an increase in area, evidence satisfactory to the Minister that any additional area requested in the application is suitable and required for use for the sequestration of captured carbon dioxide; and,

   (c) any other additional information as required by the Minister.

2. The Minister may, upon giving notice in writing, modify, increase or decrease the areas or size of the Location. The Minister's discretion to modify, increase or decrease the size of the Location under this agreement, in accordance with this Article 6(2) shall not be exercised capriciously or arbitrarily, and may be exercised where the Minister is of the opinion that such modification is in the public interest, having regard to certain factors including, but not limited to:

   (a) the pore space is no longer required due to changes in the anticipated amount of CO2 to be sequestered;

   (b) operational data presents evidence that (i) areas of pore space in the Location will not be utilized; (ii) the Location should be adjusted to reflect updated modelling of the CO2 plume; or (iii) the capacity of the pore space within the Location is lower than projected, requiring additional tenure to accommodate sequestration volumes

(c) a carbon sequestration hub is being developed in phases and the Agreement holder is transitioning lands that are under an Evaluation Agreement;

(d) the Agreement Holder has obtained prior written consent of the Minister to modify its Hub Development Plan, requiring changes to the Location; or,

(e) the Agreement Holder fails to comply with any Enactments.

3. If the Location is amended under this Article, the amended Schedule A will supersede and replace the original Schedule A, or any previously amended Schedule A.

ARTICLE 7: ISSUANCE FEE AND RENTAL

1. Alberta acknowledges that the non-refundable issuance fee of $625.00, and non-refundable rental calculated for the first year of this agreement has been paid by the Agreement Holder to the Government of Alberta. For clarity, this fee and rental is separate from any issuance fee and/or rental paid pursuant to an evaluation agreement under which an application for this agreement was made.

2. Rental for the Initial Term and any Additional Term is due and payable at the rate prescribed in section 20(3.1) of the MMAR.

3. Rental for the Initial Term and any Additional Term of this agreement is calculated and due and payable pursuant to section 20(4) of the MMAR.

4. There shall be no refund of any annual rental or issuance fee paid or abatement of annual rent or issuance fee payable if the area of the Location is decreased and removed from this agreement before the next annual rental is due, or if this agreement is terminated less than one year after an anniversary date.

5. If the area of the Location is increased before the next annual rental is due, the incremental amount of rental is due and payable as of the effective date of the amendment to the Location, and the next annual rental shall be the rental calculated for the amended Location.

ARTICLE 8: OBLIGATIONS

1. The Agreement Holder shall, in accordance with any relevant Enactments:

(a) pay all fees as may be prescribed by or under any relevant Enactments. Without limiting the generality of the foregoing, this includes payments into the Post-closure Stewardship Fund for all carbon dioxide injected into any part of the Location under this agreement;

(b) be responsible for the development of all carbon sequestration activities within the Location;

(c) establish rates to Clients which are fair and provide for reasonable cost recovery to the Agreement Holder for the relevant infrastructure services and activities. The Agreement Holder shall further provide information to enable Clients and Alberta to understand how rates are set;

(d) ensure that the project, as described in the Hub Development Plan, is designed and constructed to optimize utilization of the subsurface pore space to support any infrastructure interconnection that may be necessary to permit the Alberta emissions market access to the Agreement Holder's sequestration facilities; and,

(e) ensure completion of all closure, abandonment and post-injection activities which may be required by relevant Enactments, or which may be conditions or requirements of any approvals, authorizations, licenses or permits issued by the Regulator or any other regulatory body.

Where disputes arise between the Agreement Holder and any Client or prospective Client in respect of the Agreement Holder's obligations under this Article, such disputes shall be resolved pursuant to Article 16 below.

ARTICLE 9: REPORTING AND EXAMINATION OF RECORDS

1. The Agreement Holder must submit to the Regulator, and any other applicable regulatory body, any and all reporting as required by relevant Enactments, or as otherwise may be requested or required by the Regulator or any other regulatory body.

2. The Minister may, in the Minister's sole discretion, request any information from time to time, including but not limited to any specific data, measurement, monitoring, reporting, project status, cost or operational information, which shall be furnished to the Minister within the time period determined by the Minister.

3. The Regulator may, at its discretion, direct or require the Agreement Holder to provide any specific measuring, monitoring, or reporting information, which shall be furnished to the Regulator within the time period determined by the Regulator.

4. The Agreement Holder will keep and maintain at its place of business in the Province of Alberta all records, information, and reports required under this agreement or any Enactment.

5. Upon at least ten (10) days notice to the Agreement Holder the Minister's delegate or delegates have the right to enter into the Agreement Holder's place of business for the purpose of auditing or examining any information, reporting or records which the Agreement Holder may be obliged to create, provide or maintain, whether such obligation arises pursuant to this agreement or any applicable Enactments.

6. The Agreement Holder shall ensure that, for the purposes of an audit or examination under Article 9(5):

   (a) access is provided for the Minister's delegate or delegates to the places where the information, reporting or records are kept in order that the audit or examination may be conducted;

   (b) all reasonable assistance is provided to the Minister's delegate or delegates in the conduct of the audit or examination;

   (c) all information, reporting or records required by the Minister or his delegate or delegates, including those that are in the possession of agents or employees of the Agreement Holder or that are located in a place that is not the Agreement Holder's place of business, are provided or made available by the Agreement Holder; and,

   (d) a copy of any information, report or records requested by the Minister or his delegate or delegates is provided to them.

ARTICLE 10: TERMINATION

1. Subject to Article 10(2), the Minister may terminate this agreement with written notice of ninety (90) days if:

   (a) the Agreement Holder fails to comply with any applicable Enactments;

   (b) the Agreement Holder fails to submit any report or plan, or to remedy any deficiency in a previously-submitted report or plan, as required or requested by the Minister pursuant to Article 9, or by the Regulator in accordance with any relevant Enactments or this agreement;

   (c) the Agreement Holder fails to pay any fees or rentals due and payable to Alberta during the Initial Term and any Additional Terms pursuant to Article 7;

   (d) the Minister does not consent to a material change in ownership of the Agreement Holder pursuant to Article 12;

   (e) the Agreement Holder fails to adhere to the Hub Development Plan without the prior written consent of the Minister; or,

   (f) the Agreement Holder fails to comply with any final determination or Order resulting from the Dispute Resolution Process set out in Article 16, subject to any right of appeal or review which may arise therefrom.

2. The Minister will withdraw a notice of termination under Article 10(2) if the Agreement Holder submits the required or requested information, reporting, plan, or payment to the satisfaction of the Minister, or otherwise cures the breach of default, within the notice of termination period.

3. Notwithstanding Termination of this agreement in accordance with this Article 10, the Agreement Holder shall not be relieved of any obligations which may be conditions relating to any licenses, permits, or authorizations which have been issued by the Regulator or any

other regulatory authority, nor any obligations existing outside of this agreement, including but not limited to any health, safety or environmental obligations and other legal requirements relative to activities under this agreement.

4. In any event where Alberta declines to exercise a remedy available to it under this agreement or any relevant Enactment, such forbearance shall not be deemed to represent any acquiescence to or waiver of any breach by the Agreement Holder.

5. The existence or exercise of any remedy that Alberta has under this agreement does not affect any other remedy Alberta has in law in respect of the subsurface reservoir that is the proprety of Alberta.

ARTICLE 11: ASSIGNMENT

1. This agreement cannot be transferred or assigned in whole or in part to any other party without the express written consent of the Minister, which may be granted at the Minister's discretion.

2. The Minister shall be entitled to request any information about the proposed transferee or assignee as the Minister deems necessary to evaluate that entity as a new project proponent. Where the Minister is of the opinion that:

   (a) permitting the proposed transfer or assignment would not pose any new or increased risk to Alberta or would otherwise be in the public interest, the Minister's consent to the proposed transfer or assignment shall not be unreasonably withheld; or,

   (b) permitting the proposed transfer or assignment would pose any new or increased risk to Alberta or would otherwise not be in the public interest, the Minister may refuse to consent to the proposed transfer or assignment.

ARTICLE 12: CHANGE IN OWNERSHIP OR CONTROL

1. Where the Agreement Holder becomes aware of a material change or potential material change in ownership or control, whether direct or indirect, the Agreement Holder shall give written notice of that change or potential change to the Minister and request formal written consent by the Minister for the purposes of this agreement.

2. Upon receipt of notice from the Agreement Holder in accordance with Article 12(1), the Minister shall have ninety (90) days to request any information the Minister deems necessary to evaluate any proposed change in ownership. Within 90 days of receipt of any response from the proposed owner, the Minister may request any further information the Minister deems necessary to evaluate any proposed change in ownership or, if the Minister has received all required information, may give notice to the Agreement Holder whether the Minister consents to the proposed change in ownership or not.

(a) Where the Minister is satisfied that permitting the proposed change in ownership would not pose any new or increased risk to Alberta or would otherwise be in the public interest, the Minister's consent to the proposed change in ownership shall not be unreasonably withheld; or,

(b) Where the Minister is satisfied that permitting the proposed change in ownership would pose any new or increased risk to Alberta or would otherwise not be in the public interest, the Minister may refuse to consent to the proposed change in ownership.

3. If the Minister does not consent to the proposed change of ownership, and the Agreement Holder elects to proceed with implementation of the change of ownership, this agreement may, at the sole discretion of the Minister, be terminated pursuant to Article 10(2)(e).

4. For the purposes of this Article 12:

(a) the issuance by the Agreement Holder of non-voting preferred shares or any similar transaction entered into for tax-planning purposes that does not involve voting shares in the Agreement Holder;

(b) internal reorganizations, which do not have the effect of changing the ultimate ownership or control of the Agreement Holder;

(c) the initial public offering or the issuance of or trading of publicly traded securities of an entity that directly or indirectly holds an interest in the Agreement Holder; or,

(d) an inquiry by the Agreement Holder to the Minister for the purposes of an advance ruling, in the event that the proposed transaction does not occur;

shall not be considered to be a material change in the ownership or control of the Agreement Holder and shall not be grounds for termination of this agreement.

ARTICLE 13: REPRESENTATIVES

1. The Minister designates the Assistant Deputy Minister, Energy Operations to be Alberta's representative to maintain continuing liaison with the Agreement Holder in matters relating to this agreement.

2. The Agreement Holder designates the President to be the Agreement Holder's representative to maintain a continuing liaison with Alberta in matters relating to this agreement.

3. Either Party may change their representatives and information under this Article 13 in writing by sending an email to the other Party notifying the change.

ARTICLE 14: NOTICES

1. Any notice to be made under this agreement is to be made pursuant to sections 4 and 5 of the MMAR to the following:

Alberta: Alberta Energy and Minerals

Address: 9945 – 108 Street NW, Edmonton, AB T5K 2G6

Attention: Doug Lammie, Assistant Deputy Minister, Alberta Energy and Minerals Operations

Contact: Email: Douglas.Lammie@gov.ab.ca; Ph: (780) 422-6656;

The Agreement Holder: Bison Low Carbon Ventures Inc.

Address: Suite 325, 440 2nd Avenue SW, Calgary AB, T2P 5E9

Attention: Matthew Brister, President

Contact: Email: mbrister@bisonlowcarbon.ca; Ph: (587) 899-6335;

2. The Parties respectively designate for the time being, the individuals identified in this Article 14 as having the authority to give notice, and notice given by these individuals is binding on the Party giving the notice.

3. Either Party may change its information in this Article 14 by giving notice to the other in the manner described in Article 14(1).

ARTICLE 15: CONFIDENTIALITY & FREEDOM OF INFORMATION AND PROTECTION OF PRIVACY

1. Subject to Articles 15(2), 15(3), 15(4), 15(5) and 15(6), unless otherwise expressly agreed upon by the Parties, the Agreement Holder and Alberta agree that all information, including this agreement, any reports and plans provided or collected under this agreement (**"Documents and Information"**), shall be considered confidential and not disclosed by either Party unless those Documents and Information are required to be produced in accordance with other applicable Enactments.

2. Notwithstanding Article 15(1), Alberta may use the Documents and Information for Alberta's internal purposes relevant to this agreement, including disclosure to other Government of Alberta ministries and the Regulator for use by the Regulator and their respective employees and contractors for the internal purposes of the Regulator relevant to this agreement and activities under this agreement.

3. Further notwithstanding Article 15(1), the Agreement Holder agrees that the Minister shall be at liberty to utilize aggregated and de-identified metrics and information contained within the Documents and Information for purposes relating to policy development, public reporting, promotion and advancement of carbon capture, utilization and storage and related activities within the province, provided that such information and metrics:

   (a) would not reveal trade secrets, or commercial, financial, labour relations, scientific or technical information of or specific to the Agreement Holder; and,

   (b) if disclosed, would not reasonably be expected to harm significantly the competitive position or interfere significantly with the negotiating position of the Agreement Holder.

4. The Agreement Holder acknowledges that the *Freedom of Information and Protection of Privacy Act*, RSA 2000, c.F-25, as amended ("**FOIP**"), applies to all Documents and Information that are in the custody of or under the control of Alberta and that, notwithstanding Article 15(1) above, without limitation, all Documents and Information *may* be subject to disclosure pursuant to FOIP.

5. Upon request, the Agreement Holder shall, at the Agreement Holder's expense, and within five (5) Business Days, provide to Alberta any records that are subject to the access provisions of FOIP that are in the custody or under the control of the Agreement Holder. Where Alberta concludes that any requested Documents and Information are producible in accordance with FOIP, the Agreement Holder will be given notice of the request and will be given an opportunity to make representations as to why the information should not be disclosed.

6. Should the Agreement Holder receive an access request under FOIP in relation to this agreement, the Agreement Holder shall not respond to it, but shall immediately forward the access request to the Minister for further handling. The Agreement Holder shall provide such reasonable assistance to Alberta as may be required in order for Alberta to respond to any FOIP request.

ARTICLE 16: DISPUTE RESOLUTION

1. The Minister may, in the Minister's sole discretion, establish alternative dispute resolution processes in relevant Enactments.

2. Notwithstanding Article 16(1), the Minister shall not be obliged to establish alternative dispute resolution processes, and in any case the Enactments shall govern.

3. Disputes arising between the Agreement Holder and any Client or prospective Client, in relation to rights and obligations of the Agreement Holder under this agreement shall be resolved in accordance with any procedures set out in relevant Enactments.

4. Disputes arising between the Agreement Holder and the Minister in relation to rights and obligations of the Participants under this agreement, including but not limited to any alleged breach on non-compliance, shall be resolved in accordance with any procedures set out in any relevant Enactments or as otherwise established.

ARTICLE 17: INDEMNITY & INSURANCE

1. The Agreement Holder shall keep Alberta indemnified against

   (a) all actions, claims and demands brought or made against Alberta which may arise directly or indirectly out of any act or omission, whether negligent or otherwise, by the Agreement Holder or any other person including Clients, in the exercise or purported exercise of the rights granted and duties imposed under this agreement or arising from or related to the development, design, construction, installation, ownership, operation, maintenance, removal, presence or existence of the carbon sequestration hub; and,

   (b) all losses, damages, costs, charges and expenses that Alberta sustains or incurs in connection with any action, claim or demand referred to in Article 17(5).

   Such indemnification shall survive the termination of this agreement, until the issuance of a closure certificate under the MMA.

2. Alberta shall not be liable to the Agreement Holder and the Agreement Holder waives and releases Alberta in connection with any claim for any special, incidental, indirect or consequential loss or damages suffered by or brought against the Agreement Holder with respect to any matter related to this agreement or to the carbon sequestration hubs. This provision shall survive this agreement.

3. Every right, exemption from liability, defence and immunity of whatsoever nature applicable to Alberta or to which Alberta is entitled in this agreement, shall also be available and shall extend to protect each agent and employee of Alberta, acting in the course of or in connection with his or her employment. For the purposes of all the foregoing provisions of this section, Alberta is or shall be deemed to be acting as agent or trustee on behalf of and for the benefit of each person who is or who becomes the agent or employee of Alberta from time to time.

4. At its own expense and without limiting its liabilities herein, the Agreement Holder shall maintain errors and omissions liability, general liability insurance and environmental liability insurance with terms, coverages and amounts acceptable to Alberta and appropriate for the level of risk existing for the development, design, construction, installation, ownership, operation, and maintenance of carbon sequestration hubs.

5. The Agreement Holder shall provide the Minister with evidence of insurance required under this Article 17. Such proof shall be in the form of certificates of insurance and certified copies of all insurance policies prior to commencing any activity on the Location under this agreement, at the renewal of the insurance policies and at any other time requested by

Alberta. Delivery to and examination by Alberta of any policy of insurance evidencing such insurance shall not relieve the Agreement Holder of any of its obligations pursuant to the provisions of this agreement and shall not operate as a waiver by the Minister of any rights.

6. The Agreement Holder is responsible for obtaining insurance to cover its owned or leased property, including the carbon sequestration hubs and the Agreement Holder agrees to waive all rights of recourse against Alberta for loss or damage to such property owned or leased by the Agreement Holder.

ARTICLE 18: SURVIVAL OF TERMS

1. Notwithstanding any other provision of this agreement, the following articles of this agreement shall survive the termination of this agreement and shall continue to be binding on the Parties until their requirements have been fully met:

   (a) Article 8 Obligations

   (b) Article 9 Reporting

   (c) Article 15 Confidentiality

   (d) Article 17 Indemnity & Insurance

   (e) Article 18 Survival of Terms

ARTICLE 19: GENERAL PROVISIONS

1. This agreement contains the entire agreement of the Parties concerning the subject matter of this agreement and except as expressed in this agreement, there are no other understandings or agreements, verbal or otherwise, that exist between the Parties.

2. The Parties agree that all headings herein are included for convenience only and shall not be deemed to affect the substantive terms or interpretation of this agreement.

3. Any alteration or amendment to the terms and conditions of this agreement must be in writing and duly executed by all Parties except as described in Article 6 for amendments to the Location.

4. Any waiver by either Party of the performance by the other of an obligation under this agreement must be in writing, and such waiver does not constitute a continuing waiver of the performance of that obligation unless a contrary intention is expressed in writing.

5. If any provision of this agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision and everything else in this agreement shall continue in full force and effect, provided however that this agreement is not materially altered.

6. The Parties agree that this agreement will be governed by the laws of the Province of Alberta and the Parties irrevocably attorn to the exclusive jurisdiction of the courts in Alberta.

7. This agreement may be executed electronically and in counterparts, in which case (i) the counterparts together shall constitute one agreement, and (ii) communication of execution emailed in PDF or electronically via Alberta Energy and Minerals' Electronic Transfer System ("ETS") shall constitute good delivery. All notices, consents, requests, reports and other documents authorized or required to be given pursuant to this agreement shall be in writing and either delivered by hand, mailed by registered or certified first class air mail, postage prepaid, sent by email, or electronically transmitted via the ETS.

IN WITNESS WHEREOF the Parties have executed this agreement as of the Effective Date:

HIS MAJESTY IN RIGHT OF THE PROVINCE OF ALBERTA, as represented by the Minister of Energy and Minerals

Brian Jean, K.C., ECA

Minister of Energy and Minerals

BISON LOW CARBON VENTURES INC.

Per:

Matthew Brister

President

SCHEDULE "A": LOCATION

ATTACHED TO AND FORMING PART OF CARBON SEQUESTRATION AGREEMENT NO. 5924070002

EFFECTIVE DATE OF AGREEMENT:
July 30, 2024

AGGREGATE AREA:
15,360 HECTARES

DESCRIPTION OF LOCATION:

4-25-057: 01 – 05, 8 – 17, 20 – 29, 32 – 36

4-25-058: 01 – 05, 8 – 17, 20 – 29, 32 – 36

PORE SPACE IN THE WOODBEND GROUP DRRZD 258 FORMATION

RESTRICTIONS

SHA010301 SENSITIVE RAPTOR RANGE

LAND DESCRIPTION
4-25-057:01
4-25-057:02
4-25-057:03
4-25-057:04
4-25-057:05
4-25-057:08
4-25-057:09
4-25-057:10
4-25-057:11
4-25-057:12
4-25-057:13
4-25-057:14
4-25-057:15
4-25-057:16
4-25-057:17
4-25-057:20
4-25-057:21
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4-25-057:24
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4-25-057:29
4-25-057:32

4-25-057:33
4-25-057:34
4-25-057:35
4-25-057:36
4-25-058:01
4-25-058:02
4-25-058:03
4-25-058:04
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4-25-058:26
4-25-058:27
4-25-058:28
4-25-058:29
4-25-058:32
4-25-058:33
4-25-058:34
4-25-058:35
4-25-058:36

IS/ARE WITHIN A SENSITIVE HABITAT AREA.

SURFACE ACCESS IS SUBJECT TO SPECIFIC RESTRICTIONS

SHA010401 SHARP-TAILED GROUSE

LAND DESCRIPTION
4-25-057:01
4-25-057:02
4-25-057:03
4-25-057:04
4-25-057:05
4-25-057:08
4-25-057:09
4-25-057:10
4-25-057:11

4-25-057:12
4-25-057:13
4-25-057:14
4-25-057:15
4-25-057:16
4-25-057:17
4-25-057:20
4-25-057:21
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4-25-057:34
4-25-057:35
4-25-057:36
4-25-058:01
4-25-058:02
4-25-058:03
4-25-058:04
4-25-058:05
4-25-058:08
4-25-058:09
4-25-058:10
4-25-058:11
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4-25-058:16
4-25-058:17
4-25-058:20
4-25-058:21
4-25-058:22
4-25-058:23
4-25-058:24
4-25-058:25
4-25-058:26
4-25-058:27
4-25-058:28
4-25-058:29
4-25-058:32
4-25-058:33
4-25-058:34
4-25-058:35
4-25-058:36

IS/ARE WITHIN A SENSITIVE HABITAT AREA.

SURFACE ACCESS IS SUBJECT TO SPECIFIC RESTRICTIONS

Appendix N: Notification Letter

BISON
LOW CARBON
VENTURES

Suite 325, 440 2nd Ave SW
Calgary, Alberta T2P 5E9
www.bisonlowcarbon.ca

August 30, 2024

[Offset Company]
[Address]
[Address]

Attention: *[Offset Owner]*

Dear Sir/Madam:

Re: Application for Approval of a Class III Carbon Dioxide Disposal Scheme
Bison Meadowbrook Carbon Storage Project
103/16-29-057-25W4/0

Bison Low Carbon Ventures (Bison) proposes to apply to the Alberta Energy Regulator (AER) under *Directive 065: Resources Applications* (Directive 65), for approval of a Class III Carbon Dioxide Disposal scheme. The objective of the application is to obtain approval to operate the proposed Meadowbrook Carbon Storage Project for the injection and storage of carbon dioxide into the Leduc and Cooking Lake formations at a depth of approximately 1,300 to 1,600 meters below ground surface at 16-29-057-25 W4M.

You are being notified of the application as part of the AER notification requirements pursuant to Directive 65. The following assets are located within the notification area:

- *List wells (UWIs) and / or leases*
-

If you have questions about this application, do not hesitate to contact the undersigned at (403) 850-3444. If you have any concerns respecting the potential for the application to affect your interest, send a letter stating your concerns by e-mail to gwierzba@bisonlowcarbon.ca, or by mail to:

Bison Low Carbon Ventures
Suite 325, 440 2nd Ave. SW
Calgary, Alberta T2P 5E9

It will be considered an indication of non-objection should we not receive a response on or before September 20, 2024.

The AER application process is a public process, and all documents filed with the AER will be placed on the public record unless otherwise authorized by the AER in accordance with Section 12 of the *Alberta Energy Regulator Rules of Practice and Responsible Energy Development Act*.

If you would like to receive a copy of Bison's application, please contact the undersigned.

Yours truly,

Grant Wierzba
Chief Operating Officer
Bison Low Carbon Ventures

APPENDIX O: INJECTION AND FALLOFF TEST

Leduc Injection & Falloff Test

103/16-29-057-25W4/00 – Preliminary Results

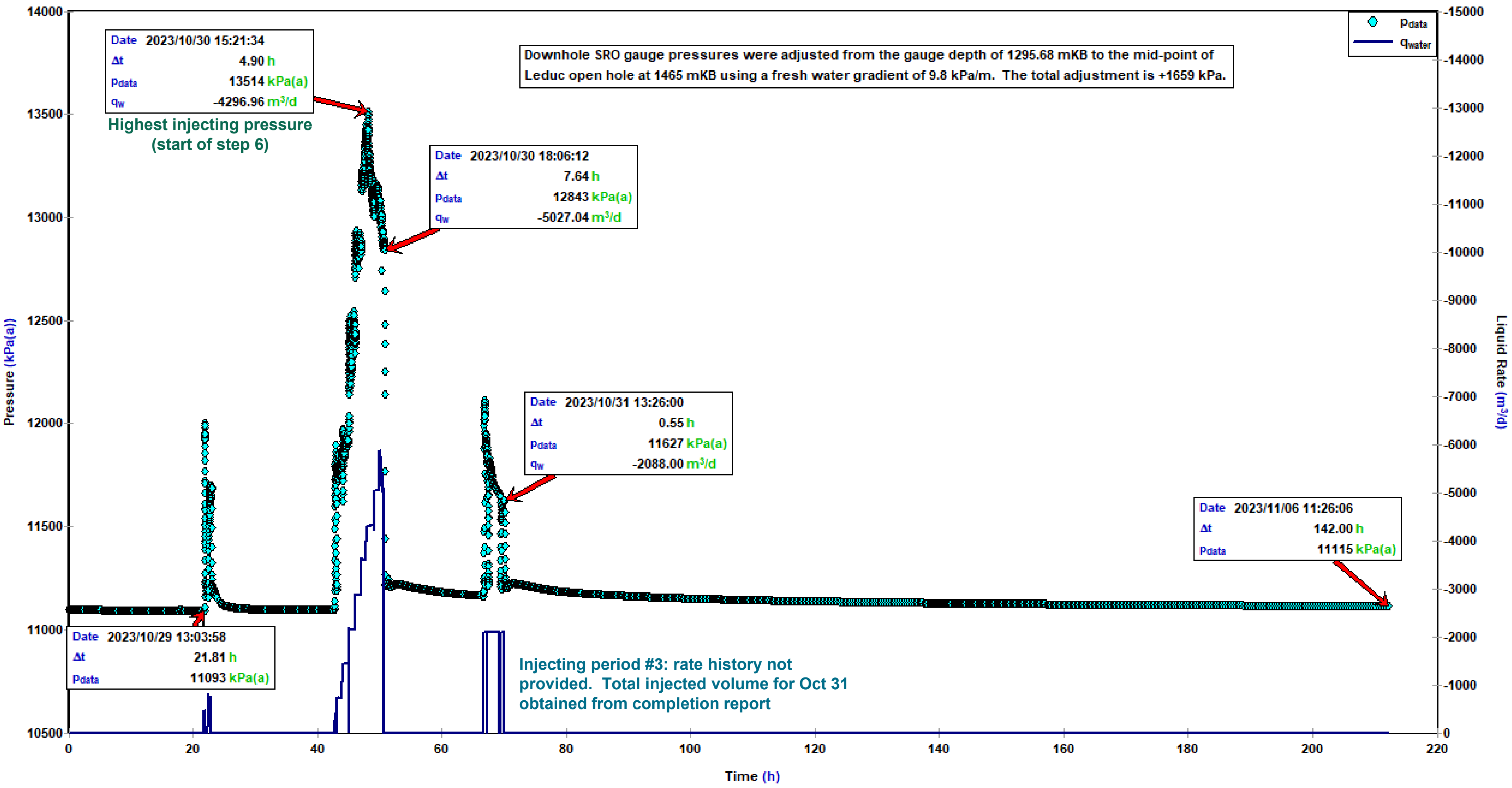
S&P Global
Commodity Insights

November 2023

Contents

The test sequence includes a step rate injection test and three analyzable falloff periods

Total Test View

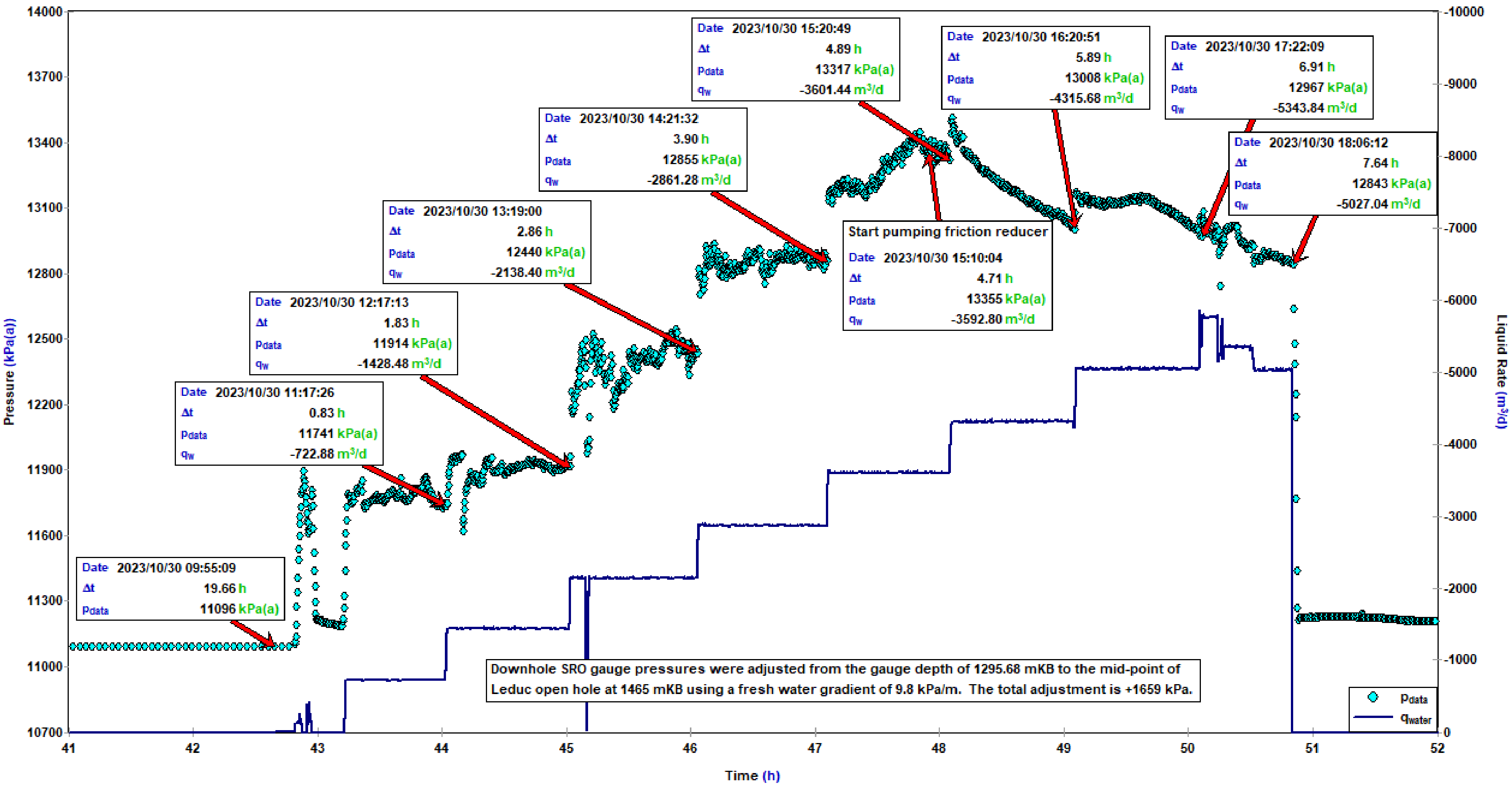


Source: S&P Global Commodity Insights.
©2023 S&P Global

- A constant pressure adjustment of +1659 kPa was applied for the whole dataset to adjust the pressures from recorder run depth to mid-point of Leduc open hole
- Majority of frictional pressure loss during injection occurs in the 88.9 mm tubing. There is only 13.3 m of 88.9 mm tailpipe below the recorder. Frictional pressure loss in the 7” open hole section is minimal. A wellbore model was constructed and it was established that the error associated with using a static vs injecting water gradient is slightly over 100 kPa
- Three analyzable falloffs are available, although detailed water rate history for the third injecting period was not provided

Step rate test reached a bottomhole pressure of 13.5 MPa at a rate of 4316 m^3/d on step 6

Expanded View of Step Rate Test



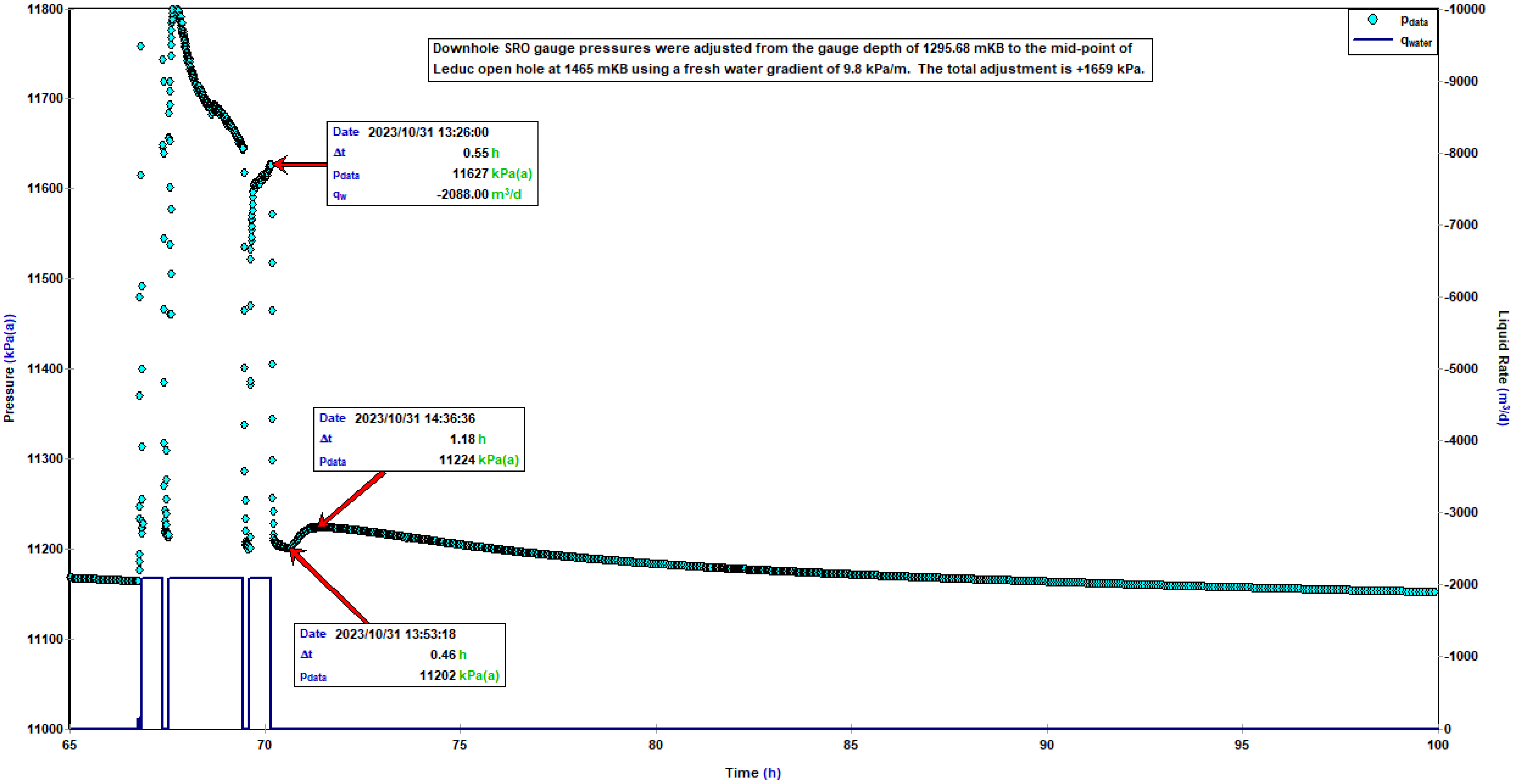
Source: S&P Global Commodity Insights.

©2023 S&P Global

- A step rate injection test consisting of 8 steps of 1 hour duration per step was conducted
- The highest observed bottomhole injecting pressure was 13514 kPaa at a water rate of 4316 m^3/d at the start of step 6 (not labeled)
- The final bottomhole injecting pressure was 12843 kPaa at a water rate of 5027 m^3/d
- Friction reducer injection began during step 5. While it produced a substantial pressure drop at the wellhead, the pressure drop downhole is not as pronounced
- Subsequent steps saw a decline in injecting pressure, which can be attributed to the effect of friction reducer in the formation or to an improvement in injectivity due to opening up additional net pay at higher injecting pressure.

Falloff #3 is the longest falloff, however, it is negatively impacted by a non-reservoir effect

Expanded View of Early-Time Falloff #3

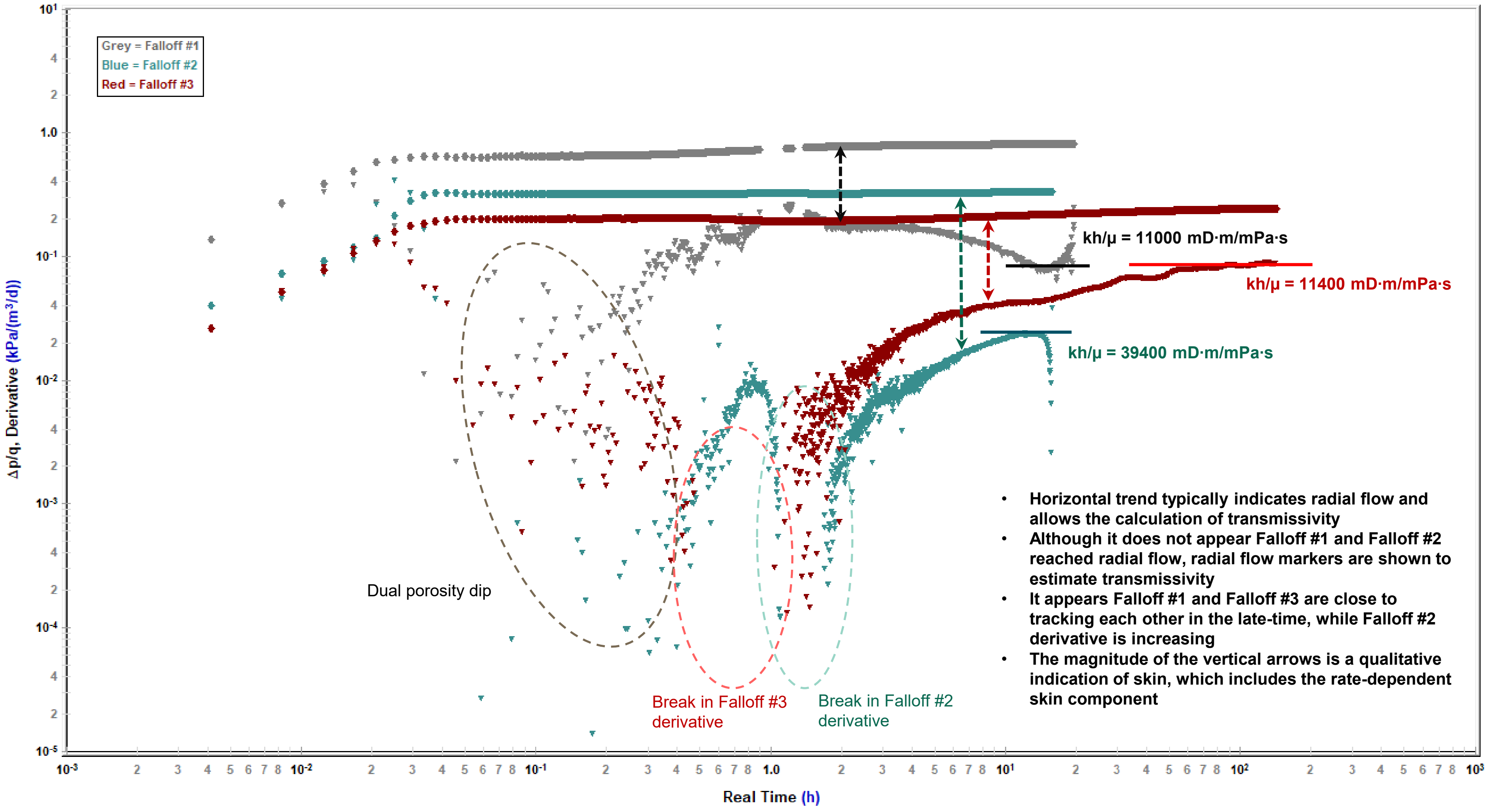


- Falloff #2 and Falloff #3 are negatively impacted by a non-reservoir effect shortly after shut-in, which causes a 'break' in the early-time pressure derivative and makes it near impossible to establish near wellbore permeability and skin uniquely
- Regardless, analysis focuses on Falloff #3, even though a detailed rate history is not available
- Early-time falloff data is sparse. Pressure data was supplied at 15 second interval

Source: S&P Global Commodity Insights.
©2023 S&P Global

Falloff comparison shows an increase in kh/μ for falloff #2 and presence of rate dependent skin

Log-Log Typecurve and Pressure Derivative Comparison Plot



Source: S&P Global Commodity Insights.

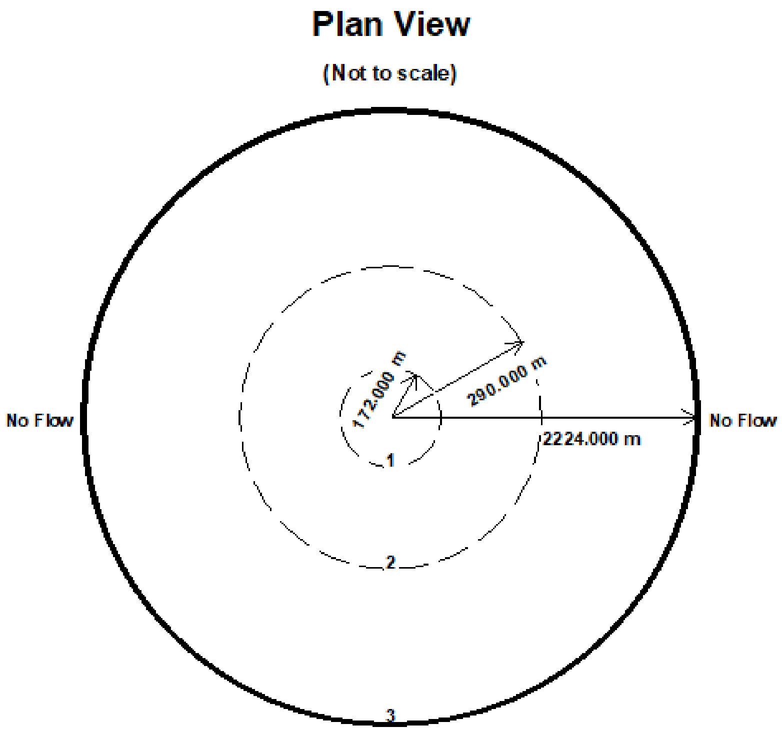
©2023 S&P Global

- All three tests show a dip between 0.1 and 0.4 hrs, which may be attributed to a dual porosity response
- Falloff #2 exhibits a break in the pressure derivative after 1.0 hr of shut-in. Falloff #3 exhibits a break in pressure derivative between 0.5 and 1.0 hrs. These disturbances coincide with a wellbore effect visible on the cartesian plot where pressure increases briefly prior to resuming the falloff trend. The cause of this is not understood, although it is not reservoir related
- Falloff #2 exhibits the highest transmissivity (kh/μ), although the pressure derivative is increasing in the late-time, suggesting a gradual reduction in far-field transmissivity
- Falloff #2 exhibits the highest pressure drop due to skin, which is consistent with the highest injection rate. Falloff #1 and Falloff #3 exhibit lower pressure drop due to skin due to lower final injecting rates
- Variation in kh/μ between the three falloffs may be attributed to a combination of improving injectivity with injection and the effect of friction reducer on non-Darcy flow

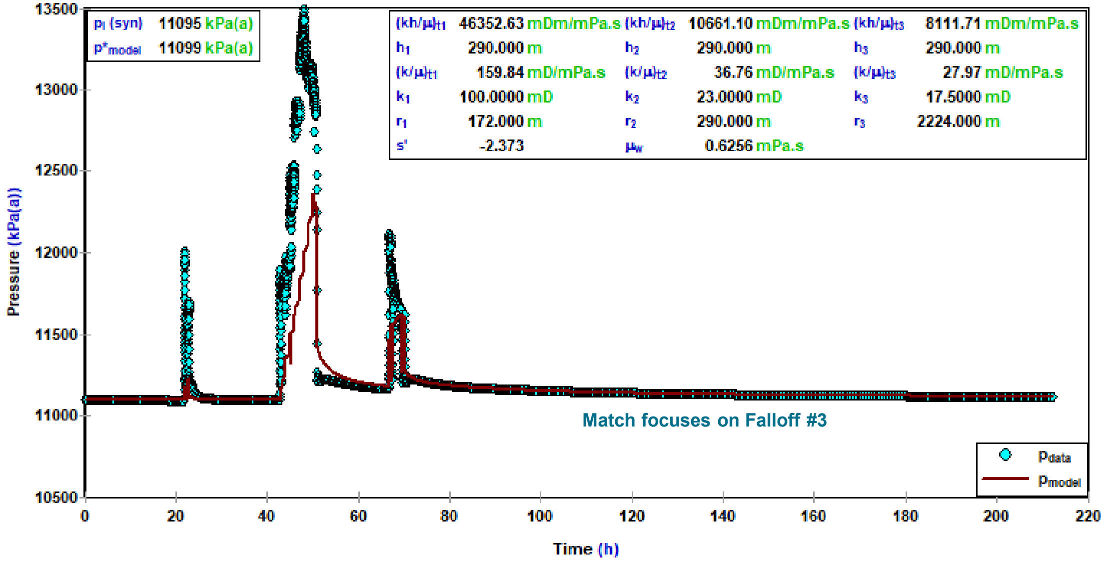
Contents

Composite Reservoir Model

- History matching focused on Falloff #3 while honoring pressure prior to injection and Falloff #1 and Falloff #2
- A history match to the observed test data was achieved by decreasing permeability to water from 100 mD to 23 mD at a distance of 172 m away from the wellbore, then decreasing to 18 mD at a distance of 290 m away from the wellbore
- A skin value of -2.4 was required for the match.
- The reservoir size cannot be established from the test and a 6 section reservoir size (r_e = 2224 m) was assumed to extrapolate the reservoir pressure.
- By reducing the reservoir size until the match to the observed pressure data begins to deteriorate, **it is estimated that an area of 1.7 sections (r_e = 1250 m) was investigated during the test (i.e. Falloff #3)**

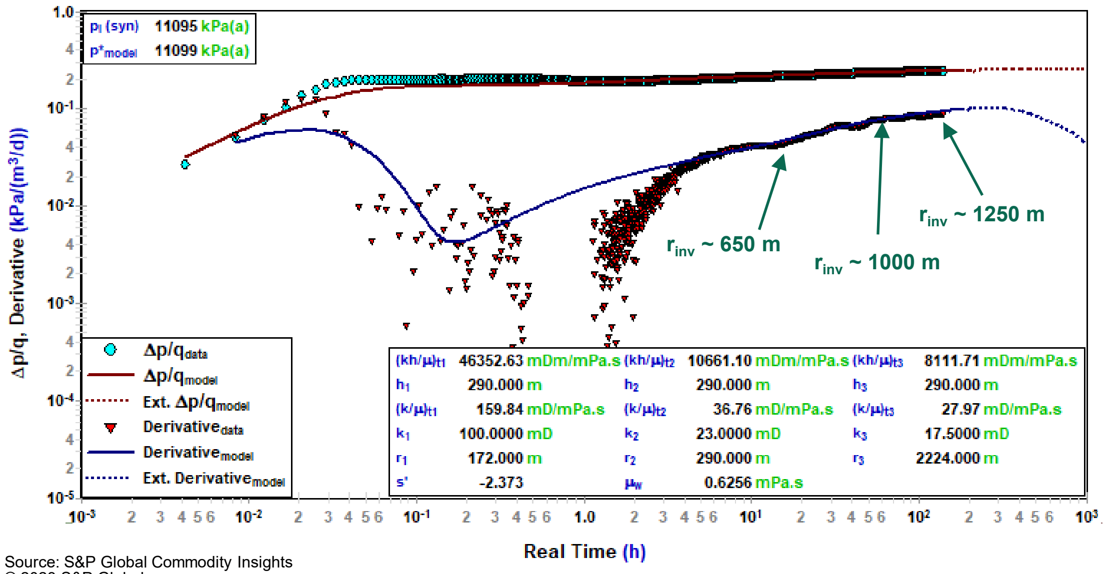


Total Test Plot



Source: S&P Global Commodity Insights
© 2023 S&P Global.

Log-Log Typecurve and Pressure Derivative



Source: S&P Global Commodity Insights
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Composite Reservoir Model (cont’d)

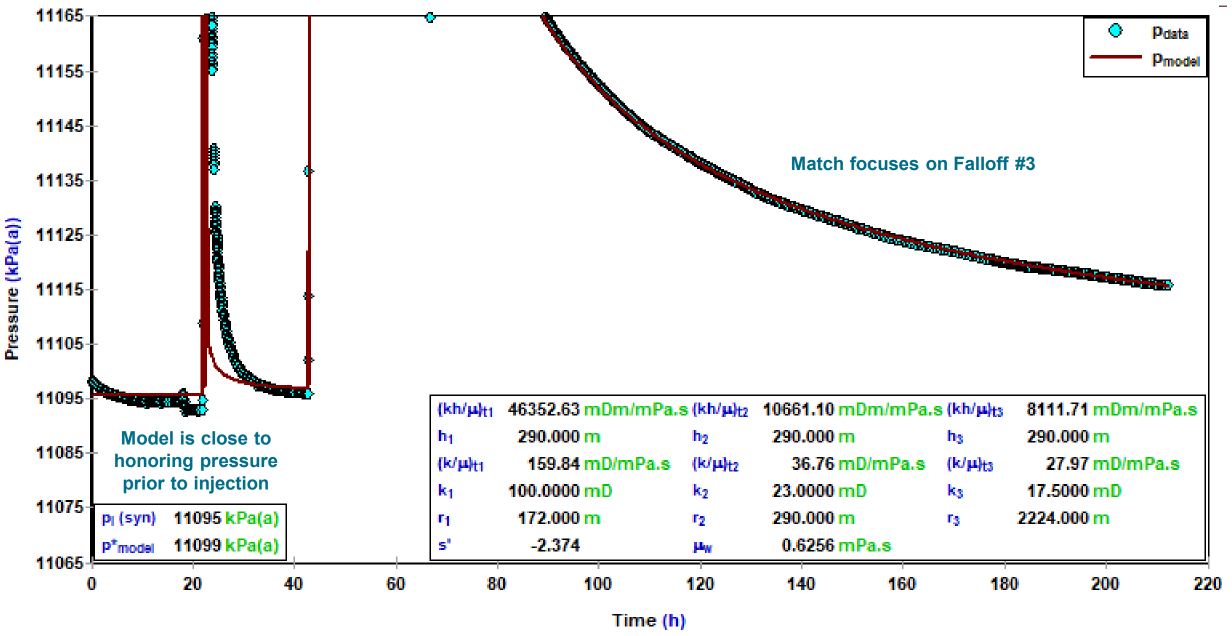
- To note, near wellbore permeability and skin cannot be established uniquely since early-time pressure data is distorted by non-reservoir effects (i.e. the aforementioned break in the pressure derivative)
- The final falloff pressure on November 6, 2023 (Δt = 142 hrs) was 11,115 kPaa. Based on an assumed 6-section reservoir size, the model is close to honoring the pressure of 11,094 prior to start of injection and extrapolates the falloff trend to an average reservoir pressure of 11,099 kPaa
- Based on a depth of 1465 mKB, an underpressured reservoir gradient of 7.6 kPa/m is calculated

Reservoir Characteristics

COMPOSITE RESERVOIR MODEL		METRIC		FIELD	
Initial Reservoir Pressure (History Match)	**(p_R)**	**11095**	**kPaa**	**1609**	**psia**
Average Res Pressure (History Match)	**(p_R)**	**11099**	**kPaa**	**1610**	**psia**
Net Pay (Provided)	(h)	290	m	951	ft
Region 1					
Total Mobility	$(k/\mu)_{t1}$	160	mD/mPa·s	162	md/cP
Permeability to Water	(k_{w1})	100	mD	101	md
Total Skin	(s)	-2.4		-2.4	
Storativity Ratio	(ω)	0.02		0.02	
Interporosity Coefficient	(λ)	2.5e-6		2.5e-6	
Region Radius	(r_1)	172	m	564	ft
Region 2					
Total Mobility	$(k/\mu)_{t2}$	37	mD/mPa·s	37	md/cP
Permeability to Water	(k_{w2})	23	mD	23	md
Region Radius	(r_2)	290	m	951	ft
Region 3					
Total Mobility	$(k/\mu)_{t3}$	28	mD/mPa·s	28	md/cP
Permeability to Water	(k_{w3})	17.5	mD	17.8	md
Region Radius (Assumed)	(r_e)	2224	m	7300	ft

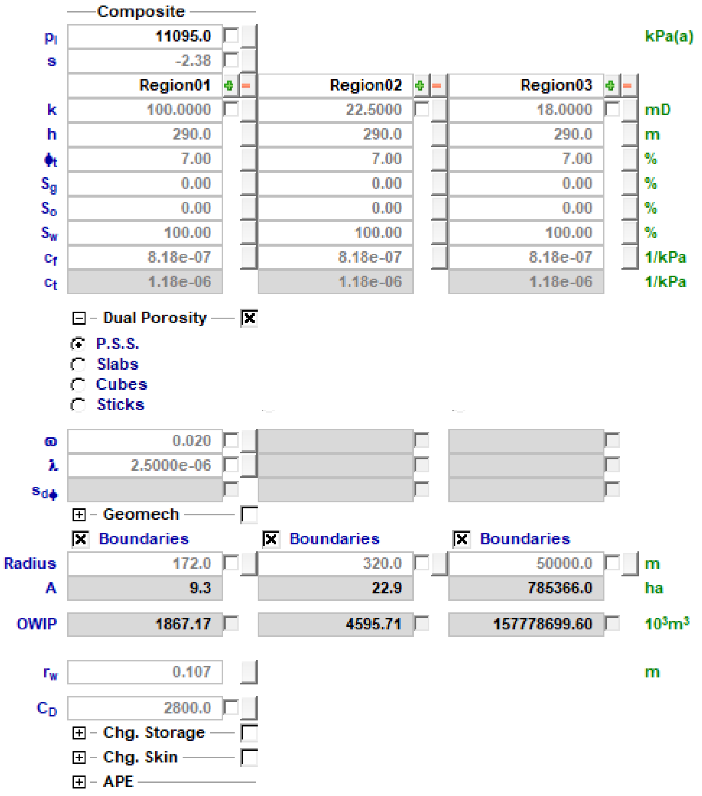
As of November 10, 2023
Source: S&P Global

Expanded View of Falloff Pressure

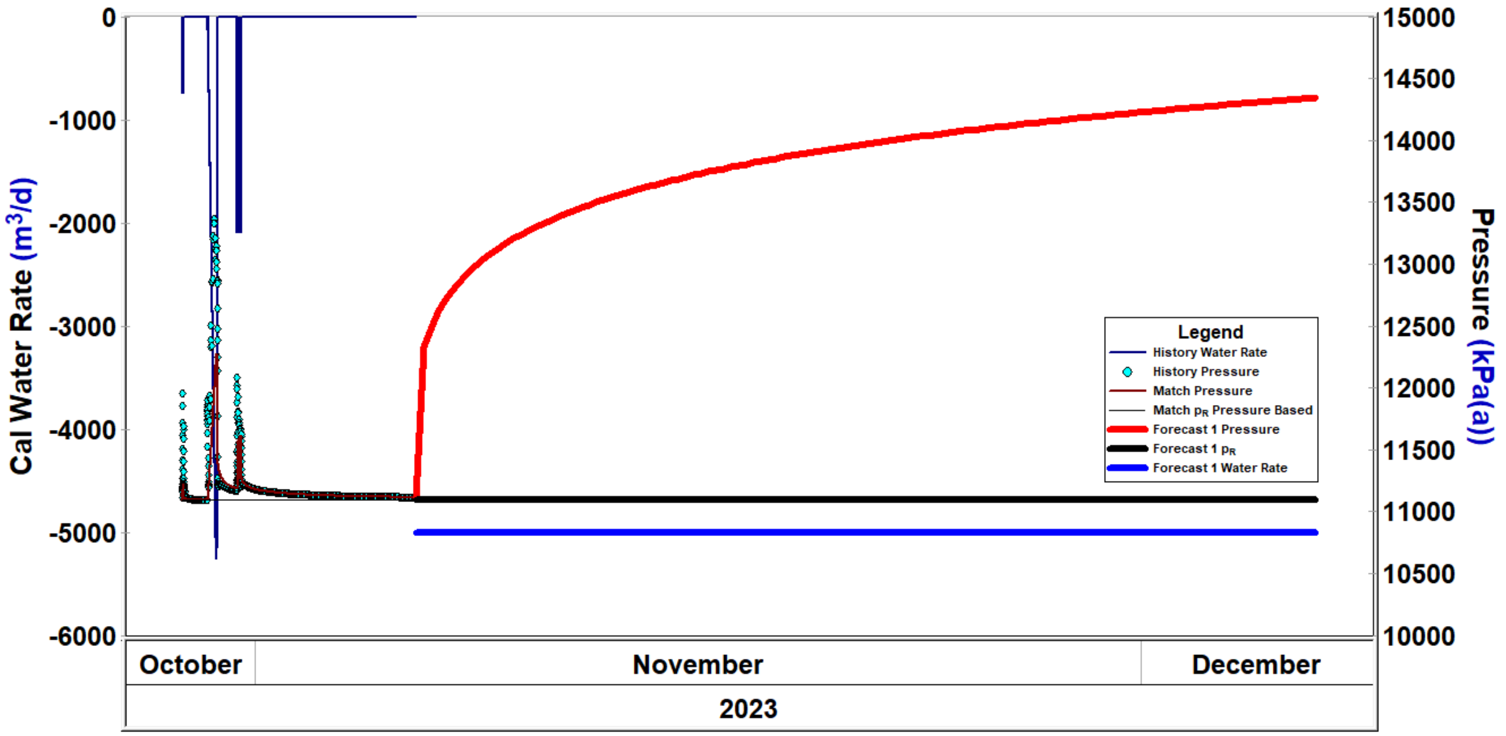


Source: S&P Global Commodity Insights

Composite Reservoir Model (cont'd)



1 Month Injectivity Forecast



Source: S&P Global Commodity Insights

- A 3030 section reservoir size (r_e = 50000 m) was assumed to generate the 1 month injectivity forecast

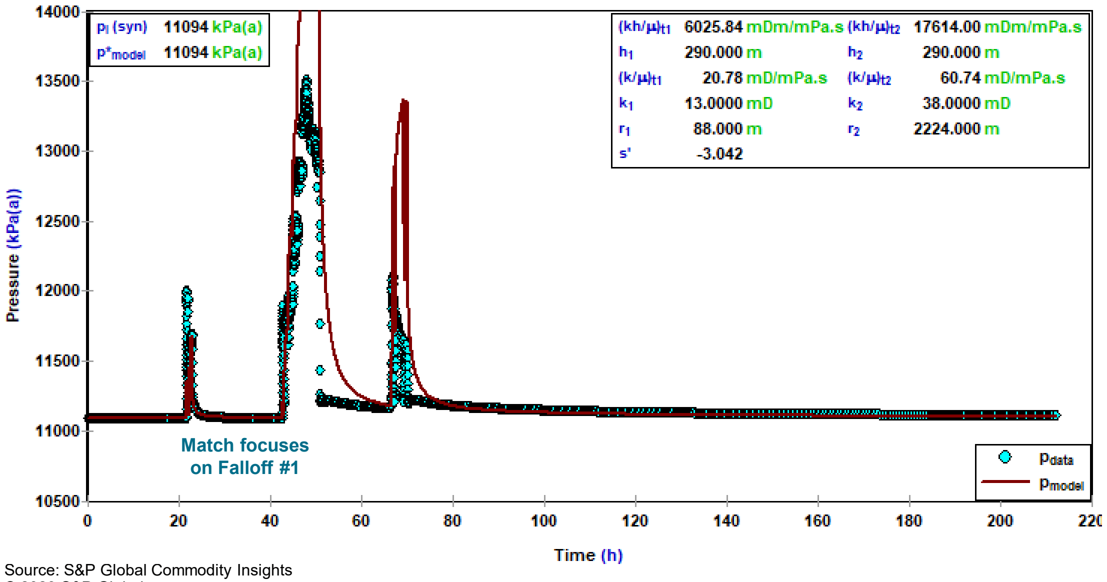
Falloff #1 Model

Reservoir Characteristics

COMPOSITE RESERVOIR MODEL (Falloff #1)		METRIC		FIELD	
Initial Reservoir Pressure (History Match)	**(p_R)**	**11094**	**kPaa**	**1609**	**psia**
Average Res Pressure (History Match)	**(p_R)**	**11094**	**kPaa**	**1609**	**psia**
Net Pay (Provided)	(h)	290	m	951	ft
Region 1					
Total Mobility	$(k/\mu)_{t1}$	21	mD/mPa·s	21	md/cP
Permeability to Water	(k_{w1})	13	mD	13	md
Total Skin	(s)	-3.0		-3.0	
Region Radius	(r_1)	88	m	289	ft
Region 2					
Total Mobility	$(k/\mu)_{t2}$	61	mD/mPa·s	62	md/cP
Permeability to Water	(k_{w2})	38	mD	39	md
Region Radius (Assumed)	(r_e)	2224	m	7297	ft

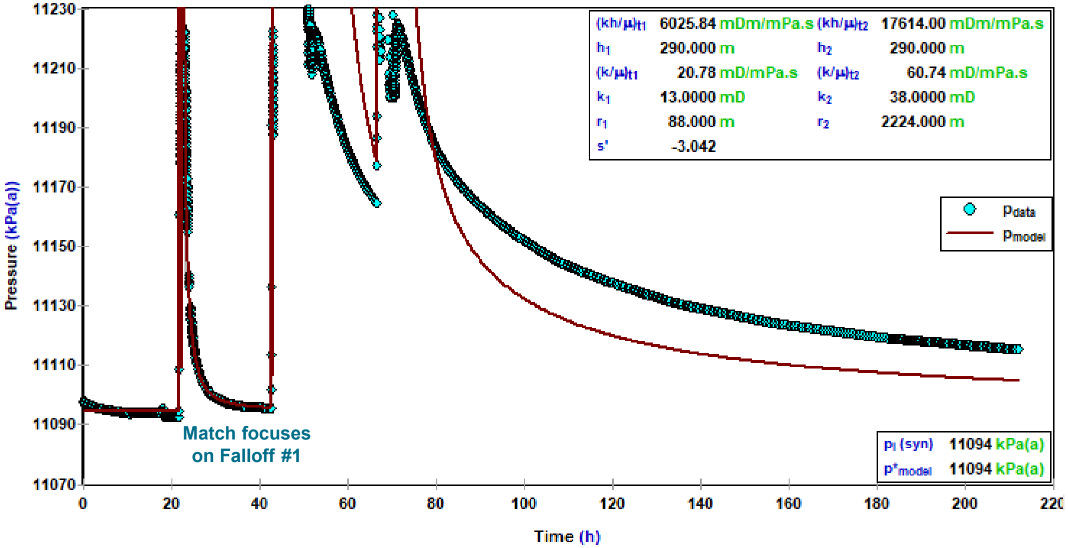
As of November 21, 2023
Source: S&P Global
© 2023 S&P Global

Total Test Plot



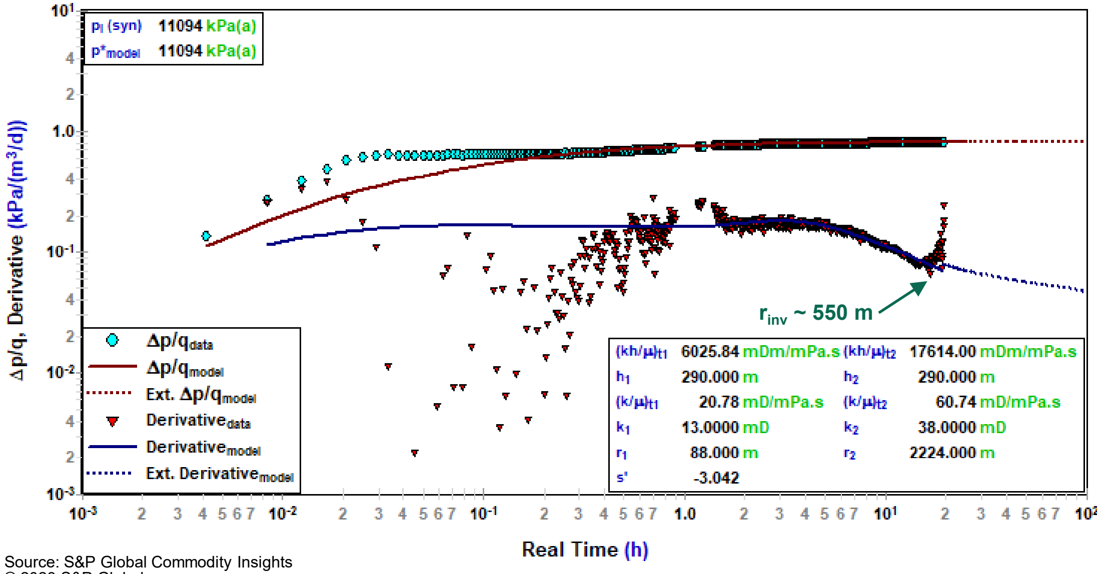
Source: S&P Global Commodity Insights
© 2023 S&P Global.

Expanded View of Falloff Pressure



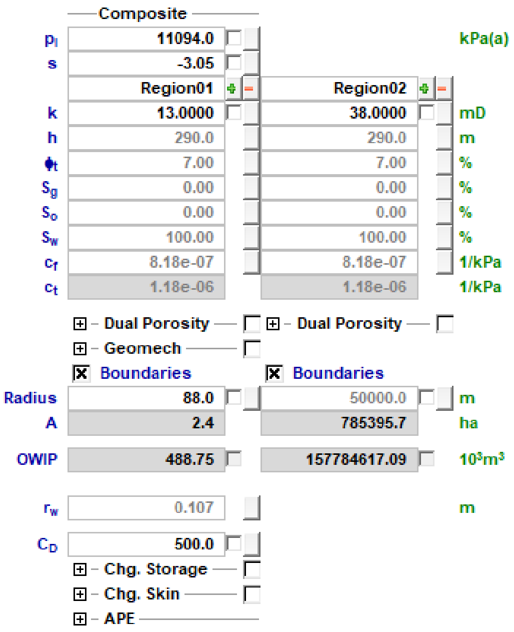
Source: S&P Global Commodity Insights
© 2023 S&P Global.

Log-Log Typecurve and Pressure Derivative

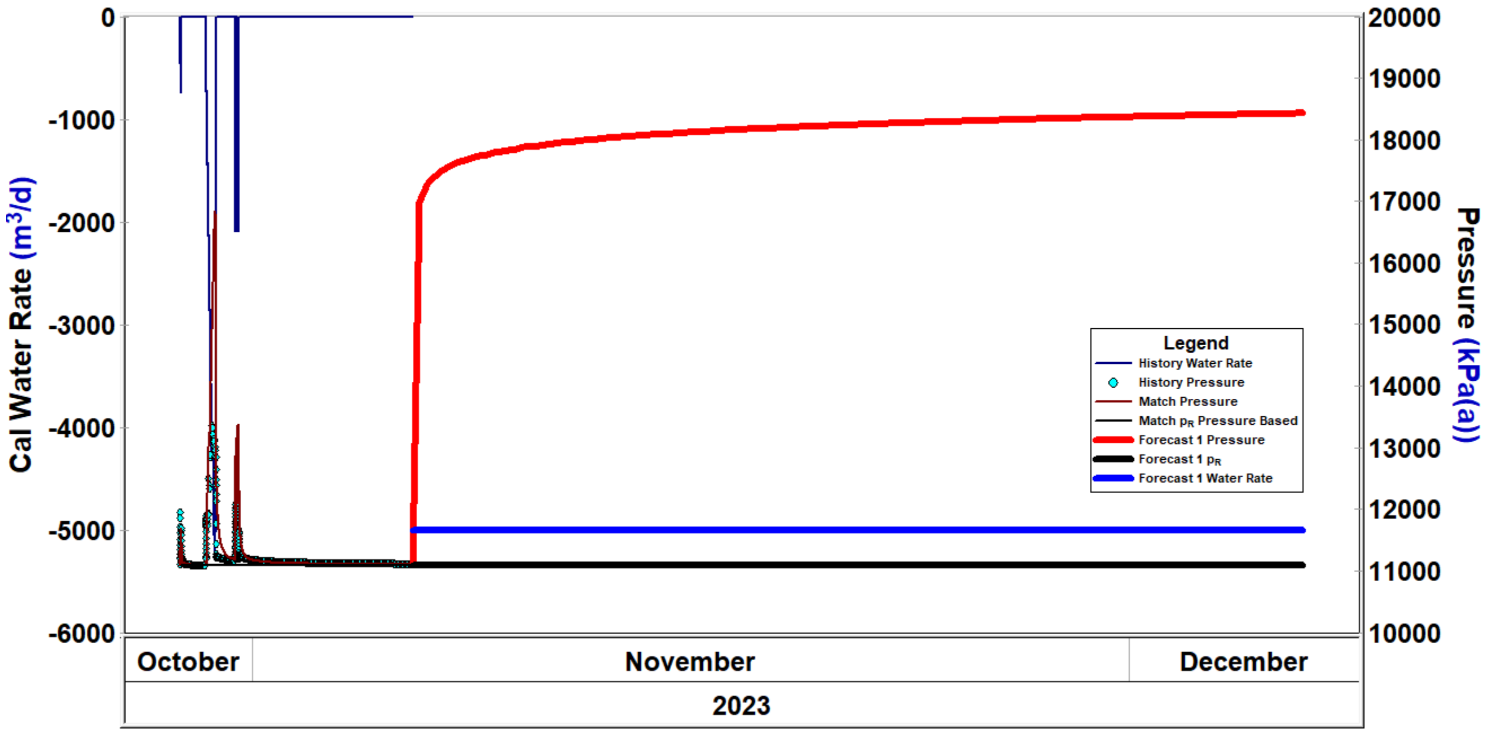


Source: S&P Global Commodity Insights
© 2023 S&P Global.

Falloff #1 Model (cont'd)



1 Month Injectivity Forecast



Source: S&P Global Commodity Insights
© 2023 S&P Global.

- History matching focused on Falloff #1
- The reservoir size cannot be established from the test and a 6 section reservoir size (r_e = 2224 m) was assumed to extrapolate the reservoir pressure.
- A 3030 section reservoir size (r_e = 50000 m) was assumed to generate the 1 month injectivity forecast

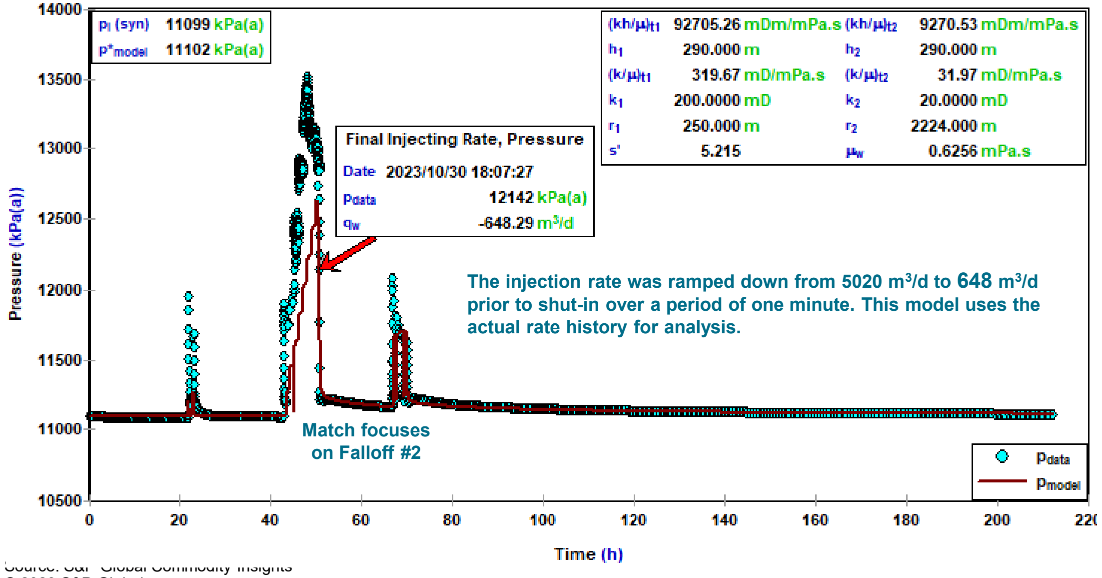
Falloff #2 Model

Reservoir Characteristics

COMPOSITE RESERVOIR MODEL (Falloff #2)		METRIC		FIELD	
Initial Reservoir Pressure (History Match)	**(p_R)**	**11099**	**kPaa**	**1610**	**psia**
Average Res Pressure (History Match)	**(p_R)**	**11102**	**kPaa**	**1610**	**psia**
Net Pay (Provided)	(h)	290	m	951	ft
Region 1					
Total Mobility	$(k/\mu)_{t1}$	320	mD/mPa·s	324	md/cP
Permeability to Water	(k_{w1})	200	mD	203	md
Total Skin	(s)	+5.2		+5.2	
Region Radius	(r_1)	250	m	820	ft
Region 2					
Total Mobility	$(k/\mu)_{t2}$	32	mD/mPa·s	32	md/cP
Permeability to Water	(k_{w2})	20	mD	20	md
Region Radius (Assumed)	(r_e)	2224	m	7297	ft

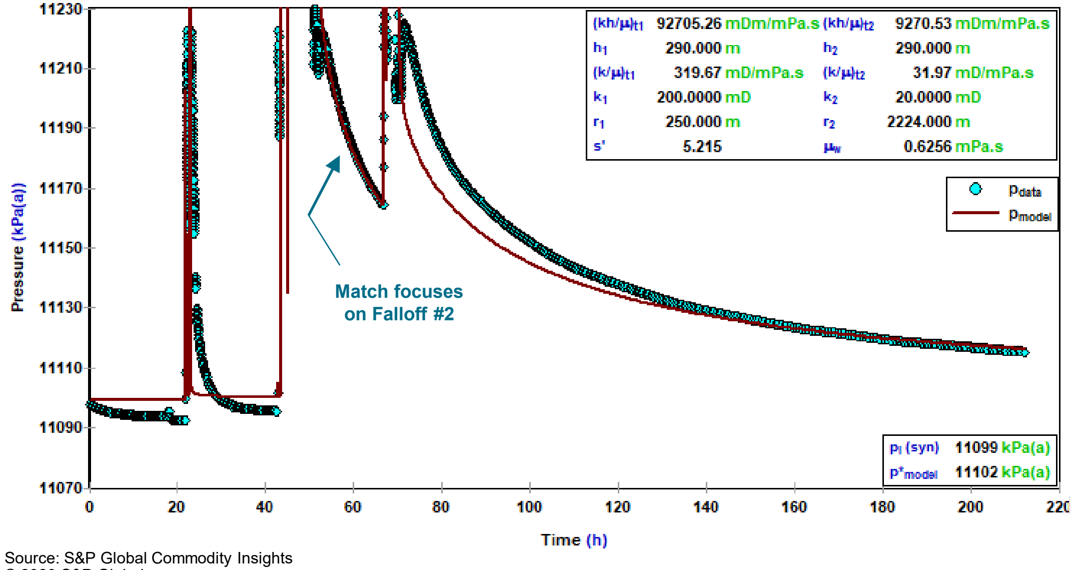
As of November 21, 2023
Source: S&P Global

Total Test Plot



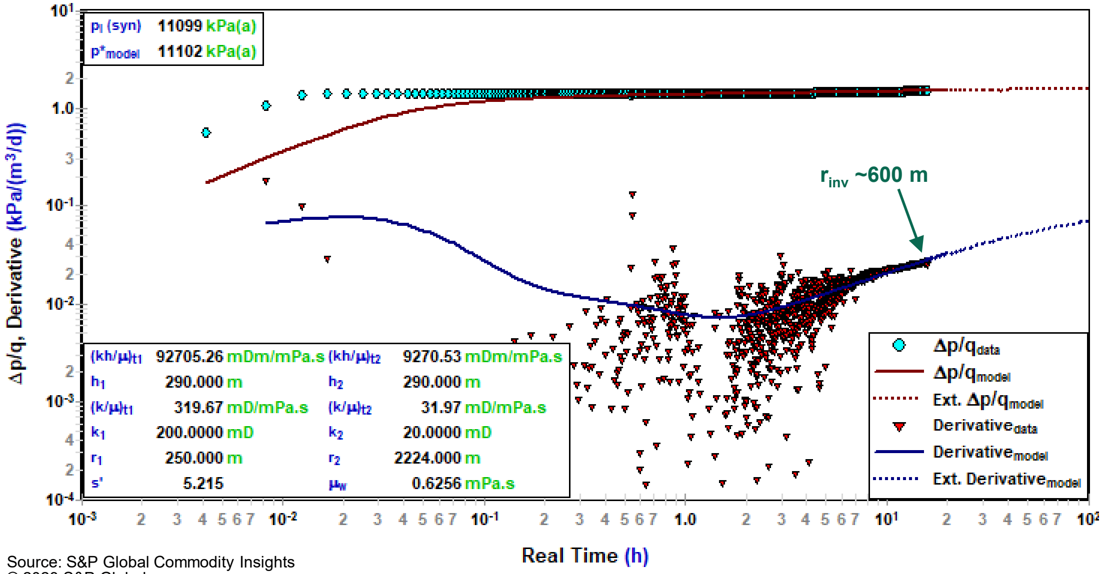
Source: S&P Global Commodity Insights

Expanded View of Falloff Pressure



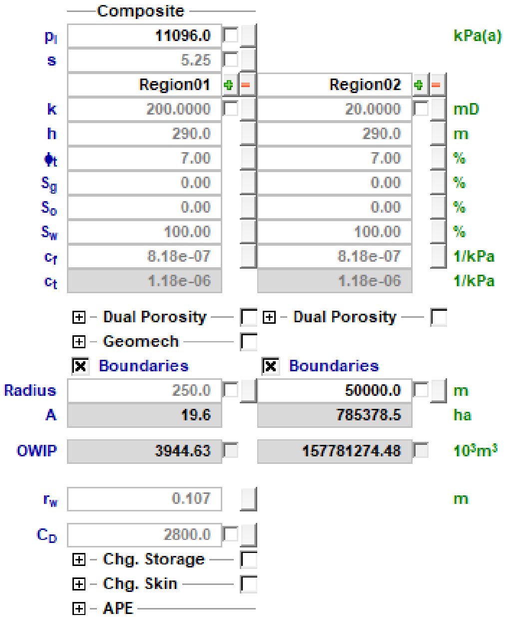
Source: S&P Global Commodity Insights

Log-Log Typecurve and Pressure Derivative

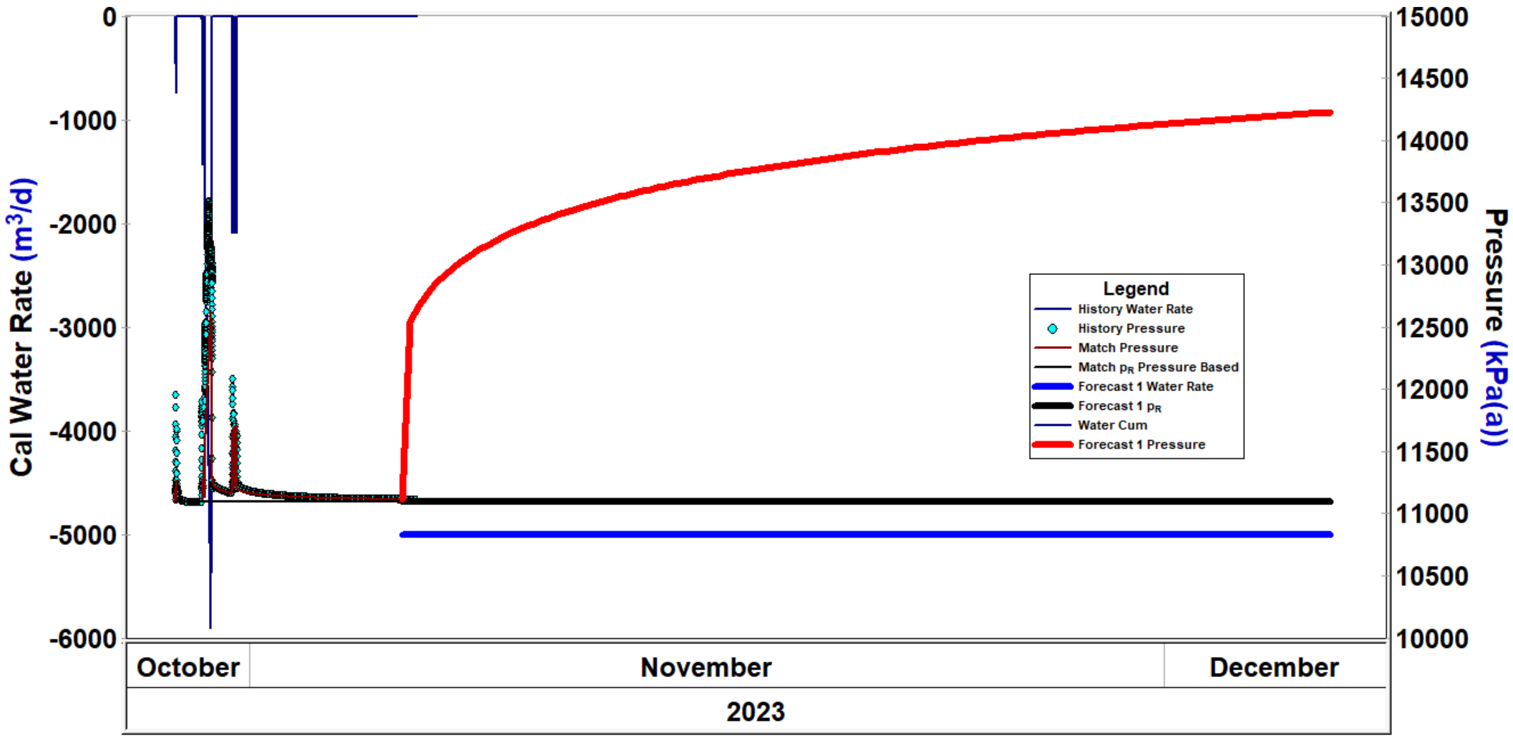


Source: S&P Global Commodity Insights

Falloff #2 Model (cont'd)



1 Month Injectivity Forecast



Source: S&P Global Commodity Insights

- History matching focused on Falloff #2
- Early-time data is impacted by non-reservoir effects, which makes it ambiguous to establish region 1 permeability and skin uniquely
- A two region model was used, making it difficult to honor pressure prior to injection (i.e. a third region would be needed to honor pressure prior to injection)
- The reservoir size cannot be established from the test and a 6 section reservoir size (r_e = 2224 m) was assumed to extrapolate the reservoir pressure
- A 3030 section reservoir size (r_e = 50000 m) was assumed to generate the 1 month injectivity forecast

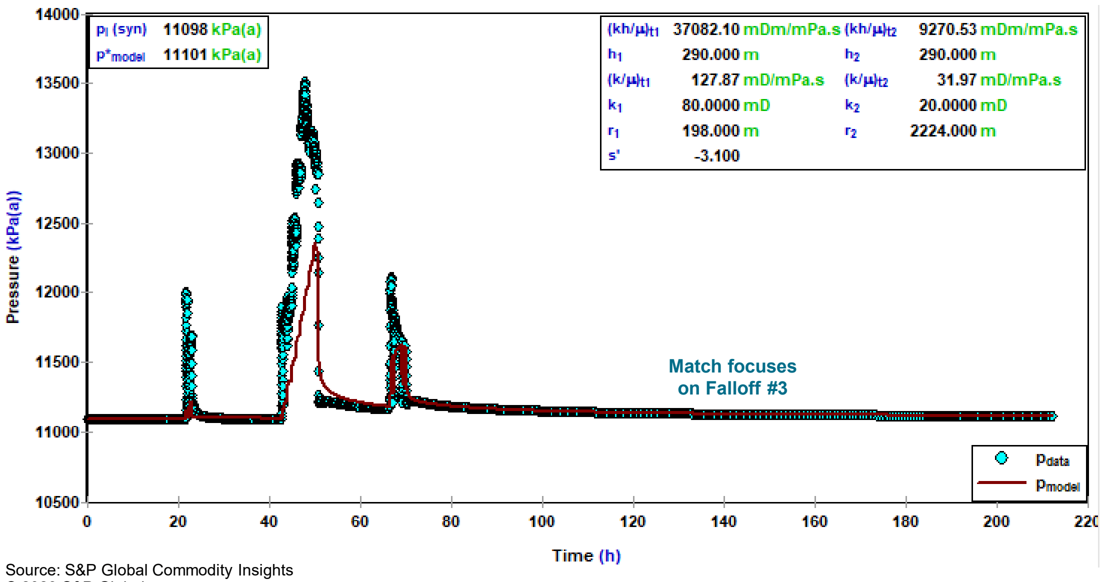
Falloff #3 Model

Reservoir Characteristics

COMPOSITE RESERVOIR MODEL (Falloff #3)		METRIC		FIELD	
Initial Reservoir Pressure (History Match)	**(p_R)**	**11097**	**kPaa**	**1610**	**psia**
Average Res Pressure (History Match)	**(p_R)**	**11101**	**kPaa**	**1610**	**psia**
Net Pay (Provided)	(h)	290	m	951	ft
Region 1					
Total Mobility	$(k/\mu)_{t1}$	128	mD/mPa·s	130	md/cP
Permeability to Water	(k_{w1})	80	mD	81	md
Total Skin	(s)	-3.1		-3.1	
Region Radius	(r_1)	198	m	650	ft
Region 2					
Total Mobility	$(k/\mu)_{t2}$	32	mD/mPa·s	32	md/cP
Permeability to Water	(k_{w2})	20	mD	20	md
Region Radius (Assumed)	(r_e)	2224	m	7297	ft

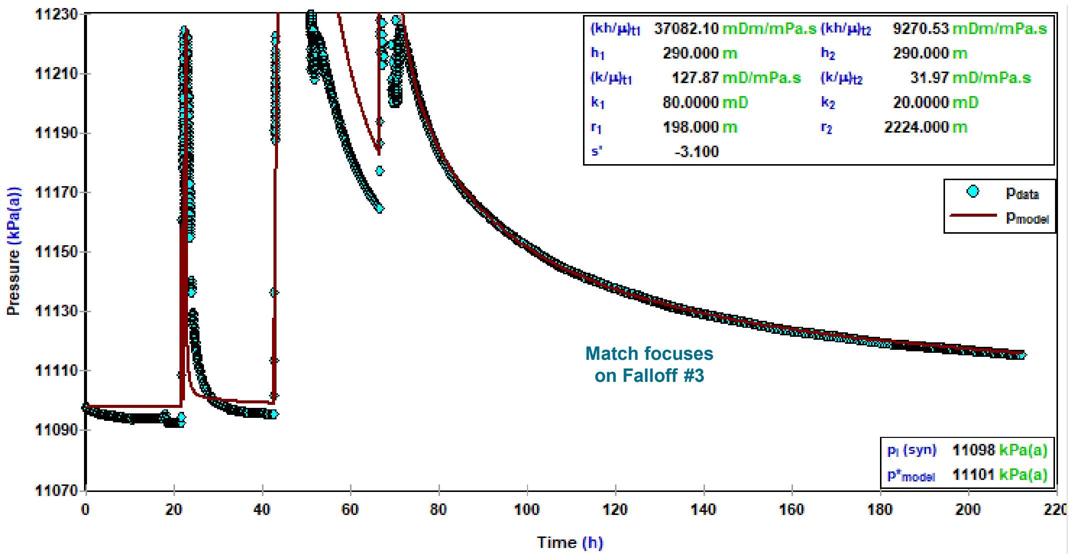
As of November 21, 2023
Source: S&P Global

Total Test Plot



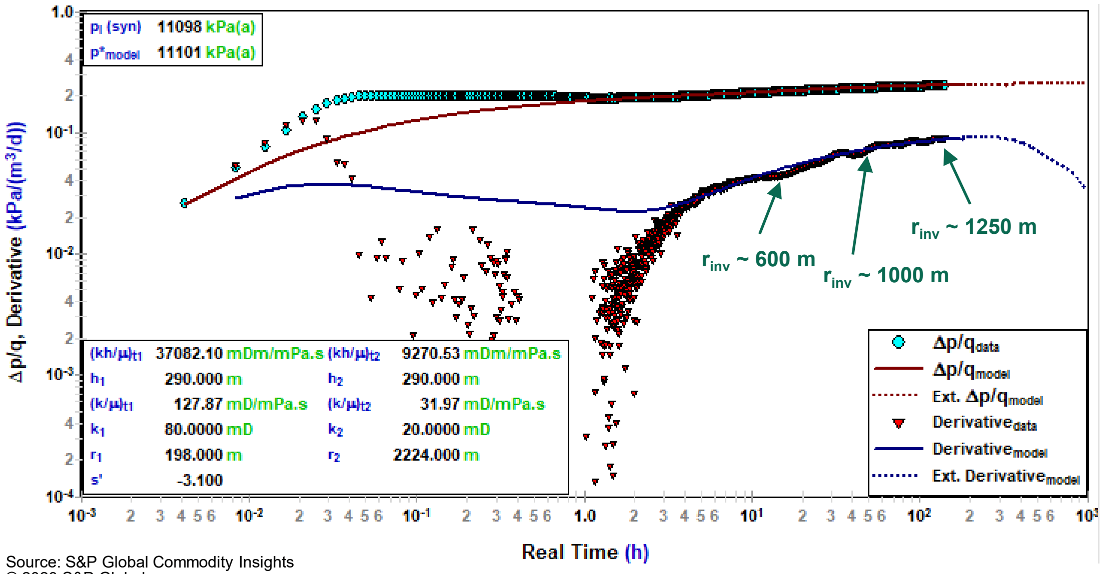
Source: S&P Global Commodity Insights

Expanded View of Falloff Pressure



Source: S&P Global Commodity Insights

Log-Log Typecurve and Pressure Derivative

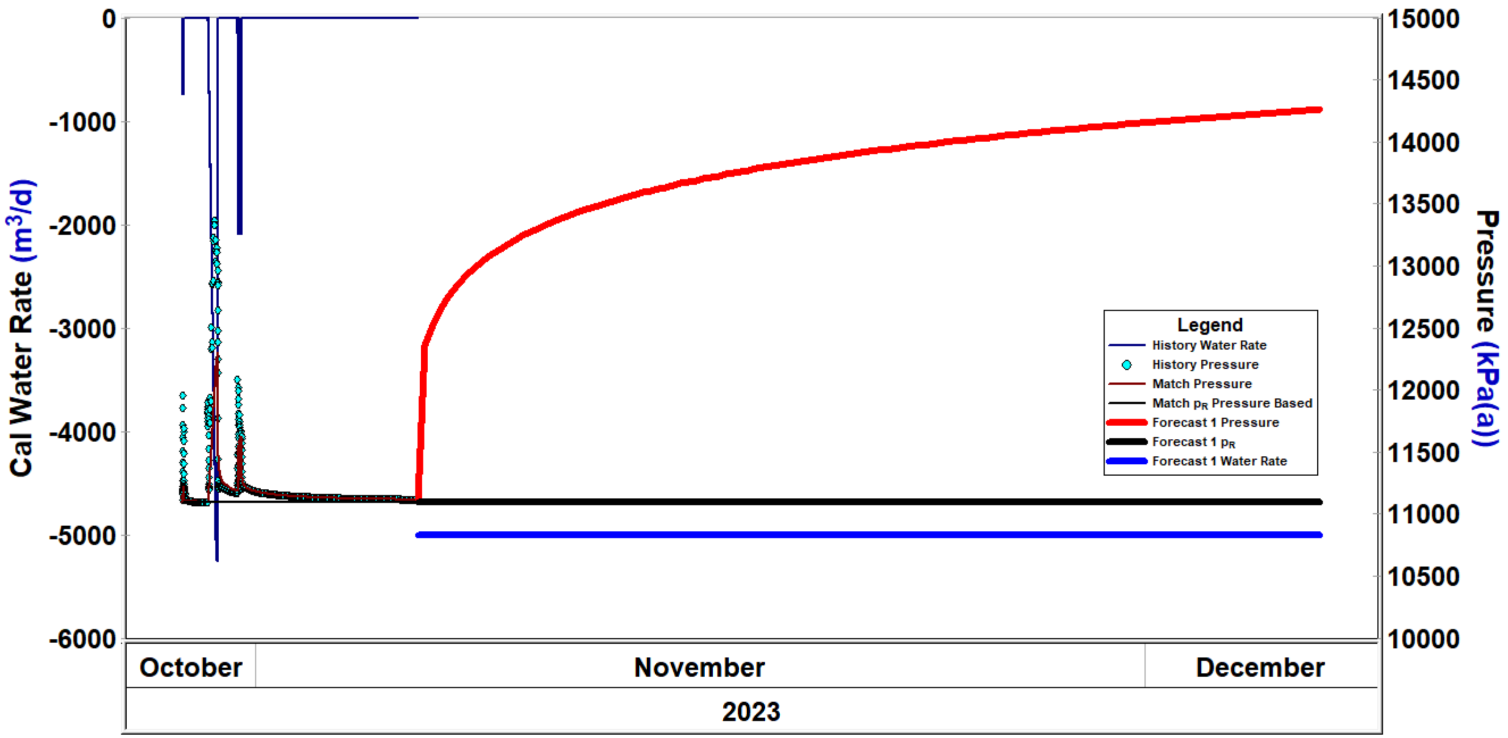


Source: S&P Global Commodity Insights

Falloff #3 (cont'd)

	Composite		
p_i	11097.0		kPa(a)
s	-3.10		
	Region01	Region02	
k	80.0000	20.0000	mD
h	290.0	290.0	m
ϕ_t	7.00	7.00	%
S_g	0.00	0.00	%
S_o	0.00	0.00	%
S_w	100.00	100.00	%
c_f	8.18e-07	8.18e-07	1/kPa
c_t	1.18e-06	1.18e-06	1/kPa
	Dual Porosity	Dual Porosity	
	Geomech		
	Boundaries	Boundaries	
Radius	198.0	50000.0	m
A	12.3	785385.8	ha
OWIP	2474.32	157782801.42	$10^3 m^3$
r_w	0.107		m
C_D			
	Chg. Storage		
	Chg. Skin		
	APE		

1 Month Injectivity Forecast



Source: S&P Global Commodity Insights
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- History matching focused on Falloff #3
- Early-time data is impacted by a break in the pressure derivative, which makes it ambiguous to establish region 1 permeability and skin uniquely
- A two region model was used, making it difficult to honor pressure prior to injection (i.e. a third region would be needed to honor pressure prior to injection)
- The reservoir size cannot be established from the test and a 6 section reservoir size (r_e = 2224 m) was assumed to extrapolate the reservoir pressure
- A 3030 section reservoir size (r_e = 50000 m) was assumed to generate the 1 month injectivity forecast

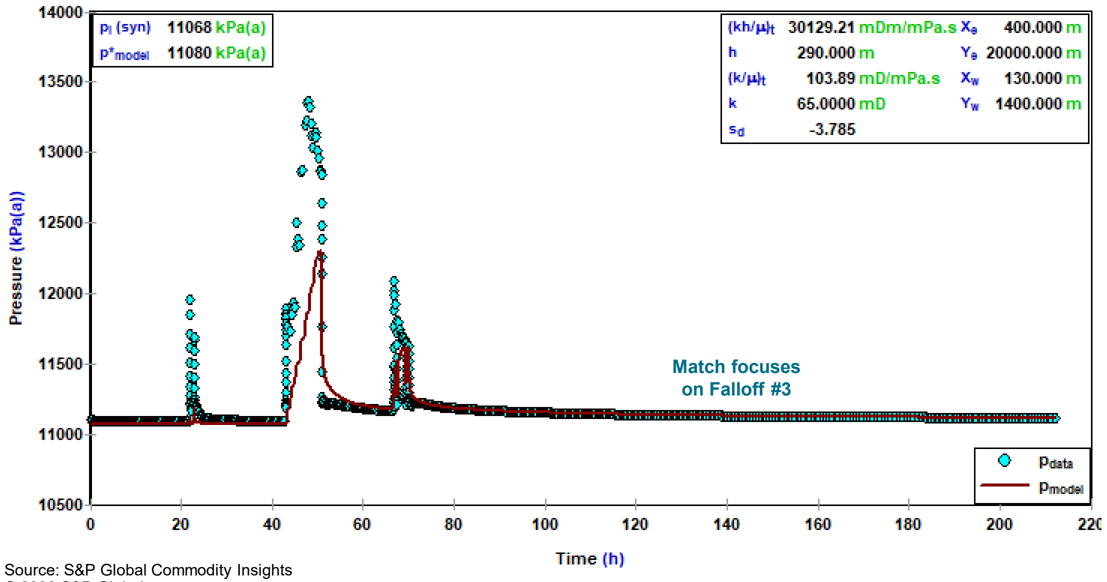
Channel Model

Reservoir Characteristics

CHANNEL RESERVOIR MODEL		METRIC		FIELD	
Initial Reservoir Pressure (History Match)	**(p_R)**	**11068**	**kPaa**	**1605**	**psia**
Average Res Pressure (History Match)	**(p_R)**	**11080**	**kPaa**	**1607**	**psia**
Net Pay (Provided)	(h)	290	m	951	ft
Total Mobility	$(k/\mu)_{t1}$	104	mD/mPa·s	105	md/cP
Permeability to Water	(k_{w1})	65	mD	66	md
Total Skin	(s)	-3.8		-3.8	
Reservoir Width	(X_e)	400	m	1312	ft
Reservoir Length	(Y_e)	20000	mD/mPa·s	65620	md/cP
X-Location of Well	(X_w)	130	mD	427	md
Y-Location of Well	(X_w)	1400	m	4593	ft

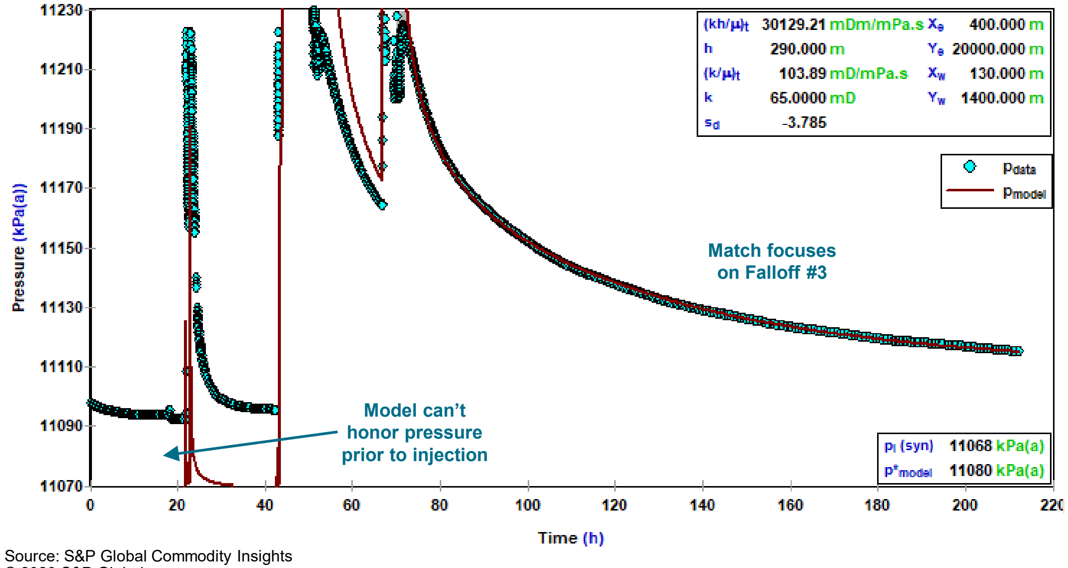
As of November 21, 2023
Source: S&P Global

Total Test Plot



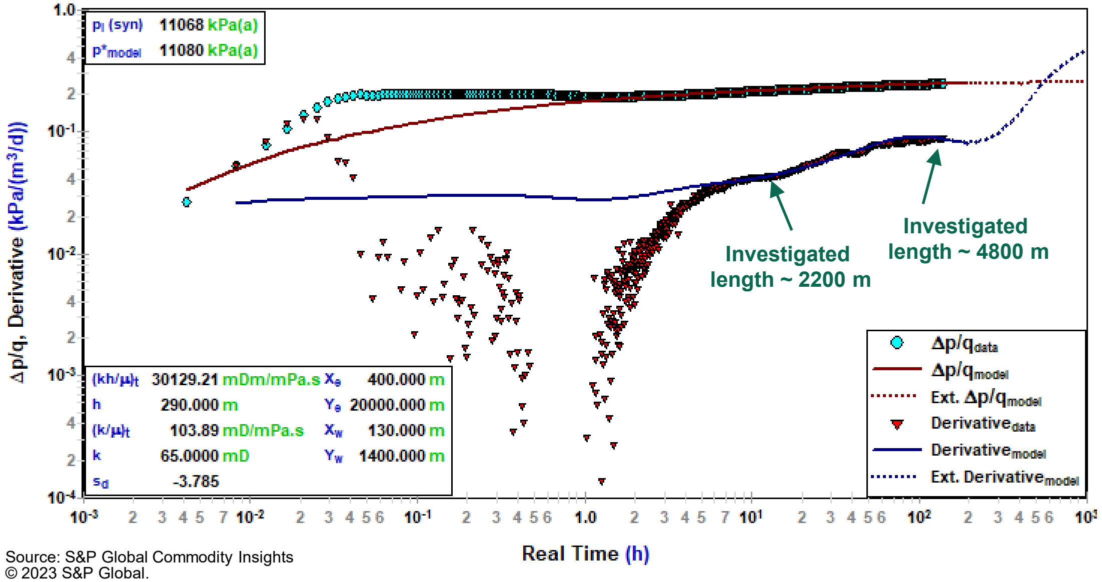
Source: S&P Global Commodity Insights

Expanded View of Falloff Pressure



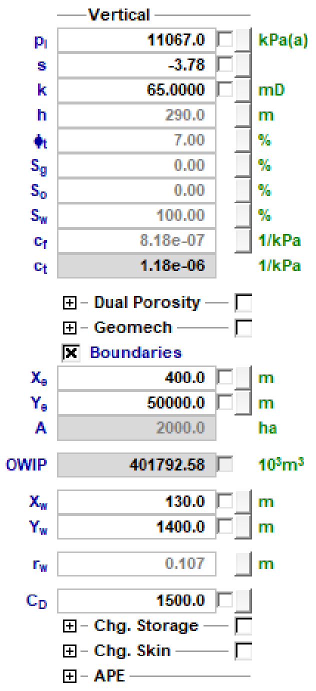
Source: S&P Global Commodity Insights

Log-Log Typecurve and Pressure Derivative

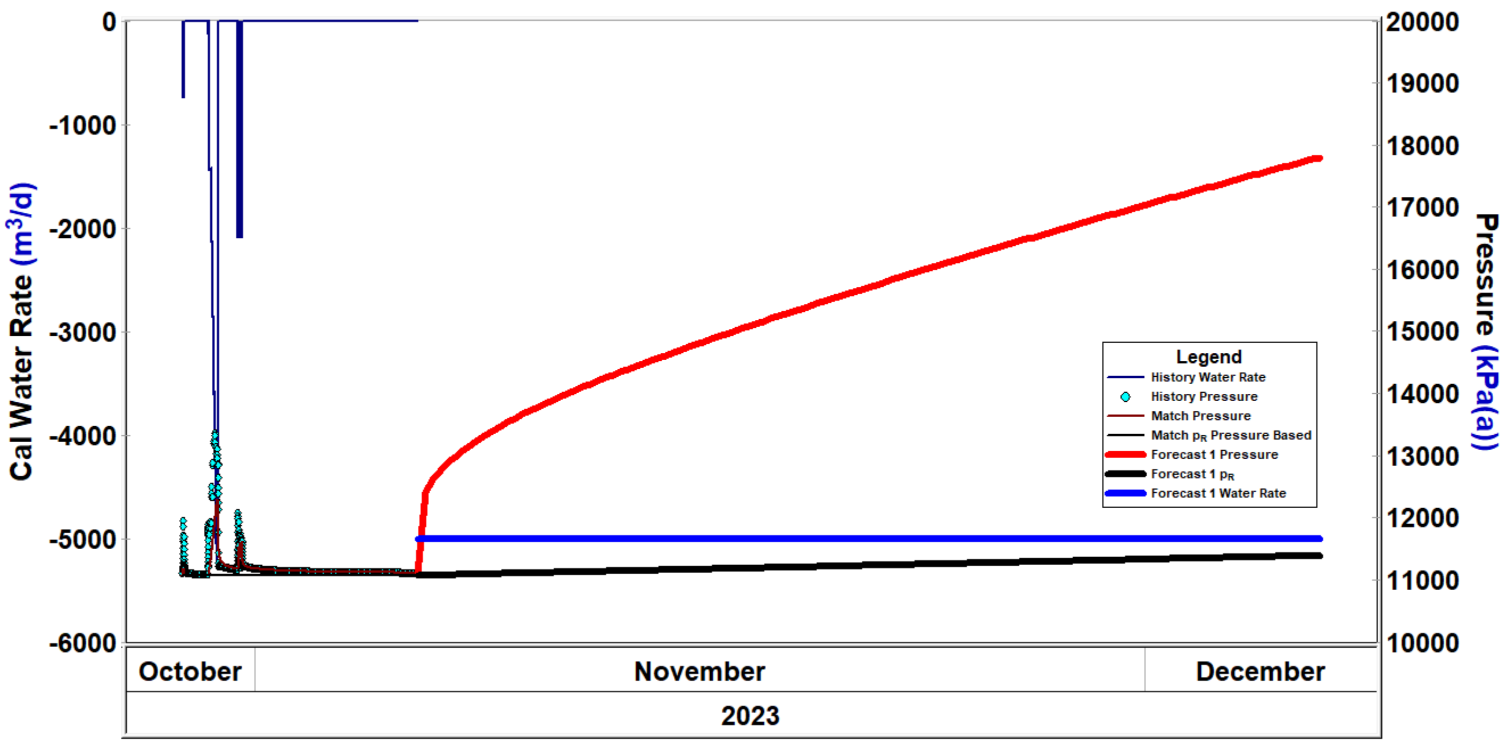


Source: S&P Global Commodity Insights

Channel Model (cont’d)



1 Month Injectivity Forecast



Source: S&P Global Commodity Insights
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- History matching focused on Falloff #3
- Early-time pressure data impacted by the pressure derivative break was ignored during history matching. Permeability and skin cannot be established uniquely
- To obtain a match with this model, the well was placed near one end of a channel like reservoir
- The reservoir length cannot be established from the test. A reservoir length of 20000 m (3 section reservoir size) was assumed to extrapolate the reservoir pressure
- A reservoir length of 50000 m (7.7 section reservoir size) was assumed to generate the 1 month injectivity forecast

Contents

Wellbore model was generated to calibrate the wellbore roughness using the recorded wellhead/downhole pressure and temperature data and estimate MWHIP for CO_2 injection

- Wellbore calculations were conducted using SPG Compositional VirtuWell module which allows the user to perform single and multi-phase flow calculations for different wellbore geometries such as vertical, slant, horizontal or complex configurations. The compositional module (equipped with EOS PVT model), enables the user to accurately calculate phase changes in the wellbore, etc
- The software calculates the Hydrostatic Pressure Difference and Friction Pressure Loss components individually, and then adds (or subtracts) them to obtain the total pressure loss inside the wellbore
- SPG compositional Virtuwell incorporated a rigorous adaptation of different correlations with hydrostatic pressure drop calculation such as Modified Beggs & Brill, Gray, Hagedorn & Brown, etc

- The wellbore model was calibrated using the measured water rate, wellhead/downhole pressure and temperature data before SRT#6 when a friction reducer was added to injected water
- The standard depth-related MWHIP value specified in AER Directive 061 (appendix O) for the target depth of 1,465 mKB at 16-29 location is 4,400 kPag. A corresponding BHP of 18,858 kPaa (pressure gradient of 12.9 kPaa/m) was determined at MPP depth using the hydrostatic pressure of fresh water
- Pure (100%) CO_2 composition was assumed for MWHIP calculations
- MWHIP values for CO_2 injection at rates of 1, 0.5 and 0.25 Mtonne/yr were calculated, taking into account the the estimated maximum BHP of 17,196 kPaa and utilizing the EOS-based wellbore model
- The calculated MWHIP values are significantly higher than the D-061 standard values

Wellbore Configuration

	103/16-29-057-25W6/00		
KB, m	715.4		
Flow Path	Tubing		
Reservoir Temperature, °C			
	ID (mm)	OD (mm)	Depth (mKB MD)
CSG	157.07	177.8	1,275.79
TBG	76.00	88.90	1,308.82
Liner	N/A	N/A	N/A
Open Hole		152	1,310.79 – 1,612.00
Top Perf			1,320.79
Bot Perf			1,612.00
MPP			1,465.00

MWHIP Calculation

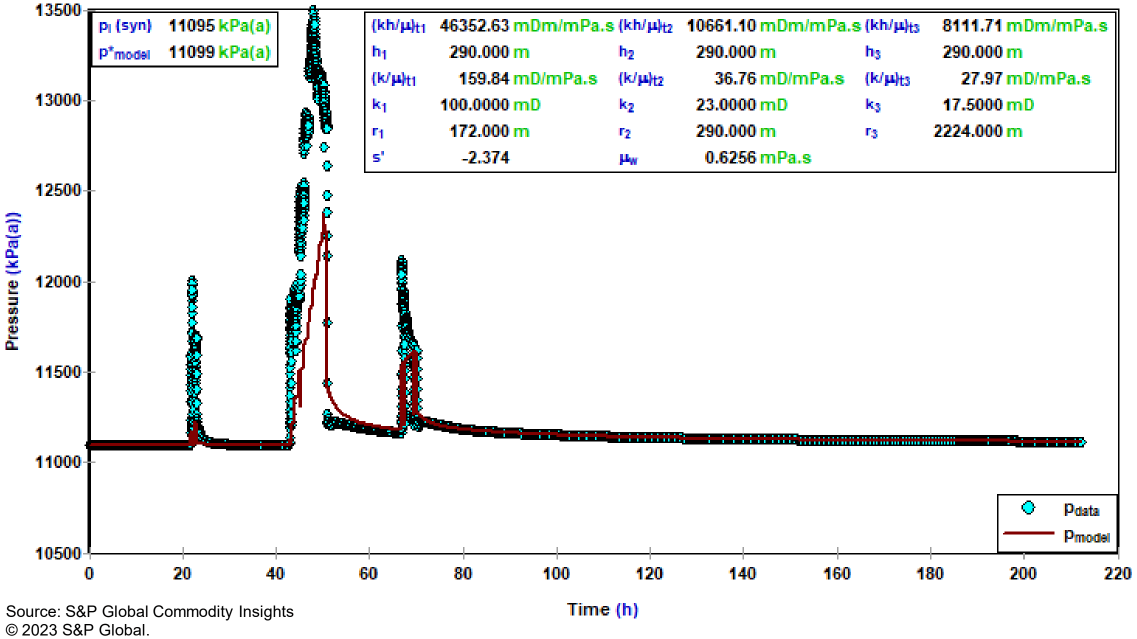
Case	Maximum BHP @ MPP (kPaa)	Gas Injection Rate (Mtonne/yr)	WHP (kPaa) (1, 2)
Match to 2.5 m^3/min	18,858	1.00	12,153
		0.50	8,058
		0.25	7,043
		0.00	7,611
Match to 1.5 m^3/min	18,858	1.00	14,759
		0.50	8,699
		0.25	7,196
		0.00	7,611

For wellhead to sandface temperature variation:
1) Isenthalpic assumption was assumed for injection rates of higher than 0.01 Mtonne/yr
2) Geothermal gradient assumption was assumed for injection rates of less than 0.01 Mtonne/yr

Contents

Interpretation Remains the Same if Working with Pressures at RRD or MPP

History Match – Pressure Adjusted to Leduc MPOH (1465 mKB)



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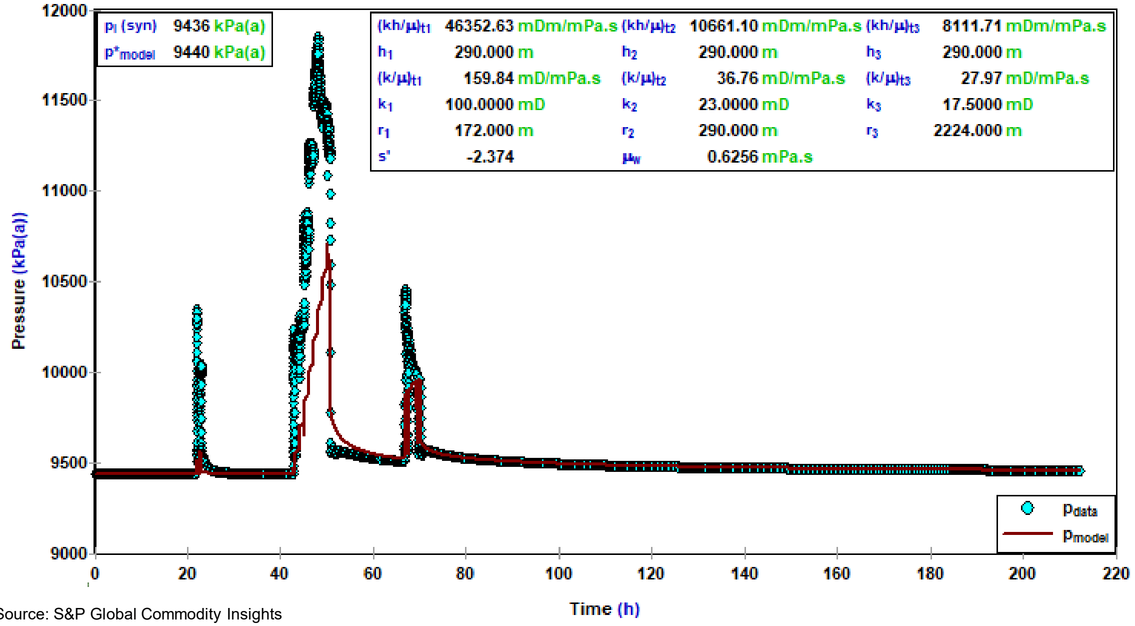
History Match – Pressure Presented at RRD (1295.68 mKB)



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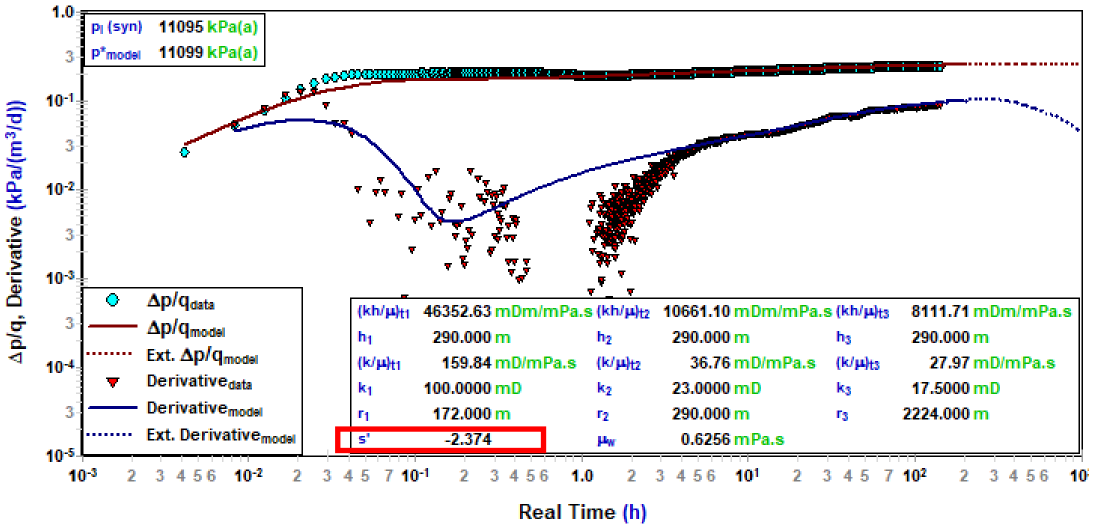
A Model Without Dual Porosity Yields Very Similar Results

Log-Log Typecurve and Pressure Derivative (w Dual Porosity)



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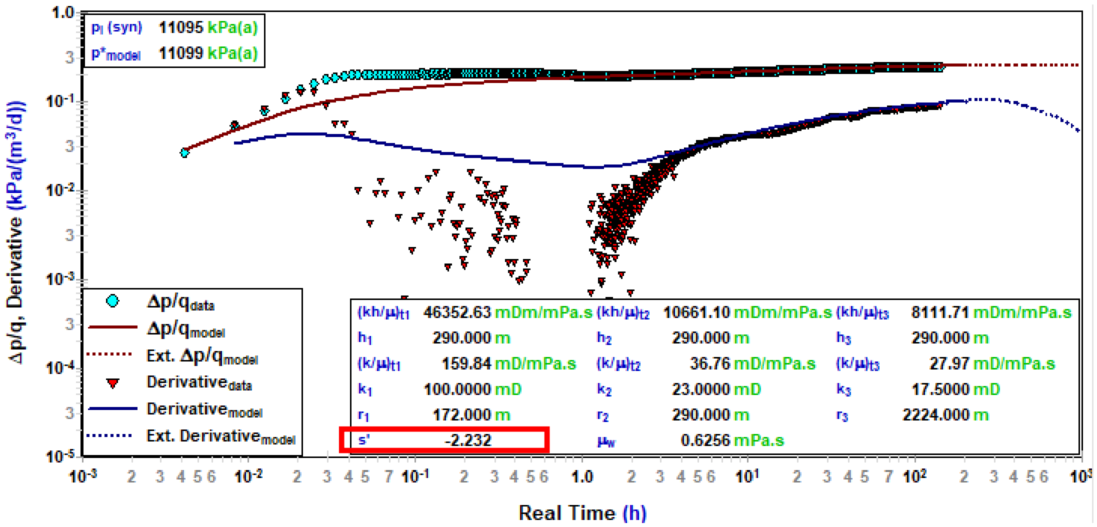
Log-Log Typecurve and Pressure Derivative (w/o Dual Porosity)



Source: S&P Global Commodity Insights
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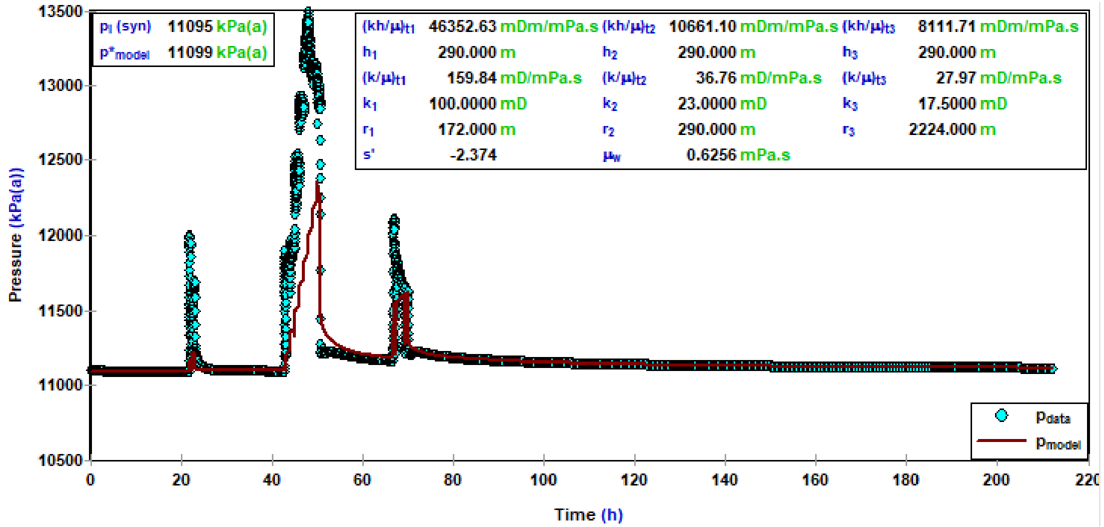
Total Test Plot (w Dual Porosity)



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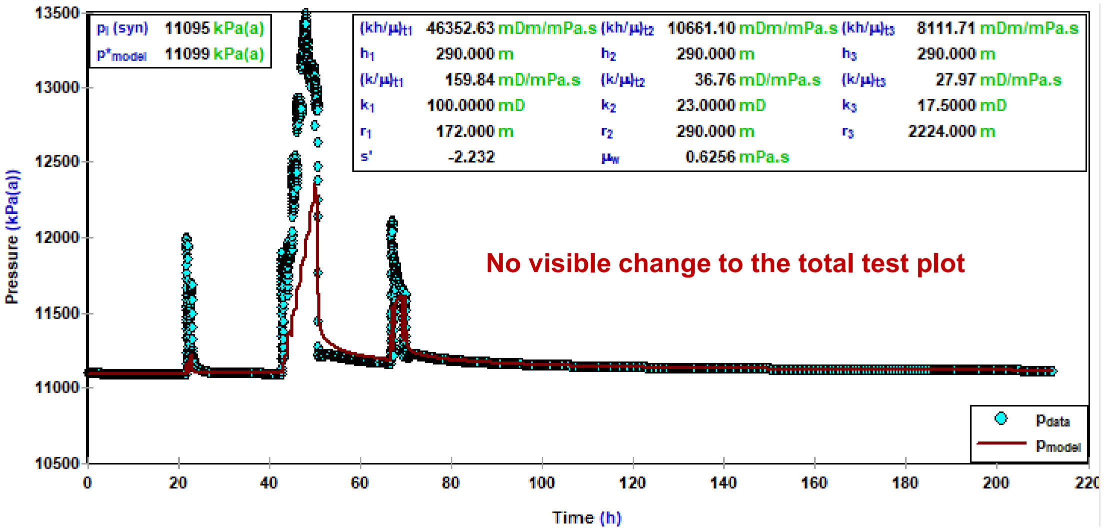
Total Test Plot (w/o Dual Porosity)



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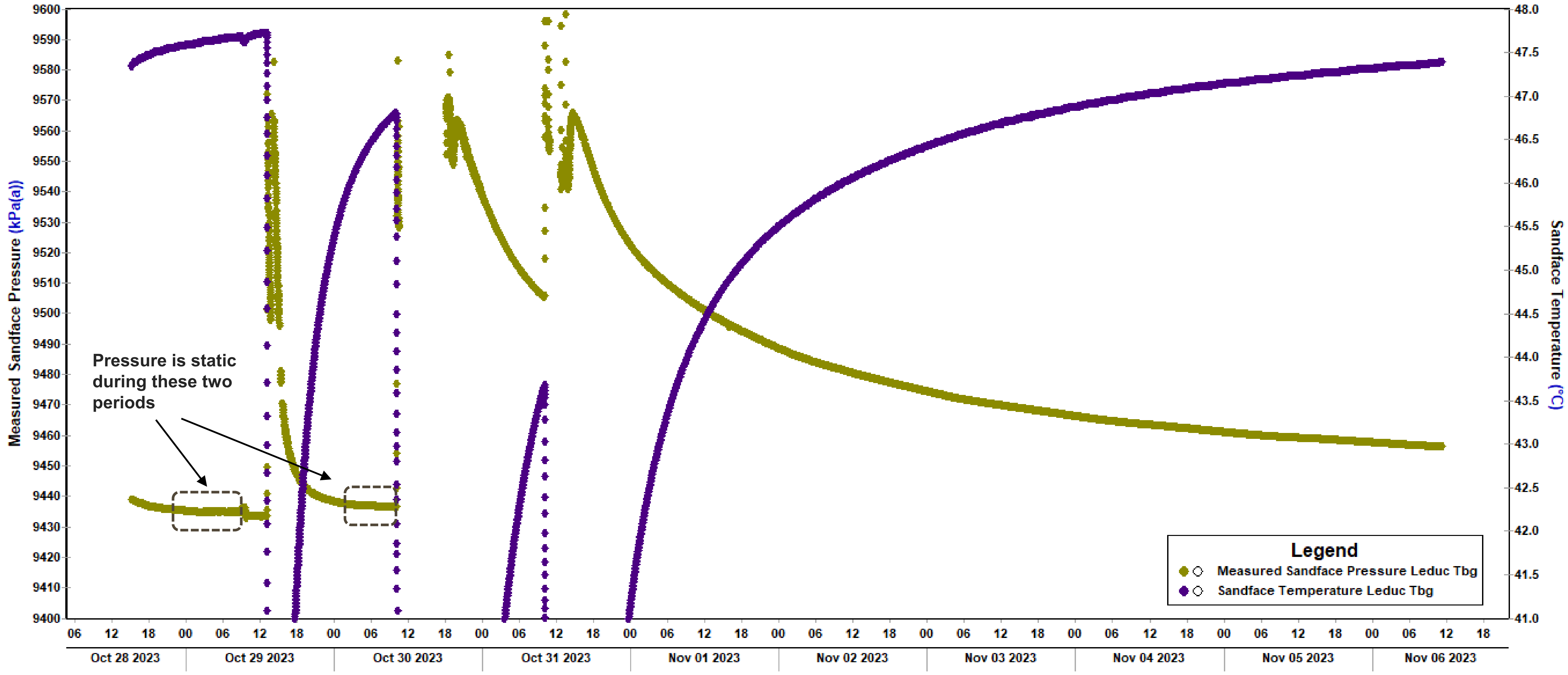
Two Periods with Static Pressure Were Recorded While Temperature Was Increasing

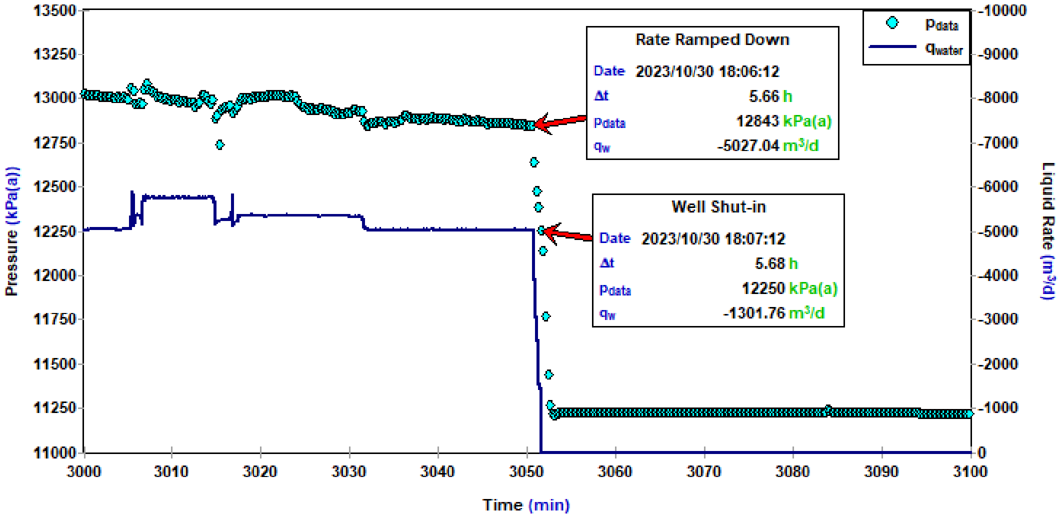
Total Test View



Source: S&P Global Commodity Insights.

The Final Rate Impacts Δp/q and Has Minimal Effect on the Pressure Derivative

End of Injecting Period #2: Actual Rate History



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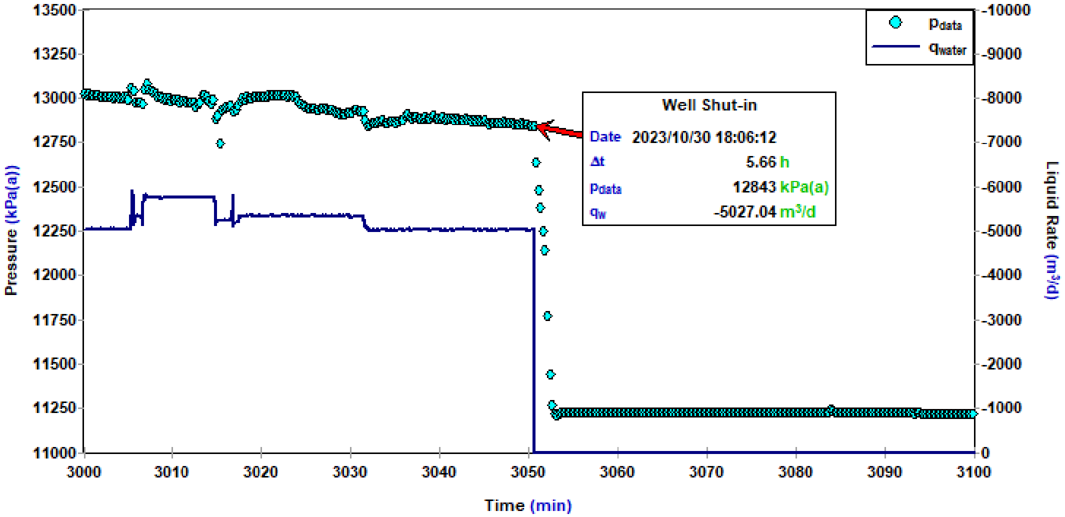
End of Injecting Period #2: Rate History Used for Analysis



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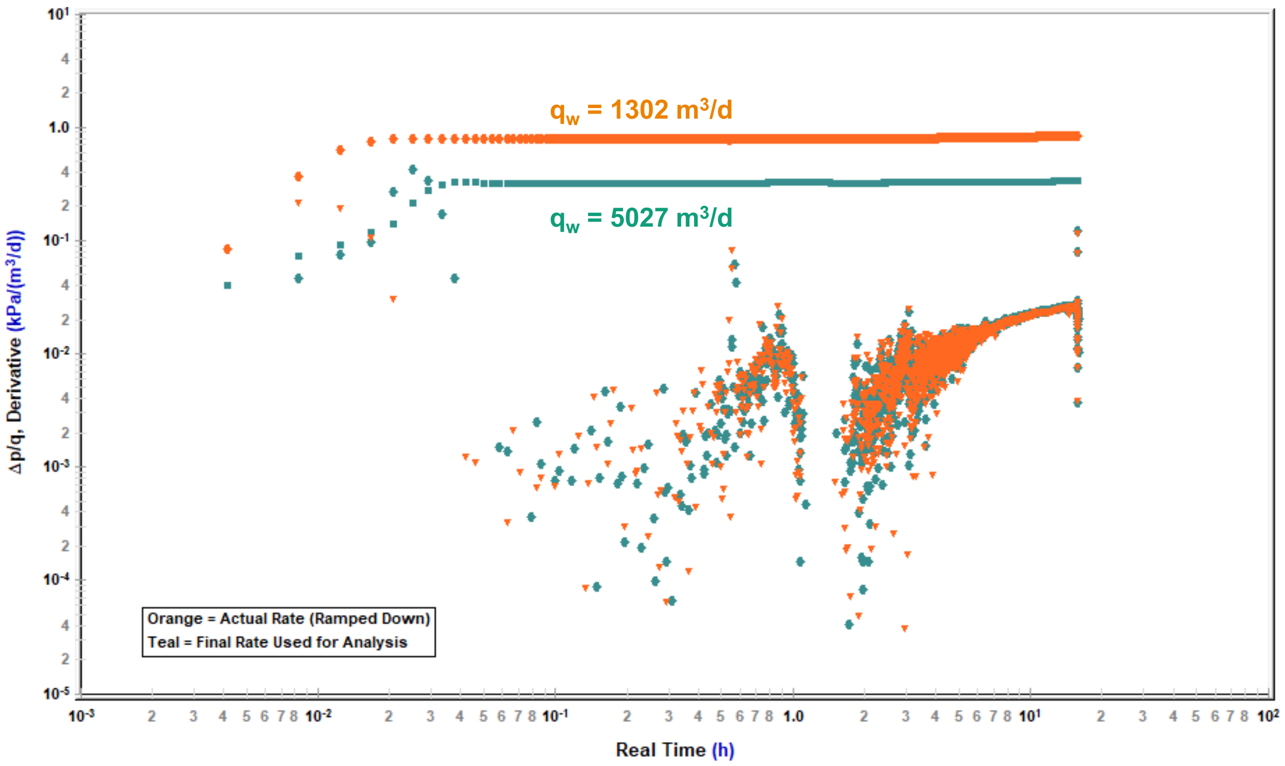
- Analysis was conducted using the rate prior to ramping down the pumps
- Although a new transient was generated while ramping down the pumps, its effect is negligible compared to that generated during the extended injection period

Log-Log Typecurve and Pressure Derivative Comparison



Source: S&P Global Commodity Insights
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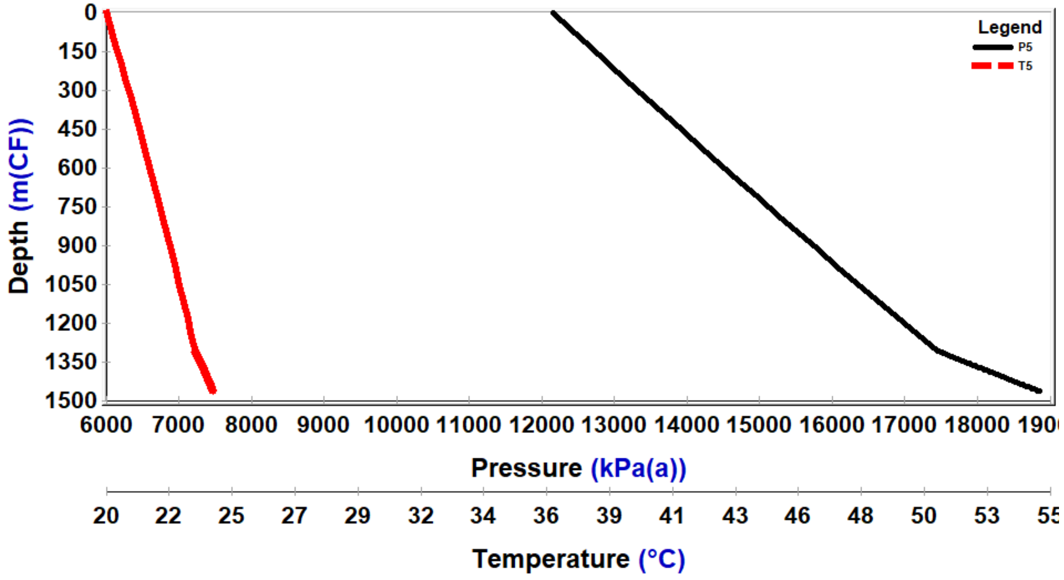
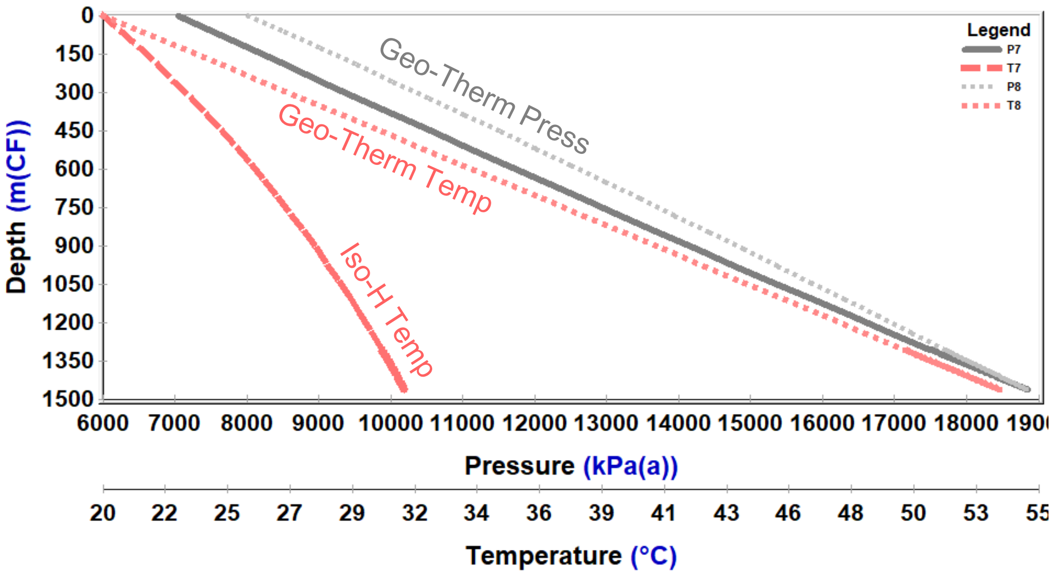
MWHIP Calculation: Match to 2.5 m³/min

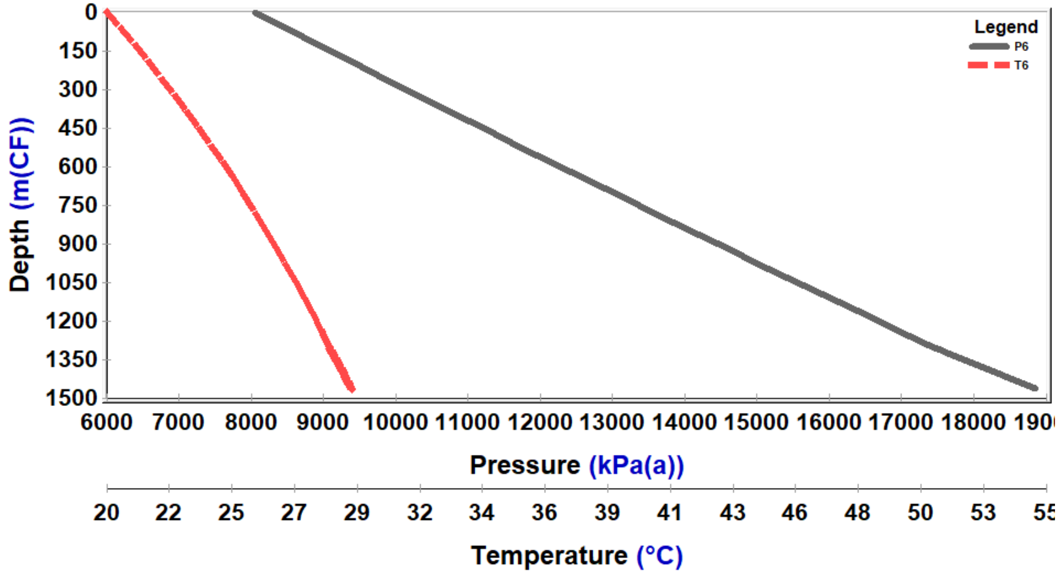
1 Mtonne/yr



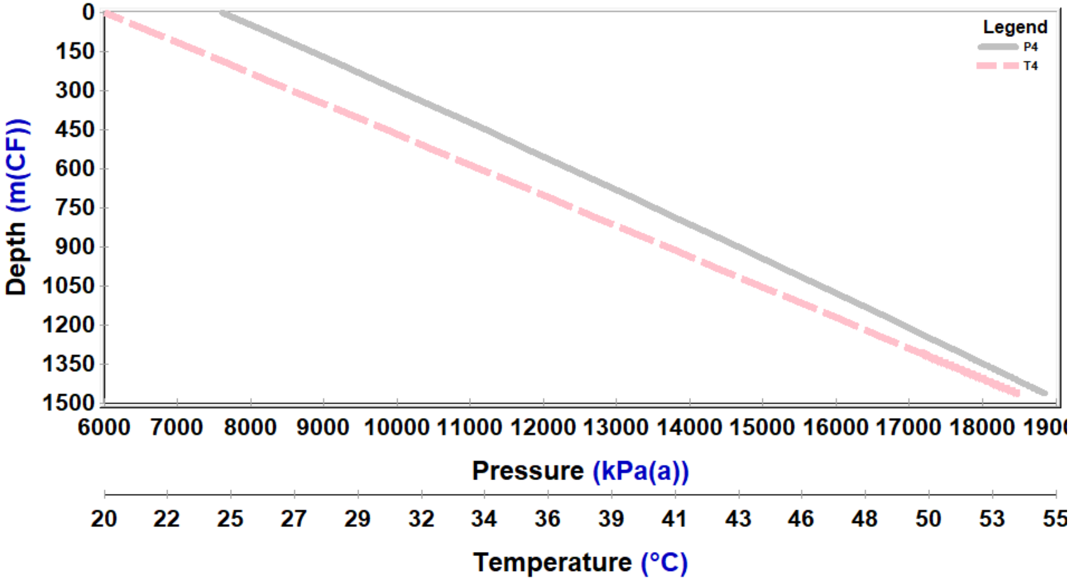
0.25 Mtonne/yr



0.5 Mtonne/yr

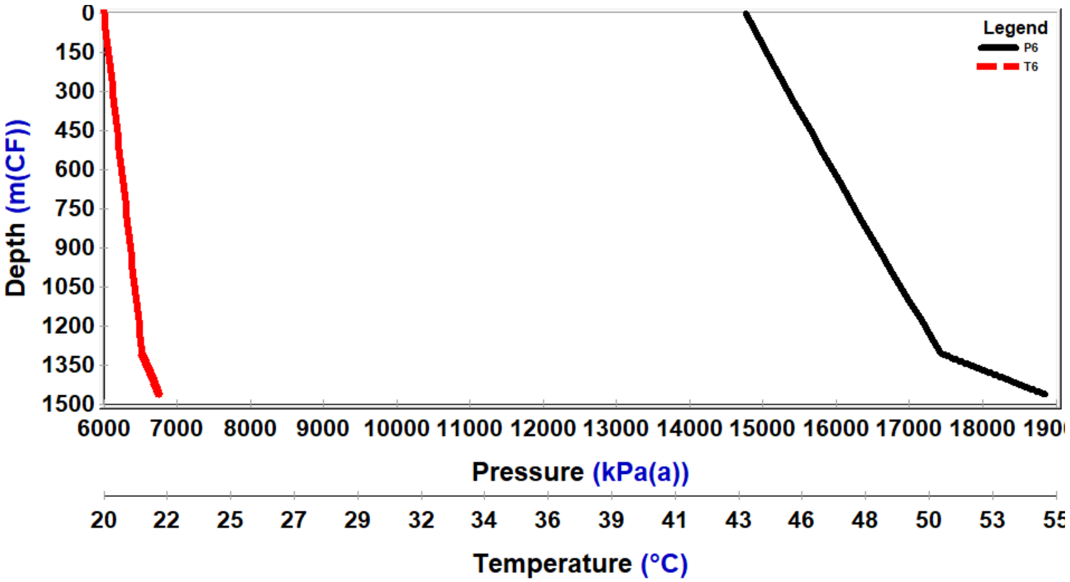


0.0 Mtonne/yr

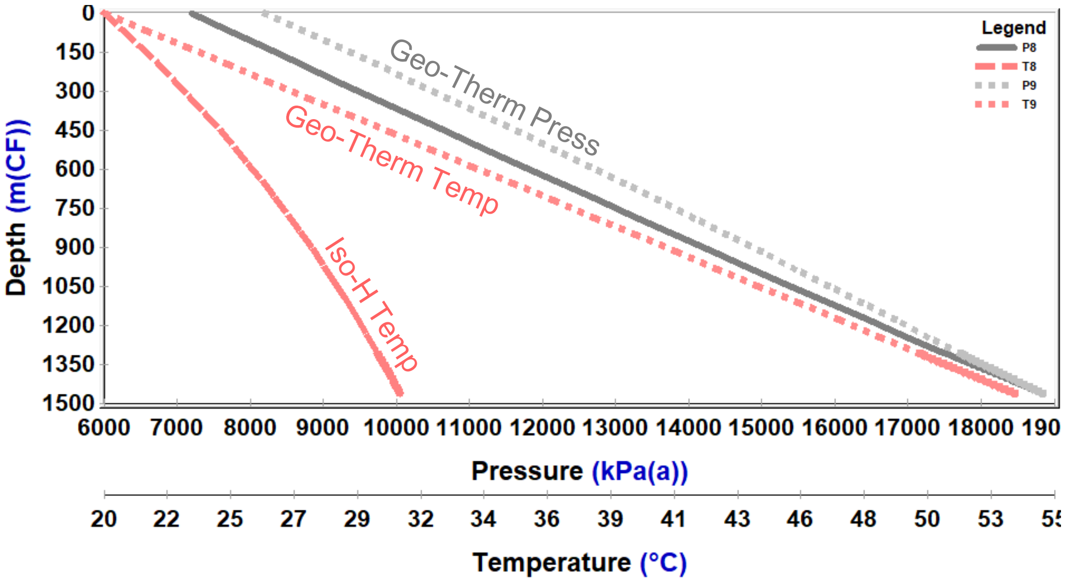


MWHIP Calculation: Match to 1.5 m^3/min

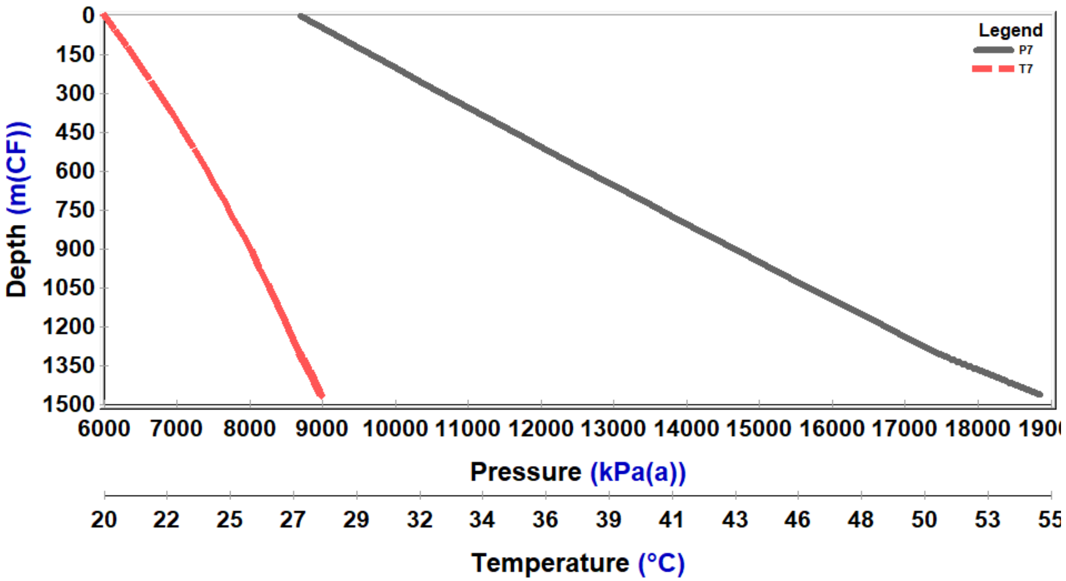
1 Mtonne/yr



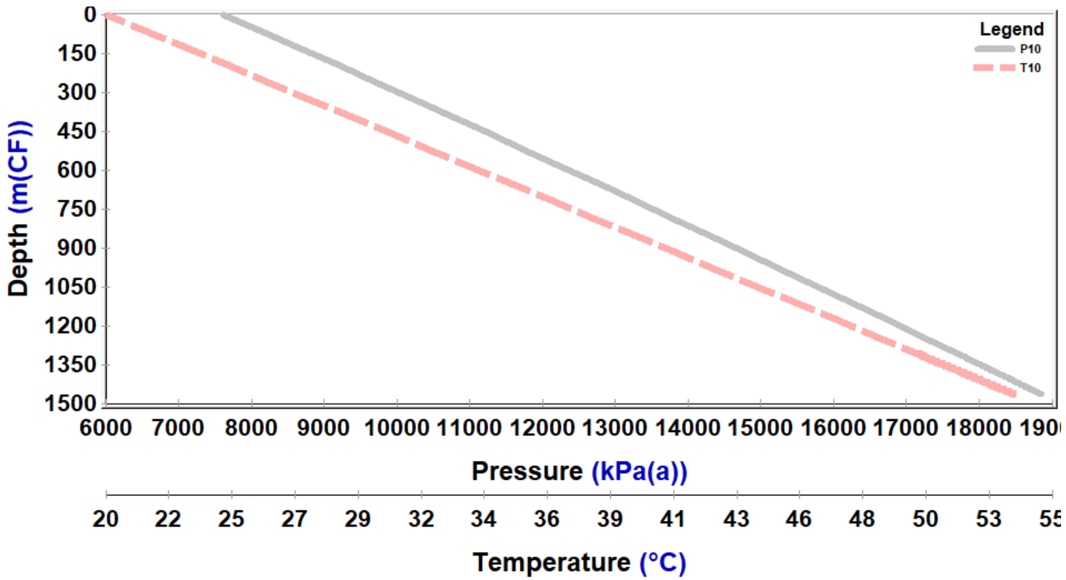
0.25 Mtonne/yr



0.5 Mtonne/yr



0.0 Mtonne/yr



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APPENDIX P: RISK REGISTRY

Meadowbrook
Risk Registry

Identified Risk	Consequence	Likelihood	Severity	Risk Score	Owner	Mitigation
Technical Risk - Resource/Reservoir	Insufficient well injectivity	1	4	4	GG	Confirm inj prior (SRT?). Have additional wells licensed and ready to drill. Detailed review of reservoir/ geology, including kH+CL, add wells, add clusters, add zones.
	Reservoir does not contain the CO_2 (IS, fault, mechanical)	2	4	8	GG/RE	Progression: Design (caprock work, Gassmann), assess & avoid, mitigate, minimize or eliminate, remediate Model, mature analogue and LOT support containment. 5 element monitoring/trigger protocol. Added a secondary seal in Duvernay
	Long term Capacity is limited (P up)	1	3	3	GG	Detailed review of reservoir/ geology, including kH+CL, add wells, add clusters, add zones. Consider additional zones CL, add D2 and BCS. Cycle downdip water to Cooking Lake.
	CO_2 brine/rock interaction (salt, ppt-dis, 'dry out')	1	3	3	GG/RE	Implementation & administration of an effective MMV plan. DFIT, P&T fibre, annual PT, plume visibility. Viscosity banking polymer. This commnet applies to capacity above. For this item the mitigation is "complete reactive transport modeling, monitor injectivity pressures."
	CO_2 brine/rock interaction (H_2S concentration at plume edge)	1	5	5	GG/RE	Reactive transport modeling quantifies potential occurrence (very low). Review of offset wells to determine potential migration and any gas migration history.
	Induced seismicity (lo P-fault slip, or hi P >FG)	1	4	4	GG	Baseline data beginning Mar '24. Check historic IS=quiet. Minimize connectivity to structure at depth. Confirm containment. Perf CL, add D2 and BCS. Cycle downdip water to Cooking Lake Pressure envelope-seismic discontinuity review Surface array w DAS
	Reservoir- Thermal contraction effect on strain (compression to tension induced fractures in the reservoir or caprock). Critical parameters are thermophysical properties, CO_2 surface temp, rate, formation temp.	2	3	6	GG	Develop thermal modeling capability (and recognize constraints). Ensure micro seismicity capability to hear 'snap, crackle, pop' Warm CO_2 at surface (plus increase pressure). Reduce delta T with offset from caprock (well design or scab liner), including Injection into the Cooking Lake. Moved injection zone strategraphically lower into Cooking Lake
Technical Risk -Drilling	Poor cement on SC	2	2	4	DR	Reciprocate and rotate pipe while pumping cement. Use 50% excess. Confirm water compatibility with cement. Stage surface cement.
	Poor cement long string	3	2	6	DR	Bond log, squeeze. Review of program is ongoing. Heal any losses in D2 and D3 by running cement plugs and drilling out plugs prior to running intermediate casing.
	Lost circulation in D2 or D3	4	2	8	DR	Lost circulation material. Drill D3 blind and POH with continuous top fill method. (used and worked, healed to support underbalanced hydrostatic). Heal any losses with cement plugs prior to running intermediate casing.
	Corrosion, LT well integrity	2	3	6	DR	Metallurgy, annual PT, FO P&T. Ensure CO_2 stream is dehydrated
	Inconclusive data to support FID or AER approval.	3	3	9		Injectivity? Caprock integrity? Develop fact based 'local' analogues.
	Failure on fibre installation	1	2	2		Using qualified services Avoid remedial cement necessity, see above.
Technical Risk - Surface Facilities	Inability to deliver specification CO_2 to PL or Hub (or phase change)	3	3	9	PM/OPS	Proper sampling and metering at custody transfer, facility entrance and pt of injection. Ensure commercial contracts clearly identify risks and contractual receipt specification and instrumentation prevents excursions; avoid liquidated damages or consequential risks (MRD)
	Inability to inject liquid CO_2 delivered to Hub (or phase change)	4	3	12	PM/OPS	Step Rate testing has indicated an very high reservoir permeability and lower than expected reservoir pressure. Design considerations to avoid phase change issues on surface will be required Hub facility redundancy/design to minimize outages. Understand possibility of hydrates due to pressure drop at pump or wellhead and be design accordingly
Schedule Risk	Failure to meet project schedule, related to customer commitments.	3	2	6	PM	Implementation of a rigorous stage gate process in planning/ execution phases to minimize unforeseen causes of delays.
	Failure to convert permit to license within 5 years.	1	5	5	EX	Identify long lead items early and understand those impacts to schedule.
	Partner Issues	3	3	9	EX	Proactive management of JVA and provide partners issues and recommendations early and often Ensure commercial contracts clearly identify Bison's responsibilities and limit exposure only to those factors within Bison's control (MRD) Develop steps plan, and execution plan to achieve it, in yr. 1, and update semi annually
Budget Risk	Cost overruns resulting from schedule, equipment costs, contractor costs.	3	3	9	PM	Implementation of a rigorous stage gate process in planning/execution to maintain current costs. Frequent (monthly) reporting of budget, actual, forecast and variances to project team to ensure frequent monitoring and mitigation of issues
	Significant scope changes due to current technical or regulatory uncertainties. (p50 plan)	2	2	4	EX/ALL	Implementation of a disciplined cost control system to monitor project exp. Seek guidance early and often, seek conclusive answers early. This is a 'highly likely' outcome and needs a 'manage' vs 'avoid' strategy. Communication Retention of qualified Regulatory personnel
Foreign Exchange Risk	Cost overruns related to unexpected foreign exchange variances	1	1	1	PM/EX	Limit requirement to secure foreign sourced equipment or services

Meadowbrook
Risk Registry

Identified Risk	Consequence	Likelihood	Severity	Risk Score	Owner	Mitigation
Scope Risk Post FID	Changes in project scope resulting impacting schedule, budget.	3	3	9	PM	Implementation of a detailed design review process Implementation of a disciplined Management of Change policy
	Regulatory requirement exceeds current expectation.	3	3	9	PM/EX	Seek regulatory guidance early and often, seek conclusive answers early Commercial contracts to identify custody transfer details so that scope is clear between counterparties (MRD)
Environmental Risk	Impacts to environment related to drilling.	1	2	2	DR	Initiate ground water monitoring prior to spudding any well.
	Shallow gas flow/migration risk identified at 90m.	3	2	6	PM	Assess volume/rate/control asap. Mitigate leakage 100%, retain 'observation' if possible. Work on legacy wells to reduce likelihood
	Impacts to environment related to construction.	2	3	6	PM	Baseline soil analysis, limited at this stage due to single lease scope.
	Impacts to environment related to operations activities (PL, facility, well, emissions, seep, leak, failure)	2	4	8	PM	Robust vendor management plan / Construction personnel understand requirements Adequate supervision Effective Emergency Response Planning implementation and oversight Understand the degree of complexity and design accordingly. Seek front line supervision with direct relevant experience. Properly emphasize priorities. Same plus critically assess how this differs from our past experience. Same plus critically assess how this differs from our past experience. Review of potential vendors environmental incident records prior to contracting
	Impacts to environment if the reservoir does not contain the injected C02 (baseline/background, seep, leak, failure)	1	5	5	GG/RE	Ensure MMV program is robust and adhered to Proper regulatory process in place Model the likely pathways, time/distance/volume that a potential ;leak' could represent, and identify potential triggers to be tracked, and surface effects (air quality, soil effect, credit impact).
Safety Risk	Drilling safety issues	1	3	3	DR	Implementation of detailed safety management plans , including incident ladder and tracking, audit, and comp element.
	Construction Safety Issues	3	3	9	PM	Requirement for all contractors to have properly certified HSE programs.
	Operational safety Issues	3	3	9	OP	Use of experienced site safety supervision
	Achieving closure and post closure safety risk	1	3	3	OP	Annual MMV reservoir performance reconciliation/prediction Minimize surface footprint
Political & Commercial Risk	Failure to deliver announced guidance.	3	4	12	EX	Develop effective Government Relations strategy and execute
	Changes to government policy related to carbon capture.	5	3	15	EX	Engage government officials to become a leading voice and trusted industry expert within government circles
	Credit claw back- AEP claws back monetized credit, owing to re-assessment	2	4	8	EX	Catastrophic failure would effect 'go forward' recognition not historic approved credits, Minimal risk in underbalanced reservoir, migration in low perm rock <1m/yr, difference between lack of conclusive volume 'in place' determination (1P vs 2P) and a 'leak' (evidence needed for where it is vs isn't?) Confirm standard is: Mechanical evidence for injection into the complex, and no evidence of it being in any other zone or interval, with approved MMV plan. If PDP required to avoid claw back, insurance may be required. (Ops history, visibility, ability to log), BLCV could build an 'insurance product' of .5Mt over say 5 years to back stop CCS (attractive to Hub operators, Insurers, emitters).
Unresolvable Stakeholder concerns or Activism Risk	Schedule, cost or program re-design impacts resulting from unresolved stakeholder concerns or stakeholder activism.	3	4	12	EX	Insure community engagement early and often in the project. Ensure messaging is clear, accurate and EARLY. Maintain as high degree of surface flexibility as possible. Particularly for pipelining have optionality on routing. Maintain strong relationship with first nation group(s) and engage cooperatively in the community when the opportunity arises. Consider community charity donations to maintain favourable reception by residents (MRD) Communicate clearly and consistently, using independent data where possible
	First Nations Consultation	2	3	6	EX	Engage Alexander consultation team and ACO
Regulatory Risk	Operator and Well license approval	1	5	5	EX	
	Approval for TIER project registration.	2	4	8	EX	Ensure complete understanding of Regulatory requirements form plan as required
	Commercial Sequestration Lease (CSL) approval (AE phase 1)	0	3	0	EX	seek expert and regulator advice as required. apply early.
	D065, MMV and AEP approval (phase 1)	2	4	8	EX	Engage qualified intermediary to guide the application preparation process internally. Track resource allocation and results, augment as necessary.
	CSL approval (AE phase 2)	1	5	5	EX	
	D065, MMV and AEP approval (phase 2)	1	5	5	EX	

Meadowbrook
Risk Registry

Identified Risk	Consequence	Likelihood	Severity	Risk Score	Owner	Mitigation
Human Resource Risk	Inability to hire qualified people for Bison	1	3	3	EX	Expand on Bison use of personal contacts for potential candidates Public Relations to build Bison brand and image to attract candidates
Commercial Risk	Inability to contract for sequestration revenues	3	5	15		Maintain steady focus on BD efforts
	Ability to secure effective CCUS insurance	2	4	8		Use Bison relationships for leads, networking
	Customer Credit Risk /Default on payment	3	2	6		Design and Acquire appropriate project level Insurance for JV
	Ineffective Credit Management	2	2	4		Design and Acquire appropriate project level Insurance for JV Credit management of delivery of credit on receipt of payment (credit transfer mechanism) Use Bison investors and support companies (legal, enviro) to build customer lists (MRD)
Funding Risk	Partners unwilling to fund	3	3	9	EX	Effective GR strategy to ensure ITC's and APIP available for Bison
	Bison unable to get necessary debt financing	2	3	6	EX	Proactive discussions and reporting with Partners to determine if ability to fund / participate changes
	IRC unable to fund	5	1	5	EX	Ensure contingency in place to cover IRC costs if necessary
Partner Risk	Partners are not aligned with development plan	2	2	4	EX	Properly management notice provisions
	Ability to block or slow development	1	5	5	EX	Enforce governance to ensure efficient decision making process

MEADOWBROOK CO2 HUB RISK MATRIX

SEVERITY

LIKELIHOOD	1	2	3	4	5
1	LOW – 1 –	LOW – 2 –	LOW – 3 –	MODERATE – 4 –	MODERATE – 5 –
2	LOW – 2 –	MODERATE – 4 –	MODERATE – 6 –	HIGH – 8 –	HIGH – 10 –
3	LOW – 3 –	MODERATE – 6 –	HIGH – 9 –	HIGH – 12 –	EXTREME – 15 –
4	MODERATE – 4 –	HIGH – 8 –	HIGH – 12 –	EXTREME – 16 –	EXTREME – 20 –
5	MODERATE – 5 –	HIGH – 10 –	EXTREME – 15 –	EXTREME – 20 –	EXTREME – 25 –

APPENDIX Q: MEASUREMENT, MONITORING AND VERIFICATION PLAN

Meadowbrook Carbon Storage Project

CSA Measurement, Monitoring and Verification (MMV) Plan.

October 21, 2024

Submitted by Bison Low Carbon Ventures Inc.

Meadowbrook Carbon Storage Hub **October 21, 2024.**

Proposed Monitoring, Measurement and Verification (MMV) Plan for the Phase 1 CSA approved area.

The Meadowbrook carbon storage project requires an MMV and risk management plan for the initial phase Carbon Sequestration Agreement (CSA) application that address's the degree to which our activities will not only deliver on the safe, secure and permanent geological storage objective of the tenure award, but assess how they may impact other land use activities, wildlife habitat, hydrocarbon recovery, alternate mineral tenure/pore space use, and any other land use. The phase 1 CSA MMV plan presented herein, is intended to ensure long term containment and permanent safe storage of carbon dioxide (CO_2) and demonstrate a robust iterative risk management plan incorporating assessment, measurement and mitigation of risk through the life of the project. Phase 1 is expected to start at 70-100ktpa in 2025 and add volume as customer demand and reservoir performance support. All phase 1 volumes will be delivered via tractor trailer and the pipeline connection of the Hub to a larger customer will signal progression to phase 2 and will be the subject of a second AER application and approval. All phase 1 storage operations will occur on a single wellsite at 16-29-57-25W4M.

As required for our D065 approval, and as per section 17(1) of the Carbon Sequestration Tenure Regulation, Article 9.2 of our Carbon Sequestration Evaluation Agreement (CSEA), and article 3 of CSA 5924070002, Bison Low Carbon Ventures Inc. will request AER approval of our MMV plan for the portion of our tenure defined on Schedule A to CSA 5924070002 between Bison and the Minister, effective July 30, 2024 (and attached here for reference).

In support of our request, we have considered and incorporated a plan to address the following issues, and their related uncertainties.

1. Risk Management Plan And Emergency Preparedness.
2. Atmosphere- Air Quality Measurement And Monitoring.
3. Hydrosphere- Groundwater Quality Measurement And Monitoring.
4. Biosphere Impacts (Soil Quality, Vegetation And Wildlife).
5. Geosphere- Downhole CO_2 Containment Monitoring.
6. Geosphere- Geophysical Plume Monitoring.
7. Geosphere- Monitoring For Induced Seismicity
8. Geo-Chemical Interaction Of Brine/CO_2 And Rock.
9. Geo-Mechanical Characterization And Mechanical Earth Model. (Including Thermal Effects)
10. Hydraulic Isolation And Legacy Well Risk.
11. Pipeline Design, Monitoring And Dispersion Modeling.
12. Post Project Closure Plan.
13. Potential Effects On Hydrocarbon Recovery.
14. Potential Impact On Current Land Use.
15. Potential Impacts On, And From, Alternative Pore Space Uses.
16. Conservation Of Pore Space As A Resource.
17. Bison LCV Risk Management Process Schematic.

In support of the discussion of these MMV program elements we also include the following appendices;

1. CSA 5924070002 (Appendix M D065 application)
2. Bison MCSH Risk Registry (Appendix P D065 application)
3. Millenium Baseline Groundwater Study
4. 16-29 water well lithology log.
5. Matrix Groundwater Survey plan.
6. 16-29 well data (LOT, SRT). (Appendix J & O D065 application)

7. 16-29 completion/recompletion well schematics. (Appendix G D065 application)
8. ESG 16-29 site Seismicity data March-May 2024.
9. Geo-Mechanical Characterization and Analysis.
10. TSR report.
11. SLB 1D Mechanical Earth Model
12. Legacy well assessment. (Appendix H D065 application).
13. Species at Risk Assessment for 16-29-57-25W4M site.
14. Goechemistry - Reactive Transport Model for MCSH

In recent years, several international authorities have published guiding principles for MMV plans of Carbon Capture and Storage (CCS) projects which underscore the importance of site-specific risk assessments that are adapted to storage performance over time. Our proposed MMV and risk management program incorporates principles from CSAZ741, the Alberta Energy March 2022 'Principles and Objectives' guidance, the July 2024 guidance from AER regarding amendments to D065 around seismicity and MMV, and learnings from precedent project annual reports (Quest), in a plan adapted to our specific project and reservoir. Human health and safety are the primary concerns in the design and operation of all phases of the project including the MMV and risk management plans. Beyond that, the data collected and analyzed as part of the MMV plan is intended to ensure minimized impact on the environment by compliance with all AER/AEPA regulations and permanent containment of the CO2 throughout all stages of the evaluation, development, operation, abandonment, and post-project closure operations. It is expected that based on project performance, discussions with the AER, and an assessment of risk on an ongoing basis, that the frequency and design of the MMV program elements may change to be more relevant and effective.

Evaluation Phase activities are complete, our CSA has been approved, and we are integrating all data gathered into the final technical support for our AER approvals (D065, D051, D071) including this MMV plan, which we intend to submit to the AER as soon as practical.

The scope of operation proposed in our request for AER D065 approval, to which this MMV program is to be applied, is the construction and operation of a single CO2 injection site that will receive, temporarily store and inject up to 500ktpa of trucked liquid phase CO2. Increased volume up to our design capacity of 3Mtpa and the pipeline connection of the Hub to emitter customers will be the subject of a subsequent application at a later date, timed to coincide with an emitter customers project start.

1. Risk Management Plan and Emergency Preparedness

The project risk management plan delivers an evolving site, scope and time specific assessment of project risks and incorporates the MMV program derived data to measure performance, adjust practices and inform decisions. As mentioned previously, the risk management plan is based on the process and principles outlined in CSAZ741 and incorporates ongoing site-specific assessment, avoidance, measurement, mitigation, and reporting of project and process risks. An integral element of the plan is our risk registry which evolves through a monthly multi-disciplinary review as the project progresses, knowledge is gained, and as risks change or are identified. A copy of the current risk registry is attached to this application (Appendix 2). Going forward, we will incorporate an independent audit, and industry best practices commitment, to ensure our program meets or exceeds the required standard.

Our risk management plan is entirely consistent with Bison values as a company and our objective for the Meadowbrook project. The guiding principle in assessing risk prioritizes human health and safety over project performance. Our internal risk management plan is augmented with the resources of external subject experts to provide a level of independence and ongoing critical assessment. **Jeff Weaver**, Founder and CEO of InUnison Technologies Corp. provides extensive experience and expertise in the areas of Safety, Training, Competency, Maintenance and Management of Change to Bison and the MCSH project. The integrated management system, and the associated technical advisors, provided by InUnison will provide the tools to the project that assist in protecting all stakeholders and operations, lower our risk profile, and drive compliance.

From a general safety perspective, CO2 in low concentrations is not considered a health risk (air we breath is 400ppm) but at a high enough concentration for a long enough period, CO2 can be an asphyxiant. CO2 is also heavier than ambient air and will settle until it disperses. CO_2 is not combustible. Our operation will handle >95% pure CO_2 in a liquid phase under high pressure and low temperature, which facilitates safer long-term handling (corrosion) and storage. At atmospheric conditions CO_2 is a gas, heavier than air, and any release will flash to gas phase and dissipate in a matter of minutes to concentrations not considered a health hazard. In most Alberta weather conditions (10C and 70% humidity) a CO_2 release will be visible as it condenses to snow or fog. Project specific modeling of the dispersion plume created by a catastrophic release in terms of release rate, volume and duration will inform the D071 (Emergency Preparedness and Planning) risk assessment. This will inform the design of the pipeline system in later phases, but in phase 1, will concentrate on the dispersion risk from a 55t storage tank onsite. Design considerations to reduce the likelihood of a failure, reduce the volume if there is a failure, and increase the chance of detection before a failure will be combined with location considerations, to mitigate potential health impacts.

The potential release rate and volume for this phase of the project will be limited by the capacity of the trailers used to transport (25t, and 35t B train) and store (55t) the dense phase CO_2 (2200kpa, -24C) delivered by tractor trailer to the initial Meadowbrook storage site at 16-29-57-25W4M. Initial volumes will be delivered by and from Ferus Industries Ft Saskatchewan facility. Any additional volumes sourced will be delivered by Ferus or other licensed, bonded contractors with experience handling similar materials.

With regards to emergency planning for the proposed Bison installation, the worst case scenario would entail a catastrophic failure of one of the 55 tonne liquid CO_2 storage tanks. Assuming a 100% full tank operating at -24C and 2200kPaa this would result in a release of approximately 25,000 Sm^3 of CO_2 assuming the entire tank volume converted to gas phase. More likely, given the sudden drop in temperature, a portion of the volume would form a solid, dry ice, which would gradually sublimate to gas phase. For the purposes of calculating the length of time for the vessel to depressurize, an 8” failure in the vessel wall was considered and it was determined that the vessel would attain atmospheric pressure in just over one minute. From a safety perspective, the extreme cold would pose a risk to personnel in the immediate vicinity. In addition, gas phase CO_2 is heavier than air and hypoxia would be a risk in confined or low lying areas close to the venting tank. However, given the relatively low potential volumes of gas phase CO_2, the concentrations would disperse in the atmosphere very rapidly in the area surrounding the facility and would pose very limited risk or impact to people or animals outside a 100m radius of the facility. Regarding risk to operating personnel in close proximity, those risks are mitigated by Bison’s safety program and Standard Operating Procedures.

Bison has reviewed the safety protocols of operators involved in trucking liquid CO_2 and concludes that there are limited stakeholder risks in the event of a release of CO_2 from the proposed facilities and consistent with other operators operating under similar conditions, recommends a 100m EPZ.

As a practical comparison, modeling of a 1500ton release from a fullbore rupture of a 50km 8” pipeline at 11Mpa had a maximum 158m2 plume of 10% CO_2 concentration 2.5m high after 3 minutes (UK Energy Institute reference). A full rupture of all three tanks onsite would release approximately 10% of that volume and form a plume much smaller than the 150m2, on a lease where the first 500m2 in any direction (assuming a 10m wide plume focused in a single direction) would be contained within the lease boundary.

Failure of a high pressure steel container (pipeline or vessel) can have an explosive effect that would pose a significant risk for a short distance. This risk would be greatest at our plant site and be mitigated by proper design, ongoing testing and preventive maintenance, proper training and safe work practices.

2. Air quality measurement and monitoring (Atmosphere)

Bison has engaged with Millenium EMS Solutions Inc. (MEMS) and SenseNet Inc. to deliver our atmospheric monitoring strategy for emissions and leak detection. We have designed a robust innovative program that will be refined as data is generated.

The 103/16-29 injection well has a non-serious surface casing vent flow that was measured in November 2023 at 4.1m3/d of 96% methane (trace CO_2). As per AER regulations we will re-test the well within 90 days of injection commencing, annually for two years, to determine any changes and the defined go forward monitoring plan required. In addition, we will sample the rate and composition of the SCVF gas at least annually for as long as it lasts.

SenseNet (www.sensenet.ca) will deploy a permanent continuous AI enabled ‘mesh net’ wireless sensor array sensitive to 40ppm CO_2/CH_4, at our 16-29 injection facility site, and at five other sites and residences within the project area. Our site array will initially require a 12 sensor array around the wellhead area, one gateway to transmit data to the cloud, and soil gas measurement instruments to support source location determination attributable to any atmospheric change. This will be operational prior to commencement of CO2 injection. The technology is currently deployed in early forest fire detection and is supported by a range of credible sponsors including the Governments of Canada and BC, and is an ideal solution for consistent, real-time, cost-effective monitoring over a wide area. As part of the technologies testing and validation, we will conduct a number of small duration/volume 'leaks' to optimize arrays and determine sensitivities, which can then be compared against currently deployed solutions.

The four additional deployment sites will be a combination of the two remediated gas migration 'leaks', local resident locations and an oil and gas industrial site within our tenure. Access to the SenseNet arrayed data is intended to be available to any stakeholder online, in real time.

In addition, subject to landowner consent, we will conduct **baseline** and annual air monitoring test of all legacy well sites that penetrated the storage complex within 2 miles of the injection well for indications of leaks, GM/SCVF gas releases, for a minimum of three years, and report the results. Any flows will be assessed in terms of rate, composition (isotopic and element) and changes over time.

As reported by Quest (AR 2021), daily operator rounds have proven capable of picking up smaller emissions more quickly than sensors have recognized them, and we will also rely on diligent operators as a primary monitoring mechanism.

3. **Groundwater quality measurement and monitoring (Hydrosphere)**

Alberta Innovates completed a regional assessment of the groundwater resource in association with the Quest project (reference 2, Brydie et al) which provides useful information as our project is within the study area. From Lea Park to surface in ascending order there are 4 aquifers (Basal Belly River, Foremost, Oldman/Horseshoe Canyon and Surface/Bearspaw zone) with the McKay coal zone above the BBR recognized as an aquitard, but the top three being in communication. In our project area the Basal Belly River sand (21m thick, 25% porosity, 10,000ppm TDS) is at 350m and the required surface casing depth today (base groundwater protection) is 429m. Wells in our project area produce from the Horseshoe Canyon (at <10m to 90m depth) with an average TDS of 1350mg/l. The AO for Alberta drinking water is 500mg/l and anything above 4000mg/l is not considered potable. Cisterns for drinking water and dugouts for agricultural use are the preference of many neighbors in our project area. The town of Legal, 2 miles east of the site, and our immediate neighbor to the west have both encountered coal seems >1m within 10m of surface.

Bison commissioned a groundwater resource assessment for the application and surrounding area (by Millenium Environmental Mgmt., appendix 3) and followed up with a baseline groundwater sampling program which began in Q4 2023 (see Baseline data section of the D065 application). A second round of groundwater testing is happening in October 2024 that will re-test all wells from last year and an additional 5 wells. The groundwater resource management program is designed to understand and protect the potable groundwater resource in the project area and recognize any impact the project operations may have on groundwater, including detection of injected CO2. The further baseline testing is intended to establish an evidence based statistically relevant 'no effect' baseline against which any future variations can be measured. These measurements could trigger, or provide backup information to another containment trigger, by recognizing the introduction of CO2 or crossflow from a deeper more saline aquifer.

Table B1 in Appendix 3 shows the registered water wells in the area within a one mile radius of the injection well and figure 7 is a stick diagram of well depths and water well lithologies. Several wells in the registry are not recognized as being 'in existence' by the current landowner and are no longer in use or intended for future use. We have agreement to test four more neighbor wells once a well clean out can be performed. We will retest 8 baseline groundwater sources before commencing CO2 injection and will test all wells at least once annually after that. Triggers we will monitor which could signal contamination by injected CO2 include a) increased salinity or CO_2 concentration, b) acidification (pH change), c) an increase in trace element concentrations, d) change in the C+ isotope 'finger print'.

Our routine analysis will look for these triggers and track detailed water elemental analysis, metals, physical properties, conductivity, pH, TDS, and a gas compositional analysis of any gas exsolved from the sample. When CO_2 or methane are recovered in sufficient quantities, we will also complete an isotopic analysis to finger print against any future increase or compositional changes.

Work to date has shown that the potable aquifer potential in the application area is variable and low quality. Naturally occurring springs (artesian flow) are present in the area and dugouts are commonly used. A majority of wells on record are not used for domestic or agricultural use and owners had limited interest in testing. We have tested (rate, water chemistry, gas composition where available) five neighbor water sources in use (three wells, one dugout, one spring), in addition to analyzing water from a deep observation well drilled on our injection well site. These results are consistent with the Alberta Groundwater Atlas.

Bison's deep groundwater monitoring well was drilled to 90 m with the intention of testing all productive aquifers capable of producing potable water. A copy of the lithology log from the well is Appendix 4 and shows that no aquifers were encountered until 75m below ground level. The well did encounter a low quality sand over the basal 15m of the well and we did encounter a hydrocarbon show (gas TSTM) near the base of the well. Water recovered from a bail test had TDS 4400 mg/l. The static water level was 49m and no sustained rate could be determined as fluid level continued to drop. Based on the water quality, water rate and paucity of uphole aquifer presence, we do not plan to drill additional observation wells but will continue to test this well as part of the 'baseline' and 'ongoing' monitoring programs. Gas analysis indicated 96% CH_4 and 1.5% Nitrogen and is highly likely coal bed methane derived.

As the well does not have multiple aquifer levels it remains a single zone bottom hole completion with a sand pack over the bottom 10+ meters. We will annually sample and analyze fluid, gas (dissolved and free, isotope on any CO_2, CH_4), pressure and free water level, and report this information annually as part of our project report.

The Meadowbrook project does not require, or plan for any diversion or industrial use of surface water, or shallow non-saline groundwater resource in the commercial phase of our project. The 16-29 well and all future observation and injection wells will cement surface casing to a minimum depth signaled by the AER (base of groundwater protection is 400m in our project area), which is deeper than the deepest recognized potable water resource in the area (<90 m). Surface casing will isolate and protect any potable water zone from communicating with a deeper saline aquifer, or CO_2 sequestration zone. Surface water drainage from all sites will be managed to ensure runoff does not enter any watercourse or leave the lease.

For the sampled groundwater to be properly assessed we also need to monitor the composition and key isotopic fingerprint of the injected CO_2 stream. **We will monitor and measure gross gas mass and composition annually, and report that data.** Should we recognize elevated levels of CO_2, methane or any sign of H_2S in the groundwater, we will use the isotopic data to identify the source. Generally, it is recognized that d13C isotopic values range by source from -9 (air), -19 to -27 (vegetation) to >-33 from geological sources. H_2S produced by bacterial reduction of HCO_3 is also isotopically different from thermally derived H_2S at depth.

Appendix 5 summarizes the specific details of the groundwater sampling and analysis program that will gather additional baseline data in late 2024 and continue through at least the first two years of the project.

4. **Impacts on the Biosphere, including Soil quality (monitoring and impact) and Vegetation, Wildlife or Human Health (discussed in HSE section).**

Impact on the biosphere could occur as a result of excessive surface disturbance, leaks to the atmosphere or spills affecting soils, groundwater, or the biota that reside in those environs. Minimizing our effect on the biosphere will include reducing our footprint whenever possible. New land use will be minimized. In this initial phase our surface disturbance will be localized to a single <2ha wellsite. At full commercial scale, we will add three well-sites (2ha) and one plant site (3-4ha) to the previous count of >300 sites within the boundaries of the tenure. Sites will be connected by a 30m wide pipeline 'right of way', which will be reclaimed and returned to agricultural use once installation is complete. Where possible, we will re-use existing leases, lease roads and rights-of-way. There are no pits or flares associated with the post drilling phases of either the Evaluation or commercial phase activities. CO_2 migration through a soil horizon would represent a breakdown in containment or loss of hydraulic isolation and should be detected by other MMV methods before becoming a soil concern, but soil monitoring at all locations identified as potential hazards is part of the trigger recognition protocol. Spillage of produced fluids at surface, especially saltwater, could negatively impact the biosphere but is unlikely as the project targets injection, not production, and any fluid recovered at our facility from line pigging or CO_2 stream dehydration will be safely gathered, stored in bermed tanks and disposed of as per AER regulations. Any spills that may occur will be reported as required to the AER and result in a revised Operations risk assessment.

We will conduct **baseline** soil gas sampling at all sites we develop, and regular right-of-way inspection of all pipeline routes to recognize early indications of any impacts. The initial phase of the project (the subject of this application) includes development of only the 16-29 injection well site. As identified previously as a portion of the SenseNet air monitoring, we will have a soil monitoring capability at a minimum of 6 sites initially, including an 12 probe array at 16-29, three adjacent reclaimed sites, and a legacy site flagged by our stop light risk assessment as warranting further observation. Each site will also deploy a continuous measurement sensor (EMS). The intention would be to recognize the presence of any CH_4 or CO_2 and then identify the source and mitigation strategy most appropriate.

We will monitor soils for signs of potential migration from the storage complex at the 16-29 injector site utilizing an 12 station array with measurements at .5, 1.0 and 2.0m depth as shown on the attached site plan (appendix 5). This survey will be deployed for baseline data in October 2024 and subsequently the 36 measurements will be completed in the spring once fields are dry, seeded and initial signs of uniform germination are visible at surface (early June), and again at the point of maximum crop development (late September). This data set will establish a baseline and performance history against which any changes in surface soil gas can be measured.

In addition, we will acquire a photogrammetry survey over 150% of the forecast plume area at an appropriate resolution to assess vegetative health. This involves a multispectral photo mosaic via drone to establish a soil health indicator that will be replicated annually and provide an early indication of change over a wider aperture than possible with soil sensors. Change visible on the PG survey will be followed by sensor deployment to help ascertain if it can be correlated to project emissions in any manner. The baseline survey will be acquired in October 2024.

Significant effort will be spent on determining the pre injection profile as an accurate baseline determination of any legacy emissions. This will properly differentiate leaks attributable to the storage project from any existing emissions, and also provide critical information from a credit accounting perspective. It's not quite as simple as suggesting gas migration issues are CH_4 and we will be injecting CO_2, although both those assumptions are correct, as CMC has shown with their Newell County project that bacterial sulfate reduction has generated isotopically unique CO_2 in SCVF's. This needs to be identified, properly characterized, and differentiated isotopically from injected CO_2, which the monitoring program will be designed to accomplish.

We will not be developing pipeline infrastructure during this phase of the project so dispersion modeling of a plume was not undertaken for this project application.

Liquid phase (2200kpa, -24C) CO_2 will be transported in 26-35t loads via tractor trailer and stored at similar pressure and temperature onsite in 55t trailers designed, licensed and utilized specifically for CO_2 in oilfield and industrial applications in Alberta today. Ferus Industries Inc. is the transportation contractor for the initial contracted volumes and is licensed and insured for the provision of those services and equipment. The SenseNet sensor array at the 16-29 site will identify any emissions attributable to unloading/tank leakage or injection related leaks. The sensitivity to identifying leaks will be determined, demonstrated, periodically tested, and reported. We are targeting process losses of 1% or better.

Table 3 Exposure reactions to carbon dioxide

Concentration in air (% v/v)	Effect
1 %	Slight increase in breathing rate.
2 %	Breathing rate increases to 50 % above normal level. Prolonged exposure can cause headache, tiredness.
3 %	Breathing increases to twice normal rate and becomes laboured. Weak narcotic effect. Impaired hearing, headache, increase in blood pressure and pulse rate.
4-5 %	Breathing increases to approximately four times normal rate; symptoms of intoxication become evident and slight choking may be felt.
5-10 %	Characteristic sharp odour noticeable. Very laboured breathing, headache, visual impairment, and ringing in the ears. Judgment may be impaired, followed within minutes by loss of consciousness.
10-15%	Within a few minutes exposure, dizziness, drowsiness, severe muscle twitching, unconsciousness.
17-30%	Within one minute, loss of controlled and purposeful activity, unconsciousness, convulsions, coma, death.

With regards to the health risk of a catastrophic failure of one of the 55 tonne liquid CO2 storage tanks. Assuming a 100% full tank operating at -24C and 2200kPaa this would result in a release of approximately 25,000 Sm3 of CO2 assuming the entire tank volume converted to gas phase. More likely, given the sudden drop in temperature, a portion of the volume would form a solid, dry ice, which would gradually sublimate to gas phase. For the purposes of calculating the length of time for the vessel to depressurize, an 8” failure in the vessel wall was considered and it was determined that the vessel would attain atmospheric pressure in just over one minute. From a safety perspective, the extreme cold would pose a risk to personnel in the immediate vicinity. In addition, gas phase CO2 is heavier than air and hypoxia would be a risk in confined or low lying areas close to the venting tank. However, given the relatively low potential volumes of gas phase CO2, the concentrations would disperse in the atmosphere very rapidly in the area surrounding the facility and would pose very limited risk or impact to people or animals outside a 100m radius of the facility. Modeling of large scale ruptures (UK Energy Institute reference) shows a dispersion of much larger leaked volumes to <5% concentration in <3 minutes and a ‘Significant likelihood of toxicity’ of >60 minutes. Regarding risk to operating personnel in close proximity, those risks are mitigated by Bison’s safety program and Standard Operating Procedures.

The entire surface area of the phase 1 CSA tenure is considered habitat for endangered or species at risk (Sage Grouse and raptor) and the entire Evaluation tenure is within a migratory bird ‘fly way’. **Baseline** surveys conducted by qualified independent biologists have been completed on work to date and will establish if the presence of species at risk will have an effect on either the timing of activity or location of a segment of the project. We did respond to an expressed concern over impact on migratory birds and adjusted the test well location away from the edge of Manawan Lake until further review and engagement could properly assess and inform landowner concerns.

5. **Downhole CO2 containment and monitoring (Geosphere).**

This application requests approval to inject up to .5Mtpa for 15 years into a single injection well at 16-29-57-25W4M, for a total injection volume of <10Mt. As summarized in the reservoir modeling portion of this application, the static plume (base case) for this volume should have a radius from the well of < 1000m and cover an area of 2.5sq km after 15 years injection and 4.5 sq km 15 years after injection ceases (30 years on). The modeled plume outline is included as figure R-14 in the reservoir modeling section of the D065 application, with a version included below (figure 1). Notwithstanding the relatively small volume, this phase of the project should provide important conclusive evidence of near wellbore containment, injectivity effects, and plume visibility. We are highly confident of containment being established with the Evaluation phase well operations completed to date, and that the methodology we propose for this initial commercial phase will properly monitor that stability, and immediately identify any loss of containment.

Containment today. Wellbore isolation of the injection zone has been established by multiple independent measurements in the 16-29 well (Array Annular Sensor and DAS/DTS data transmission during Leakoff and step rate injectivity testing) and will be re-confirmed annually as part of our D051 injection well approval with the AER through annual packer isolation testing and continuous real time monitoring of the storage interval and caprock integrity.

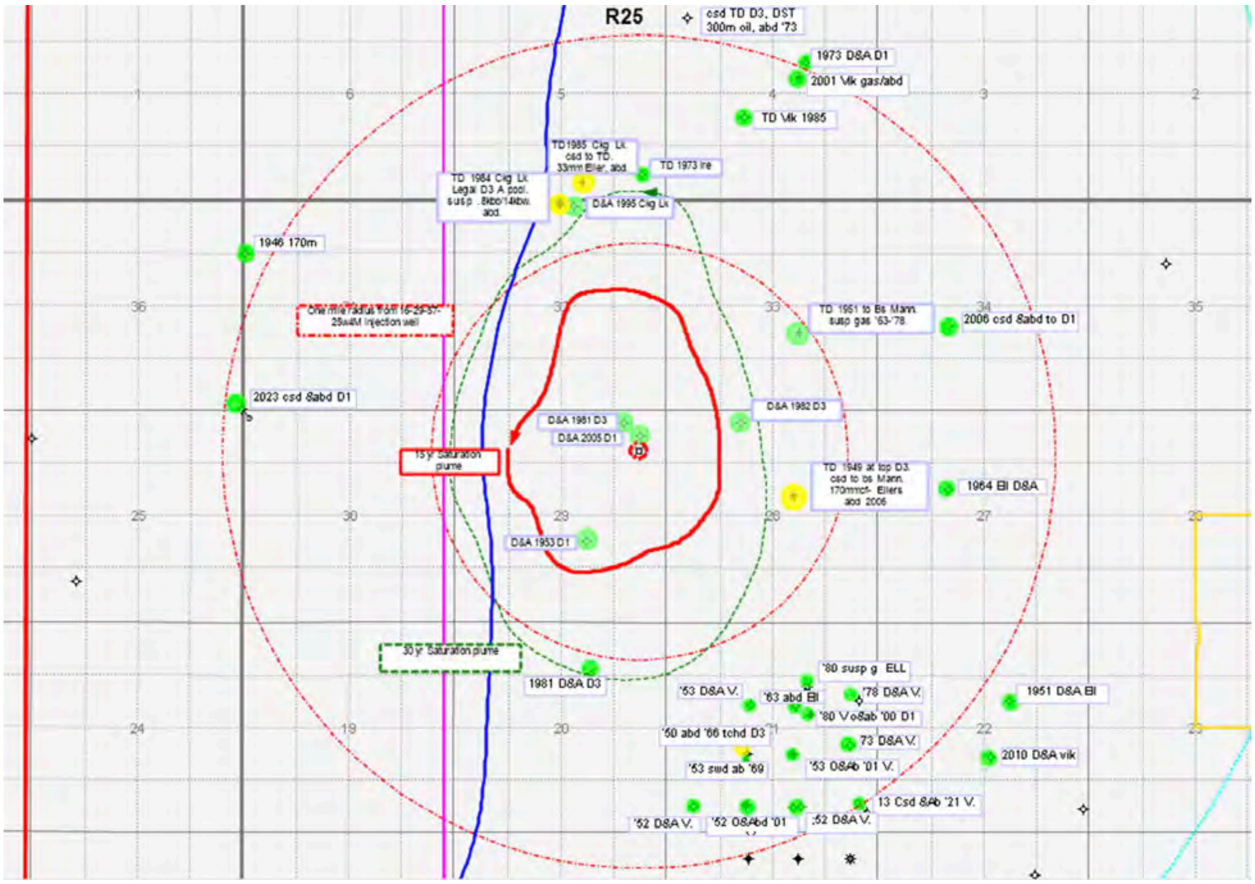


Figure 1. Saturation plume after 15yrs injection & at 30 years centered on 16-29-57-25W4M. 1 &2 mile radius from 16-29=red dash. Amber/green= legacy stop light designation

The 16-29 Evaluation phase well was designed with multiple objectives in mind, including the acquisition of all key data required in support of the final characterization of the Woodbend Grp. for safe permanent commercial scale storage, and hopefully future use of the wellbore in the project as an injector and/or observation well. With multiple objectives in mind and recognizing lost circulation resulting from a combination of formation under-pressure and exceptional reservoir quality as a primary consideration, the well was drilled and cased into the caprock (Ireton), with the nearest uphole aquifer (Nisku) behind casing, and the storage complex (Leduc and Cooking Lake formations) left open hole. The well operation included a core of the Ireton caprock, and a Leakoff test below the casing set 8m above the top Leduc, which confirmed integrity of the Ireton caprock, and no communication to the Nisku (operation summary and report attached as appendix 6). The SCAL of the Ireton core included detailed mineralogy (SEM, XRD), tight rock analysis, unconfined stress analysis and measurement of some geomechanical properties.

- As part of the casing string set above the storage complex, Bison deployed two Haliburton Array Annular pressure and temperature sensors strapped external to the casing string, as part of a fibre optic bundle that also included DAS (acoustic) and DTS (temperature) cables, that are cemented in the Nisku interval and are generating real time P&T data today (reservoir pressures of 8603 and 9201kpa and Temperatures of 47.5 and 48.2 degrees celsius respectively, at depths of 1235 and 1270m kb, on Sept 19, 2024) and have been operational through the Leak-off and step rate testing portions of the well. We have attached two presentations of the data (appendix 6) which clearly demonstrate isolation of the base Nisku sensor from any pressure response during the Leak-off test of the Ireton caprock, and isolation of the base Nisku sensor from any pressure response to the Leduc step rate test. The Distributed Temperature Sensing (DTS) cable will also provide a qualitative assessment of any breakdown in containment being reflected in a temperature change along the well, as zones begin communicating.

On drilling the storage complex we did experience significant losses in both the Leduc and Cooking Lake formations that appeared to stabilize at a fluid level that equilibrated to the estimated BHP, which gave us an ‘on the fly’ early indication of injectivity, but also compromised the value of formation fluid sampling we were able to obtain via MDT testing.

Well Completion operations in October 2023 involved a chrome alloyed bottom hole assembly that will protect all tubulars exposed to a formation brine/CO_2 mixture from corrosion. (program attached as appendix 7). A step rate injectivity test and fall off, where 800 m^3 of freshwater were injected at rates up to 4.0m^3/min (approximately equal to 2Mtpa), was completed and confirmed injectivity of at least four times that required for the initial phase, and twice our target for the commercial phase, on an injectivity/well basis. The BHIP of 13,000kpa, only increased 15% above static formation pressure and is >1000kpa below hydrostatic pressure. As mentioned previously, and visible on the Haliburton sensor chart (appendix 6), the Leduc pressure gauge shows only minor pressure response downhole to the stair step change in rates, and the sensor reading the lower Nisku zone pressure does not move at all. The gauge reading also covered the Leakoff test in the Ireton and confirmed that there was no annular, fracture, or reservoir communication from the storage reservoir through the caprock to the Nisku ‘quiet zone’.

As described in the previous sections, having a robust set of compositional data able to differentiate injected CO_2, soil gas and SCVF gas, acquired before and during injection, will be a valuable trigger signal and comparative source identifier of a loss of containment if we recognize CO_2 changes in the future.

Based on the planned recompletion of the well we feel that 16-29 well is capable of;

a) **CO_2 injection** well in excess of the 1400tpd requested in this application, at a requested bottom hole injection pressure limit of <18,200 kpa. It is estimated that if operating at the licensed capacity of 500ktpa we could run the injection <25% of the time. The pressure and temperature gauges run on the tubing string and open to the storage complex are generating injection and shut in data for the Cooking Lake and will provide the same **storage complex performance** information to determine any discontinuities or potential loss of containment indications from the storage complex, for the initial phase of the operation requested.

b) Containment monitoring of the first ‘quiet zone’ aquifer above the storage complex (Nisku), and caprock integrity in the wellbore area, are provided by the two Array Annular P&T gauges operating in the Nisku, with proven isolation from the storage complex.

On the basis of the functionality demonstrated, we do not think additional observation wells, or redundancy in injection capacity is required to support this initial phase 1 of the project (<100ktpa). Subject to injection well and reservoir performance, and contracting volumes above 100ktpa, we would complete the phase 1 facility expansion (additional tankage, grid power) and drill a second well from the same wellsite that would provide identical functionality and redundancy in all three roles (storage complex observation, injection, and ‘quiet zone’ aquifer observation). We feel the two well configuration and facility design requested in this application will support the 500ktpa full volume over the life of the project.

When developing the full commercial project (3 clusters at 1Mtpa) we would also plan to utilize two additional two well clusters, with similar functionality in all three uses.

Mechanical well integrity will also be demonstrated before injection commences, and every year by way of a packer isolation test as required by AER D051. Tubing and Casing Inspection logs will be run every 5 years, or in response to a change in casing pressure.

Potential presence of Faults. The risk of loss of containment owing to the presence and potential for leakage along faults has been assessed through a combination of tools and measurements and is also discussed in the Geomechanical risk section of this submission. We have acquired a grid of seismic data that demonstrates that faults with sufficient offset to displace reflectors above or below the complex are not present within the forecast plume area. We will add to this data set to guide the selection of additional cluster locations. Geophysical plume monitoring will track the potential movement of CO2 vertically along sub-seismic faults, or by any other mechanism. As discussed in the next section, demonstrating the visibility of the plume geophysically is a primary objective of the initial phased approach and will be an important component of demonstrating containment.

As part of the open hole evaluation of the well we also acquired a continuous borehole imaging survey (FMI) that is designed to identify linear features that could represent fractures or faults. There were no fractures or faults associated with the caprock interval.

Future Seismic focused containment Monitoring. The geophysical Induced Seismicity Monitoring, both surface and DAS deployed, will target detection of movement or re-activation along natural or induced faults or fractures in the near wellbore area. In addition, in support of data to assess containment risk we cut a core in the Ireton, conducted a Leakoff test that confirmed an absence of any fractures or faults in the immediate wellbore area, and we also acquired wireline formation micro scanner (FMI) data that would detect and orient evidence of faults/fractures intersecting the wellbore. None of these data provide any indication of elevated containment risk by fractures or faulting in the area investigated by the respective tool.

Following commencement of injection, a fault breach of containment more distal to the wellbore than can be seen in the existing 'near wellbore' data will be detected in a proximal area by a change in T or P in the shallow zone observation well, and distally with a change in character in the dispersion plume.

The Leduc formation and Ireton top seal are also extremely well studied in the project area and fault breach is not recognized as a local or regional issue for the Ireton aquitard (Bachu et al 2004, Subsurface Characterization of the Edmonton Area Acid-Gas Injection Operations). Supporting the site specific work we have attempted to demonstrate the integrity of the caprock is the reality that the Ireton is recognized as a world class seal capable of trapping >1bn bbls of oil within 50 miles, which is also a very important factor.

6. **Geophysical Plume monitoring (Geosphere).**

Initial results from Quest, Boundary Dam and Tomakomai (Japan) projects have been encouraging in supporting 4D (time) seismic data imaging the change in impedance as CO2 displaces brine away from an injection wellbore in the storage reservoir. VSP, 2D and 3D data have all been shown to be effective in certain circumstances. The ability for this to work for Bison's project will be subject to zone thickness, rock quality, acoustic attributes, volume injected, saturation change and frequency content of the data. Our initial Biot Gassmann fluid replacement modeling of CO2 displacement of brine in the Woodbend Grp. carbonates at Meadowbrook suggests that we should be able to see a response as the plume migrates in the reservoir.

Prior to the start of the commercial CO2 injection in significant volumes we will acquire a **baseline** three element Walkaway Vertical Seismic profile (WVSP) data acquisition program utilizing a vibrator energy source shooting into a buried surface geophone array and the DAS delivered via the fiber cable, to show the response against which the plume development will be measured over time when compared with subsequent surveys (4D). At the later of 1 year post injection startup, or injection of 100,000t of CO2 and periodically thereafter, we will re-shoot the WVSP and seismic surveys, in a time lapse fashion to measure the expansion and orientation of the fluid substitution effect (CO_2 plume) in the reservoir. This is not only intended to help verify visibility in the storage complex (i.e. containment) but if CO_2 enters an overlying formation it is highly likely it will demonstrate a similar fluid substitution effect that would be visible and be an early indicator of non-conformance or loss of containment.

The planned program layout is shown below and in the initial two surveys will involve the acquisition of 2D Vibroseis, 3D mega-bin, and 3D crossed array surveys that will allow us to determine what acquisition effort strikes the balance between required data quality to effectively image the plume, and cost. Several other parameters (sweep, buried vs surface phones) will be tested and the optimal configuration will be adopted for future surveys. As the plume begins to exceed a distance of approximately 600m offset from the injector, additional seismic arrays will augment VSP data in mapping the expanding plume.

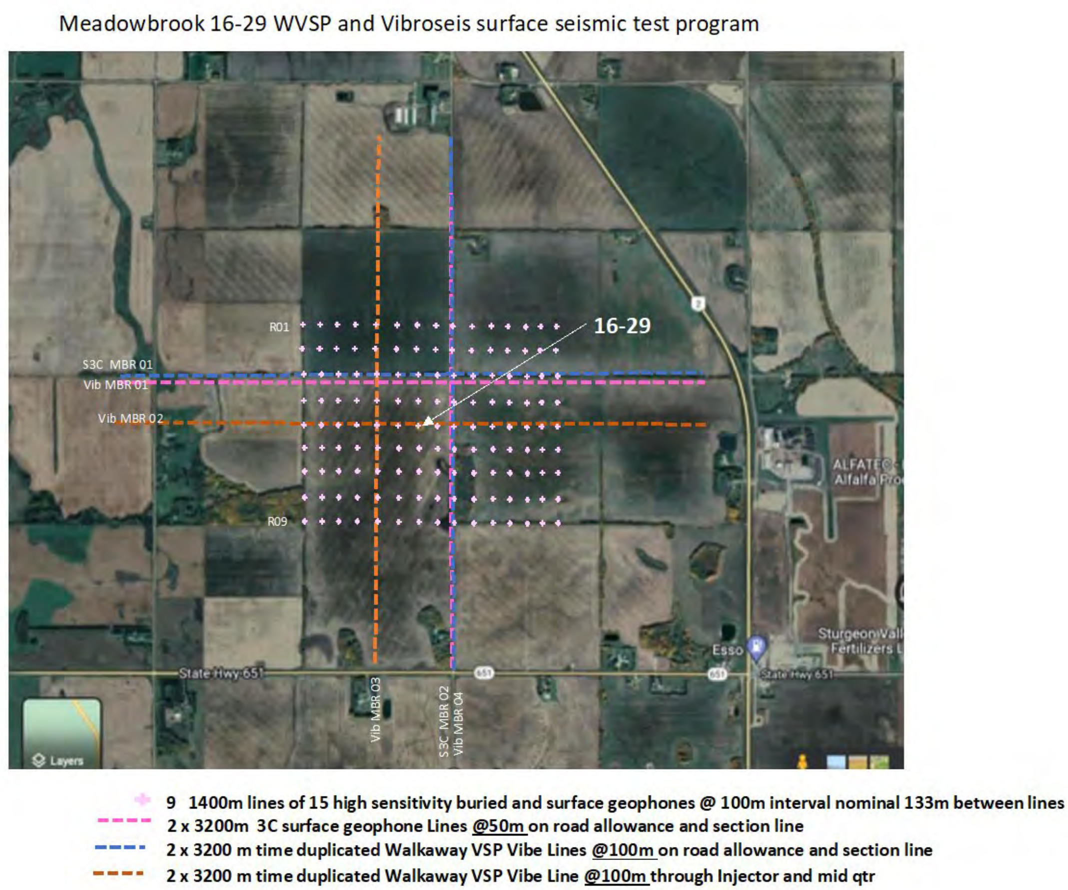


Figure 2. Proposed multi aspect Seismic survey layout, first baseline to be acquired fall 2024.

Using a combination of the seismic plume modeling for area, pressure response during shut in periods in the injection zone, and having the ability of follow-up well logging of the injection well for CO_2/water saturation and thickness, Bison should have the best method to monitor the performance of the reservoir in handling the long-term injection of large quantities of CO_2, both during the commercial lease phase of the project, and during the post closure period.

The Distributed Acoustic Sensing (DAS) fiber cable deployed in one well of each cluster, and the array of surface phones required for the ISM, will also be utilized as ’permanent’ receivers for the VSP and plume migration seismic surveys.

7. Monitoring for induced seismicity (Geosphere).

Induced seismicity can result from CO_2 or fluid injection where formation pressure increases to a level that causes the rock to fracture, where pressure changes into a fault plane, or where injection into an adjacent reservoir changes the magnitude of in-situ stress. All of these can cause existing zones of weakness to be reactivated by the injected fluid. This is differentiated from natural seismicity but is no less important when considering its possible effect on containment in a CO_2 project. Our induced seismicity monitoring efforts target the recognition and measurement (for location, magnitude and risk) of all seismicity that could influence permanent containment and induced seismicity which may affect safety of people or property, structural integrity of the storage complex, or alternate pore space or land use.

Seismicity below the storage complex in the PreCambrian basement has been seen at the Quest project but is not considered by Quest to be a mitigatable risk at present as it has generally been below the 2.0ML level, although recognized by Zoback to be increasing in both frequency and magnitude and attributable to injection (figure 3). In Alberta, well completion operations (frac’ing) utilize a ‘traffic light’ approach where seismicity events >2.0ML are reported and events exceeding 4.0ML require operations to cease. We understand Quest has adopted a similar trigger threshold on a voluntary basis and we would propose to do so as well, subject to discussions with the AER. Events exceeding 3.5ML can often be ‘felt’ at surface. Over 95% of events recognized at Quest have been <0.0ML and there were no events >2.0 before 2019 and there have been 7 recognized events >2.0 since 2020 (to YE 2023). It is plausible that this seismicity at Quest is due to injected fluid reactivation of zones of weakness in the basement as the storage complex is in the Basal Cambrian Sand sitting immediately above the basement. As referenced by Zoback (2023, Managing Earthquake Risk) the magnitude of an event is related to the size of the fault that slips, NOT the magnitude of the pressure change, resulting in increased risk with increased pressure plume area and connectivity to faulted terrain (basement vs strata bound). The increase in seismicity in the greater Edmonton area extends across a broad area well beyond the Quest tenure and as more proponents commence operations it will become increasingly critical to understand both the level and location of any increase in seismicity. Although our injection is targeting a stratigraphic interval separate from both basement and the BCS, this evolving seismicity situation frames the backdrop into which both our project and our seismicity monitoring program need to integrate to properly assess and manage OUR induced seismicity risk.

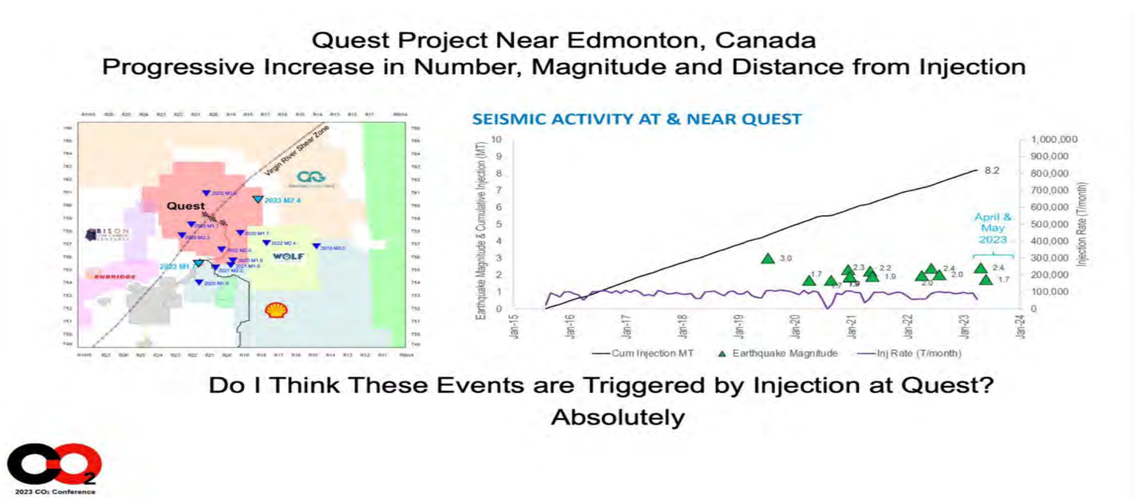


Figure 3..Taken from Zoback, Managing Earthquake Risks Associated with Large-Scale CO2 Storage

An increased level of concern regarding injection induced seismicity has emerged in Alberta in 2023 around events >5.0ML which have occurred in the Springburn area, postulated to result from long term high volume injection into the Leduc Fm. where it represents the aquifer sitting on basement. This induced seismicity only becoming evident many years after injection started is a clear example of the necessity and scope of the measurement and monitoring required. At Meadowbrook, we are extremely unlikely to connect with the basement as there is >700m, including an evaporite interval, between the Woodbend Grp. storage complex and basement. Stratabound seismicity is also very unlikely as the operating injection pressure will be safely below the regulated limit, the reservoir is naturally underpressured to begin with, our operating range is well below SHmin., and there are no fault displacements recognized seismically that could signal a potential risk of re-activation. The AER establishes an injection pressure envelope that we need to operate within to not induce fracturing. In our application that limit would be approximately 90% of predicted SHmin of >26MPa BHIP (>23MPa BHIP). Our injection pressure is not forecast to exceed 70% of the limit, or 18.2MPa BHIP, which was confirmed by our step rate test as more than adequate for as much as 2Mtpa at <13.5MPa BHIP, vs our requested volume of up to .5Mtpa.

The Leakoff test conducted on the Ireton caprock, after drilling out the casing set above the storage complex, confirmed that there was no breakdown with a pressure build to 26Mpa. Operating within the AER approved pressure envelope will significantly mitigate the risk of induced seismicity due to over-pressuring the reservoir by virtue of injection.

Monitoring Plan. Notwithstanding an operating plan to mitigate the occurrence, we will have an active monitoring capability to recognize if seismicity occurs, either induced or natural. We began passive monitoring on March 14, 2024 with the deployment of 5 Hawks geophones arrayed approximately 1500m offset from the 16-29 injection site. This array will record all naturally occurring baseline seismicity until injection begins. This array is capable of detecting events down to 0.5ML scale within the injection area and has demonstrated its effectiveness in picking up events correlatable in time and magnitude with the Alberta Raven system, during our first two data dumps (appendix 8). During the installation of our surface array, we conducted a field test where an artificial source was used and recorded by the surface and downhole arrays. Notwithstanding the ‘lightweight’ surface source (post pounder), indications of the events were seen at all stations and the data is currently being processed and interpreted by our research consortium partner CMC. This data may better inform the lower resolution limit of the existing array. The pre-injection information is a record not a trigger and will NOT be monitored in real time as it is intended to establish a baseline against which we can compare the impacts of injection. We are also conducting our own ‘induced’ surface generated seismicity experiments to determine the operational capability and sensitivity.

Once injection commences we will continue to monitor the surface geophone array to recognize any seismicity that occurs and report magnitude and frequency. This data will be screened and analyzed to identify any anomalous seismicity that could change the risk profile attributable to the containment of the storage complex and trigger an appropriate response, which could include 24/7 real time interrogation, and escalating the induced seismicity monitoring from the surface array to incorporate downhole acoustic measurements via a Distributed Acoustic sensor (DAS) fibre optic cable which acts as a vertical geophone array to help provide the accuracy in depth. If we recognize events of a magnitude greater than 2.0ML that are reasonably correlatable to injection activities we will begin interrogating the DAS cable feed which incorporates downhole measurements which will allow us to more accurately determine the event location in the vertical plane. Bison’s ISM array deployment will be supported by CMC, with data interpretation and interrogation provided by ESG.

The same geophysical fibre infrastructure deployed for ISM also provides a key measurement and verification function by helping seismically image the CO_2 plume as it develops and migrates by way of time lapse walkaway VSP’s (plume Modeling- containment). The DAS cable also provides an ability to recognize and interpret microseismicity which could result if fracture propagation, fault slippage, fluid movement, and pressure relaxation in a formation were caused by pressure changes and associated stress changes within the reservoir.

8. Geo-chemical characterization and CO2/brine/rock interactions.

The introduction of dense phase CO2 to the relative equilibrium in the storage complex will have an impact in a number of areas that need to be measured (or estimated) and modelled for their possible effect on mineralogic changes on injectivity, or containment. Assessing the potential for dissolution, precipitation or dehydration within the storage complex over the life of the project (15 year injection period followed by 500 years post injection) through a reactive transport model (RTM, with Tough2/ToughReact program) was completed by Matrix Solutions Inc. for CO2 injection into the Leduc and Cooking Lake formations saturated with native brine.

The model input parameters included thin section, XRD and SEM analysis of the detailed lithology of characteristic intervals in the Ireton, Leduc and a middle Leduc/Duvernay shale tongue, from drill cuttings from the 16-29 well and the spectral gamma ray/litho-density log derived lithology. The native brine analysis was taken from a drill stem test recovery of a full string of saltwater from 2-5-58-27W4M 1.2 miles north of our site. This well was characteristic of five full column water recoveries within two miles of 16-29. The MDT samples recovered from the 103/16-29 well operation were heavily contaminated with filtrate water (50% and 100%) owing to lost circulation while drilling and were not representative of the native brine.

With respect to potential reactivity with dense phase CO2 in the storage complex, 2D radial modeling work has shown that during injection there was a slight dissolution of dolomite and slight precipitation of calcite and that no other minerals had a significant effect on the reservoir and that there was no meaningful (<1%) change in porosity. There was a slight reduction in pH which was the driving mechanism for dolomite dissolution. By the post injection period the area of the plume is in relative equilibrium and maintains a pH at 6.4. Very small amounts of Ankerite (between 1-2kg/m3 Ca(Fe,Mg,Mn)(CO3)2) begin to be sequestered as a mineral. As the plume contacts the caprock the relative reactivity increases owing to the variations in Ireton mineralogy but the volumes are small and the effects are the same as above plus the dissolution of Siderite, none in volumes considered material. Small amounts of H2S in the brine are quenched by the expanding plume and H2S in the plume area decreases. The acidification of the water due to CO_2 injection results in $H_2S_{(aq)}$ forming with small amounts of $H_2S_{(g)}$ being exsolved from the fluid which will begin to react with any available source of iron (siderite, ankerite or clays in the Ireton) to form pyrite. The full report on the reactive transport modeling is included as appendix 14.

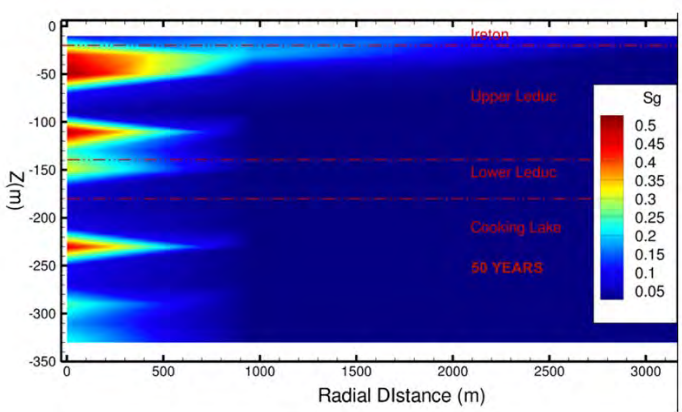


Figure 4. Spatial distribution of CO2 gas phase 50 years post injection (from Matrix RTM report).

Bison has also discussed CO_2 rock interactions with Dr Ben Tutolo of UCalgary, who has performed detailed studies on similar applications (Tutolo et al) in the context of both CCS and EOR. His research work had guided to CO_2 and water forming a weak acid (carbonic acid) which has an affinity for causing dissolution and/or precipitation of carbonate minerals (such as the dolomites that make up our storage reservoir) dependent on temperature. The saturating brine today is in equilibrium with the rock and is also slightly acidic (pH 6.0-6.9 at 25C) and considered sour with H_2S content of <100 ppm. At our relatively low temperatures (<50C) we were not expected to have a material amount of dissolution, and any degree of precipitation was likely measured in centuries. This expectation was confirmed by the reactive transport modeling.

Thermal induced fracturing of the caprock is a potential problem in a CCS application that is sensitive to assumptions and factors including the thermophysical properties of the rock, the respective temperatures of the formation and the fluid at the sand face, the rate of injection and the standoff from the caprock. Recent work by Samaroo et al has also flagged that temperature change in the formation caused by injection of cold fluid can cause changes in insitu stress and strain, and in some instances induce fracturing. this is discussed in detail in section 9 on Geo-Mechanical risk mitigation.

When considering other thermal or geochemical reactivity issues we recognize it is highly probable that our reservoir will experience ‘drying out’ on long term injection of pure CO_2, necessitating our management of salt precipitation in the near wellbore area. The phenomenon has been recognized in several CCS related situations, including Quest and Boundary Dam, and involves progressively increasing salinity of the irreducible water saturated phase near the wellbore, with successive pore volumes of injected CO_2. The dry CO_2 absorbs a portion of the Swi water, increasing the salinity, and eventually precipitating salt. The most often used resolution is a form of freshwater soak, or wash, on a prescribed frequency which is refined with operational experience. With respect to dehydration specifically our RTM showed that under our reservoir conditions for our period of injection we did not reach conditions where halite would precipitate in the near wellbore area. With larger volumes, higher rates or over a longer period, we expect this would be inevitable at some stage. The mitigative measures to avoid the impact of this if it were to occur would include increasing the injection interval or performing a wash with fluid capable of dissolving halite in the near wellbore area.

9. Geo-Mechanical characterization, Caprock Integrity and Mechanical Earth Modeling.

Geo-Mechanical risk involves assessing the stress regime and the hydraulic integrity of the storage complex and wells that penetrate it, including the risk of fault propagation or reactivation, shear failure of the caprock, hydraulic fracturing (planned or accidental connecting out of zone), and mechanical communication introduced by well penetrations (bad cement, rugose hole).

The work that we have done in assessing the geo-mechanical risk associated with the operation of a CO_2 storage Hub at this location includes an integration of published material from similar studies in the immediate area, integration of more than 200 km of seismic data, core based rock geo-mechanical assessment of a portion of the caprock interval, a pressure test intended to introduce failure in the caprock, the integration of that data into a 1D mechanical earth model and a series of simulations of caprock failure and potential reservoir deformation under varying scenarios. The full report summarizing the Geo-Mechanical characterization and analysis of the principal total stresses in the reservoir and the caprock, the mechanical rock properties and the failure envelope, and a failure analysis is attached as appendix 9. This information has been incorporated into a Mechanical Earth Model referred to as a 1D MEM, created by SLB (appendix 11). Appendix 10 describes the geo-mechanical response of the reservoir and the caprock associated with CO_2 injection under various relevant scenarios and sensitivities. The results are based on coupled heat, fluid flow and geo-mechanical simulation studies using the GEM model of Computer Modeling Group (CMG). **These workflows characterize the Woodbend Grp. storage complex at the Meadowbrook site as stable today and unlikely to develop any instability from a rock mechanics perspective under the operating conditions for the CCS project**.

In assessing the likelihood of pre-existing faults influencing the geo-mechanical stability, a one mile grid of 2D seismic data was acquired over the western rim of the Meadowbrook reef in order to improve the accuracy of the top reservoir topography interpretation and recognize any regional or local seismic discontinuities that could signal faulting visible at seismic scale. There were no faults identified along the western rim of the reef or within any area that could come in contact with a plume created by this phase of the project (>5 mile radius). There was a possible fault indication 9-10 miles E-NE of the project, at depth, which we would likely attribute to an element of the Snowbird tectonic zone (STZ). The STZ is a basement lineament oriented NE-SW that is postulated to have developed along a subduction hinge in the PreCambrian basement. Although natural seismicity is not recognized in the Edmonton area, and our injection zone is >700m and two salt layers separated from basement, it will be monitored at our project and reported and analyzed if it occurs. We have seismicity monitoring operating onsite today(Appendix 8) and generating data that correlates well with the Alberta Raven survey.

When combined with the understanding of the current reservoir conditions (especially pressure and injectivity), the required pressures to achieve the rates forecast in both the initial .5Mtpa and ultimate 3Mtpa commercial phases of the project, the failure envelope calculated in the geo-mechanical study, and the modeled reservoir capacity, we would conclude that the risk of reactivating or initiating a fault or fracture is very low. This is consistent with the conclusions of similar work in the greater Edmonton area dealing with Devonian reservoirs.

Injection of cold CO_2, as we plan for phase 1 of the project, will cause a cooling of the storage complex by way of conductive heat transfer and dependent on the magnitude of T change, and level of heat transfer from the storage interval to the caprock, it could result in thermally induced stress changes in the storage reservoir or the caprock. The magnitude of this effect and the potential risk it presents is discussed in detail in Part II of the accompanying geo-mechanical report (appendix 10). Recognition and avoidance of this early phase risk was one key driver of the decision to recomplete the 16-29 well to inject lower in the section. The 16-29 well will inject into the Cooking Lake portion of the reservoir at a depth >150m from the base of the Ireton caprock in part to ensure adequate thermal cushion for any migration of cool fluid coming in contact with the caprock. CO_2 arriving and stored in pressurized vessels at approximately -20C will be heated to 5C before injection through the installation of a line heater. Both these design elements have been included in the geo-mechanical modeling.

This issue has a greater chance of presenting a problem in the initial Phase 1 stage where our CO_2 surface temp is approximately -20C as delivered via tractor trailer, vs >15C when delivered by pipeline as envisioned for the large majority of volumes from phase 2 on.

The risk mitigation waterfall to address this risk will employ;
1. listening for microseismicity during early injection,
2. monitoring temperature diffusivity,
3. heating the CO_2 at surface before injection,
4. adjusting the rate of injection to enhance heat adsorption,
5. creating > vertical standoff between the injection sandface and the caprock,
6. injecting into the Cooking lake rather than the Ireton.

Notwithstanding the low risk profile today, an equally important aspect involves our ability to monitor for a breakdown or loss of hydraulic integrity, for any reason, in the operating phase of the project. This is covered in detail in the containment, legacy well and the ISM sections 5, 10 and 7 respectively of this MMV program, but incorporates no less than four strategies/triggers to recognize and assess if, how, and to what degree a loss of containment has occurred. Depending on the severity, an appropriate response could be to report and monitor the situation over an agreed period with an agreed protocol, or it could involve the suspension or re-location of a specific injection cluster, or if severe in the extreme, a suspension and abandonment of the project.

10. **Hydraulic isolation and legacy well risk.**

CO_2 containment in the Woodbend Grp. and hydraulic isolation from uphole zones, has been confirmed pre injection at the 16-29 injection well location by;

a) A pre injection packer isolation test.
b) cement bond logs,
c) the placement and response observed from external fibre optic pressure and temperature sensors in the Nisku,
d) a Leakoff test of the Ireton caprock.

Hydraulic isolation will be continually monitored and re-confirmed by the real-time measurements of the 'external to casing' fibre optic sensors in the Nisku and the tubing conveyed gauges open to the Cooking Lake and Leduc (combined the Woodbend Grp.) injection intervals.

Our Evaluation phase activities included a core of the caprock interval and Leakoff test of the Ireton formation which confirmed a pressure envelope up to 26Mpa, below which a failure would not occur in the cap rock. We also completed a step rate injectivity test (SRT) into the reservoir to confirm the bottom hole pressure limits required for injection at both our forecast volumes for this phase of the development (.5Mtpa), and at the full commercial volumes which we had modeled at >1Mtpa/well. The SRT proved injectivity at rates up to 4.0m3/min at 12,967 kpa (1871kpa above static reservoir pressure and >1000 kpa below hydrostatic pressure estimated as 14,300kpa, which is a short duration test at a rate equivalent to 2Mtpa/well. These rates, and formation permeabilities, exceeded our forecast but were not totally unexpected as published studies quote effective permeabilities between pools connected by an infinite regional Cooking Lake aquifer in excess of 2 darcies, and we have Leduc water injection well histories from adjacent pools having demonstrated long term injection at >25,000bfpd and cumulative injected volumes of >100mm bbls/well, with no material pressure effect on the reservoir.

Based on this data we can conclude that we have proven, and can continually monitor, isolation between the storage zone and the first aquifer above the storage zone, and that we can inject the volume that will be requested in our AER scheme approval (up to .5Mtpa) at forecast BHIP that will not exceed 18.2 Mpa, the limit requested and calculated utilizing Table O of D065.

In summary, the 16-29 well will be continuously monitoring the following data once injection begins;

- Nisku (first aquifer above the storage interval) pressure and temperature via fibre conveyed sensors (2 sets) external to the casing. These sensors have confirmed isolation from the Leduc through several subsequent well operations and currently confirm reservoir pressures of 8603 and 9201kpa and Temperatures of 47.5 and 48.2 degrees celsius respectively, at depths of 1235 and 1270m kb, on Sept 19, 2024.
- Cooking Lake Fm., storage interval pressure and temperature, both during injection and shut in periods.
- DAS (acoustic) fibre 'listening' for seismicity AND wellbore events. We have recognized that the DAS configuration provides a useful data source for changes external to the wellbore.
- DTS changes in temperature which could occur with mixing of brine on any loss of containment or breakdown external to the casing.
- Realtime data acquisition will be provided by a permanent onsite interrogator processing and forwarding the fibre optic feed.

Through a combination of the measurements we would expect any loss of isolation to be identified by multiple tools and strategies immediately.

The 16-29 well does have a surface casing vent flow recognized that has been measured at 4.1m3/d (<1 scfm) and sampled. From a shut in pressure of 1890kpa we have determined it is likely from the 225m interval, approximately equal to the McKay coal interval. We will monitor the rate and isotopic composition for any changes annually or when any change is recognized. Our pre drill groundwater resource assessment involved both offset well testing and the drilling of a 90m groundwater test well on our site. We DID NOT encounter a water productive sand capable of a measurable rate but did encounter a ‘gas blow’ at 85-90m which has subsequently died and produces a small amount of water with TDS of 4400mg/l. We will manage the SCVF impact on the shallow groundwater resource in the area by our regular soil gas monitoring program and an isotopic comparison between any biogenic, methanogenic or deep sourced methane. We do not consider the existence of the SCVF to be a risk of migration from depth because the leak off test performed prior to drilling out confirmed the wellbore isolation at the base of groundwater protection (440m bgl) .

Legacy well risk, refers to the potential for a containment breach from ’historic’ wellbore penetrations through a casing failure, poorly cemented casing or incomplete aquifer isolation on abandonment of the sequestration reservoir, that could provide an avenue for leakage by migration along a pathway that may not be fully contained by the top seal. This risk already exists with every suspended and abandoned wellbore in the province where cross formational flow of fluid, or the potential for a gas migration or vent flow of natural gas, is managed to within an acceptable tolerance with the application of good oilfield practice and adherence to license conditions. The unique aspect of this risk in a CCS project is more of a fiscal risk resulting from a credit reversal, as the potential for this to evolve into either a safety or environmental risk is extremely low both from a released volume and concentration perspective. Notwithstanding the likely low impact of a legacy well related leak we recognize this as having a higher likelihood of occurrence owing to poor cement jobs resulting from lost circulation due to the underbalanced pressure and exceptional permeabilities in the Nisku, Leduc and Cooking Lake intervals.

We have completed a legacy well risk assessment based on a well by well review of AER wellbore records of wells that have penetrated the storage complex and ranked them as to what risk they may represent depending on the age of the well, the original and current status, the amount and quality of information available on the original wellbore condition and configuration, and whether there is a record of any well integrity issue (known gas migration or SCVF occurrence). A well that did not penetrate the storage complex cannot provide a pathway for loss of containment. Historically, D&A wells that have plugs set properly represent a lower legacy leak risk than cased wells that are subsequently abandoned.

This analysis resulted in a ‘traffic light’ ranking where a red or amber ranking would result in **baseline and subsequent periodic** monitoring incorporated into our MMV plan, based on assessment of the following criteria,

a) penetration of the storage complex
b) any recognized migration or flow that remains unresolved.
c) well having been cased to the storage complex.
d) confirmation of proper abandonment (age and data dependent)

Every well that penetrated the storage complex (a) was reviewed in detail. It is given a **green** ranking if it has no flow history AND records show it was abandoned as per AER regs (**no further review planned)**. It is flagged as **yellow** if it has been recognized as having, or having had, a migration issue (b), or the well was cased to the storage complex and sits within a forecast saturation plume area (c+), or the well file review is unavailable or inconclusive as to proper abandonment having been completed (d+). A **yellow ranking requires further investigation;**

- A **yellow** ranking requires further review to designate it as green (no recognized risk) or red (high risk), based in part on its proximity to active development of the tenure,
- All yellow designated wells within 1.5km of a forecast CO2 plume fairway (3km from 16-29) will require a surface inspection, an initial season’s photogrammetry survey, and a 30 day air monitoring test to determine a pre injection baseline.

A **red** ranking would be attached to any yellow ranking that upon further investigation demonstrates recognizable surface flow of gas. We would commit to reporting this to both the AER and the well operator for further monitoring as deemed appropriate by those parties. There have been no red ratings identified by our work to date.

If an initial surface site inspection shows no sign of migration/flow or leak, the ranking shifts to **green**.

The area of application has been assessed and three wells with yellow rankings have been flagged. All yellow rankings will be downgraded to green, or upgraded to red, prior to the commencement of injection.

Further Mitigation of legacy well risk on our project is achieved by:

- avoiding areas with pre-project penetration within areas identified as the likely sequestration plume area, and minimizing the required penetrations to only those needed to manage the project. There are NO producing wells that penetrate the sequestration strata within the forecast plume area. We estimate that there are 7 historic penetrations through the top of the sequestration interval strata (top Leduc Formation) and 3 of those that fully penetrate the section (Cooking Lake Formation or deeper) within the forecast CO2 plume area. One well, 15-32-57-25W4M, is 1 mile from the 16-29 well cluster site and had a reported gas migration issue that was reported as resolved in 2000. That site has been flagged and will be monitored and reported as part of the MMV phase application.
- integrate any wells that penetrate the sequestration reservoir (future Legacy wells) but are NOT abandoned, into the observation/monitoring scheme to enhance the MMV program. We have identified 2 existing wellbores that could possibly be integrated into the observation/monitoring scheme, if they can be acquired (one is an orphan well). Neither of these wells is within, or relevant to this initial phase application.

In our selection of the 16-29 injector location, consideration was given to the number of penetrations of the Woodbend Reef within the expected plume area, the status of those wellbores as to whether they have/had casing or cement plugs to ensure isolation, the age of the wells, whether there is any AER record of leakage or cross flow, and whether a surface inspection shows any evidence of flow.

11. **CO2 Pipeline design, monitoring and dispersion modeling.**

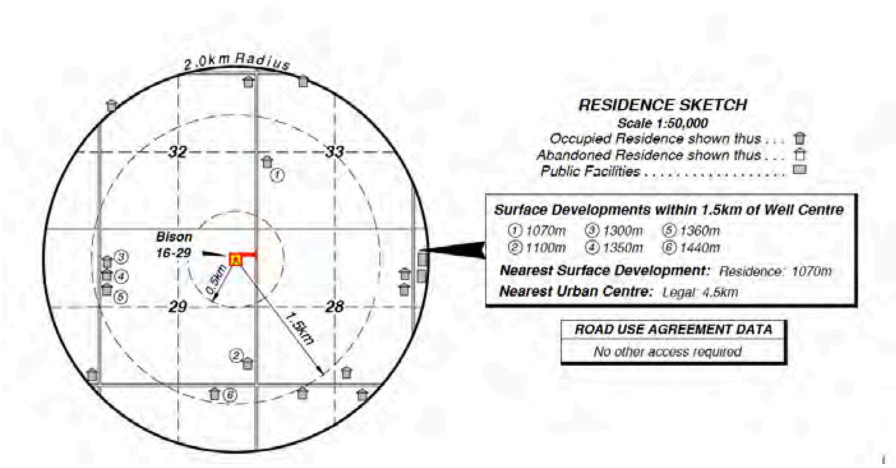
During this initial phase of the project we are not planning for the installation or operation of either an inlet pipeline or injection lines off our lease as all volumes will be trucked under our current plan, and we will only operate a single injection well located on the same site as the receipt/storage/metering facility.

A pipeline from the Alberta industrial heartland area (either connecting to an existing CO2 trunkline or emitter customer site) is still an integral part of our full commercial development plan, as are injection lines from the central facility to 2-3 injection cluster sites. Once the pipeline is operational, we will be equipped to continuously monitor pipeline inlet and terminus volume, temperature and pressure so that any leak is recognized immediately. There would be emergency shutdown capability on any pressure loss and the pipeline route would be monitored for CO2 leak detection as specified by AER regulations over the life of the line's usage.

Guidance contained in CSA Z071 regulations identify the required setbacks of the pipeline from residences and other occupants. Setbacks are a function of pipe volume and the potential release rate and plume size that could develop on a line failure worst case scenario. The pipeline is partitioned with the installation of risers and emergency shut-down (ESD) valves that limit the capacity of an individual segment to a volume less than the volume designated in determining the setback distance. In that manner, even in the unlikely event of a complete failure, the plume dispersion would have CO2 concentrations below serious human health limits.

We will complete CO2 dispersion modeling prior to finalizing the design of the pipeline to ensure that site specific topography and dominant conditions are factored into the final safe design. During this initial phase we will not be operating any CO2 pipelines.

This application has considered a CO2 release onsite that could arise if we ruptured the onsite storage vessels (150t in total). The EPZ in this instance is considered to be 50m meters from the point of release. The closest residence is 1.07 km away and there are six residences within 1.5 km.



12. **Post-Project Closure Plan.**

At the end of the Commercial Lease Phase of the project we will implement the post-closure stewardship plan that will have been agreed, and updated over the project life biennially with the Alberta Department of Energy (ADOE) and the AER. The description in this section will apply to the scope of our application for a single injector with volumes <.5Mtpa for 15 years (no pipeline), with an understanding that the closure plan will adjust as the project scale and duration increases.

The major elements of the project closure plan will include;

- Ongoing, evolving understanding of reservoir performance and conformance of observed results (pressure, plume monitoring) to the project's dynamic reservoir model, from project start through to suspension of injection. This will frame the stability of the reservoir and injected CO2 plume at the outset of the closure period and guide an informed estimate of the scope and duration, or effort to properly demonstrate a 'stable and permanent' subsurface plume.
- We expect that the first 3-5 years of injection will frame the risk profile we are very likely to experience with respect to conformance of the reservoir performance to the dynamic model as its adjusted with real data, and in confirming the visibility and accuracy of the CO2 plume measurement. Over this period <5% of the ultimate volume we target to store over the project life will have been introduced to the storage complex, and any adjustments required to minimize post closure risk will be incorporated at an early stage.
- We will establish a properly funded closure contingency account (in addition to PCSF and any LMR requirements) to ensure that in any circumstance the operator, on behalf of the JV, is properly funded to complete the required scope and duration of work.
- On the assumption that we have been able to model the plume distribution over the life of the project and that we have not experienced any recognized breaches of containment, the post closure plan would be proposed to the AER, and once accepted, we would proceed as per the agreed plan.
- All wells and monitoring equipment would remain in place until they were no longer required to facilitate reservoir access or monitoring data generation, at which point we would complete the downhole zone

and well abandonment of the 16-29-57-25W4M injection well, and any other wells that have been added to the scheme over its life.
- The surface facilities would be dismantled and any piping buried < 4’ would be removed from the site. There is no pipeline planned for this phase of the project.
- All monitoring equipment would be shut and removed in conformance with the agreed AER plan and schedule.
- Site remediation and reclamation would commence and once complete, a lease reclamation certificate and closure certificate would be sought from AEPA and the AER

We expect to be able to demonstrate that the CO_2 is performing in a stable and predictable manner and meets all requirements of section 120(3) of the Mines and Minerals Act (MMA) requiring we demonstrate sequestration performance and compliance with legislation, applications and approvals. If the project operates in a stable fashion, particularly over the second half of its life, we feel an estimate of the time required to demonstrate the required stability could reasonably be three to five years. We recognize that in different jurisdictions this window has been suggested to be in excess of 20 years in some instances. We recognize the transition of the lease back to the Crown is a performance based exercise and will ‘take as long as it takes’.

13. Potential Effect on Hydrocarbon Recovery

The proposed initial phase of Meadowbrook Hub project will have no effect on hydrocarbon recovery from any existing accumulation and is unlikely to adversely effect any future exploration activity. The project will be restricted to and contained within the Woodbend Group (Leduc and Cooking Lake formations) and have no effect on hydrocarbon recovery from any other zones. The Cooking Lake is not recognized as productive anywhere in the Meadowbrook complex or the surrounding area. The Leduc has been productive within the Meadowbrook complex in two scenarios, both of which are very close to the end of their economic life.

Along the western edge of the reef there is a series of eight small accumulations, four of which are still producing from one or two wells each, at water cuts above 90% with a total estimated remaining recognized recoverable reserve of less than 31,800 m3 (200,000 bbls) of oil, having recovered 715,445 m3 (4.5 mm bbls) since roughly 1980. The closest currently producing well on this fairway is 18km south of our proposed injection site at 14-32-55-25W4M (operated by Response Energy Corp.). The CO_2 plume from Bison LCV’s scheme is expected to have no effect on these producers as they are downdip and distal to the forecast plume. The increased pressure in the aquifer owing to CO_2 injection will be undetectable during the remaining life at these offset producing wells and minimal (< 3500 kPa) at any point in the future.

The second trap configuration is along the eastern rim of the reef complex and is productive at the Fairydell Bon Accord Leduc ‘A’ pool, 7.5 miles east of our proposed injection site. This was a highly prospective exploration target in the mid 1960’s but no similar accumulations within the Meadowbrook complex have been discovered over the last 60 years. The FBA Leduc “A” Pool still produces from three wells after the recovery of over 2.9 106 m3 (18 mm bbls) of oil and is forecast to have almost 31,800 m3 (200,000 bbls) remaining to be recovered. The plume, as modeled, does not extend within 8 km (5 miles) of the accumulation, and the pressure effect on the Leduc aquifer is predicted to be < 3000 kPa. Bison has met with Coastal Resources, the operator of the Fairydell field, and described our project and its potential impact on the remaining resource.

The western side of the Meadowbrook complex, where Bison LCV’s scheme will be located, is considered the downdip edge and not highly prospective for trapping hydrocarbons in commercial accumulations. Oil shows suggest a reduction in crude gravity to 10-17 degrees API as one moves north, further limiting the exploration prospectivity, and commercial potential.

Current interest is very low as evidenced by land sale activity and the large percentage of open crown land for rights below the base of the Mannville Group. The prospectivity of the geologic section from the base

Woodbend Group to basement is considered very low as there are no local or regional hydrocarbon shows in the Beaverhill Lake or Elk Point within several townships of Bison LCV's application area.

Outside of the immediate CO_2 plume area the effect on P&NG activity will be insignificant as the pressure increase in the Woodbend aquifer owing to CO_2 injection will be < 3500 kPa, still below the hydrostatic pressure, and should not pose a risk of over pressure for any future drilling activity through the Woodbend Group. We would recommend the AER notify any well licensee drilling through the Woodbend Grp. within our forecast plume area so that they are aware of the pressure anomaly and the need to properly segregate the zone if a well is to be cased though that interval.

14. **Potential Impact on Current Land Use (Commercial and Natural).**

The surface land use impact for this phase of the project will be minimal as we will have only a single site and no pipeline. The main impact will be the nuisance factor of increased trucking on local residents, particularly over the 1.5km of gravel between our site and Hwy 651.

The dominant surface land use in our project area, and at our current site specifically is agricultural. Approximately 80% of the land is actively farmed seasonally with a mix of residential acreages, treed parkland, livestock (chicken, dairy) and light industrial (Alfalfa, tire recycling, oil recycling). We have hosted meetings with the County council, landowners, the Alexander First Nation and business interests in the area and incorporated their initial advice into our proposed plans. Our stakeholder engagement is ongoing. We have contacted over 900 landowners/residents within our CSA tenure and will report on those interactions in a timely manner as you review this application. In addition, we have fulfilled the specific engagement requirements of owners and residents proximal to our activity and the other mineral tenure owners and well licensee's that could be affected by our project.

When considering the full commercial scale of the project and notwithstanding that from an individual property owner perspective, any level of industrial activity may be material, when compared with historic activity to date, our impact on current land use will be minimal. We expect to add no more than 4 sites (<120m x120m, <2ha in total) to approximately 300 well-sites that have been developed within our tenure boundary over the last 75 years of oilfield activity. Of the four, only our single plant site will have more than light vehicle operator activity on a daily basis, none will have pits or flares, and only the plant site will have any equipment noise level.

Portions of our tenure are subject to restrictions to surface access, either seasonally or permanently, based on wildlife or biodiversity restrictions that designate those areas as sensitive habitat. Approximately 65% of the surface area of the tenure is within Sharp Tailed Grouse and Sensitive Raptor ranges which require investigation of the presence, avoidance if present, and habitat protection strategies. Millenium (MEM) has completed a species at risk assessment for the surface activity conducted during our Evaluation phase activity and we did not recognize any impact or encroachment. This assessment is enclosed as appendix 13. We currently do not plan any increased level of surface disturbance, other than associated with the deployment of MMV equipment and monitoring capabilities, in association with the approvals we are seeking in this application. In any case, prior to conducting any operations on the commercial lease, or the residual Evaluation permit, we will conduct the appropriate assessment and adjust operations as results dictate.

15. **Potential Impact on, and from, Alternative Pore Space Uses.**

The Meadowbrook project reservoir has limited potential use in either geothermal or brine mineral recovery as the formation brine is relatively fresh (120,000ppm) and cool (<50C) when compared to similar opportunities that have announced intentions to pilot mineral extraction (190,000ppm+) and geothermal heat recovery (90C+). Bison LCV cannot at this time predict what other resources could potentially be affected, but we will take that into consideration when preparing our annual update reports, and when we execute our monitoring plan.

There are two brine tenures (Indigo and NumberCo) that signal an interest in Lithium within the limits of our Evaluation permit, with Indigo's acreage overlapping a portion of the CSA we have been granted. We have attempted to contact Indigo to describe our operational plan and present our view that our current operation is unlikely to have any impact on their potential activity because our current activity is up-dip from their tenure. We did connect with Mr Paul Cowley who declined the request to meet. CO2 will not migrate downdip unless a pressure sink is created which will minimize our potential impact on the exploitation of their tenure, should they progress its testing. If future brine tenures are awarded updip of the current acreage, or as our project expands either north or south, there is the potential for overlapping influences, but also the potential for collaboration to avoid conflict. The spent brine will need to be re-injected at a location that doesn't interfere with future native brine concentrations, likely up-dip from the actively worked brine production. As long as we locate up-dip of this position, our operations should not interfere.

We have not been able to identify the ownership of the NumberCo through the Alberta corporate registry and as a result have not made contact with them. This block begins >20 miles north of the proposed 16-29 injection site. As modeled, our CO2 plume would not at any point reach that far.

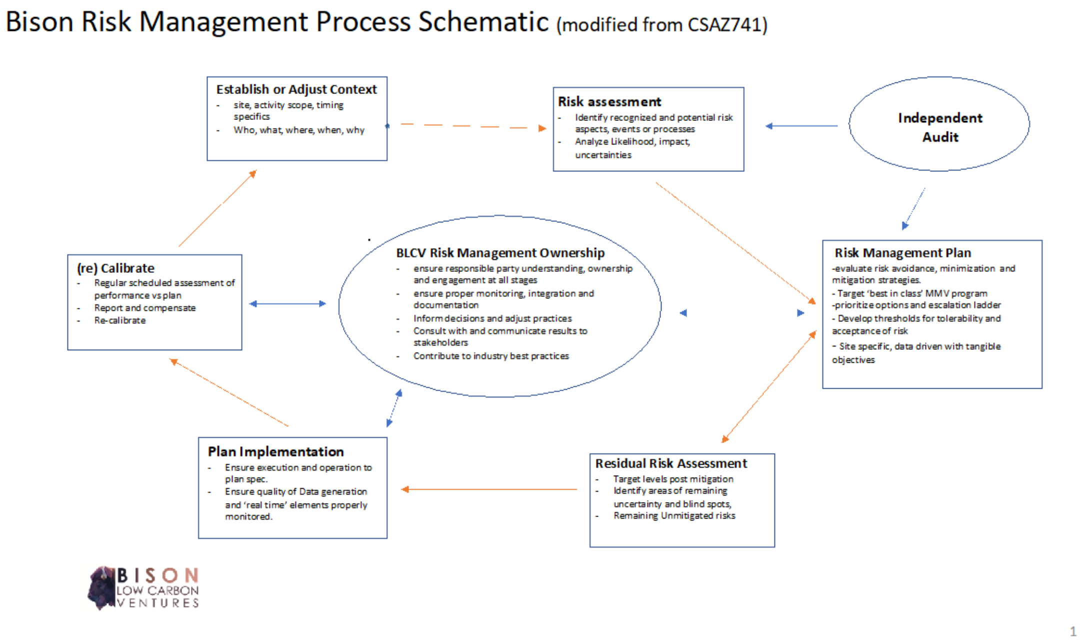
The commerciality of the quality lithium resource in this area is unproven and the intent or ability to progress a possible development in a timely manner is unknown. Using mining brokerage RFC Ambrian research as a source (August 2023 Lithium Market Review), the lowest concentration brine in commercial development anywhere in the world today is a small Argosy Minerals project in Argentina at 325mg/l, with other commercial brine projects having 500-700mg/l. Two projects with relatively low concentrations are under construction or planned in Germany (180) and Argentina (390). Pre-feasibility studies average 330mg/l and range from two Canadian projects at 70mg/l, to South American projects at 750mg/l. Brine concentrations within the Woodbend Grp in this area are <40mg/l. At <15% the commercial limit in production today, and just over half the aspirational goals of the most aggressive developers in the world, we would hope to see a legitimate intention to attempt to develop a resource before materially adjusting the commercial development of the storage complex, but we remain committed to participate in stakeholder discussions of any kind.

Our tenure is immediately offset to the south and northeast by tenures awarded for CO2 injection for CCS into the BCS. Given the significant stratigraphic interval and multiple aquitards between the BCS and the top of the Beaverhill Lake (base of our complex) we expect Meadowbrook to have no effect from, or on, these projects. Approximately two townships south of our tenure, the Enbridge consortium's tenure proposes to utilize the Nisku Formation as the storage reservoir which is the aquifer above our storage interval that we will monitor for confirmation of top seal integrity. We have engaged with Enbridge and discussed the sharing of operational information that could allow each operator to assess the impact on their project from the neighbouring tenure. Both parties were supportive of investigating the concept as we moved closer to the start date.

16. Conservation of Pore Space Resource

We feel our current application addresses that concern and mitigates the risk of 'over allocation' or underutilization of pore space for CCS early in an evolving industry with our request for only a subset of the tenure that was awarded initially, in line with the phased nature of our proposed development. Our application is for a commercial lease over 21% (15,600ha) of our Evaluation Permit of roughly 70,000ha. When compared with the single existing commercial Sequestration tenure issued today (the Shell Quest project) our application proposes to increase the intensity level of usage for sequestration from approximately 2.3t/ha per year at Quest to >30t/ha per year at Meadowbrook. We do hope to expand our CSA tenure as we secure larger committed volumes.

17. Bison LCV Risk Management Process Schematic



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Appendix 1 – Carbon Sequestration Agreement

(refer to Appendix M of D065 application)

Appendix 2 – Risk Registry

(refer to Appendix P of D065 application)

Appendix 3 – Hydrogeological Assessment

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Meadowbrook Hub Project
Hydrogeological Assessment

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File #23-00474-00

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1.0 INTRODUCTION

Bison Low Carbon Ventures (Bison) has been issued one of the initial six carbon storage hubs for the sequestration of carbon emissions from Alberta's Industrial Heartland (AIH), the Meadowbrook Hub Project (the Project). The Project will include the carbon storage hub area, the injection location and surface facilities, and a pipeline from AIH to storage hub location.

The carbon storage hub (72,000 ha) will be located west of the Town of Legal in Sturgeon County, Alberta (Figure 1). Surface facilities will include a small plant site / compression facility and three injection wells. A 44 km pipeline will transport 5 million tonnes of liquid carbon dioxide (CO_2) per year, captured from third party producers in AIH, to the storage hub for injection.

Bison has retained Millennium EMS Solutions Ltd. (MEMS) to conduct a background hydrogeological assessment prior to the initiation of Bison's drilling and injection testing program. The initial planned injection location is to be on the Bison 103/16-29-057-25 W4M lease. The target for the CO_2 injection is the Leduc Formation within the Woodbend Group, which is at a depth of approximately 1,650 metres below ground level (m bgl).

The injected fluid will be 99.5% CO_2 with the balance being made up of nitrogen and water. Well-head pressures are expected to be less than atmospheric (*i.e.*, vacuum) with injection zone pressures rising minimally from existing formation pressures.

1.1 Scope of Work

The hydrogeological assessment includes descriptions of both the regional as well as the local hydrogeology in the vicinity of the 103/16-29 lease. The Regional Study area is shown on Figure 2 and the Local Study Area is shown on Figure 3. As part of the assessment, the following was conducted.

- Review of publicly available hydrogeology data and reports. This included, but is not limited to, published hydrogeological studies and mapping for the area, water well completion data, and available groundwater quality data.
- Review Bison's operational plans and how they may affect the local hydrogeology.
- Conduct a detailed review of the water well records within Local Study Area around the 103/16-29 lease.
- Collection and review of oil and gas well data in the vicinity of the 16-29 lease (such as drill stem test (DST) data and drilling occurrence data).
- Provide groundwater monitoring recommendations.

2.0 HYDROGEOLOGY

This background hydrogeological assessment will focus on the Local Study Area (Figure 3) with reference to a broader regional setting as data are available from Bibby (1974) and Hydrogeological Consultants Ltd. (HCL, 2001).

The Base of Groundwater Protection at 16-29 is at a depth of 304 m above sea level (m asl). This hydrogeological presentation will therefore be divided into two parts:

- the shallow groundwater regime above a depth of approximately 300 m; and
- the deep groundwater regime from a depth of approximately 300 m to the injection zone at a depth of 1,650 m.

2.1 Shallow Groundwater Regime

The generalized regional stratigraphy for the Local Study Area is provided below based on HCL, 2001, Prior, *et.al.*, 2013, and Glass, 1997.

- The surficial deposits are in the order of 20 m thick.
  - Based on regional mapping conducted by HCL (2001), there are no significant aquifers within the surficial deposits in the vicinity of the 103/16-29 lease.
- The upper most bedrock consists of approximately 60 m of the Horseshoe Canyon Formation.
  - Lithology: interbedded sandstone, siltstone, and shale.
- The Bearpaw Formation underlies the Horseshoe Canyon Formation and is approximately 100 m in thickness.
  - Lithology: claystone, shale, and siltstone with subordinate sandstone.
- Underlying the Bearpaw Formation is the Belly River Formation. The thickness of the Belly River Formation rarely exceeds 350 m.
  - Lithology: interbedded mudstone to fine-grained sandstone with subordinate coarser-grained sandstones.
- The Lea Park Formation underlies the Belly River Formation and is up to 200 m in thickness.
  - Lithology: shale.

The formations described above are illustrated in Figure 4. The figure shows the Horseshoe Canyon, Bearpaw, and Belly River Formations as well as the Lea Park Formation which is identified as an aquitard. Aquitards are composed of material that limits and/or prevents the movement of groundwater through them.

HCL (2001) indicates that there are no buried bedrock valleys within 20 km of the proposed Project.

Regional mapping conducted by HCL (2001) indicates that water wells completed in the upper bedrock within the Local Study Area can have apparent yields in excess of 100 cubic metres per day (m^3/day) (15 imperial gallons per minute (igpm)). For the Horseshoe Canyon and Bearpaw Formations, water wells generally had yields of less than 10 m^3/day (1.5 igpm), but the regional mapping indicated yields in excess of 100 m^3/day may be possible. No significant aquifers within the surficial deposits were identified by HCL (2001) and there was insufficient information to determine yields for the Belly River Formation.

In addition, the regional groundwater study conducted by HCL (2001) indicates that:

- Where present, aquifers within the surficial deposits may be expected to contain groundwater with more than 1,500 milligrams per litre (mg/L) total dissolved solids (TDS).
- Groundwater in the upper bedrock may be expected to have TDS in the 500 to 1,500 mg/L range.
- In the upper bedrock, groundwater flow is downward beneath uplands and upward beneath creeks.

Bibby (1974) prepared a cross section (Figure 5) through the proposed site which used different, but stratigraphically equivalent naming and identified the upper bedrock as the Wapiti Formation rather than the Brazeau Group which includes the Horseshoe Canyon, Bearpaw and Bellow River. This cross section denotes downward groundwater flow under upland areas and upward beneath creeks. The report further indicates that TDS in the bedrock under the proposed site was expected to be approximately 1,700 mg/L.

2.1.1 Water Wells

The Government of Alberta Water Well Database (GOA, 2023) includes 139 water well records within the Local Study Area around the 103/16-29 lease. Of the 139 water well records, 39 were identified as part of a federal water well survey conducted in the late 1920's and early 1930's. Although some of these water wells may still exist, it is expected that the majority of these wells no longer exist and therefore they are not included in the compiled water well list due to the age of the wells.

Of the remaining 100 water wells, 70 are for domestic purposes, nine are for domestic and stock purposes, 13 are for stock watering, seven are for industrial use, and one is for municipal use. The average well depth is 33.9 m bgl and the deepest well is 103.6 m bgl. The location of the water well records from the Water Well Database within the Local Study Area are shown on Figure 6, and summarized in Table B1.

2.1.2 Alberta Environment Authorizations Database

The Alberta Environment Authorizations database indicates that there are seven authorized groundwater diversions within the Local Study Area. Six are registrations for traditional agricultural use and one is for a licence issued under the *Water Act* for stock watering purposes. None of these registrations or licences expire. The closest groundwater user to the 103/16-29 lease is listed as Robert Chauvet in NW 29-057-25 W4M, at approximately 1 km distance (Approval IDs 208343 and 208345).

The locations of the groundwater licences from the Alberta Environment Authorization database that are within the Local Study Area are shown on Figure 6 and summarized in Table B2.

2.1.3 Groundwater Use and Aquifers

The following comments can be made regarding groundwater use based on the collected water well and authorized users data.

- Although the one water well identified in the GOA Water Well Database as being used for municipal purposes is related to the Town of Legal (located in sections 23, 24, 25 and 26). It is assumed that this water well is no longer in use as there is currently no active licence for this well.
- The Town of Legal obtains its water supply from a regional pipeline from the North Saskatchewan River. It is not known at this time whether other developments along Highway 2 west of the town currently also use this regional water supply.
- The most recent record for water wells in the Local Study Area was in 1999. In consultation with a local water well drilling contractor (personal conversation with Summers Drilling Ltd., September 2023) who is local and familiar with this area, although groundwater is available, water well yields are typically low. It is reported that many landowners currently utilize cisterns to supply their domestic purposes. This is aligned with the results from HCL (2001) where water wells completed in the Horseshoe Canyon Formation generally have yields of less than 10 m^3/day (1.5 igpm).
- Based on information available from the GOA Waterwell Database for the Local Study Area:
  - The elevations of water levels in water wells range from 721 m asl to 608 m asl (0 metres below ground level (m bgl) (*i.e.*, flowing) to 61.0 m bgl).
  - The completion elevations of water wells range from 700 m asl to 572 m asl.
- The Base of Groundwater Protection (BGWP) is at a depth of 406 m bgl (304 m asl) underlying the Local Study Area. The BGWP is the depth below which groundwater is considered saline (4,000 mg/L).

Cross-section A-A' (Figure 7) shows the range of typical water well construction depths across the Regional Study Area along with the range in water level elevations from these water wells. The cross-section is based on data available from the GOA Water Well Database and the range in water levels is based on all the water level data available from the Regional Study Area and not just the water levels from the wells on the cross-section.

2.2 Deep Groundwater Regime – (Below the Base of Groundwater Protection)

Bachu *et al* (2008) present a comprehensive overview of the hydrogeological regime in the Edmonton area including shallow deposits and extending to the lower Devonian. The purpose of this research was to review possible impacts of acid-gas injection that began in the area in 1990. The authors specifically state that the general principles of acid-gas injection will apply to CO_2 injection.

As noted previously, the Base of Groundwater Protection is at an elevation of approximately 300 m asl (depth of 400 m) beneath the 16-29 lease (Figure 8). The proposed injection well is to be completed at an elevation of -950 m asl (950 m below sea level and a depth of 1,650 m bgl) into the Woodbend Group. Figure 4 shows the aquitards that have been identified on a basin-wide scale within this interval (Bachu *et al* 2008). At the location of the Bison 103/16-29 well, the Lea Park, Colorado , and Clearwater aquitards are expected to be present.

The combined thickness of these layered aquitards below the Base of Groundwater Protection would argue for hydraulic isolation of the injection zone and protection of potable groundwater resources and the wells that utilize that resource. Bachu *et al* (2008) stated the following.

- *"If only the natural setting is considered, including geology and flow of formation waters, the basin- and local-scale hydrogeological analyses indicate that injecting acid gas into these deep geological units in the Edmonton region is basically a safe operation with no potential for acid gas migration to shallower strata, potable groundwater and the surface. At Redwater the acid gas is already dissolved in water and it will dissolve further in the formation water, with no possibility for migration or leakage, being contained in the Redwater reef."*
- *"The entire stratigraphic interval from the Beaverhill Lake Group to the Lower Mannville Group is overlain by thick shales of the Colorado Group and Lea Park Formation. There are many barriers to acid gas migration from an injection zone into other strata, and the flow process, if it will ever happen, would take an extremely long time on a geological time scale. Any acid gas plume would disperse and dissolve in formation water during flow on such large time and spatial scales."*

2.2.1 Hydraulic Head and Flow

Bachu *et al* (2008) reported that hydraulic heads in the Cooking Lake Formation (part of the Woodbend Group) are approximately 300 m asl (calculated for a fluid density of 1,080 kg/m^3). This could be recalculated to 325 m asl for freshwater as used elsewhere in this document. They imply that the Devonian geological units have been "under pressured" for millennia – not just as a result of hydrocarbon production.

There has been hydrocarbon production from the Woodbend Group in this area since approximately 1953, which provides some useful data. Table 1 presents calculated freshwater hydraulic heads calculated from selected drill-stem tests (DST) completed in the Woodbend Group in and near the Regional Study Area. The table is arranged in chronological order from older to younger testing date. The following comments may be made to summarize this information:

- The test data in the 1950's show freshwater hydraulic heads in the Woodbend Group in the range of 357 to 395 m asl.
- The tests done in the 1980's consistently show freshwater hydraulic heads in the range of 382 to 401 m asl in the Woodbend Group. This is notably consistent with Bachu *et al* (2008).
- The DSTs from 2000 and 2001 show freshwater hydraulic heads in the Woodbend Group to be in the range of 357 to 395 m asl.
- The conclusion is that freshwater hydraulic heads in the Woodbend Group have not changed in any significant way since very early in the history of the petroleum development in the area.
- The hydraulic heads are approximately 300 m asl (400 m bgl), and likely have been so for millennia as noted by Bachu *et al* (2008).

These heads may be compared to those in local water wells which are as low as 608 m asl (approximately 60 m bgl). This means that the hydraulic gradient is directed downward from the near surface toward the formations of the Woodbend Group. Therefore, the direction of groundwater flow is downward from the near-surface aquifers toward the injection formations. Bachu *et al* (2008) also noted that groundwater flow direction is downward from the shallow Cretaceous sediments toward the Devonian units. Bachu *et al* (2008) further added that this downward hydraulic gradient has likely been in place since the retreat of glaciation.

Several significant conclusions result from this fact:

- The direction of the movement of fluids from any poorly constructed or abandoned hydrocarbon wells is currently downward – not upward – away from shallow groundwater aquifers.
- Bottom-hole pressures are not anticipated to rise significantly under injection conditions and therefore upward movement of injected CO_2 liquid is not expected to occur from poorly constructed or abandoned hydrocarbon wells. This would require the bottom-hole pressure to

rise to approximately 15,000 kilo Pascals (kPa) and the current expectation is to no more than approximately 13,000 kPa.

As shown on Cross-Section B-B′ (Figure 8), the Leduc Formation is more than 900 m deeper than the Base of Groundwater Protection, and more than 1,500 m deeper than the aquifers in which the water wells are completed. The cross-section also shows the maximum head pressure (based on fresh water level) expected within the Woodbend Group at more than 300 m below the range of water levels in the shallow aquifers. This indicates the overall downward hydraulic gradient and the injection of CO_2 into the Leduc Formation is not expected to be sufficient to have gas or fluids migrate upwards. As a result, the movement of gas and/or fluids from the Leduc Formation upward into shallow aquifers is not expected based on the downward hydraulic gradient as well as the presence of the aquitards (Figure 4) between the Leduc and the shallow aquifers.

Table 1 Freshwater Shut-in Pressures (FSIP) Hydraulic Heads in Vicinity of Project

Well Location W4M	Test Year	KB Elevation (m)	Test Interval (m below KB)	FSIP (kPa)	FSIP (m freshwater)	Hydraulic Head (m ASL)	Formation (Woodbend Group)
3-21-57-24	1953	708	1,223 – 1,226	8,963	914	397	Leduc
10-32-58-24	1954	657	1,197 – 1,204	8,825	900	357	Leduc
14-8-58-24	1954	680	1,189 – 1,195	8,791	896	385	Ireton
16-24-56-26	1983	712	1,600 – 1,604	12,679	1,293	382	Cooking Lake
2-5-58-25	1985	686	1,495 – 1,507	11,898	1,218	399	Cooking Lake
2-17-58-25	1984#2	681	1,480 – 1,485	11,784	1,202	401	Leduc
2-17-58-25	1984#1	681	1,493 – 1,498	11,875	1,211	397	Cooking Lake
12-21-58-25	1983	667	1,252 – 1,267	9,557	975	382	Ireton
12-9-57-24	2000	703	1,222 – 1,228	8,891	907	385	Ireton
4-16-57-24	2001	705	1,223 – 1,229	8,713	888	367	Ireton

2.2.2 Chemical and Buoyant Effects

Akono *et al* (2019) provide some insight into possible effects that might be considered:

- CO_2 injected solution is acidic and therefore limestones and dolomites may be subject to dissolution thus increasing dissolved calcium, magnesium, and bicarbonate/ carbonate.
  - However, at distance this dissolving action will diminish as the pH rises toward stable background values.
  - As the injection zone is carbonate reef, the dissolving action will increase the porosity and act to reduce injection pressures.
- CO_2 injected solution could be less dense than formation water so it will tend to rise in the receiving zone.
  - Bison has informed MEMS that at a formation pressure of 11,500 kPa and 61 Degrees C the density of the CO_2 will be approximately 400 kg/m^3. The density of the formation fluid is approximately 1,100 kg/m^3. This means that the injected fluid will be buoyant.
  - The confining strata and the aquicludes/aquitards of the geological sequence at this location have been successful at containing buoyant hydrocarbons for millennia. There is no reason to believe that buoyant CO_2 will migrate upwards from the proposed injection zone.
  - The issue of upward migration of CO_2 through well penetrations will be the subject of a future application for CO_2 injection wherein Bison will address the records of each existing well.

3.0 CONCLUSIONS

Bison's carbon storage operations are not expected to adversely affect the shallow groundwater aquifers or nearby water wells. The injection scheme is fundamentally no different from typical acid-gas or other CO_2 injection operations.

There is an overall downward hydraulic gradient from the shallow non-saline aquifers towards the injection zone. The injection of CO_2 into the Leduc Formation is not expected to be sufficient to cause gas or fluids to migrate upwards. Unless formation pressures increase from approximately 12,000 kPa to approximately 15,000 kPa there can be no upward leakage of injected fluid because the current freshwater hydraulic head in the receiving formations is approximately 300 m below ground surface. As a result, the movement of gas and/or fluids from the Leduc Formation upward into shallow aquifers is not expected based on the downward hydraulic gradient as well as the presence of aquitards (identified on Figure 4) between the Leduc Formation and the shallow aquifers that are conducive to containing the CO_2.

4.0 RECOMMENDED GROUNDWATER MONITORING

The following groundwater monitoring plan (GWMP) has been developed in the context that:

- The depth of the injection, number of aquicludes and the low hydraulic head makes it very unlikely that any injected fluids will escape upwards from the injection zone.
- The chemical nature of the injected fluids, along with dispersion and diffusion over substantial distances, makes it very likely that injected fluids will be diluted to background before reaching any receptor.

4.1 Existing Water Wells

The following sections contain recommendations for the monitoring of existing water wells in relation to Bison's carbon storage operations. The recommendations have been based on the following existing Alberta Energy Regulator (AER) directives, Alberta Environment and Protected Areas (EPA) guidelines and procedures, and Alberta Research Council (ARC) procedures. Many were developed in relation to coal bed methane extraction in Alberta and the methods and procedures include groundwater yield and quality testing, as well as the monitoring of gasses in the shallow groundwater.

- Directive 035: Baseline Water Well Testing Requirement for Coalbed Methane Wells Completed Above the Base of Groundwater Protection (AER, 2022).
- Standard for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal Operations (EPA, April 2006).
- Gas Sampling Requirements for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal Operations (EPA, June 2006).
- The Free Gas Sampling Standard Operating Procedure for Baseline Water Well Testing (ARC, 2009).

In general, the main indicator parameter is expected to be the pH of the groundwater as the addition of CO_2 into groundwater results in a pH decrease. This lowering of the pH will result in corresponding changes in other dissolved chemical constituents as they are brought into solution as a result of the change in the carbonate equilibrium. However, it should be noted that the carbonates of the Leduc Formation, into which the CO_2 is to be injected, is expected to buffer potential pH changes.

To help establish a baseline of the groundwater quality and aquifer parameters in the nearby water wells, the following are the recommended tasks related to the testing of existing water wells within the Local Study Area. This will also help to alleviate any concerns of local stakeholders with respect to Bison's operations potentially adversely affecting their water wells.

- Field-verified water well survey in within the Local Study Area.
- Based on the field-verified water well survey, select representative water wells to include in the testing program.
- Conduct water well testing program.
  - Conduct pumping test.
  - Collect groundwater samples.
  - If free gas is present in the water well, collect samples of the gas.
  - Document condition of water well.

The above existing water well testing is intended to provide a comprehensive baseline suite of data. This data includes parameters that can be directly related to Project operations as well as data related to other typical domestic water well and aquifer characterization based on MEMS' experience with investigating concerns raised by landowners in proximity to industrial operations. This dataset can be used to help address any potential landowner concerns.

4.1.1 Field-Verified Water Well Survey

Conduct a field-verified water well survey using the water well records available in the GOA Waterwell Database for the Local Study Area as a starting point. When contact is made with a landowner, attempt to confirm the data available from the GOA Waterwell Database, measure the water level in the water well if practical, obtain coordinates for water wells using a consumer-grade hand-held GPS unit, and obtain any other information regarding the well that the landowner is prepared to provide. If a water well is identified that was not part of the GOA Waterwell Database, then obtain as much information as possible for the water well and it will be added to the list of wells within the study area.

4.1.2 Selection of Representative Wells to Include in Testing Program

Directive 035 requires all water wells that are within 600 m of the injection well be included in the testing program for CBM wells. Based on the differences between CO_2 injection and CBM operations (*i.e.,* lower well density), it is suggested that a radius in the order of 1,600 m (one section) be considered for this Project from which to identify select water wells to include in the testing program as part of a scientifically targeted approach.

Using the results of the field-verified water well survey, representative water wells will be selected to be included in the baseline testing program. This may be in the range of three to four wells from within the suggested radius, pending the results of the field-verified well survey and landowner participation, to provide a representative dataset. The criteria to be used will include, but may not be limited to, the following.

- Identify water wells that have sufficient information from the GOA Waterwell Database to determine the completion interval and that have lithologic information for the well.
- Identify at least one water well in each aquifer(s) that may be present.
- Water wells will be selected that have well constructions conducive to conducting a test. This includes access into the well to take water levels.

Once a list of potential water wells is compiled, landowners will be approached to determine if they would be interested in participating in the baseline testing program. Consideration should also be given to selecting some representative water wells for long-term monitoring.

4.1.3 Water Well Testing Program

It is proposed that the water well testing program be conducted based on the Standard for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal Operations (EPA, April 2006). The results will provide a comprehensive basis for comparison if any concerns arise in the future regarding potential effects of Bison's operations on adjacent shallow groundwater aquifers.

A summary of the proposed water well testing is as follows.

- Water Well Capacity
  - Conduct a pumping test with the water well.
  - To obtain the best results, bypass the pressure system if possible.
  - Measure the drawdown of the water level while pumping the well at a constant rate.
  - Collect groundwater samples (further described below) toward the end of the pumping interval and then measure the water level recovery in the well after the pump is turned off.
- Water Well Quality
  - Collect water samples for the following analyses.
    - Routine potability (major anions and cations).
    - Dissolved metals.
    - Bacteriological analysis (iron-related, sulphate-reducing, total coliform and E.coli bacteria).

- Determine if free gas is present in the groundwater discharge from the water well.
    - If present, collect a sample of the gas and determine the volume of gas using a flow-through cell.
    - Submit the gas for compositional analysis.
    - Although when free gas occurs naturally in shallow groundwater aquifers the composition is almost always primarily methane, consideration should be given to conducting an isotopic analysis of any constituents of the gas to confirm whether they are the same as those being injected by Bison as part of their carbon capture project.

Once completed, provide the landowners with the results of the test with their water well(s).

4.2 On-Site Monitoring Wells

Three monitoring wells will be installed on the Project site:

- They will be installed in separate drillholes by industry standard techniques appropriate to the depths and regulatory constraints. Water levels, water samples and gaseous monitoring will be expected of these wells.
- One well will be approximately 90 m deep which will provide information regarding the potable groundwater regime.
- If multiple water-bearing intervals are identified during the drilling of the 90 m deep monitoring well, up to two additional monitoring wells will be completed adjacent to the 90 m deep well.

Analysis of water samples will be consistent with those obtained from the domestic water well testing program. Three samples will be collected, with a minimum of one month between each monitoring event, prior to injection to establish baseline conditions.

4.3 Isotopic Analysis

It is also suggested that the composition of the CO_2 injection mixture be recorded, and isotopic analyses conducted on the CO_2 and potentially other select gasses in the injection mixture. This will provide a baseline for comparison in the event concerns arise on the effect of the injection on adjacent shallow groundwater intervals.

5.0 LIMITATIONS OF LIABILITY

This report pertains solely to the assessment of the Bison Low Carbon Ventures project centred on 16-29-057-25 W4M. Information obtained by site investigation or provided by third parties is believed to be accurate and reflective of site conditions but is not guaranteed. The assessment was conducted using industry accepted hydrogeological practices to satisfy the requirements of the applicable regulations, approvals and/or directives. Millennium EMS Solutions Ltd. has exercised reasonable skill, care, and due diligence in assessing the information acquired during the preparation of this report.

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6.0 CLOSURE

We thank you for the opportunity to be of assistance to Bison Low Carbon Ventures. Should you have any questions, please contact either of the undersigned at 403.592.6180.

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PERMIT TO PRACTICE
MILLENNIUM EMS SOLUTIONS LTD

RM SIGNATURE: ____________

RM APEGA ID #: 58088

DATE: 2023-09-18

PERMIT NUMBER: P007002
The Association of Professional Engineers and Geoscientists of Alberta (APEGA)

Validated by:
Jason Sanders, P.Geol.
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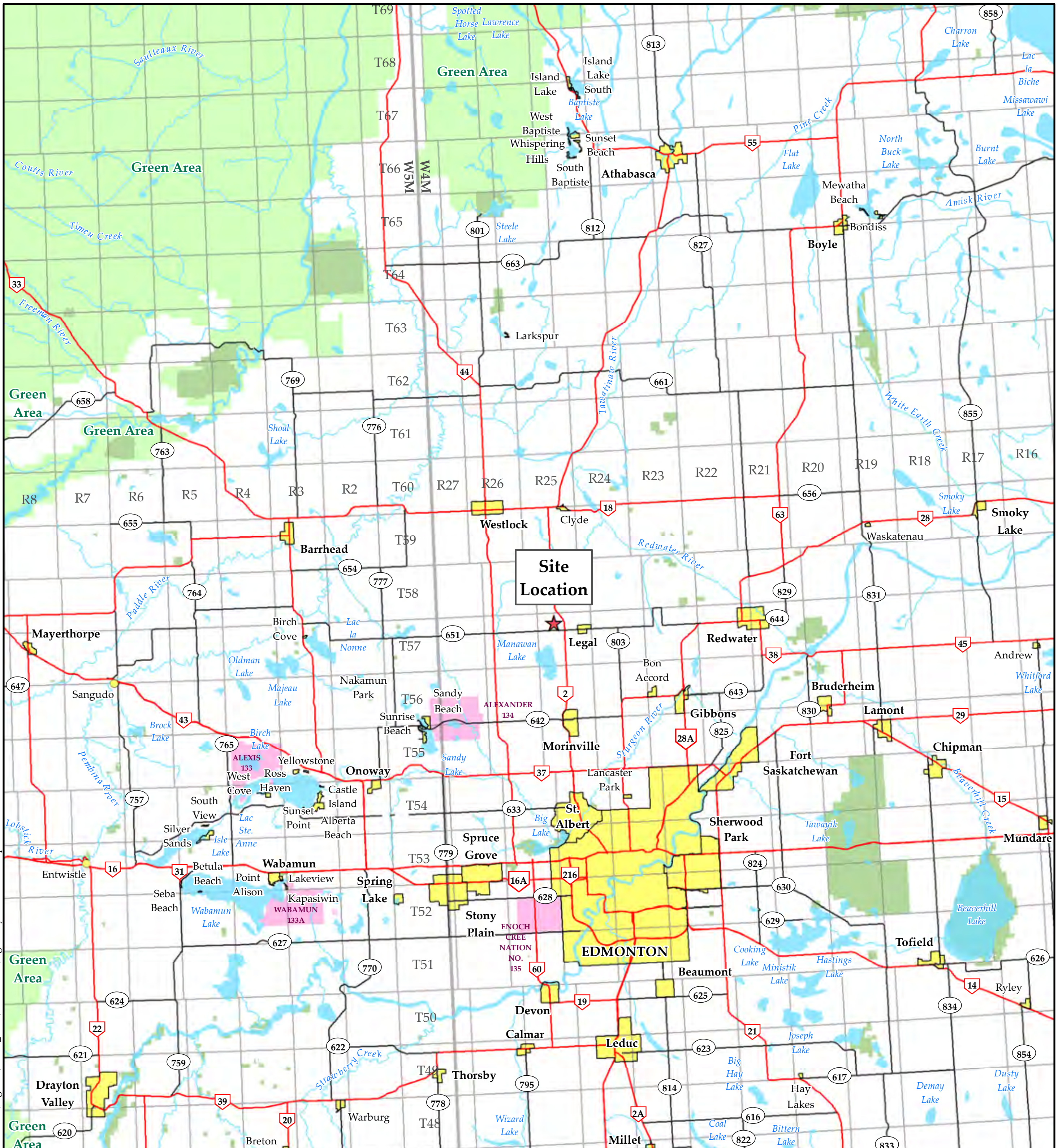
APPENDIX A: FIGURES



LEGEND

- ★ Site Location
- Primary Highway
- Secondary Highway
- Park/Protected Area
- Green Area
- First Nations Reserve/Metis Settlement
- Populated Place

BISON LOW CARBON VENTURES
16-29-057-25 W4M
REGIONAL HYDROGEOLOGICAL ASSESSMENT

MILLENNIUM EMS Solutions Ltd.

PROJECT LOCATION MAP

AltaLIS, 2019, 2020; GeoBase, 2015, 2017, 2019; MEMS, 2023;

Coordinate System: NAD 1983 UTM Zone 11N

PROJECT: 23-00474
DRAWN BY: NBUSAAN
CHECKED BY: JS
DATE: AUGUST 28, 2023

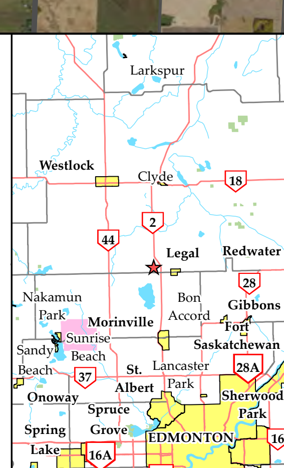
0 20 40
Kilometres

FIGURE 1

Document Path: K:\Active Projects 2023\AP 23-00451 to 23-00500\23-00474\Figures\Water_Well\2023-08-28\Fig 1 Project Location Map 23-00474.mxd

LEGEND

- ★ Well Centre (Survey Location)
- ● Water Well
- Cross-section A - A'
- Cross-section B - B'
- Local Study Area
- Regional Study Area



BISON LOW CARBON VENTURES

BISON LOW CARBON VENTURES
16-29-057-25 W4M
REGIONAL HYDROGEOLOGICAL ASSESSMENT

SITE MAP - REGIONAL STUDY AREA

MILLENNIUM EMS Solutions Ltd.

AltaLIS, 2022; MEMS, 2023;
Valtus, 2023 (Image Date: 2017)

Coordinate System: NAD 1983 UTM Zone 12N

0 4 8
Kilometers

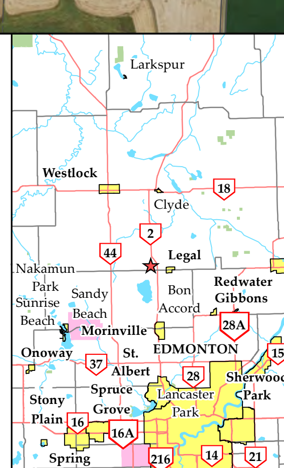
PROJECT: 23-00474
DRAWN BY: NBUSAAN
CHECKED BY: JS
DATE: SEPTEMBER 12, 2023

FIGURE
2

Document Path: K:\ Active Projects 2023\ AP 23-00451 to 23-00500\ 23-00474\ Figures\ Water_Well\ 2023-08-28\ Fig 2 Site Map - Regional Study Area 23-00474.mxd

LEGEND

- ★ Well Centre (Survey Location)
- Lease Boundary
- Access RoW
- Local Study Area



BISON LOW CARBON VENTURES

BISON LOW CARBON VENTURES
16-29-057-25 W4M
REGIONAL HYDROGEOLOGICAL ASSESSMENT

SITE MAP - LOCAL STUDY AREA (4 X 4 SECTIONS)

MILLENNIUM EMS Solutions Ltd.

AltaLIS, 2022; MEMS, 2023;
Valtus, 2023 (Image Date: 2017)

Coordinate System: NAD 1983 UTM Zone 12N

0 1 2
Kilometers

PROJECT: 23-00474
DRAWN BY: NBUSAAN
CHECKED BY: JS
DATE: AUGUST 28, 2023

FIGURE 3

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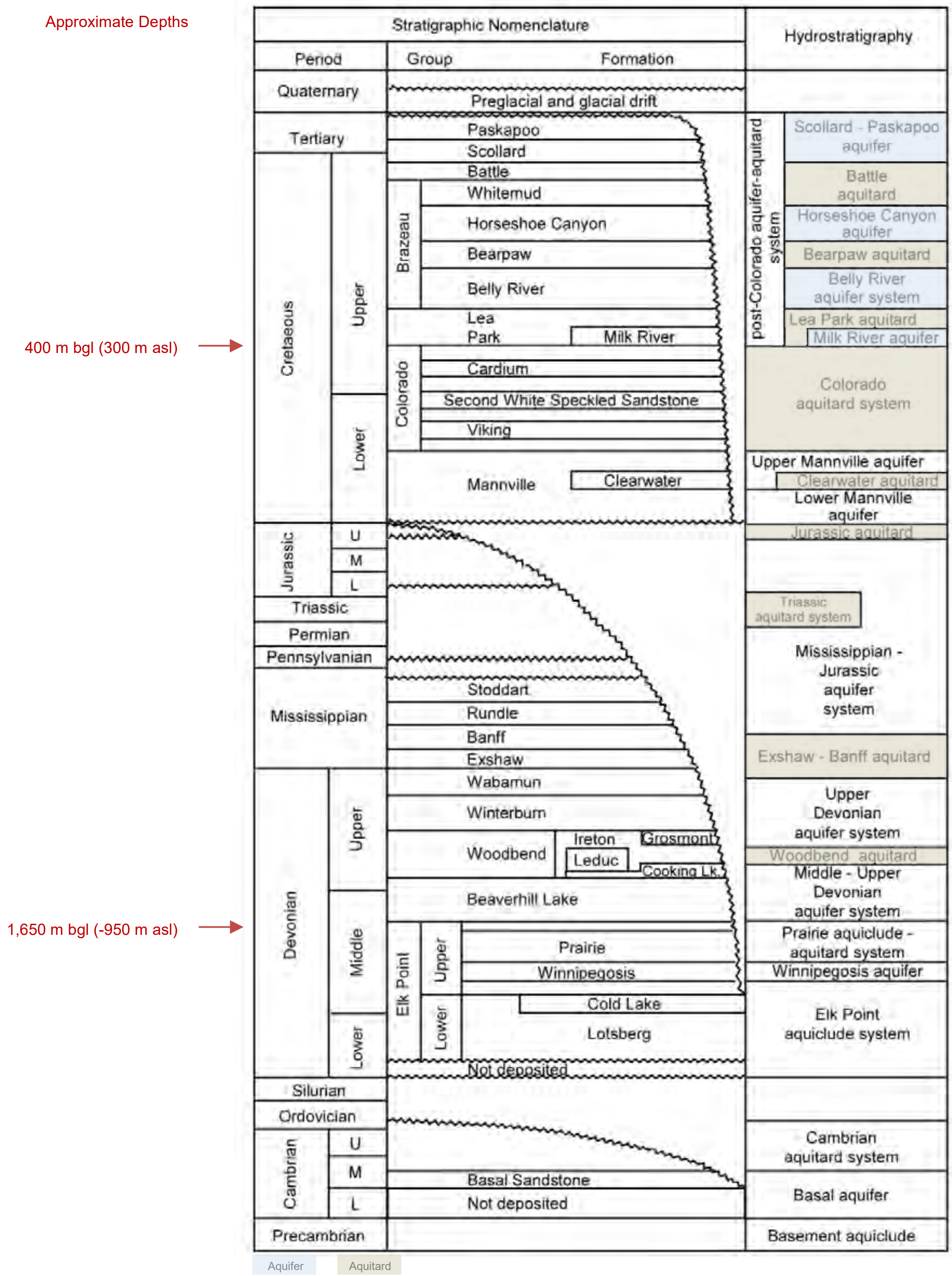
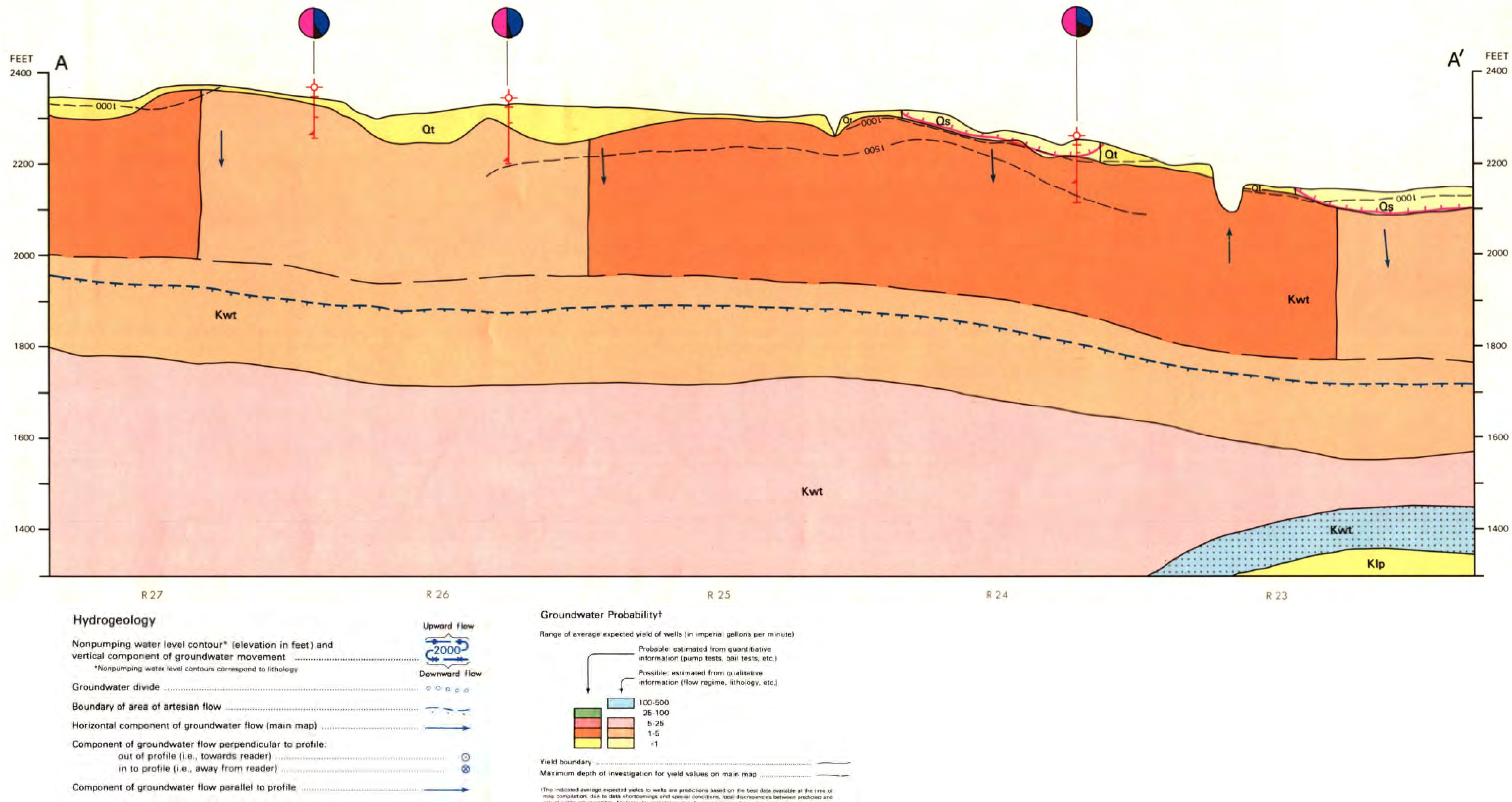


Figure 4. **Basin Scale Stratigraphic Delineation and Nomenclature** (after Bachu, 1999)



LEGEND

QUATERNARY

Qs	Sand	Qpsg	Saskatchewan Sands and Gravels
Qt	Till	Ql	Lacustrine clay, silt

CRETACEOUS

Kwt	Wapiti Formation	Klp	Lea Park Formation

BISON LOW CARBON VENTURES

BISON LOW CAPTURE VENTURES
16-29-057-25 W4M
REGIONAL HYDROGEOLOGICAL ASSESSMENT

MILLENNIUM EMS Solutions Ltd.

CROSS-SECTION (from Bibby, 1974)

PROJECT: 23-00474-00
DRAWN BY: JS
CHECKED BY:
DATE: AUGUST 25, 2023

MEMS 2023;

SCALE N/A

FIGURE
5

LEGEND

Water Well Use (GIC_WELL_ID Label)

- Domestic
- Domestic & Stock
- Stock
- Industrial
- Municipal
- Unknown/Other

- Licensed Groundwater User
- Well Centre (Survey Location)
- Watercourse (Definite)
- Watercourse (Indefinite)
- Waterbody (Definite)
- Waterbody (Indefinite)
- Lease Boundary
- Access RoW
- Local Study Area

BISON LOW CARBON VENTURES
16-29-057-25 W4M
REGIONAL HYDROGEOLOGICAL ASSESSMENT

WATER WELLS & LICENSED GROUNDWATER USERS MAP

AltaLIS, 2022; MEMS, 2023;
Valtus, 2023 (Image Date: 2017)

Coordinate System: NAD 1983 UTM Zone 12N

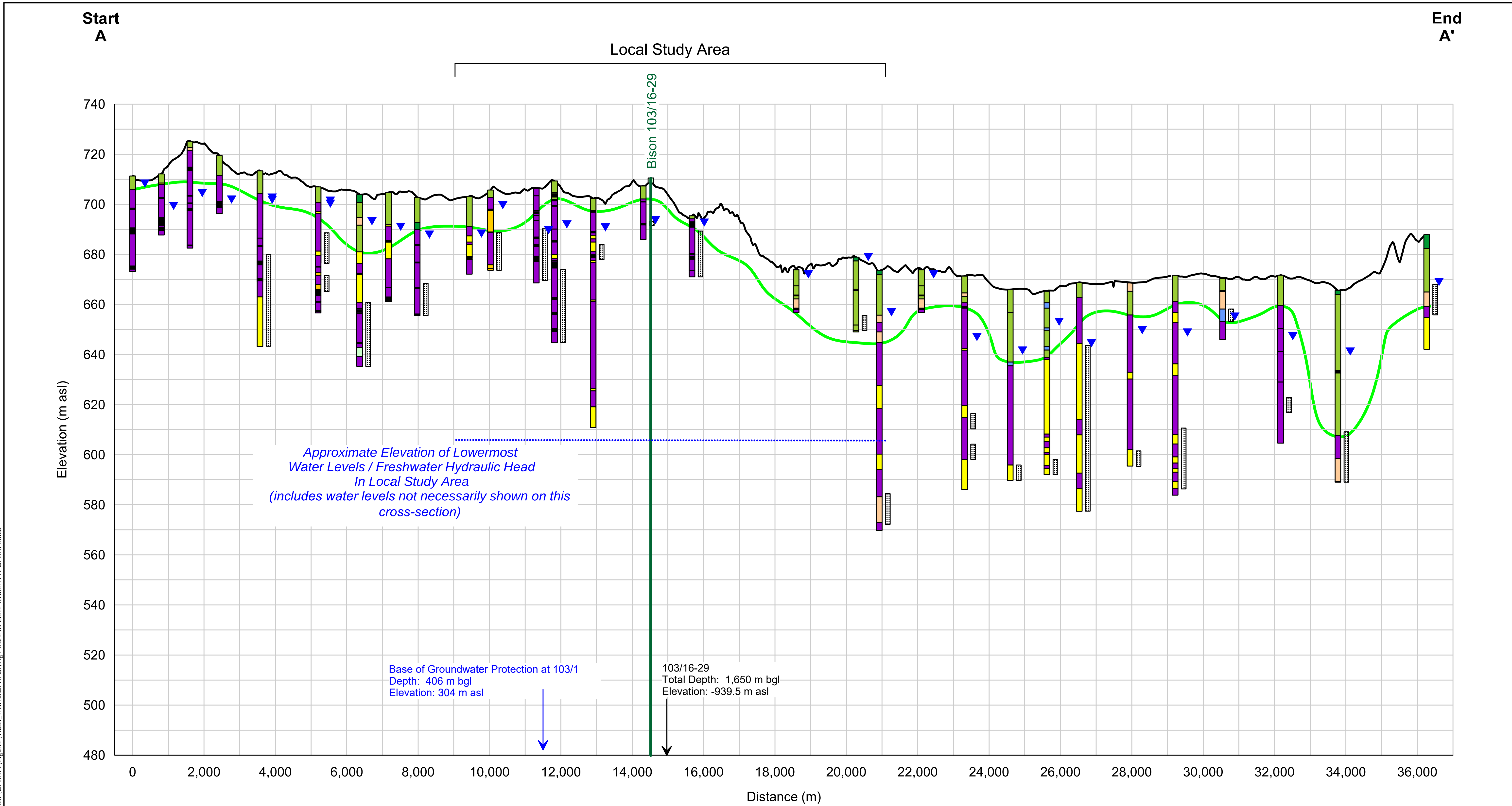
0 1 2
Kilometers

MILLENNIUM EMS Solutions Ltd.

PROJECT: 23-00474
DRAWN BY: RHART
CHECKED BY: JS
DATE: SEPTEMBER 13, 2023

FIGURE
6

Document Path: K:\Active Projects 2023\AP 23-00451 to 23-00500\23-00474\Figures\Water_Well\2023-08-28\Fig 6 WW And Licensed Water Users - Local Study Area 23-00474.mxd



LEGEND

- Clay
- Shale & Sandstone
- Shale
- Sandstone
- Coal/ Coal & Sandstone
- Gravel
- Top of Bedrock
- Water Level
- Completion Interval

BISON LOW CARBON VENTURES

BISON LOW CARBON VENTURES
16-29-057-25 W4M
REGIONAL HYDROGEOLOGICAL ASSESSMENT

MILLENNIUM EMS Solutions Ltd.

CROSS-SECTION A - A'

PROJECT: 23-00474
DRAWN BY: NBUSAAN
CHECKED BY: JS
DATE: AUGUST 28, 2023

MEMS 2023;

SCALE N/A

FIGURE 7

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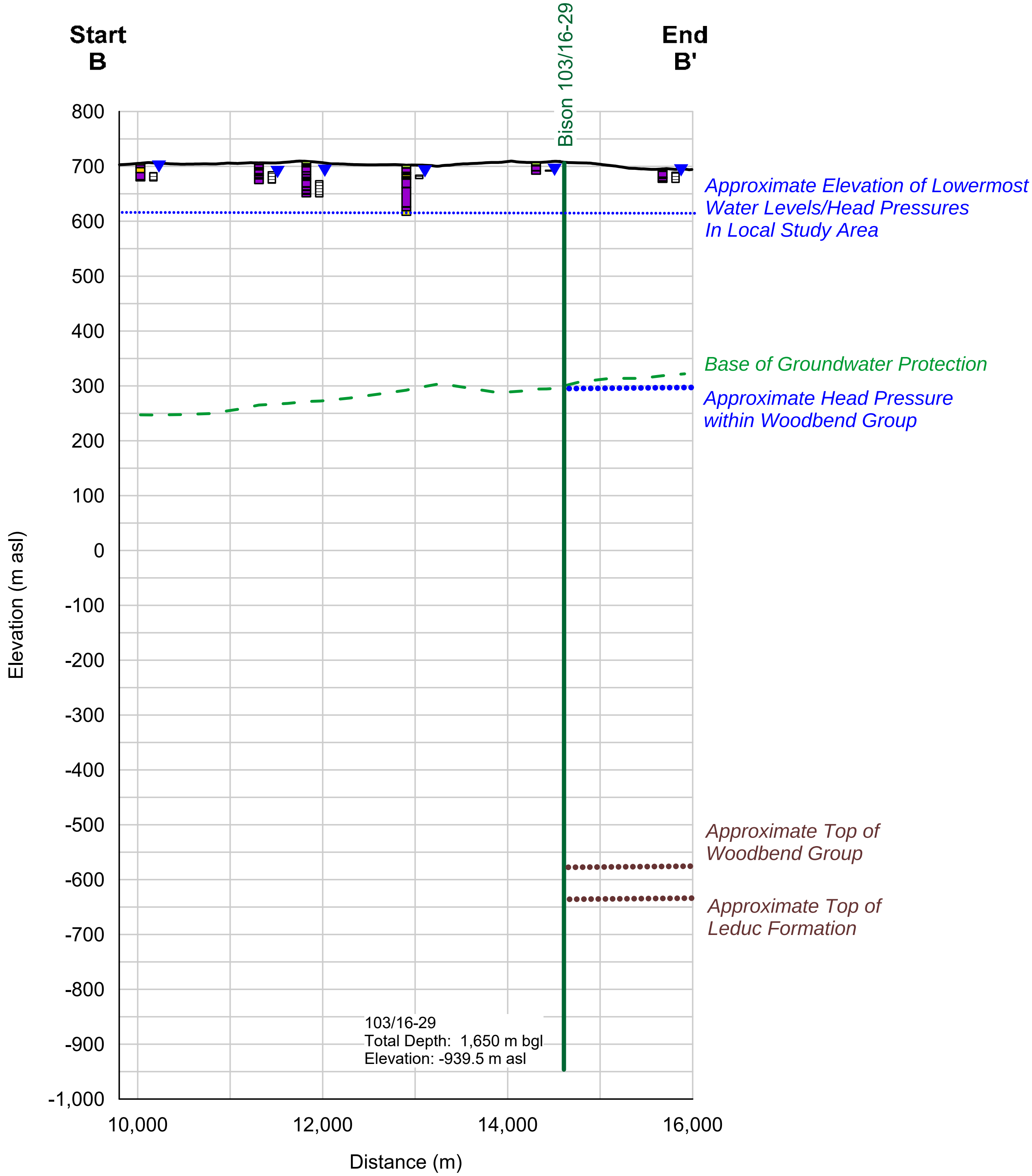

LEGEND

- Clay
- Shale & Sandstone
- Shale
- Sandstone
- Coal/ Coal & Sandstone
- Gravel
- Water Level
- Completion Interval

BISON LOW CARBON VENTURES
16-29-057-25 W4M
REGIONAL HYDROGEOLOGICAL ASSESSMENT

CROSS-SECTION B - B'

MEMS, 2023;

PROJECT: 23-00474	
DRAWN BY: NBUSAAN	
CHECKED BY: JS	
DATE: AUGUST 30, 2023	

SCALE N/A

FIGURE 8

Disclaimer: This figure was derived from multiple data sources and while we make every effort to assure its accuracy, Millennium EMS Solutions Ltd. disclaims any representation or warranty and assumes no liability either for any errors, omission or inaccuracies that may occur.

APPENDIX B: SUMMARY TABLES

Table B1. Water Well Records within the Local Project Area

Well ID	Easting	Northing	Elevation (m asl)	Distance from 103/16-29 (m)	LSD	SEC	TWP	RGE	M	Drilling Company	Date Completed	Depth Drilled (m)	Type of Work	Use	Well Owner	Static Level (m)	Pumping Method	Test Rate (L/min)
265032	324,804	5,982,312	707.3	217	NE	29	57	25	4	TOWN & COUNTRY WATER WELL BORING LTD.	1995/08/15	21.3	New Well	Stock	CHAUVET, S.	13.72	Bailer	113.7
168272	325,021	5,983,479	693.9	1,072	SW	33	57	25	4	UNKNOWN DRILLER		11.0	Chemistry	Domestic	LAFLECHE, MAURICE/CINDY			
267568	325,248	5,981,550	708	1,095	SW	28	57	25	4	UNKNOWN DRILLER		25.9	Chemistry	Domestic	RIVARD, F	12.19		
163072	325,095	5,983,535	695.4	1,151	SW	33	57	25	4	GERALD MCGINN DRILLING LTD.	1991/11/14	24.4	New Well	Domestic & Stock	LAFLECHE, MAURICE/CINDY	2.74	Bailer & Air	34.1
267593	324,746	5,981,307	705.6	1,167	1	29	57	25	4	FEDORVICH DRILLING	1978/05/13	9.8	Reconditioned	Domestic	WYNNYCHUK, A.			
267630	323,435	5,982,145	701.8	1,264	NW	29	57	25	4	UNKNOWN DRILLER		36.6	Chemistry	Domestic	SCHREIBER, J/A			
267617	323,376	5,982,517	702.8	1,281	13	29	57	25	4	FEDORVICH DRILLING	1978/09/15	18.6	New Well	Domestic & Stock	COMPTON, W.	9.14	Bailer	9.1
267603	323,420	5,982,084	702.3	1,295	5	29	57	25	4	KAP'S DRILLING LTD.	1981/08/12	91.4	New Well	Domestic	SCHIEBER, A	11.58	Bailer	18.2
273825	323,331	5,982,426	703.1	1,326	NW	29	57	25	4	GERALD MCGINN DRILLING LTD.	1977/05/26	28.7	New Well	Domestic	MCLEOD, M	10.67	Bailer	45.5
267634	323,325	5,982,299	703.7	1,342	NW	29	57	25	4	UNKNOWN DRILLER		36.6	Chemistry	Domestic	TEETER, J			
271717	324,311	5,981,062	705.1	1,451	NE	20	57	25	4	BIG IRON DRILLING LTD.	1980/01/31	42.7	New Well	Domestic	MAURIER, CLAUDE	9.14	Bailer	13.6
267004	324,372	5,981,006	704.7	1,492	NE	20	57	25	4	KIELBAUCH DRLG	1968/06/06	45.7	New Well	Stock	MAURIER, C.	7.62	Unknown	9.1
267653	323,172	5,982,854	700.6	1,533	SE	31	57	25	4	UNKNOWN DRILLER		0.0	Chemistry	Domestic	CHAMBERLAND, D			
267014	324,363	5,980,959	704.7	1,540	15	20	57	25	4	KC DRILLING (LEDUC)	1983/03/09	29.6	New Well	Domestic & Stock	MAURIER, C.			
267650	323,154	5,982,893	700.3	1,560	1	31	57	25	4	TOWN & COUNTRY WATER WELL BORING LTD.	1981/01/28	15.2	New Well	Domestic	CHAUVET, M.	6.10	Bailer	22.7
273860	325,821	5,983,533	698.8	1,576	SE	33	57	25	4	UNKNOWN DRILLER		22.9	Chemistry	Domestic	ELIASON'S LTD			
161828	325,325	5,983,970	691.5	1,642	NW	33	57	25	4	UNKNOWN DRILLER		54.9	Chemistry	Domestic	SABOURIN, DONALD			
161829	325,325	5,983,970	691.5	1,642	NW	33	57	25	4	UNKNOWN DRILLER		30.5	Chemistry	Domestic	PREEPER, ED			
267689	325,325	5,983,970	691.5	1,642	NW	33	57	25	4	UNKNOWN DRILLER		18.3	Chemistry	Domestic	KOTYLAK, P			
267573	325,753	5,981,248	709	1,643	4	28	57	25	4	UNKNOWN DRILLER		27.4	Chemistry	Stock	RIVARD, F	21.34		
267556	325,708	5,981,185	709.1	1,661	SW	28	57	25	4	UNKNOWN DRILLER		33.2	Chemistry	Domestic	RIVARD, F	16.76		
267579	326,345	5,982,240	706.5	1,705	NE	28	57	25	4	UNKNOWN DRILLER		15.2	Chemistry	Domestic	MERCIER, R.	3.05		
267681	324,885	5,984,239	688.1	1,783	16	32	57	25	4	SEIS-TEST	1964/06/04	38.1	New Well	Domestic	DE CHAMPLAIN, G	6.10	Unknown	11.4
260139	324,616	5,984,275	687.3	1,804	NE	32	57	25	4	MAR-WAYNE WATER WELL DRILLING SERVICES LTD.	1995/08/25	36.6	New Well	Stock	MICHAUD, CLAUDE	10.88	Pump	18.2
158084	325,267	5,984,280	688.5	1,909	NW	33	57	25	4	BIG IRON DRILLING LTD.	1991/07/08	30.5	New Well	Domestic	MCNEIL, ARNOLD	6.10	Bailer	6.8
164455	323,070	5,981,399	706.4	1,914	SE	30	57	25	4	GERALD MCGINN DRILLING LTD.	1992/01/28	37.8	New Well	Domestic & Stock	LUTZ, ALBERT	16.76	Bailer & Air	31.8
266973	323,351	5,981,043	709.8	1,934	NW	20	57	25	4	UNKNOWN DRILLER		42.7	Chemistry	Domestic	RIVARD, D			
266990	323,395	5,981,003	709.3	1,935	13	20	57	25	4	MAR-WAYNE WATER WELL DRILLING SERVICES LTD.	1979/04/19	64.6	New Well	Domestic & Stock	RIVARD, D	17.37	Bailer	13.6
267544	325,987	5,981,063	711.2	1,938	SE	28	57	25	4	MCISAAC GARRY N	1979/07/18	30.5	New Well	Domestic	HERRICK, J	6.10	Bailer	36.4
273865	326,461	5,983,195	702.9	1,945	SE	33	57	25	4	UNKNOWN DRILLER		61.0	Chemistry	Domestic	MONTPETIT, R.	4.57		
273863	326,438	5,983,290	698.9	1,961	SE	33	57	25	4	FERLAND ENTERPRISES	1976/07/05	76.2	New Well	Domestic	MONTPETIT, R.	22.86	Bailer	1.5
267655	322,850	5,983,258	697.4	1,970	SE	31	57	25	4	HOLLAND DRILLING LTD.	1986/09/21	67.1	New Well	Domestic	CZERNICK, K	11.58	Air	6.8
267672	323,359	5,984,034	684.7	2,031	NW	32	57	25	4	JIM'S DRILLING	1978/06/05	10.4	New Well	Stock	CHAUVET, R.	0.76		9.1
153458	325,665	5,984,239	691.9	2,036	NW	33	57	25	4	RENE ARTS WATERWELL LTD.	1990/07/18	97.5	New Well	Domestic & Stock	DECHAMPLAIN, LEO	7.62	Pump	11.4
267685	326,433	5,983,485	695	2,046	SE	33	57	25	4	BIG IRON DRILLING LTD.	1980/02/13	30.5	New Well	Domestic	MCCONNELL, B.	13.72	Bailer	13.6
136189	325,263	5,984,425	688.4	2,046	SW	4	58	25	4	UNKNOWN DRILLER		0.0	Chemistry	Domestic	NOWICKI, BERT			
291016	324,832	5,984,519	686.2	2,056	SE	5	58	25	4	MAR-WAYNE WATER WELL DRILLING SERVICES LTD.	1998/06/18	36.6	New Well	Stock	SPECPARMS, ERNIE CHAUVET	6.86	Pump	20.3
136195	324,806	5,984,522	686	2,056	SE	5	58	25	4	JIM'S DRILLING	1978/06/03	9.4	New Well	Domestic	CHAUVET, PAUL	0.61		3.4
267540	326,324	5,981,205	709.2	2,094	SE	28	57	25	4	UNKNOWN DRILLER		44.5	Chemistry	Domestic	TRUDEL,			
136190	324,865	5,984,606	685.7	2,145	4	4	58	25	4	HILL DRILLING LTD.	1982/08/20	59.4	New Well	Domestic	VANDENHAUTER, RICHARD	0.00	Bailer	18.2
136196	324,865	5,984,606	685.7	2,145	1	5	58	25	4	HOLLAND DRILLING LTD.	1984/08/02	73.2	New Well	Domestic	CHAUVET, PAUL/ERNIE	16.76	Air	5.9
267342	326,497	5,981,150	709.4	2,266	SW	27	57	25	4	UNKNOWN DRILLER		0.0	Chemistry	Domestic	LEGAL CORNER CAFE			
267304	326,770	5,981,166	709.2	2,484	4	27	57	25	4	FEDORVICH DRILLING	1977/10/05	19.5	New Well	Industrial	ST MARTIN, R	6.10	Pump	4.5
267340	327,069	5,981,687	707.3	2,537	6	27	57	25	4	FEDORVICH DRILLING	1980/04/25	13.4	New Well	Domestic	POOL	7.62	Bailer & Pump	6.8
267334	326,828	5,981,112	708.1	2,562	SW	27	57	25	4	KIELBAUCH DRLG	1968/05/31	45.7	New Well	Domestic	BAKER, A	9.14	Unknown	13.6
267499	327,278	5,981,880	702.1	2,688		27	57	25	4	UNKNOWN DRILLER		5.5	Chemistry	Domestic	LEGAL, TOWN OF	2.74		
242415	327,278	5,981,880	702.1	2,688	SE	27	57	25	4	BIG IRON DRILLING LTD.	1981/06/30	50.3	New Well	Domestic	KREMER, MARCEL	13.72	Bailer	11.4

Notes:
-: Information not Available
P & A: Pump and Air ; Dom. & Stock: Domestic and Stock; FWS: Federal Well Survey

Table B1. Water Well Records within the Local Project Area

Well ID	Easting	Northing	Elevation (m asl)	Distance from 103/16-29 (m)	LSD	SEC	TWP	RGE	M	Drilling Company	Date Completed	Depth Drilled (m)	Type of Work	Use	Well Owner	Static Level (m)	Pumping Method	Test Rate (L/min)
136187	326,354	5,984,555	678.9	2,688	1	4	58	25	4	GRANT COMFORT ENTERPRISES LTD.	1982/09/24	29.9	New Well	Stock	DECHAMPLAIN, LEO	0.00	Bailer & Pump	13.6
266937	323,206	5,980,184	706	2,708	5	20	57	25	4	REKLOW WATER WELL DRILLING	1983/08/31	41.5	New Well	Domestic & Stock	RIVARD, N	17.37	Pump	13.6
266952	323,251	5,980,126	705.2	2,734	SW	20	57	25	4	UNKNOWN DRILLER		12.2	Chemistry	Domestic	RIVARD, N			
266924	323,052	5,980,242	704.6	2,746	4	20	57	25	4	FEDORVICH DRILLING	1983/07/07	18.3	Reconditioned	Domestic	RIVARD, N			
267041	326,841	5,980,664	708.2	2,835	NW	22	57	25	4	UNKNOWN DRILLER		30.5	Chemistry	Domestic	MAURIER, R	10.67		
267357	327,501	5,982,476	693	2,845	15	27	57	25	4	FEDORVICH DRILLING	1980/08/13	25.0	Deepened	Domestic	PELLETIER, D	6.71	Pump	2.3
267357	327,501	5,982,476	693	2,845	15	27	57	25	4	FEDORVICH DRILLING	1980/08/13	25.0	Deepened	Domestic	PELLETIER, D	10.06	Bailer	27.3
267358	327,501	5,982,476	693	2,845	15	27	57	25	4	FEDORVICH DRILLING	1978/07/01	20.7	New Well	Domestic	MONTPETIT	6.40	Bailer	11.4
152104	324,629	5,979,604	703.2	2,867	SE	20	57	25	4	MAR-WAYNE WATER WELL DRILLING SERVICES LTD.	1990/05/23	48.8	New Well	Domestic	HAUPTMAN, MIKE	10.06	Bailer	13.6
267321	327,240	5,981,187	705.5	2,885	4	27	57	25	4	KIELBAUCH DRLG	1969/06/03	89.9	New Well	Domestic	MARTIN, D	13.72	Unknown	9.1
267644	321,799	5,982,907	713.7	2,890	11	30	57	25	4	JIM'S DRILLING	1978/06/05	13.4	New Well	Stock	CHAUVET, L.	0.00		2.3
267344	327,272	5,981,122	705.8	2,943	3	27	57	25	4	FEDORVICH DRILLING	1988/03/30	29.9	New Well	Industrial	LEGAL ALFALFA	0.00	Pump	4.5
163078	322,913	5,984,887	677.9	2,979	SE	6	58	25	4	UNKNOWN DRILLER		0.0	Chemistry	Domestic	FOWLER, DIANE/SHAWN			
215319	322,913	5,984,887	677.9	2,979	SE	6	58	25	4	UNKNOWN DRILLER	1976/05/01	12.2	Chemistry	Domestic	LEDET, PAUL	7.62		
136200	322,913	5,984,887	677.9	2,979	SE	6	58	25	4	UNKNOWN DRILLER		12.2	Chemistry	Domestic	FOWLER, LYLE			
256341	321,879	5,981,333	706.2	3,001	3	30	57	25	4	COUNTRYSIDE DRILLING	1994/05/27	57.9	New Well	Domestic	RIVARD, ROY	18.29	Pump	18.2
157113	327,695	5,982,268	694.8	3,046	NE	27	57	25	4	UNKNOWN DRILLER		21.9	Chemistry	Domestic	CLOUTIER, RICHARD			
157114	327,695	5,982,268	694.8	3,046	NE	27	57	25	4	UNKNOWN DRILLER		17.7	Chemistry	Domestic	TRITHART, LYLE/DEE DEE			
267353	327,695	5,982,268	694.8	3,046	NE	27	57	25	4	UNKNOWN DRILLER		6.1	Chemistry	Domestic	BRETTELLE, N			
267418	327,695	5,982,268	694.8	3,046	NE	27	57	25	4	UNKNOWN DRILLER		29.0	Chemistry	Domestic	MONTPETIT, M.			
267422	327,695	5,982,268	694.8	3,046	NE	27	57	25	4	TOWN & COUNTRY WATER WELL BORING LTD.	1988/06/21	36.9	New Well	Domestic	DE CHAMPLAIN, R	15.24	Unknown	9.1
267432	327,695	5,982,268	694.8	3,046	NE	27	57	25	4	BOYD'S WATER WELL DRILLING	1988/08/04	50.3	New Well	Industrial	ALFALFA PLANT #1 WELL	8.23	Unknown	11.4
267443	327,695	5,982,268	694.8	3,046	NE	27	57	25	4	BOYD'S WATER WELL DRILLING	1988/08/05	41.1	New Well	Industrial	ALFALFA PLANT # 2 WELL	0.00	Unknown	13.6
267451	327,695	5,982,268	694.8	3,046	NE	27	57	25	4	BOYD'S WATER WELL DRILLING	1989/05/03	54.9	New Well	Industrial	ALFALFA PLANT #1	9.14	Air	2.3
267475	327,695	5,982,268	694.8	3,046	NE	27	57	25	4	BOYD'S WATER WELL DRILLING	1989/05/09	45.7	New Well	Industrial	ALFALFA PLANT #3	14.94	Air	4.5
287872	322,267	5,984,407	688.7	3,075	NW	31	57	25	4	MAR-WAYNE WATER WELL DRILLING SERVICES LTD.	1997/07/03	36.6	New Well	Stock	COURSAUX, GERRY	22.86	Air	27.3
136192	325,029	5,985,568	691.7	3,119	NW	4	58	25	4	UNKNOWN DRILLER	1961/01/01	19.8	Chemistry	Domestic & Stock	DECHAMPLAIN, LEO	8.23		
218199	321,818	5,981,127	705.7	3,140	14	19	57	25	4	BOYD'S WATER WELL DRILLING	1993/07/15	32.0	New Well	Domestic	COURNOYER, DAN	6.10	Air	27.3
278181	327,243	5,980,649	707.5	3,164	NH	22	57	25	4	WAREHIME, JACK DRILLING	1995/10/01	91.4	New Well	Domestic	PIPKE FARMS	19.81	Pump	18.2
267283	327,665	5,981,463	697.8	3,173	SE	27	57	25	4	UNKNOWN DRILLER		7.9	Chemistry	Domestic	STASIUK, J M	1.83		
267247	327,665	5,981,463	697.8	3,173	SE	27	57	25	4	ELLIOTT DRLG	1977/10/19	54.9	New Well	Domestic	AUGER, J	1.52	Bailer	
267298	327,665	5,981,463	697.8	3,173	SE	27	57	25	4	MAR-WAYNE WATER WELL DRILLING SERVICES LTD.	1985/10/30	42.7	New Well	Industrial	STURGEON VALLEY FERTILIZER LTD	5.49	Bailer	9.1
267125	327,665	5,981,463	697.8	3,173	SE	27	57	25	4	WESTERN WATER WELLS LTD.	1947/09/04	35.1	New Well	Municipal	LEGAL, TOWN OF	18.29		40.9
136193	325,066	5,985,637	691.5	3,192	13	4	58	25	4	GRANT COMFORT ENTERPRISES LTD.	1985/03/01	30.5	New Well	Stock	DECHAMPLAIN, LEO	7.92	Pump	18.2
267730	327,406	5,984,171	676.7	3,233	NW	34	57	25	4	UNKNOWN DRILLER		0.0	Chemistry	Domestic	LETOURNEAU, N.			
267745	327,377	5,984,219	676.1	3,234	15	34	57	25	4	KIELBAUCH DRLG	1969/01/14	56.4	New Well	Domestic	LETOURNEAU, N.J.	12.19	Unknown	9.1
216351	326,980	5,984,732	673.4	3,242	SW	3	58	25	4	GRANT COMFORT ENTERPRISES LTD.	1993/05/14	103.6	New Well	Domestic	DUBIS, LARNARD	16.55	Air	68.2
267368	327,903	5,982,461	690	3,247	16	27	57	25	4	FEDORVICH DRILLING	1980/07/26	25.3	Deepened	Domestic	PELLETIER, D	10.36	Bailer & Pump	22.7
267356	327,903	5,982,461	690	3,247	16	27	57	25	4	FEDORVICH DRILLING	1978/07/10	15.8	New Well	Domestic	MONPETIT, M.	7.62	Pump	2.3
136198	323,763	5,985,660	675.1	3,312	NW	5	58	25	4	UNKNOWN DRILLER		30.5	Chemistry	Domestic	CHENARD, DENNIS	1.22		
267517	327,754	5,981,201	699.9	3,348	1	27	57	25	4	BIG IRON DRILLING LTD.	1982/05/20	30.5	New Well	Domestic	KREMER, M.	9.45	Bailer	11.4
160366	326,811	5,979,859	710.8	3,386	SW	22	57	25	4	BENN, W. ENTERPRISES LTD.	1990/04/05	18.3	Reconditioned	Domestic & Stock	VISSCHER FARMS/JOBE, R.W.	10.67	Bailer	181.8
156674	327,753	5,983,879	675.2	3,402	NE	34	57	25	4	UNKNOWN DRILLER		4.9	Chemistry	Domestic	ST MARTIN, NORMAND			
157115	327,753	5,983,879	675.2	3,402	NE	34	57	25	4	UNKNOWN DRILLER		6.1	Chemistry	Domestic	ST MARTIN, NORMAND			
267038	326,603	5,979,666	713	3,415	4	22	57	25	4	TOWN & COUNTRY WATER WELL BORING LTD.	1975/05/15	25.6	New Well	Stock	JOBE, R	10.36	Bailer	2.3
267294	327,859	5,981,255	698.3	3,426	1	27	57	25	4	SLECZKA TED	1975/06/11	53.3	New Well	Stock	LEGAL HOTEL '66 LTD	2.44	Unknown	13.6
266895	321,813	5,980,531	703.2	3,442	12	19	57	25	4	MCISAAC GARRY N	1978/06/12	31.1	New Well	Domestic	COURIGAN, D	14.94	Bailer	36.4

Notes:
-: Information not Available
P & A: Pump and Air ; Dom. & Stock: Domestic and Stock; FWS: Federal Well Survey

Table B1. Water Well Records within the Local Project Area

Well ID	Easting	Northing	Elevation (m asl)	Distance from 103/16-29 (m)	LSD	SEC	TWP	RGE	M	Drilling Company	Date Completed	Depth Drilled (m)	Type of Work	Use	Well Owner	Static Level (m)	Pumping Method	Test Rate (L/min)
292796	322,943	5,985,691	675.3	3,647	NE	6	58	25	4	HILL,DWIGHT (752663 ALBERTA LTD.	1999/09/29	28.0	New Well	Domestic	KLANN, HARRY	3.05	Bailer	81.8
267765	327,962	5,984,072	674.1	3,673	16	34	57	25	4	FEDORVICH DRILLING	1981/01/01	17.4	New Well	Domestic	LETOURNEAU, G	2.13	Bailer	45.5
136181	327,784	5,984,702	669.2	3,842	SE	3	58	25	4	UNKNOWN DRILLER		61.0	Chemistry	Domestic	JOHNSON, GWEN			
136182	327,784	5,984,702	669.2	3,842	SE	3	58	25	4	UNKNOWN DRILLER	1962/01/01	70.1	Chemistry	Domestic	COULOMBE, EMILIEN	60.96		
292787	321,642	5,979,762	703.3	4,053	SW	19	57	25	4	PAPLEY DRILLING LTD.	1999/10/29	42.7	New Well	Stock	CORNELIS, M.	15.09	Pump	45.5
266886	321,574	5,979,770	703.6	4,098	4	19	57	25	4	KAP'S DRILLING LTD.	1980/10/09	25.0	New Well	Domestic	MARCJARDY, G	0.00	Bailer	31.8

Notes:
-: Information not Available
P & A: Pump and Air ; Dom. & Stock: Domestic and Stock; FWS: Federal Well Survey

Table B2: Licensed Groundwater Users within the Local Study Area

Water Allocation ID	Approval ID	Priority No.	Easting	Northing	Distance from 103/16-29 (m)	QTR	LSD	SEC	TWP	RGE	M	Applicant	Type	Source	Quantity (m^3/year)	Pumping Rate*	Consumptive Use (m^3)	Losses (m^3)	Return Flow (m^3)	Specific Purpose	Licence Type	Licenced Date	Expiry Date	Upper Production Interval (mbgs)	Lower Production Interval (mbgs)
134492	208343	19851230431	323646	5982473	1,010	NW	-	29	57	25	4	Chauvet, Robert	GW	Unn. Aquifer - Potable	1,384	0	1,384	0	0	REGISTRY	WAREG	14/May/04	<Null>	0.0	0.0
134493	208343	19951231778	323646	5982473	1,010	NW	-	29	57	25	4	Chauvet, Robert	GW	Unn. Aquifer - Potable	4,866	0	4,866	0	0	REGISTRY	WAREG	14/May/04	<Null>	0.0	0.0
134494	208345	20020103013	323646	5982473	1,010	NW	-	29	57	25	4	Chauvet, Robert	GW	Unn. Aquifer - Potable	3,466	0	3,466	0	0	STCKWT	WALIC	14/May/04	<Null>	0.0	0.0
57195	165079	19680601003	324510	5984051	1,587	NE	-	32	57	25	4	Claude & Rose Marie Michaud	GW	Unn. Aquifer - Uncl.	2,365	0	2,365	0	0	REGISTRY	WAREG	5/Mar/02	<Null>	0.0	30.5
134487	163004	19801230825	322852	5983308	1,989	SE	-	31	57	25	4	Clifford & Sandra Jones	GW	Unn. Aquifer - Potable	4,663	0	4,663	0	0	REGISTRY	WAREG	14/May/04	<Null>	0.0	0.0
134486	163004	19861231779	322852	5983308	1,989	SE	-	31	57	25	4	Clifford & Sandra Jones	GW	Unn. Aquifer - Potable	211	0	211	0	0	REGISTRY	WAREG	14/May/04	<Null>	0.0	0.0
60731	168433	19501231388	325392	5985648	3,261	NW	-	4	58	25	4	De Champlain, Dorothy	GW	Unn. Aquifer - Uncl.	759	0	759	0	0	REGISTRY	WAREG	7/Mar/02	<Null>	0.0	18.3

Notes
*Pumping Rate: Surface Water - m^3/sec; Groundwater - m^3/day
unn. = unnamed; uncl. = unclassified; - = no information

Appendix C: Millennium EMS Solutions Ltd. Third Party Reliance Agreement

MILLENNIUM
EMS Solutions Ltd.

#148, 2257 Premier Way
Sherwood Park, AB T8H 2M8
tel: 780.496.9048
fax: 780.496.9049

Suite 202, 701 64 Avenue SE
Calgary, AB T2H 2C3
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#102, 11312 98 Avenue
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fax: 780.357.5501

Suite 218, 852 Fort Street
Victoria, BC V8W 1H8

#105, 116 Research Drive
Saskatoon, SK S7N 3R3
tel: 306.518.2442

toll free: 888.722.2563
www.mems.ca

[Name of recipient]

[Date]
DELIVERED VIA E-MAIL

Dear [name],

RE: RELIANCE LETTER PERTAINING TO HYDROGEOLOGICAL ASSESSMENT

Bison Low Carbon Ventures (Bison) L.P. ("**Client**") retained Millennium EMS Solutions Ltd. ("**Millennium**") to prepare the Hydrogeological Assessment ("Report") for the property located within 16-16-050-01 W5M.

We understand that you wish to rely on the information presented in the Report. Millennium has agreed to allow you to rely on the contents of the Report based on the terms and conditions below:

1) The limitations and assumptions stated in the Report in association with any closure statement continue to apply to your use of the Report.
2) You may have an interest in the Report that conflicts with the interest of Client. Millennium takes no responsibility for claims, liabilities, damages or expenses that arise because of such conflict.
3) Millennium expressly disclaims any and all warranties in connection with the Report. This disclaimer of warranties includes, without limitation, any warranty that the Report and any associated site investigation work has uncovered all potential environmental liabilities associated with the property that is the subject of the Report. Millennium disclaims any warranty of the completeness or accuracy of information supplied to Millennium that was relied upon in the preparation of the Report. You will waive any claim against Millennium, its officers, employees, agents, assignees and successors as a result of use of the Report.
4) You agree to defend, indemnify, protect and hold harmless Millennium and its officers, employees, agents, assignees and successors from any and all claims, liabilities, damages or expenses, including but not limited to delay of project commencement or completion, reduction of property value, fear of or actual exposure to or release of toxic or hazardous substances, or conflicts of interest, whether foreseeable or unforeseeable, which may arise directly or indirectly, to any party, as a result of your use of the Report.
5) Millennium's and its officers, employees, agents, assignees, and successors liability arising out of or relating to the use of the Report is limited to one thousand Canadian dollars (CAD$1,000.00). We will not be liable for consequential, incidental or indirect damages as a result of your use of the Report.
6) Use of the Report, including all information and recommendations prepared or issued by Millennium within the Report or pertaining to the Report, is for your exclusive use. No other use is authorized, including distribution to any other party without our prior written consent, which may be arbitrarily withheld. You will release us from liability and agrees to defend, indemnify, protect and hold harmless Millennium and its officers, employees, agents, assignees and successors from any and all claims, liabilities, damages or expenses arising, in whole or in part, from such unauthorized distribution.

Please sign in the space provided below to indicate your acceptance to the above conditions.

Regards,

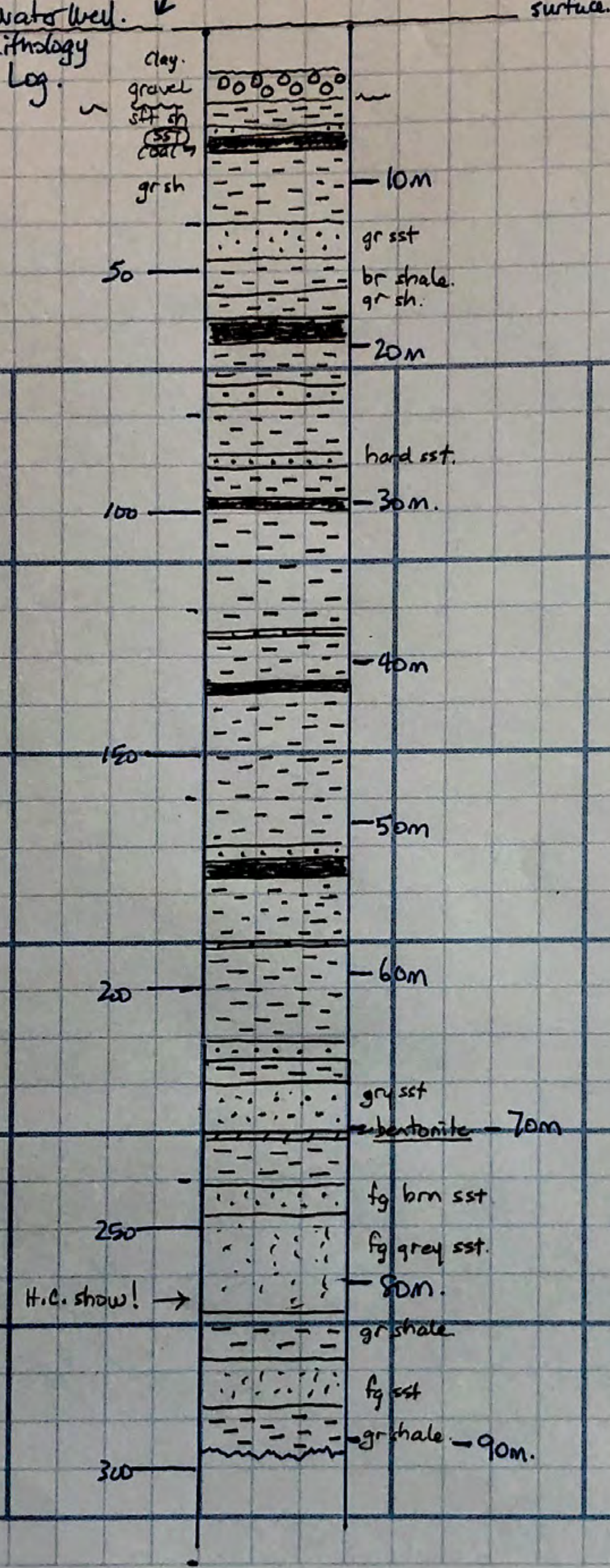
	Agreed to this _____ day of __________ .
MILLENNIUM EMS SOLUTIONS LTD.	[THIRD PARTY]
By: ________________________________	By: ________________________________
MEMS Representative	Name:
Title	Title
Date	Date

Appendix 4 – 16-29 Groundwater Control Well Lithology Log

Oct 2023. 16-29-57-25w4M.

Water Well.

Lithology Log.



Appendix 5 – Soil Vapour & Groundwater Monitoring Program

April 19, 2024

Matt Brister
BISON LOW CARBON VENTURES
325, 440 - 2 Ave. SW
Calgary, AB T2P 5E9

Subject: Work Plan and Cost Estimate for Installation of Soil Vapour Monitoring Points, Instrumentation of a Groundwater Well, and Monitoring Schedule

Dear Matt Brister:

1 INTRODUCTION

Matrix Solutions Inc., a Montrose Environmental company, is pleased to provide Bison Low Carbon Ventures with this work plan and cost estimate to install and monitor 12 soil vapour monitoring points, 1 groundwater well, and associated instrumentation at 16-29-57-25W4M and monitoring of up to 5 landowner wells. This work is associated with the measurement, monitoring, and verification plan for Bison's proposed Meadowbrook Carbon Storage Project consortium located 3 km west of the Town of Legal, Alberta.

The purpose of this document is to present the scope of work and estimated costs and key assumptions to complete the work.

2 OBJECTIVES AND SCOPE OF WORK

The objective of the work is to complete installations to monitor the hydrosphere and biosphere injection well site at the Meadowbrook site. The monitoring program will be used to assess whether impacts are occurring due to the proposed carbon capture activities.

Key tasks to complete the current scope of work include:

- installing probes and groundwater monitoring well
- conducting project planning and technical meetings
- completing field safety planning including job safety analysis development
- installing 12 soil vapour monitoring points
- installing one sonde with solar powered 4G/LTE data transmission into the existing groundwater well
- preparing a report

Sampling of soil vapour and groundwater wells:

- completing field safety planning including job safety analysis development
- collecting soil vapour samples from 12 soil vapour monitoring wells
- collecting water samples from one groundwater well located onsite and up to five landowner wells
- installing, downloading data, and checking operation of the sonde located at the onsite groundwater well
- preparing a report

3 METHODS

3.1 Safety and Ground Disturbance

Matrix personnel will be required to comply with legislated, Matrix, and Bison's health and safety standards.

Ground disturbance procedures will be followed according to Matrix policies. Matrix will submit a Utility Safety Partners (formerly Alberta One-Call Corporation) request and prepare a ground disturbance package highlighting known buried facilities in the area in relation to the proposed drilling location. Private utility locates will be organized by Matrix, which will include locating and marking of all underground facilities within a 30 m radius of the injection well location. Line locates and ground disturbance information, including Utility Safety Partner responses, will be reviewed in detail by the Matrix field lead before drilling starts.

3.2 Soil Vapour Monitoring Points – Drilling and Installation

A total of 12 soil vapour monitoring points will be installed at the injection well site. Each will be completed with a 1-foot screen, and completed to a depth of 1.5 m. A sand pack will be installed across the screened length and for a minimum of 1-foot above the top of the screen. Bentonite will be used to seal the top of the borehole above the sand pack, and points will be completed with flush-mount casings. The well screen and casing will be 2-inches in diameter. The points will be installed by a drilling company, CP Drilling Inc. of Rimby, Alberta, under the supervision of Matrix personnel. The points will be completed with a cap with a valve and hose barb fitting supplied by Rice Resource Technologies of Calgary, Alberta.

The probes will be installed in four distinct transects roughly orientated north, south, east, and west of the injection well. Each transect will consist of three probes installed at 5 m, 10 m, and 15 m from the center of the injection wellhead.

3.3 Instrumentation of the Groundwater Well

The existing groundwater well located on the injection site will be instrumented with a sonde which will collect pH, electrical conductivity, and temperature data hourly. The sonde is connected to a remote monitoring station which is solar powered and connected to the 4G/LTE wireless network. Data from the sonde can be polled from the operations supervisory control and data acquisition site using MODBUS TCP once every 24 hours. If required, a dedicated pump will be installed.

3.4 Soil Vapour Sampling

A total of 12 soil vapour monitoring wells will be sampled for soil gas at the injection well site twice annually. After purging the soil gas well of at least three times the wellbore volume using a greenhouse gas analyzer, the gas samples will be collected and analyzed for their chemical and isotopic compositions. The concentration and isotopic parameters that are to be analyzed for gas samples include:

- **Gas concentrations**: CO_2, N_2, O_2, He, Ar, CH_4, C_2H_6, and C_3H_8
- **Gas isotopes**: $\delta^{13}C$-CO_2, $\Delta^{14}C$-CO_2, $\delta^{13}C$-CH_4, $\delta^{2}H$-CH_4, and $\delta^{13}C$-C_2H_6

Where elevated methane concentrations are detected (>0.1% or 1,000 ppm methane), additional samples may be collected for C_1 to C_6 hydrocarbon and isotopic analysis. It is assumed that 15% of the site will require additional sampling (i.e., two additional samples will be collected) as a result of elevated methane concentrations. The gas samples for compositional analysis will be collected in summa canisters and for isotope analysis in evacuated serum bottles.

3.5 Groundwater Monitoring

The existing groundwater monitoring well present at the injection site and the five other landowner wells will be sampled four times a year. During these trips data from the sondes will be downloaded. Groundwater samples from the project well and landowner wells will be collected using dedicated pumps using low flow sampling technicque and a gas flow-through cell. This will allow for the samples of exsolved gas to be collected. Should this technique not work, then groundwater samples will be collected for dissolved gas analysis. The concentration and isotopic parameters that are to be analyzed for gas samples include:

- **Gas concentrations**: CO_2, N_2, O_2, He, CH_4, C_2-C_6 and hydrocarbons
- **Gas isotopes**: $\delta^{13}C$-CO_2, ^{14}C-CO_2, $\delta^{13}C$-CH_4, and $\delta^{2}H$-CH_4

Separate groundwater samples are to be collected without the flow-through cell and analyzed for the following concentration and isotopic parameters:

- **Routine inorganic parameters**, including: Na, K, Ca, Mg, HCO_3, CO_3, OH, SO_4, NO_2, NO_3, Cl, Br, I, pH, EC, total dissolved solids, alkalinity, total hardness, and ion balance

- **Dissolved metals**, including: Al, Sb, As, Ba, Be, B, Cd, Cr, Co, Cu, Fe, Hg, Pb, Li, Mn, Hg, Mo, Ni, Se, Si(SiO_2), Ag, Sr, Tl, Sn, Ti, U, V, and Zn

- **Isotopic parameters**, including: $\delta^{13}C$-DIC, $\delta^{37}Cl$, $\delta^{11}B$, and $^{87}Sr/^{86}Sr$

- Access to the drilling locations will be readily available and operators will be on hand to issue any applicable permits or orientations.

- Adverse weather conditions will not significantly affect the time required to complete the field work and the well installation. The work is anticipated to occur during spring conditions and additional costs would apply for added time due to adverse conditions or other delays beyond the control of Matrix or its subcontractors.

Sampling Program:

- The field sampling program will take 2 days to complete when both groundwater and soil vapour points are sampled together including mobilization and demobilization. The number of field days is based on a crew of two people.

- The field sampling program will take 1 day to complete when only groundwater wells are sampled including mobilization and demobilization. The number of field days is based on a two person crew.

- Includes initial mobilization and final demobilization from Edmonton, Alberta.

- The site will be accessible by 4x4 vehicle.

- A 10% markup will apply for any third-party costs that are invoiced to Matrix.

- Any changes in scope will be discussed with and approved by Bison before they are implemented.

Appendix 6 – 16-29 Well Data

(refer to Appendix J and Appendix O of D065 application)

Appendix 7 – 16-29 Completion

(refer to Appendix G of D065 application)

Appendix 8 – Seismicity Data

Bison – Batch I
ISM Report
March-May 2024

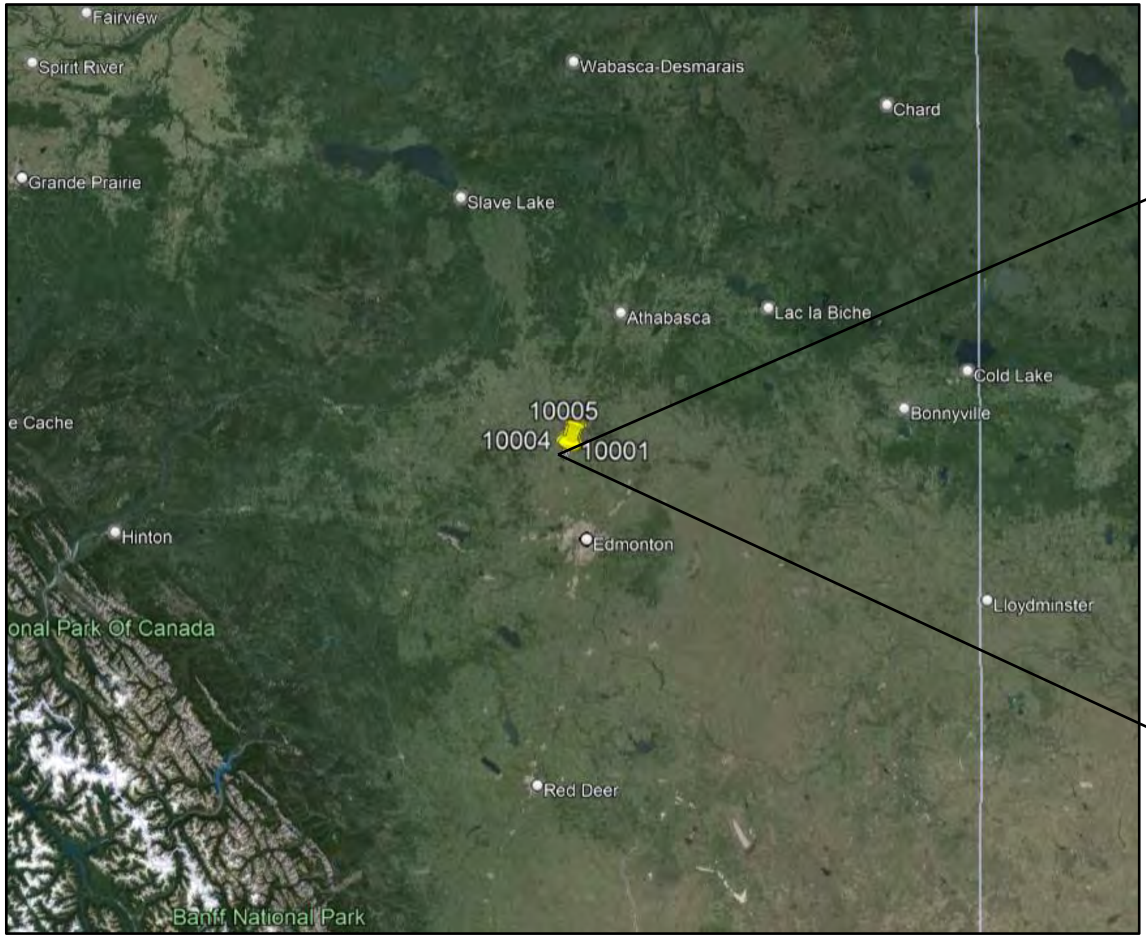
August 16th, 2024

Report Outline

- ❑ Project summary
  - ❑ Array Geometry
  - ❑ Seismicity Metrics
- ❑ Seismicity: March 14 – May 12, 2024
- ❑ All Located Regional Events: March 14 – May 12, 2024
- ❑ Phase I: March 14 – April 2, 2024
- ❑ Phase II: April 2 – April 22, 2024
- ❑ Phase III: April 22 – May 12, 2024
- ❑ Total Events: March 14 – May 12, 2024
- ❑ Events Catalog - Regional Events: March 14 – May 12, 2024

Project Summary: Array geometry

The ISM Bison array consists of six surface stations.



CONFIDENTIAL DOCUMENT

Project Summary: Seismicity Metrics (March 14th – May 12th, 2024)

- **Station Location (UTM12N_NAD27):**

Station Name	X(m)	Y(m)
10001	324782.88	5982287.97
10002	324942.08	5984003.75
10003	326372.90	5982076.36
10004	324854.71	5981158.45
10005	323373.95	5982053.28
10010	324782.56	5982284.27

- This report contains all events detected and located for Batch I, which includes Phase I (March 14th to April 2nd), Phase II (April 2nd to April 22nd), and Phase III (April 22nd to May 12th).

- There were 30 detected events around the Bison ISM Array between March 14th and May 12th, 2024.
  - All recorded events were manually triggered according to the detectability parameters.
  - All the high-quality events were located and had a moment magnitude determined.

- There were 20 events reported by NRCan, AER and USGS around the Bison ISM Array during the reporting period.

Seismicity: March 14th – May 12th, 2024

Below are the seismicity metrics from the reporting period:

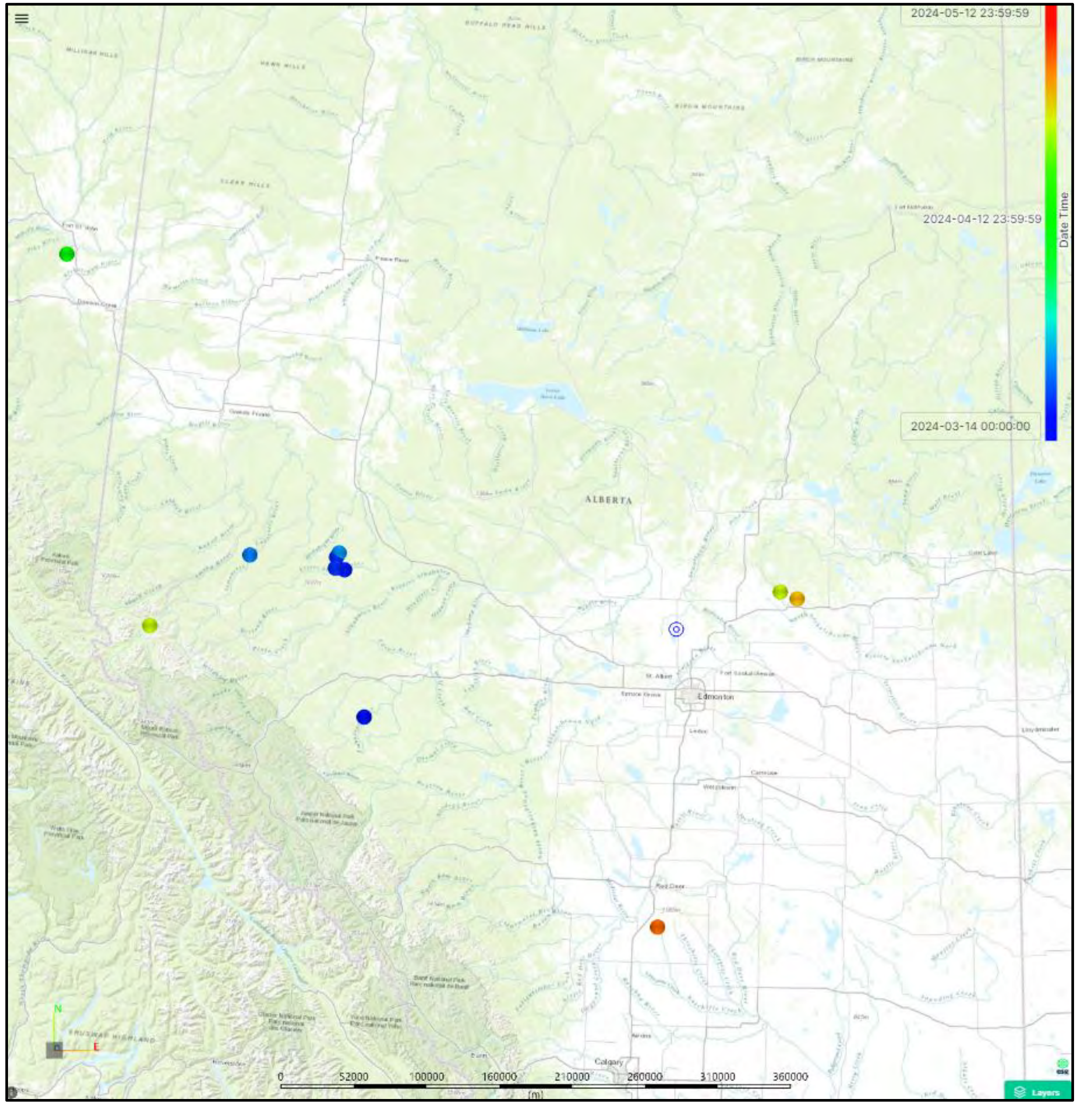
Table 1: Summary of processed data during the reporting period

Trigger type	Trigger Count
Regional Event	11
Unlocatable Regional Event	3
Single-phase Event	16
Total	30

Definition of terms:

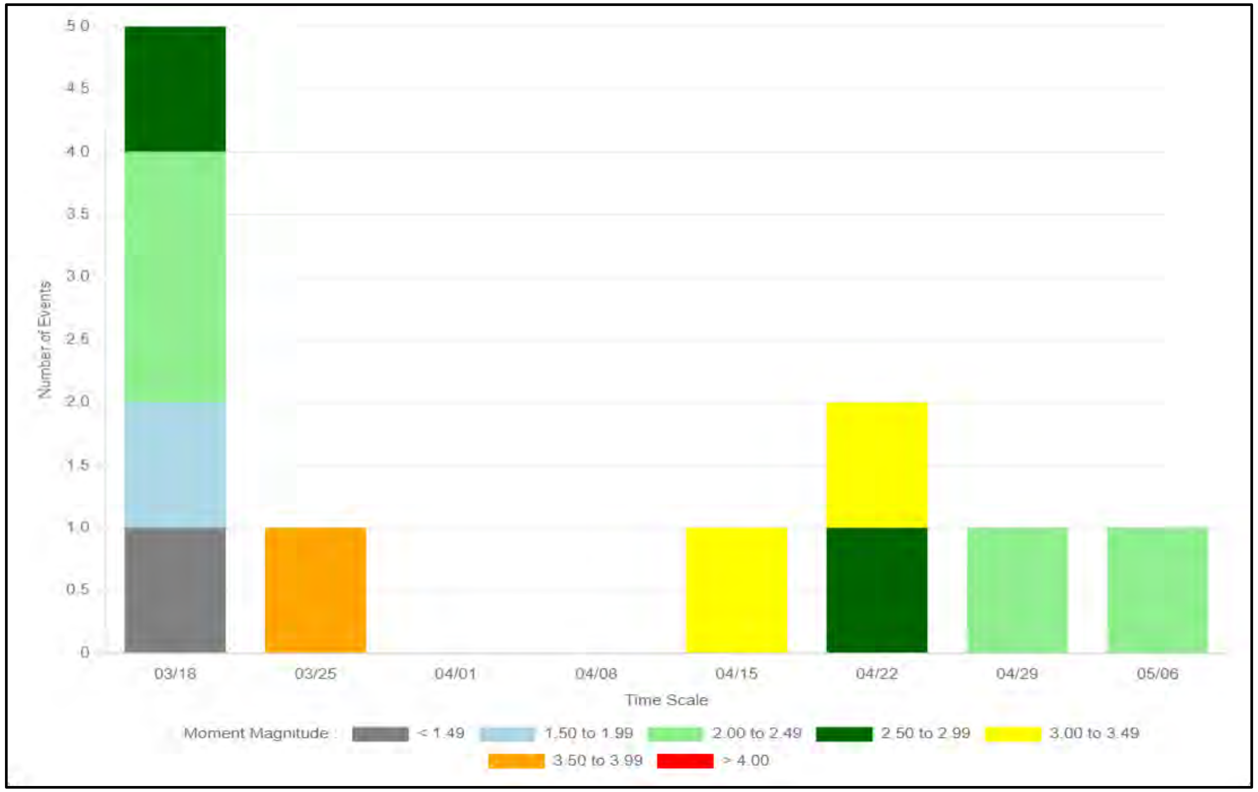
- **Regional Event:** A real detected seismic event outside of the area of interest.
- **Unlocatable Regional Event:** A low-quality real detected seismic event outside of the area of interest.
- **Single-phase Event:** A low-quality real detected seismic event presenting only one clear arrival.

All Located Regional Events: March 14th – May 12th, 2024



Note: Events are scaled by Moment Magnitude and colored by Time.

Event Frequency Plot



Note: Each bar represents one week.

CONFIDENTIAL DOCUMENT

Phase I
March 14 – April 2, 2024

Seismicity: March 14th – April 2nd, 2024

Below are the seismicity metrics from the reporting period:

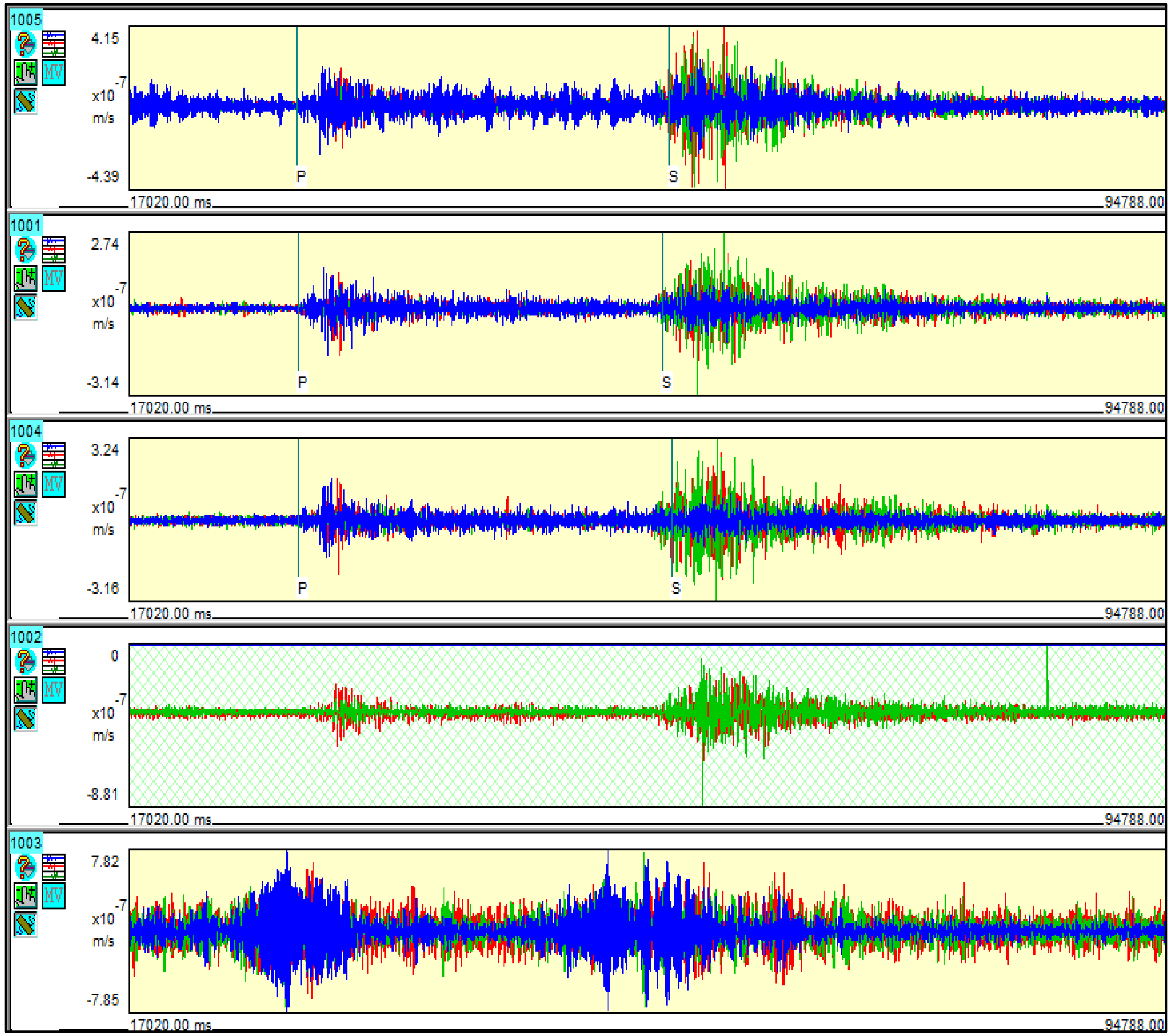
Table 2: Summary of processed data during phase I

Trigger type	Trigger Count
Regional Event	6
Unlocatable Regional Event	2
Single-phase Event	10
Total	18

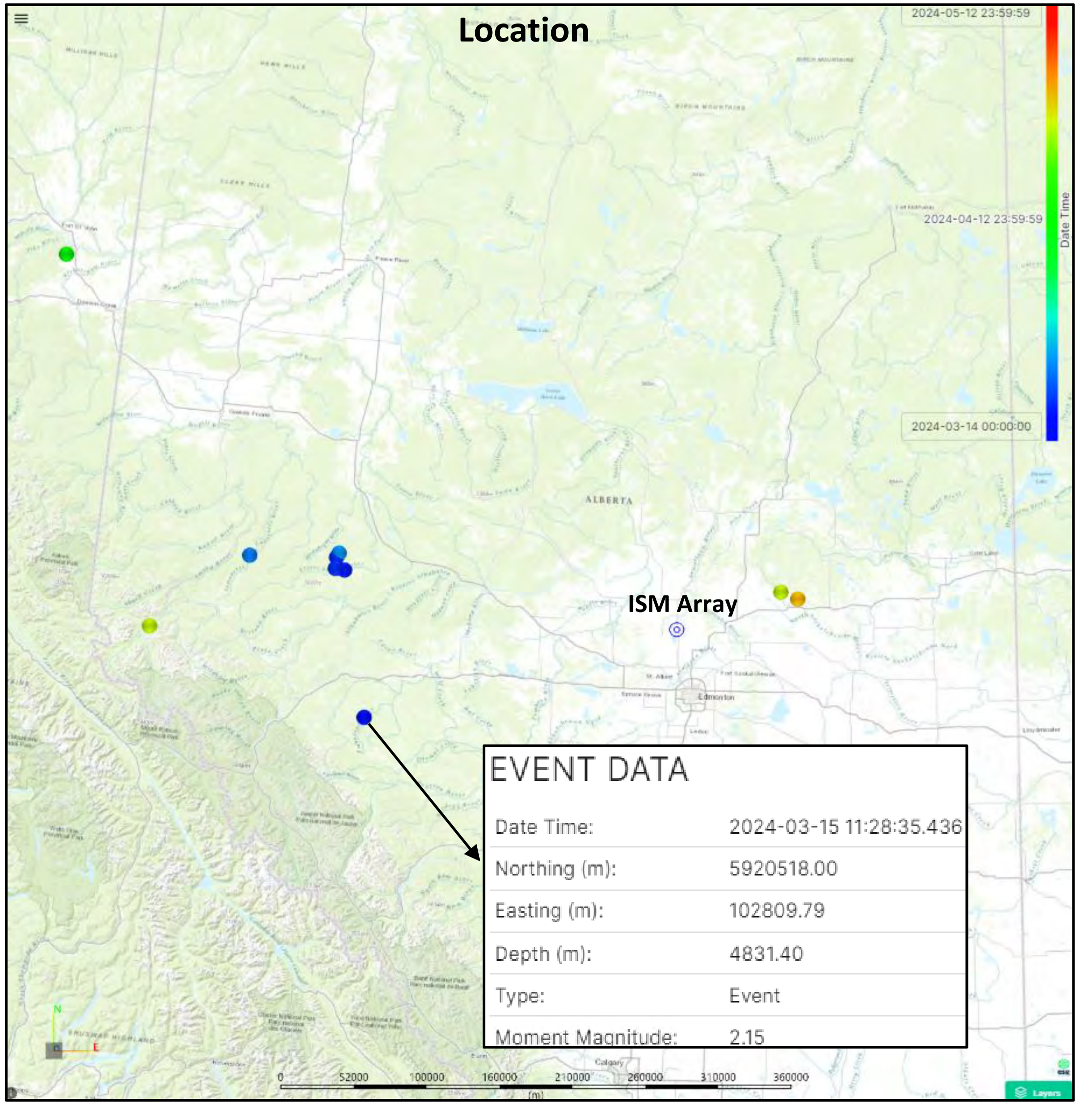
Definition of terms:

- **Regional Event:** A real detected seismic event outside of the area of interest.
- **Unlocatable Regional Event:** A low-quality real detected seismic event outside of the area of interest.
- **Single-phase Event:** A low-quality real detected seismic event presenting only one clear arrival.

Regional Trigger: 2024-03-15/11:28:35.436 UTC

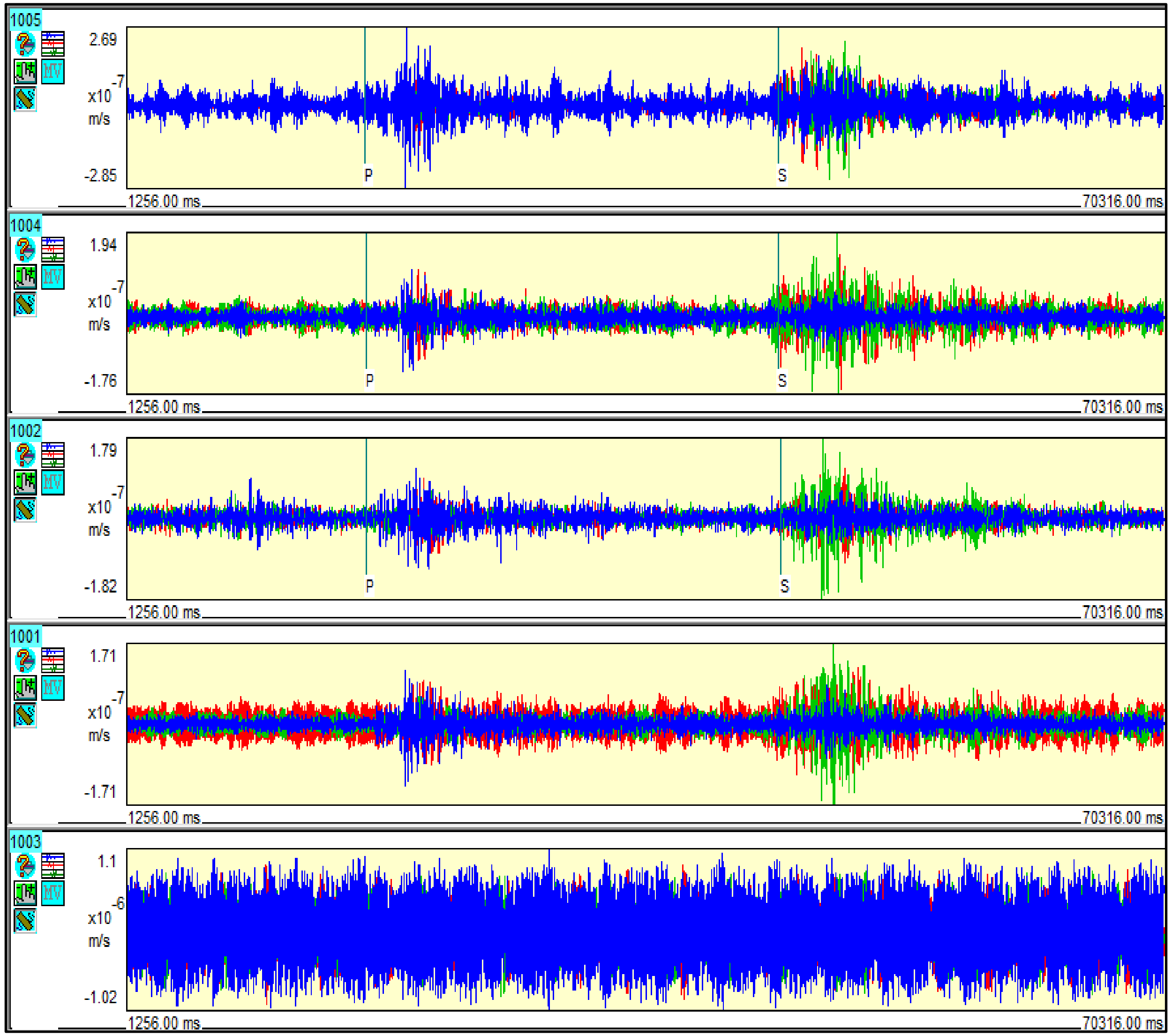


Note: The trace is 77.66 seconds long.

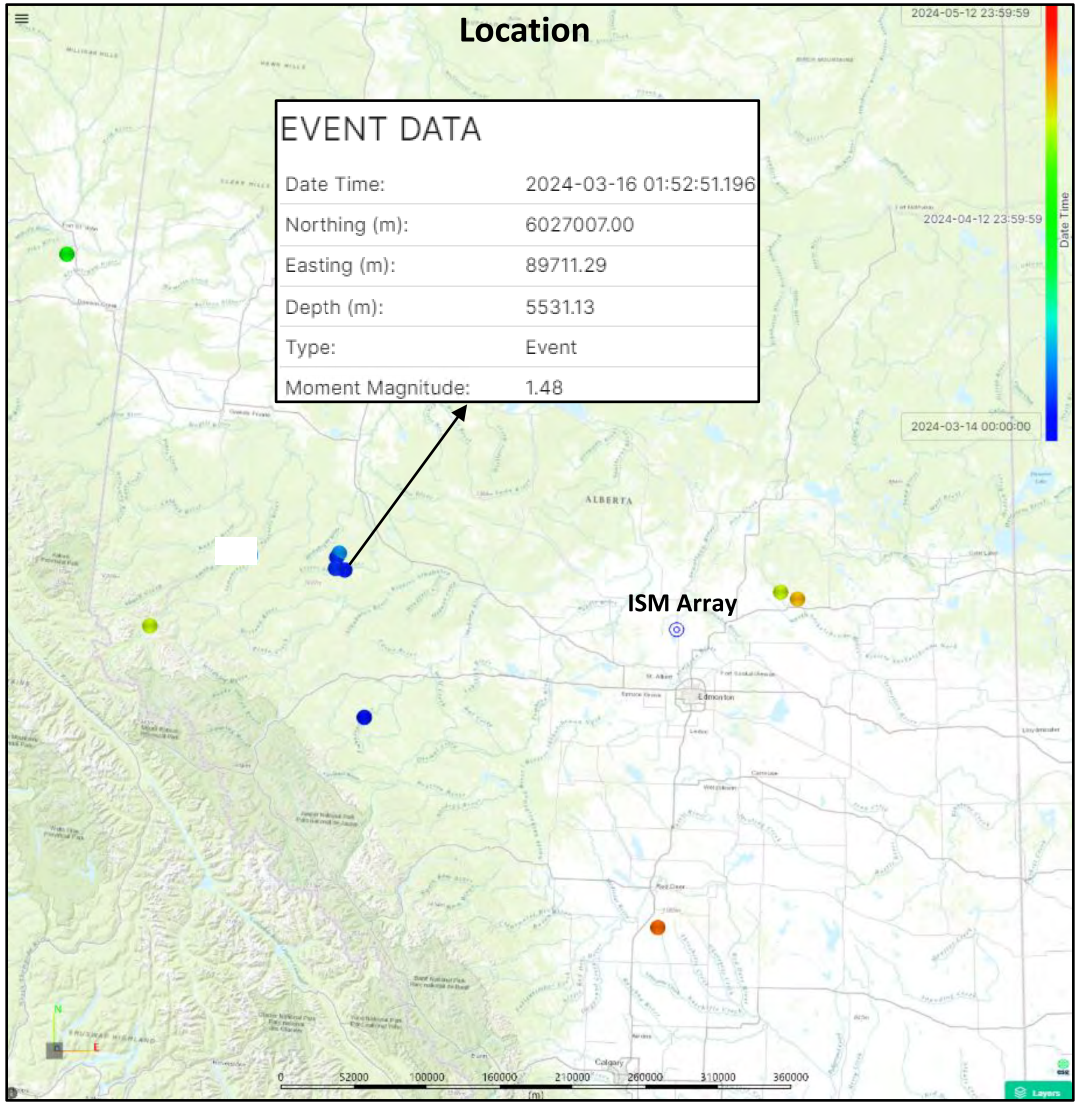


Note: Events are scaled by Moment Magnitude and colored by Time.

Regional Trigger: 2024-03-16/01:52:51.196 UTC

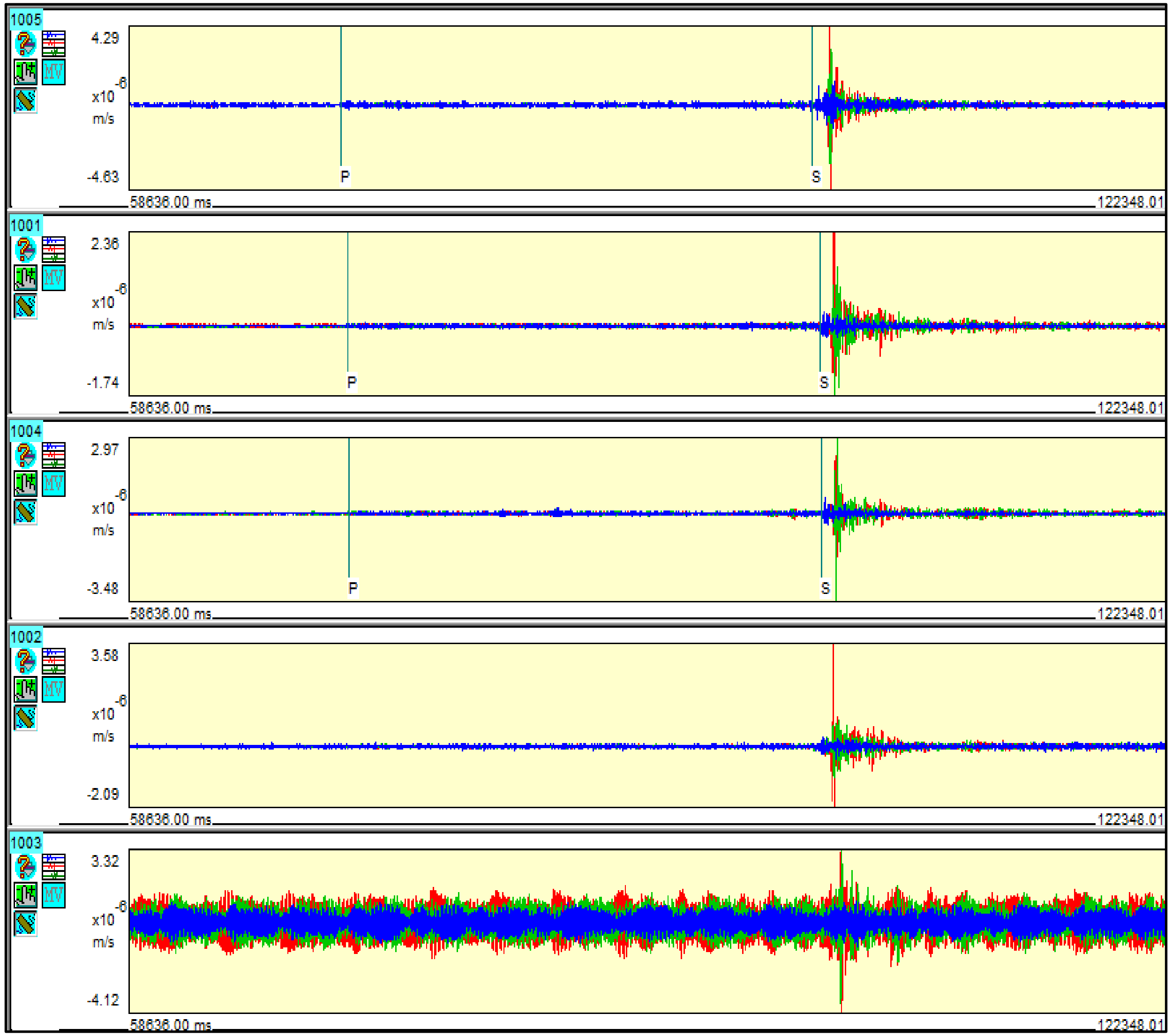


Note: The trace is 68.88 seconds long.

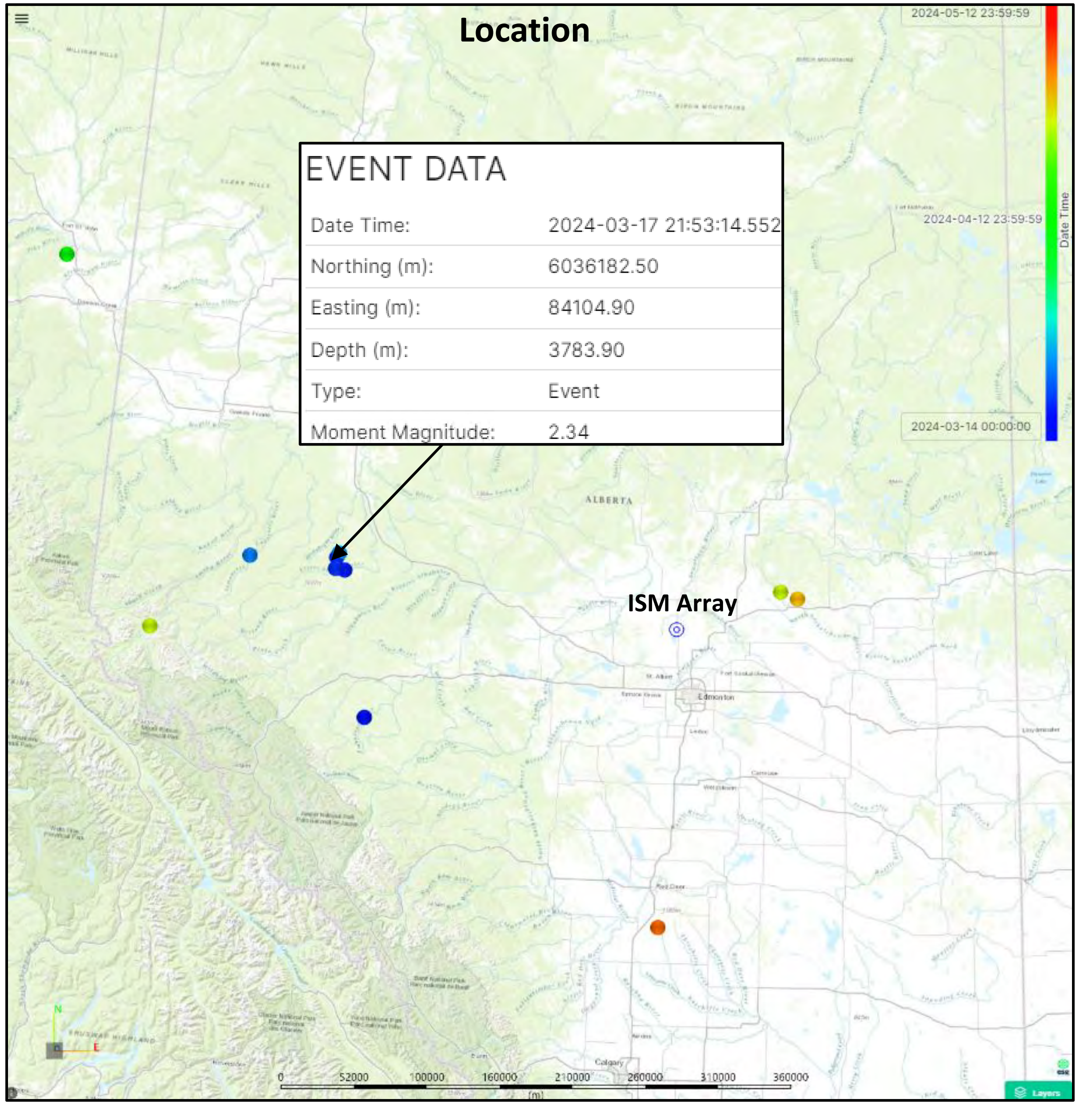


Note: Events are scaled by Moment Magnitude and colored by Time.

Regional Trigger: 2024-03-17/21:53:14.552 UTC

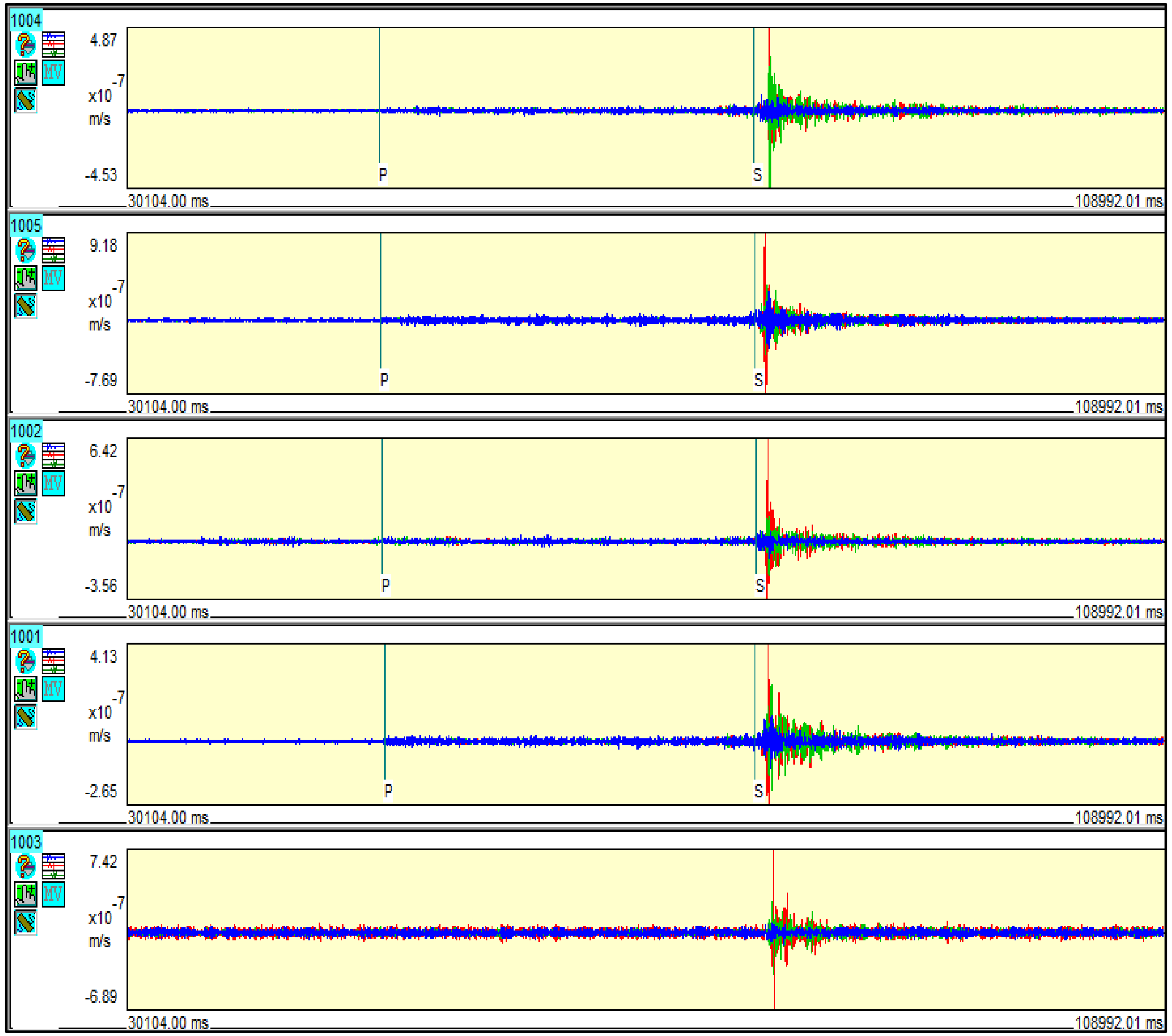


Note: The trace is 63.64 seconds long.

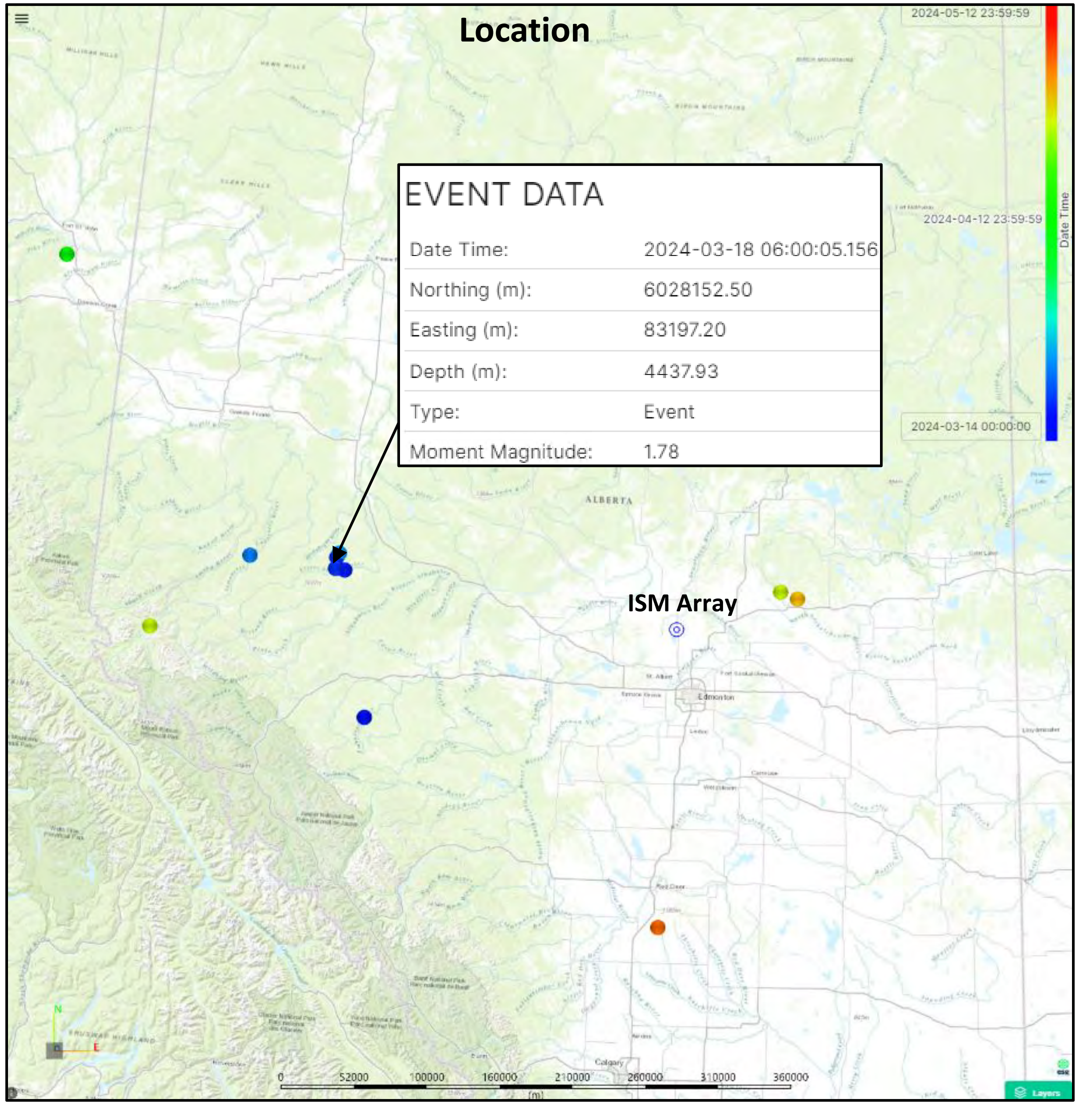


Note: Events are scaled by Moment Magnitude and colored by Time.

Regional Trigger: 2024-03-18/06:00:05.156 UTC

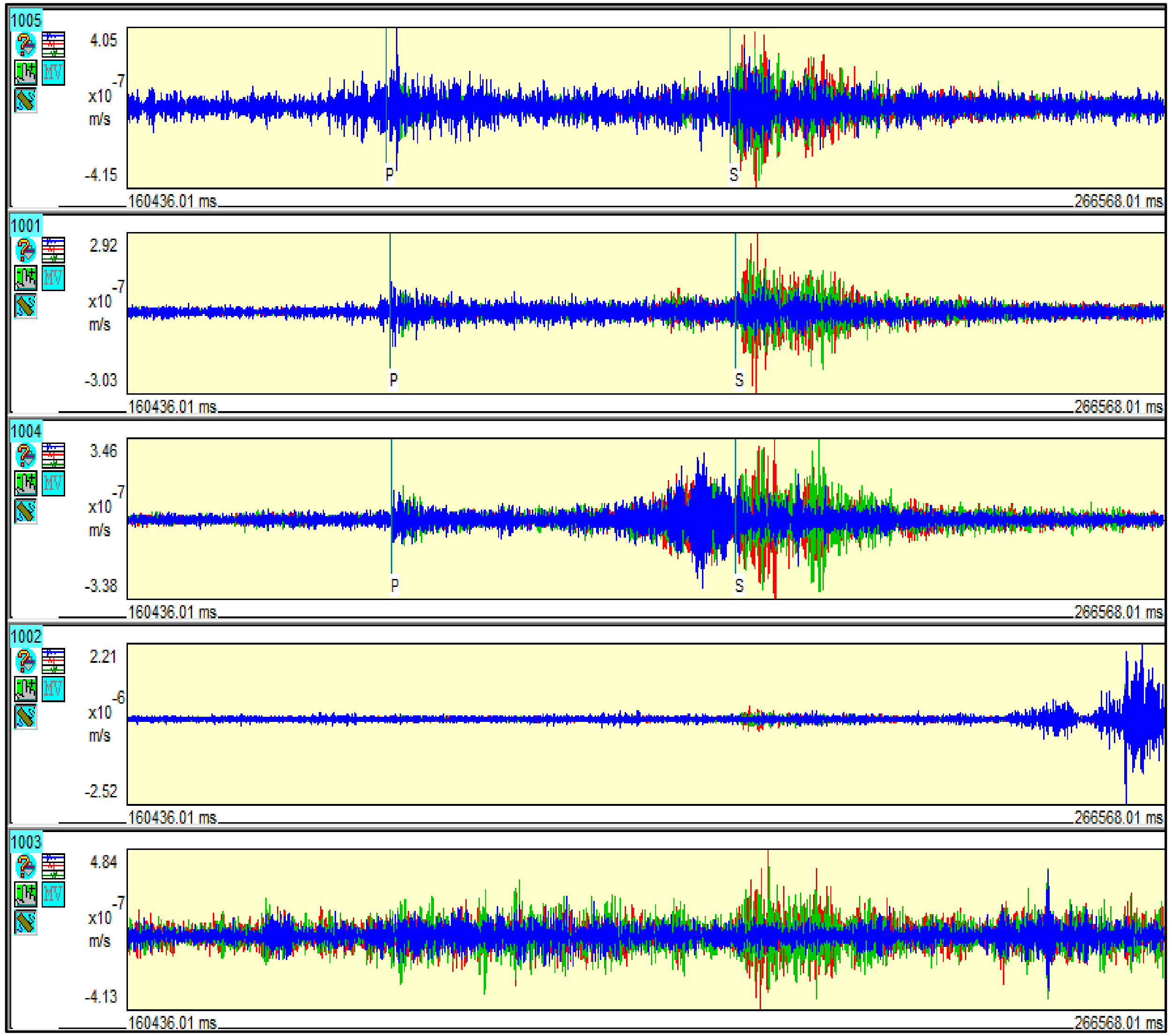


Note: The trace is 78.79 seconds long.

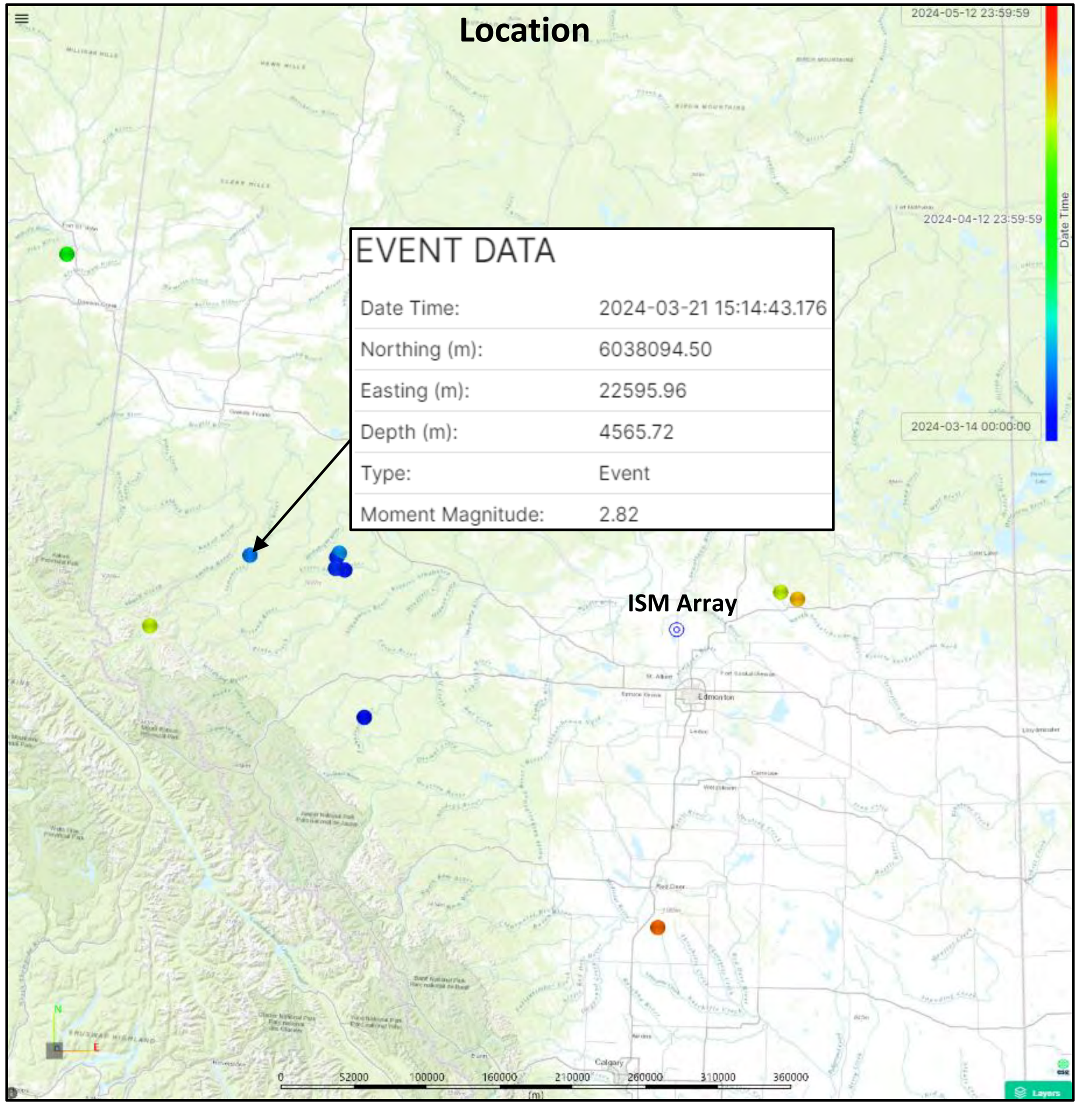


Note: Events are scaled by Moment Magnitude and colored by Time.

Regional Trigger: 2024-03-21/15:14:43.176 UTC

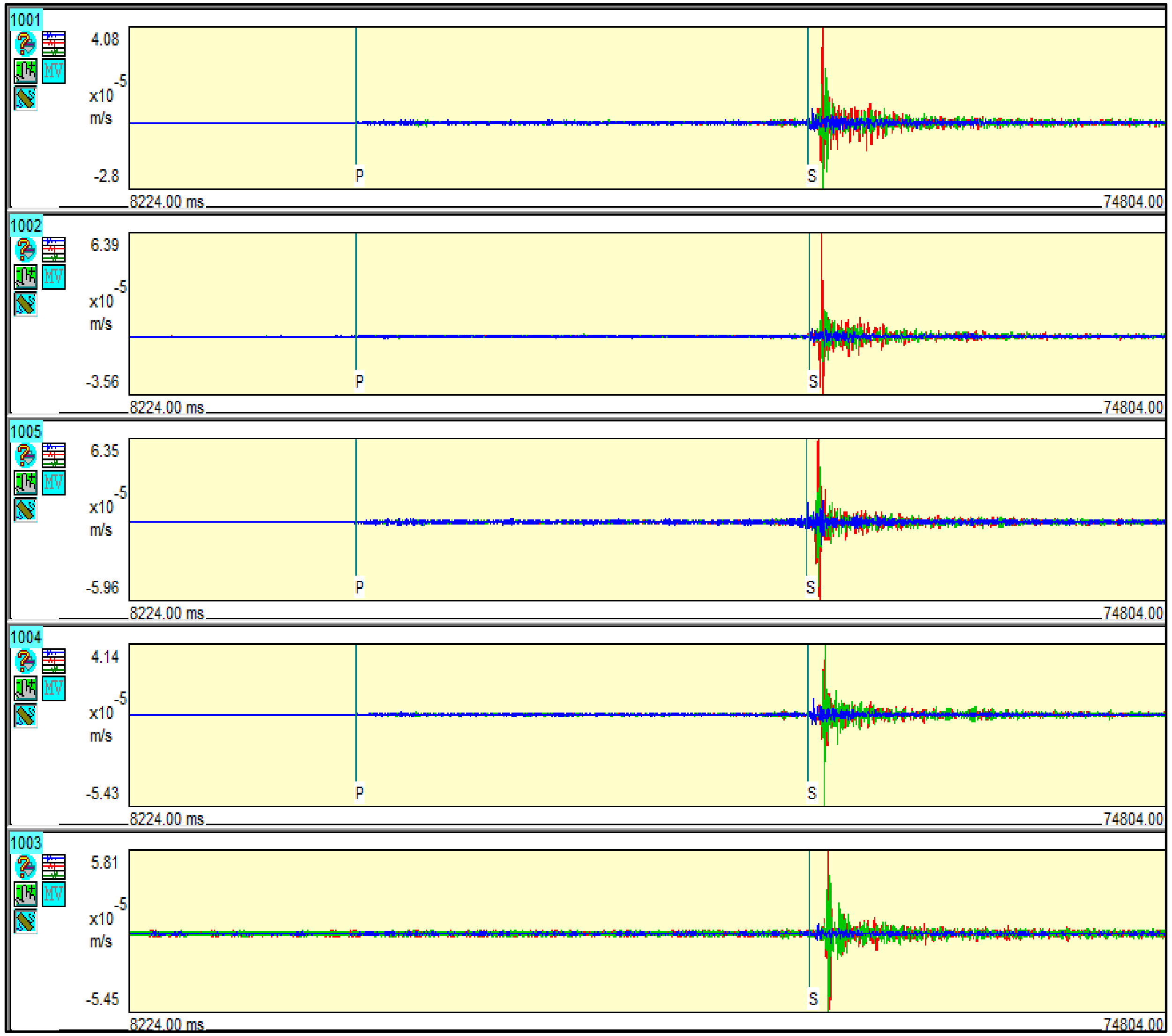


Note: The trace is 105.86 seconds long.

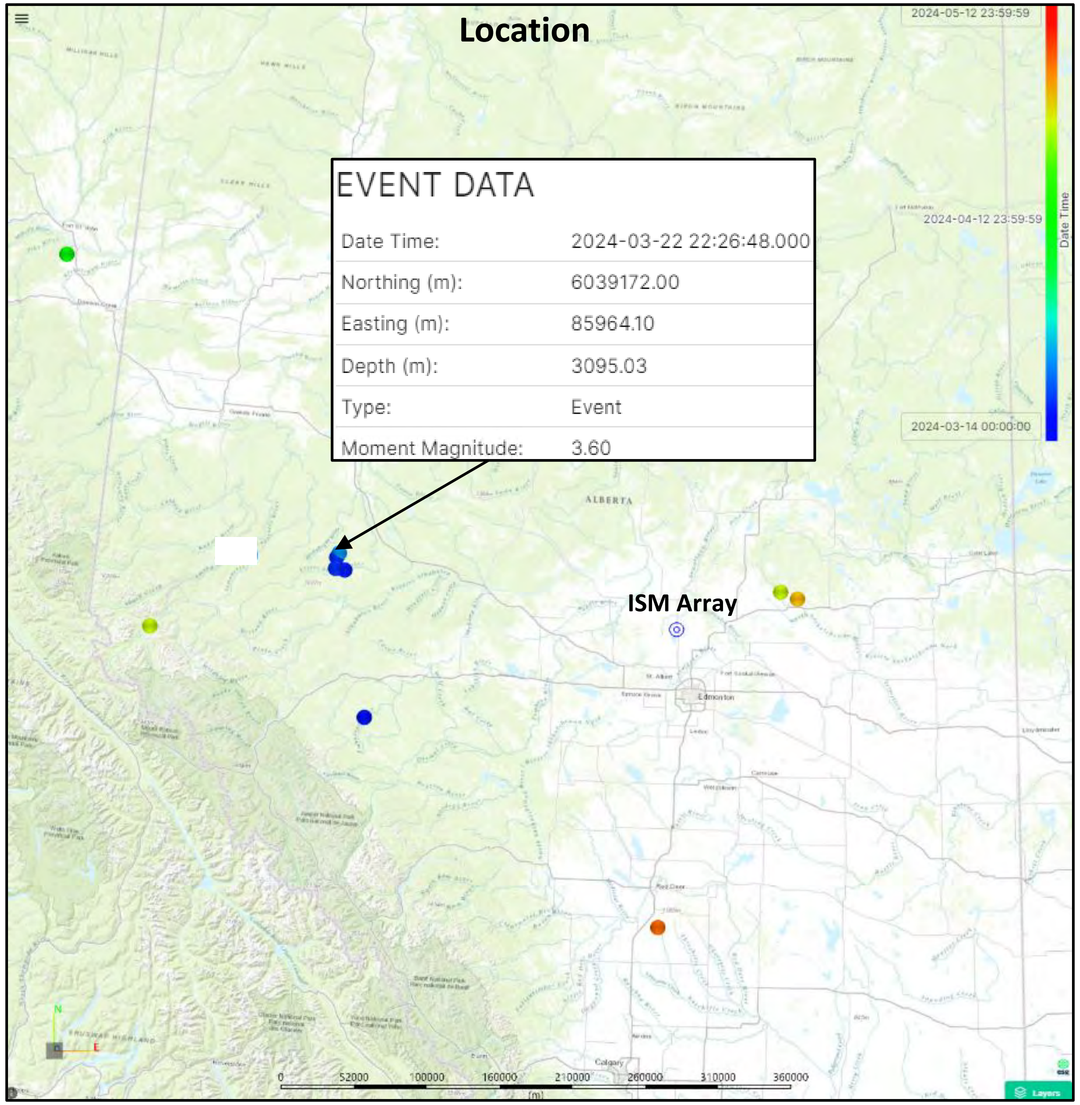


Note: Events are scaled by Moment Magnitude and colored by Time.

Regional Trigger: 2024-03-22/22:26:48.000 UTC



Note: The trace is 66.24 seconds long.



Note: Events are scaled by Moment Magnitude and colored by Time.

Phase II
April 2 – April 22, 2024

Seismicity: April 2nd – April 22nd, 2024

Below are the seismicity metrics from the reporting period:

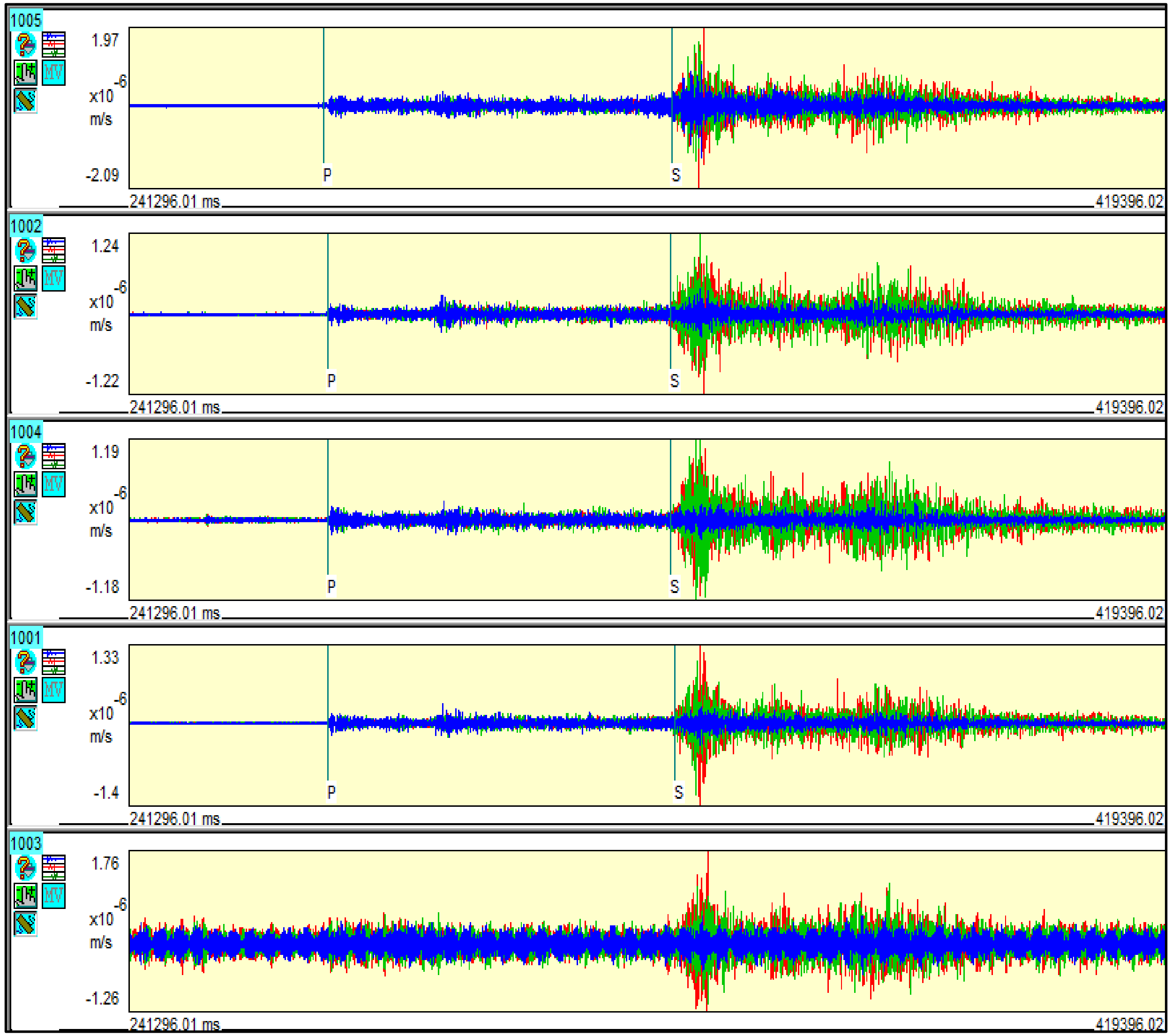
Table 3: Summary of processed data during phase II

Trigger type	Trigger Count
Regional Event	1
Unlocatable Regional Event	1
Single-phase Event	2
Total	4

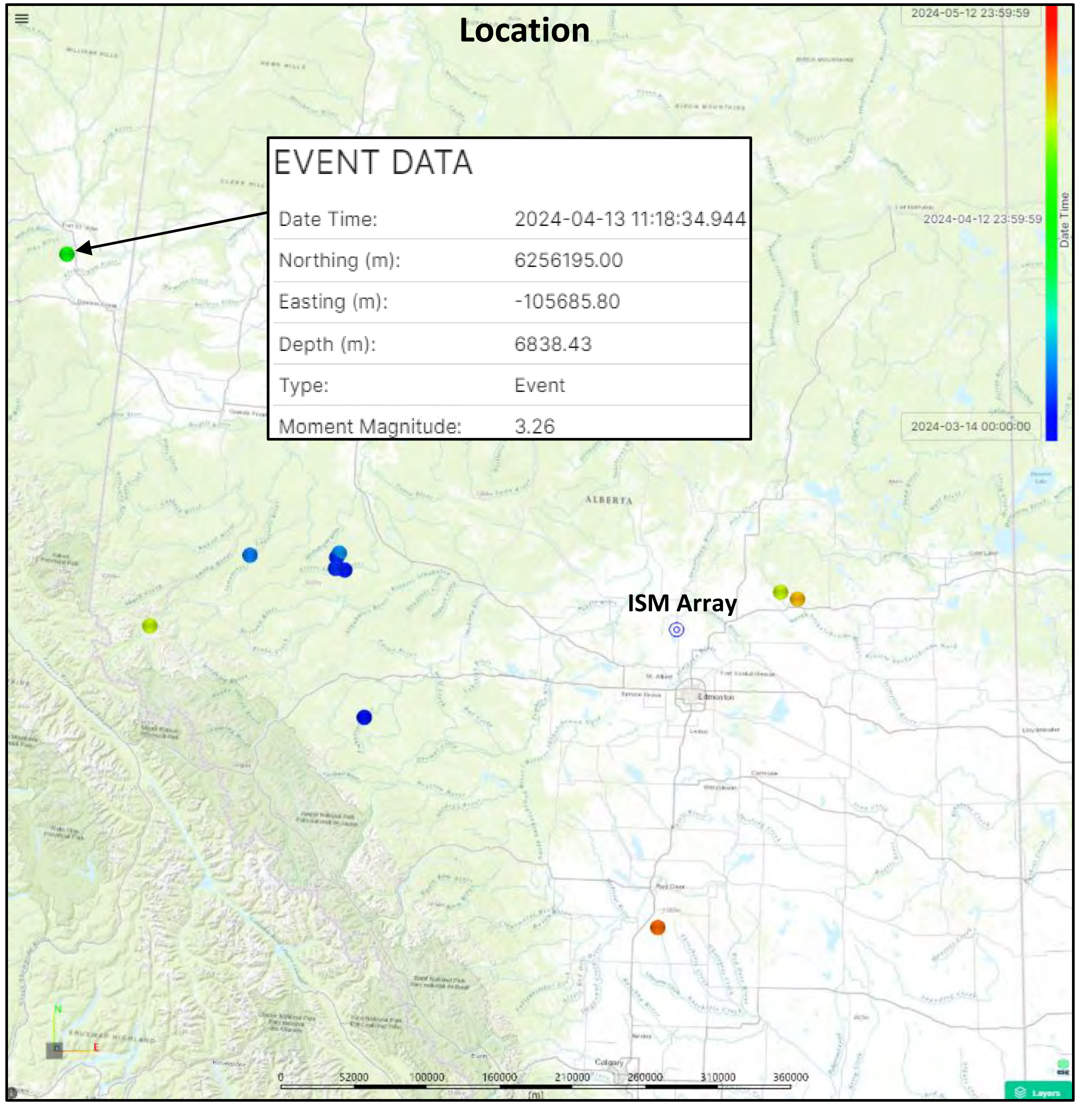
Definition of terms:

- **Regional Event:** A real detected seismic event outside of the area of interest.
- **Unlocatable Regional Event:** A low-quality real detected seismic event outside of the area of interest.
- **Single-phase Event:** A low-quality real detected seismic event presenting only one clear arrival.

Regional Trigger: 2024-04-13/11:18:34.944 UTC



Note: The trace is 177.87 seconds long.



Note: Events are scaled by Moment Magnitude and colored by Time.

Phase III
April 22 – May 12, 2024

Seismicity: April 22nd – May 12th, 2024

Below are the seismicity metrics from the reporting period:

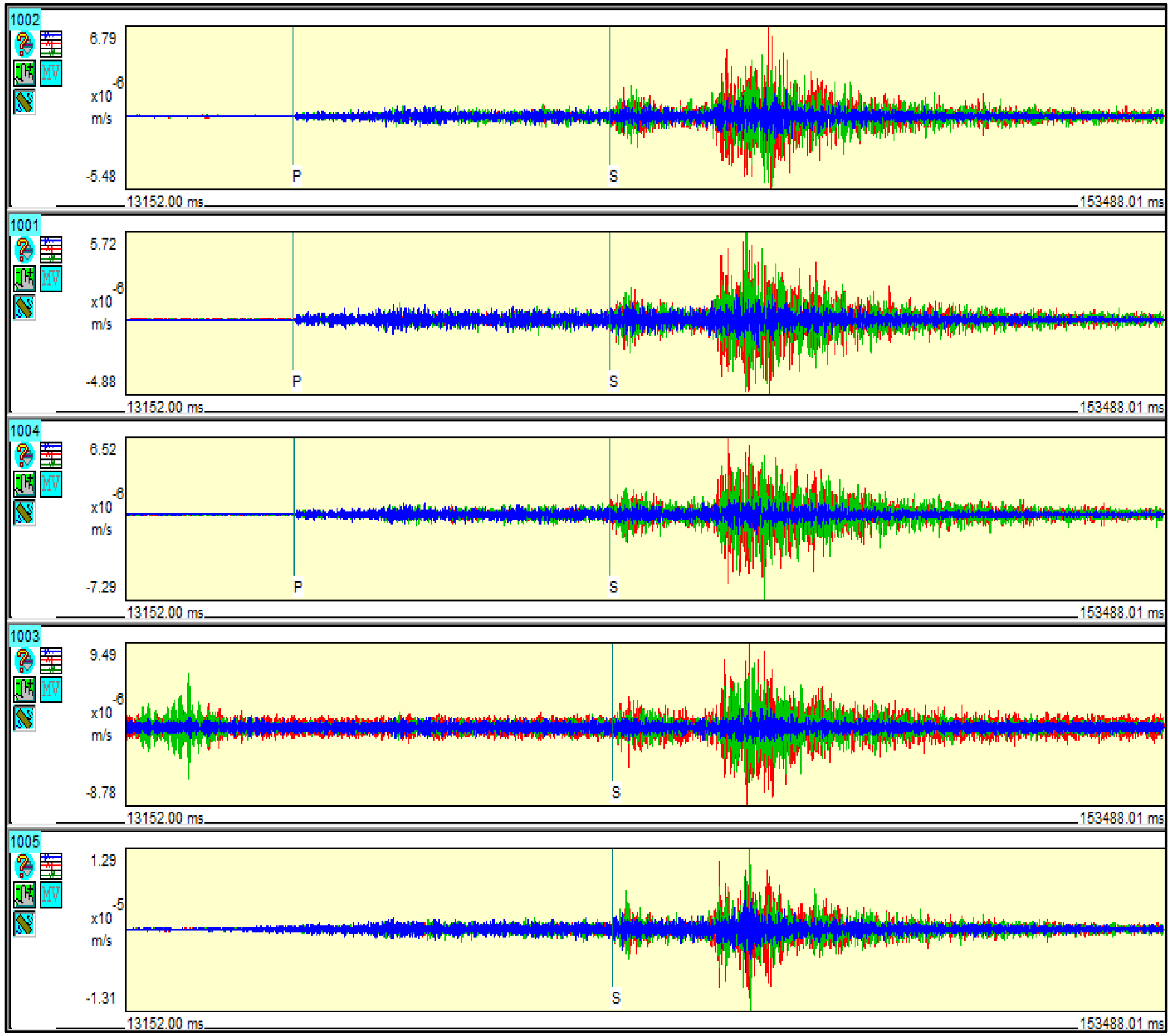
Table 4: Summary of processed data during phase III

Trigger type	Trigger Count
Regional Event	4
Unlocatable Regional Event	0
Single-phase Event	4
Total	8

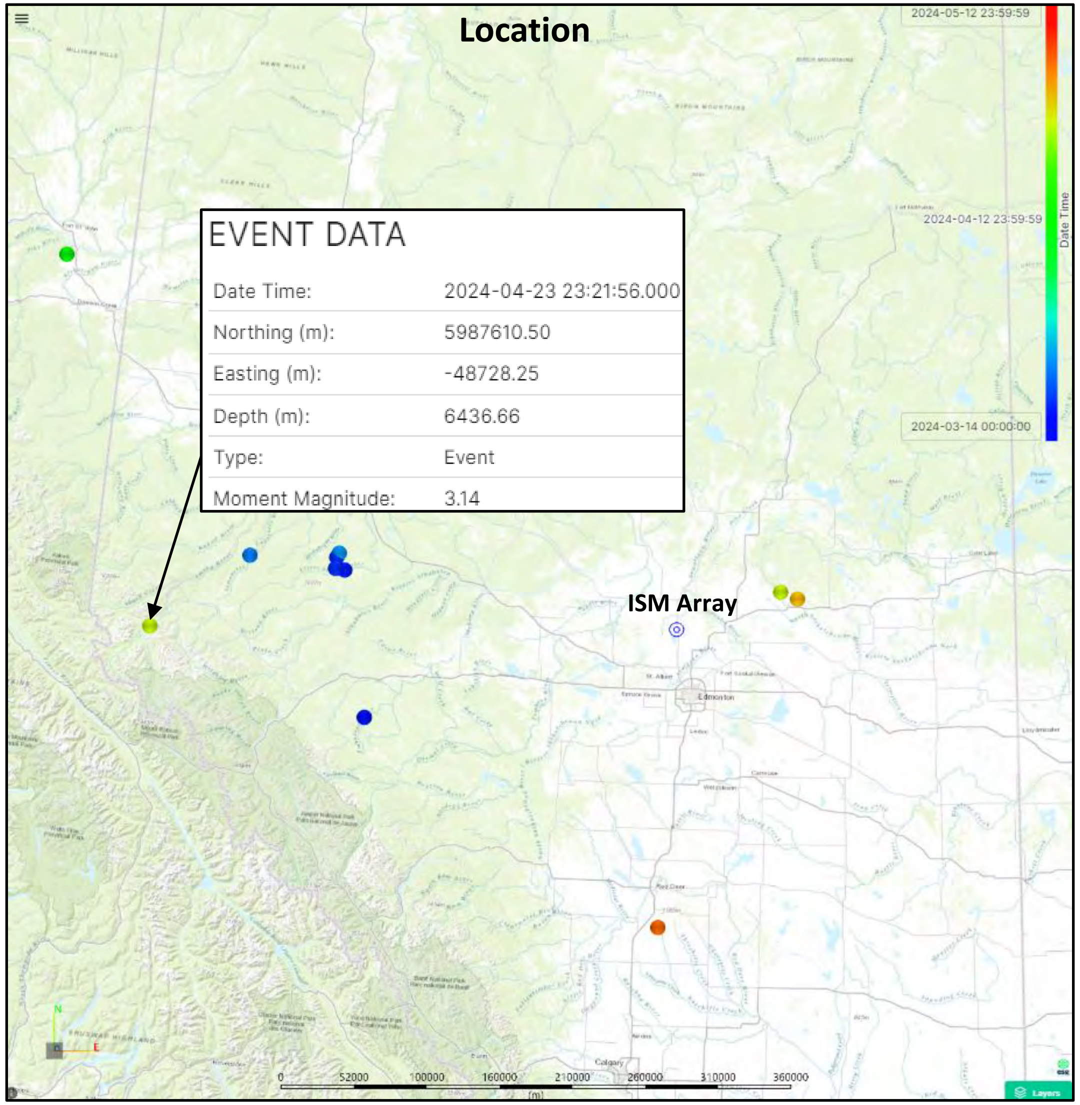
Definition of terms:

- **Regional Event:** A real detected seismic event outside of the area of interest.
- **Unlocatable Regional Event:** A low-quality real detected seismic event outside of the area of interest.
- **Single-phase Event:** A low-quality real detected seismic event presenting only one clear arrival.

Regional Trigger: 2024-04-23/23:21:56.000 UTC



Note: The trace is 140.33 seconds long.

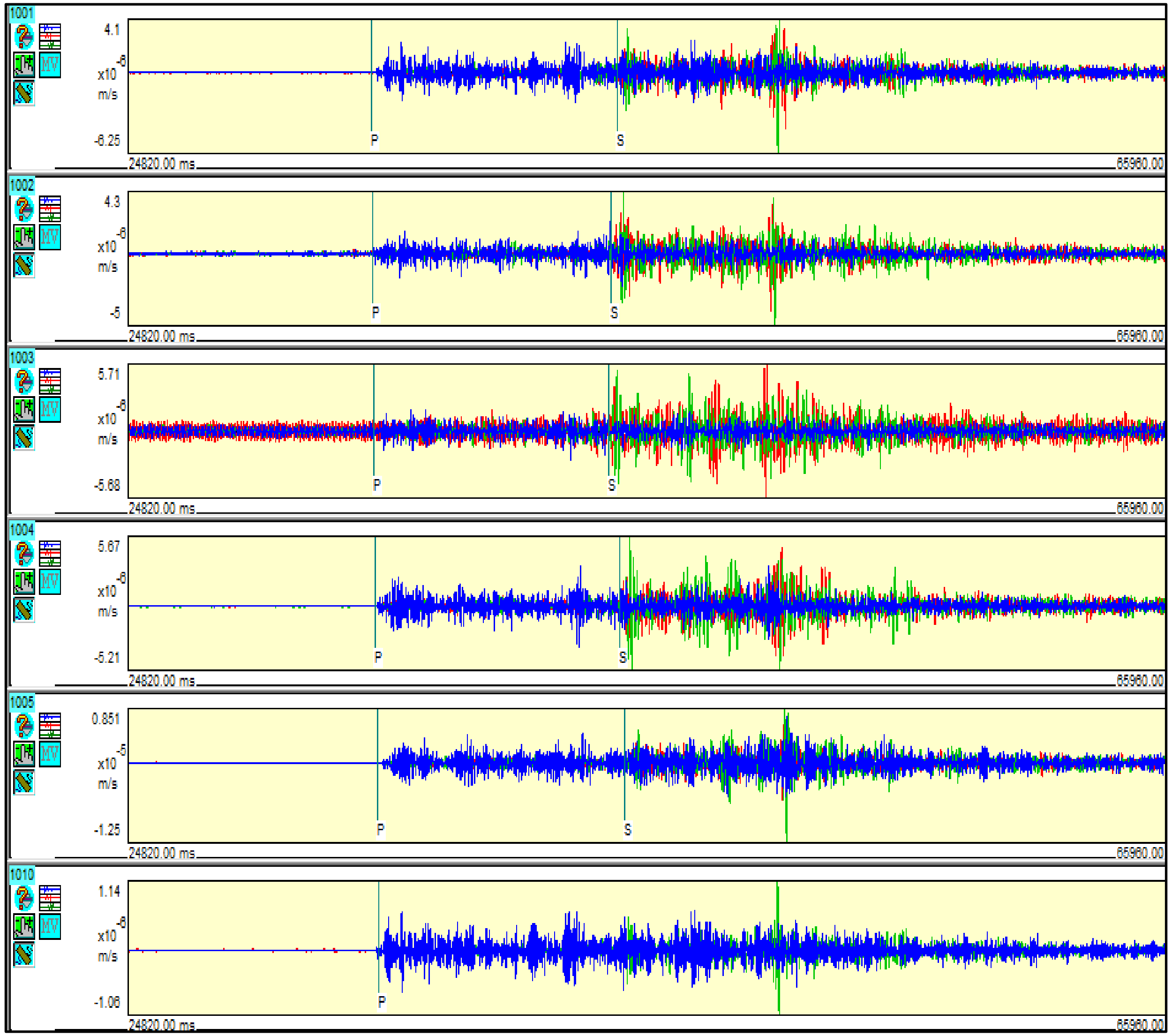


EVENT DATA

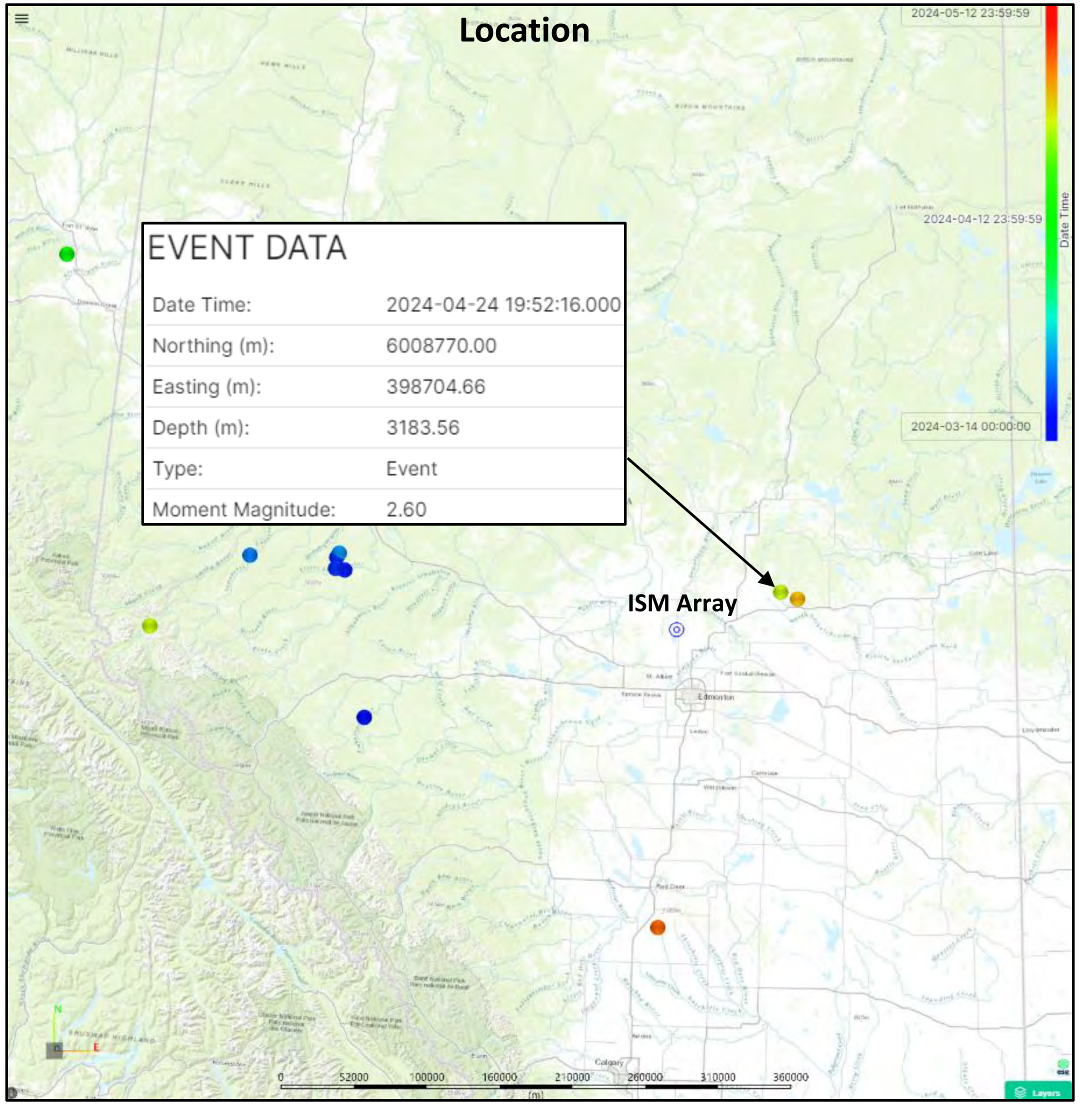
Date Time:	2024-04-23 23:21:56.000
Northing (m):	5987610.50
Easting (m):	-48728.25
Depth (m):	6436.66
Type:	Event
Moment Magnitude:	3.14

Note: Events are scaled by Moment Magnitude and colored by Time.

Regional Trigger: 2024-04-24/19:52:16.000 UTC

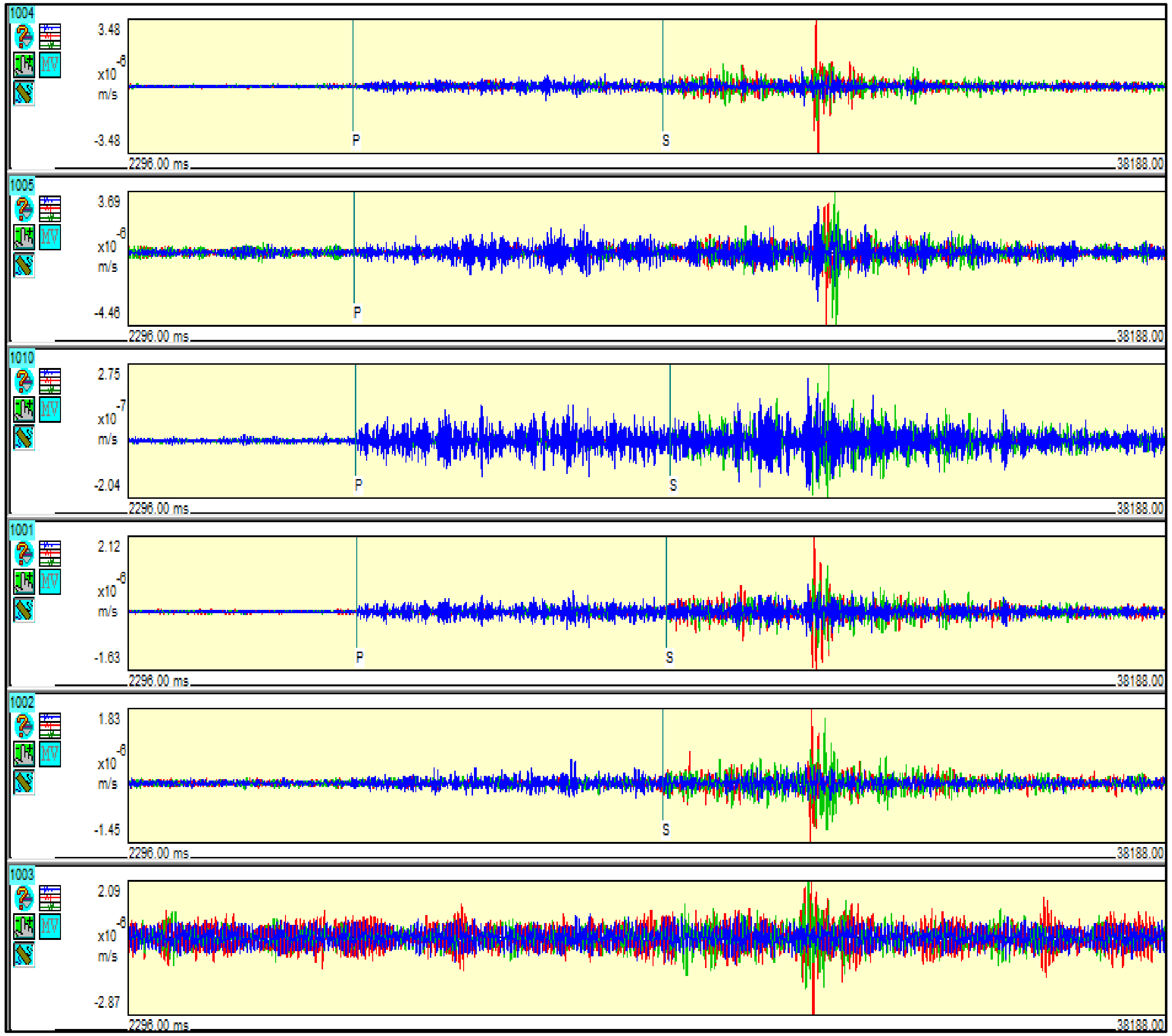


Note: The trace is 40.75 seconds long.

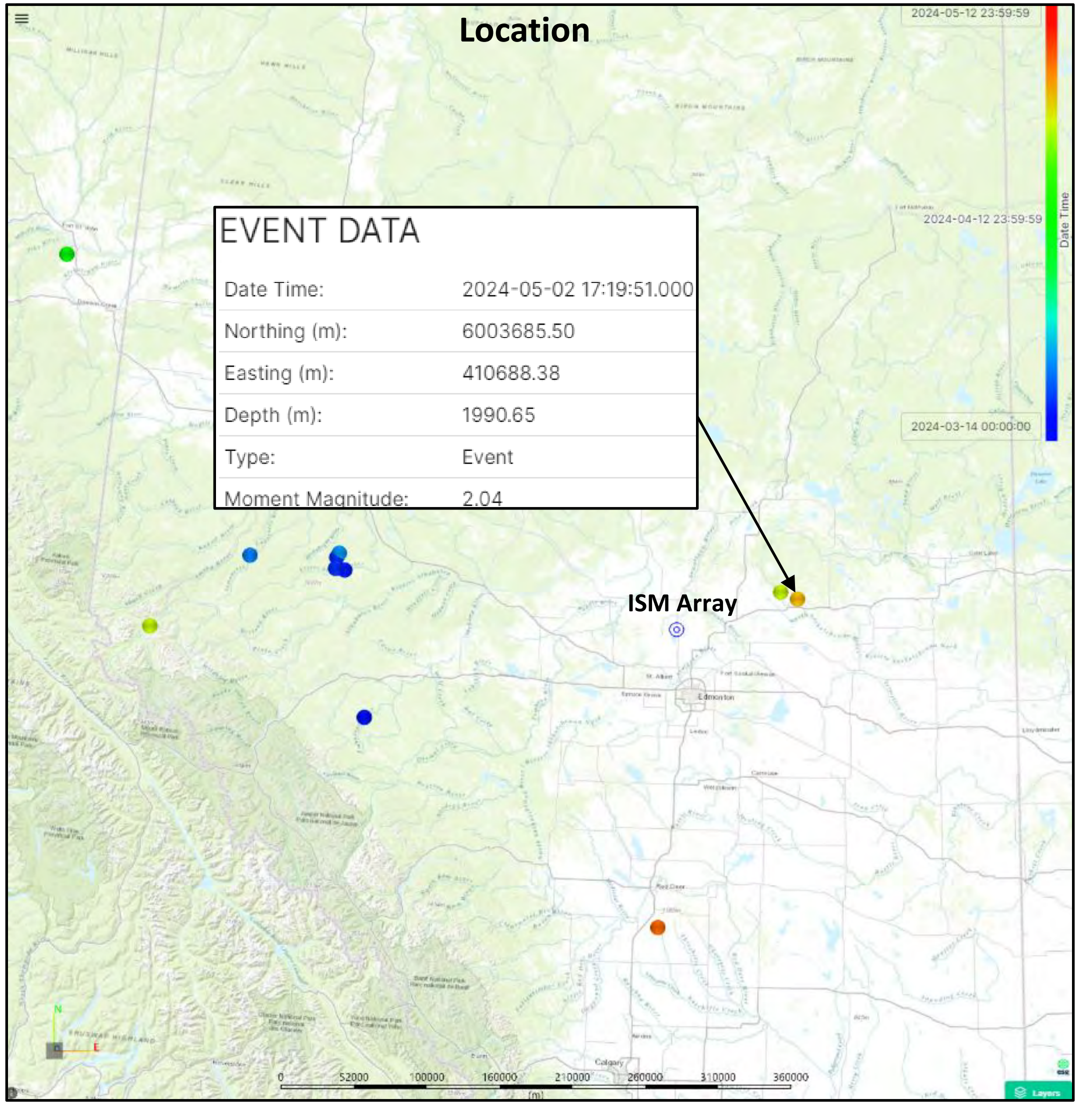


Note: Events are scaled by Moment Magnitude and colored by Time.

Regional Trigger: 2024-05-02/17:19:51.000 UTC

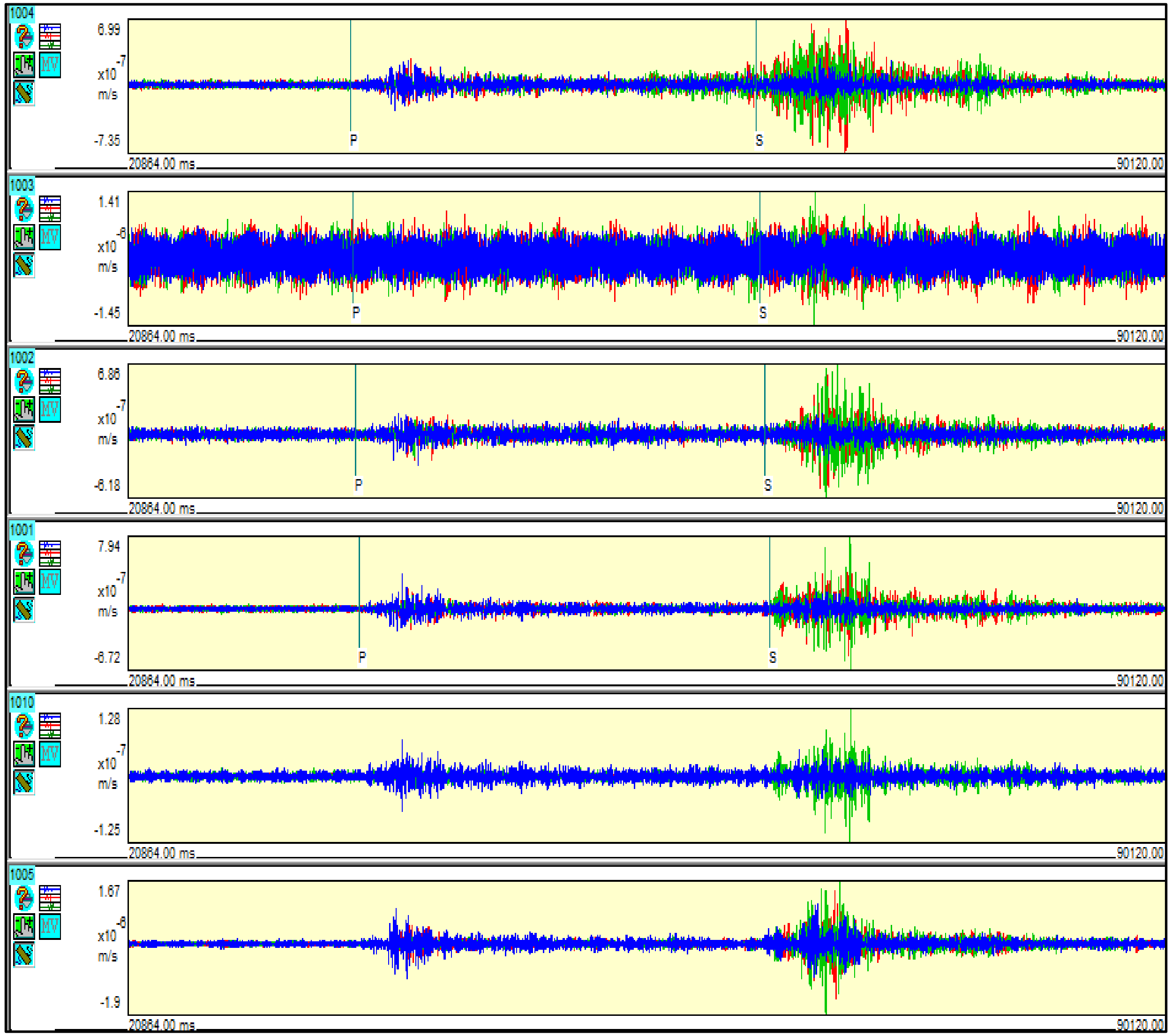


Note: The trace is 35.70 seconds long.

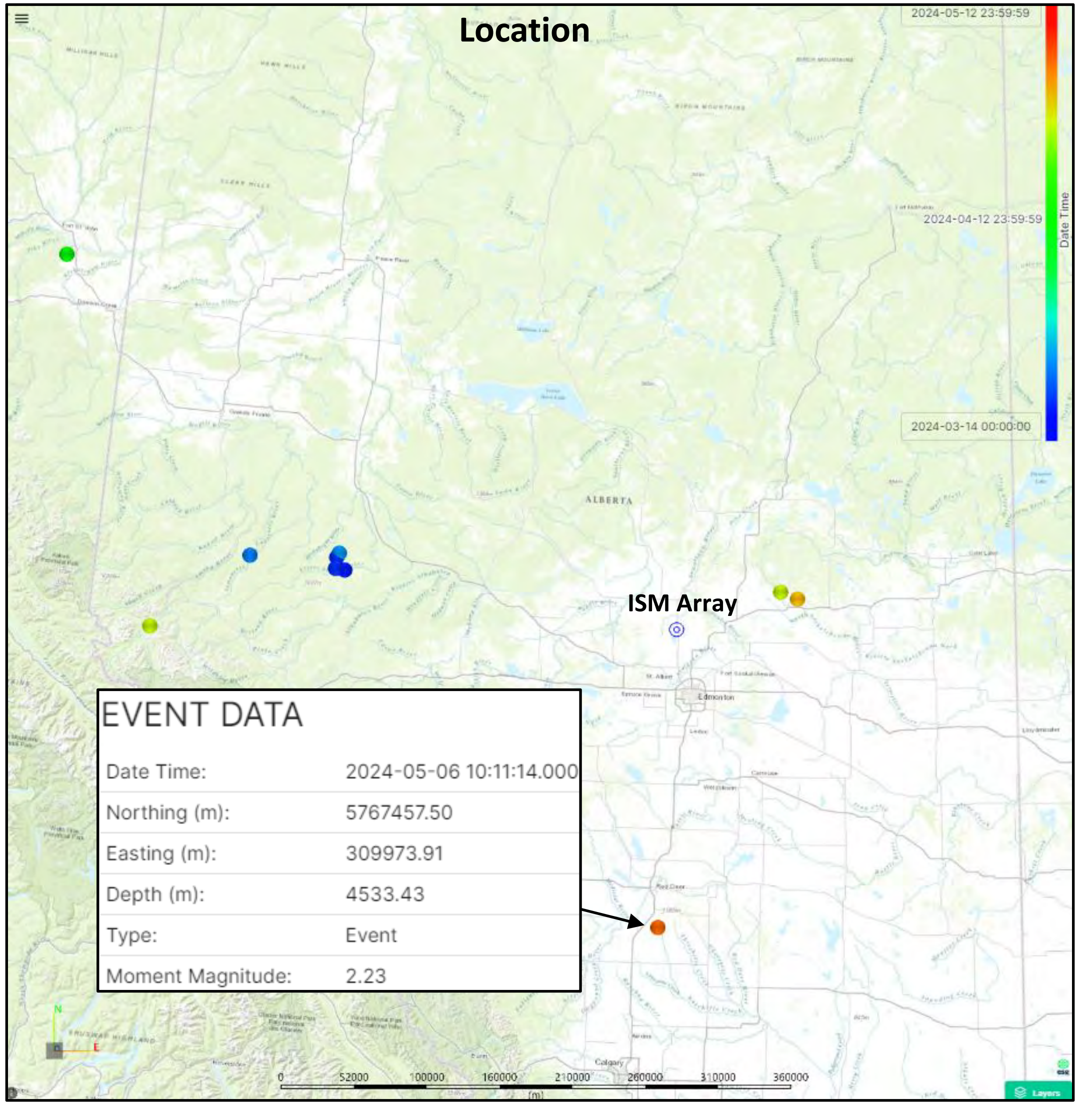


Note: Events are scaled by Moment Magnitude and colored by Time.

Regional Trigger: 2024-05-06/10:11:14.000 UTC



Note: The trace is 69.25 seconds long.

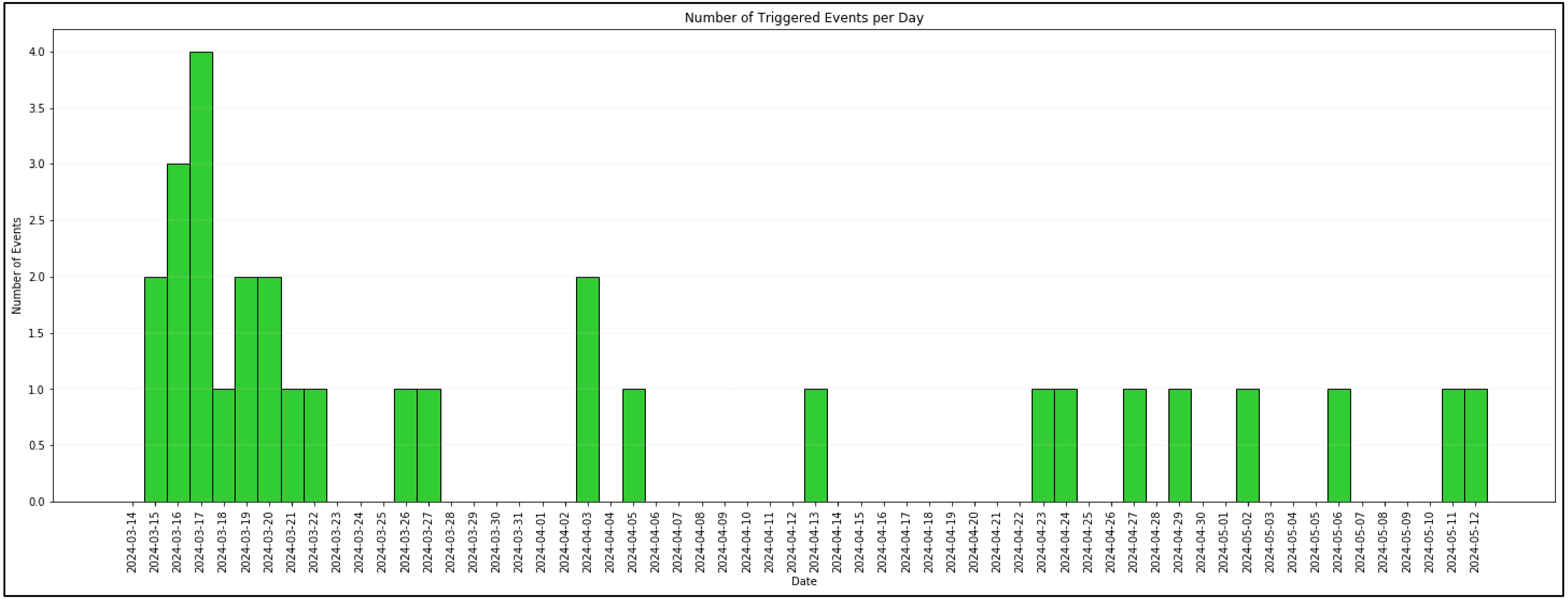


EVENT DATA

Date Time:	2024-05-06 10:11:14.000
Northing (m):	5767457.50
Easting (m):	309973.91
Depth (m):	4533.43
Type:	Event
Moment Magnitude:	2.23

Note: Events are scaled by Moment Magnitude and colored by Time.

Total Events: March 14th – May 12th, 2024



- This graph includes Single Phase Events, Regional Events, and Unlocatable Regional Events.
- The highest number of events recorded in a single day was 4 on March 17th, 2024.

Events Catalog - Regional Events: March 14th – May 12th, 2024

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Table 5: Summary of processed data during the reporting period

Date/Time (UTC)	Northing (m)	Easting (m)	Depth (m)	Mw	Northing Error (m)	Easting Error (m)	Depth Error (m)	Reported by		
								NRCan	AER	USGS
2024/03/15 11:28:35.000	5920518	102810	4831	2.146	207	69	291			
2024/03/16 01:52:51.000	6027007	89711	5531	1.484	314	235	316		X	
2024/03/17 21:53:14.000	6036182	84105	3784	2.337	307	254	316		X	
2024/03/18 06:00:05.000	6028152	83197	4438	1.776	315	279	309			
2024/03/21 15:14:43.000	6038094	22596	4566	2.821	312	139	316		X	
2024/03/22 22:26:48.000	6039172	85964	3095	3.596	309	148	316		X	
2024/04/13 11:18:34.000	6256195	-105686	6838	3.261	137	154	316			X
2024/04/23 23:21:56.000	5987610	-48728	6437	3.135	314	147	316	X		
2024/04/24 19:52:16.000	6008770	398705	3184	2.603	195	128	306	X	X	
2024/05/02 17:19:51.000	6003686	410688	1991	2.035	90	89	87		X	
2024/05/06 10:11:14.000	5767458	309974	4533	2.226	52	315	316	X	X	

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Appendix 9 – Geomechanics Characterization and Analysis

Geomechanical Characterization and Analysis

Background: The dolomitized Leduc in the Meadowbrook reef possesses an excellent reservoir quality similar to other dolomitized reefs of the Homeglen-Rimbey Leduc Reef trend. As demonstrated during the step-rate test with injection at rates up to 4 m^3/min (~5800 m^3/day) at near hydrostatic conditions and further studied in the Reservoir Modelling Section of this Application, these excellent reservoir qualities are expected to allow CO2 injection at pressures significantly lower than the formation fracture pressure. A maximum bottomhole injection pressure of 18.2 MPa is requested based on Directive 65, Appendix O, Table 1, corresponding to a pressure gradient of 13.7 kPa/m at top of Leduc 1326 m TVD.

Similarly, the Ireton is a well-studied regional caprock which has supported formation of large gas and oil accumulations in the vicinity of, and also to significant distances away from the Meadowbrook reef (Belyea 1955, Oliver and Cowper 1965). Development of these reservoirs has been associated with injection of (of cold water and gas at rates that surpass what is considered in this application by many times) without any known loss of caprock integrity. .

It is within this regional context that this section, as required by the AER, examines the site-specific geomechanical response of the reservoir and its caprock to injection of CO2 at the specific rates and temperatures of interest in this Application. This report addresses the question of caprock integrity and containment of the stored CO2.

Reports prepared by SLB on the development of 1D Mechanical Earth Model (MEM) and by TRS Energy Consultants detailing results of a series of geomechanical simulation studies are included as Appendices 10 and 11, respectively. A summary of these studies and their findings is presented here in two parts; Part I and II address the 1D MEM and Geomechanical Modelling, respectively.

In part I, we provide an assessment of the principal total stresses including the minimum horizontal stress (σ_{hmin}) in the reservoir and the caprock which is an important parameter in safety of the operations. In addition to the initial stresses, any geomechanical study requires a characterization of the mechanical properties and the failure envelop. The parameters addressed here are those of isotropic media with linear-elastic behaviour with a failure analysis that follows the linear Mohr-Coulomb criterion. Therefore, the main parameters addressed here include Young's Modulus and Poisson's ratio for characterization of the mechanical properties, as well as UCS and Friction Angle for the failure envelop. These collectively make up the 1D MEM, and the approach used is their determination based on wireline data.

The comparison of the parameters thus determined and their calibration against analogue information, field data and laboratory measurements are also addressed as detailed in Appendix 10. Because in Bison's proposed project, the CO2 will arrive at the sandface at temperatures that are lower than reservoir temperature, and this is expected to result in a change in the stress field, characterization of thermal properties is also addressed in this section.

In Part II, the geomechanical response of the reservoir and the caprock associated with CO2 injection is studied. Various scenarios and sensitivity studies are included. The results are based on coupled heat, fluid flow and geomechanical simulation studies using the GEM (with Geomechanics) model of CMG and detailed in Appendix 11.

In the Meadowbrook reef and in the vicinity of the injection well, Bison has >100km of 2D seismic data and no faults or discontinuities that would signal fault displacemnet have been mapped. Appendix 11 also addresses geomechanical response of any unmapped fault. This study concluded that a minimum pore-pressure increase of Δp=15 MPa would be required to cause any slippage along any unmapped faults. Since, the maximum bottomhole injection pressure requested here, insures that the maximum pressure increase to be approximately half of this value, fault slippage is not discussed further in this summary report.

Part I: 1D MEM

The mechanical earth model developed for this study is based on the stratigraphic units as observed in the logs of 16-29 well acquired and processed by SLB along with the use of appropriate correlations for the conversion of dynamic mechanical properties to static ones and determination of failure properties. For shallow sections where log data was not acquired, we use the geomechanical study of the Redwater reef conducted as part of the HARP project (Soltanzadeh and Hawkes 2012, and Bachu et al, 2011). The Redwater Leduc reef, which is approximately 2 townships east of the Meadowbrook reef and is approximately 300 m shallower, is considered an analogue, especially its western dolomitized regions (Amthor et al. 1994).

Four components that constitutes a 1D MEM include the mechanical properties, the strength (or failure) properties, the pore pressure, and the initial total stresses. These properties are determined at a vertical resolution of 0.5 m, with the exception of pore pressure that is given per stratigraphic unit. In Part II and for the geomechanical modelling a single value (i.e. the median) is used for each mechanical-stratigraphical unit.

In the following a more detailed description of the workflow for the determination of the four groups of properties is presented with focus on the reservoir and the caprock. The caprock is divided into two stratigraphic unit; the (upper) Ireton representing the more calcareous section (1295 m to 1311 m) and the shalier Lower Ireton (1311 m – 1326 m)[1]. The reservoir is divided into three units; (upper) Leduc, Lower Leduc, and the Cooking Lake. The stratigraphic continuity and the nature of the (Upper) and Lower Ireton is addressed in the Geology Section of the Application.

Mechanical Properties: For rocks with isotropic linear elastic behaviour (such as that considered here), two mechanical properties are sufficient to characterize the mechanical rock behaviour; the Static Young's Modulus (E) and the Static Poisson's Ratio (ν). In the log-based approach for the determination of mechanical properties, wire-line data are used to determine first the dynamic Young's Modulus and Poison's ratio. The dynamic values are then corrected to static values using correlations that may be developed for each lithology.

As detailed in Appendix 10, the compressional and shear wave velocity (V_c and V_s) and bulk density (ρ_b) are first used along with Equations 1a and 1b to determine the Dynamic Young's Modulus (E_d) and the Dynamic Poisson's Ratio (ν_d)

$$E_d = \frac{\rho_b V_s (3V_c^2 - 4V_s^2)}{V_c^2 - V_s^2} \qquad \text{1a}$$

$$\nu_d = \frac{V_c^2 - 2V_s^2}{2(V_c^2 - V_s^2)} \qquad \text{1b}$$

For the determination of the static properties from dynamic ones, no conversion was applied for Poisson's ratio (Soltanzadeh and Hawekes 2012, Andrews and de Lesquen, 2019). For Young's Modulus however, various correlations were tested. Some correlations generated results that exceeded acceptable values. These were rejected. Further criteria for the selection of the appropriate correlations included a wellbore stability analysis calibrated against FMI log, Caliper and the regional knowledge, as discussed in Appendix 10.

Figure G1 shows the "synthetic log" plot of the reservoir and its caprock, where the tracks from the left include name of the mechanical stratigraphic unit, Gamma Ray, density/neutron porosity, resistivity and lithology. The final two tracks show the Static Young Modulus and Static Poison's Ratio. The straight line shown on these two tracks exhibits the Median of the corresponding mechanical properties for each stratigraphic interval. Also shown are the corresponding values from the HARP study and the Static

[1] The terminology of (Upper) Ireton, with paracentesis, is used in this report to refer to the upper section of the Ireton. Appendix 10 uses "Ireton" for this upper section of the caprock. The shalier lower part of Ireton is called Lower Ireton here and Appendix 10. Similarly, the reservoir is divided into three stratigraphic layers called (Upper) Leduc, Lower Leduc and the Cooking Lake.

Young Modulus and Possion's ratio determined in the laboratory for two cores from the caprock.

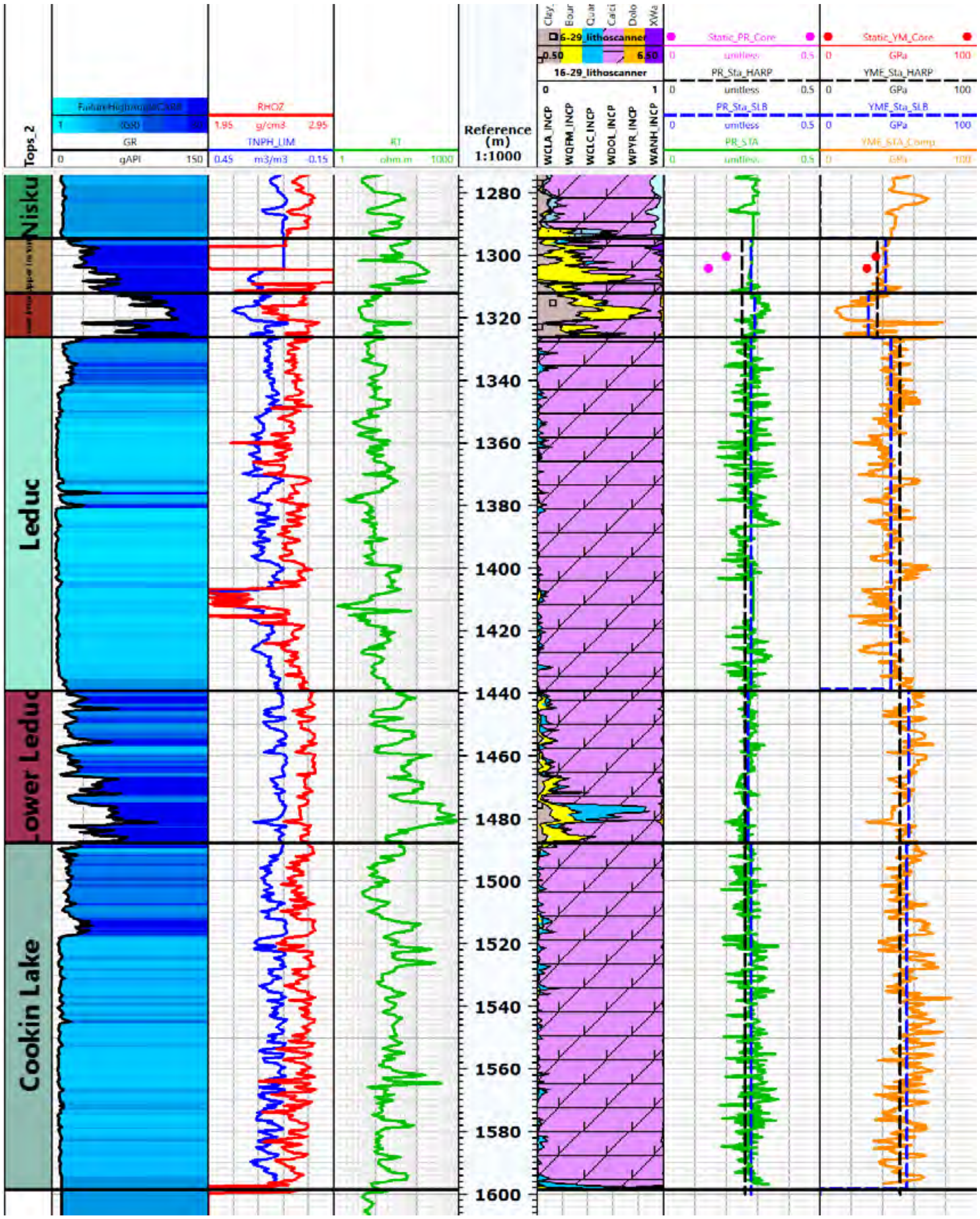


Figure G1: "Synthetic log" of 16-29 over the reservoir and its caprock, where the two tracks from the right show the Poisson's Ratio and Static Young Modulus.

Table G1 provides a summary of the mechanical properties in the reservoir and its caprock as determined at the 16-29 well and from the HARP study.

Table G1: Mechanical and Strength properties in the reservoir and its caprock as determined at the 16-29 well using wireline data (SLB_Base). Also given are those determined in the laboratory and from the HARP study (Soltanzadeh and Hawekes 2012)

	Static Young's Modulus, E (GPa)			Static Poisson's Ratio, ν			UCS, MPa			Friction Angle, ϕ (°)	
	SLB	HARP	Lab	SLB_Base	HARP	Lab	SLB	HARP*	Lab	SLB_Base	HARP
(Upper) Ireton	41.8	36.5	36.3/30.9	0.28	0.25	0.2/0.15	132.6	20.0	55.0/58.6	38.0	36
Lower Ireton	30.8			0.29			33.3			34.3	
(Upper) Leduc	45.2	51.2		0.28	0.26		80.2	93.1		38.9	40
Lower Leduc	56.5			0.27			135.9			40.2	
Cooking Lake	55.5			0.28			96.6			40.5	

It can be seen in Table G1 and Figure G1 that in the Cooking Lake, the Young's Modulus from SLB is larger than HARP. As the results in Part II show, the largest potential geomechanical response is the near-wellbore tensile fracturing in the reservoir, as a result of injection of cold CO2 over the openhole interval (e.g. in the Cooking Lake for the Base-Case considered). The magnitude of stress changes due to cooling is proportional to the product of Young's Modulus and thermal expansion coefficient (Samaroo et al. 2024, Eq.1). Therefore, it is expected that if the values of Young Modulus as estimated from the HARP study are used the potential for tensile fracturing by cooling would be lower than that found here.

As mentioned in the previous paragraph, the other material property that affects geomechanical response associated with temperature change is the linear coefficient of thermal expansion. Samaroo et al. (2024) discuss the importance of this parameter and the challenges in its measurement. In this work, we use a value of $1\text{x}10^{-5}$ 1/°C, similar to the one used by Samaroo et al. (2024, Table 4). This is consistent with values given by Robertson (1988), which present a range of between 0.7 and 1.1 $\text{x}10^{-5}$ 1/°C for various kinds of rock[2]. For sensitivity studies, we use a value of $1.5\text{x}10^{-5}$ 1/°C; 50% larger than the base value.

Strength Properties: The failure analysis considered here is based on the linear M-C analysis. Generally, two parameters are sufficient to characterize the failure envelope: Unconfined Compressive Strength (UCS), and the Friction Angle[3]. Since it is thought that

[2] Values of linear thermal expansion coefficient are from Roberton's (1988, Tables 10 and 11) and by considering that the linear coefficient of thermal expansion coefficient is one-third of the volumetric values.
[3] Alternatively, one may choose to characterize the M-C failure envelope using Cohesion and Friction Angle, where the relation between Cohesion, UCS and Friction angle is given by: $\mathrm{UCS} = 2\mathrm{C}\left(\sqrt{\tan \varphi^2 + 1} + \tan \varphi\right)$ where C is Cohesion and φ is the friction angle of the material. For the HARP study which provides Cohesion and Friction Angle, this relation is used to calculate UCS, (see Table G1).

the linear M-C analysis overpredicts the tensile strength of the material, the Tensile Strength of the rock is further limited to 10% of the UCS[4].

As outlined in Appendix 10, lithology-based correlations are used to calculate UCS (Horsrud 2001, Chang et al. 2006) and Friction Angle (Lal 1999) for all the mechanical stratigraphic layers in the 16-29 well including the three units in the reservoir and the two units of the caprock. These (along with other parameters determined in the 1D MEM model) were constrained by the wellbore stability analysis calibrated against FMI log and Caliper, as shown in Appendix 10.

Figure G2 shows the "synthetical log" plot of the reservoir and its caprock, where the two tracks from the right show the Friction Angle and UCS. The straight lines shown on these two tracks include the Median of the corresponding strength properties for each stratigraphic interval. Also shown are the corresponding values from the HARP study and the UCS determined in the laboratory for two cores from the caprock.

Table G1 provides a summary of the strength properties as determined from the wire-line data (called SLB_Base) as well as those given in the HARP study. Also given are the data acquired from the uniaxial laboratory testing of two core samples from the caprock in the 16-29 well.

[4] To be further conservative, in the Results Section below, we have assessed the potential for the onset of tensile fracturing by defining a Tensile Stress Level (TSL) which assumes a tensile strength of zero.

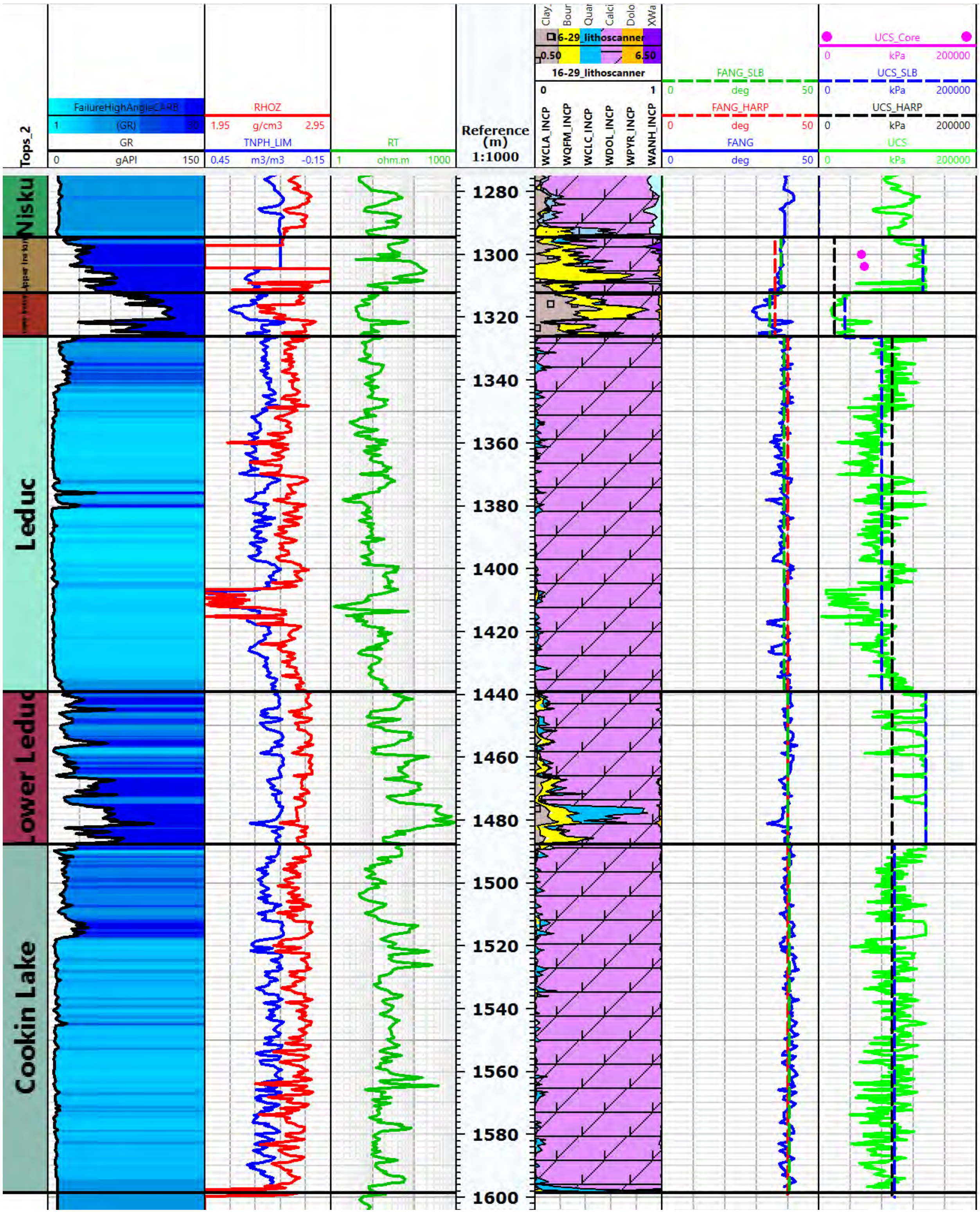


Figure G2: "Synthetic log" of 16-29 over the reservoir and its caprock, where the two tracks from the right show the Friction Angle (FANG) and UCS.

Pore Pressure: Figure G3 shows the profile of pore pressure (p) vs. depth determined at the 16-29 well. The Nisku pressures are measured using the behind-the-casing permanent gauges while the Leduc pressures are from MDT. The pore-pressure gradient in the Upper Leduc is ~7.4 kPa/m increasing to 7.8 kPa/m towards the bottom (reflecting the formation fluid that exhibit a hydrostatic pressure gradient of 10.5 kPa/m). The pressure gradient in Leduc is representative of a significantly sub-pressured regime as expected in the basin. Soltanzadeh and Hawkes (2012) reported a pore-pressure gradient of 7.5 kPa/m for the Redwater reef, which compares well with those found here.

The pressures presented in Figure G3 demonstrate that the Nisku and Leduc are on a similar pressure trend. For the Ireton too, the same pore-pressure gradient is considered.

For the stratigraphic units above Nisku, values from the HARP study are used. These too represent a state of pressure that is significantly lower than hydrostatic, except above the ground-water level.

A tubular version of the pore-pressure gradients in the reservoir and its caprock as determined at the 16-29 well along with the corresponding values from the HARP study is given Table G2.

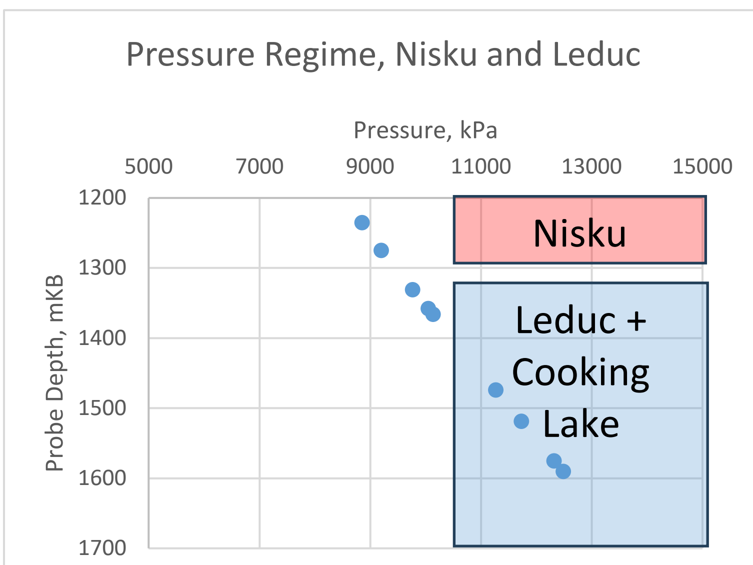


Figure G3: Initial pore pressure vs. depth at the 16-29 well

Initial State of Total Stress: The vertical total stress (σ_v) is based on the weight of all overlying strata and is determined by integrating the bulk density log data. For shallow sections without density measurements a density gradient of 21.8 kPa/m is used

(Soltanzadeh and Hawkes 2012). The resulting gradient of the vertical total stresses are reported in Table G2.

Table G2: State of pore pressure and total stress determined at the 16-29 well (SLB_Base and SLB_Low) and from the HARP study

	$p_{\_Grad}$ (kPa/m)		$\sigma_{v\text{-}Grad}$ (kPa/m)		$\sigma_{hmin\text{-}Grad}$ (kPa/m)			$\sigma_{hmax\text{-}Grad}$ (kPa/m)		
	MDT @ 16-29	HARP	SLB_Base	HARP	SLB_Base	SLB_Low	HARP	SLB_Base	SLB_Low	HARP
(Upper) Ireton	7.2	7.0	23.6	22.5	19.2	16.3	16.0	22.7	20.0	20.4
Lower Ireton	7.2		23.6		18.0	15.8		20.5	18.2	
(Upper) Leduc	7.4	7.5	23.7	22.8	19.9	16.6	16.6	23.5	20.7	21.5
Lower Leduc	7.6		23.8		20.3	16.8		24.5	21.3	
Cooking Lake	7.8		24.0		20.5	17.2		24.4	21.4	

For the determination of the horizontal stresses in an isotropic medium, the poroelastic horizontal strain model is used (See Equations 2a and 2b). In this model, the horizontal stresses (σ_{Hmax} and σ_{hmin}) is made up of two components, a poroelastic component of the horizontal stress (a portion of the vertical effective stress transferred to the horizontal plane via a coefficient that is related to the Poisson's ratio, ν), plus a tectonic component that is associated with the strain in the direction of maximum and minimum stress (ε_{Hmax} and ε_{hmin}).

$$\sigma_{hmin} - \alpha p = \frac{\nu}{1-\nu}(\sigma_V - \alpha p) + \frac{E}{1-\nu^2}(\varepsilon_{hmin} + \nu\varepsilon_{Hmax}) \quad (2a)$$

$$\sigma_{Hmax} - \alpha p = \frac{\nu}{1-\nu}(\sigma_V - \alpha p) + \frac{E}{1-\nu^2}(\varepsilon_{Hmax} + \nu\varepsilon_{hmin}) \quad (2b)$$

where α is the Biot's coefficient and E is the Young's Modulus as determined above.

For tectonic strain in the direction of maximum and minimum horizontal stress values of ε_{Hmax} =2.4x10^{-4} and ε_{hmin} =1x10^{-4}. The former was from Soltanzadeh and Hawkes (2012), while the latter was used so that the ratio of the maximum to minimum horizontal stress remains less than 1.3. These parameters were determined from a study of the horizontal stresses in the Alberta basin (Bachu et al. 2008).

Using the above approach (along with a Biot's coefficient of 1) the gradients of the maximum and minimum horizontal stress are calculated.

As seen in Table G2; the gradient of the minimum horizontal stress in the Lower Ireton, (Upper) Leduc and Cooking Lake are 18, 19.9 and 20.5 kPa/m. When compared with HARP values, these are approximately 20% larger. To consider a more pessimistic state of horizontal stress, a sensitivity case is also considered where tectonic strain in the direction of maximum and minimum horizontal stress values are lowered to ε_{Hmax} =2x10^{-4} and ε_{hmin}

=0.5x10^{-4} and a Biot's coefficient of 0.8 is used. These lower values of horizontal stress are labelled SLB_Low (See Table G2) and will be used for a sensitivity study in Part II below.

Note that the horizontal stress gradients in the (Upper) Ireton are larger than those in the Lower Ireton. This reflects the larger stiffness of the Calcareous deposits of the Upper Ireton. Also note that these calculations suggest no stress barrier between the reservoir and its caprock. However, there is a stress barrier between the Lower Ireton and the (Upper) Ireton.

Part II: Geomechanical Analysis

To investigate the geomechanical response of the reservoir and the caprock we started with analytical linear poroelastic models. The uniaxial deformation analytical model used assumes a uniform change of pressure or temperature (in the horizontal direction) throughout the formation, leading to a 1D displacement in the vertical direction. The use of this model indicated that the pressure change associated with injection (to a maximum bottomhole pressure of 18.2 MPa as requested in the Application) has little effect in the stress field such that the final state of stress remained far from failure envelop in both the caprock and the reservoir.

However, when the effect of cooling was considered, significant reduction in stress was observed with potential for tensile fracturing. However, it is known that these analytical calculations over-estimate the degree of fracturing in various ways[5]. Therefore, the

[5] Foremost, the simple analytical models considered here did not allow considering the effect of injection with a vertical offset from the cap-rock. The base completion considered at the 16-26 well envisions injection into Cooking Lake, beneath the low permeability Lower Leduc and with a vertical offset of approximately 150 m from the caprock. Both of these are expected to shield the caprock from the injected CO2. Furthermore, the uniform cooling assumption presents a pessimistic view in a second way. Because of the large thickness of the reservoir, and the much larger heat capacity of the formation and the brine as compared to the CO2, it is expected that the reservoir would not be totally cooled down and the cold zone would be extended to a limited distance from the wellbore. Heat balance calculations suggested that for injection rate of 0.5 Mtpa this distance may be of the order of 10's meters (after a few years of injection) to a couple of hundred meters (after 15 years of injection). This is much smaller than the areal extent of the reservoir. When the change in temperature (and pressure) is limited to a small radius around the wellbore, the effect of "stress-arching" reduces the change in horizontal stress and brings about a change in the vertical stress, which together reduce the change in deviatoric stress as compared with the simple uniform-change analytical models considered here. Collectively this means that the analytical model used here portrays a very pessimistic view of the change in stresses. It was felt important to account for the stress-arching effect by a numerical model that account for the non-uniform change in temperature (and pressure). Finally, when the analytical model predicted possibility of fracturing, it could not predict its extent. It is thought that tensile fracturing associated with cooling occurs in some other CO2 storage projects where the CO2 temperature is as much is 50-60 °C colder than the original reservoir temperature. But even there the zone of thermal fracturing is thought to be close to the wellbore, resulting in an improvement of injectivity with little impact on the caprock. Use of a numerical model would allow investigating how large this zone could be. This is described in the main body of the report and detailed in Appendix 11.

geomechanical response of the reservoir and its caprock in the vicinity of 16-29 well is studied using a coupled numerical simulator.

The geomechanical results given in the following use the GEM simulator of Computer Modelling Group (CMG). GEM is the same model used in the Reservoir Modelling section of this Application. However, in addition to investigating flow of CO2 in the reservoir and the associated change in pressure as studied in the Reservoir Modelling Section of this Application, in this section we also investigate the effect of change in temperature and the geomechanical effects associated with injection using a one-way coupling approach.

The details of how the model is set-up are given in Appendix 11. In summary these included: Incorporation of the stratigraphic units from the reservoir to the surface and the under-burden with the various properties from the 1D MEM model described above. A temperature profile was also imposed based on temperature of 48 °C at the top of Leduc with a geothermal gradient of 20 °C/km. All cases consider an injection rate of 0.5 Mtpa, with exception of one case that considers an injection rate of 0.07 Mtpa. The complete list of Cases examined are given in Table G4, under Sensitivity Studies.

Within the reservoir, a layer-cake model was considered with petrophysical properties that are consistent with what is included at the location of 16-29 well as modelled in the Reservoir Modelling Section of this Application, with one exception. The permeability considered here corresponds to the Low-Perm case considered in the Reservoir Modelling Section (with a permeability that is 1/3 of what was considered the base-case there). This is done to create a larger pressure disturbance and be closer to the Maximum Injection Pressure requested in this Application. As we shall see below, for cases of injection in Cooking Lake the bottomhole pressure is maintained at 18 MPa. Table G3 below gives the petrophysical properties of the reservoir grid used here.

Table G3: Petrophysical properties used in the reservoir

	Layer #	Porosity	Perm, md	Thickness, m
Upper Leduc	1	7%	2.6	20
	2	10%	19	20
	3	13%	50	20
	4	7%	2.6	20
	5	10%	19	20
	6	13%	50	20
Lower Leduc	7	1%	0.001	20
	8			20
Cooking Lake	9	10%	19	20
	10	1%	0.03	20
	11	10%	19	20
	12	4%	0.3	20
	13	7%	2.6	20
	14	4%	0.3	20
	15	10%	19	20
	16	1%	0.03	20

Notes: (i) kv/kh=0.1, (ii) The Lower Leduc is charcterized with a non-zero (but low) porosity and permeability to allow pressure communication as observed in the Reservoir Modelling Section.

As expected, the injection of CO2 results in changes in pressure and temperature. These in turn result in changes in the stress field. To assess the geomechanical response of the reservoir and the caprock, linear poroelastic behaviour is assumed, and the state of stresses after injection are compared against the linear Mohr-Coulomb model (characterized by parameters determined in the 1D MEM). In order to better facilitate how close the stress field gets to the failure envelop two indices are used, a Tensile-Stress Level (TSL) and a Shear-Stress Level (SSL). Tensile stress level (TSL) is defined as the ratio of pore-pressure to minimum horizontal stress, TSL=p/σ_{hmin}. As pressure gets closer to σ_{hmin} or the minimum horizontal stress is reduced by cooling, TSL approaches 1, indicating that the rock approaches a tensile mode and the potential for tensile fracturing increases. TSL is a conservative (i.e. pessimistic) measure of potential for tensile fracturing, since it assumes no tensile strength for the rock.

Similarly, SSL is a measure of the shear stress as compared with the shear strength of the rock. SSL is defined as

$$\mathrm{SSL}=\frac{\sigma_{\mathrm{d}}}{\sigma_{\mathrm{dmax}}} \qquad \text{3a}$$

where σ_{dmax} is the maximum shear strength of the rock and given by

$$\sigma_{\mathrm{dmax}}=\frac{2C\cos\varphi+2\sigma_3'\sin\varphi}{1-\sin\varphi} \qquad \text{3b}$$

where C is cohesion, φ is the Friction Angle, and σ_d is the deviatoric stress,

$$\sigma_d=\sigma_1-\sigma_3 \qquad \text{3c}$$

where C is cohesion, φ is the friction angle, and σ_3' is the minimum effective stress.

In the following, 2D colour maps of SSL and TSL are shown to examine the potential for shear and tensile fracturing of the reservoir and the caprock.

Scenario's studied and the Results: The first scenario is for injection into the Cooking Lake, where the point of injection is approximately 150 m below the caprock and the low quality "Lower Leduc", which was tested during the MDT operations and tested "dry", separates the injection zone from the (Upper Leduc and) the caprock.

The first case studies the effect of pressure only (C9_1 in Table G4). The results indicate that a constant rate of 0.5 Mtpa can not be maintained, and the injection rate is constrained by the maximum bottomhole pressure of 18 MPa. The results shown in Appendix 11 confirm small changes in the stress field. The small changes in SSL and TSL are included in Figures G7 and G9 and discussed under Sensitivity Studies. Here, the results for the case of injection of cold CO2 (at 5 °C) in the Cooking Lake, which creates a larger change in the stress field is presented in more detail (Case2 in Table G4). Figure G4 shows the injection rate and the bottomhole pressure. With the petrophysical properties specified in Table G3, injection is constrained by the maximum injection pressure of 18 MPa to approximately 0.35 Mtpa for the 15-year duration of injection.

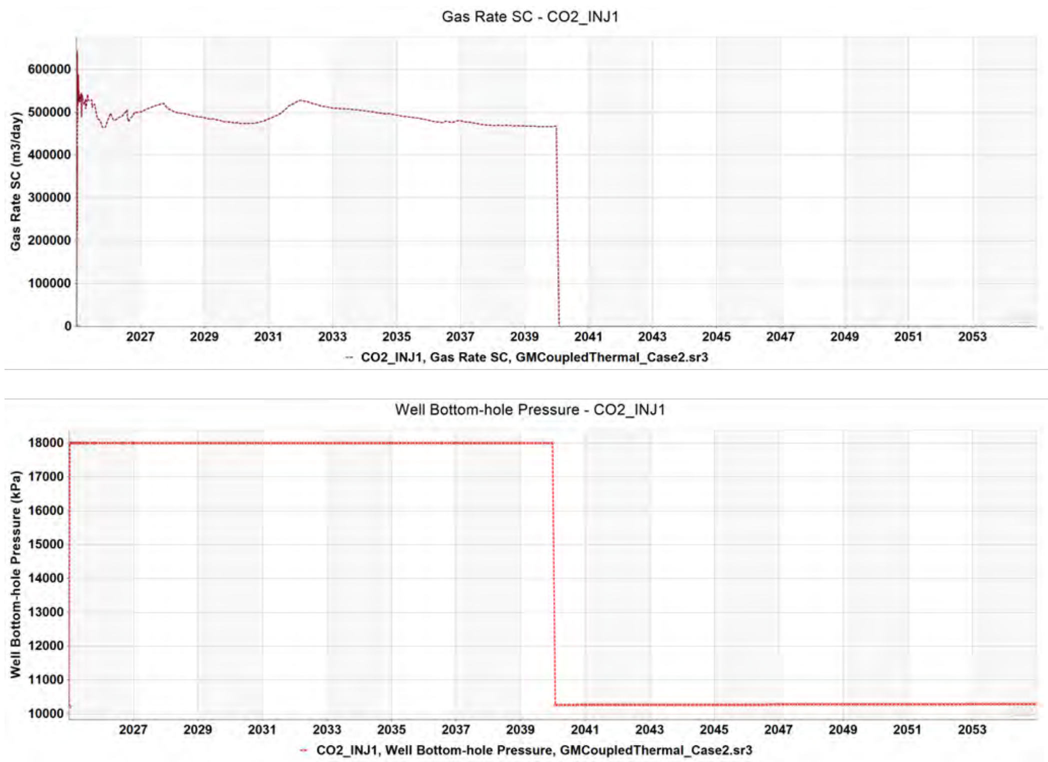


Figure G4: Injection rate (of ~500,000 m3/day or ~0.35 Mtpa) and flowing pressure (of 18 MPa) for the case of injection in the Cooking Lake at 5 °C (Case2)

Figure G5 shows the temperature distribution after 15 years of injection. Two observations are noteworthy: (i) After 15 years of injection, a region of low temperature forms close to the wellbore (in the Cooking Lake), (ii) there in no temperature effect at the caprock (identified by fine-gridding at a depth of ~1320 m).

Reduction in temperature results in reduction of the horizontal stresses and could lead to tensile fractures. Figure G6 shows the state of Tensile-Stress Level (TSL) before injection (bottom) and after 15 years of injection (top). The initial state of TSL (of nearly 0.4) reflects the ratio of pore pressure to the minimum horizontal stress, characterized by pore-pressure and minimum-horizontal stress gradients of approximately 7.5 and 20 kPa/m. After 15 years of injection, the TSL in the near wellbore region of the open interval has increased to ~1 indicating the potential for tensile fracturing as a result of near wellbore cooling. Near wellbore thermal fracturing, if it occurs, could lead to improved injectivity but is not expected to affect containment. The results in Figure G6 indicate that the TSL at the caprock is unchanged.

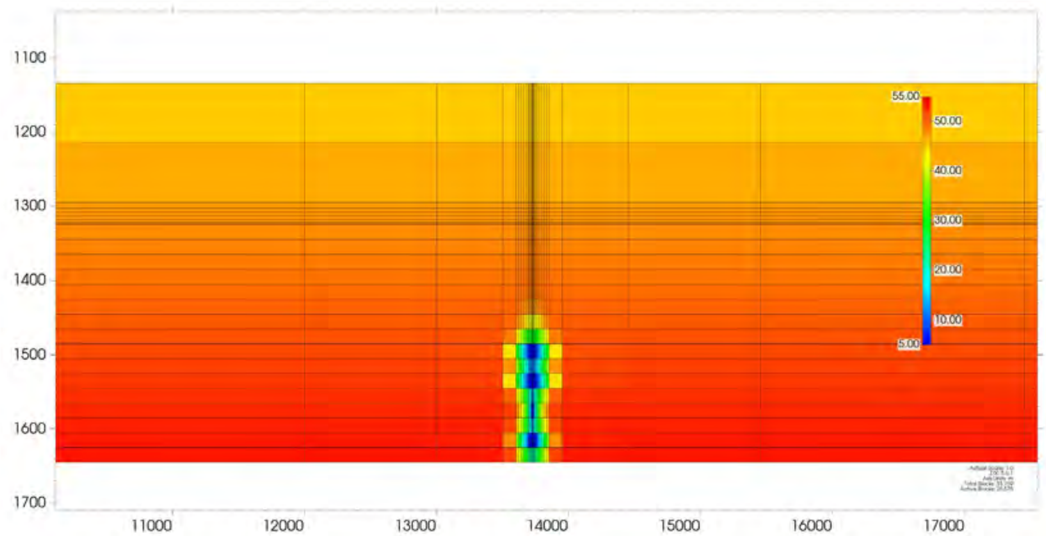


Figure G5: Temperature Distribution after 15 years of injection for the case of injection in the Cooking Lake at 5 ◦C (Case2 of Table G4)

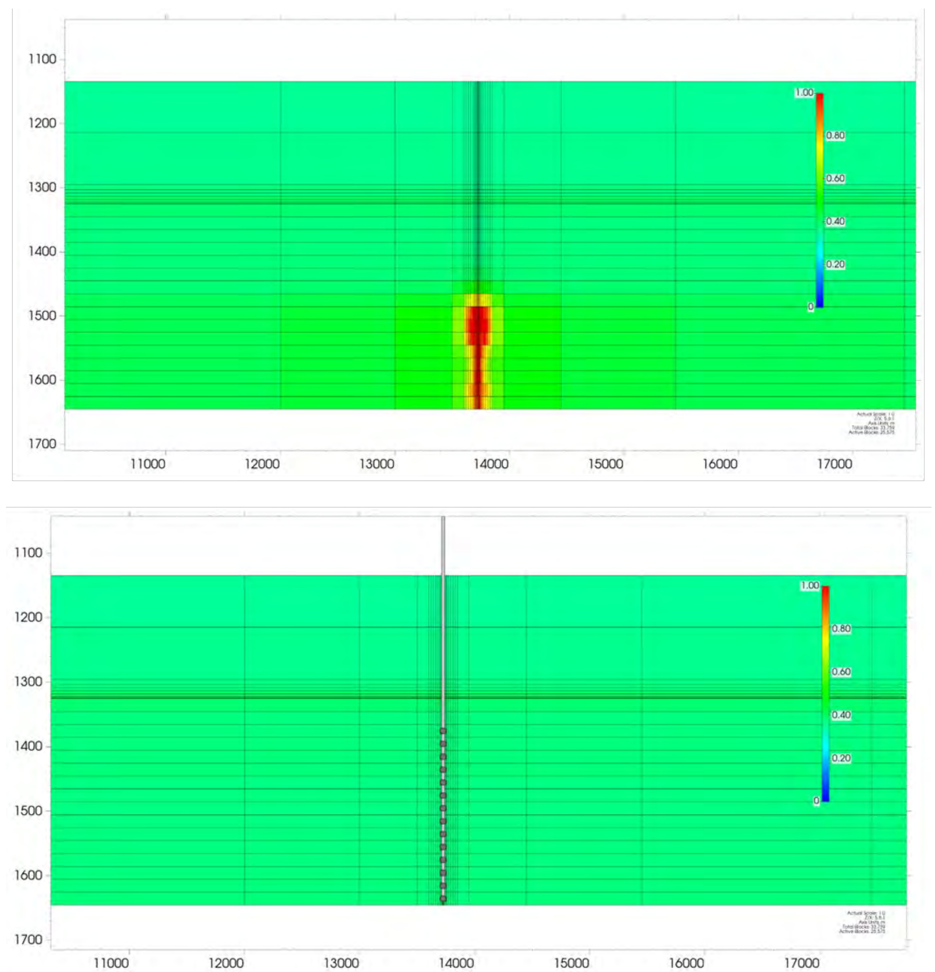


Figure G6: State of TSL (initial at the bottom) and after 15 years of injection (on top) for the case of injection in the Cooking Lake at 5 ◦C (Case2 of Table G4)

To examine the state of caprock TSL with time further, Figure G7 shows the changes of TSL with time at the base of the caprock. The results are for at the lower-most grid block in Ireton, which is closest to the injected fluids in the reservoir. Further up in the Ireton, temperature (and TSL) remains closer to its initial state.

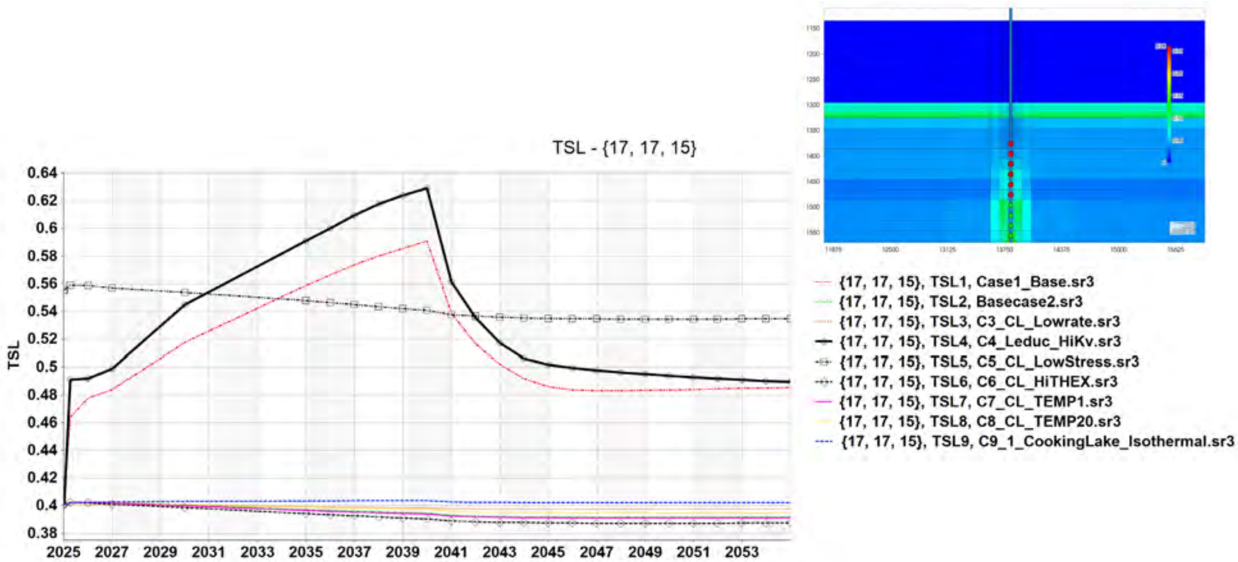
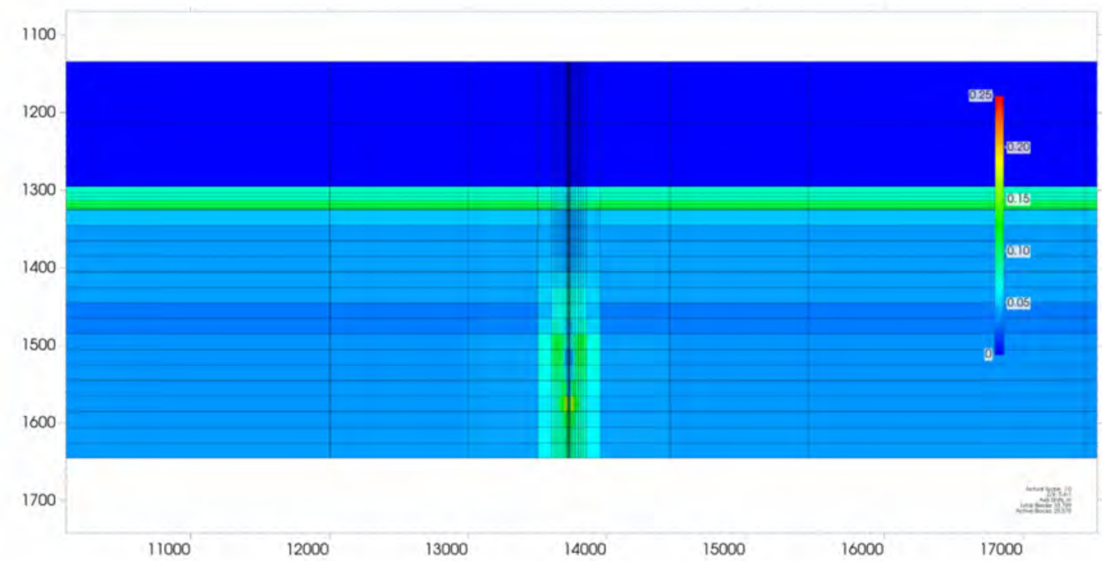


Figure G7: State of TSL at the base of the caprock for all cases shown in Table G4

Figure G7 shows the results of all sensitivity cases. These will be described under Sensitivity Studies below. The results for the injection into the Cooking Lake (Case2, shown by the dashed-green? line) which is of interest here, indicate that the TSL at the base of the caprock remains nearly unchanged at ~0.4. These results suggest that the separation between the injection zone and the caprock is large and effective enough to isolate the effect of injected fluids from the caprock.

Another mechanism of caprock failure studied in this work is associated with formation of shear fractures. This is studied through analysis of Shear-Stress Level (SSL), which quantifies how close the state of shear stress is in relation to the maximum-shear strength of the rock. Figure G8 shows the state of SSL before injection (bottom) and after 15 years of injection (top). At the initial conditions, the largest value of SSL (of approximately 0.1) is that of the Lower Ireton. This is a reflection of the low value of shear strength of the rock (associated with the low USC/Cohesion of the lower Ireton in Table G1). The state of SSL after 15 years of injection is shown in Figure G8 (top). Two observations can be made (i) Everywhere, the value of SSL remains significantly smaller than 1 and far from the onset of shear failure, and (ii) in the near wellbore region a slight reduction of SSL is seen at the caprock (and Upper Leduc). The reason for this is the increase in horizontal stress associated with local cooling in the Cooking Lake and the resulting stress arching as explained in TRS Energy Consultants' report in Appendix 11. In order to further study the caprock, Figure G9 shows the sate of the SSL at its base.



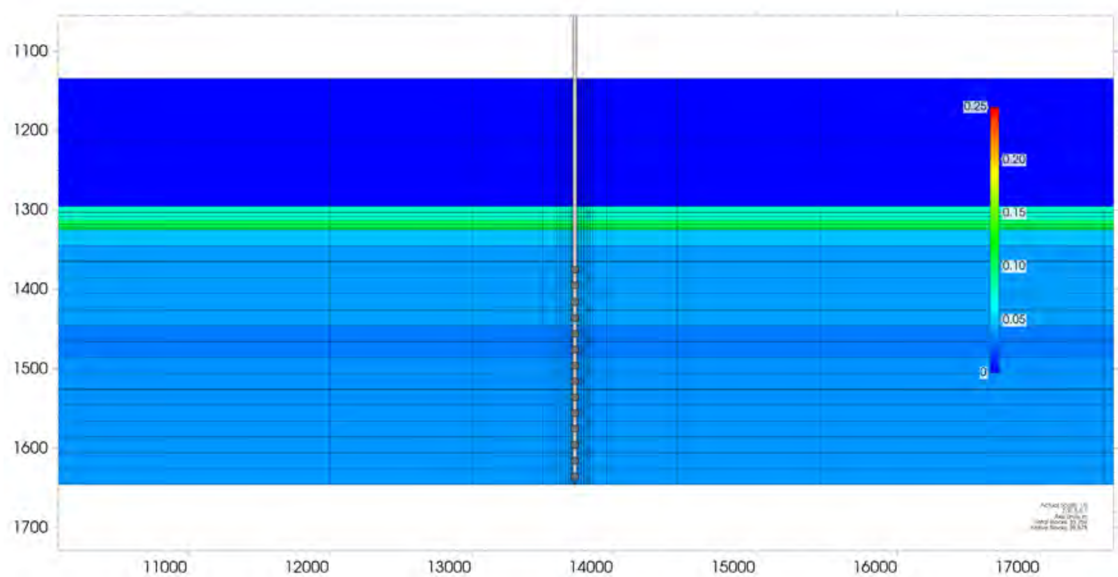


Figure G8: Initial State of SSL (at the bottom) and after 15 years of injection (on top). Injection in the Cooking Lake at 5 °C (Case2 of Table G4)

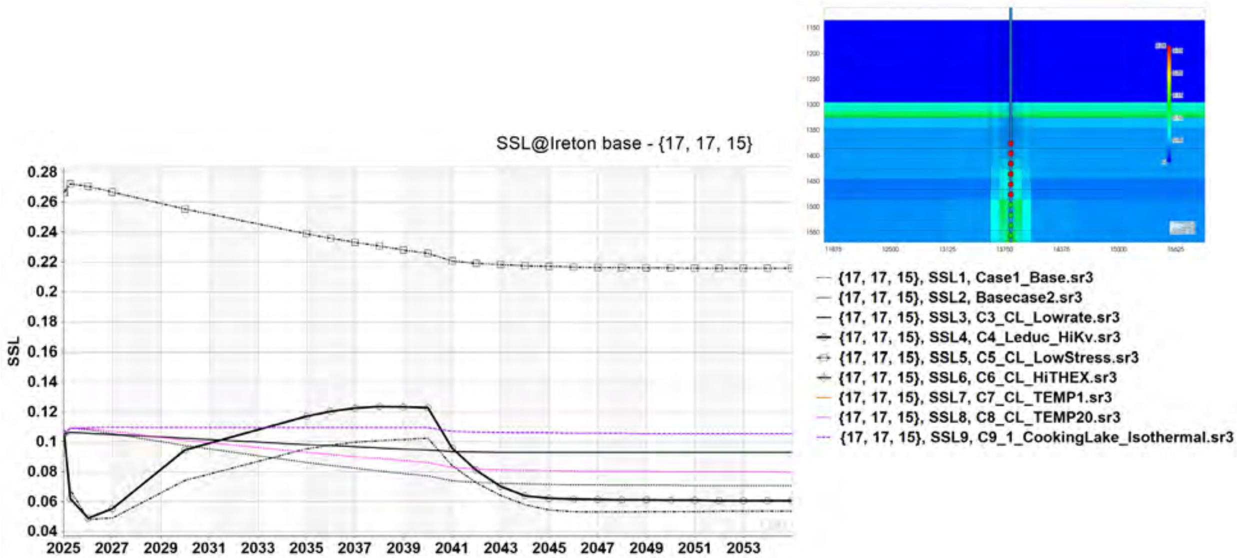


Figure G9: State of TSL at the base of the caprock for all cases of Table G4

Results in Figure G9 indicate that SSL at the base of caprock remains very close to its initial value of 0.1, and far away from the onset of shear failure. Figure G9 also includes results of other sensitivity cases. These are explained next.

In summary, for the case of cold (5 °C) CO2 injection into the Cooking Lake at a maximum bottomhole injection pressure of 18 MPa, the results indicate that (i) the cold front stays far from the caprock and therefore the caprock remains far from failure with maximum shear-Stress level (SSL) and Tensile-Stress Level (TSL) of 0.1 and 0.4, which are very close to their initial values, and (ii) a near wellbore zone in the reservoir forms that enters a tensile mode and might exhibit tensile fracturing. It is expected that if tensile fractures form, a change in injectivity might be observed with no consequences for caprock integrity (as the cold front is far from the caprock).

Sensitivity Studies: The primary completion design considered in this Application envisions a liner down to the top of the Cooking Lake with a packer set over the low-quality Lower Leduc as explained in Completions Section. For this scenario, in addition to the Case2 explained above, six additional sensitivity cases were run, two investigated the effect of uncertainty in the parameters of the 1D MEM (i.e. a smaller minimum horizontal stress and a larger thermal expansion coefficient), and four investigated the effect of change in operating conditions, i.e. sand-face injection temperatures of 1, 20 °C and isothermal, and a lower injection rate of 0.07 Mtpa as planned for the first phase of Bison's project. The complete list of cases studied along with the case names used in Appendix 11 is given in Table G4.

The TSL results shown in Figure G7 indicate for the cases of injection into the Cooking Lake, the values of TSL stays close to 0.4, with only the case of LowStress exhibiting a value approximately 0.56. As shown in Table G2, this latter case assumes a lower minimum-horizontal stress (SLB_Low) and therefore has a larger TSL at the initial state. Regardless of the initial value, the results suggest that injection in the Cooking Lake has little effect on the caprock. The same observation can be made in Figure G9 that exhibits the changes in SSL. Once again, the values of SSL at the base of the caprock remain very close to their initial values of either 0.1 for most of the cases or 0.26 for the case with low initial horizontal stress.

Table G4: List of cases studied, where the sensitivity parameter is in bold.

Case Name	Openhole interval	Inj. Rate, Mtpa	Inj. Temp, °C	State of Initial Stress	Thermal Expansion coeff, 1/°C	kv/kh
Case2	Cooking Lake	0.5	5	SLB_Base	$1x10^{-5}$	0.1
C3	Cooking Lake	0.07	5	SLB_Base	$1x10^{-5}$	0.1
C5	Cooking Lake	0.5	5	SLB_Low	$1x10^{-5}$	0.1
C6	Cooking Lake	0.5	5	SLB_Base	$1.5x10^{-5}$	0.1
C7	Cooking Lake	0.5	1	SLB_Base	$1x10^{-5}$	0.1
C8	Cooking Lake	0.5	20	SLB_Base	$1x10^{-5}$	0.1
C9_1	Cooking Lake	0.5	Iso-Thermal	SLB_Base	$1x10^{-5}$	0.1
Case1	Leduc & CL	0.5	5	SLB_Base	$1x10^{-5}$	0.1
C4	Leduc & CL	0.5	5	SLB_Base	$1x10^{-5}$	1

In addition to the scenario of injection in Cooking Lake, a second scenario is also studied where in addition to Cooking Lake, the Upper Leduc is also open to flow. The vertical offset from the caprock considered for this case is 60 m, consistent with the well design. This scenario is investigated to see the effect of injection at a closer distance from the caprock.

Results show a small degree of cooling at the base of the caprock which results in a period of upward trend in TSL and SSL as observed in Figures G7 and G9 respectively[6]. The solid black line in both Figures is related to the scenario of injection in the Upper Leduc with the extreme conditions where the vertical permeability in is assumed to be equal to horizontal permeability (and injection rate of 0.5 Mtpa). Even in this case, and after 15 years of injection, the base of the caprock stays far from fracturing conditions (TSL=0.63 and SSL=0.13).

[6] The cooling results in a reduction in minimum horizontal stress (lowering the denominator of the TSL and SSL equations) and hence an increase in their value.

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Appendix 10 – Geomechanics Simulations Study

Bison Hub CCS Geomechanics Simulations Study

Prepared for Client
by TRS Energy Consultants Ltd.

July 01, 2024

July 1, 2024

Mr. Matt Brister:

Re: Geomechanical Simulations Study on Bison Hub CCS Project

The following report summarizes the geomechanical modelling and outcomes for the Bison Hub CCS Project. In this initiative, simulations were performed to evaluate the integrity of the caprock and associated reservoir deformations resulting from CO2 injection, utilizing CMG's GEM™ software. No faults were mapped for the project area, consequently, a fault slip potential analysis assuming optimally orientated faults for slip (the worst case) was assumed for the analysis.

Enclosed is a Word document detailing the key geomechanical concepts, technical terms, and principal findings from the simulation study. Additionally, the attached PowerPoint presentation provides an overview of all scenarios tested during the project.

Please do not hesitate to contact us if you have any questions or require further information.

Sincerely,

Dale Walters

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38 Cranridge Heights SE
Calgary, AB T3M 0E7
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Geomechanical Simulations Study for Bison Hub CCS Project

TRS Energy Consultants Ltd.

1 Executive Summary

This report presents the findings of a geomechanical modeling study conducted for the Bison Hub CCS project. The primary objective of the study was to assess the geomechanical impacts of CO_2 injection into the storage reservoir rocks (Leduc and Cooking Lake formations) and to evaluate the integrity of the associated caprock (Ireton formation). For this study, we utilized CMG's GEM software. For wellbore stability simulations, we used ABAQUS.

In our simulation model, we explored both shear failure and tensile fracturing, conducting various sensitivity analyses to examine how differing rock properties, in-situ stress, and operational variables influence rock deformation and failure. The likelihood of rock failure was quantified using two indicators: Shear Stress Level (SSL) and Tensile Stress Level (TSL).

The simulations consist of two components: the CMG simulations, which concentrate on reservoir-scale modeling, and the ABAQUS FEM simulations, which focus on the local near-wellbore scale. In the CMG simulations, a linear elastic model without a tension cutoff was used for all cases. For the ABAQUS simulations, thermally induced near-wellbore tensile fracturing was evaluated and employed a Mohr-Coulomb plasticity model.

The main conclusions drawn from this study are:

1. The direct caprock, specifically the Ireton Formation, has a low risk of shear failure and/or tensile fracturing in all simulated scenarios.
2. The predicted thermal cooling effects suggest near-wellbore reservoir rock may undergo tensile fracturing if the bottom-hole temperature (BHT) drops to 5°C or lower. However, in scenarios where the BHT is maintained at 20°C or in isothermal conditions, the reservoir rock remains free from tensile fracturing.
3. A wellbore stability analysis was performed using the finite element method (FEM) in ABAQUS, which included considerations of near-wellbore stress concentrations and fully coupled thermal-hydro-mechanical (THM) simulations. The results highlight that the cooling effect is the primary factor leading to tensile fractures near the borehole. Specifically, for the Cooking Lake interval, maintaining the downhole injection temperature at 20°C appears to prevent tensile fractures. It is important to note that ABAQUS simulations focus on the wellbore and nearby rocks with a grid size on a 10-cm scale. In contrast, CMG simulations address large-scale and long-term CO_2 injection. Therefore, ABAQUS simulations are more suitable for near-

wellbore analyses (less than 5-m from wellbore), while CMG simulations are more applicable to long-term, reservoir-scale effects.

4. A fault slip analysis predicts a minimum pore pressure increase of 15 MPa is necessary to cause fault slip for faults oriented in the most critical direction. Under the current injection design, the maximum operating pressure (MOP) at Cooking Lake is 18.2 MPa, resulting in a 6 MPa increase in pore pressure. At Leduc, the MOP is 14 MPa, leading to a 4 MPa increase in pore pressure. Consequently, with this injection design, any existing faults are unlikely to slip.

2 Introduction

This geomechanical simulation study examines the impact of CO2 injection on rock deformations and the potential for rock failures within the Bison CCS Hub project, with a particular focus on the possibility of caprock failure and fault slip induced by CO2 injection. The study utilized a coupled reservoir and geomechanical simulator, CMG GEM^{TM}, and included both non-isothermal and isothermal conditions. The geological formations involved are the storage reservoir rocks—Leduc and Cooking Lake formations—and the caprock, identified as the Ireton formation. For this evaluation, the Ireton formation was divided into upper Ireton and lower Ireton layers. Rock mechanics and in-situ stresses were assigned to these layers based on predictions from a 1D Mechanical Earth Model (MEM). Fully coupled thermal-hydro-mechanical (THM) simulations using ABAQUS were conducted to study the near-wellbore deformation and tensile fracturing induced by cold CO2 injection.

2.1 Overburden stress changes during CCS operations.

Besides the reservoir deformation induced total stress changes, the geomechanical impact also comes from the fluid injection induced overburden pressure and/or temperature changes, which will also cause the total/effective stresses to change. If the caprock has a good seal capacity, normally it is not expected to see a significant pressure change in the overburden except the thermally induced stress change (in our case, it is the cooling induced effective stress reduction). However, if the injection operations cause the caprock to fail or activate natural fractures or faults, fluid excursions may occur potentially causing the overburden pressure to increase and increasing the risk of formation failure.

2.2 Shear and tensile failure mechanisms (SSL and TSL)

There are two mechanisms through which a formation may fail due to the induced effective stress changes. These failure mechanisms are important because both have the potential to induce vertical flow pathways through the caprock compromising the seal capacity.

The first mechanism is “Tensile Failure”. Such a mechanism can be seen in hydraulic fracturing operations. In this mechanism, the pore pressure exceeds the minimum principal total stress and causes a fracture plane perpendicular to that stress. The tensile failure is controlled mainly by minimum total stress and to a lesser extent the tensile strength of material. If tensile failure occurs, it has a large permeability increase, potentially a rapid growth and may grow through interfaces. Tensile failure usually has high consequences due to the magnitude of permeability enhancement and rate of propagation. The controlling parameters of this failure mechanism can be determined by stress testing (Minifrac test or DFIT measuring minimum total stress) and laboratory tests (tensile strength of material). The monitoring criterion used for the tensile failure mechanism is “Tensile Stress Level” (TSL). TSL is defined as the ratio of current pressure to current total minimum principal stress (P/σ_{min}) which represents a conservative measure of the onset of fracture initiation. The TSL assumes the tensile strength of the intact material is zero to be intentionally conservative (and overestimate TSL).

The second mechanism that may lead to the caprock failure is “Shear Failure”. In this mechanism the stress path in the caprock may reach the shear failure envelope (shear strength limit of the material) due to effective stress changes. In this case, shear fractures will form in the caprock and consequently potentially compromise the caprock integrity. The caprock failure due to geological weak planes falls into this mechanism as well. The shear failure is controlled by shear strength of the material (here, formation shear strength) which is a material property and depends on mechanical characteristics (cohesive and frictional strength). The criterion used for monitoring the shear failure is “Shear Stress Level” (SSL). SSL is defined as the ratio of maximum shear stress to shear strength. It is also defined as the current deviatoric stress to the maximum deviatoric stress allowed (stress at onset of shear failure) as the following equation shows:

$$SSL = \frac{\sigma_d}{\sigma_{d\,max}}$$

where

$$\sigma_{d\,max} = \frac{2C\cos\varphi + 2\sigma_3'\sin\varphi}{(1-\sin\varphi)}$$

In the above relations, σ_d is current deviatoric stress (S1-S3) at the location; $\sigma_{d\,max}$ is the maximum allowable deviatoric stress; C is the material cohesion; σ_3' is the minimum effective and φ is the friction angle of the material. The shear stress level measures how close the material is to the onset of shear failure. A formation that has failed in shear cannot support further shear load unless strain hardening occurs, which is not typical or significant for soils or soft rocks. However, the failure does not necessarily imply that the formation will behave as a conduit for the fluids. The formation can still show resistance against the fluid flow as the potential permeability enhancement generated by shear failure is much less than tensile failure and sometimes negligible.

However, a key situation may be where both mechanisms act together with the shear failure providing an initiation point for enhanced pressure diffusion and eventually tensile failure. This is one of the critical scenarios that will be analyzed in this study.

2.3 Fault Slip Potential (FSP)

To evaluate the risk of induced seismicity, fault stability analysis was conducted. The analysis used an analytical tool[1] [2] developed in MATLAB using the initial stress state. This tool evaluated the fault stability (slip potential, Ts) and assessed the pressure increase required for fault slip. The slip potential may be used within the framework of a normal seismic hazard assessment to include the risks of pore pressure increase in the typical probability of slip calculations. In this analysis, no hazard assessment was included, so only the probability of slipping associated with pressure changes was analyzed.

In the fault slip analysis, the pore pressure required for fault slip is evaluated (ΔP) to quantify the potential of fault slip. The possibility of a fault surface undergoing slip in a given stress field depends on its frictional characteristics (primarily controlled by rock type), the ratio of shear to normal stresses acting on the surface and the pore pressure within the fault. Frictional faulting theory assumes that shear stress controls fault slippage. A fault will remain stable when the applied shear stress (τ) is lower than the shear strength of the fault. The failure condition to initiate slippage is usually expressed in terms of the effective stress and pore pressure:

$$\tau_{crit} = \mu\left(\sigma_n - p\right) + c$$

where the critical shear stress (τ_{crit}) equals the product of the frictional coefficient (μ) and effective normal stress given by the difference between the applied normal stress (σ_n) and pore pressure p. When pore pressure increases, the critical shear stress decreases. The pore pressure at which the critical shear stress equals the applied shear stress is defined as the pore pressure required to induce fault slip. The fault cohesion value (c) is negligible under typical crustal conditions. The shear and normal stresses on a fault plane were calculated via stress tensor rotation and resolved onto the fault plane. The definition of pore pressure required to slip the fault (ΔP) is given in Figure 1. It should be noted that for the fault stability analysis, a coefficient of friction of 0.6 was assumed for the faults. There have been extensive measurements and studies of the different coefficients of friction of different rock types. However, much of the field observations tend to suggest a value of 0.6 represents the majority of cases where the critical plane fails in shear[3].

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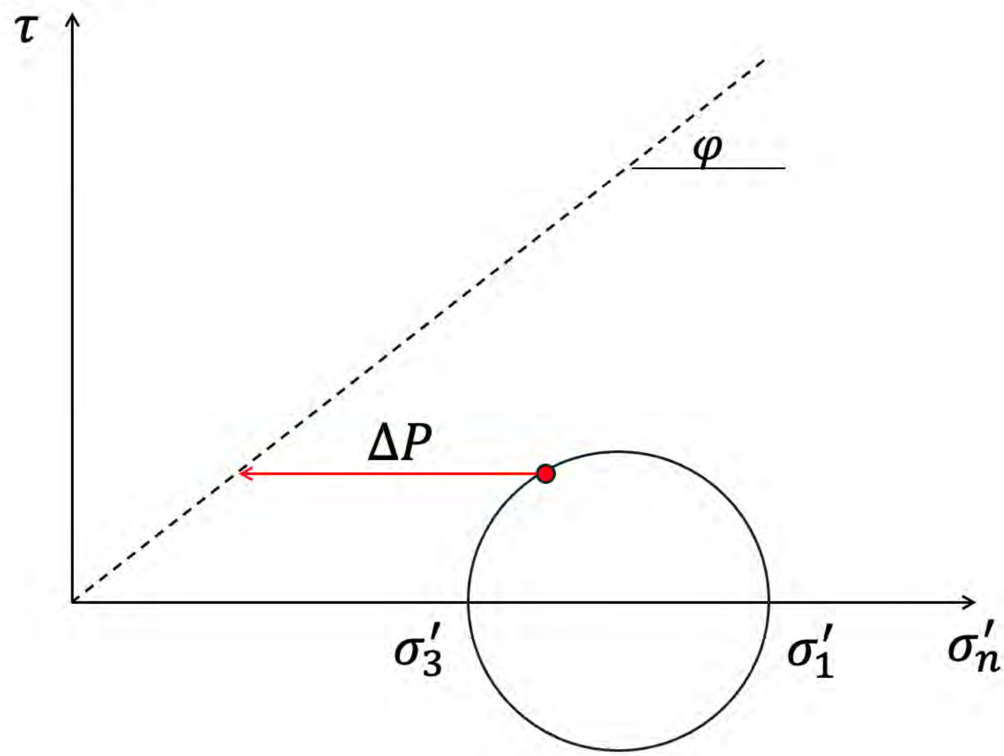


Figure 1: Definition of change in pore pressure required for fault slip (ΔP)

3 Model Setup and Calibration

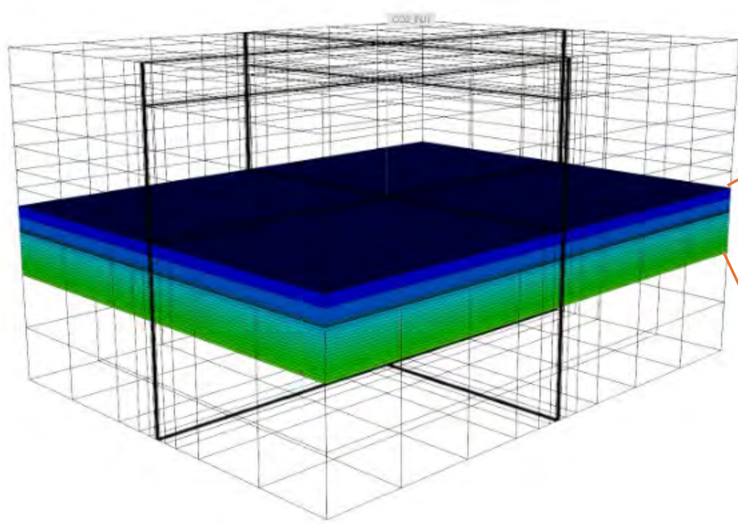
The current study employed coupled reservoir and geomechanical modelling on a 3D grid, utilizing a one-way coupled simulation within GEM. In this setup, the flow simulation updates the geomechanical simulation with pressure and temperature data, but the geomechanical simulation does not influence the flow simulation. This approach is justified given the high stiffness and tightness of the rock formations under study, which ensure minimal rock deformation and negligible impact on fluid flow. Additionally, the permeability enhancement due to rock failure was predicted to be very close to the well perforations and was designed to not occur in the caprock. This will be further discussed in Section 4.3.

3.1 3D model gridding – geological layers

Table 1 outlines the geological formations for the storage reservoir and its overlying rock strata, beginning at the surface. The reservoir grid comprises three formations: Leduc, lower Leduc, and Cooking Lake. To reduce total number of gridblocks, some overlying formations have been grouped as shown in **Table 1**. Additionally, 800 meters of underburden has been incorporated into the geomechanical model to establish appropriate boundary conditions for the simulations. **Figure 2** illustrates the 3D grid and its corresponding geological formations. The reservoir model includes storage reservoir rocks (Leduc, lower Leduc, and Cooking Lake) and two overburden formations (Ireton and Wabamun), with the Ireton formation serving as the direct caprock. The geomechanical model (GM) extends the reservoir model to the surface and incorporates an additional two layers of underburden grids, totaling 800 meters.

Table 1: Geological formations and the layers in 3d grid

CMG Grid	Formation	Lithology	Elevation (SS)	Depth (m)
Milk River	Lea Park	shale	347.0	368.4
	Milk River	shale	260.0	455.4
Colorado	Colorado Gp	shale	185.0	530.4
	Second White Specks	shale	6.0	709.4
	Base Fish Scales	shale	-84.0	799.4
	Viking	sandstone	-113.0	828.4
	Joli Fou	shale	-134.6	850.0
Manville	Manville	sandstone	-157.0	872.4
	Glauconite	sandstone	-297.0	1012.4
	Ostracod	shale	-319.0	1034.4
	Ellerslie	sandstone	-345.0	1060.4
Wabamun	Wabamun	limestone	-419.0	1134.4
	Graminia	shale	-460.0	1175.4
	Blueridge	limestone	-468.0	1183.4
	Calmar	shale	-492.0	1207.4
	Nisku	dolomite	-495.0	1210.4
Ireton	Ireton	shale	-580.0	1295.4
Reservoir	Leduc	dolomite	-611.0	1326.4
	Lower Leduc	dolomite	-723.0	1438.4
	Cooking Lake	limestone	-772.0	1487.4
Base	Base			2287.36



CMG Grid	Formation	Lithology	Elevation (SS)	Depth (m)
Milk River	Lea Park	shale	347.0	368.4
	Milk River	shale	260.0	455.4
Colorado	Colorado Gp	shale	185.0	530.4
	Second Wh	shale	6.0	709.4
	Base Fish S	shale	-84.0	799.4
	Viking	sandstone	-113.0	828.4
	Joli Fou	shale	-134.6	850.0
Manville	Manville	sandstone	-157.0	872.4
	Glauconite	sandstone	-297.0	1012.4
	Ostracod	shale	-319.0	1034.4
	Ellerslie	sandstone	-345.0	1060.4
Wabamun	Wabamun	limestone	-419.0	1134.4
	Graminia	shale	-460.0	1175.4
	Blueridge	limestone	-468.0	1183.4
	Calmar	shale	-492.0	1207.4
	Nisku	dolomite	-495.0	1210.4
Ireton	Ireton	shale	-580.0	1295.4
Reservoir	Leduc	dolomite	-611.0	1326.4
	Lower Ledu	dolomite	-723.0	1438.4
	Cooking Lak	limestone	-772.0	1487.4
Base	Base			2287.36

Figure 2: 3D grid with corresponding geological formations. The contour colour shows the initial pore pressure distribution and this part of the grid is reservoir grid. GM grid was extended to surface and 800 m under the reservoir.

3.2 Boundary conditions

In the reservoir model, no fluid flow and no thermal flux boundaries were established. For the geomechanical model, the bottom surface was fixed to allow zero vertical displacement (Uz=0). The four side surfaces were fixed with roller boundary conditions, setting displacements perpendicular to each surface to zero, while the top or ground surface was left free to deform.

3.3 Initial conditions

In the models for both the reservoir and geomechanics, gradients for both initial pressure (**Figure 4**) and temperature (**Figure 3**) were incorporated. The pore pressure at the top of the reservoir was set at 9700 kPa. A temperature gradient of of 2°C per 100 meters was used in the model resulting in a temperature at the top of the reservoir at 48°C. Additionally, the initial stress gradient provided by the client was integrated into the geomechanical model. The in-situ stresses in the lower Ireton formation for the base case were assumed:

- S_{hmin} = 17.96 kPa/m
- S_{hmax} = 20.45 kPa/m
- S_v = 23.60 kPa/m

and the orientations initial maximum horizontal stress was set at N45°E which is consistent with the database values from Alberta Geological Survey (AGS) and the World Stress Map. The in-situ stresses were also sensitized for a potential uncertainty range to understand the impact of different initial stress conditions on the overburden stress changes and the associated risk of failure. The contour plots for initial stress in the geomechanical model are given fromFigure 5 to Figure 7.

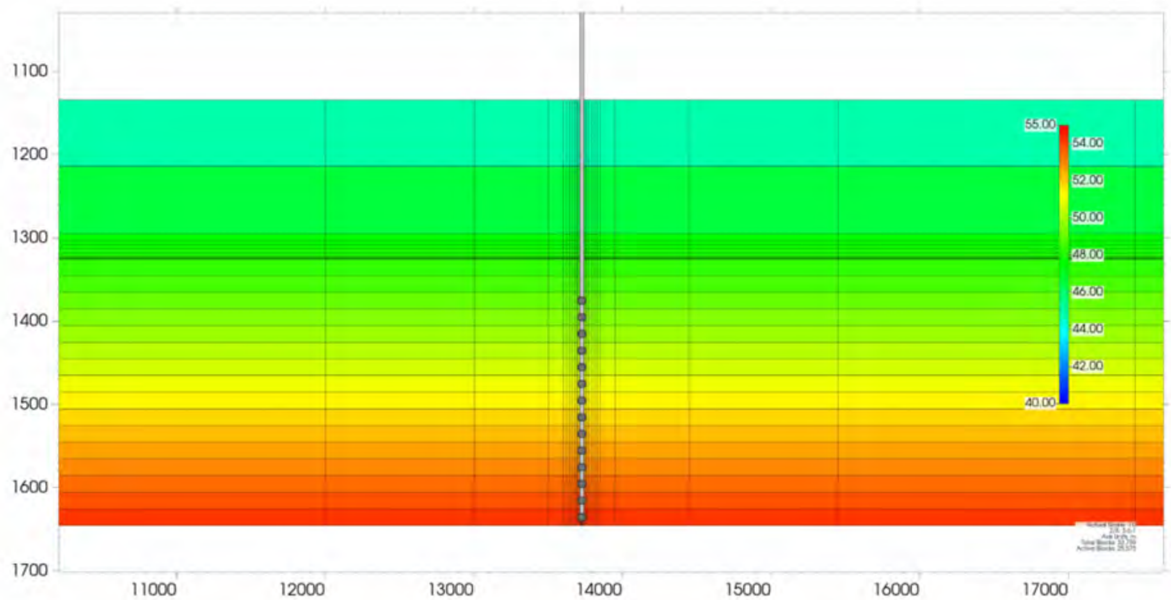


Figure 3: Initial temperature distribution in reservoir model

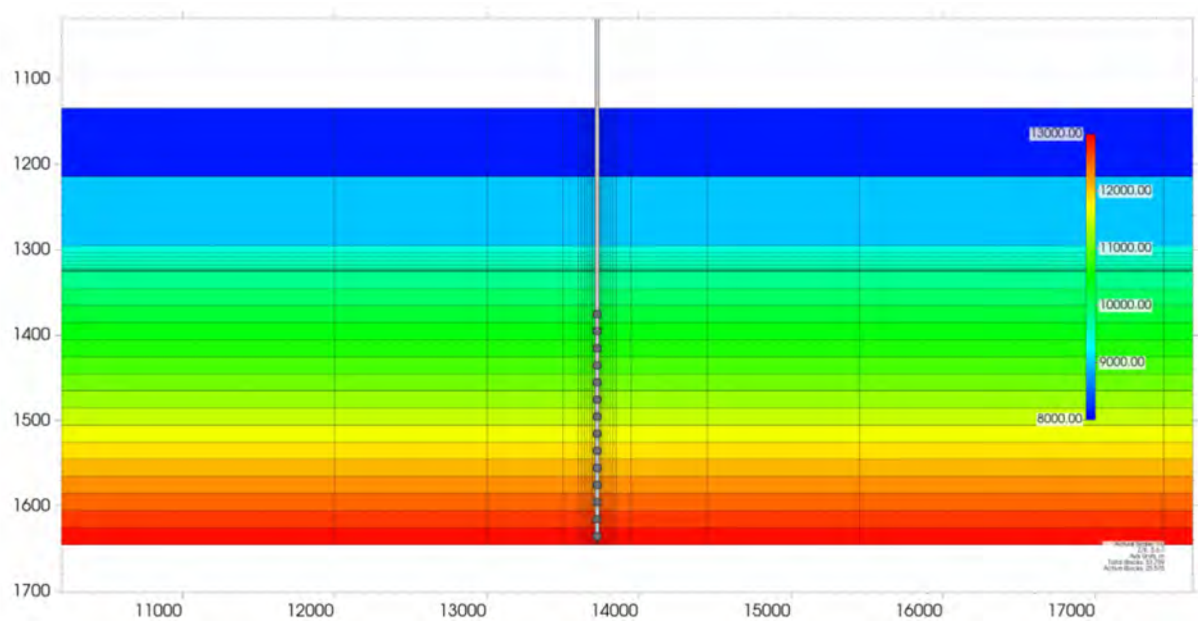


Figure 4: Initial pressure distribution in reservoir model

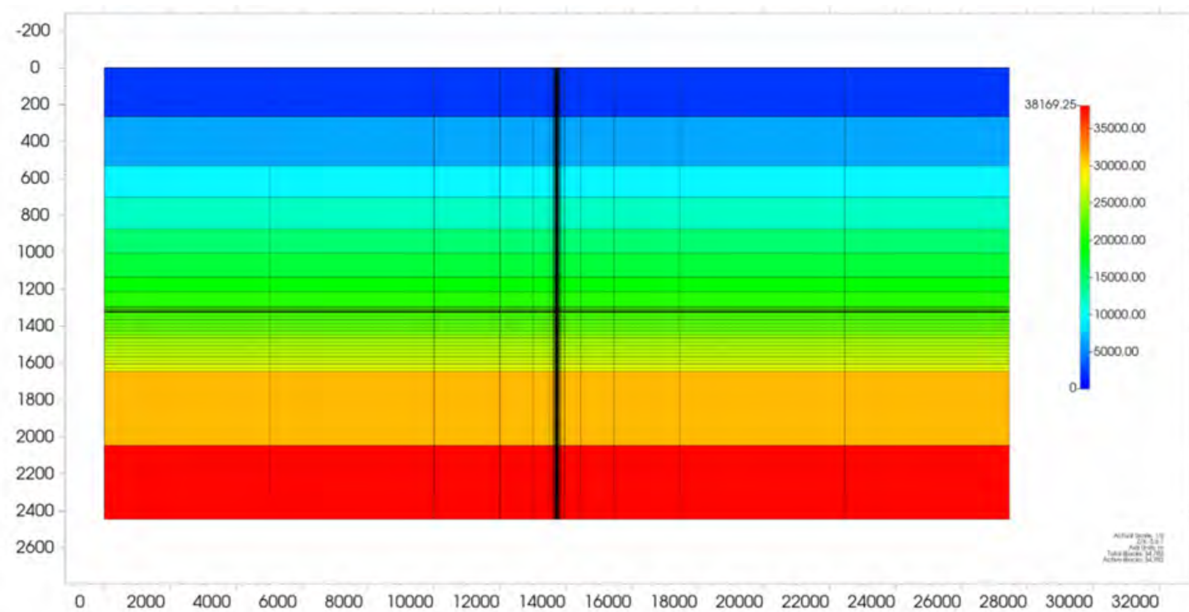


Figure 5: Effective vertical stress in the GM model

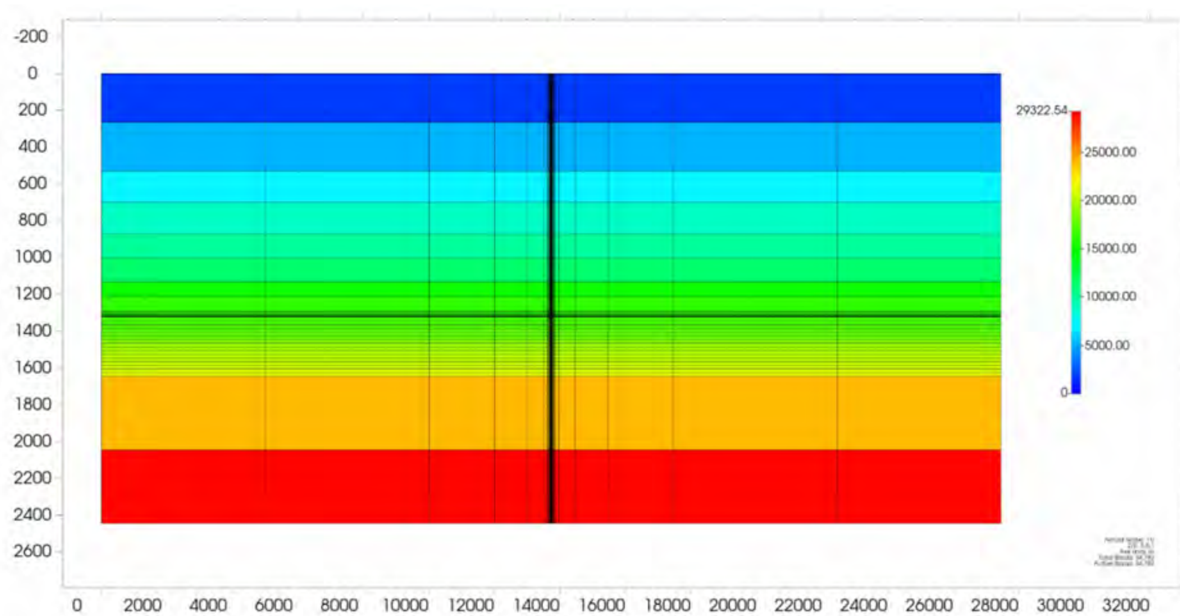


Figure 6: Effective minimum horizontal stress in the GM model

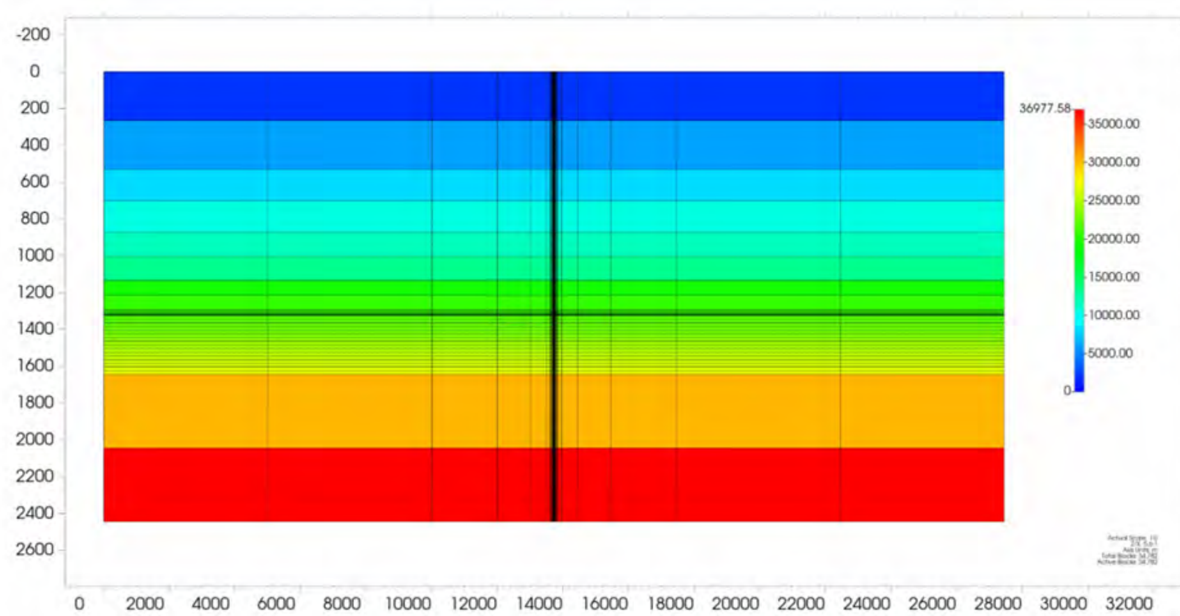


Figure 7: Effective maximum horizontal stress in the GM model

3.4 Basic reservoir and geomechanical properties

3.4.1 Basic reservoir properties

The current model employs average reservoir properties, and no lateral heterogeneity has been accounted for. These properties were supplied by the client. **Figure 8** and **Figure 9** depict the reservoir's porosity and horizontal permeability (kh), respectively. It is important to note that vertical permeability (kv) is set at 10% of kh, except in one sensitivity case where kv/kh ratio is adjusted to 1.0. In the simulations, a vertical permeability (kv) of 1e-4 md and a horizontal permeability (kh) of 1e-3 md was assigned to the Ireton caprock formation. This permits some pore pressure diffusion within the caprock, representing a conservative approach (worst-case scenario) for assessing caprock integrity.

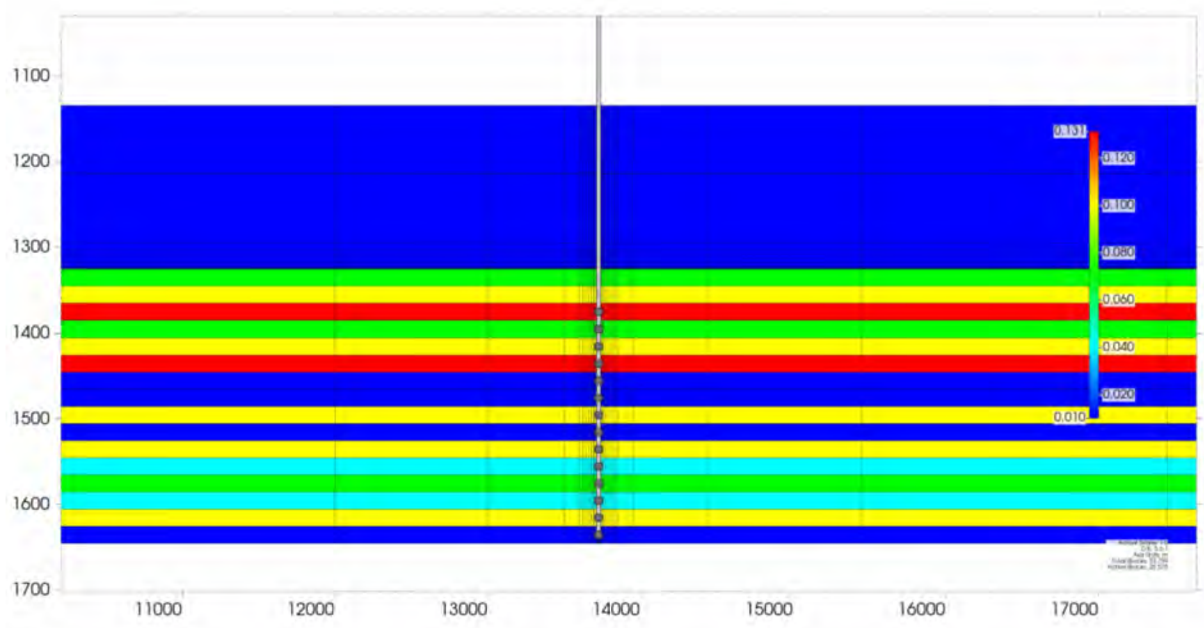


Figure 8: Reservoir porosity model in the reservoir model

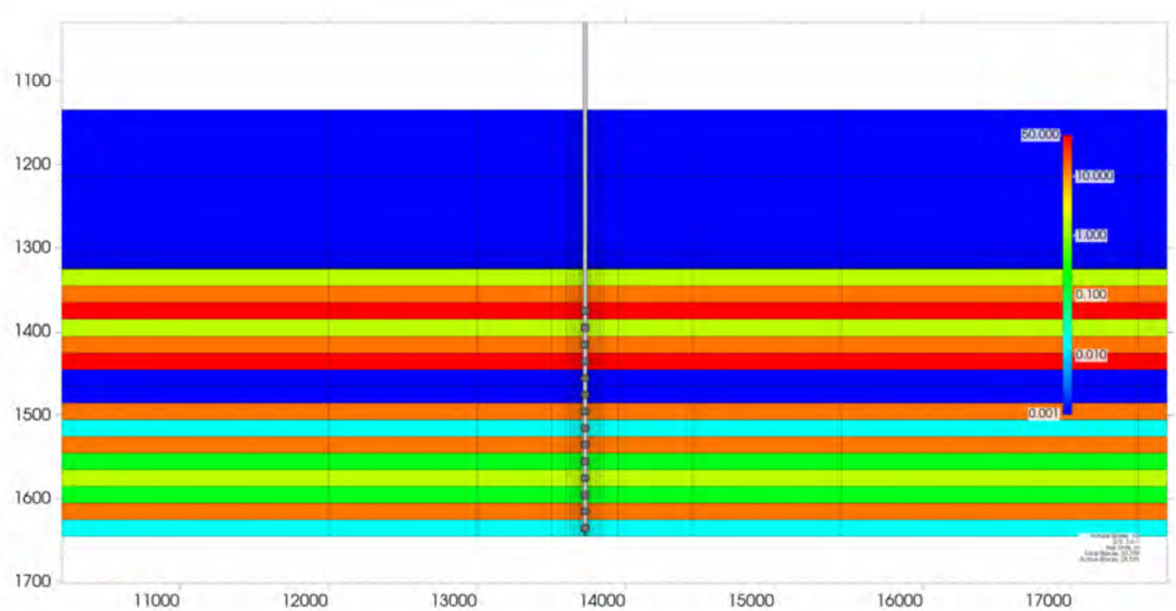


Figure 9: Reservoir permeability model (horizontal perm) in the reservoir model

3.4.2 Basic geomechanical properties

The geomechanical material properties input into the model were derived from 1D MEM data provided by the client from well BLCV LEGAL 16-29-57-25. For all the formations, a linear elasticity model was employed. The input geomechanical parameters are listed in **Table 2** for the base case. The distributions of Young's modulus and Poisson's ratio are given in **Figure 10** and **Figure 11**.

Table 2. List of mechanical properties

CMG Grid	Formation	Lithology	Elevation (SS)	Depth (m)	Es, kPa	Pois	Cohesion	Fric_ang
Milk River	Lea Park	shale	347.0	368.4	8.21E+06	0.37	3.24E+03	25.47
	Milk River	shale	260.0	455.4				
Colorado	Colorado Gp	shale	185.0	530.4	9.50E+06	0.35	3.40E+03	25.91
	ond White Sp	shale	6.0	709.4				
	ase Fish Scale	shale	-84.0	799.4				
	Viking	sandstone	-113.0	828.4				
	Joli Fou	shale	-134.6	850.0				
Manville	Manville	sandstone	-157.0	872.4	1.51E+07	0.32	5.03E+03	29.4
	Glauconite	sandstone	-297.0	1012.4				
	Ostracod	shale	-319.0	1034.4				
	Ellerslie	sandstone	-345.0	1060.4				
Wabamun	Wabamun	limestone	-419.0	1134.4	3.91E+07	0.29	1.60E+04	37.57
	Graminia	shale	-460.0	1175.4				
	Blueridge	limestone	-468.0	1183.4				
	Calmar	shale	-492.0	1207.4				
	Nisku	dolomite	-495.0	1210.4				
Ireton	Ireton	shale	-580.0	1295.4	4.18E+07	0.28	3.23E+04	37.96
					3.08E+07	0.29	8.83E+03	34.27
Reservoir	Leduc	dolomite	-611.0	1326.4	4.52E+07	0.28	1.93E+04	38.87
	Lower Leduc	dolomite	-723.0	1438.4	5.65E+07	0.27	3.10E+04	40.21
	Cooking Lake	limestone	-772.0	1487.4	5.55E+07	0.28	2.22E+04	40.48
Base	Base			2287.36	4.83E+07	0.26	2.17E+04	40

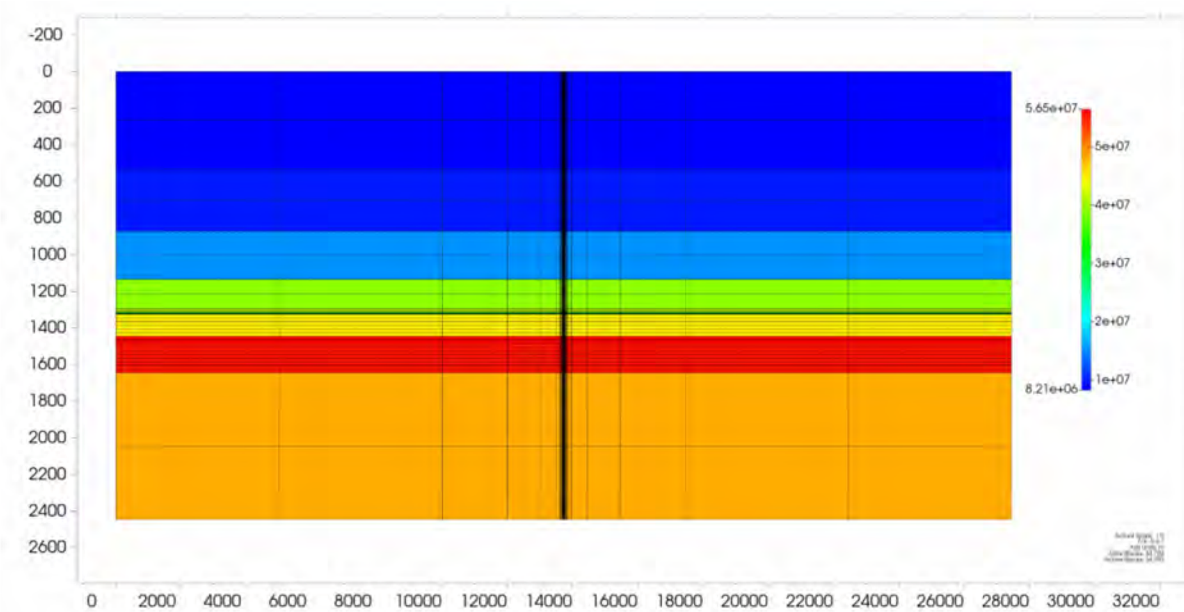


Figure 10: Young's modulus in the GM model

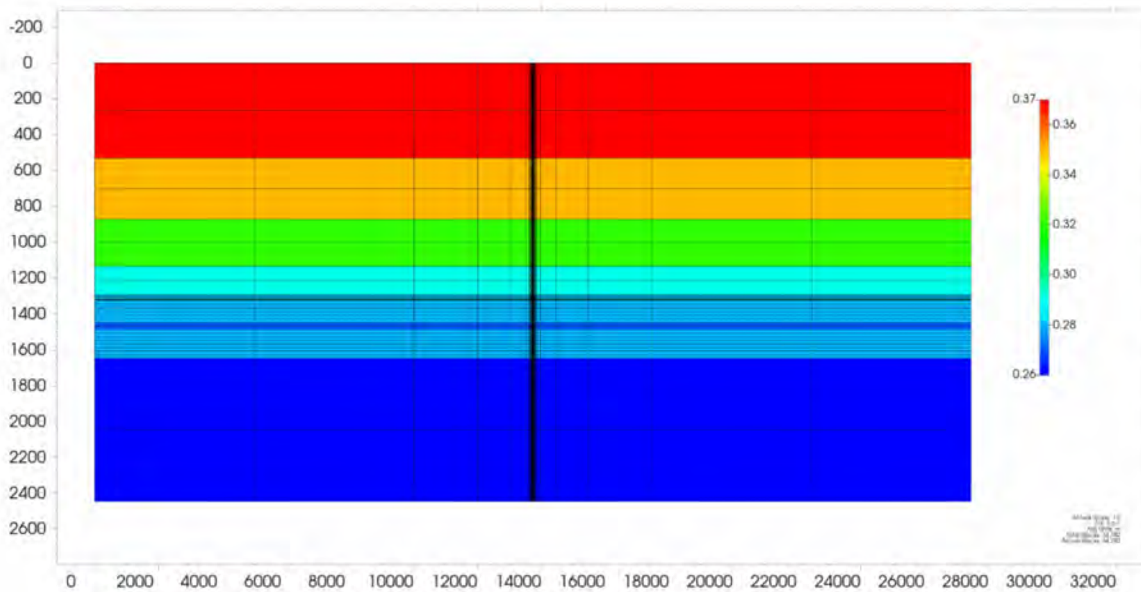


Figure 11: Poisson's ratio in the GM model

3.5 Simulation case table

Nine distinct simulation cases were conducted to assess how different operational and geological scenarios affect reservoir and caprock deformation (**Table 3**). The uncertainty surrounding in situ stress magnitude estimates was evaluated using a simulation with a lower bound in situ stress condition. The study began with two foundational cases: injections into the Leduc and Cooking Lake formations, both at 5°C with a rate of 0.5 Mtpa. In Basecase2 (Case 2), injection proceeded exclusively in the Cooking Lake formation, utilizing the same temperature and rate as Basecase1 (Case 1). Subsequent variations built upon these base scenarios, introducing temperature adjustments—one case at 1°C and another at 20°C—while keeping the injection rate steady at 0.5 Mt pa. The suite of simulations further probed the ramifications of heightened vertical permeability, presenting a Kv/Kh ratio of 1 within the Leduc (Case 4), a low initial stress profile based on SLB's 1DMEM in Cooking Lake (Case 5), and an elevated linear thermal expansion coefficient (1.5e-5/°C) in Cooking Lake (Case 6). Apart from Case 3, which scaled back the injection rate to 0.07 Mtpa, all other cases adhered to the 0.5 Mt pa rate. An additional case considered an isothermal condition, omitting temperature fluctuations yet preserving the injection rate constant. This was meant to capture the poroelastic effects only which dominate away from the cooled zone. The design of each scenario was meticulous, aiming to singularly delineate and analyze the effects of specific geomechanical and thermal factors on how the reservoir reacts to injection activities.

Table 3: Summary of simulation cases

Case #	Description	Temp, degC	Rate, Mtpa
1	Base case---inject from Leduc , T=5 C	5	0.5
2	Base case---inject from CookingLake , T=5 C	5	0.5
3	Based on Case 2, CookingLake Injection	5	0.07
4	Based on Case 1 , Leduc, T=5C, High Kv, Kv/Kh=1	5	0.5
5	Based on Case2 CookingLake, T=5C, Low Initial Stress	5	0.5
6	Based on Case 2, Cooking Lake, T=5 C, High thermal expansion	5	0.5
7	Based on Case2 CookingLake, T=1C	1	0.5
8	Based on Case2 CookingLake, T=20C	20	0.5
9	Isothermal case	N/A	0.5

4 Summary of Geomechanical Results

In summary, the following conclusions can be drawn from the current study:

4.1 Low risk of caprock tensile fracturing and shear failure.

In all simulation cases, the direct caprock (lower Ireton) showed a low risk of both tensile fracturing and shear failure. Shear failure is assessed based on the shear stress level (SSL), while tensile fracturing is evaluated using the tensile stress level (TSL). By definition, TSL does not take into account the tensile strength of the rock, providing a conservative approach. This assumes that the rock hosts natural fractures oriented in a preferential direction and that fracturing occurs once the minimum effective horizontal stress reaches zero.

Figure 12 displays time series plots of tensile stress level (TSL) and shear stress level (SSL) variations observed in a grid block situated at the caprock base near the injector, for all simulated cases. The trend indicates a decrease in SSL during the injection period in all Cooking Lake scenarios, with a minor rebound post-shut-in, except in the two Leduc injection cases. In these exceptions, the SSL falls in the initial year, increases as injection continues, and finally decreases after injection ceases. This pattern is attributable to the interplay between thermal contraction and pore pressure-induced expansion. The injection of cold CO2 leads to a temperature drop and consequent contraction of the reservoir rock. This causes an initial increase of the horizontal stresses at the caprock base (a local arching effect). Since the caprock is within a normal faulting stress regime, this increase in horizontal stresses results in initially a lowering of the shear stress and thus a reduction in SSL. However, as the pressure from the Leduc diffuses into the Ireton and the cooled zone continues to grow, the shear stress in the Ireton increases with a continued decrease in the effective stresses. This causes an elevation in the SSL, but it still remains at very low values. For the cases injecting into the Leduc, changes in Ireton shear stress are primarily attributed to variations in pore pressure and temperature within the Ireton caprock. Initially, the reduction in shear stress is largely due to the diffusion of pore pressure into the Ireton, which reduces the effective stress and causes the Mohr Circle to shrink (the vertical stress decreases more significantly than the horizontal stress, due to the effects of local pore pressure diffusion). In subsequent stages, while the pore pressure stabilizes, temperature continues to fall, as the temperature front progresses more slowly than the pore pressure. This results in thermal contraction within the Ireton, causing an additional reduction in the normal effective stress. However, the change in shear stress is less pronounced than that in normal stress, leading to an increase in SSL. Figures 13 and 14 present the changes in pressure, temperature and stresses for the selected grid block used to plot SSL for case 1 and 2, respectively. For the Leduc injection case, significant changes in both pressure and temperature at the base of the caprock have led to larger stress changes compared to the Cooking Lake injection case. In contrast, the Cooking Lake injection case experienced minimal changes in pressure and temperature, with the mechanism of shear stress change within the caprock primarily due to deformation inside the reservoir. Nonetheless, in all instances, the SSL values remain below the threshold of 0.25, well away from the shear failure point of SSL equal to 1.

The time variation of TSL at the base of the caprock for all cases is also shown in **Figure 12**. For Cooking Lake injection cases, TSL decreases over time during injection and slowly rebounds after the injection stops. This occurs because the injection interval is relatively far from the caprock, preventing caprock cooling effects in these cases. The slight TSL decrease is primarily due to a small pore pressure decrease at the caprock base caused by the coupled poroelastic effect. In contrast, for Leduc injection cases, TSL increases during injection and decreases afterward. The caprock cooling effect is more pronounced in the Leduc injection cases, leading to a decrease in effective stress and, consequently, an increase in TSL. Among all sensitivity cases, Case 6 exhibits the most significant changes in TSL due to the higher thermal expansion coefficient used, resulting in increased induced stress changes due to the cooling of the rock.

A grid block was selected to plot the stress path at the base of the caprock (Ireton) for two base cases (Case 1 and Case 2), presented in **Figure 15** and **Figure 16**, respectively. The results indicate that the stress state within the lower Ireton remains within the elastic range, well away from both shear failure and tensile fracturing. **Appendix A** provides all the contour plots of SSL at 1,5 and 15 years of injection for all the cases.

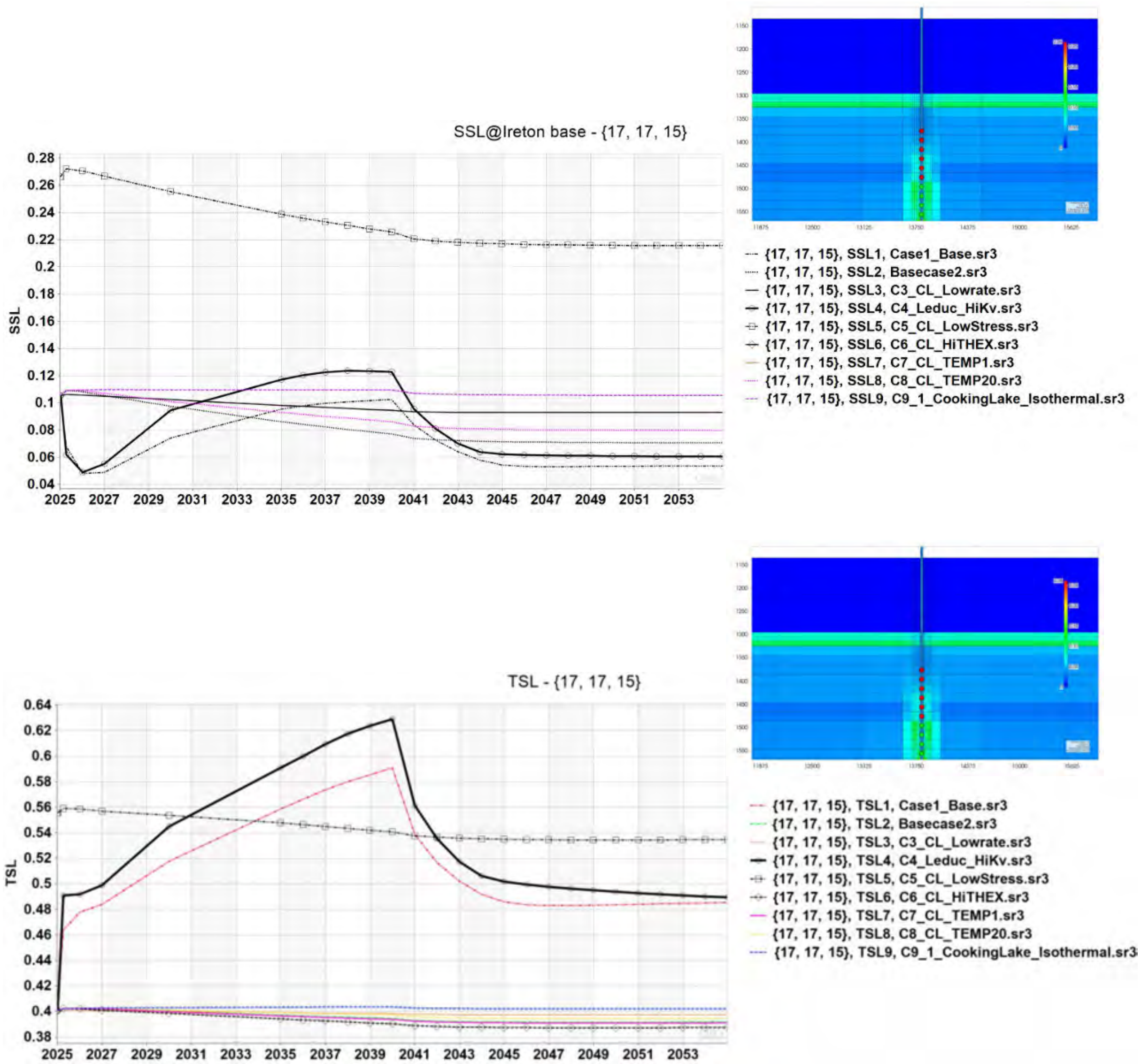


Figure 12: SSL and TSL change with time in all cases (on a grid block at the base of the caprock)

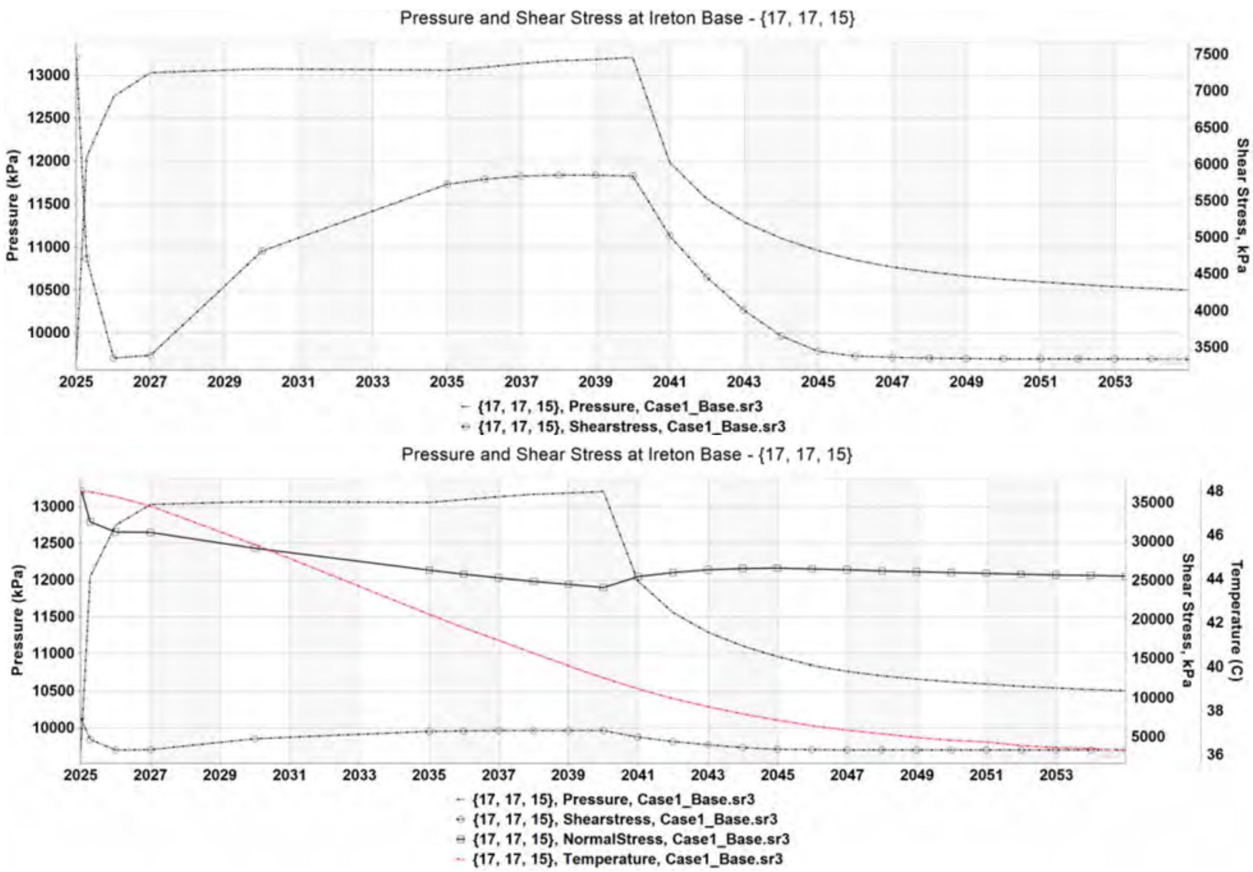
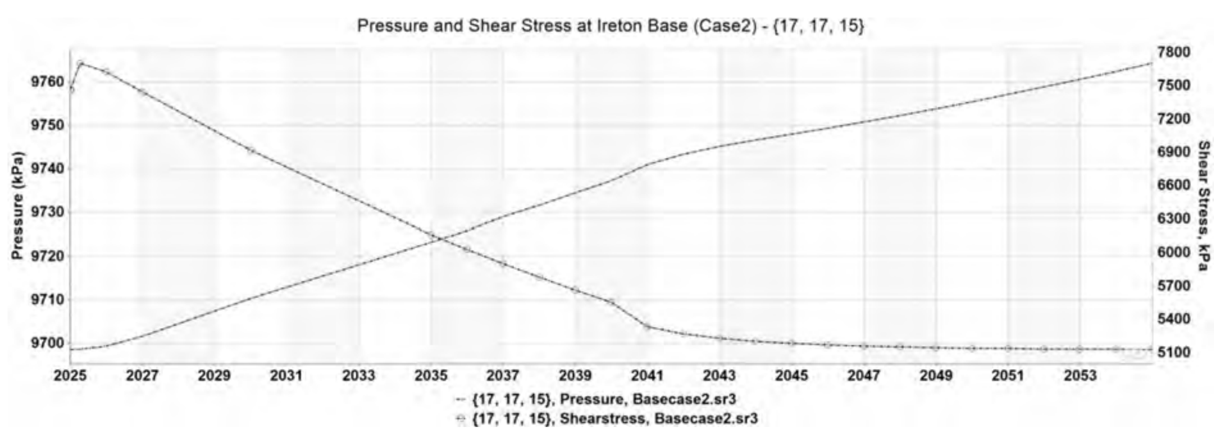


Figure 13: Pressure and temperature changes on a grid block at the base of caprock for case 1



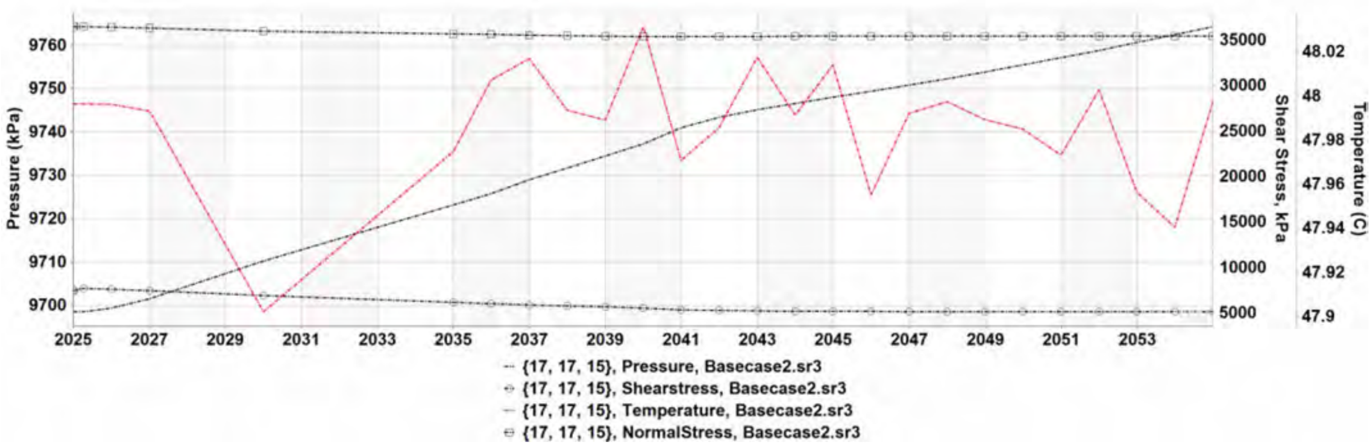


Figure 14: Pressure and temperature changes on a grid block at the base of caprock for case 2

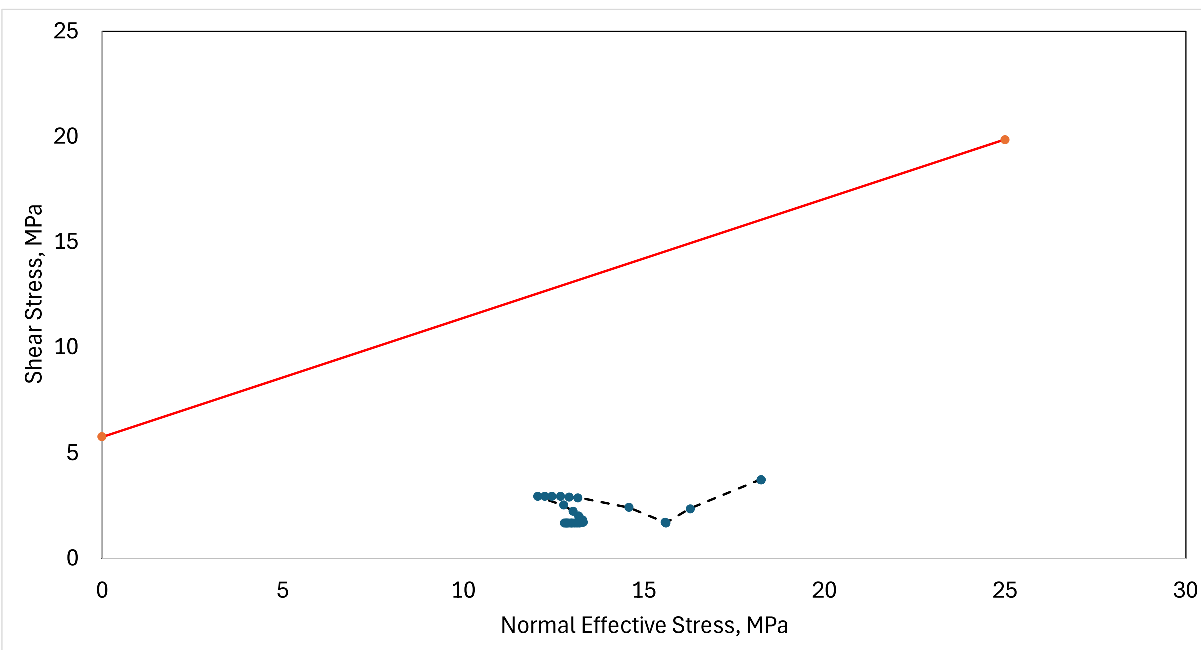


Figure 15: Stress path at the base of the caprock (near injection well) for Case1.

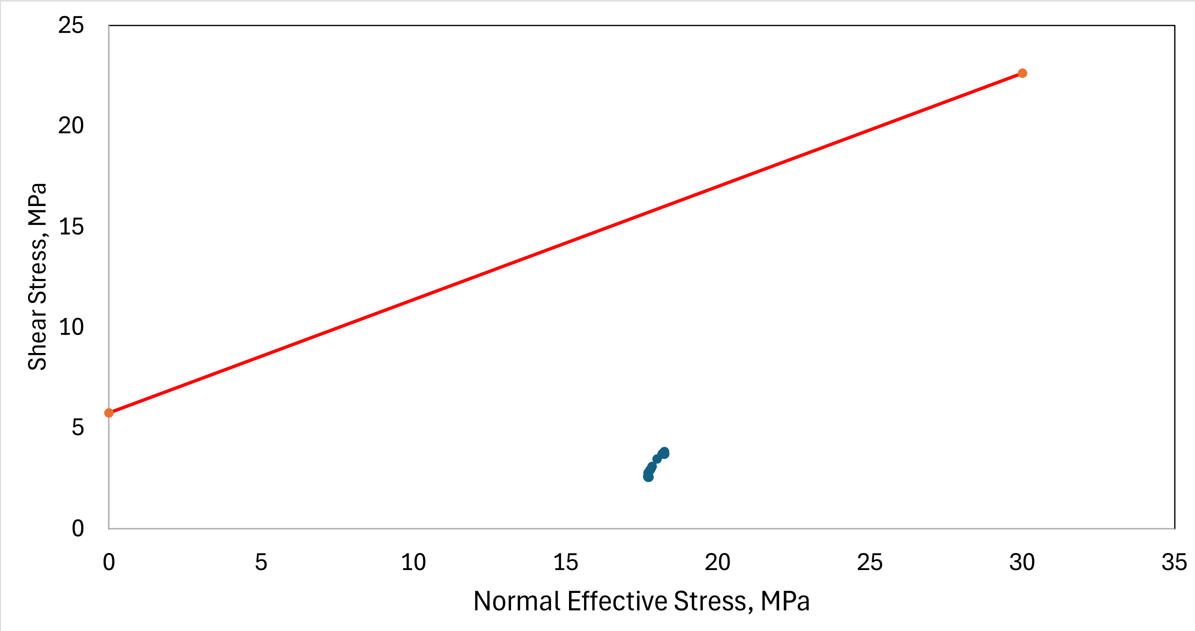


Figure 16: Stress path at the base of the caprock (near injection well) for Case2

4.2 Cooling-induced tensile fracturing in near-wellbore reservoir rock

The sustained injection of cold CO2 at industrial scales into subsurface rock formations that are typically warmer will cause significant cooling, potentially altering the rock stress and leading to tensile fracturing. Thermoelastic shrinkage within the rock induces a reduction in effective stress within the cooled zone and a corresponding transfer of stress to the surrounding uncooled areas. In reservoirs situated in strike-slip or normal faulting stress regimes, the decrease of the minimum effective horizontal stress is particularly critical. This decrease in stress can lower the threshold necessary for the initiation and propagation of tensile fractures. In all simulated scenarios, with the exception of the isothermal case and the case with injection at 20°C, tensile fracturing of the reservoir rock near the wellbore was observed. It's important to note that the tensile stress level (TSL) was used as the criterion for the initiation of tensile fracture. This method is conservative, as it operates on the assumption that natural fractures oriented in favorable directions will open once the minimum effective horizontal stress (Shmin’) drops to zero. **Appendix A** lists the TSL plots in all cases. **Figure 17** illustrates the TSL at injection depth for case 6 at the end of injection. Among all sensitivity cases, this is the case with the largest changes in TSL (due to the high thermal expansion coefficient used and resultant increased induced stress changes due to cooling of the rock).

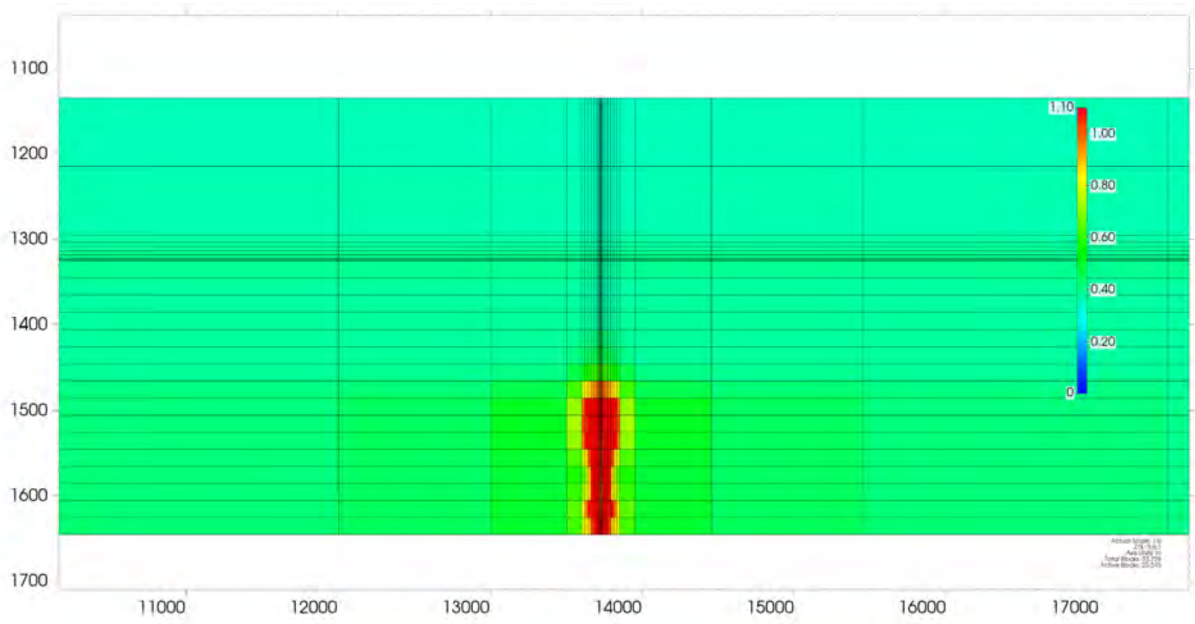


Figure 17: TSL for case 6 at the end of injection

4.3 Wellbore stability due to cold CO2 injection

The injection of cold CO2 influences wellbore stability by increasing pore pressure and reducing effective stress. In this section, a fully coupled thermal-hydro-mechanical (THM) finite element simulation in ABAQUS™ was used to investigate the cooling induced wellbore stability during CCS injection. The formulations of the fully coupled THM FEM modeling can be found in the publication by Lewis et al.[4] The simulation considers the following mechanisms:

1. **Thermal stress**: the thermal stress was simulated in ABAQUS by considering the linear coefficient of thermal expansion.
2. **Thermally induced pore pressure**: the pore pressure change from cooling was simulated by considering the linear coefficient of thermal expansion of water.
3. **Elasto-Plasticity**: the plastic deformation of rock was simulated by using the Mohr-Coulomb plasticity model. ABAQUS is famous for its fast convergence and accuracy in terms of rock's plastic simulations.
4. **Poroelastic effects**: the fully coupled FEM simulations automatically simulate the poroelastic effects by solving Biot's equations in a fully coupled formulation.

[4] Lewis, R. W., et al. (1986). "*A coupled finite element model for the consolidation of nonisothermal elastoplastic porous media*." Transport in Porous Media **1**(2): 155-178.

4.3.1 FEM model

Figure 18 presents the finite element method (FEM) mesh for the wellbore model in ABAQUS, utilizing elements that are fully coupled with thermal-hydraulic-mechanical (THM) processes. The model spans a 10m x 10m area, featuring a wellbore with a diameter of 0.2m. The simulation proceeds in three main steps:

1. **Stress Initialization**: Establishing the baseline stress conditions in the model.
2. **Wellbore Drilling**: This step involves removing the initial wellbore boundary conditions and simulating the drilling process by applying a mud weight of 1.1 g/cc.
3. **CO2 Injection**: Injecting cold CO2 into the wellbore at a consistent pressure and temperature to evaluate the model's response. This involves maintaining constant pore pressure and temperature conditions on the circular wellbore surface. An injection period of 1 hr was simulated to establish a stable near wellbore pressure and temperature distribution.

The material properties for the finite element method (FEM) simulations were taken from CMG simulations. These values were used to determine whether cooling processes could potentially induce tensile fractures near the wellbore. It should be noted that zero effective stress was used as a criterion for the initiation of tensile fractures.

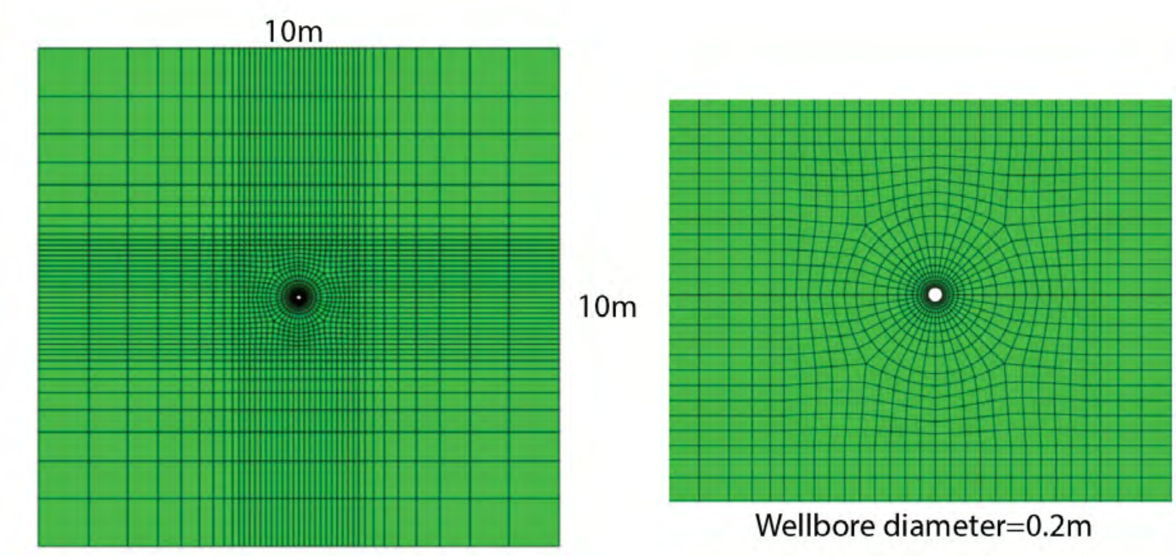


Figure 18: FEM model (Plane strain, 4 nodes coupled THM element in ABAQUS)

4.3.2 Main results

Simulations to assess wellbore stability within the Leduc and Cooking Lake formations were conducted. The bottom-hole injection temperature was set at 5°C. For the bottom-hole pressure, data from the CMG simulations was used: 18 MPa for Cooking Lake and 14 MPa for Leduc, with the latter's pressure resulting from injectivity behavior of the Leduc. **Figure 19** and **Figure 20** illustrate the distributions of effective hoop stress ($\sigma'_{\theta\theta}$) around the borehole for the Leduc and Cooking Lake cases, respectively. For contour plotting, the tensile strength of the rock at zero effective stress was set as the cutoff threshold. This conservative approach assumes that the near-wellbore region contains natural fractures that can open once the effective stress reaches zero. This is also consistent with the TSL approach taken in the CMG simulations. Areas shaded in grey represent zones where the effective hoop stress reaches zero, indicating the presence of tensile fractures. Based on this criterion, it is shown that the wellbores at both Cooking Lake and Leduc show localized fractured zones due to a combination of cooling and increased pressures due to injection.

Sensitivity analyses were performed on the Cooking Lake injection to assess the effects of varying injection pressures and temperatures on the potential for tensile fractures around the borehole (**Figure 21** to **Figure 25**). Simulations were conducted at a constant injection pressure of 18 MPa with temperatures of 10°C and 20°C. At a reduced pressure of 15 MPa, temperatures of 5°C and 10°C were simulated. The results indicate that cooling significantly contributes to the formation of tensile fractures. Notably, tensile fractures were avoided at an injection pressure of 18 MPa and a temperature of 20°C. Reducing the injection pressure to 15 MPa while maintaining a temperature of 10°C diminished but did not eliminate the tensile fracture zone. It is important to note that decreasing the injection pressure from 18 MPa to 15 MPa could significantly affect injectivity. Although the modelling suggests it is likely tensile fracturing would occur near the wellbore the zone of fracturing is relatively small and confined to the cooled zone. Thus, the thermal fracturing may enhance well injectivity but does not pose a risk to CO2 containment as the cooled zone is limited radially from the perforated zone (as computed in the CMG simulations), and there is no cooling in the Ireton caprock.

Both the CMG and ABAQUS simulations predicted tensile failure near the wellbore during cold CO2 injection, identifying a potential failure zone within a limited radius from the wellbore. According to rock mechanics theory, such tensile failure could increase the rock's permeability, potentially enhancing well injectivity. Although the CMG simulations suggest that the extent of the zone with potential for tensile fracturing could be many tens of meters (for a sustained CO2 injection operation), it is not considered a risk to caprock integrity for the following reasons:

1. The extent of the cooled zone is limited to a local area surrounding the perforated interval. The risk of induced fracturing is contained within this zone. Since these fractures are not primarily pressure driven, but temperature driven, although they may enhance injectivity they do not have the potential for uncontrolled vertical growth.
2. There is significant experience with waterflood induced fracturing in the Leduc and similar zones within Alberta. Water has a much higher specific heat than CO2 and, therefore, a greater ability to cool a larger rock volume. Although waterflood temperatures are not as low as the minimum temperature sensitized in this study, industry

experience has not had any recorded containment problems associated with injecting water cooler than the reservoir for extended periods of time.

3. The sensitivity cases show that by injecting the CO2 in a perforated interval vertically separated from the caprock the temperature effects and risk of fracturing to the caprock is significantly reduced.

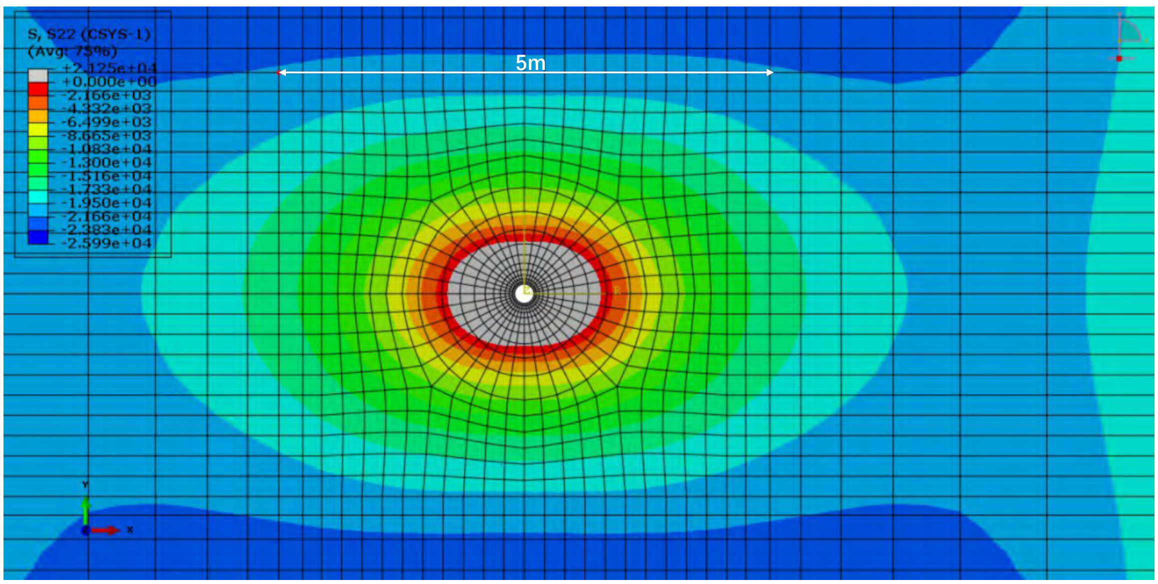


Figure 19: Tensile failure zone for Cooking Lake injection (T=5 degC and P=18 MPa). The figure plotting effective hoop stress ($\sigma_{\theta\theta}$)around borehole

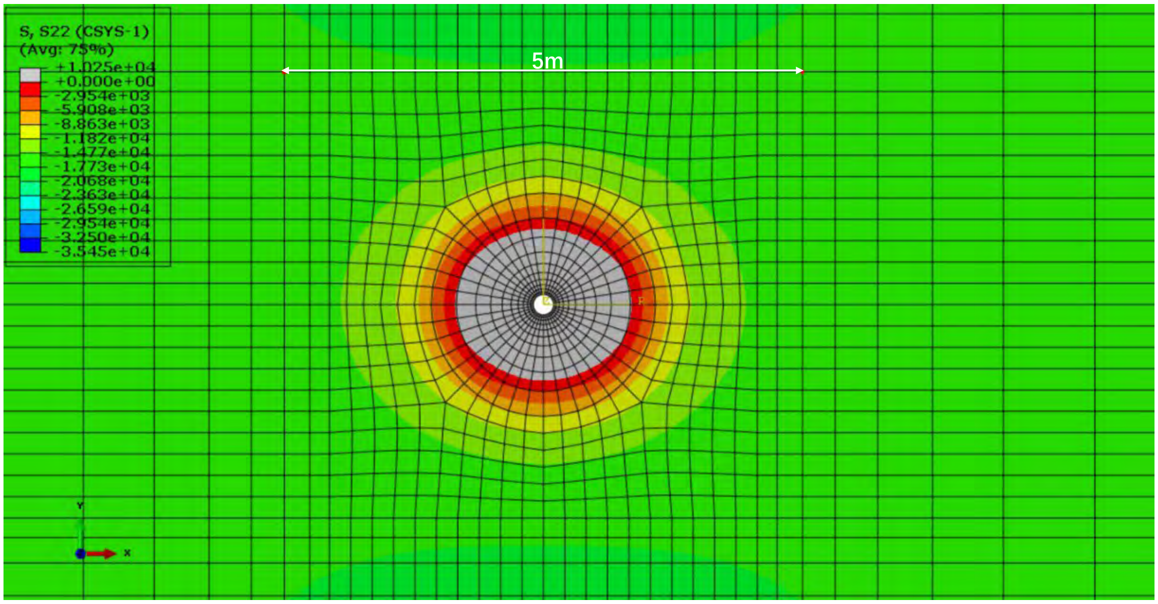


Figure 20: Tensile failure zone for Leduc injection (T=5 degC and P=14 MPa). The figure plotting effective hoop stress ($\sigma_{\theta\theta}$)around borehole

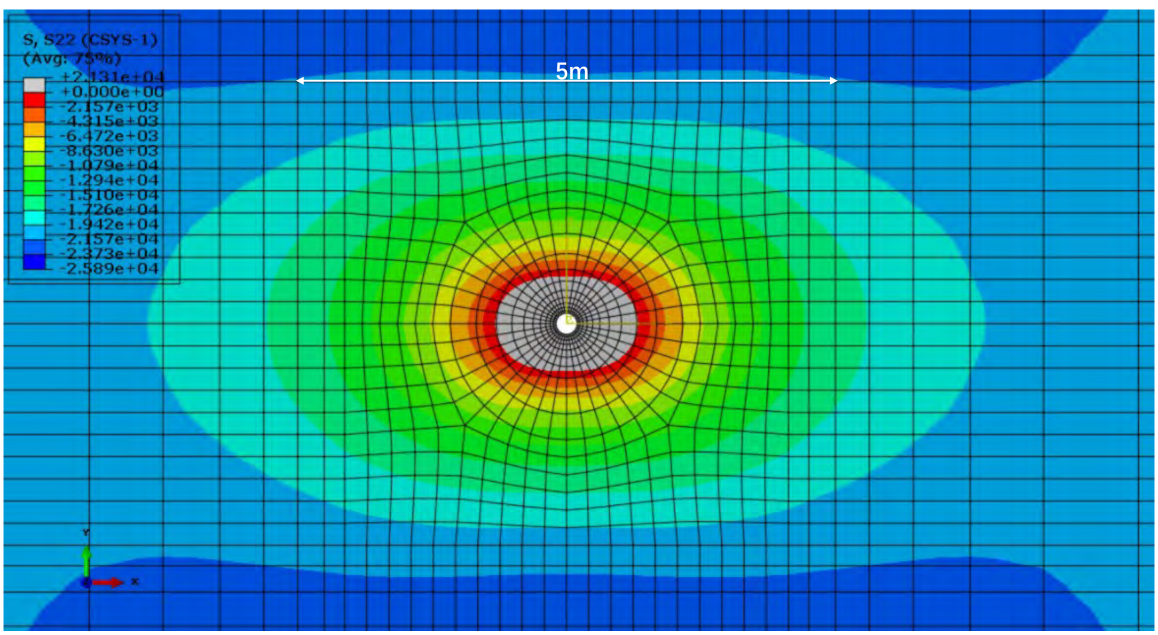


Figure 21: Tensile failure zone for Cooking Lake injection (T=10 degC and P=18 MPa). The figure plotting effective hoop stress ($\sigma_{\theta\theta}$)around borehole

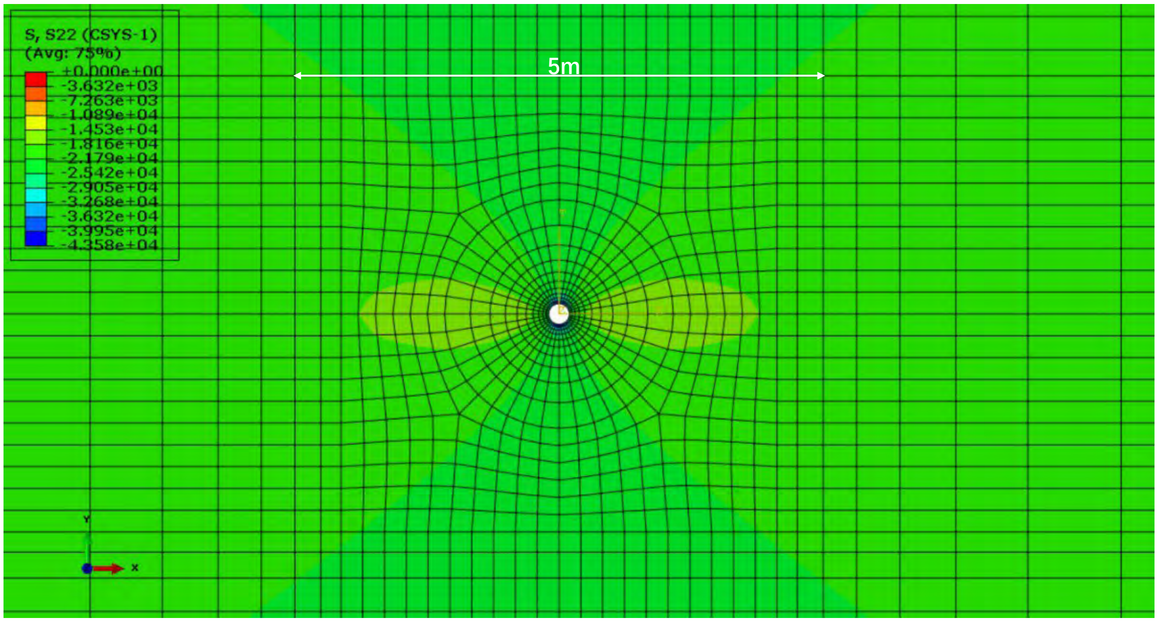


Figure 22: Tensile failure zone for Cooking Lake injection (T=20 degC and P=18 MPa). The figure plotting effective hoop stress ($\sigma_{\theta\theta}$)around borehole

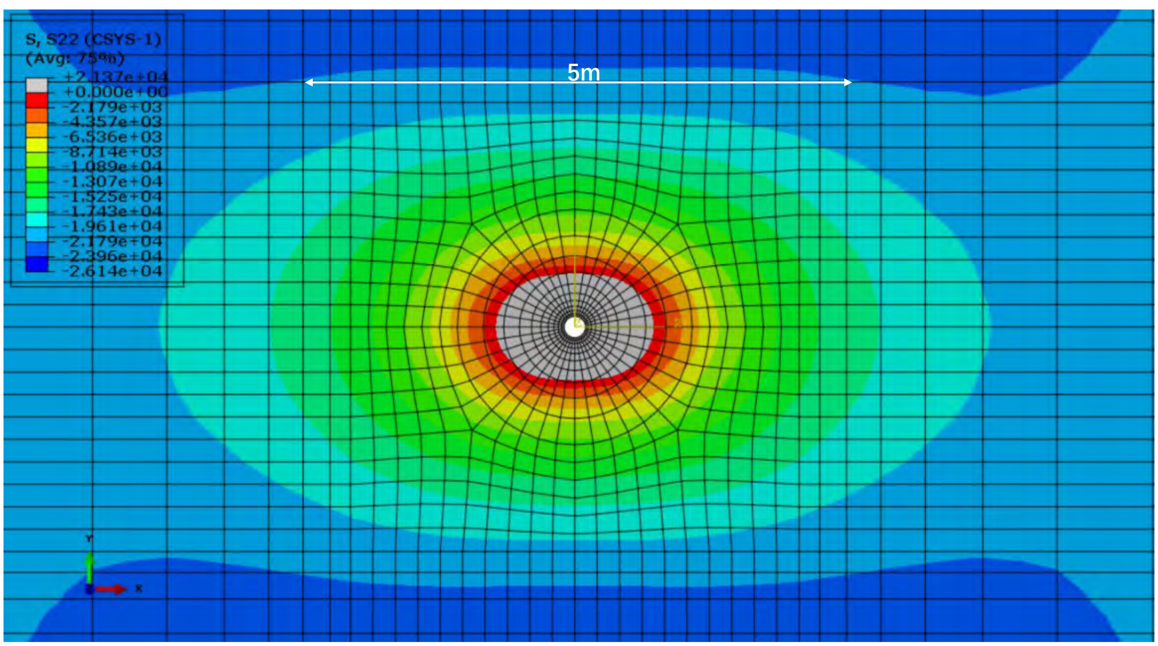


Figure 23: Tensile failure zone for Cooking Lake injection (T=5 degC and P=15 MPa). The figure plotting effective hoop stress ($\sigma_{\theta\theta}$)around borehole

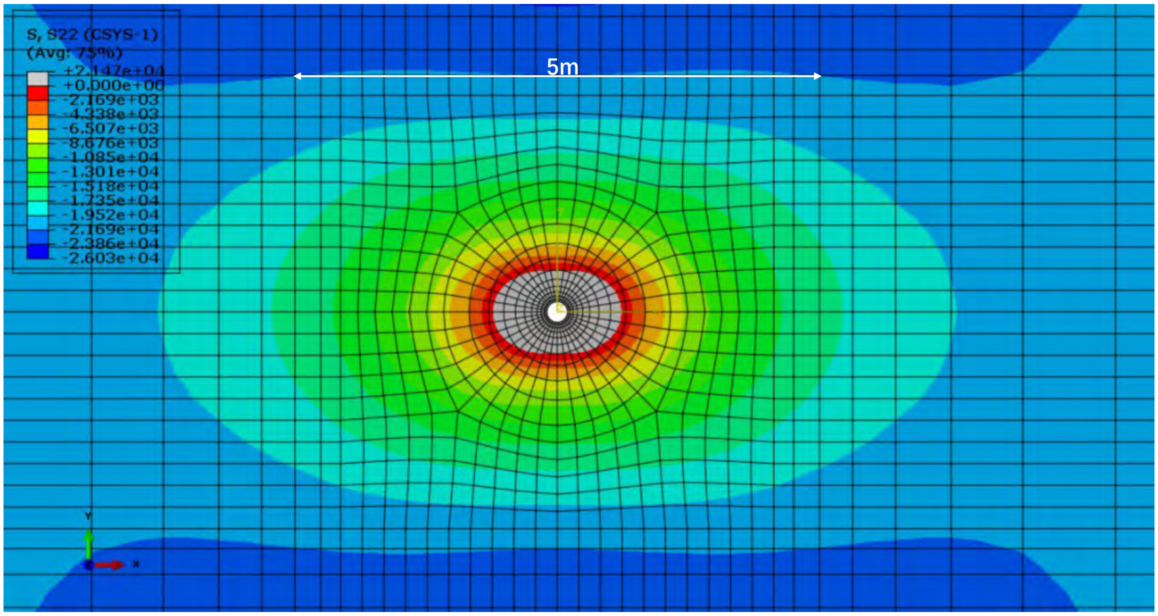


Figure 24: Tensile failure zone for Cooking Lake injection (T=10 degC and P=15 MPa). The figure plotting effective hoop stress ($\sigma_{\theta\theta}$)around borehole

4.4 Fault slip potential analysis

Currently, the geological model for the Bison CCS hub does not include fault mapping. Consequently, for this analysis, the fault orientation representing a worst-case scenario that is most favorable for fault slip was assumed. Given that the maximum horizontal stress orientation (Shmax) is NE45°, the most critical fault strikes would be NE75° or NE15°. Using the stress gradients from the Cooking Lake and Leduc formations, the pore pressure required to induce fault slip was estimated under these conditions. Additionally, as part of the sensitivity analysis, a range of fault dips from 15° to 90° was explored, specifically at 15°, 30°, 45°, 60°, 75°, and 90°.

Figure 25 and Figure 26 display the pore pressures required to induce fault slippage, derived from the stress gradients in the Leduc and Cooking Lake, respectively. The results indicate that a minimum pore pressure increase of 15 MPa is necessary to induce slip of a fault oriented in the most critical direction. Therefore, under the current injection design, the faults—if present—are unlikely to slip.

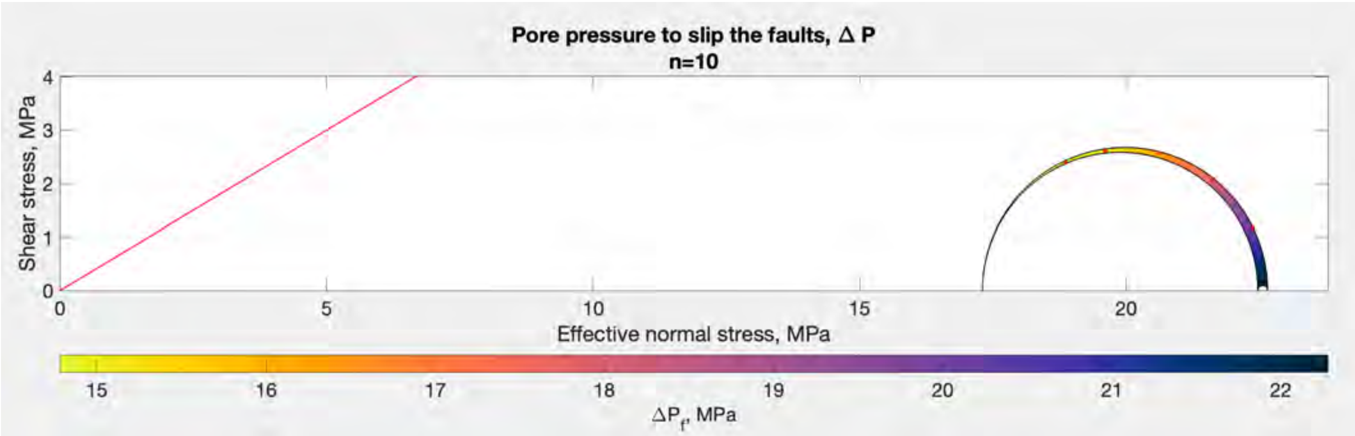


Figure 25: Pore pressure to slip the fault for Leduc stress profile

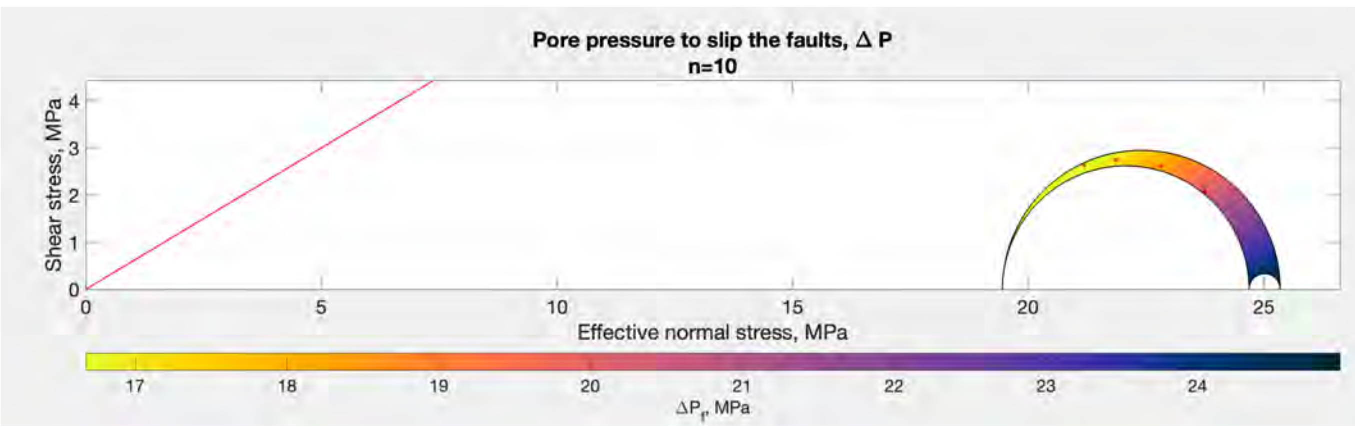


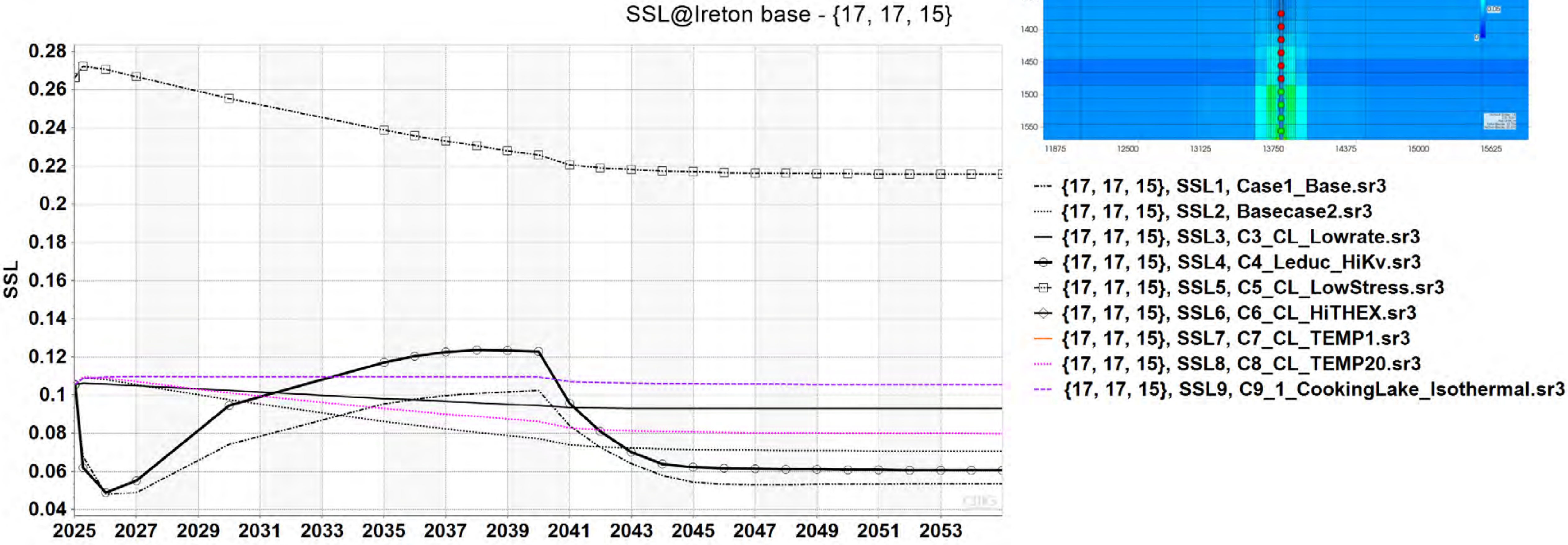
Figure 26: Pore pressure to slip the fault for Cooking Lake stress profile

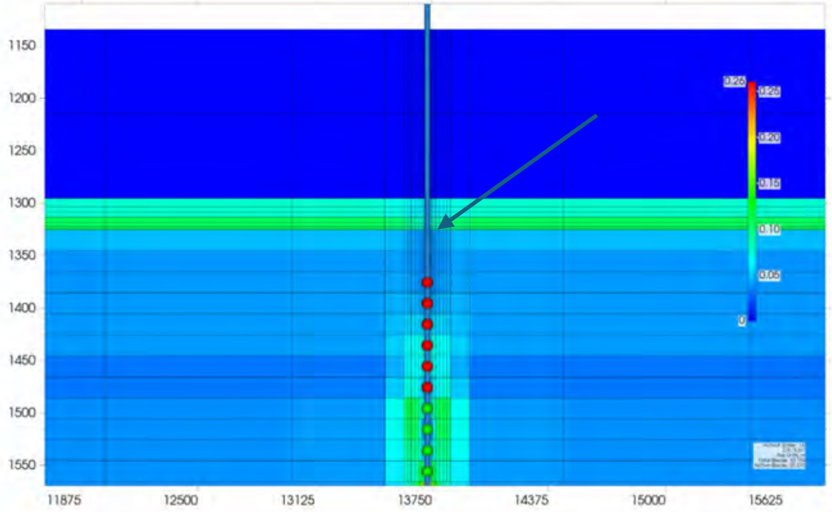
Appendix A: Simulation summary of all cases

Summary of GM Simulation Cases

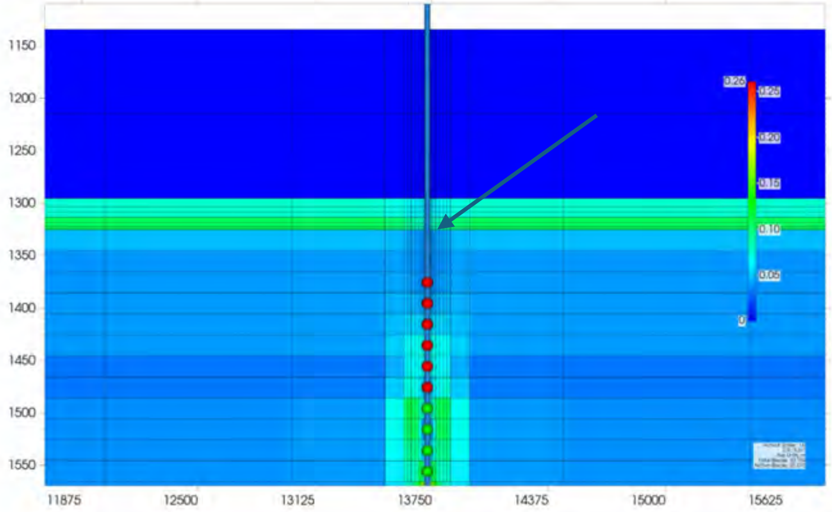
Case #	Description	Temp, degC	Rate, Mtpa
1	Base case---inject from Leduc , T=5 C	5	0.5
2	Base case---inject from CookingLake , T=5 C	5	0.5
3	Based on Case 2, CookingLake Injection	5	0.07
4	Based on Case 1 , Leduc, T=5C, High Kv, Kv/Kh=1	5	0.5
5	Based on Case2 CookingLake, T=5C, Low Initial Stress	5	0.5
6	Based on Case 2, Cooking Lake, T=5 C, High thermal expansion	5	0.5
7	Based on Case2 CookingLake, T=1C	1	0.5
8	Based on Case2 CookingLake, T=20C	20	0.5
9	Isothermal case	N/A	0.5

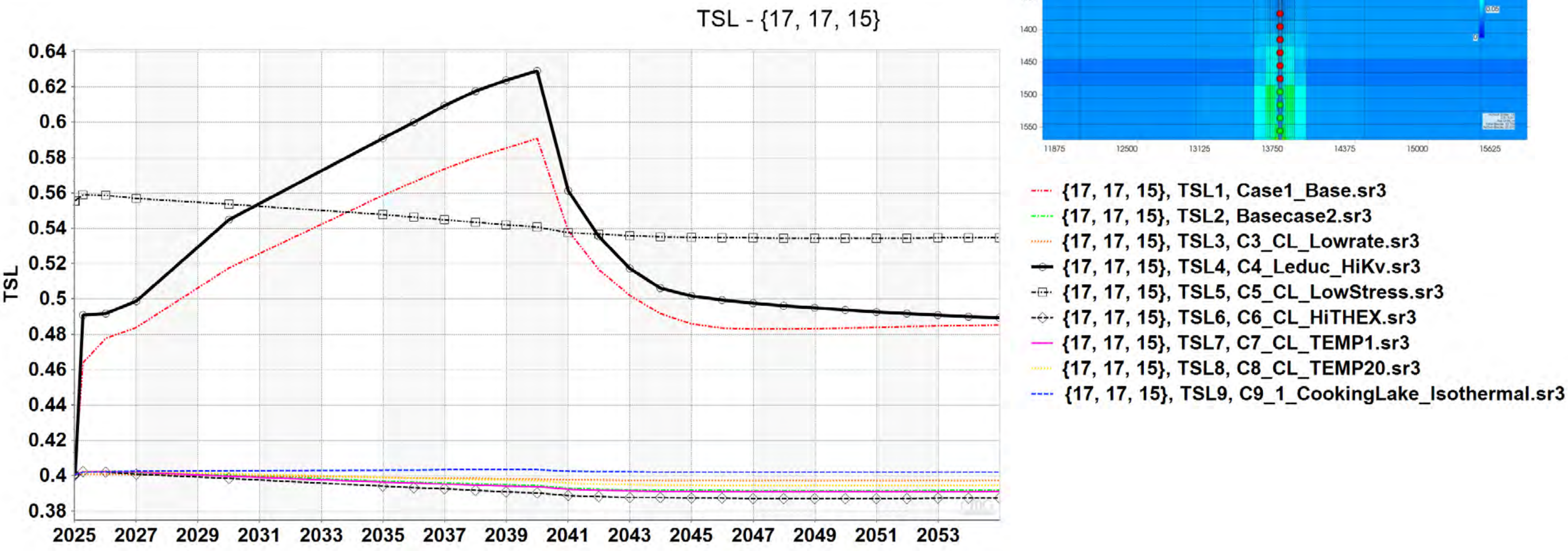
SSL in all cases





TSL in all cases





Some Geomechanics Definitions

UCS, Tensile Strength (Pt), SSL and TSL

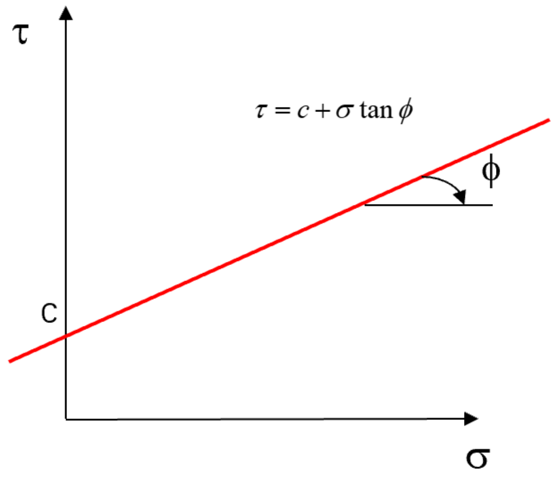
1. Calculate UCS from cohesion and friction angle in M-C criteria: $$UCS = 2C\cos\phi\frac{1+\sin\phi}{1-\sin\phi}$$

2. Tensile strength is usually taken as 10% of UCS. So, for the cooking lake, Pt=9.6MPa; For Leduc, Pt=8.0MPa

Caprock Integrity Analysis

Potential modes of Caprock failure

- Tensile fracturing ($P > \sigma_{min}$)
  - Monitor:
    - Tensile stress level (TSL) P/S_{min} = ratio of pressure to total minimum principal stress (dynamic fracture pressure) → tensile failure
- Shear fracturing (shear stress > shear strength)
  - Monitor:
    - Shear Stress Level (SSL) = ratio of maximum shear stress to shear strength → shear failure



Caprock Integrity Analysis
Potential modes of Caprock failure

Shear Failure Monitoring – Stress Level

- Based on:
  - Initial stress state and pressure
  - Mohr-Coulomb shear failure envelope

$$\boxed{(\sigma_d)_{\max} = \frac{2c\cos\phi + 2\sigma_3^{'}\sin\phi}{(1-\sin\phi)}}$$

  - Where:
    - σ_{dmax} = Maximum deviatoric stress (σ_1-σ_3)
    - c = material cohesion, ϕ = material friction angle
    - σ_3' = Minimum effective principal stress
- **SHEAR STRESS / SHEAR STRENGTH**

$$SSL = {\sigma_d}/{\sigma_{d\max}}$$

CMG Code for Calculating SSL

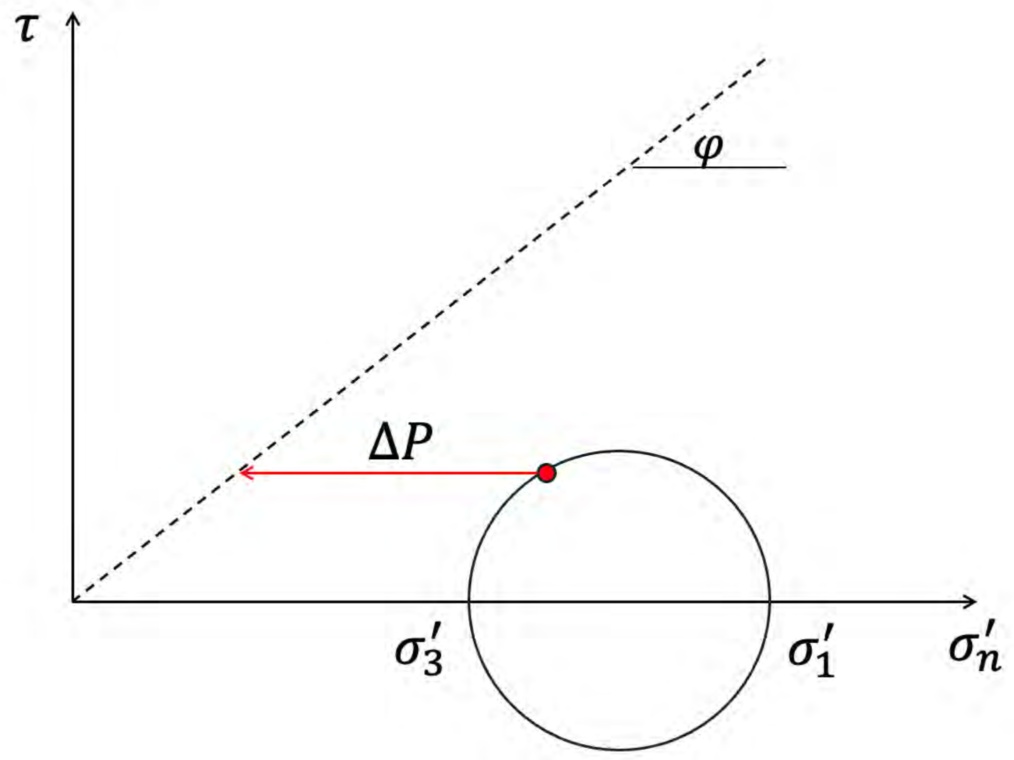
```
K = 0.001251
S1 = 0.563585
S3 = 0.193304
maxshear=(S1-S3)

cireton=8830
cLeduc=1.93e4
clowerLeduc=3.1e4
ccookinglake=2.17e4
cosireton=0.826
sinireton=0.563
cosleduc=0.778
sinleduc=0.627
coslowerleduc=0.764
sinlowerleduc=0.645
coscooking=0.761
sincooking=0.649

sd=0
SSLt=0
if K>=9 and K <=15:
            sd=(2*cireton*cosireton+2*S3*sinireton)/(1.0-sinireton)
            SSLt=maxshear/sd
if K>=16 and K<=21:
            sd=(2*cLeduc*cosleduc+2*S3*sinleduc)/(1-sinleduc)
            SSLt=maxshear/sd
if K>=22 and K<=23:
            sd=(2*clowerLeduc*coslowerleduc+2*S3*sinlowerleduc)/(1-
sinlowerleduc)
            SSLt=maxshear/sd
if K>=24 and K<=31:
            sd=(2*ccookinglake*coscooking+2*S3*sincooking)/(1-sincooking)
            SSLt=maxshear/sd
SSL=SSLt
```

Pore Pressure Required for Fault Slip

In the fault slip analysis, the pore pressure required for fault slip is evaluated (ΔP) to quantify the potential of fault slip. The possibility of a fault surface undergoing slip in a given stress field depends on its frictional characteristics (primarily controlled by rock type), the ratio of shear to normal stresses acting on the surface, and the pore pressure within the fault. Frictional faulting theory assumes that shear stress controls fault slippage. A fault will remain stable when the applied shear stress (τ) is lower than the shear strength of the fault. The failure condition to initiate slippage is usually expressed in terms of the effective stress and pore pressure:

$$\tau_{crit} = \mu(\sigma_n - p) + c$$

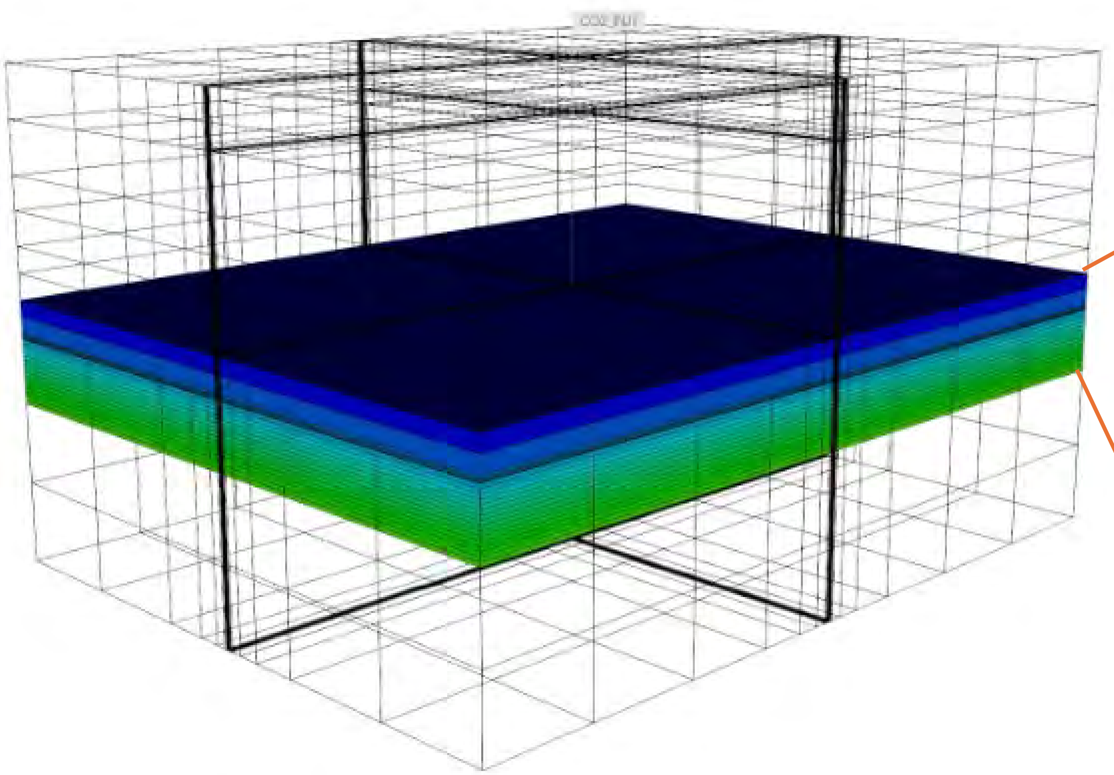
where the critical shear stress (τ_{crit}) equals the product of the frictional coefficient (μ) and effective normal stress given by the difference between the applied normal stress (σ_n) and pore pressure p. When pore pressure increases, the critical shear stress decreases. The pore pressure at which the critical shear stress equals the applied shear stress is defined as the pore pressure required to induce fault slip.



Introduction of GM Simulation Model

Summary of GM Model

Case1: inject from upper Leduc (layer 3 in the reservoir grid)
Case2: inject from cooking lake (layer 9 from reservoir grid)

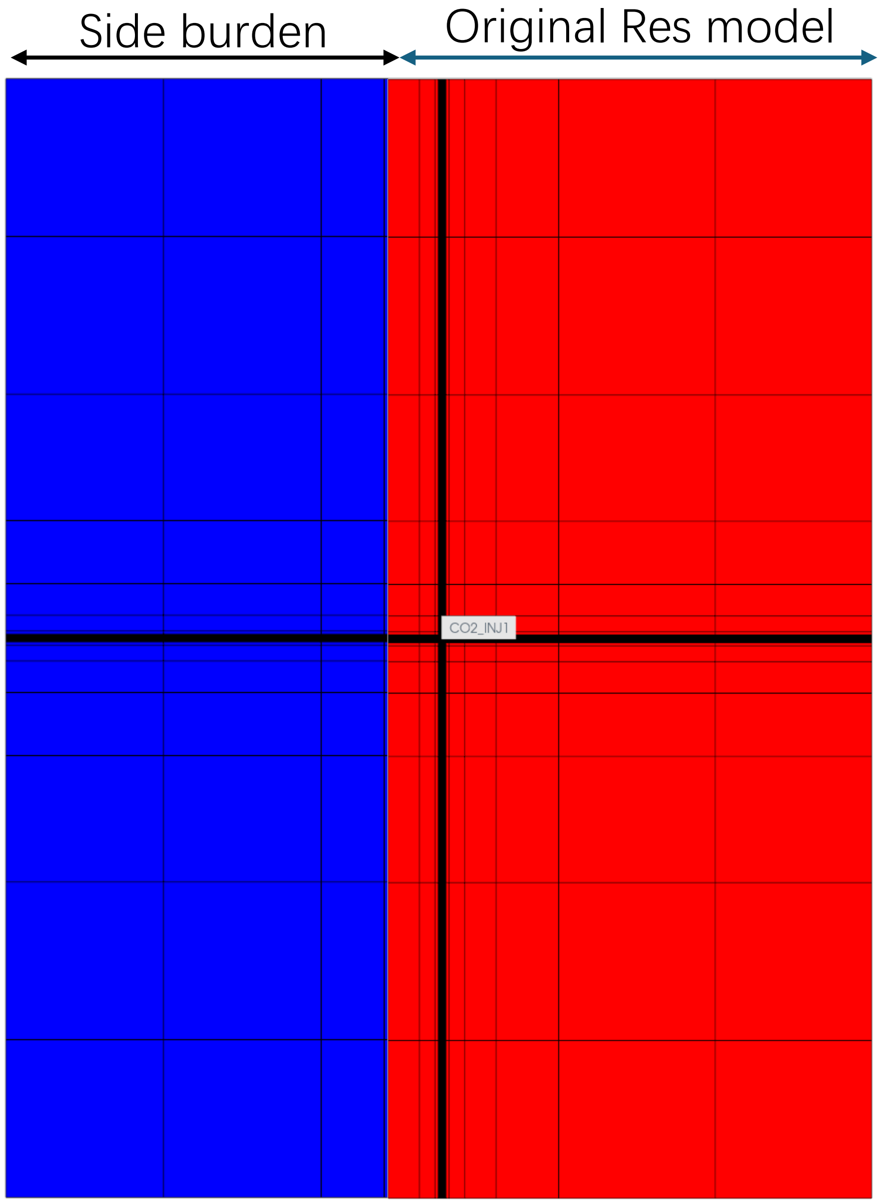


CMG Grid	Formation	Lithology	Elevation (SS)	Depth (m)
Milk River	Lea Park	shale	347.0	368.4
	Milk River	shale	260.0	455.4
Colorado	Colorado Gp	shale	185.0	530.4
	Second Wh	shale	6.0	709.4
	Base Fish S	shale	-84.0	799.4
	Viking	sandstone	-113.0	828.4
	Joli Fou	shale	-134.6	850.0
Manville	Manville	sandstone	-157.0	872.4
	Glauconite	sandstone	-297.0	1012.4
	Ostracod	shale	-319.0	1034.4
	Ellerslie	sandstone	-345.0	1060.4
Wabamun	Wabamun	limestone	-419.0	1134.4
	Graminia	shale	-460.0	1175.4
	Blueridge	limestone	-468.0	1183.4
	Calmar	shale	-492.0	1207.4
	Nisku	dolomite	-495.0	1210.4
Ireton	Ireton	shale	-580.0	1295.4
Reservoir	Leduc	dolomite	-611.0	1326.4
	Lower Ledu	dolomite	-723.0	1438.4
	Cooking Lak	limestone	-772.0	1487.4
Base	Base			2287.36

GM grid is an extension of reservoir grid: upper side is extended to surface, bottom side is extended 800 m below reservoir;

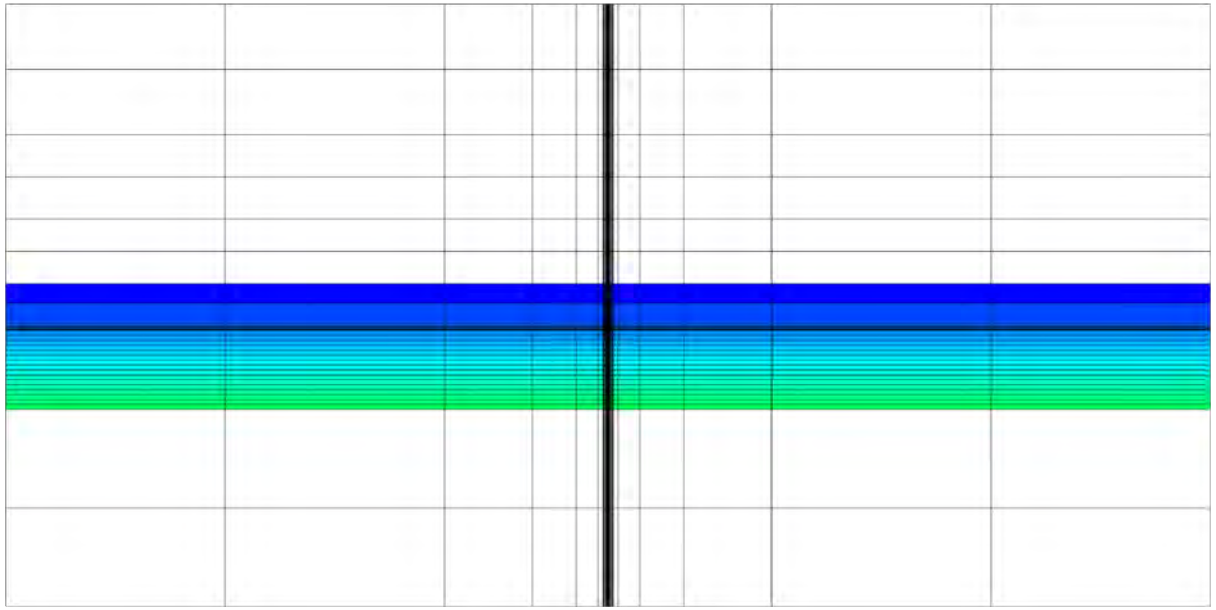
Summary GM Model

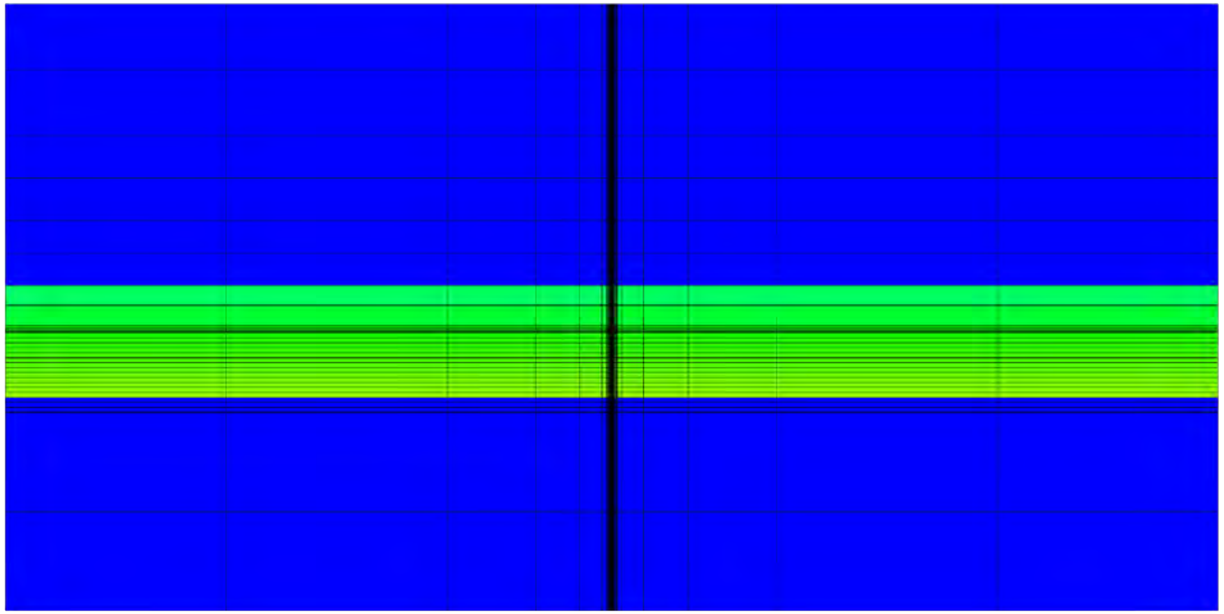
To make the GM model symmetrical and ensure proper boundary conditions , we added side burden to both reservoir model and GM model



Summary GM Model

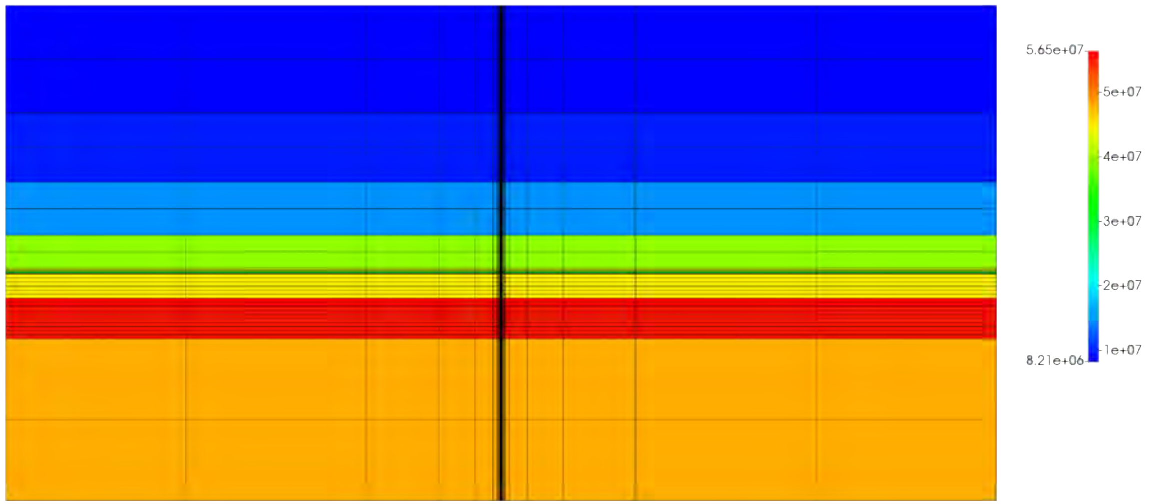
Gridding

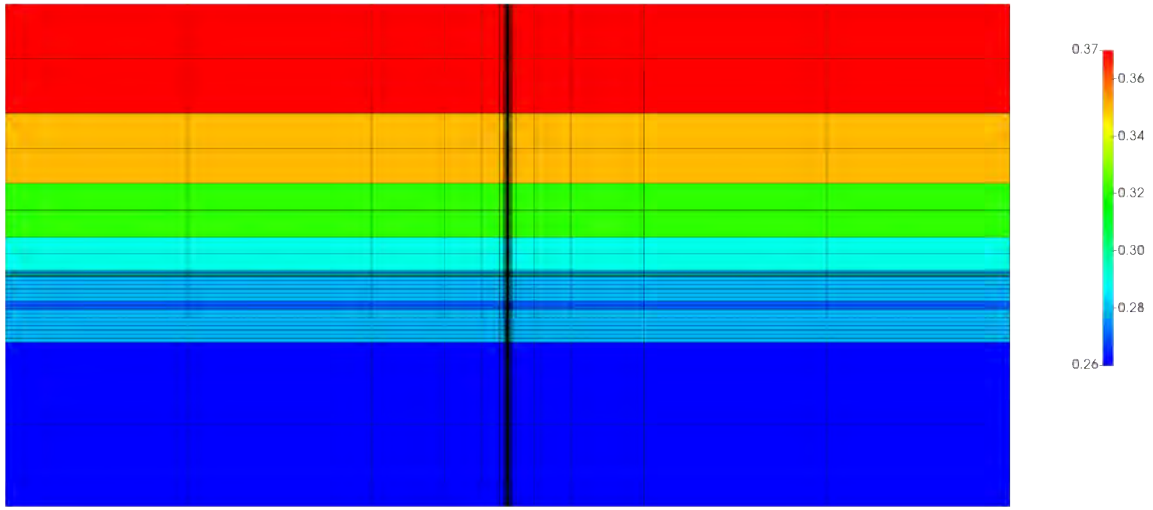




Summary of GM Model

Material Properties for GM---Young's modulus and Poisson ratio

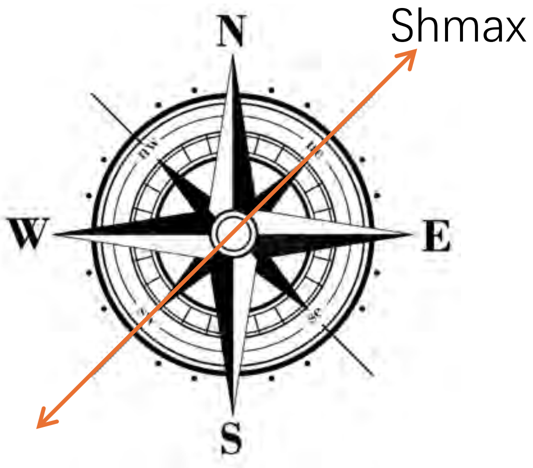




CMG Grid	Formation	Lithology	Elevation (SS)	Depth (m)	Es, kPa	Pois	Cohesion	Fric_ang
Milk River	Lea Park	shale	347.0	368.4	8.21E+06	0.37	3.24E+03	25.47
	Milk River	shale	260.0	455.4				
Colorado	Colorado Gp	shale	185.0	530.4	9.50E+06	0.35	3.40E+03	25.91
	Second Wh	shale	6.0	709.4				
	Base Fish S	shale	-84.0	799.4				
	Viking	sandstone	-113.0	828.4				
	Joli Fou	shale	-134.6	850.0				
Manville	Manville	sandstone	-157.0	872.4	1.51E+07	0.32	5.03E+03	29.4
	Glauconite	sandstone	-297.0	1012.4				
	Ostracod	shale	-319.0	1034.4				
	Ellerslie	sandstone	-345.0	1060.4				
Wabamun	Wabamun	limestone	-419.0	1134.4	3.91E+07	0.29	1.60E+04	37.57
	Graminia	shale	-460.0	1175.4				
	Blueridge	limestone	-468.0	1183.4				
	Calmar	shale	-492.0	1207.4				
	Nisku	dolomite	-495.0	1210.4				
Ireton	Ireton	shale	-580.0	1295.4	4.18E+07	0.28	3.23E+04	37.96
					3.08E+07	0.29	8.83E+03	34.27
Reservoir	Leduc	dolomite	-611.0	1326.4	4.52E+07	0.28	1.93E+04	38.87
	Lower Ledu	dolomite	-723.0	1438.4	5.65E+07	0.27	3.10E+04	40.21
	Cooking Lak	limestone	-772.0	1487.4	5.55E+07	0.28	2.22E+04	40.48
Base	Base			2287.36	4.83E+07	0.26	2.17E+04	40

Stress Orientation

Orientation of Shmax is N45E. The GM grid is N-S. Thus, the stress should be rotated to N45E. Let's assume Sv is vertical



1. **Transformed Normal Stresses**:

$$\sigma_x' = \frac{\sigma_x + \sigma_y}{2} + \frac{\sigma_x - \sigma_y}{2}\cos 2\theta + \tau_{xy}\sin 2\theta$$

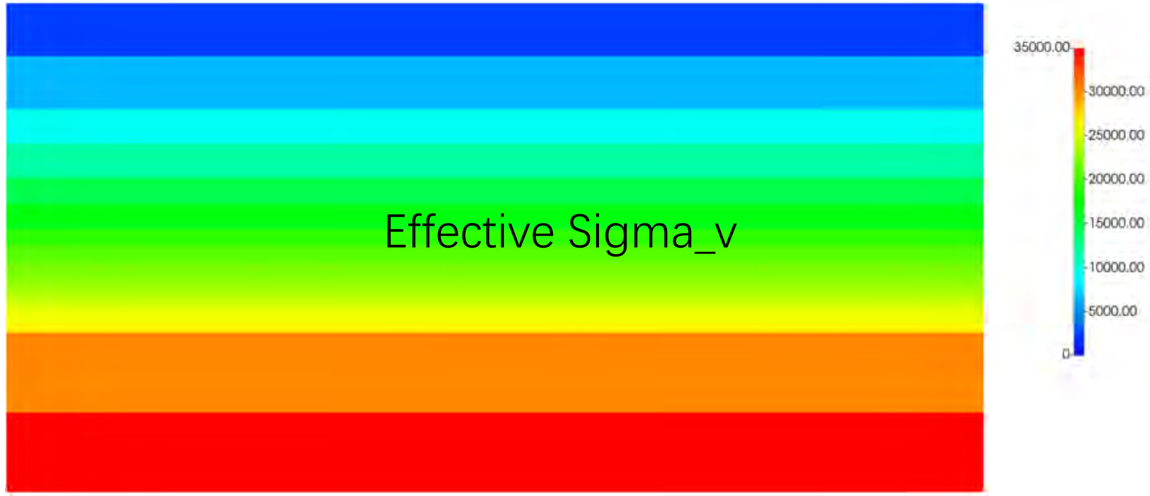
$$\sigma_y' = \frac{\sigma_x + \sigma_y}{2} - \frac{\sigma_x - \sigma_y}{2}\cos 2\theta - \tau_{xy}\sin 2\theta$$

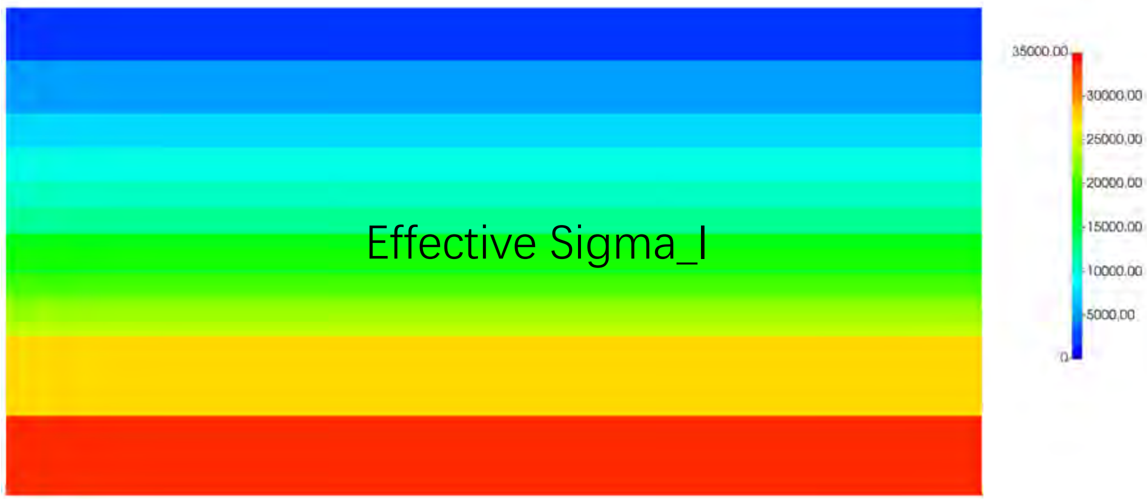
2. **Transformed Shear Stress**:

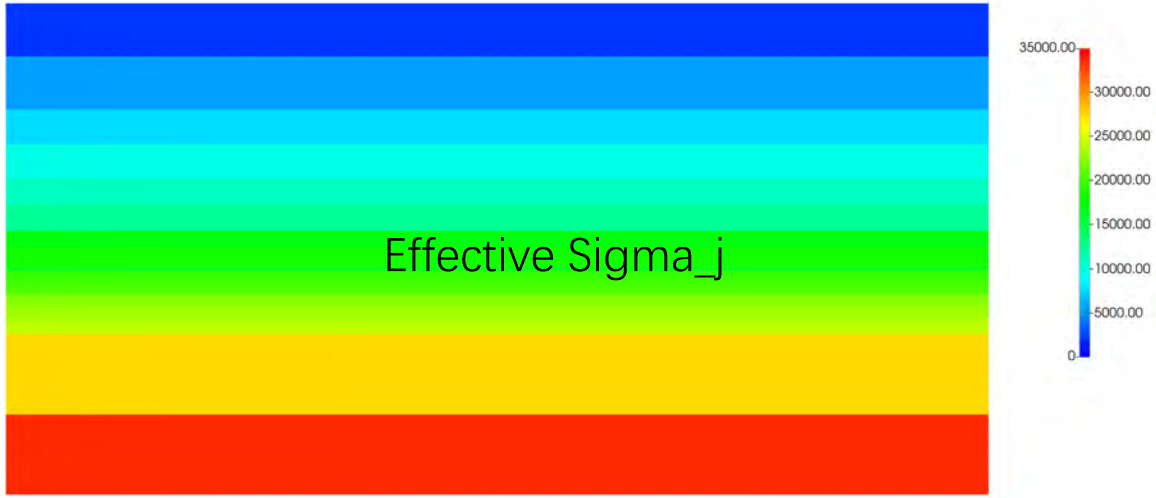
$$\tau_{xy}' = -\frac{\sigma_x - \sigma_y}{2}\sin 2\theta + \tau_{xy}\cos 2\theta$$

Summary Gridding

In Situ Stress for GM



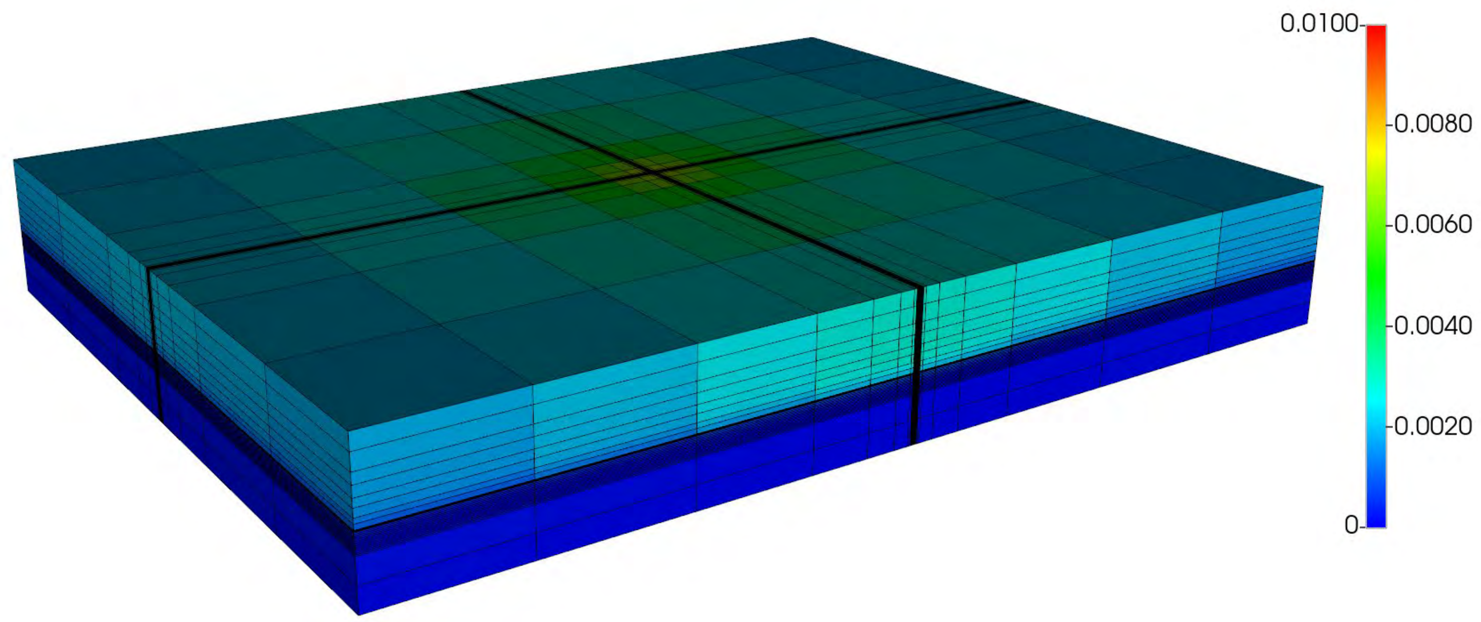


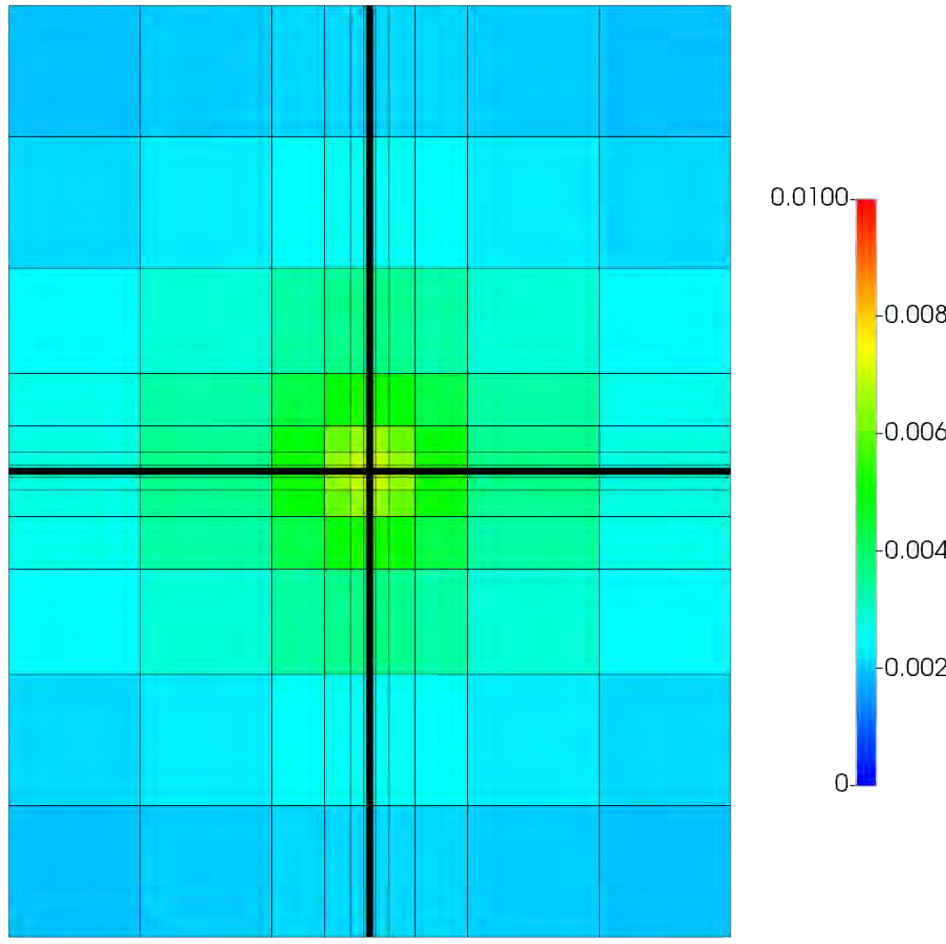


Case 1:inject from upper Leduc (from layer 3 in the reservoir grid)
Temperature= 5degC

Case1: inject from upper Leduc (from layer 3 in the reservoir grid);

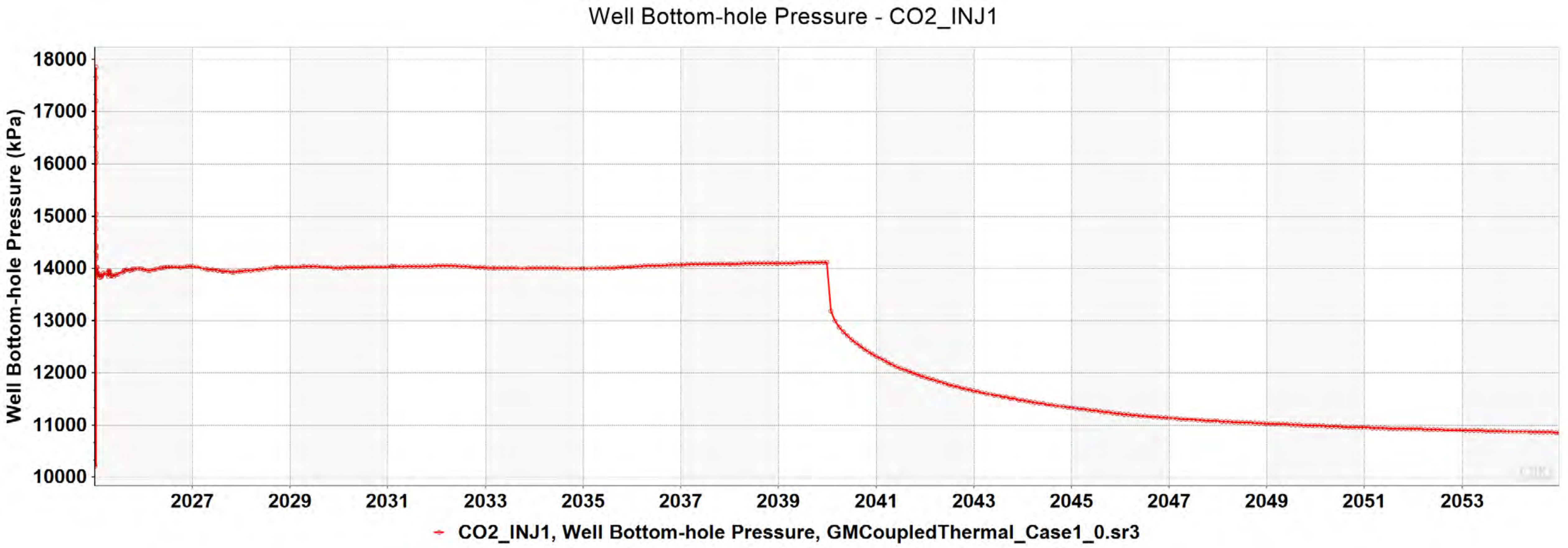
Surface heave @ end of injection 15 years (max. less than 1cm, ~5mm)





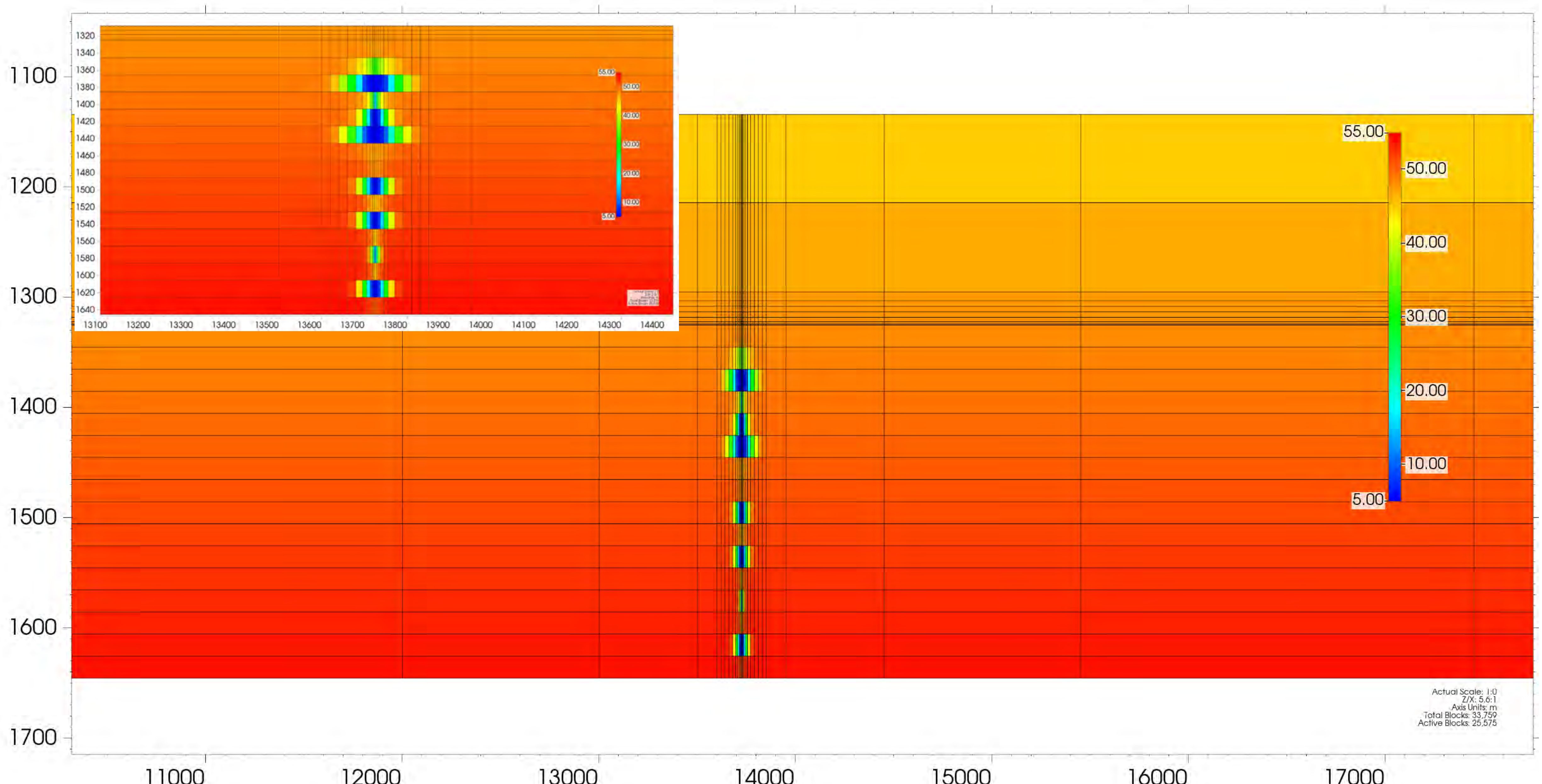
Case1: inject from upper Leduc (from layer 3 in the reservoir grid);

Injection pressure (BHP, unit: kPa)



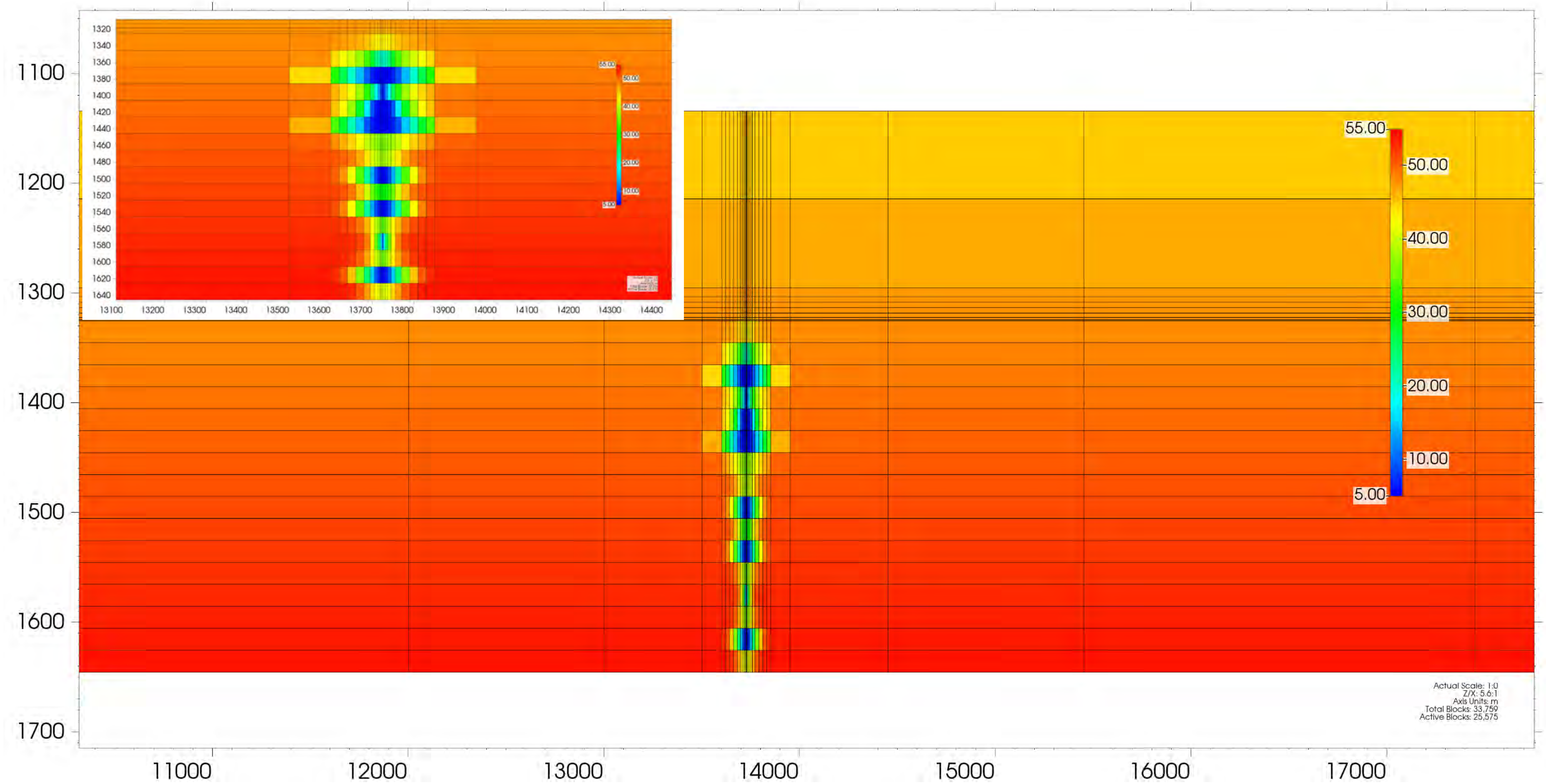
Case1: inject from upper Leduc (from layer 3 in the reservoir grid);

Temperature distribution @ 1 year



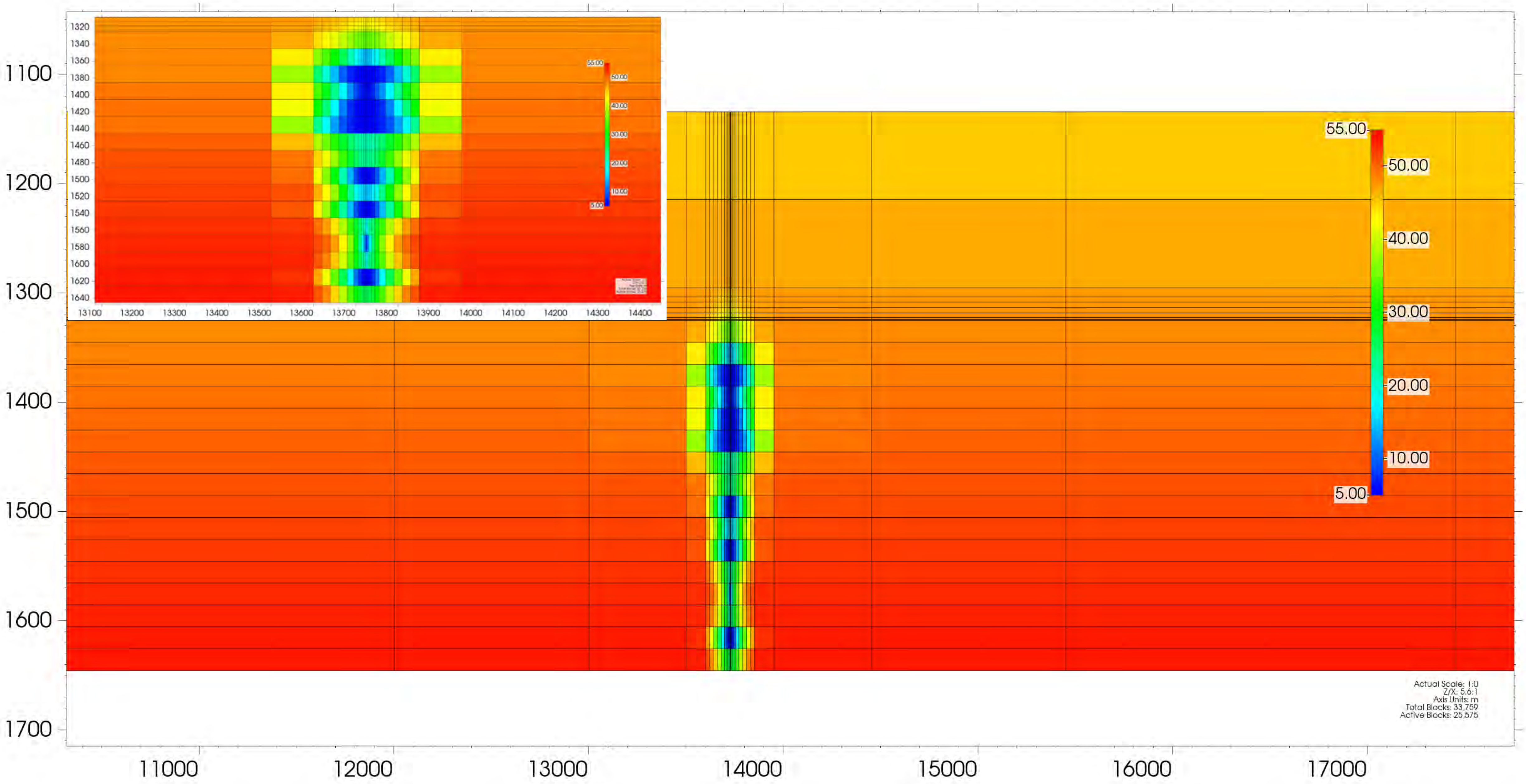
Case1: inject from upper Leduc (from layer 3 in the reservoir grid);

Temperature distribution @ 5 years



Case1: inject from upper Leduc (layer 3 in the reservoir grid);

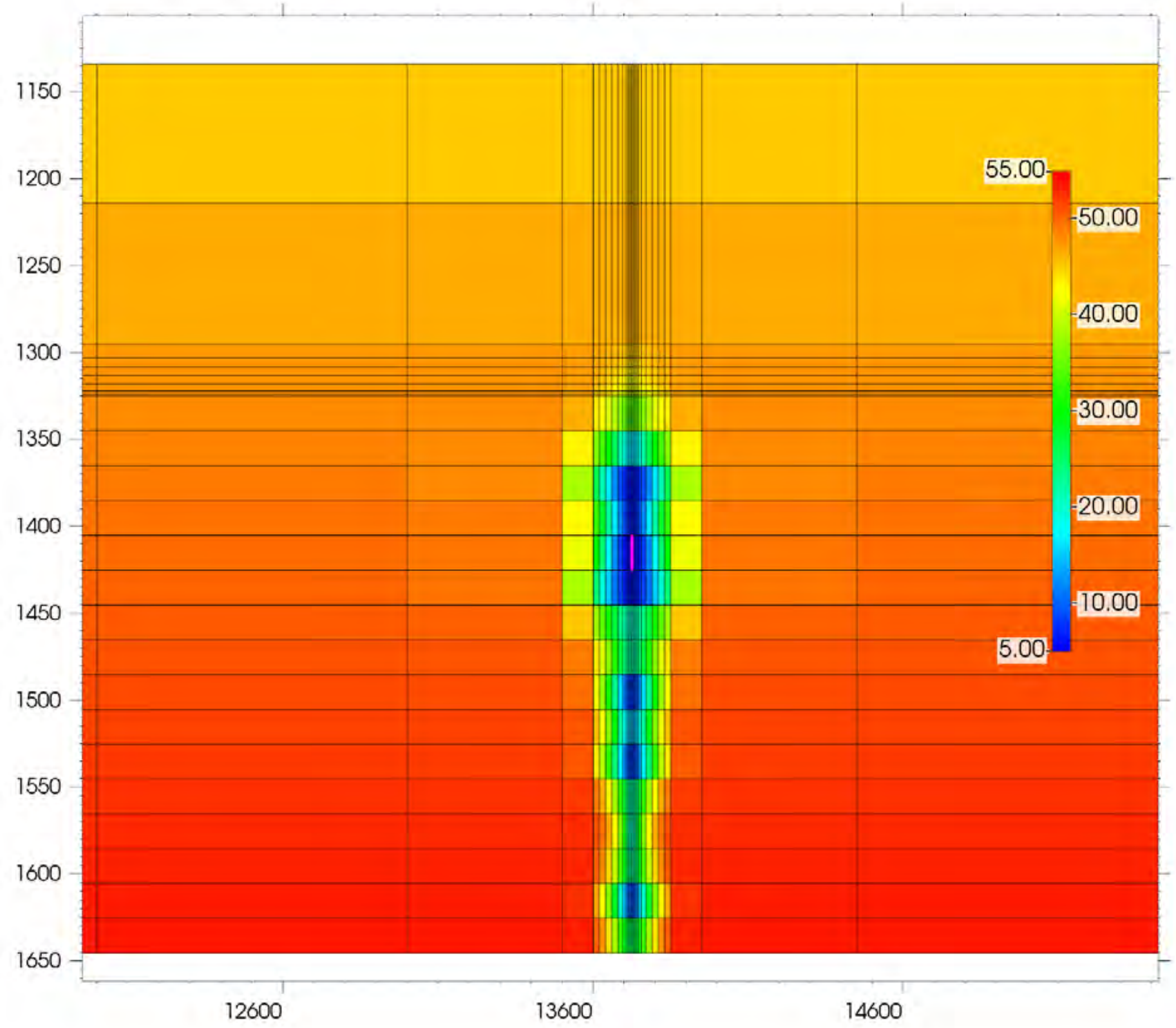
Temperature distribution @ end of injection 15 years

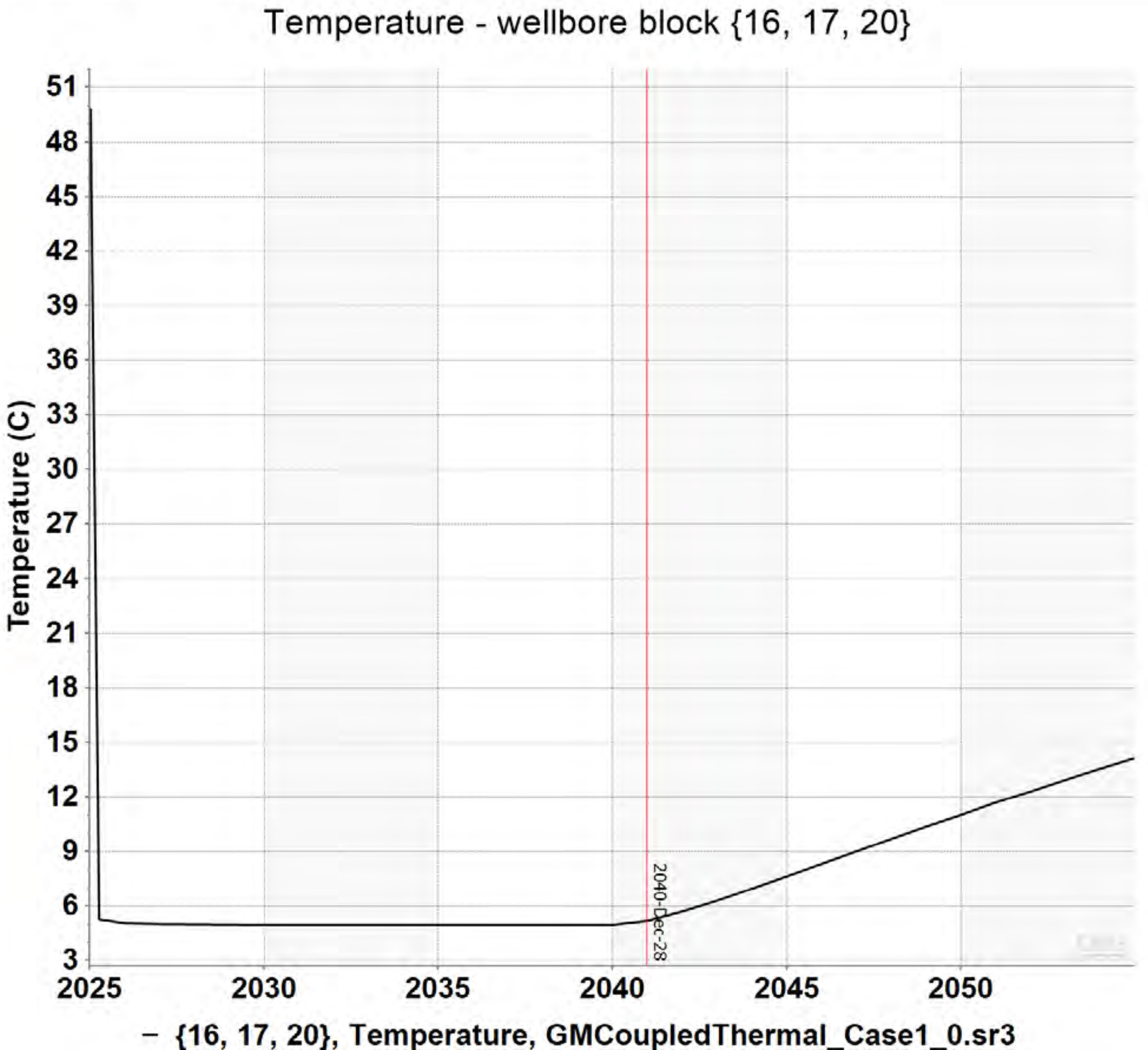


Case1: inject from upper Leduc (layer 3 in the reservoir grid);

Max temperature drop with time

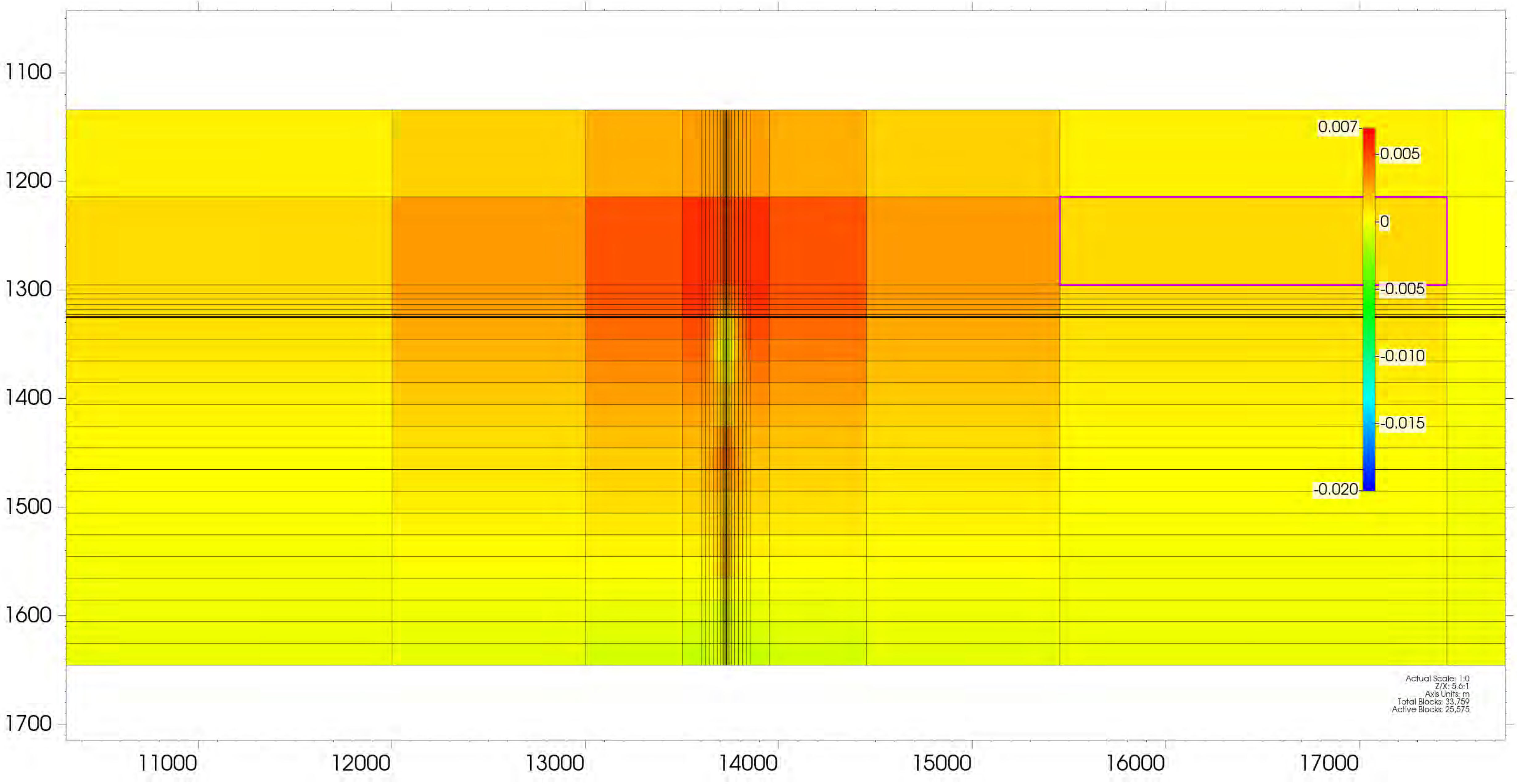
Temperature Drop with Time, Min. T=5.1 degC





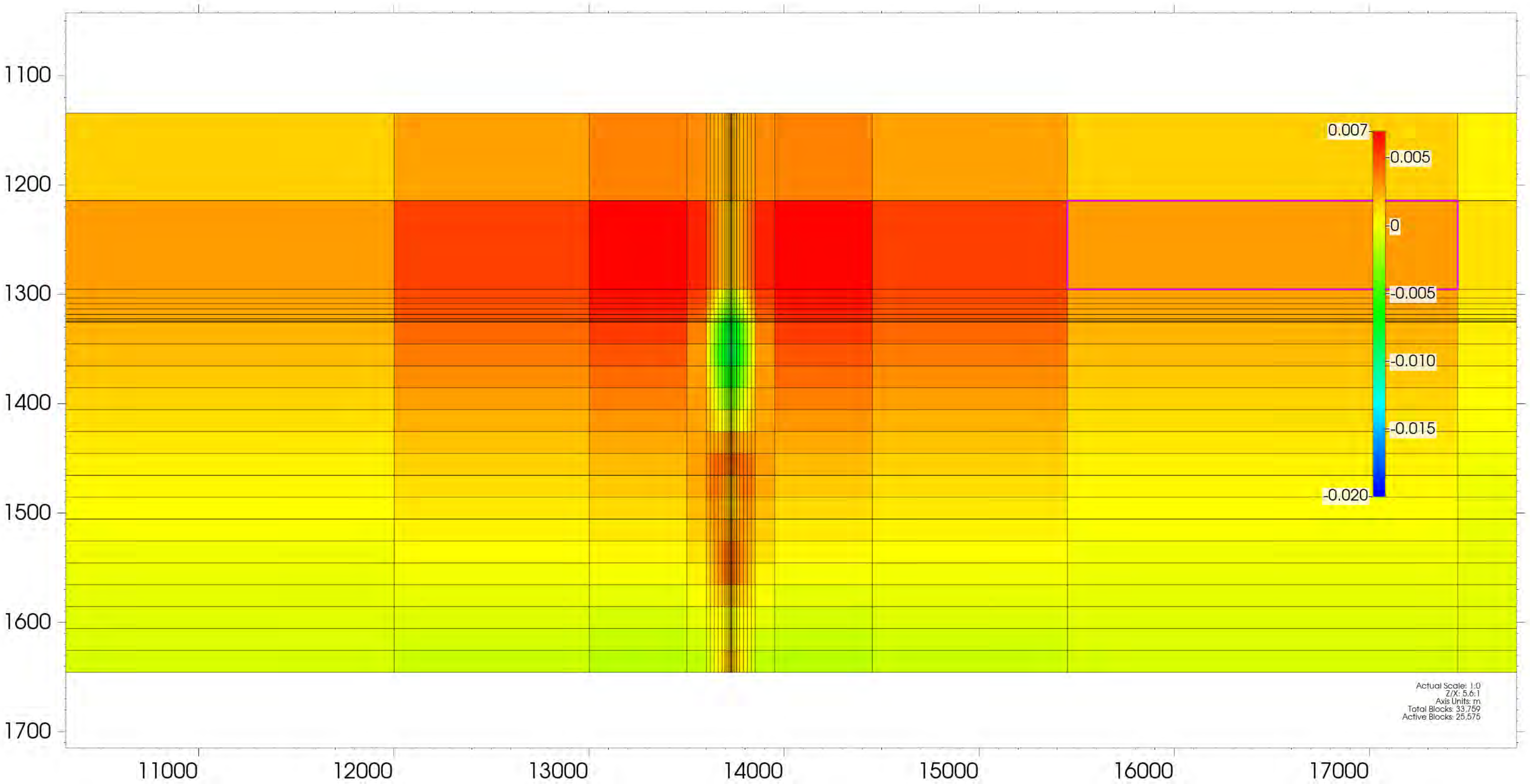
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

Deformation (Uz) @ 1 years



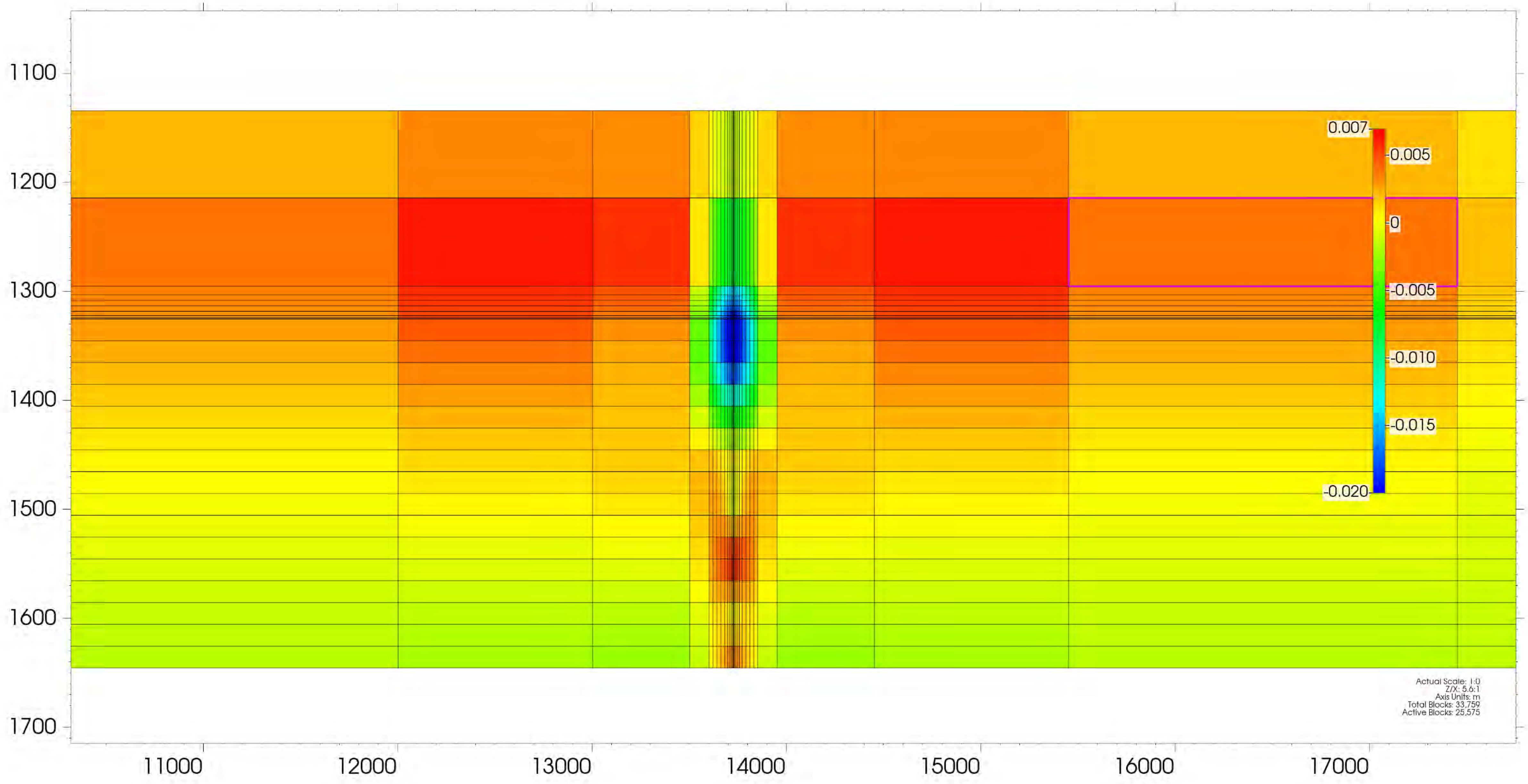
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

Deformation (Uz) @ 5 years



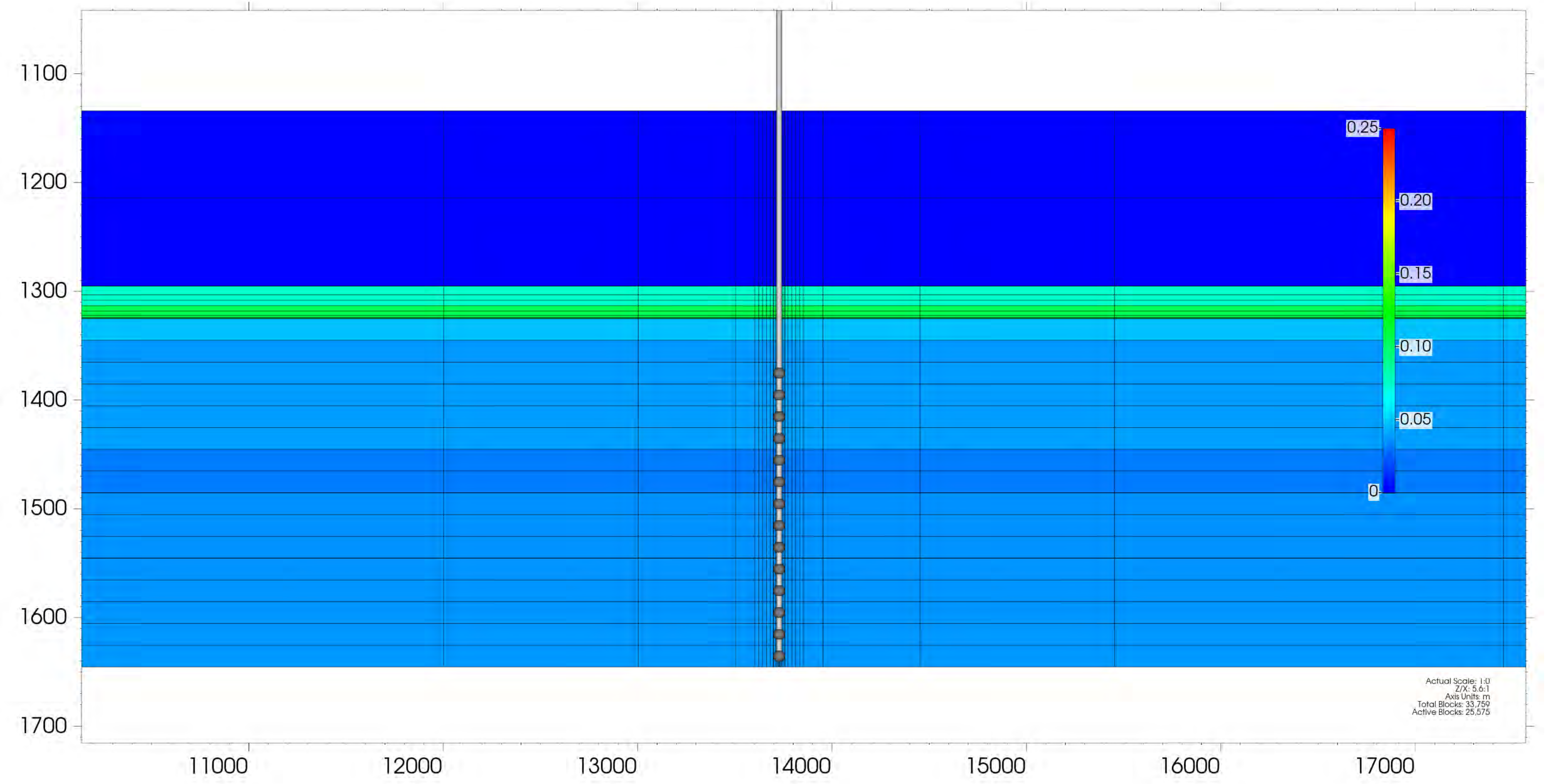
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

Deformation (Uz) @ end of injection 15 years



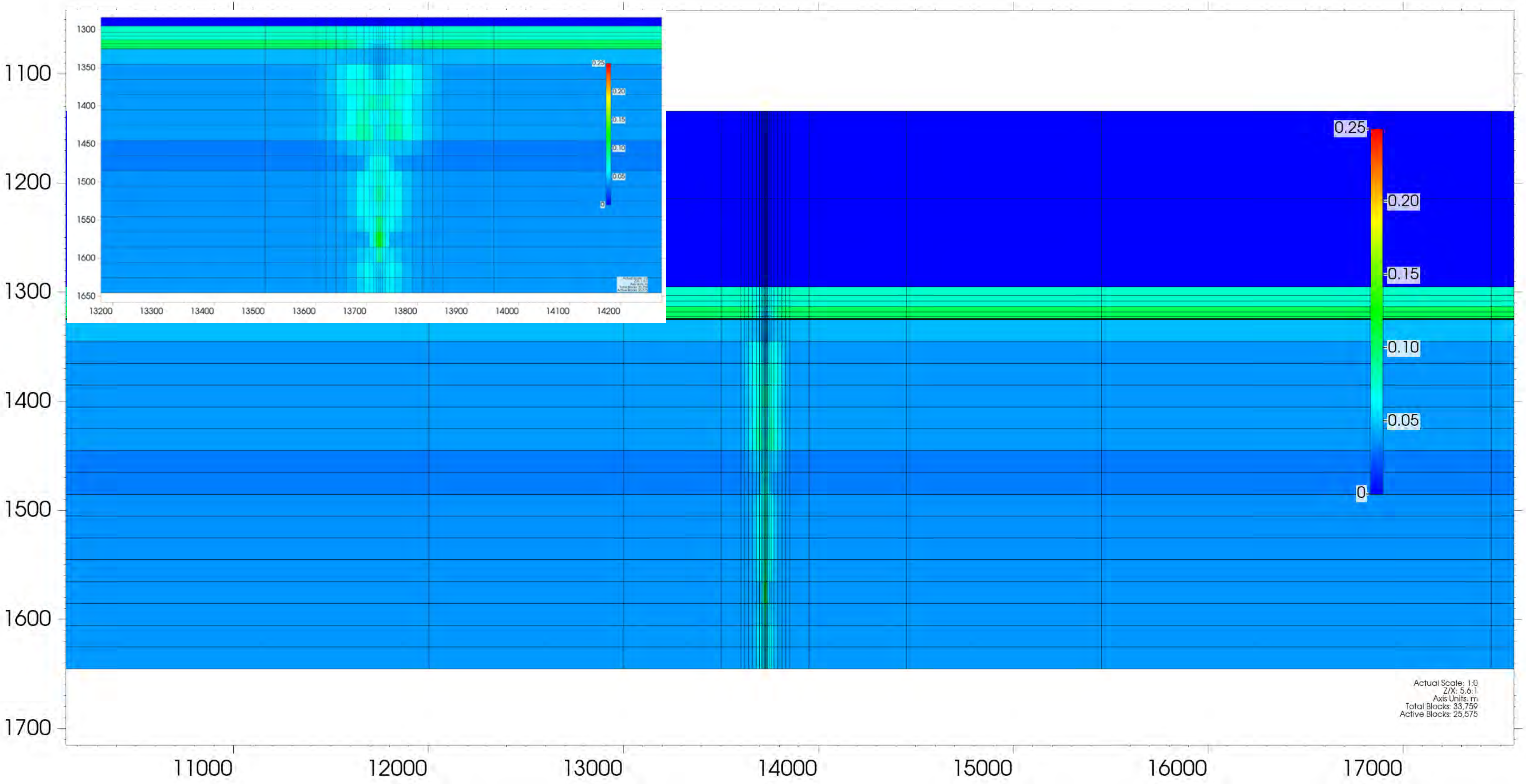
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

SSL at lower Ireton, Leduc and Cooking lake @ time=0 (only 3 formations and others are set zero)



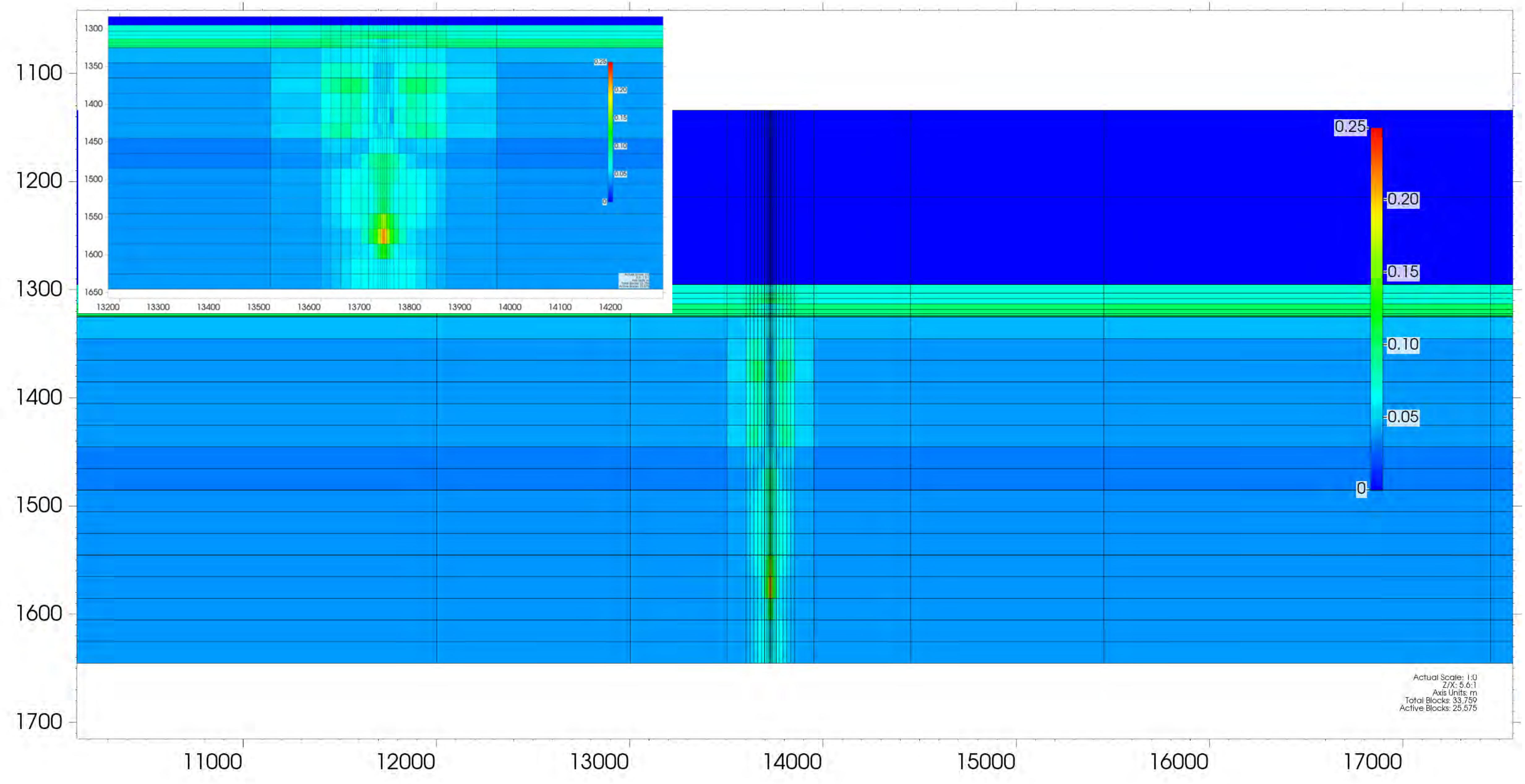
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

SSL at lower Ireton, Leduc and Cooking lake @ 1 years



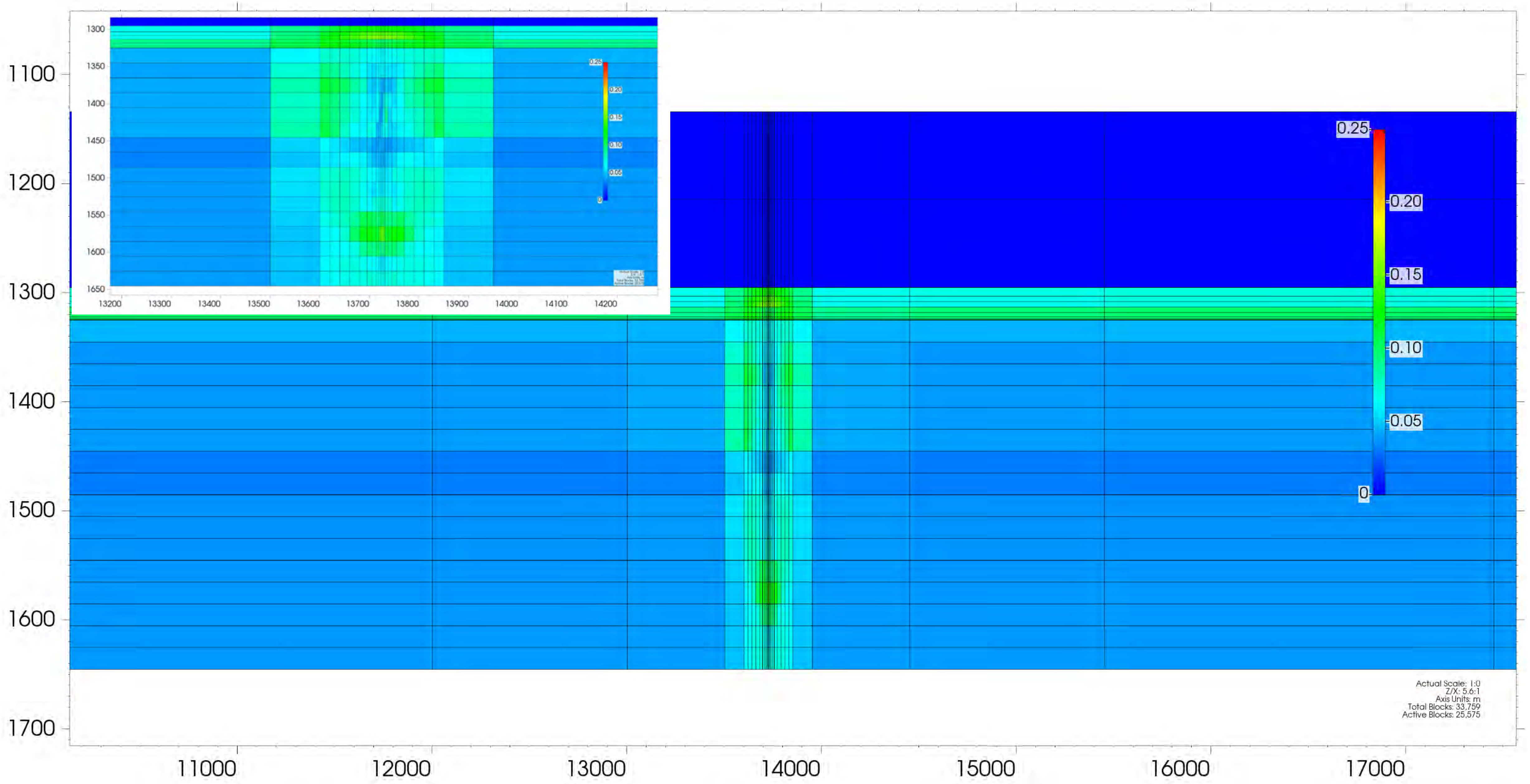
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

SSL at lower Ireton, Leduc and Cooking lake @ 5 years



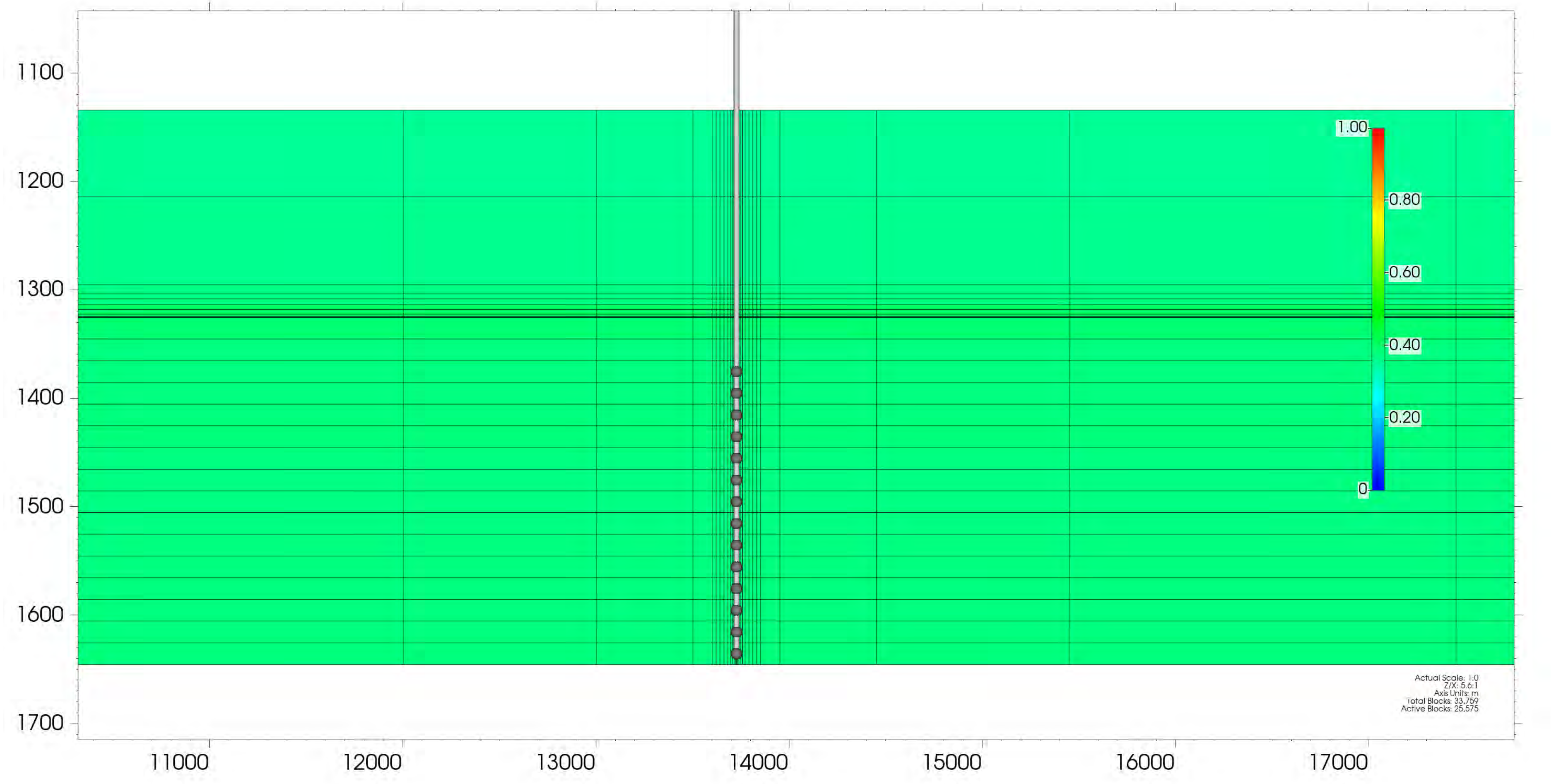
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

SSL at lower Ireton, Leduc and Cooking lake @ end of injection 15 years



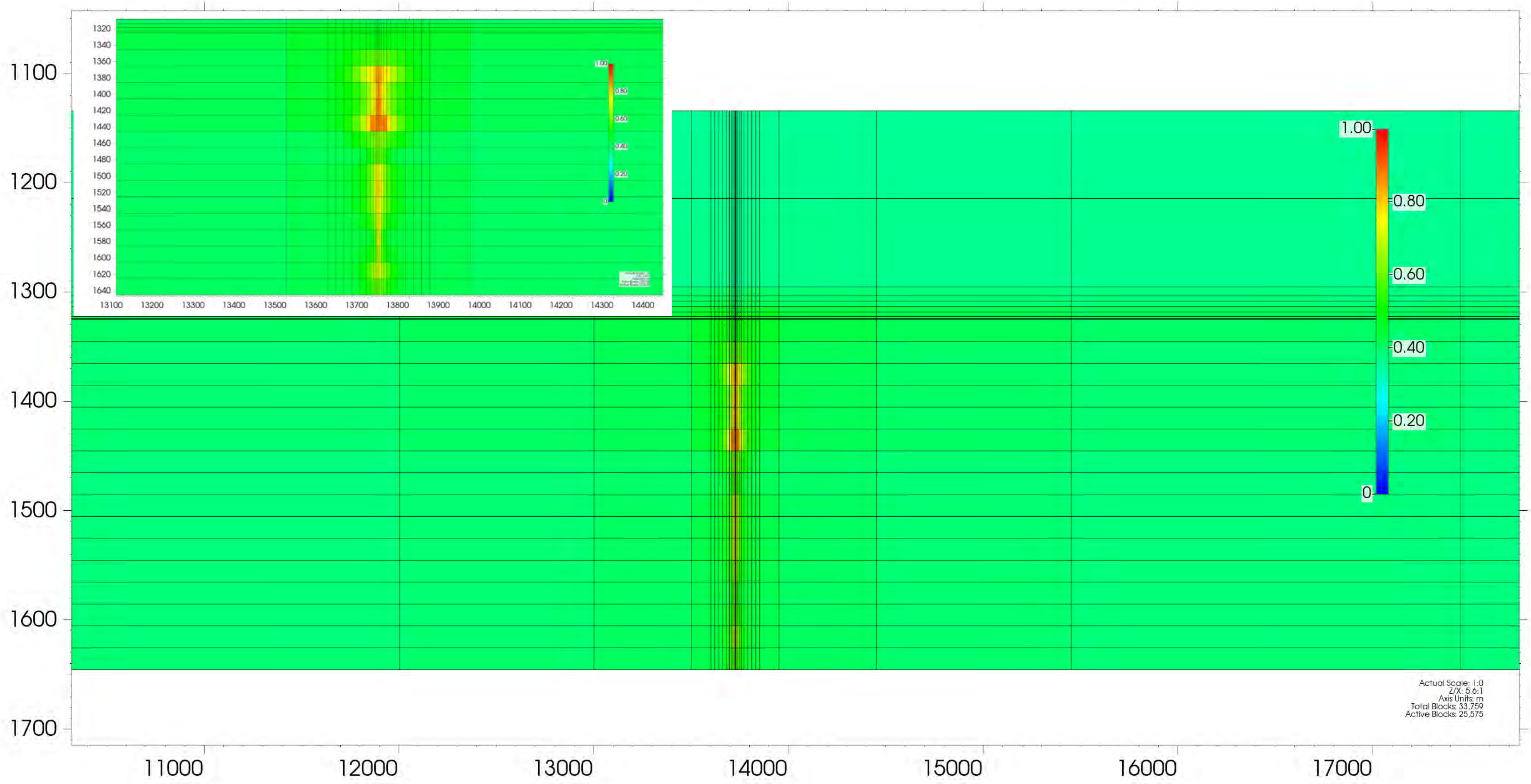
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

TSL at lower Ireton, Leduc and Cooking lake @ time=0 (only 3 formations and others are set zero)



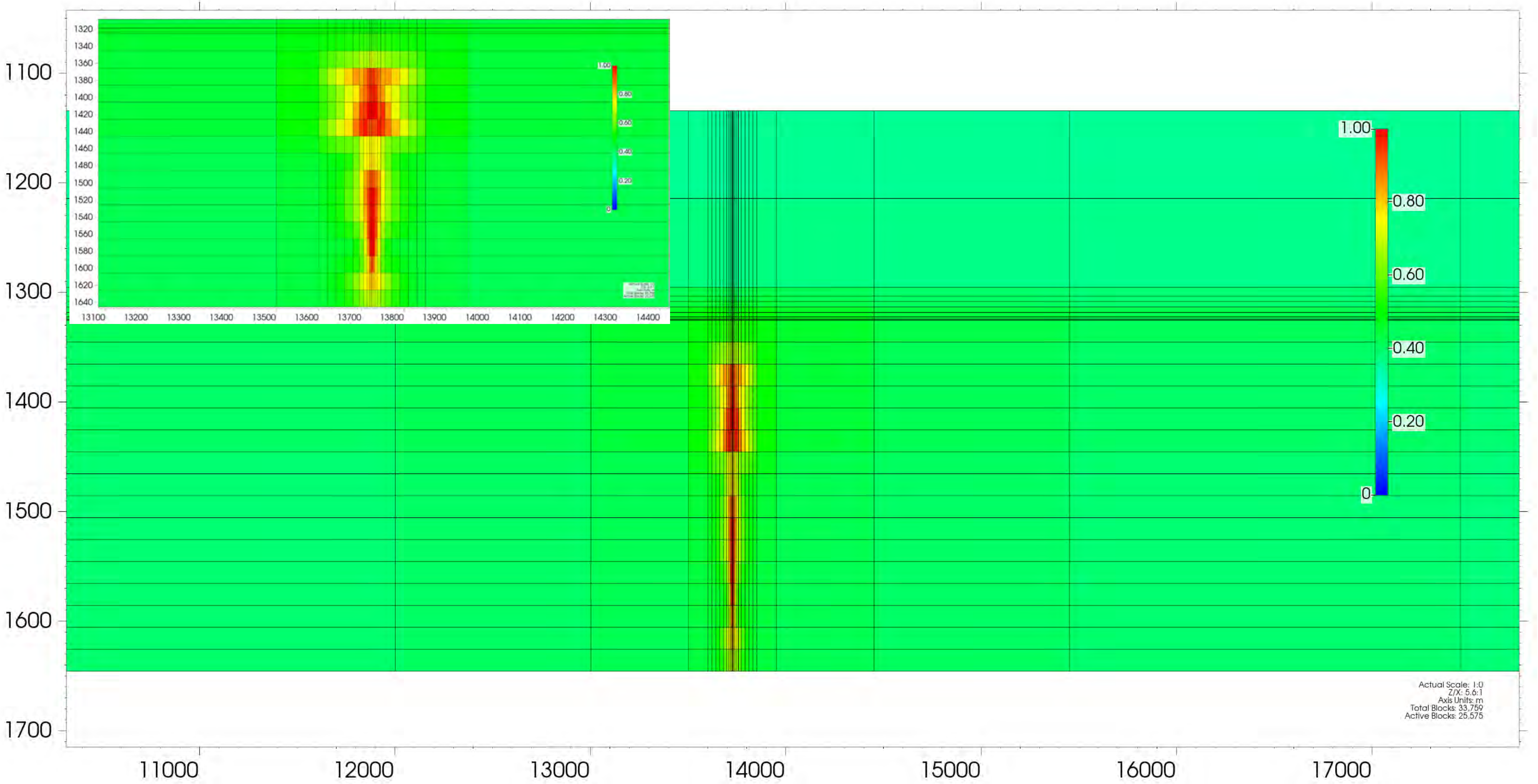
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

TSL at lower Ireton, Leduc and Cooking lake @ 1 year (fractured near wellbore)



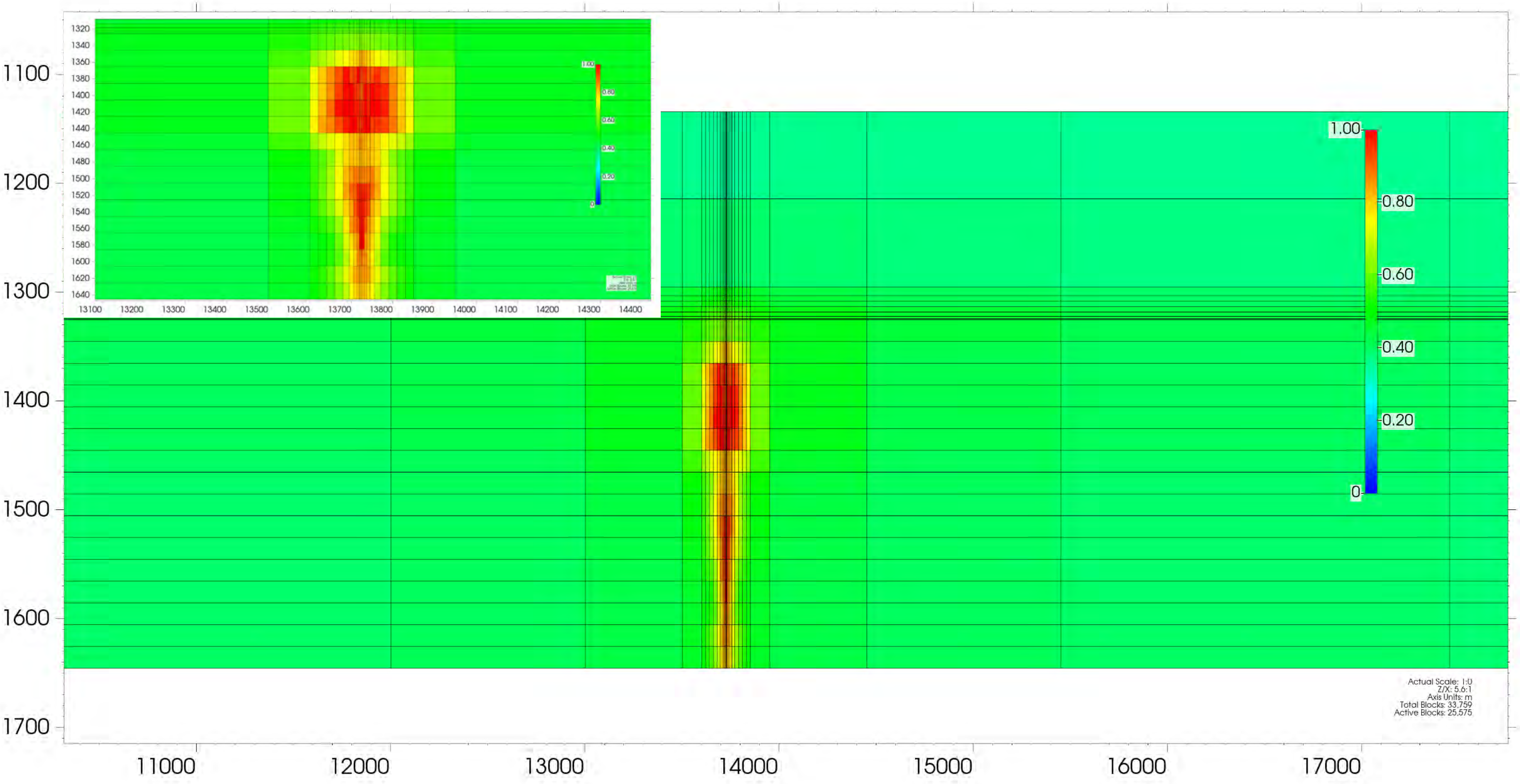
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

TSL at lower Ireton, Leduc and Cooking lake @ 5 years (fractured near wellbore)



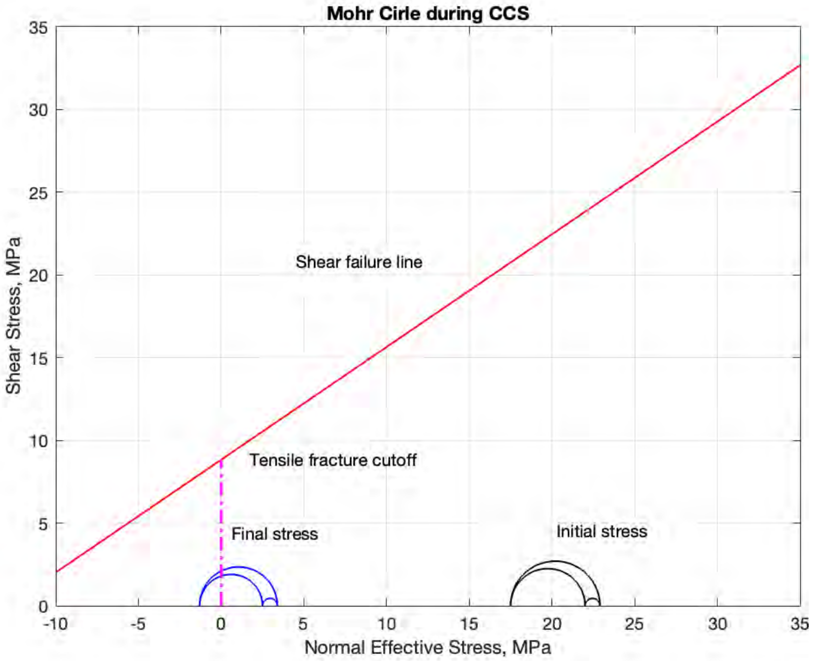
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

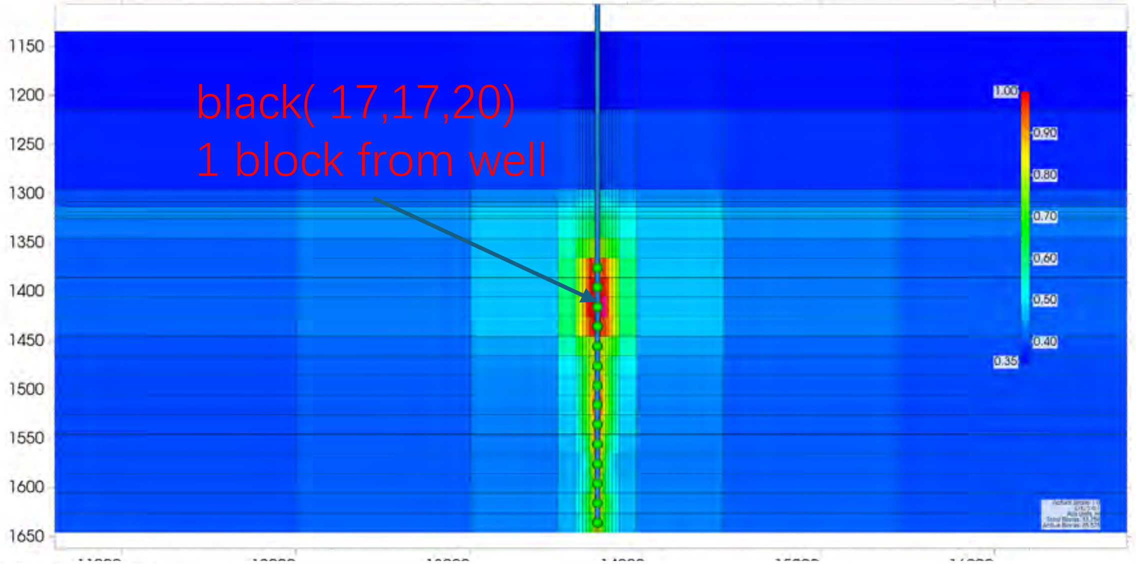
TSL at lower Ireton, Leduc and Cooking lake @ end of injection 15 years (fractured near wellbore)

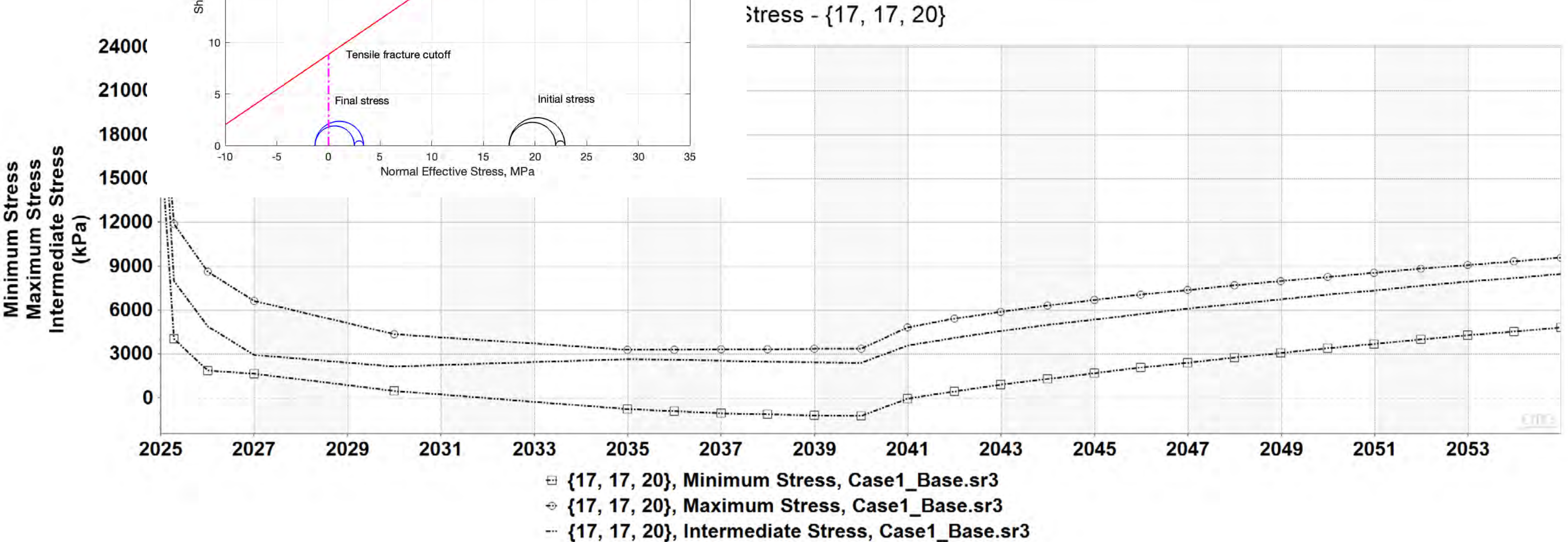


Case1: inject from upper Leduc (layer 3 in the reservoir grid);

Change of 3 principal effective stresses near wellbore ()

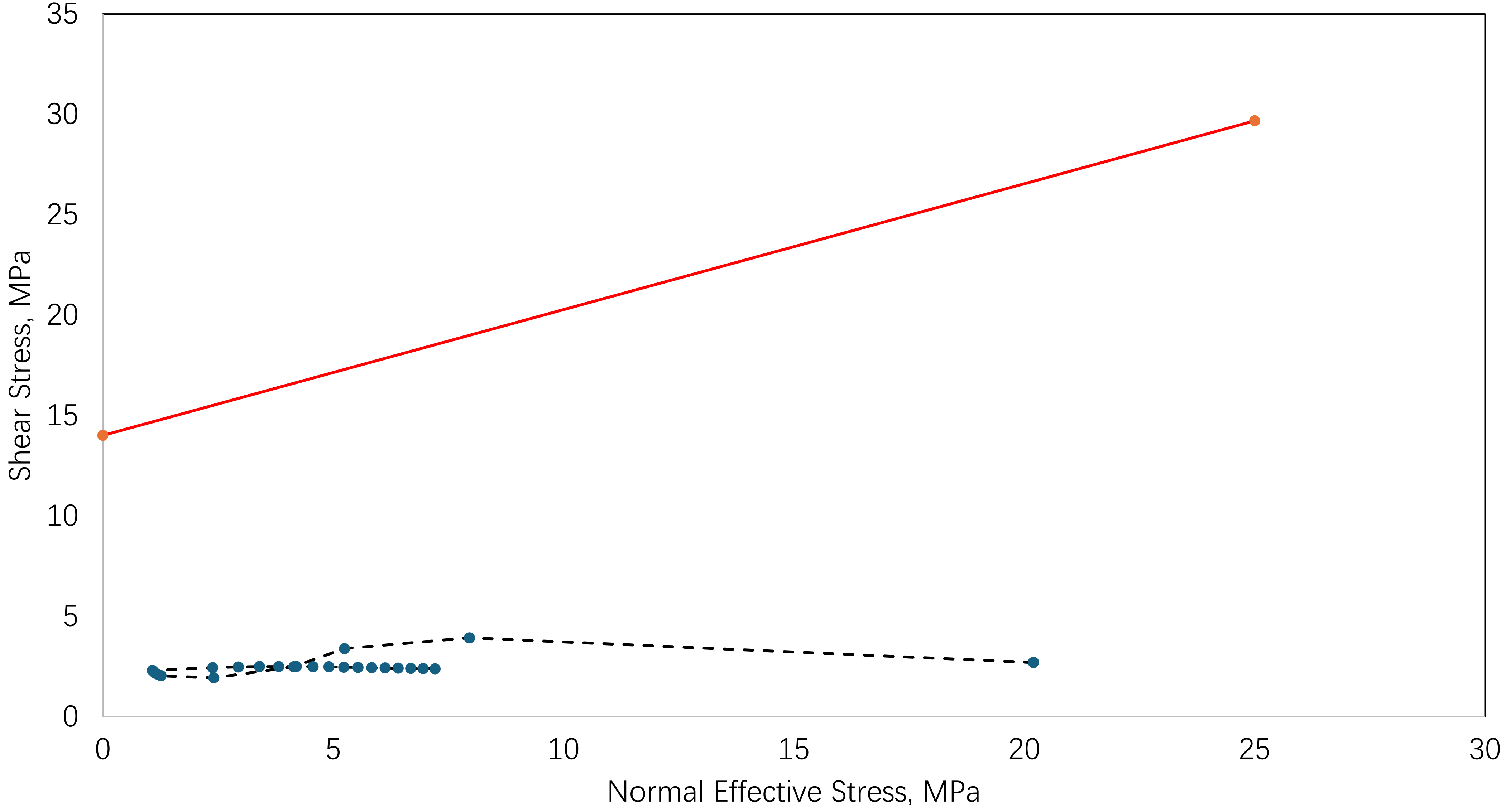






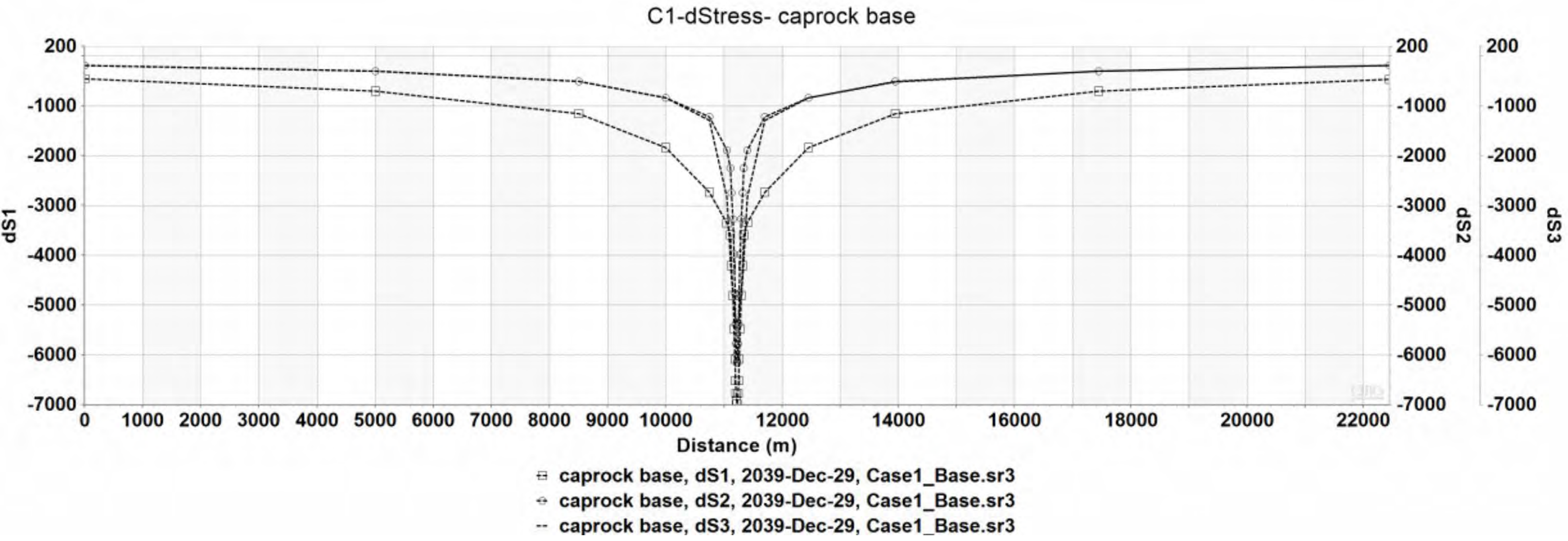
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

Stress path



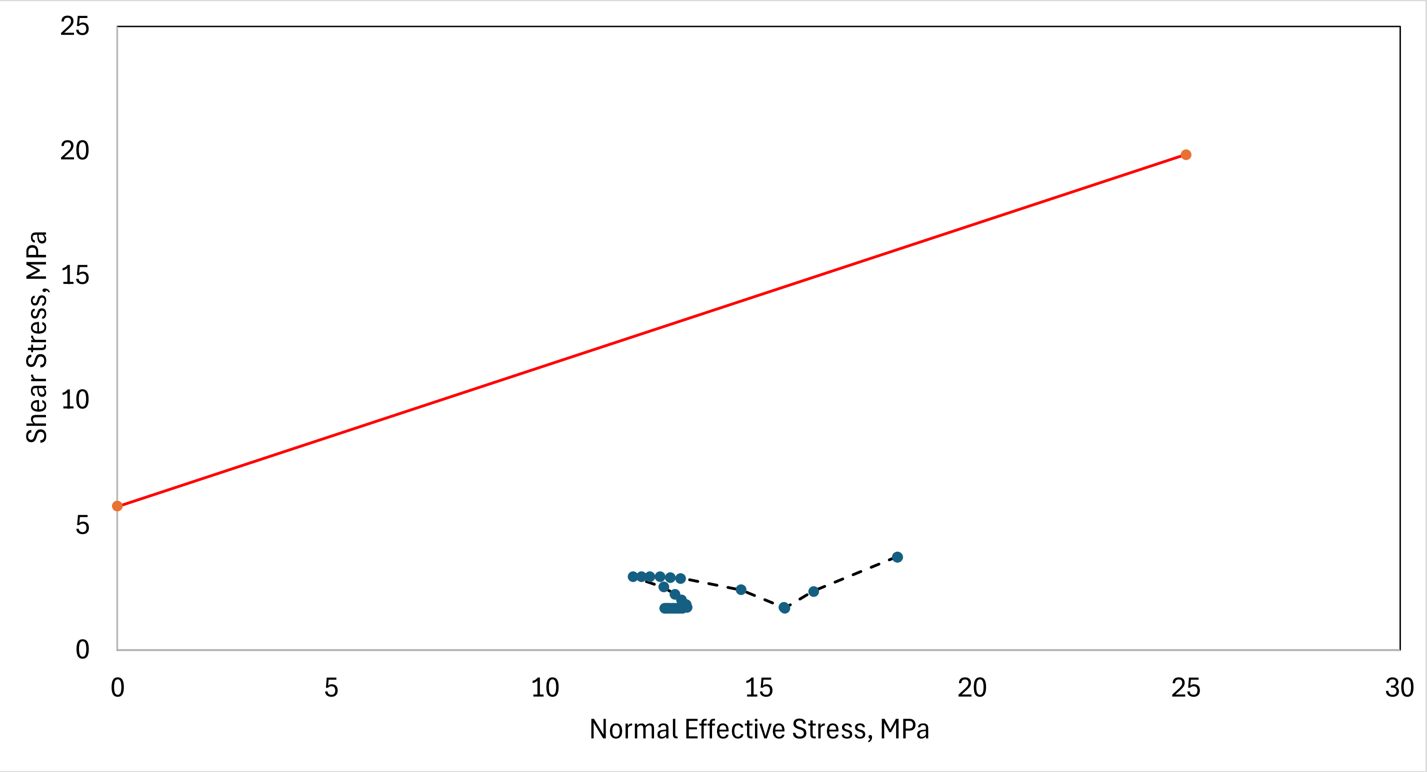
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

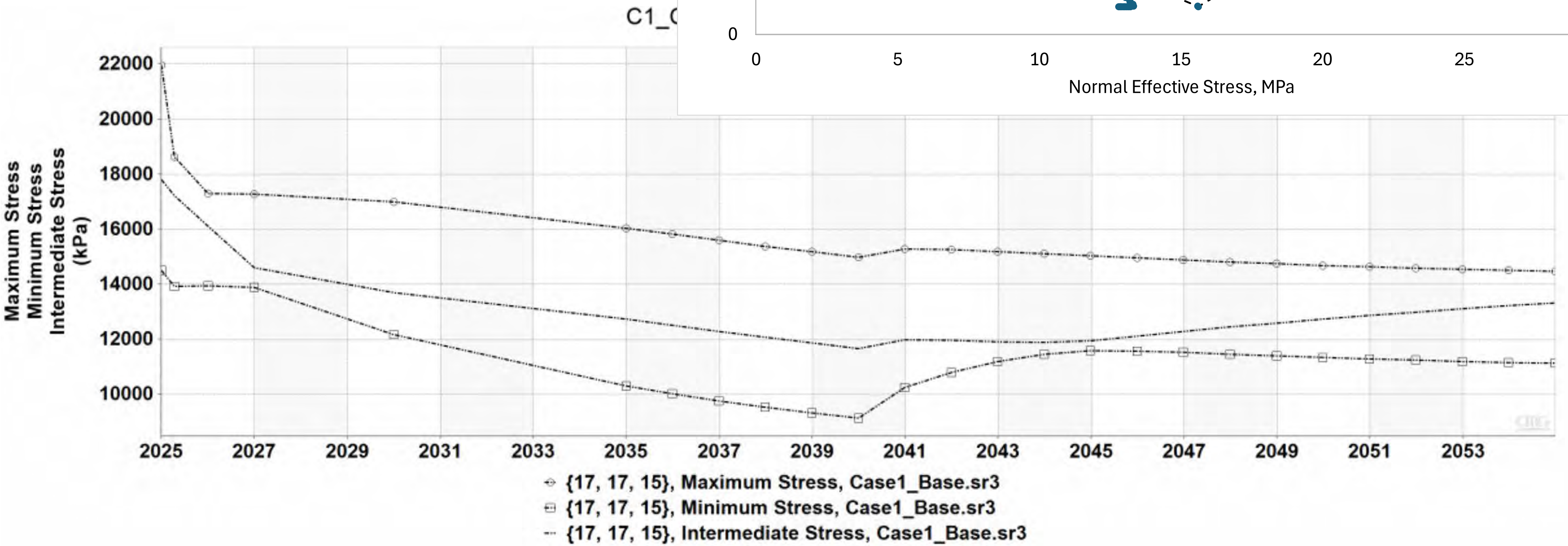
Change of stress at caprock base



Case1: inject from upper Leduc (layer 3 in the reservoir grid);

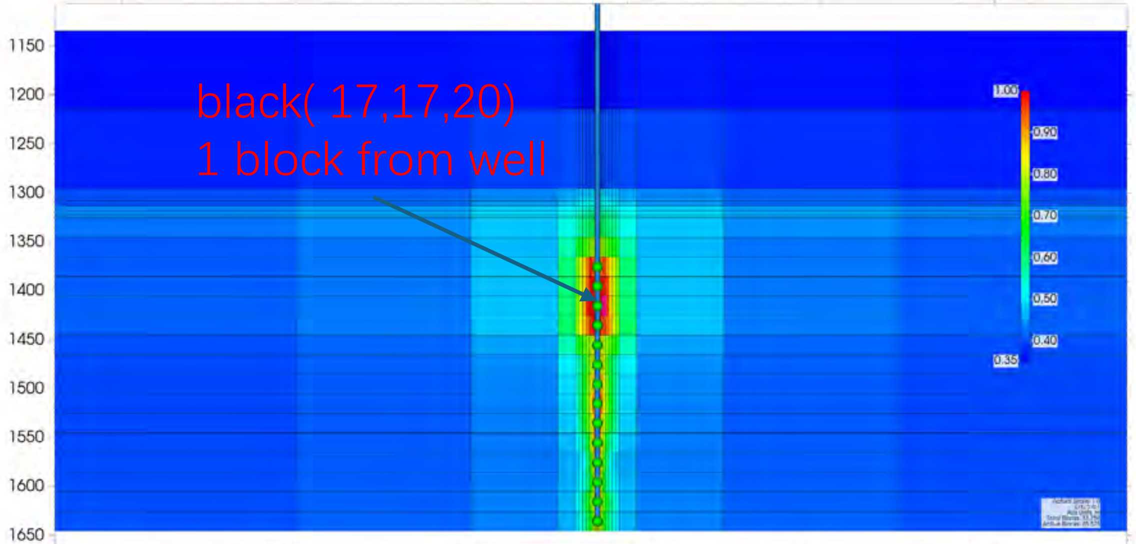
Stress path for caprock (near injection well)

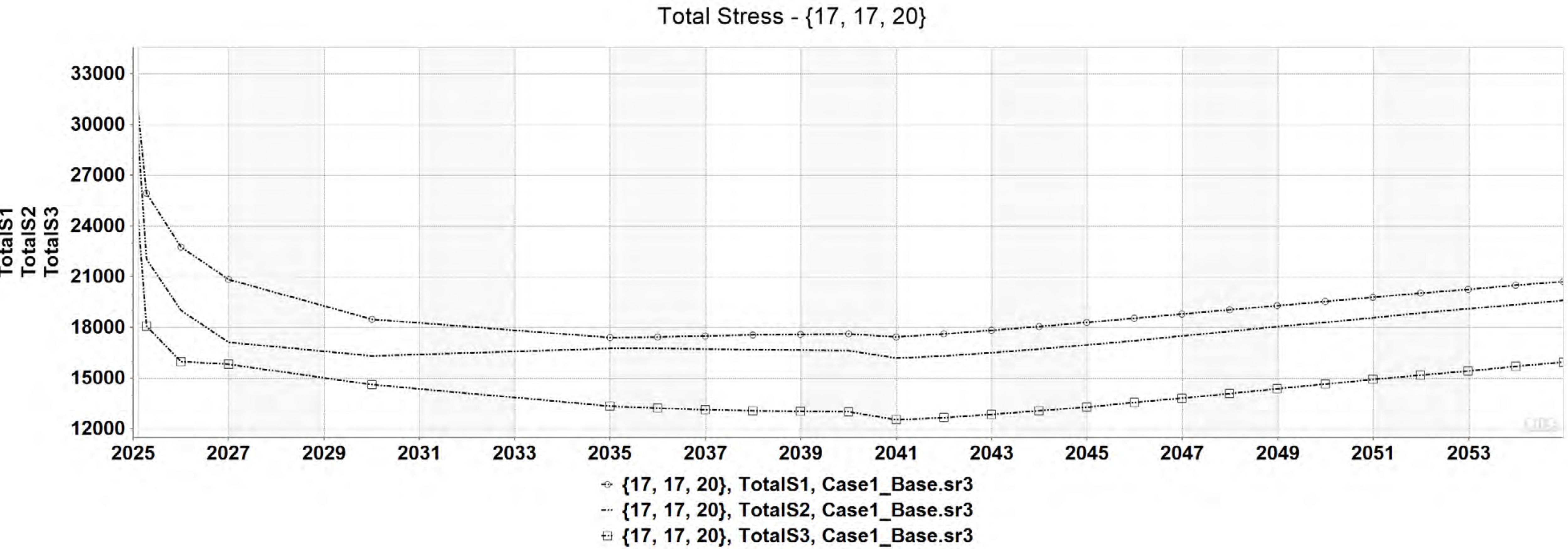




Case1: inject from upper Leduc (layer 3 in the reservoir grid);

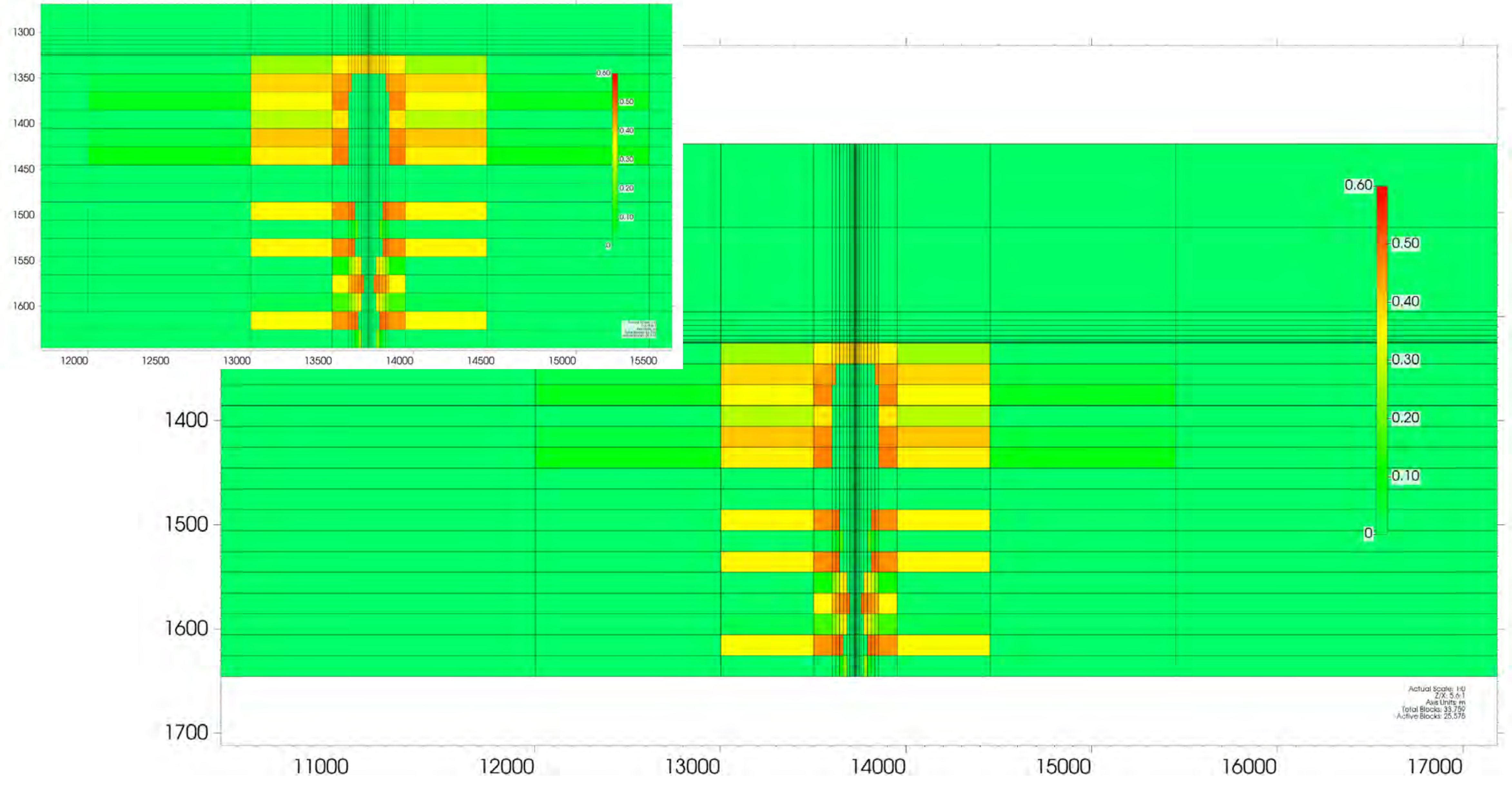
Change of 3 principal total stresses near wellbore ()





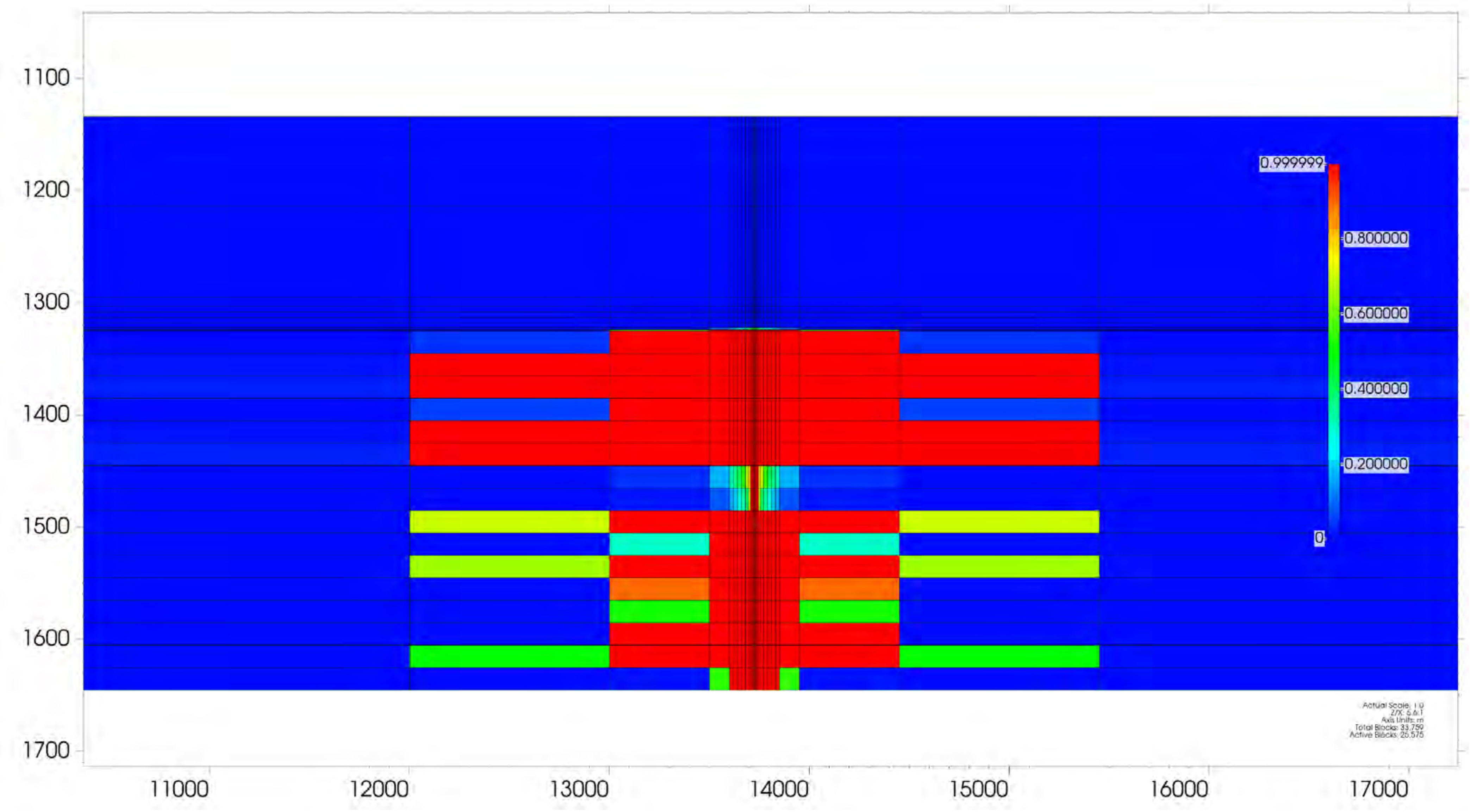
Case1: inject from upper Leduc (layer 3 in the reservoir grid);

Gas saturation @ 15 years



Case1: inject from upper Leduc (layer 3 in the reservoir grid);

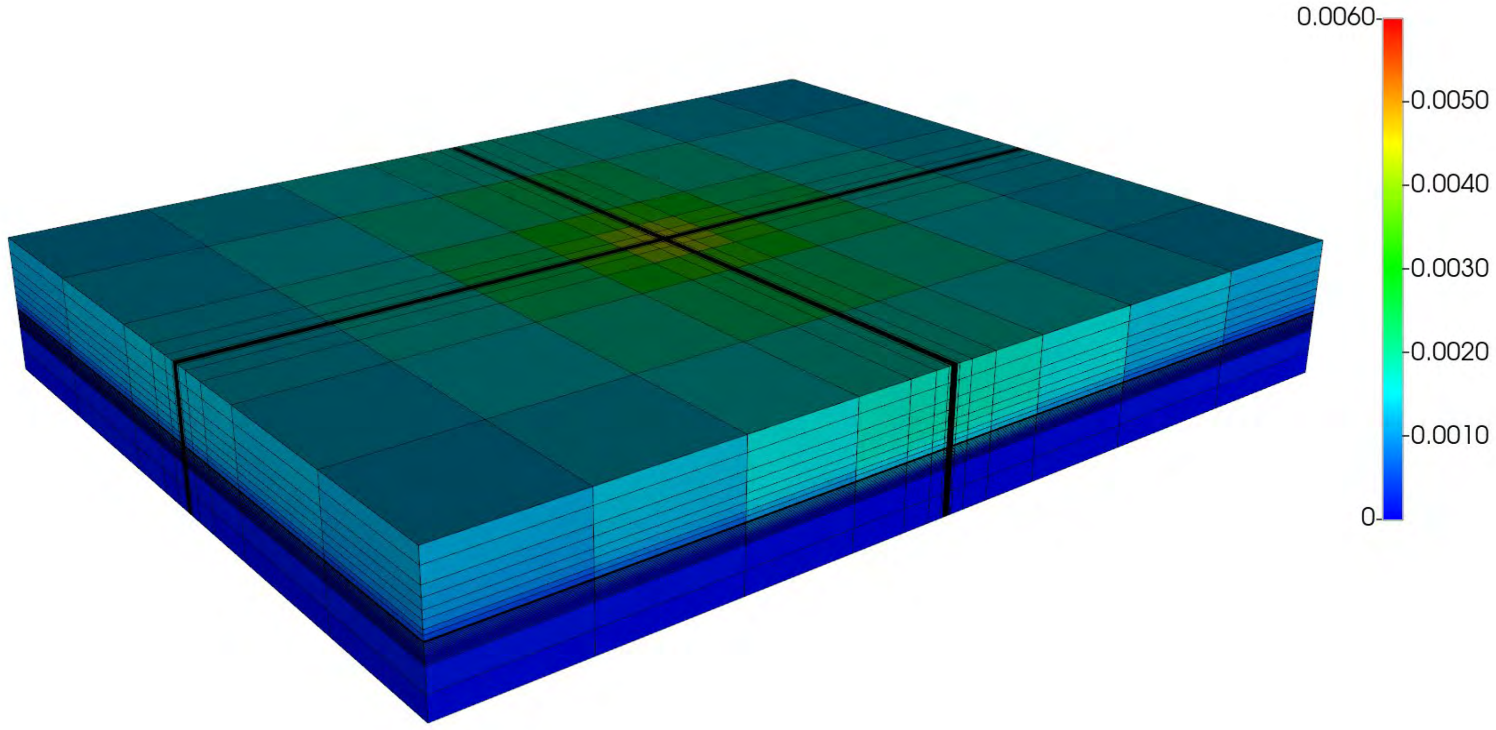
CO2 Mole fraction@ 15 years

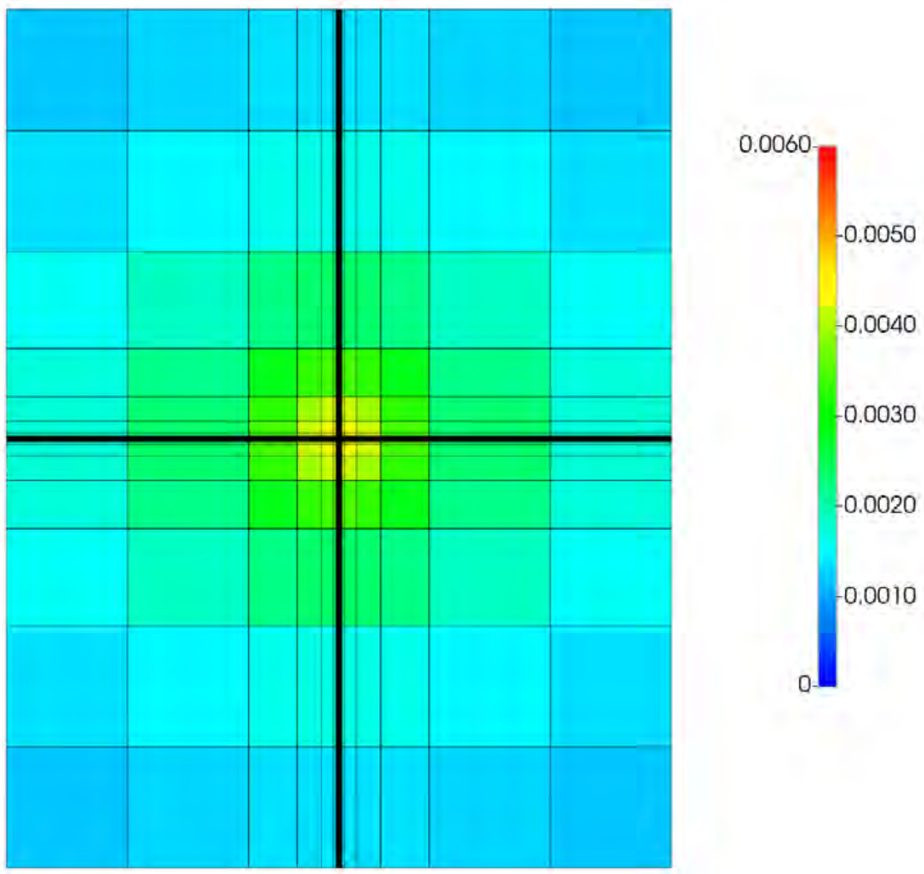


Case 2:inject from Cooking Lake (layer 9 in the reservoir grid)
Temperature= <u>5degC</u>

Case2: inject from cooking lake

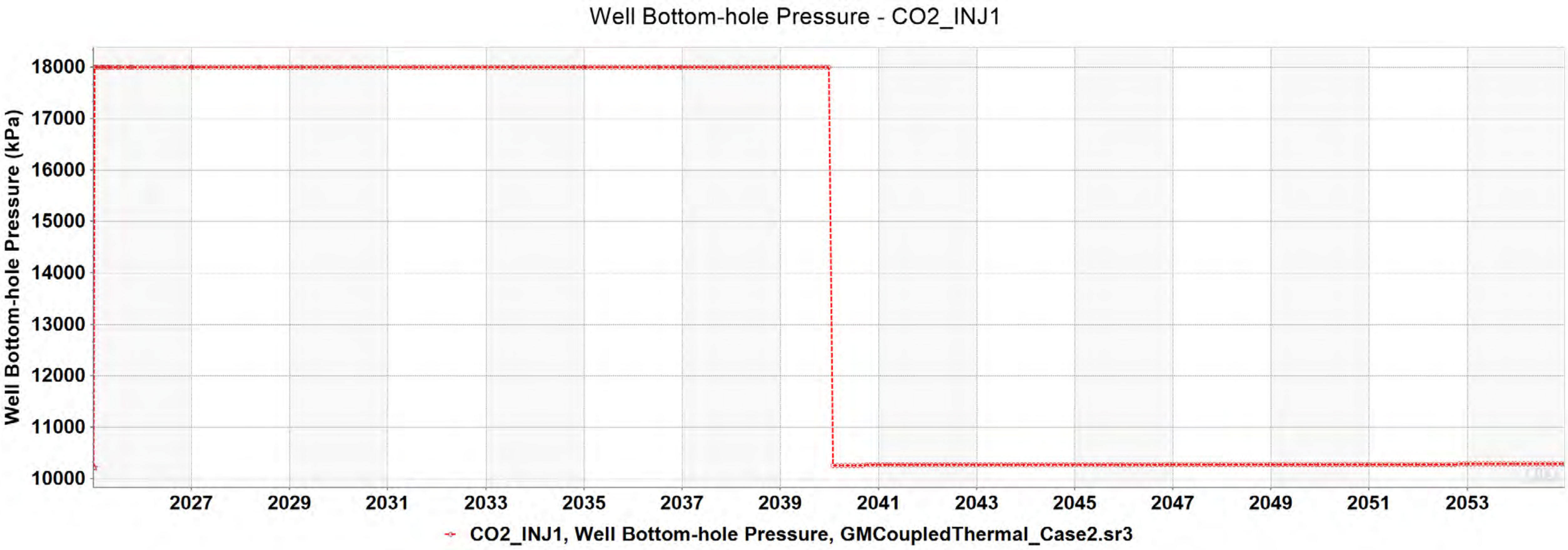
Surface heave @ end of injection 15 years (max. 3mm)





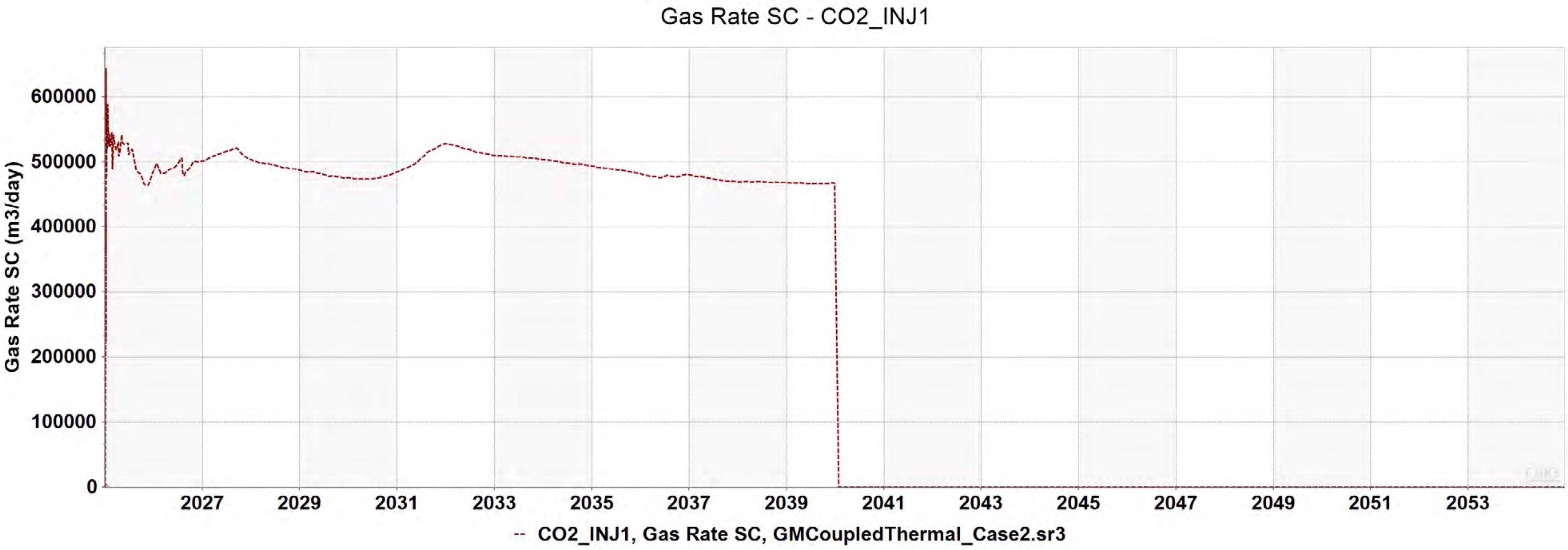
Case2: inject from cooking lake

Injection pressure (BHP, unit: kPa), Pressure max out



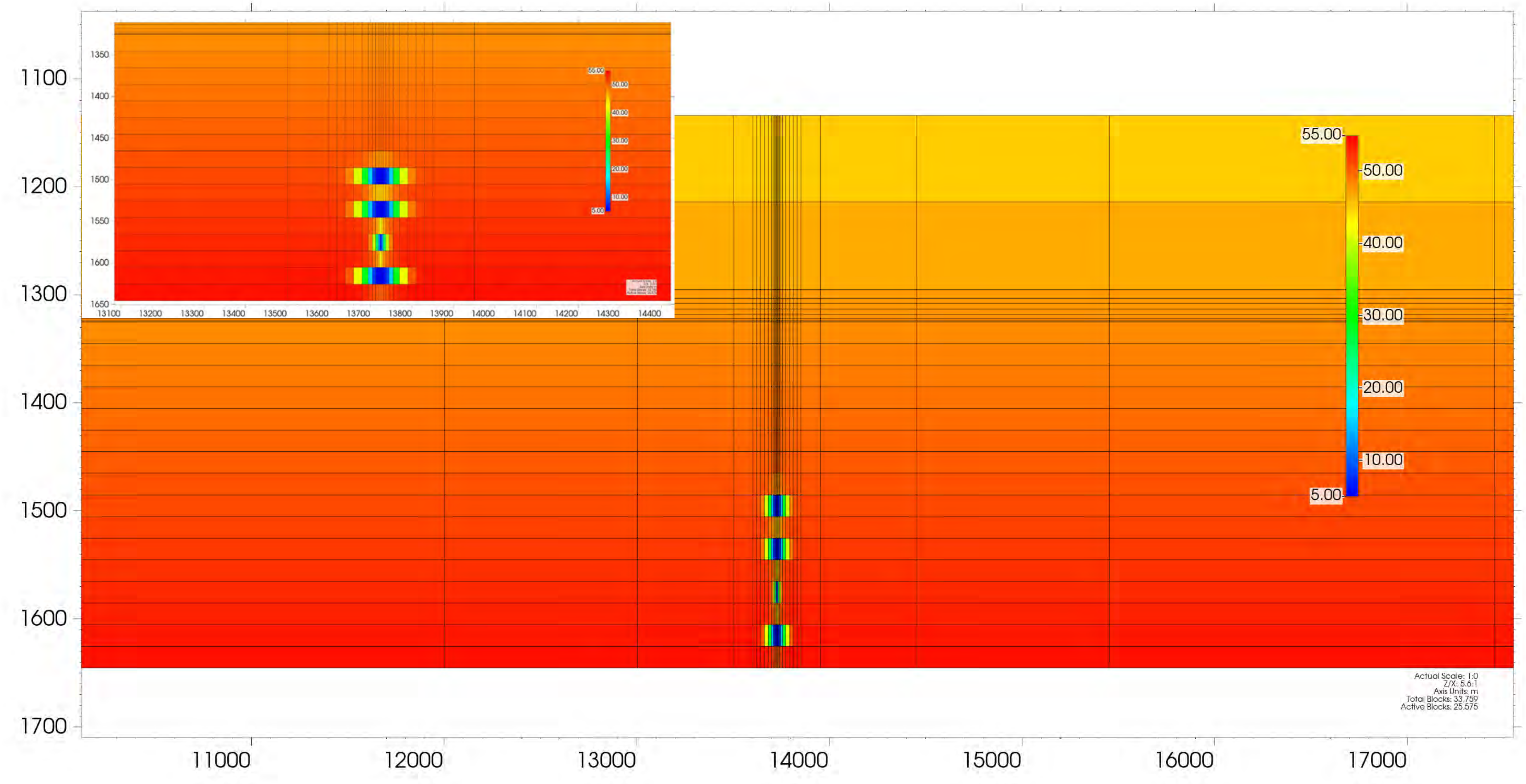
Case2: inject from cooking lake

Injection rate



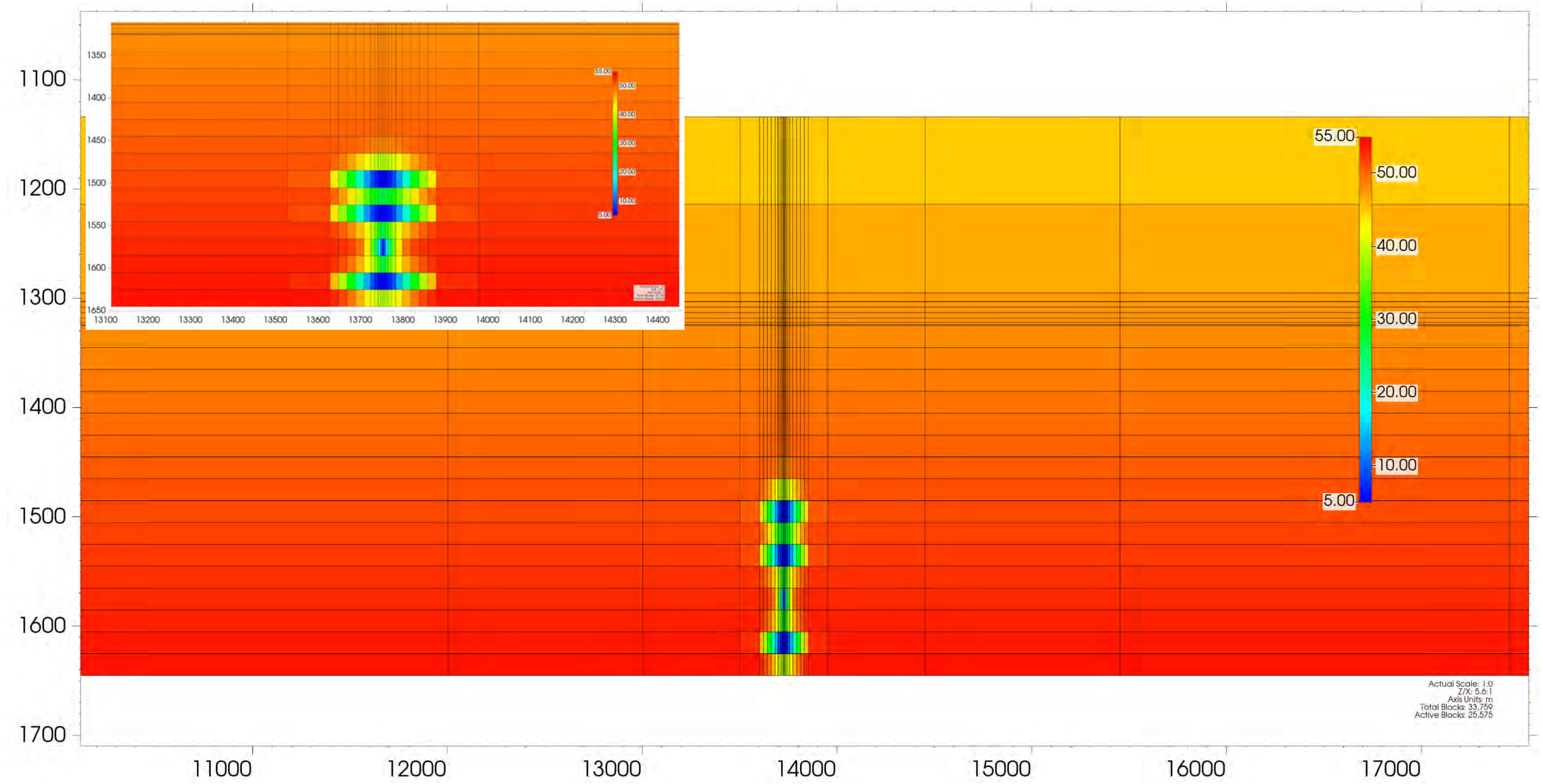
Case2: inject from cooking lake

Temperature distribution @ 1 year



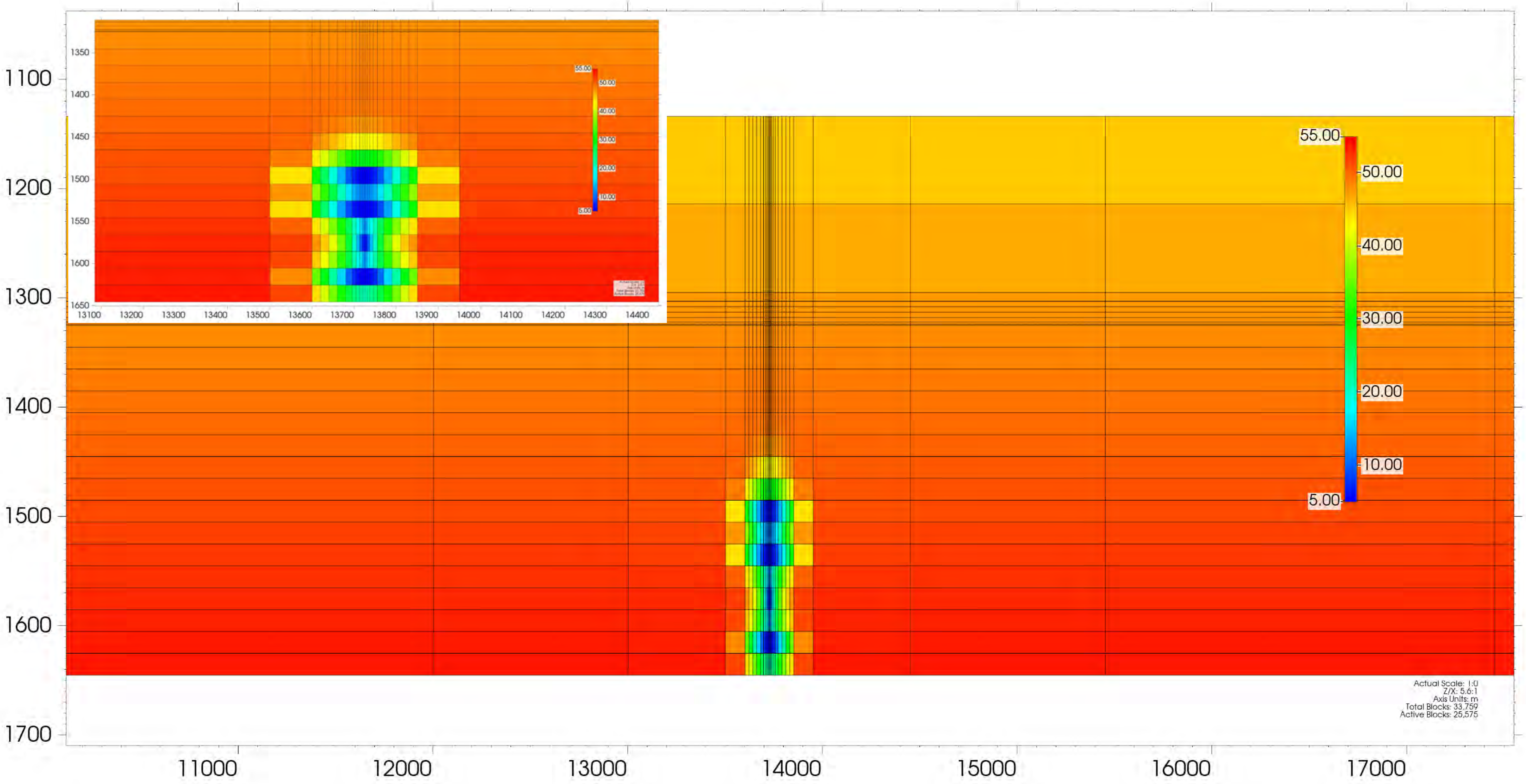
Case2: inject from cooking lake

Temperature distribution @ 5 years



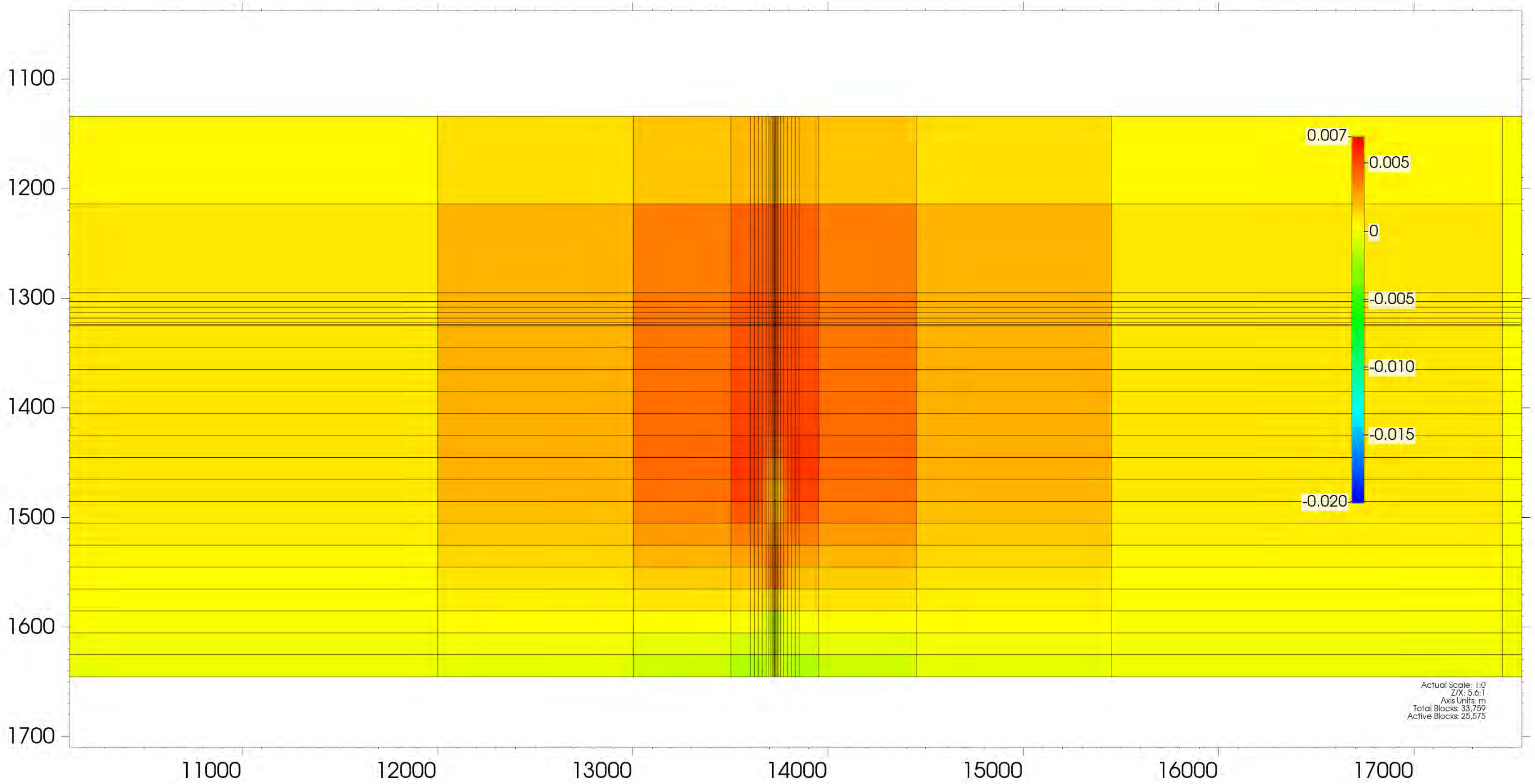
Case2: inject from cooking lake

Temperature distribution @ end of injection 15 years



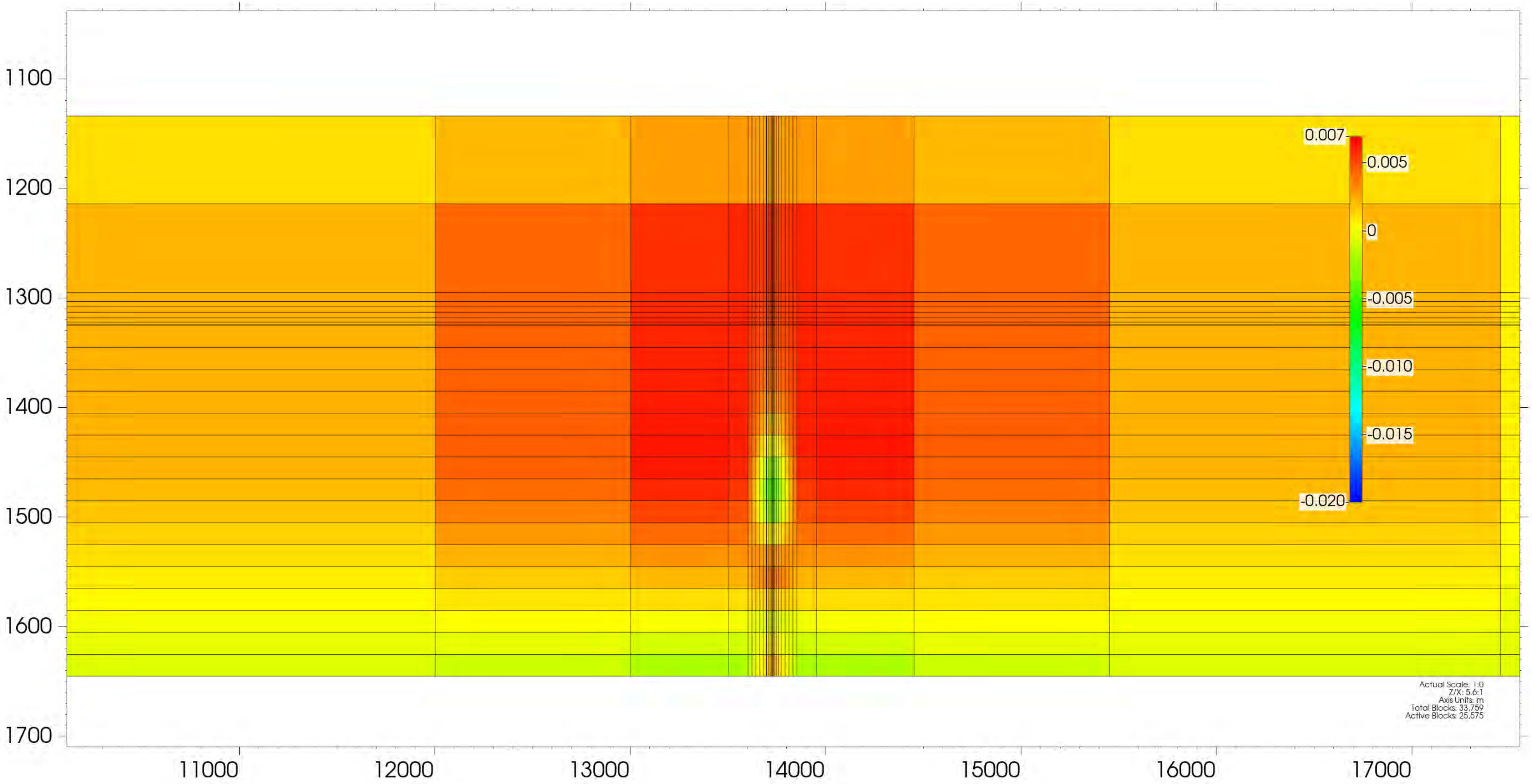
Case2: inject from cooking lake

Deformation (Uz) @ 1 year



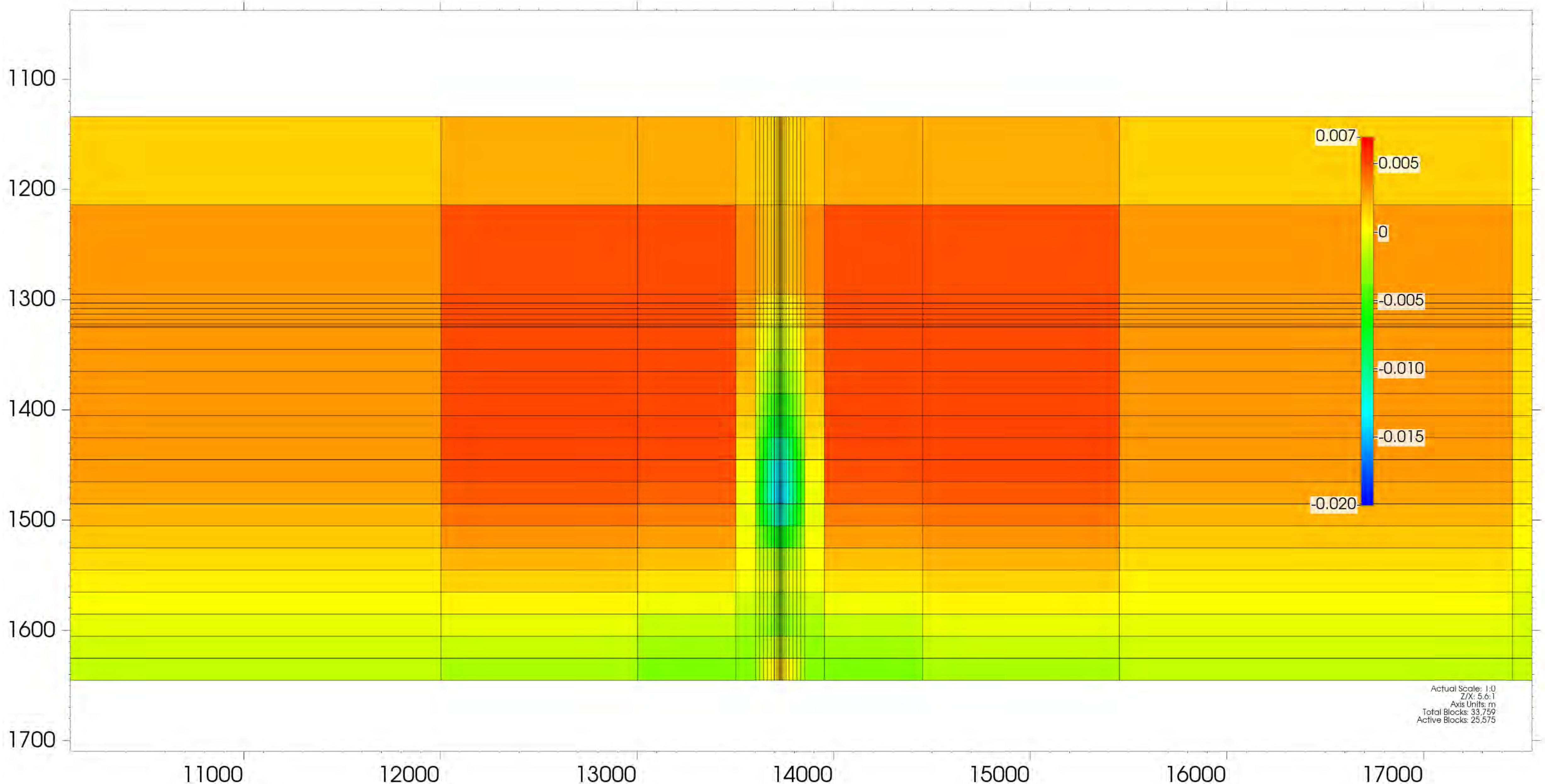
Case2: inject from cooking lake

Deformation (Uz) @ 5 years



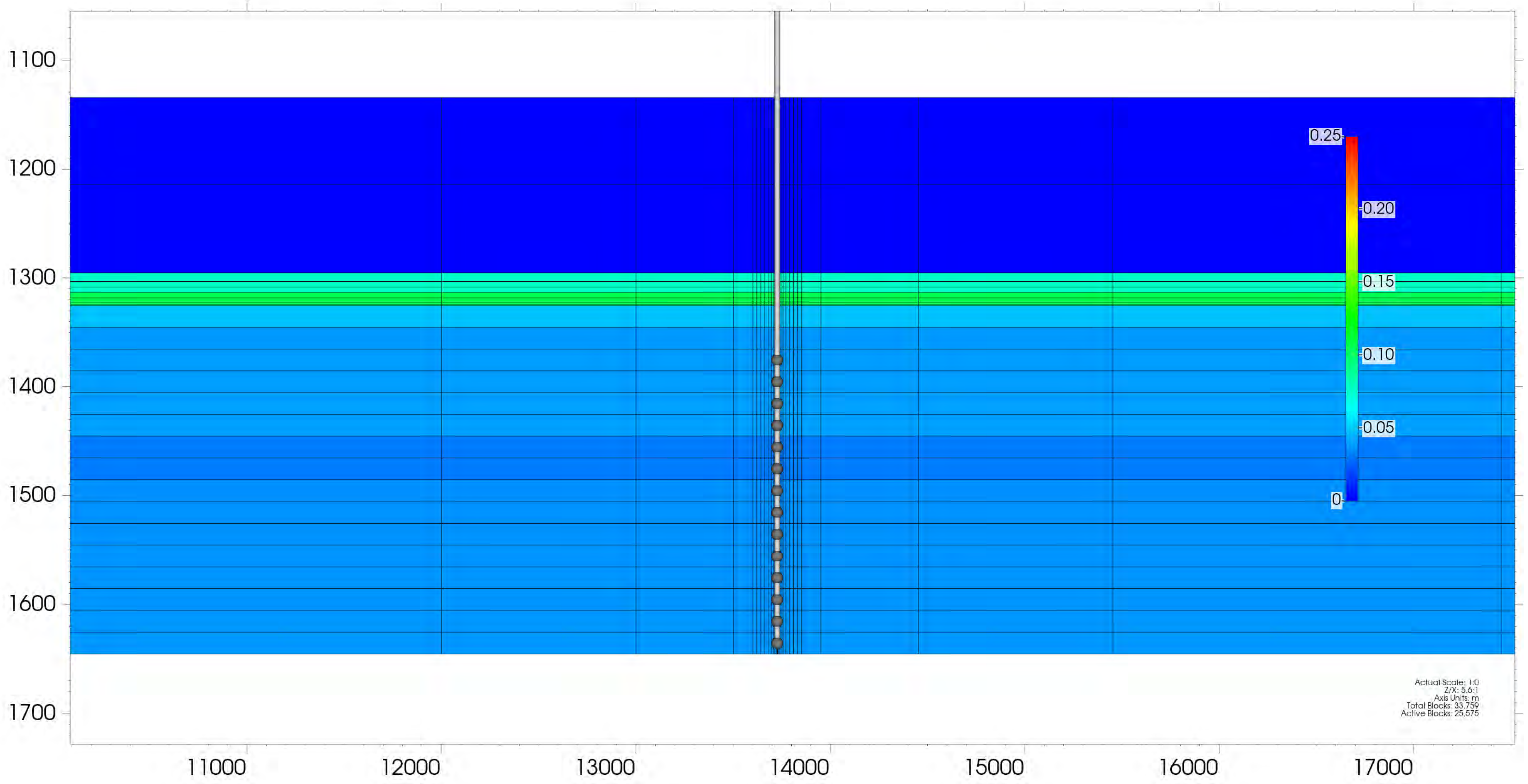
Case2: inject from cooking lake

Deformation (Uz) @ end of injection 15 years



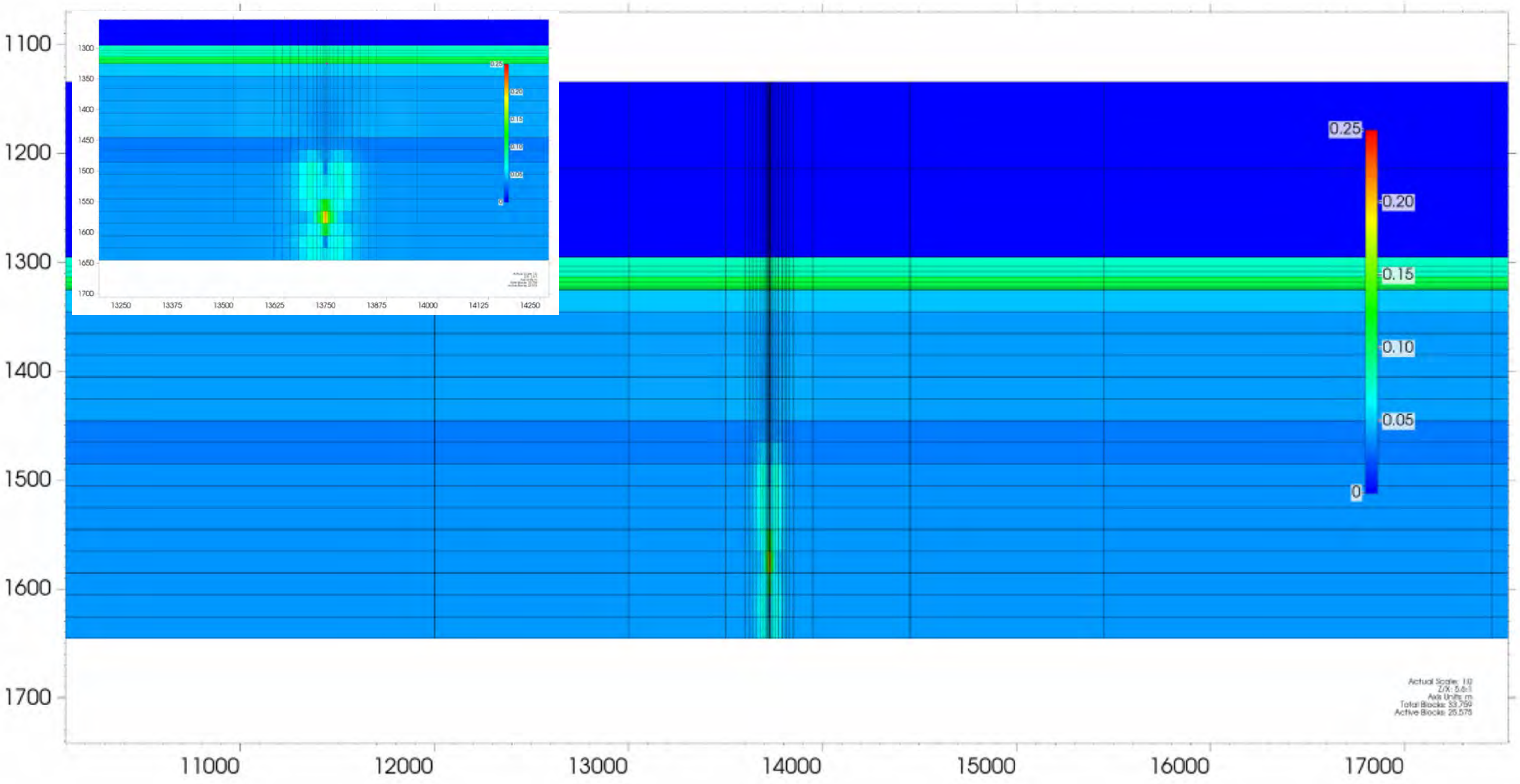
Case2: inject from cooking lake

SSL at lower Ireton, Leduc and Cooking lake @ time=0 (only 3 formations and others are set zero)



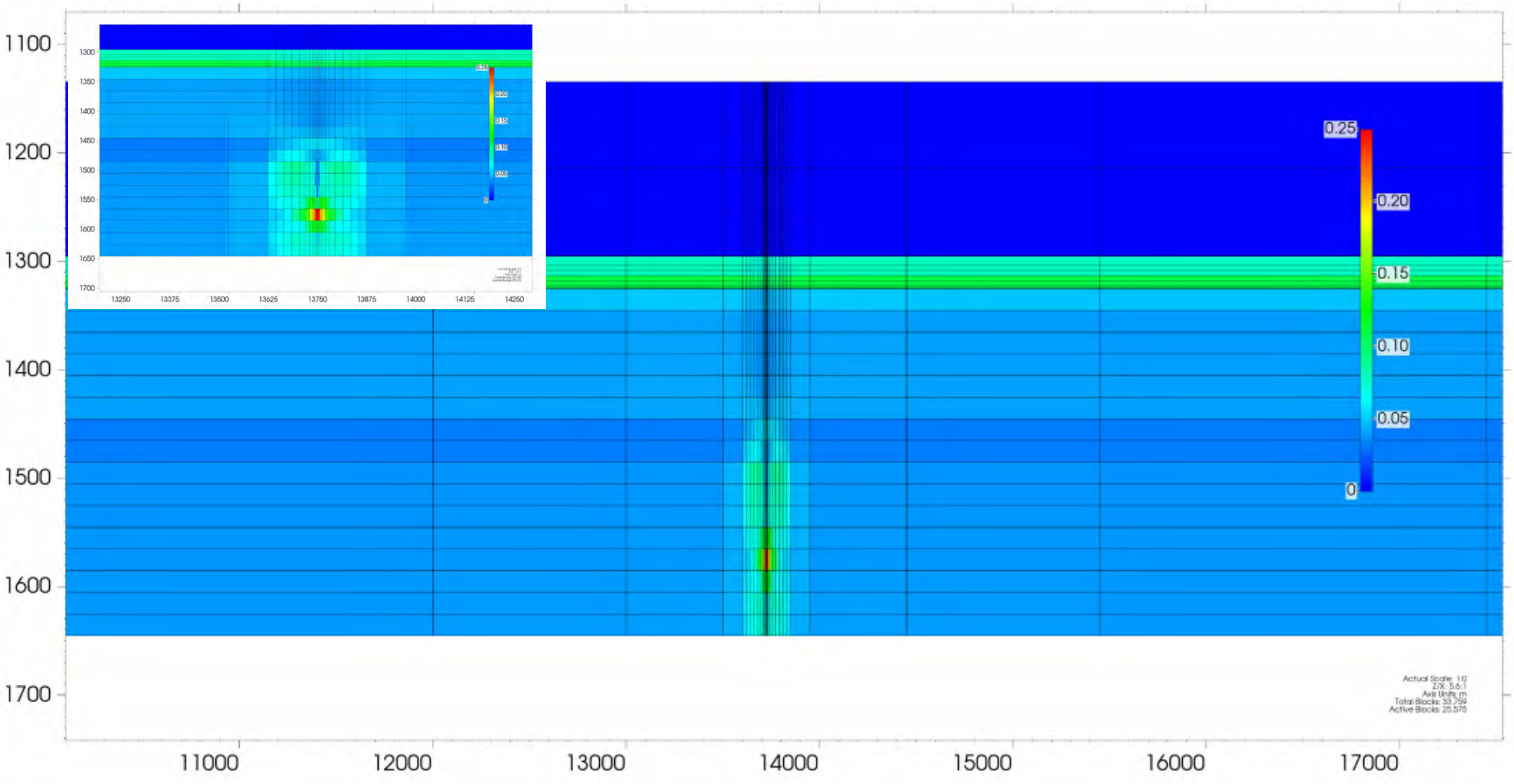
Case2: inject from cooking lake

SSL at lower Ireton, Leduc and Cooking lake @ 1 year



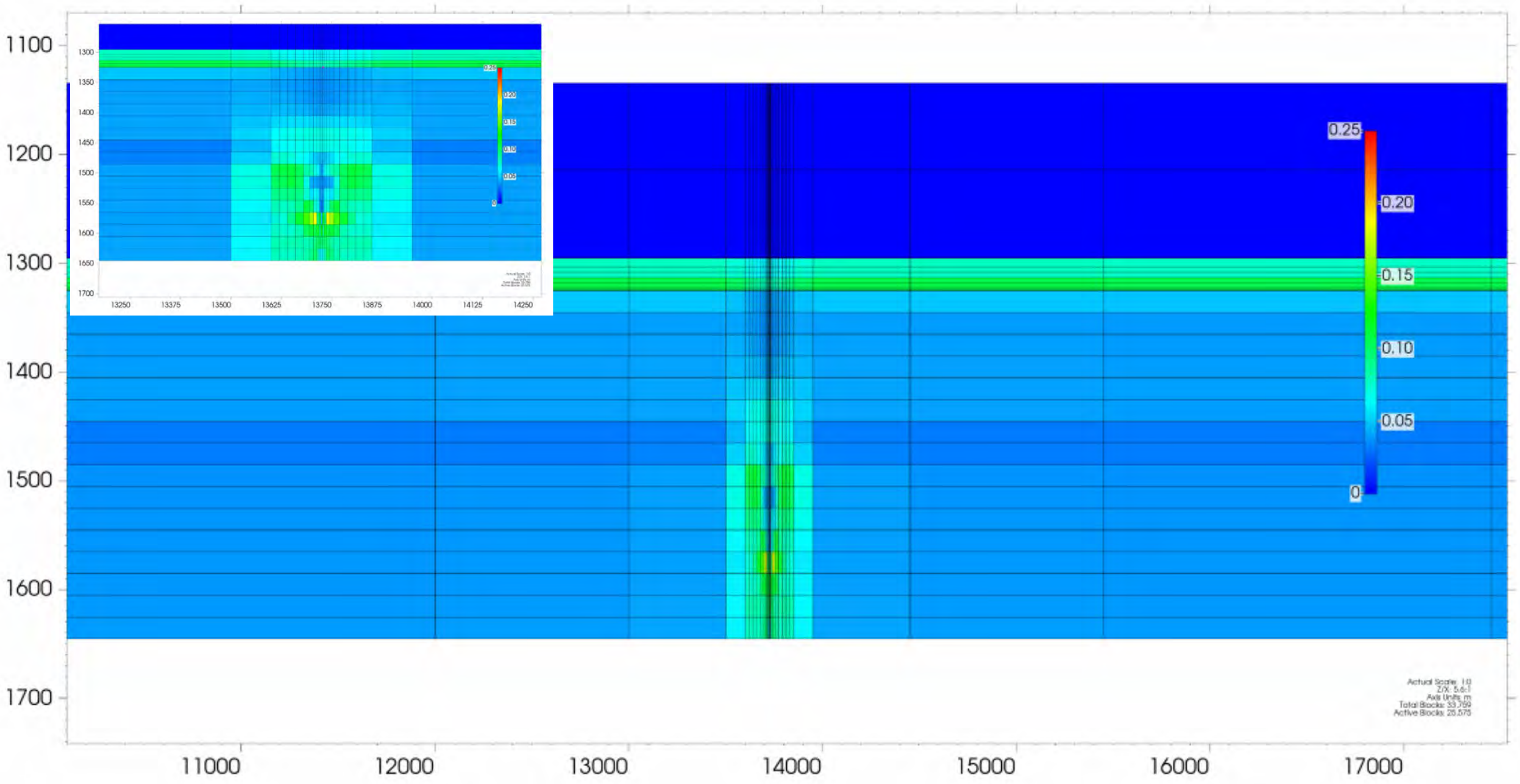
Case2: inject from cooking lake

SSL at lower Ireton, Leduc and Cooking lake @ 5 years



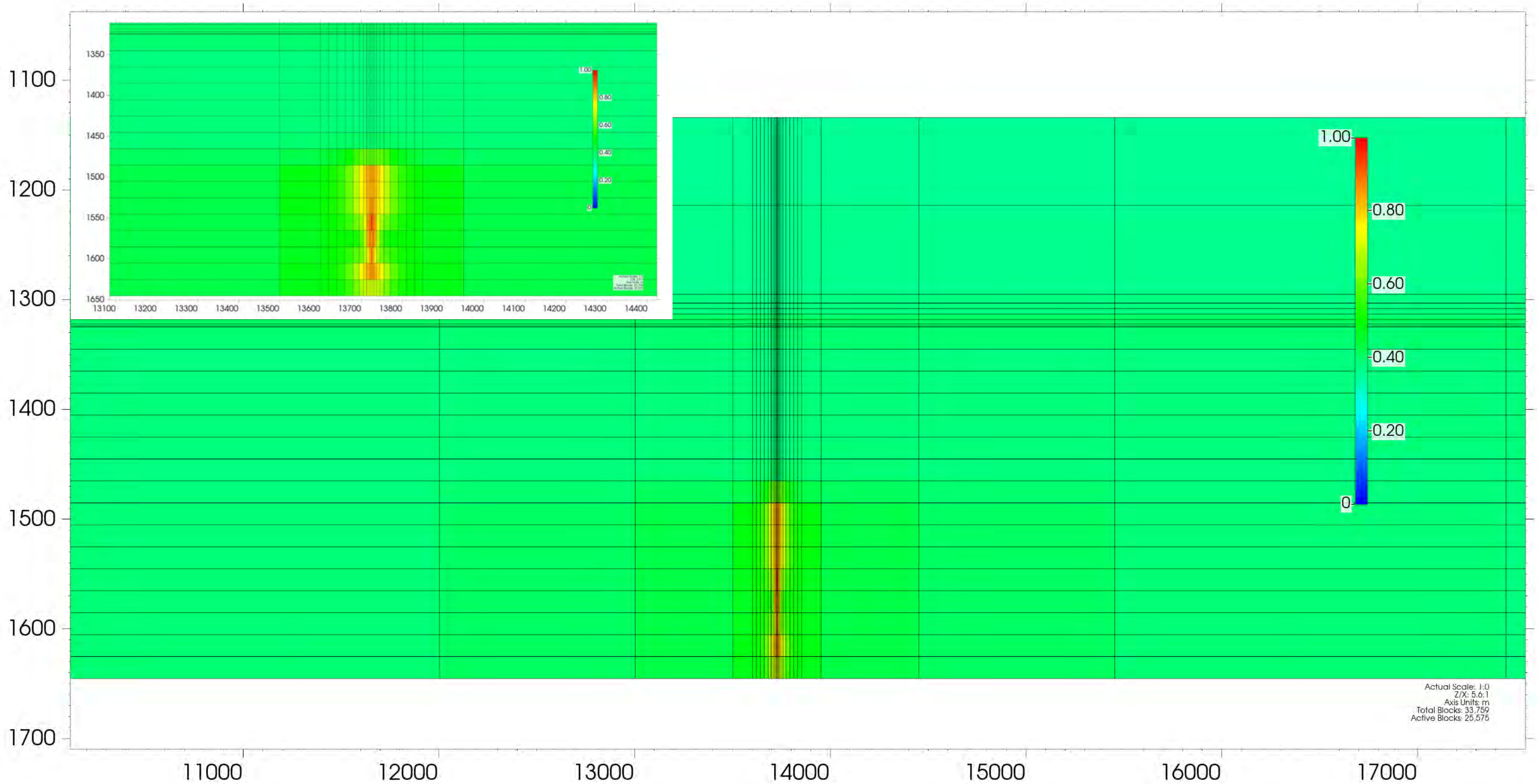
Case2: inject from cooking lake

SSL at lower Ireton, Leduc and Cooking lake @ 15 years



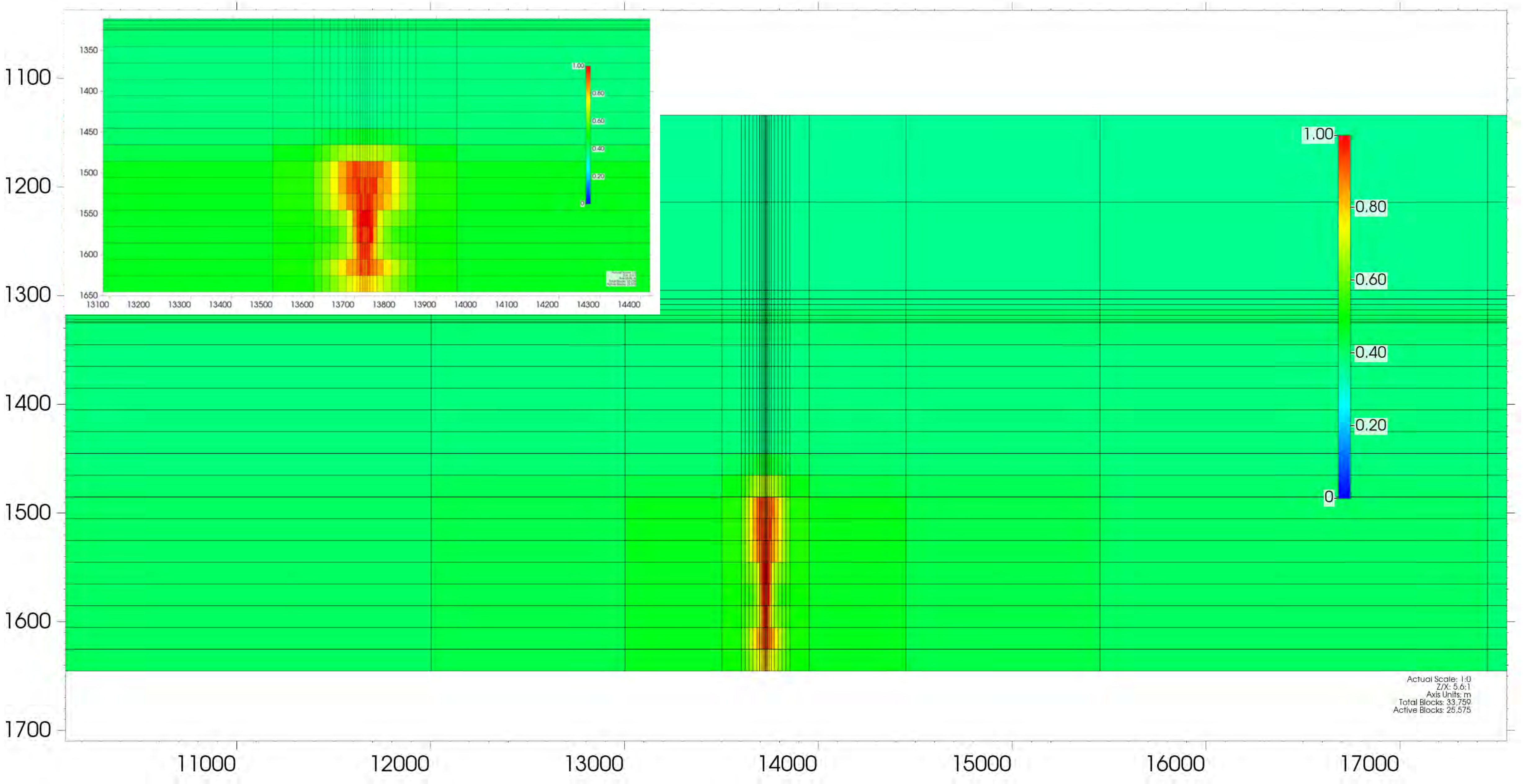
Case2: inject from cooking lake

TSL at lower Ireton, Leduc and Cooking lake @ 1 year



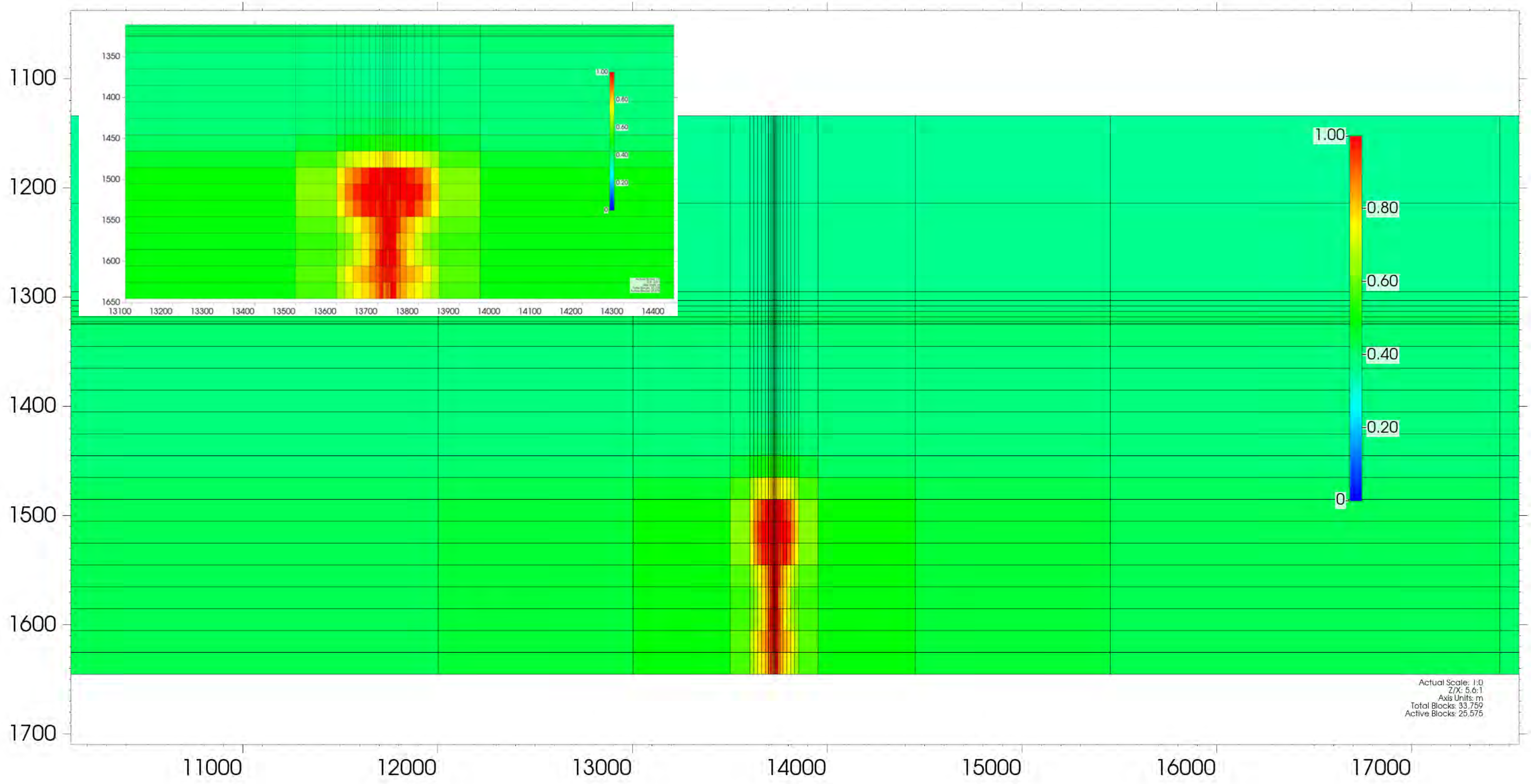
Case2: inject from cooking lake

TSL at lower Ireton, Leduc and Cooking lake @ 5 years (fractured near wellbore)



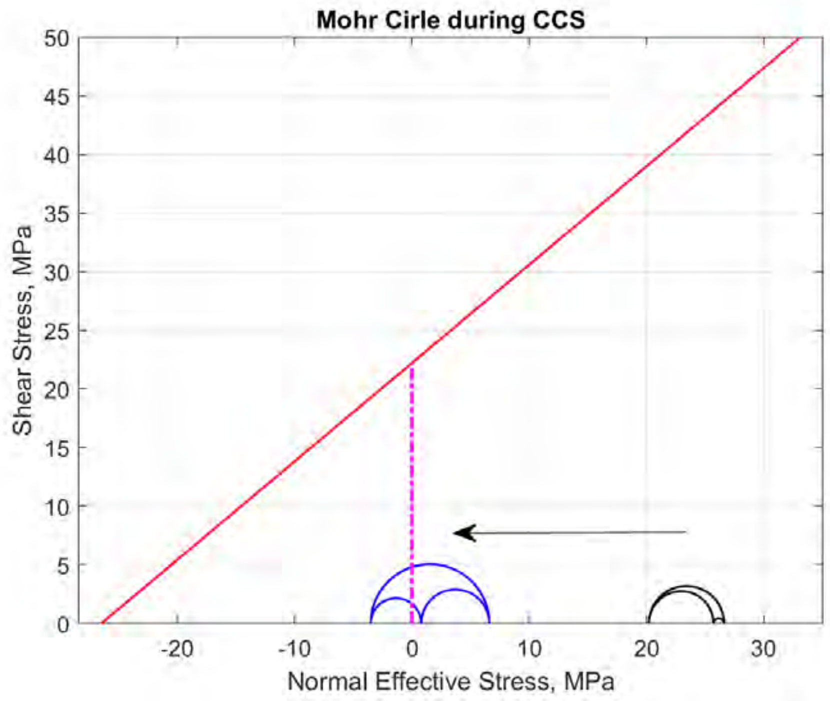
Case2: inject from cooking lake

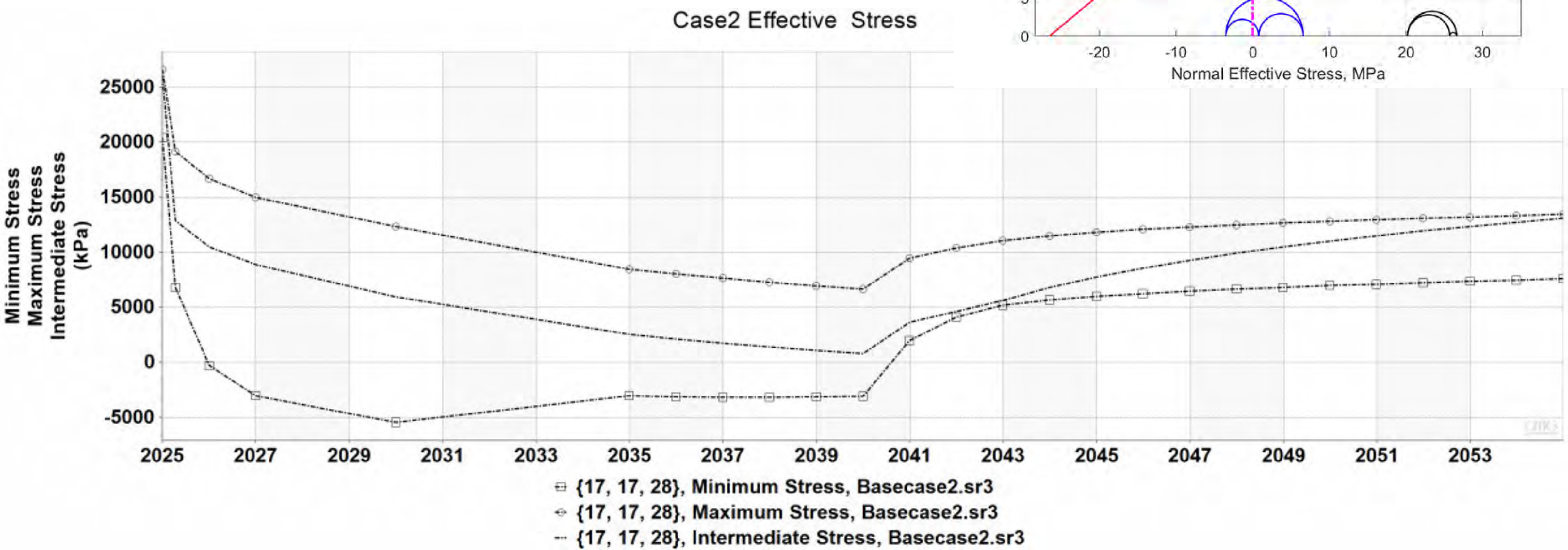
TSL at lower Ireton, Leduc and Cooking lake @ end of injection 15 years (fractured near wellbore)



Case2: inject from cooking lake

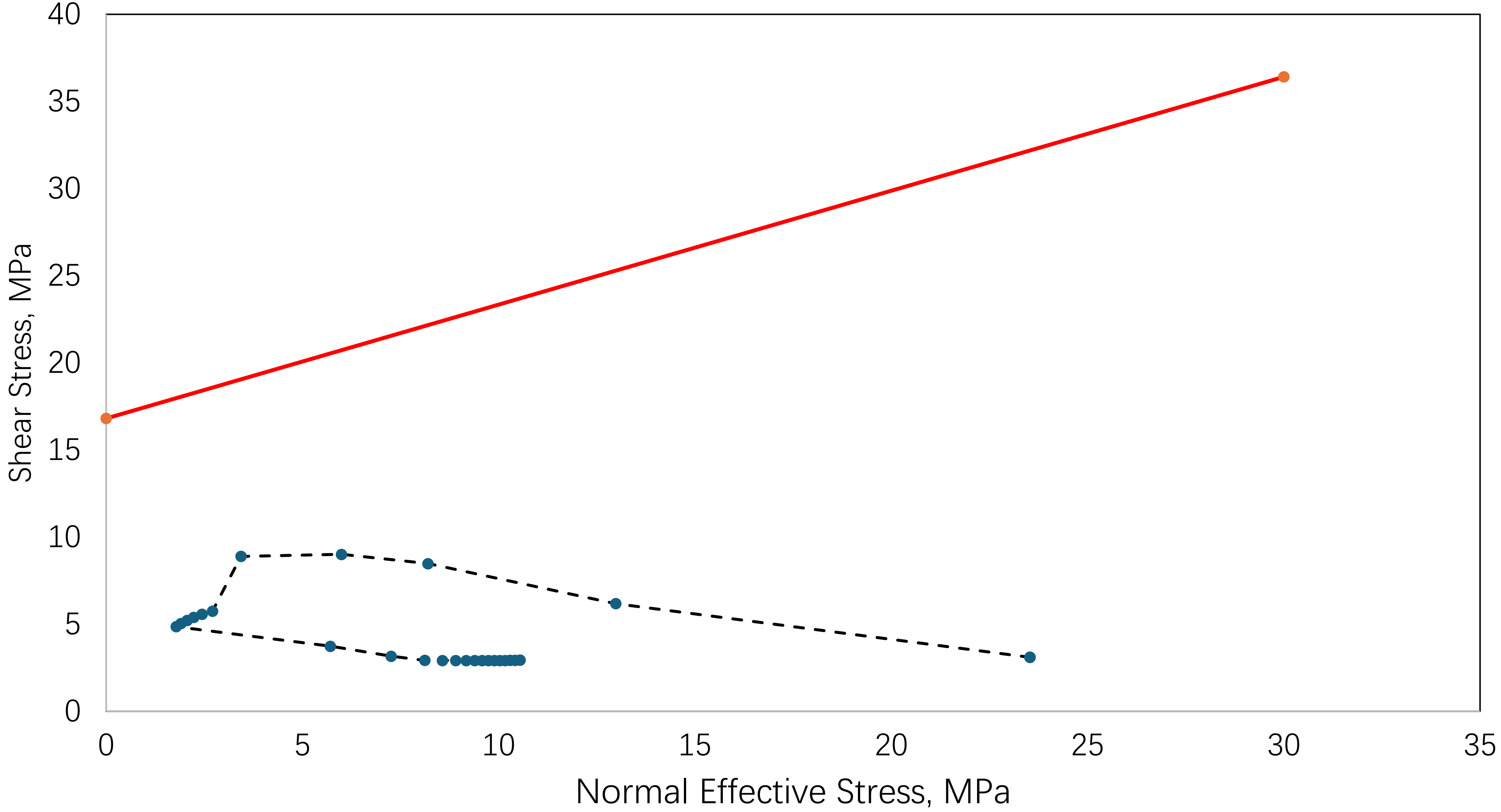
Change of 3 principal effective stresses near wellbore





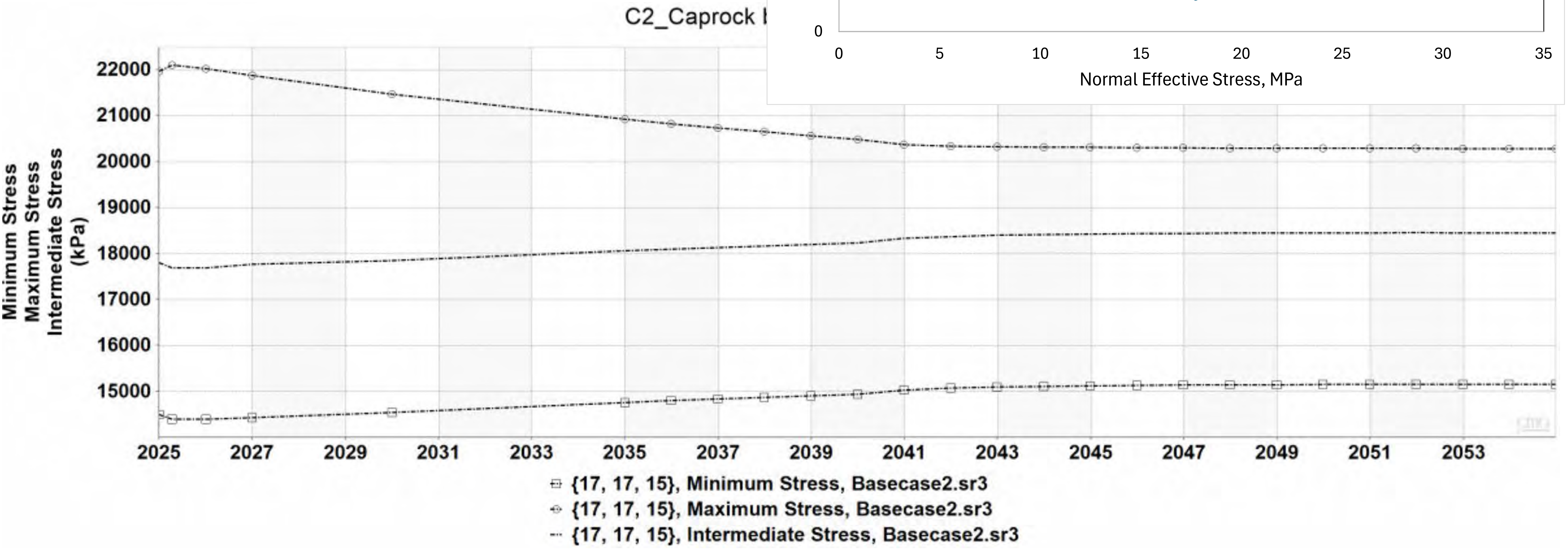
Case2: inject from cooking lake

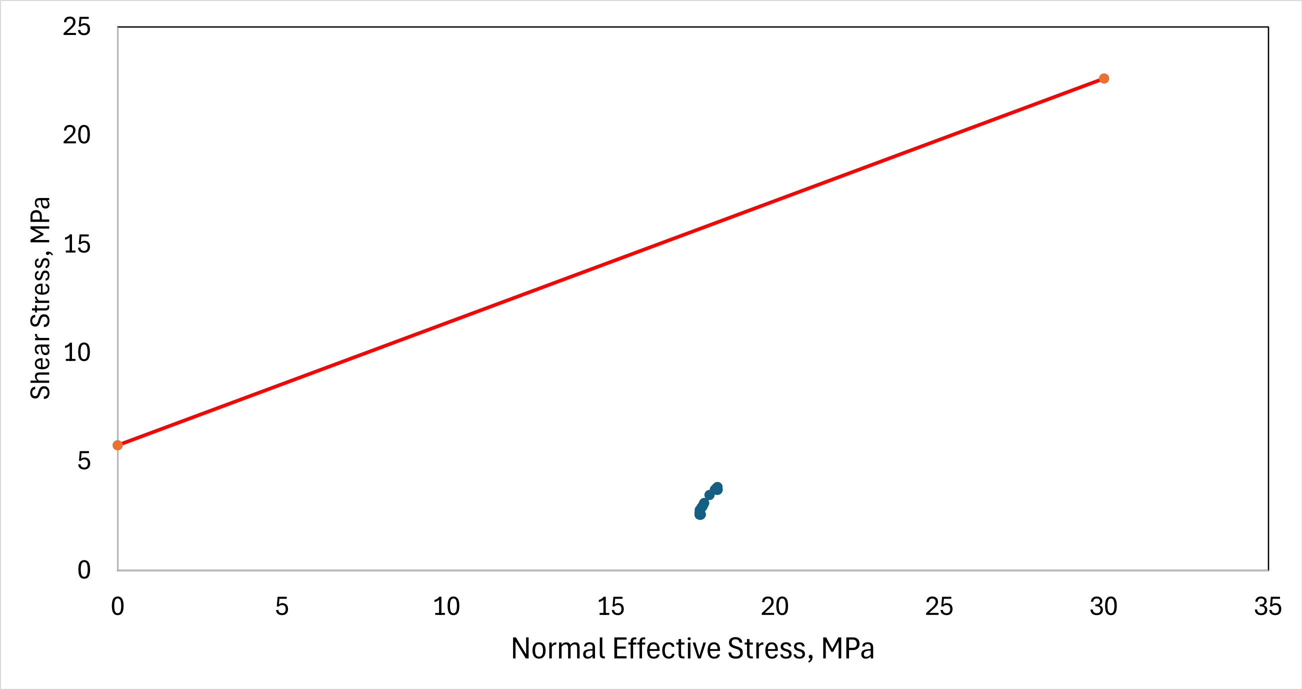
Stress path



Case2: inject from cooking lake

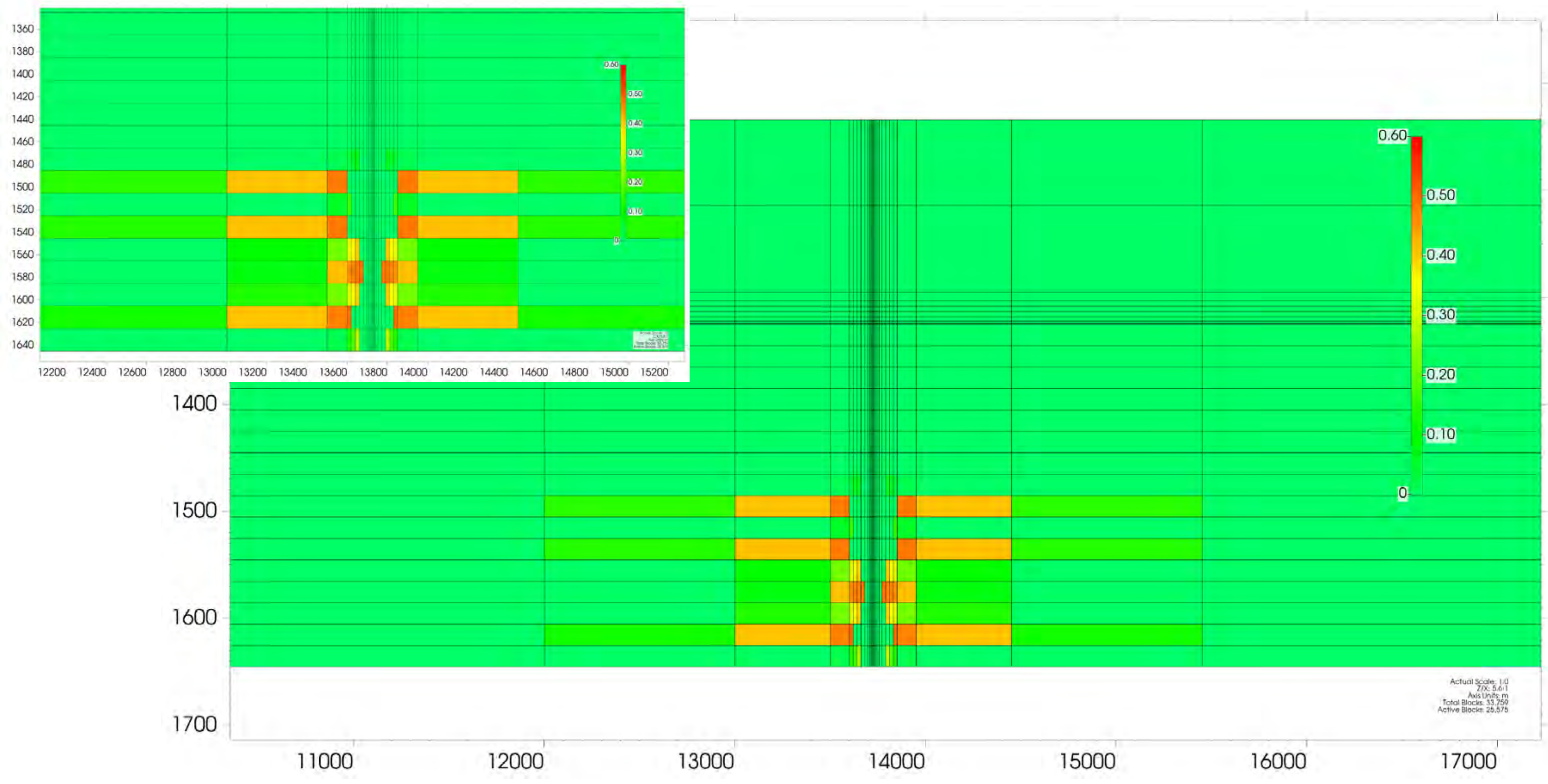
Stress path for caprock base





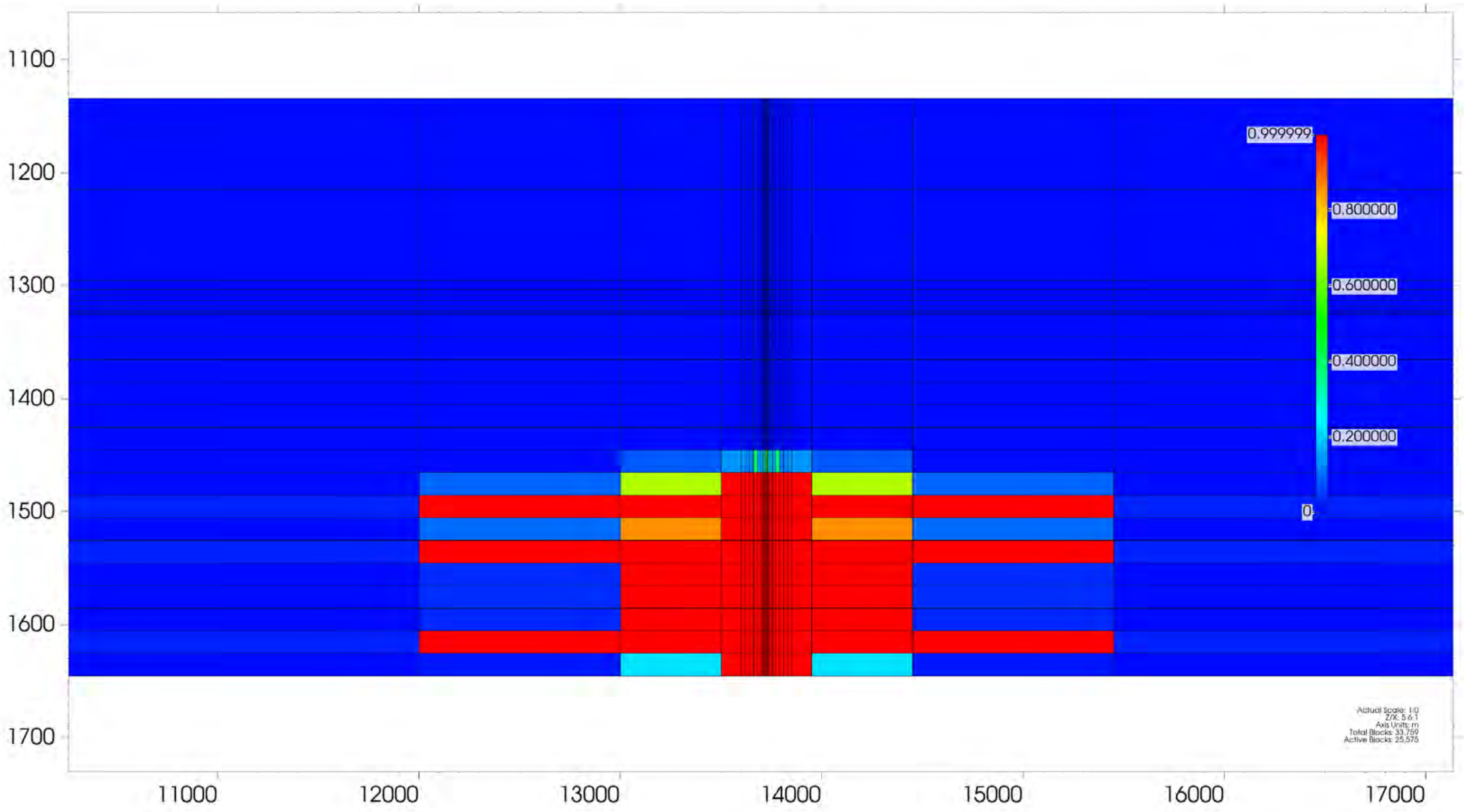
Case2: inject from cooking lake

Gas saturation @ 15 years



Case2: inject from cooking lake

CO2 Mole fraction@ 15 years



Case 3: Injection at CookingLake, Low Rate=0.07 Mtps

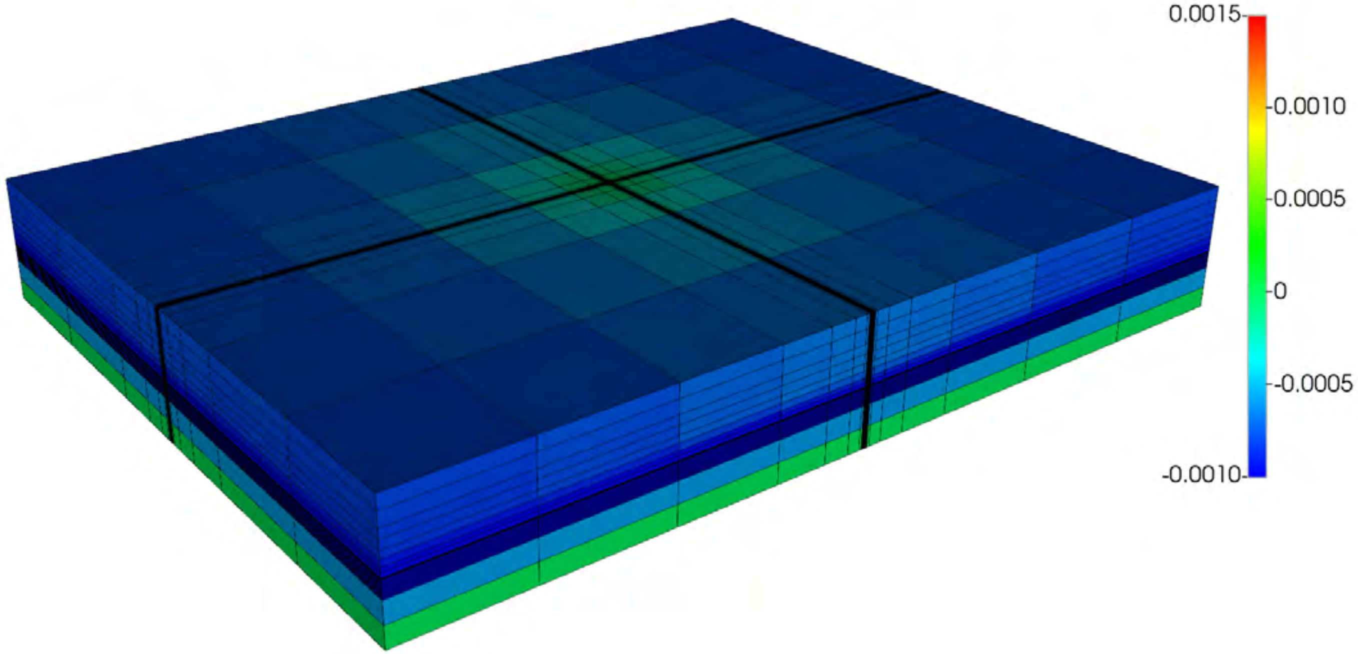
Base case: Case2

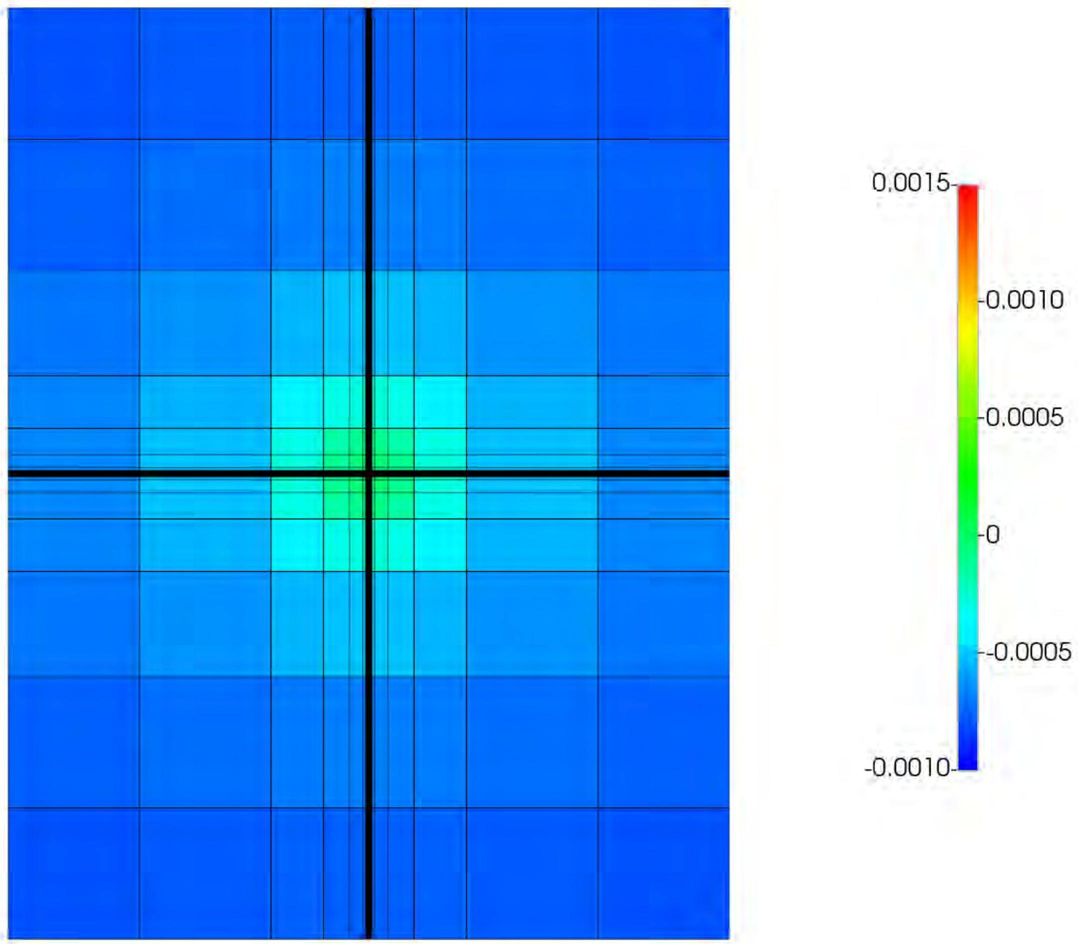
Input file change from Case 2

```
*******************************
RUN

DATE 2025 1 1
**
WELL  'CO2_INJ1'
INJECTOR 'CO2_INJ1'
INCOMP  SOLVENT  1.0
OPERATE  MAX  BHP  18000.0  CONT REPEAT
OPERATE  MAX  STG  1.02e5  CONT REPEAT  ** 0.07 Mpta
** UBA                      ff           Status  Connection
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.1  0.37  1.0  0.0
      PERF      GEOA  'CO2_INJ1'
****-----------Start from Layer 9 at reservoir  , CookingLake
** UBA                  ff           Status  Connection
    16 17 18       1.0  CLOSED    FLOW-FROM  'SURFACE'  REFLAYER
    16 17 19       1.0  CLOSED    FLOW-FROM  1
    16 17 20       1.0  CLOSED    FLOW-FROM  2
    16 17 21       1.0  CLOSED    FLOW-FROM  3
    16 17 22       1.0  CLOSED    FLOW-FROM  4
    16 17 23      1.0  CLOSED     FLOW-FROM  5
    16 17 24       1.0  OPEN     FLOW-FROM  6
    16 17 25      1.0  OPEN      FLOW-FROM  7
    16 17 26      1.0  OPEN      FLOW-FROM  8
    16 17 27      1.0  OPEN      FLOW-FROM  9
    16 17 28      1.0  OPEN      FLOW-FROM  10
    16 17 29      1.0  OPEN      FLOW-FROM  11
    16 17 30      1.0  OPEN      FLOW-FROM  12
    16 17 31      1.0  OPEN      FLOW-FROM  13
```

Case3: inject from cooking lake, Rate=0.07 Mpta

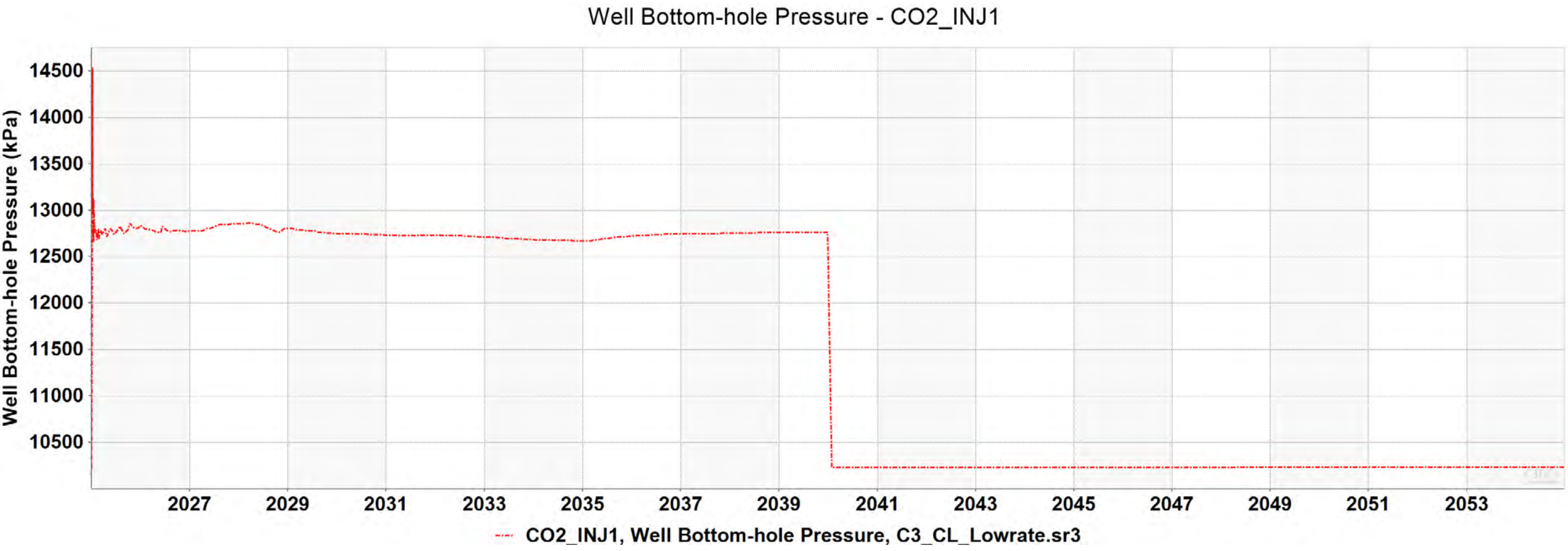
Surface heave @ end of injection 15 years (max. 1mm)





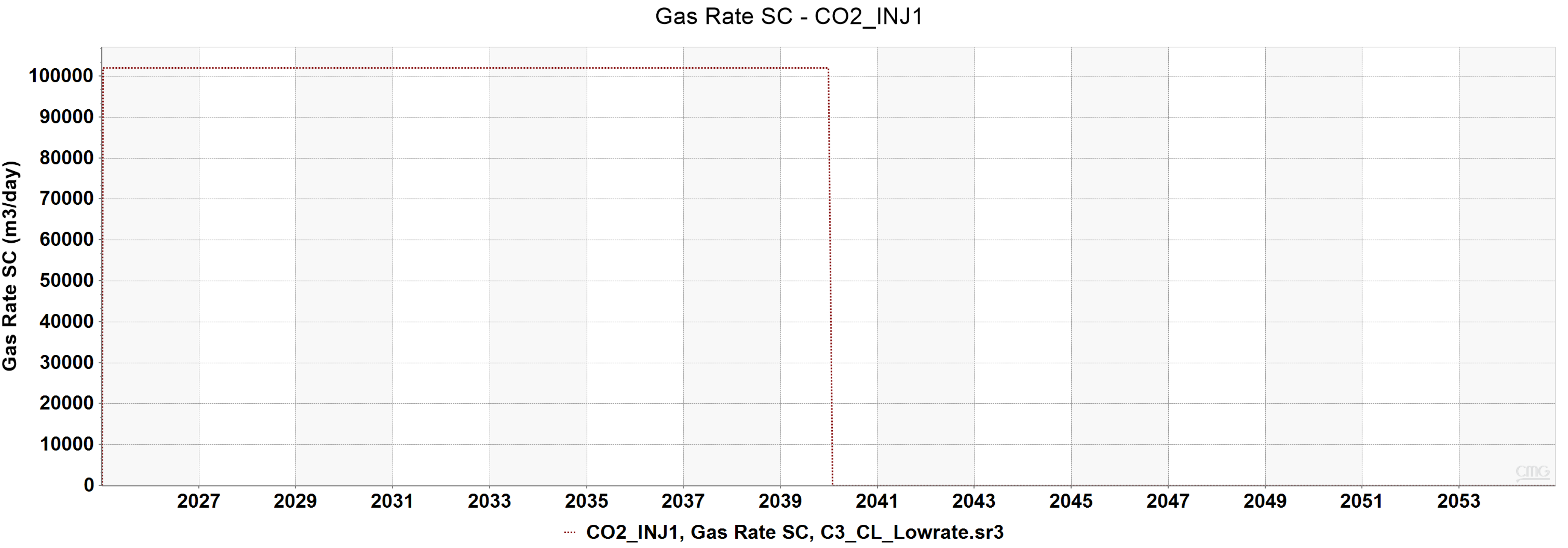
Case3: inject from cooking lake, Rate=0.07 Mpta

Injection pressure (BHP, unit: kPa)



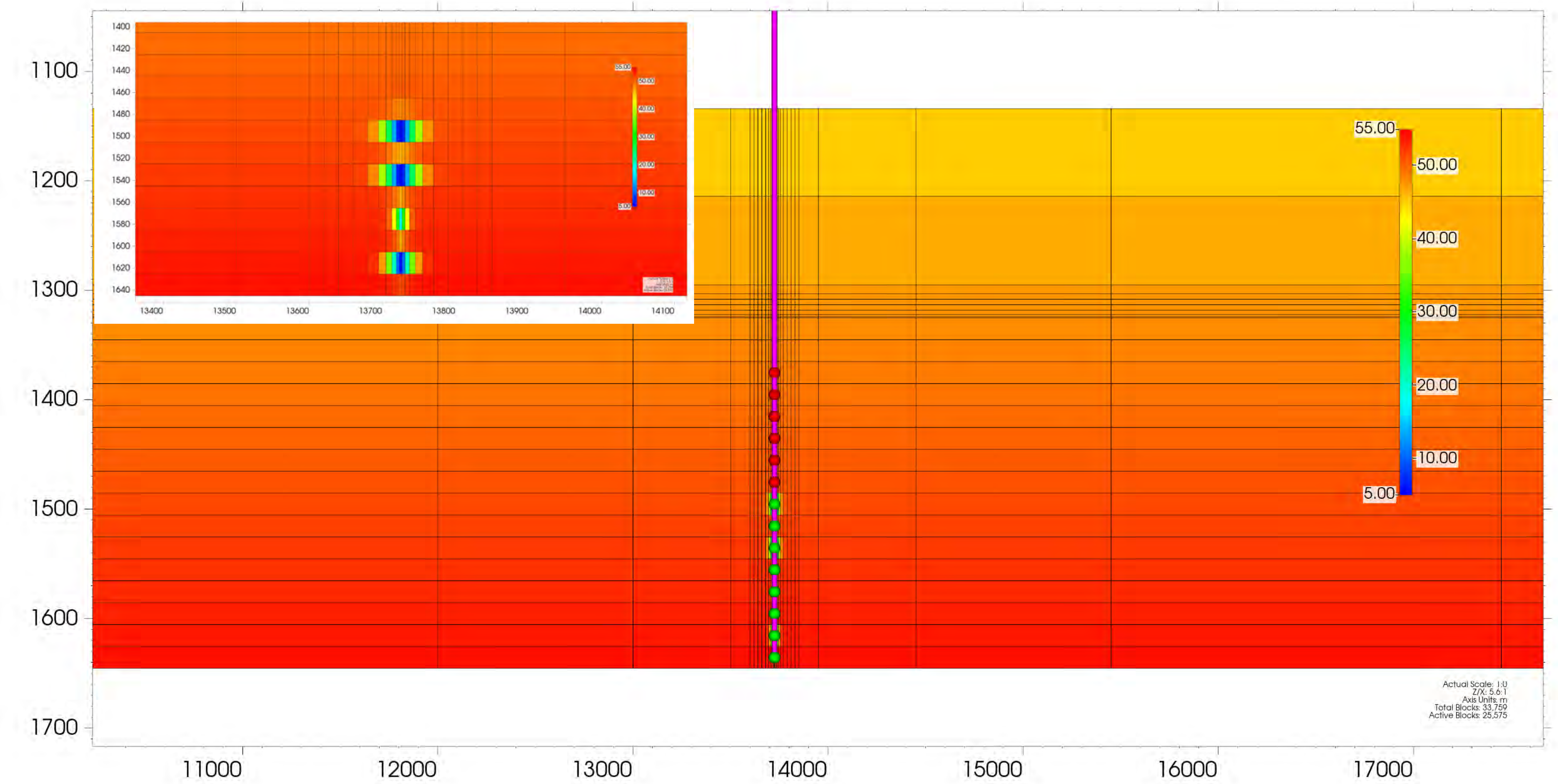
Case3: inject from cooking lake, Rate=0.07 Mpta

Injection rate



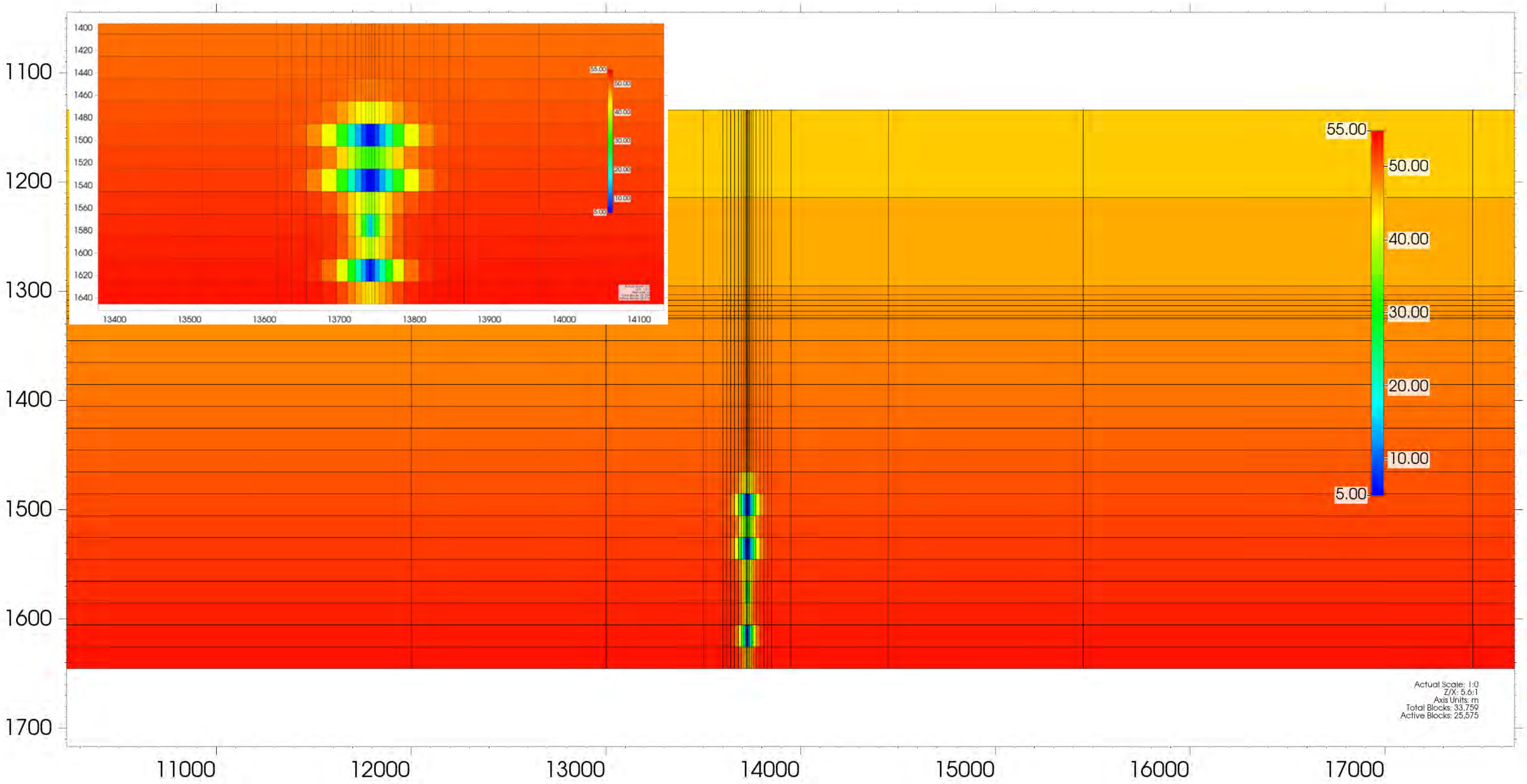
Case3: inject from cooking lake, Rate=0.07 Mpta

Temperature distribution @ 1 year



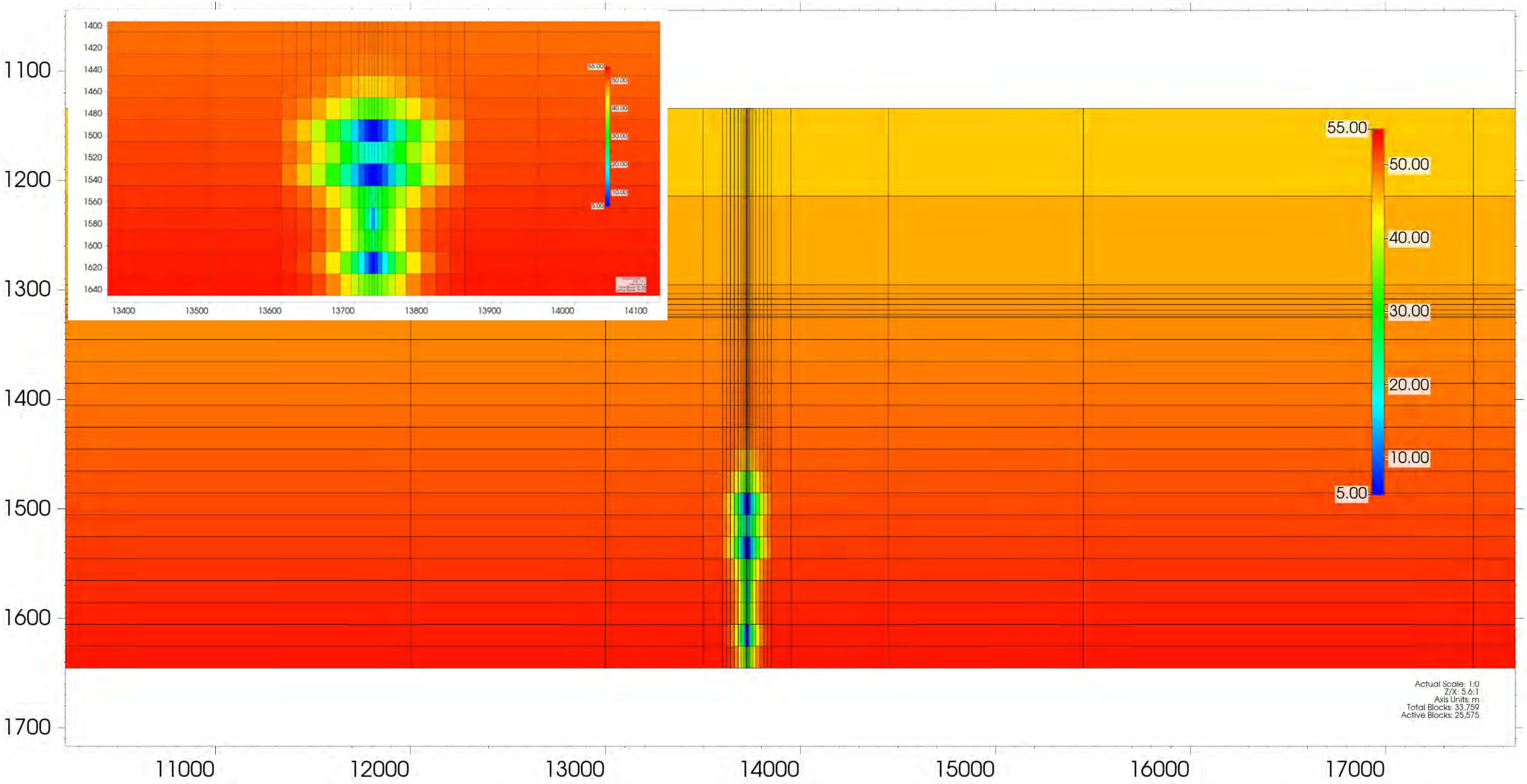
Case3: inject from cooking lake, Rate=0.07 Mpta

Temperature distribution @ 5 years



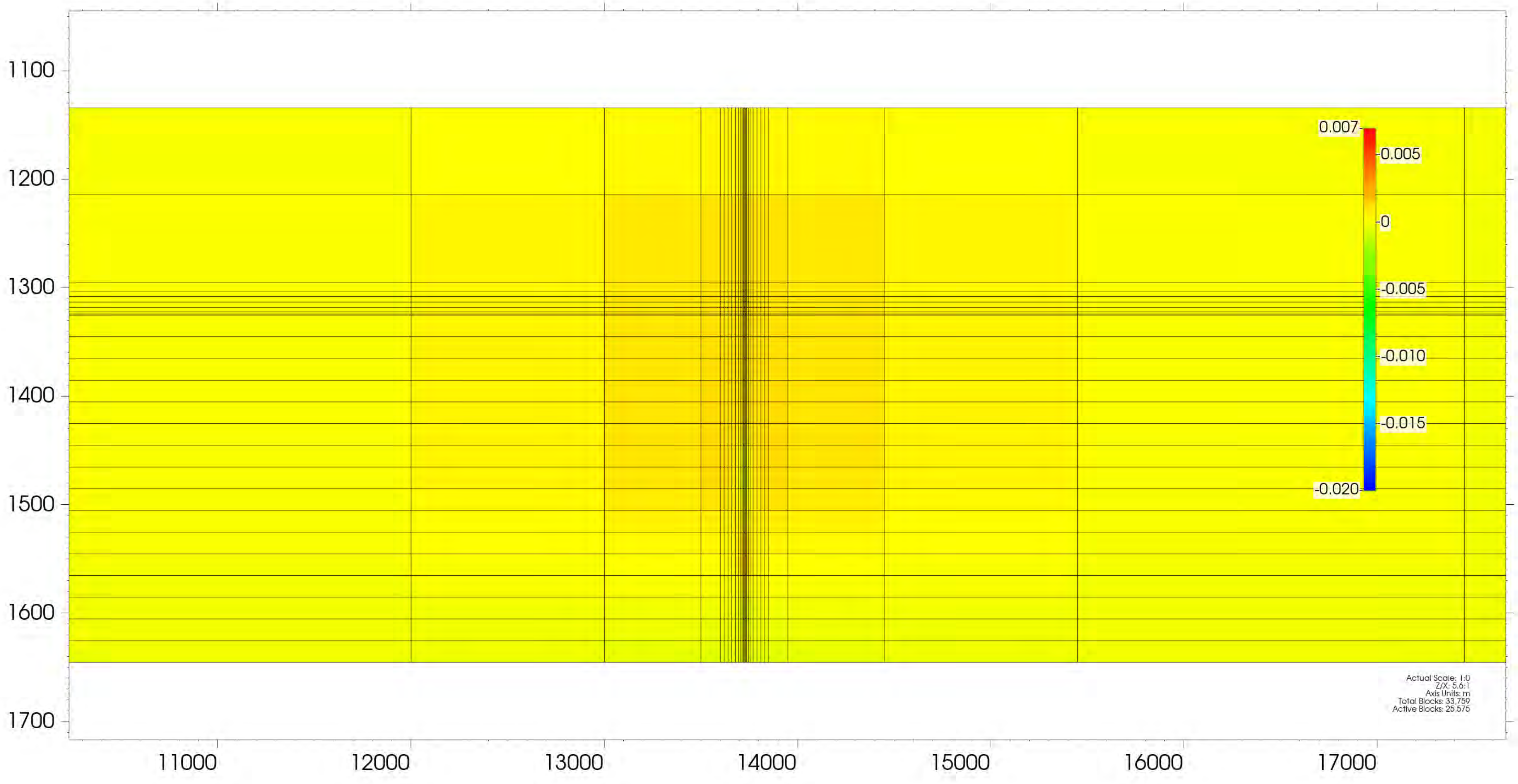
Case3: inject from cooking lake, Rate=0.07 Mpta

Temperature distribution @ end of injection 15 years



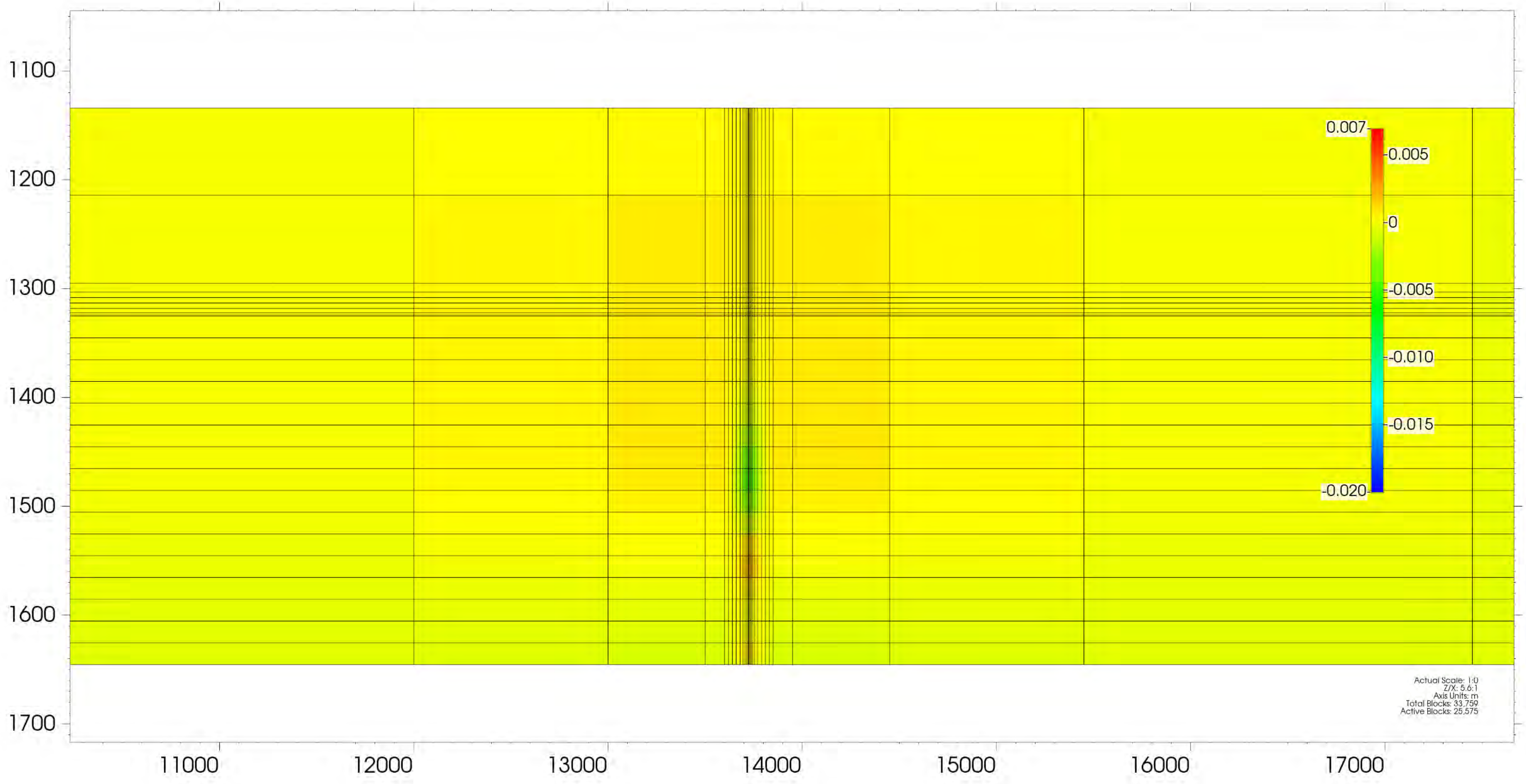
Case3: inject from cooking lake, Rate=0.07 Mpta

Deformation (Uz) @ 1 year



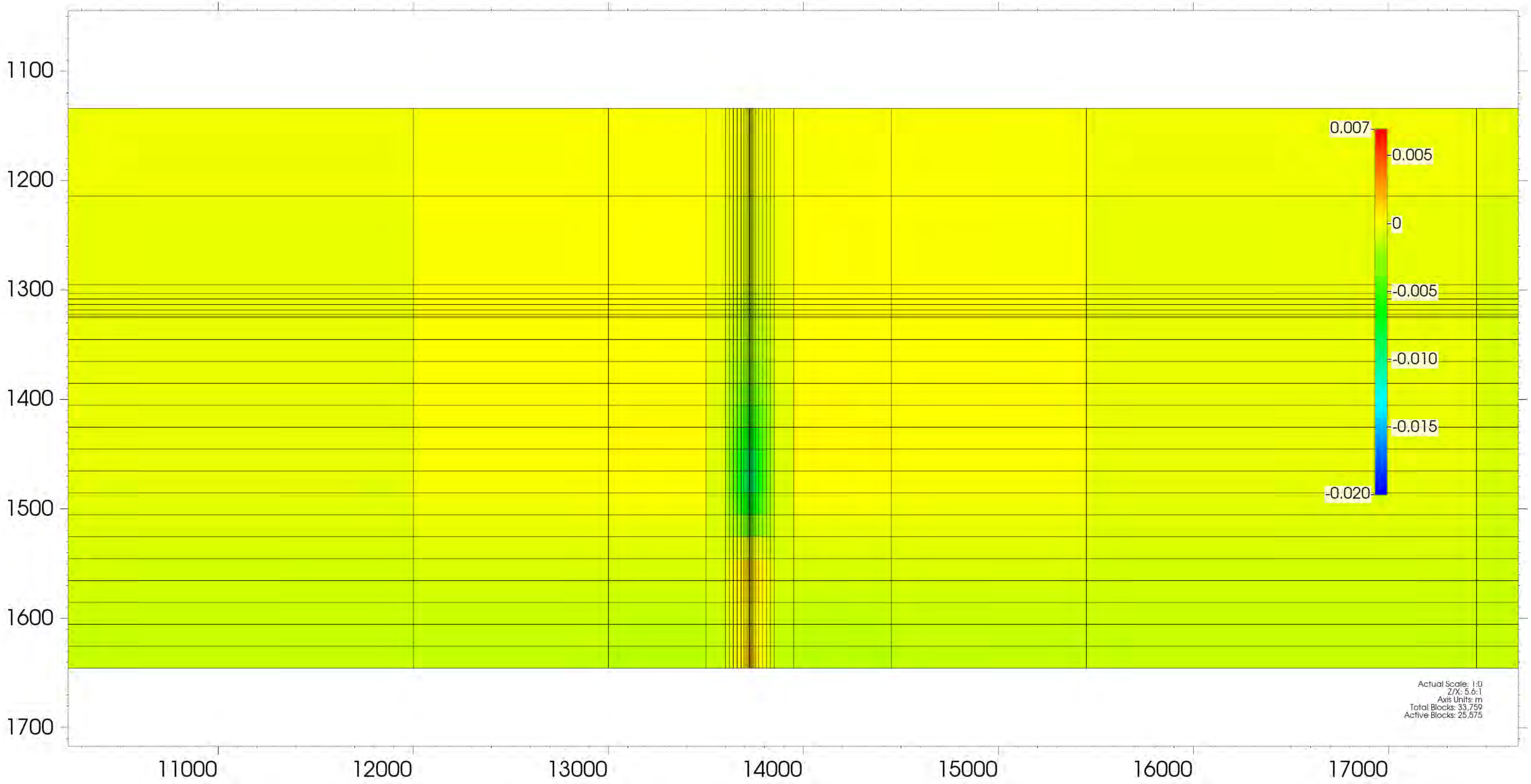
Case3: inject from cooking lake, Rate=0.07 Mpta

Deformation (Uz) @ 5 years



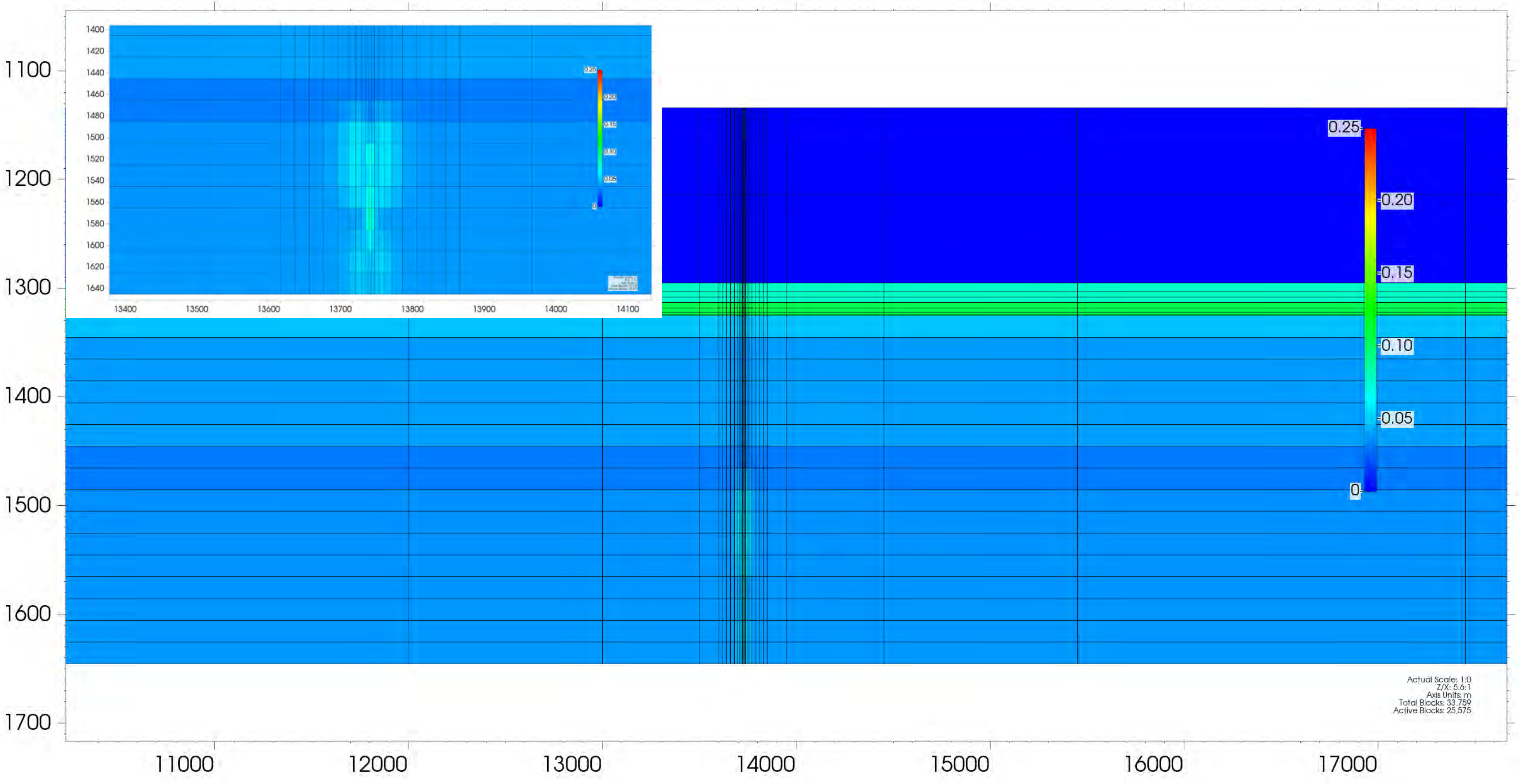
Case3: inject from cooking lake, Rate=0.07 Mpta

Deformation (Uz) @ end of injection 15 years



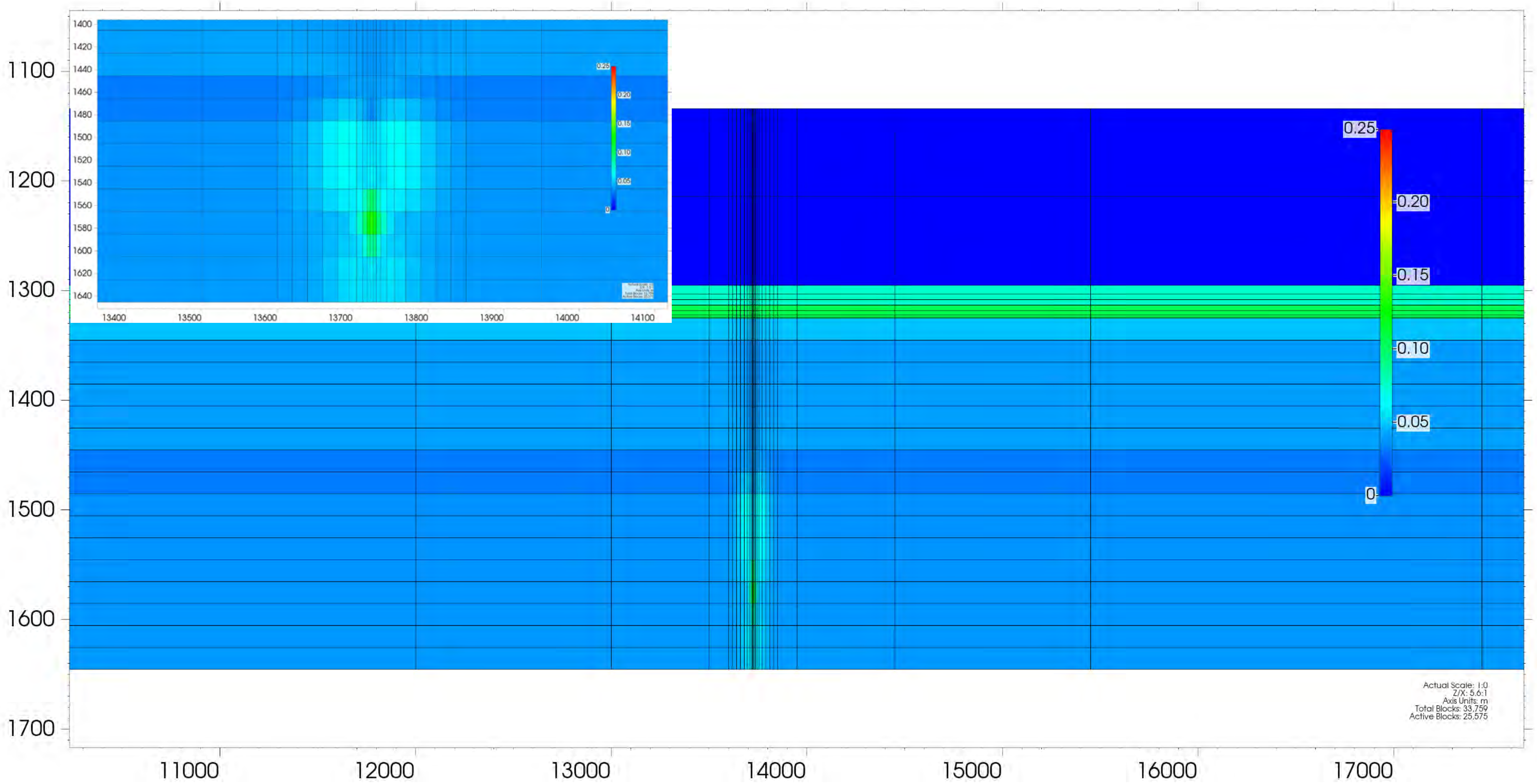
Case3: inject from cooking lake, Rate=0.07 Mpta

SSL at lower Ireton, Leduc and Cooking lake @ 1 year



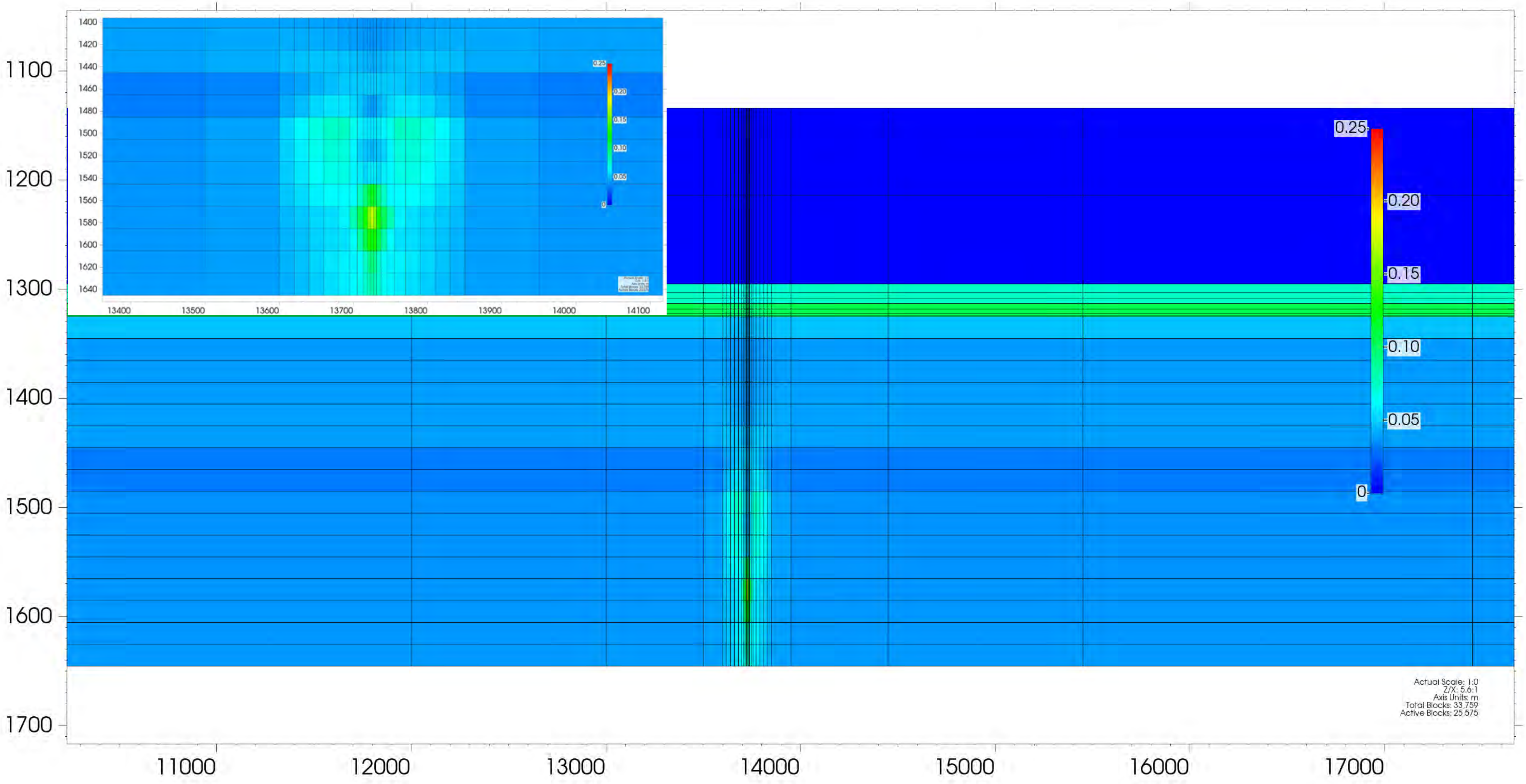
Case3: inject from cooking lake, Rate=0.07 Mpta

SSL at lower Ireton, Leduc and Cooking lake @ 5 years



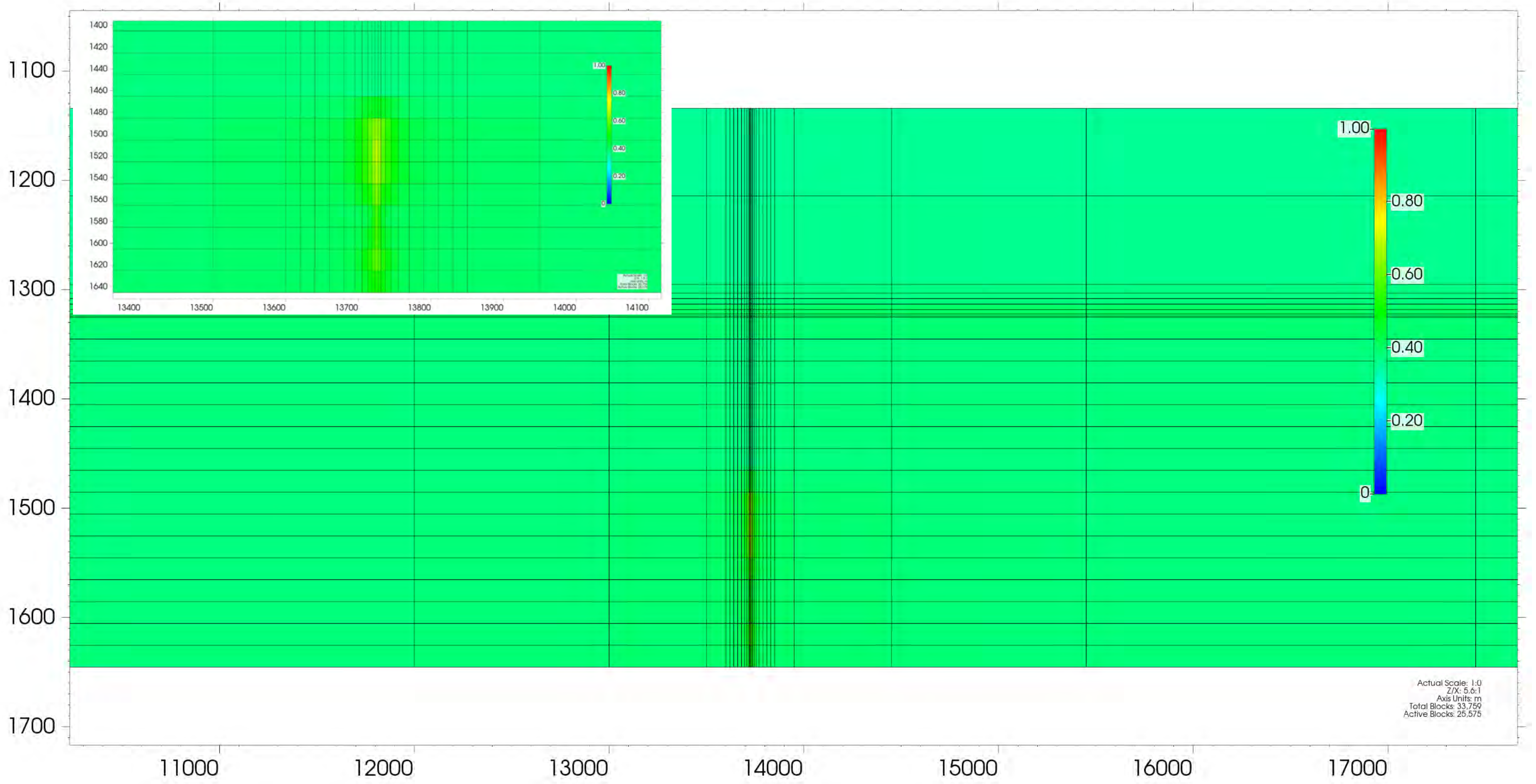
Case3: inject from cooking lake, Rate=0.07 Mpta

SSL at lower Ireton, Leduc and Cooking lake @ 15 years



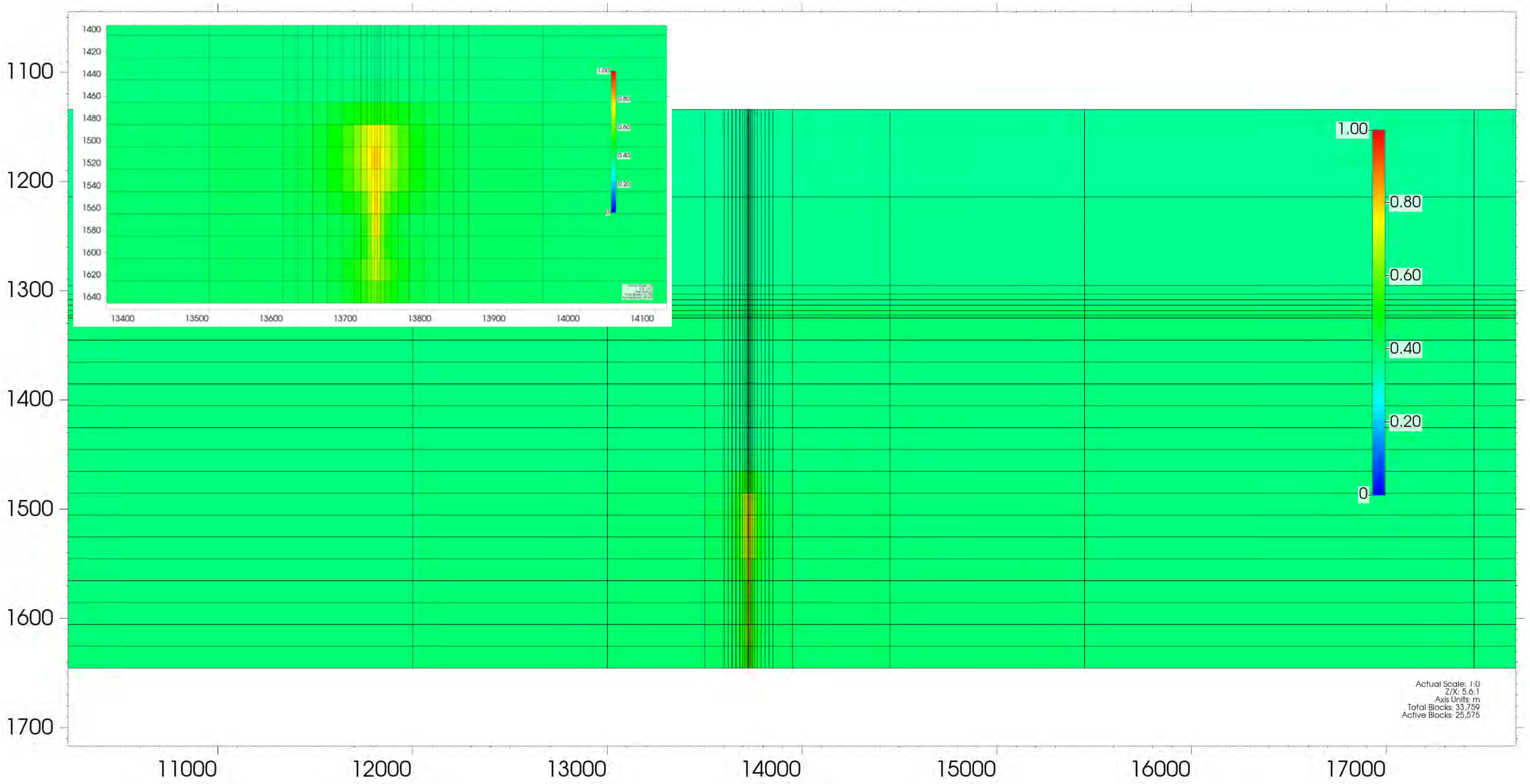
Case3: inject from cooking lake, Rate=0.07 Mpta

TSL at lower Ireton, Leduc and Cooking lake @ 1 year



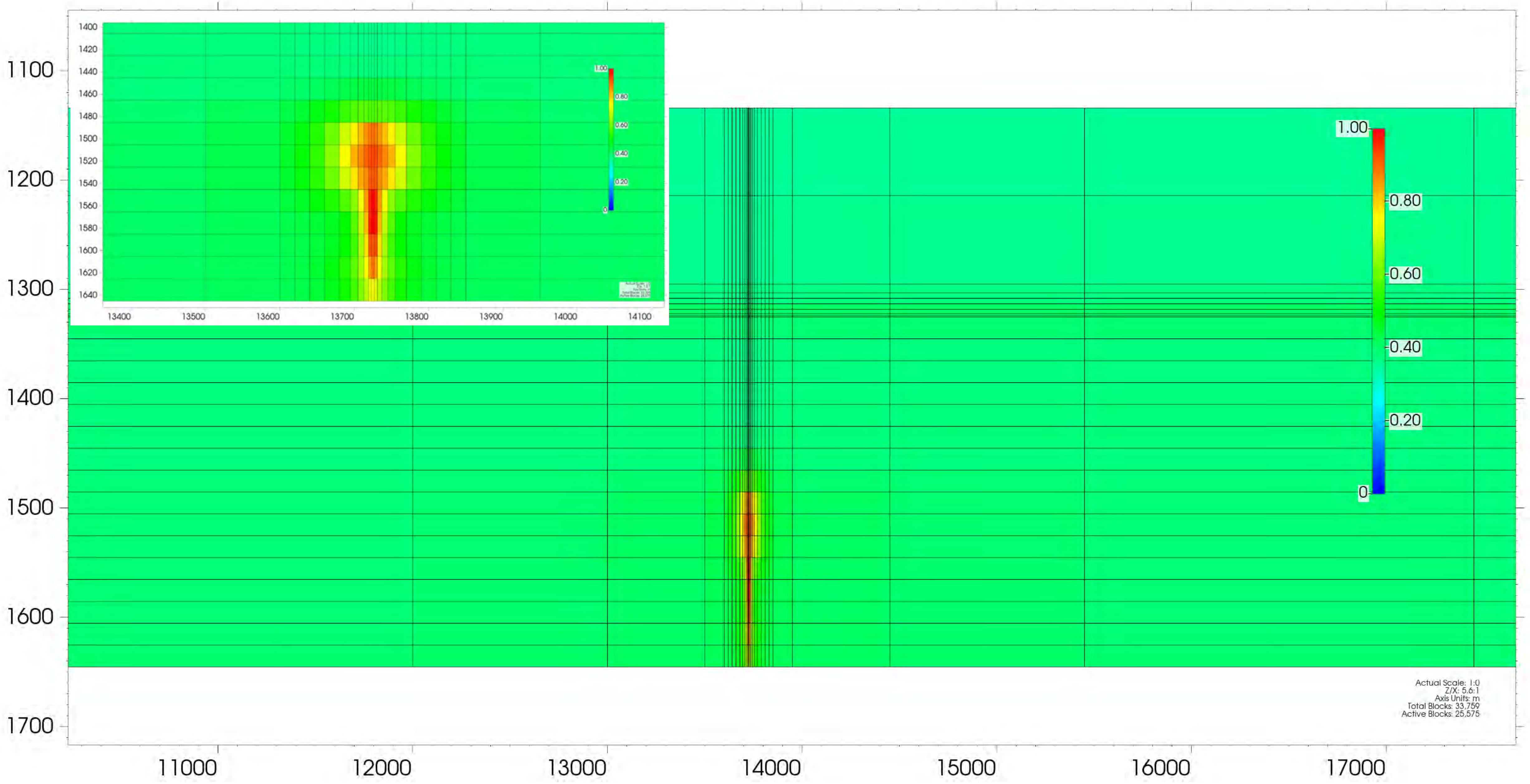
Case3: inject from cooking lake, Rate=0.07 Mpta

TSL at lower Ireton, Leduc and Cooking lake @ 5 years



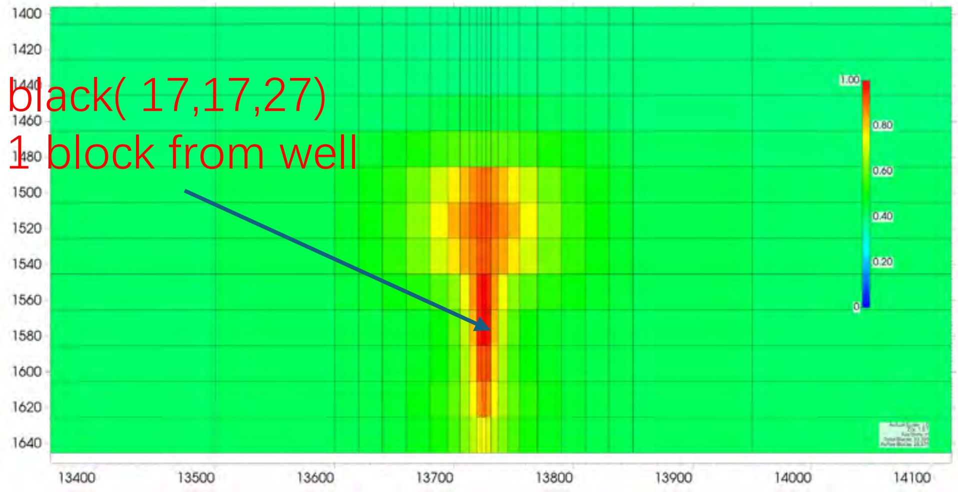
Case3: inject from cooking lake, Rate=0.07 Mpta

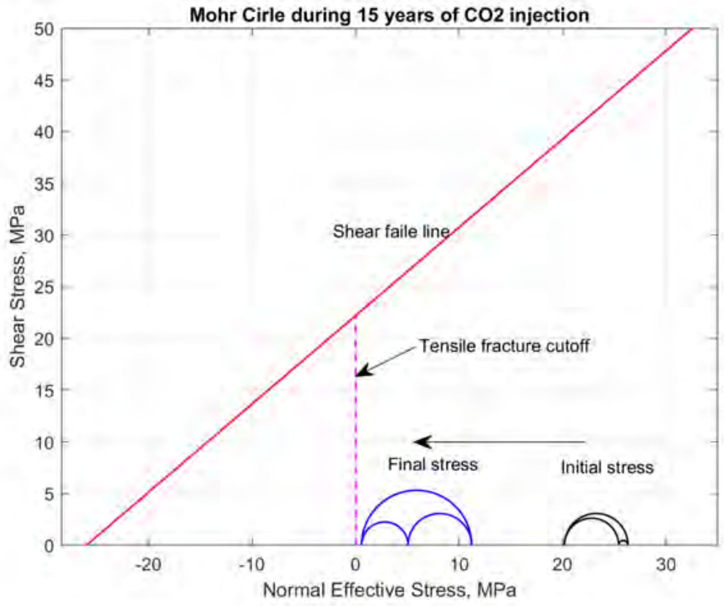
TSL at lower Ireton, Leduc and Cooking lake @ end of injection 15 years

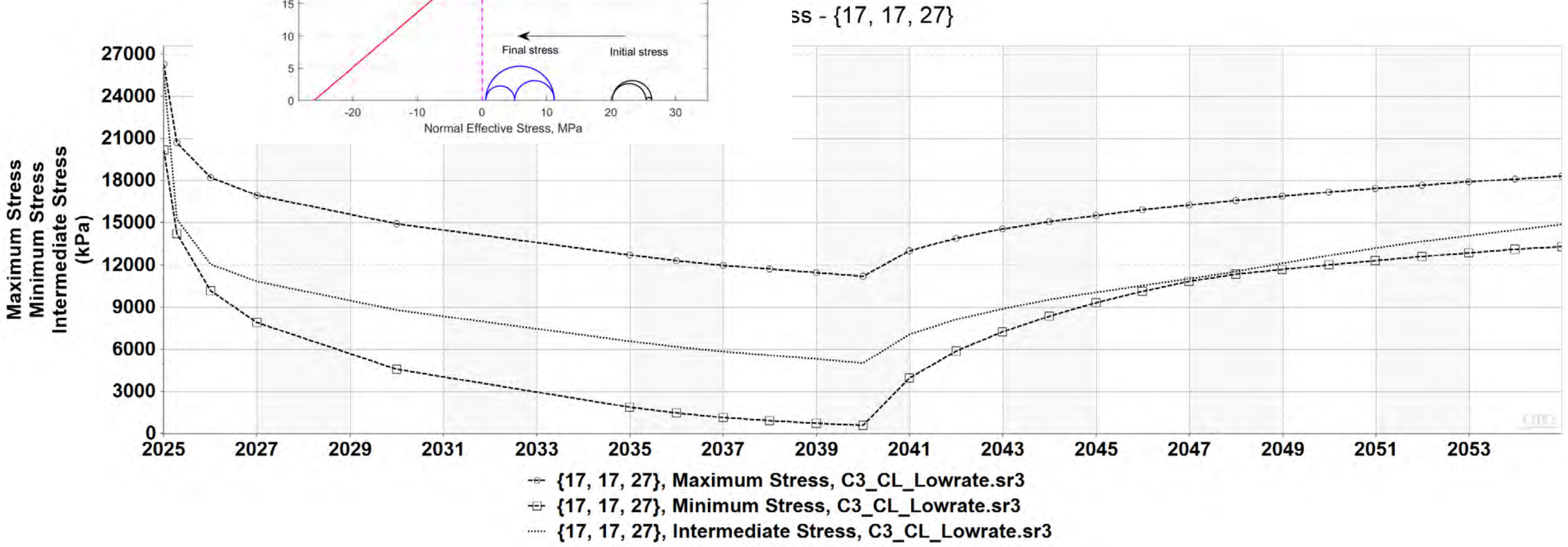


Case3: inject from cooking lake, Rate=0.07 Mpta

Change of 3 principal effective stresses near wellbore

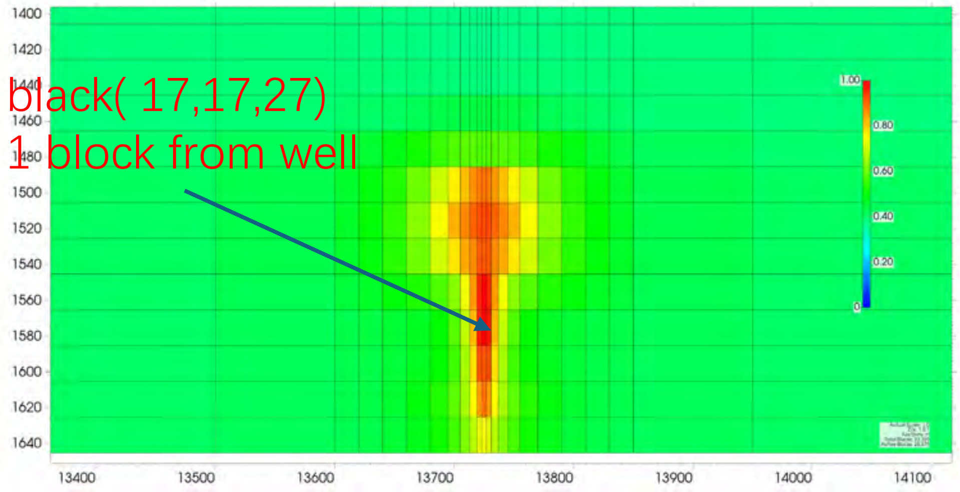


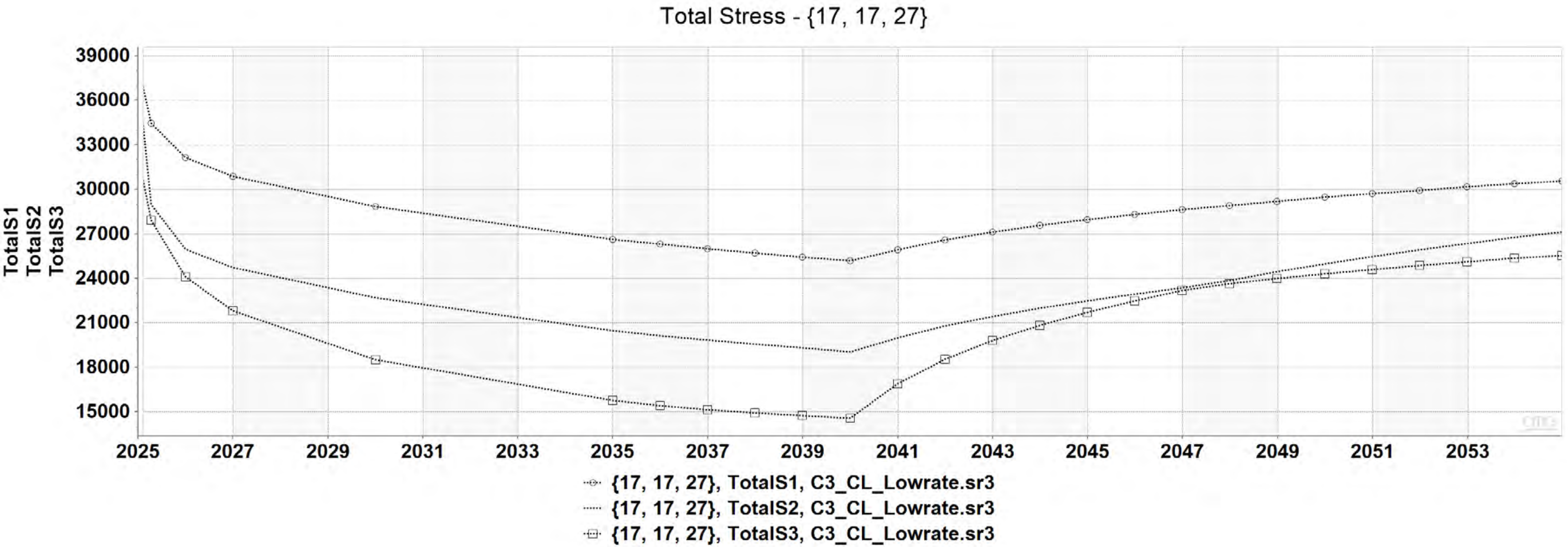




Case3: inject from cooking lake, Rate=0.07 Mpta

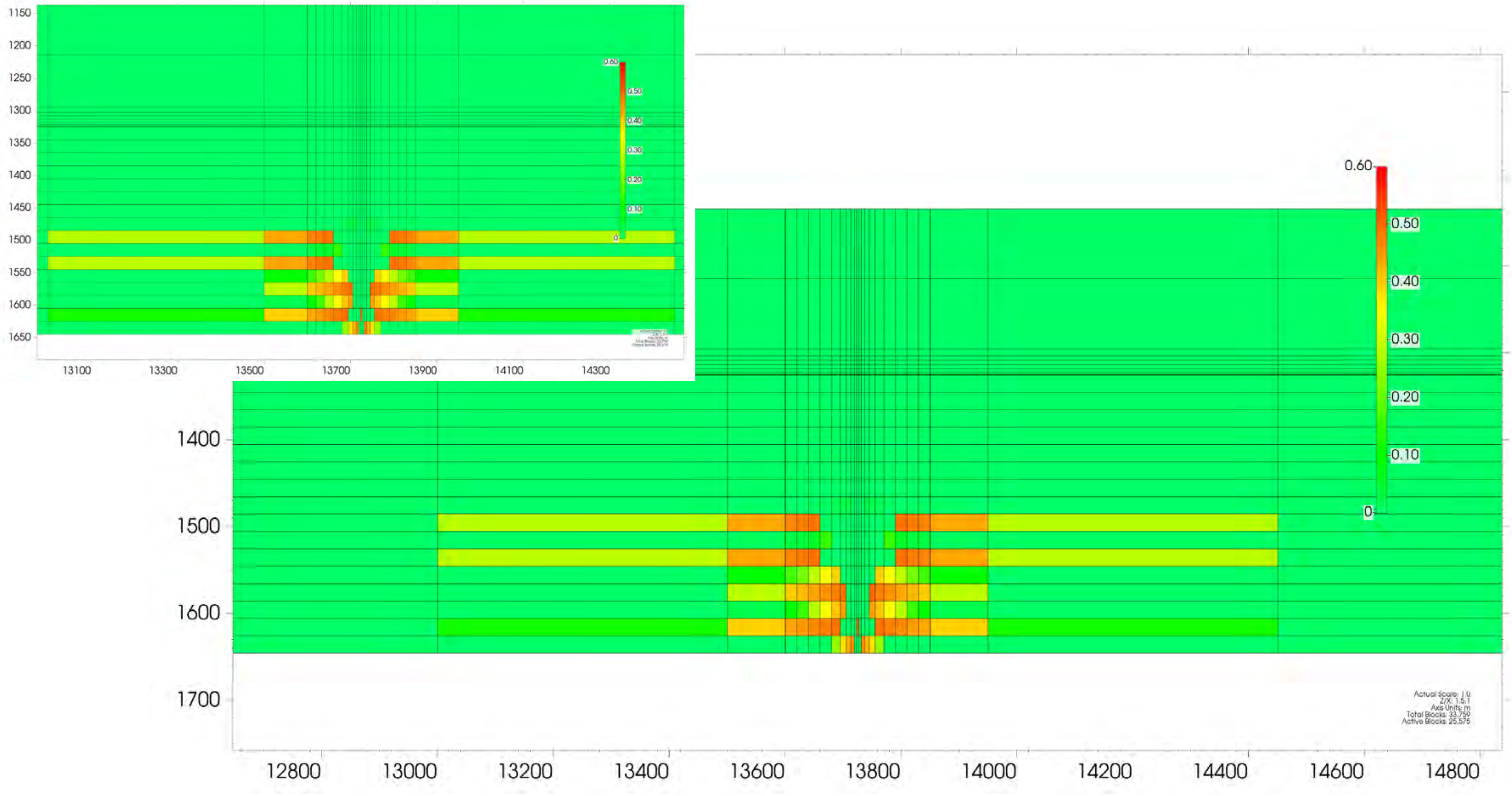
Change of 3 principal total stresses near wellbore





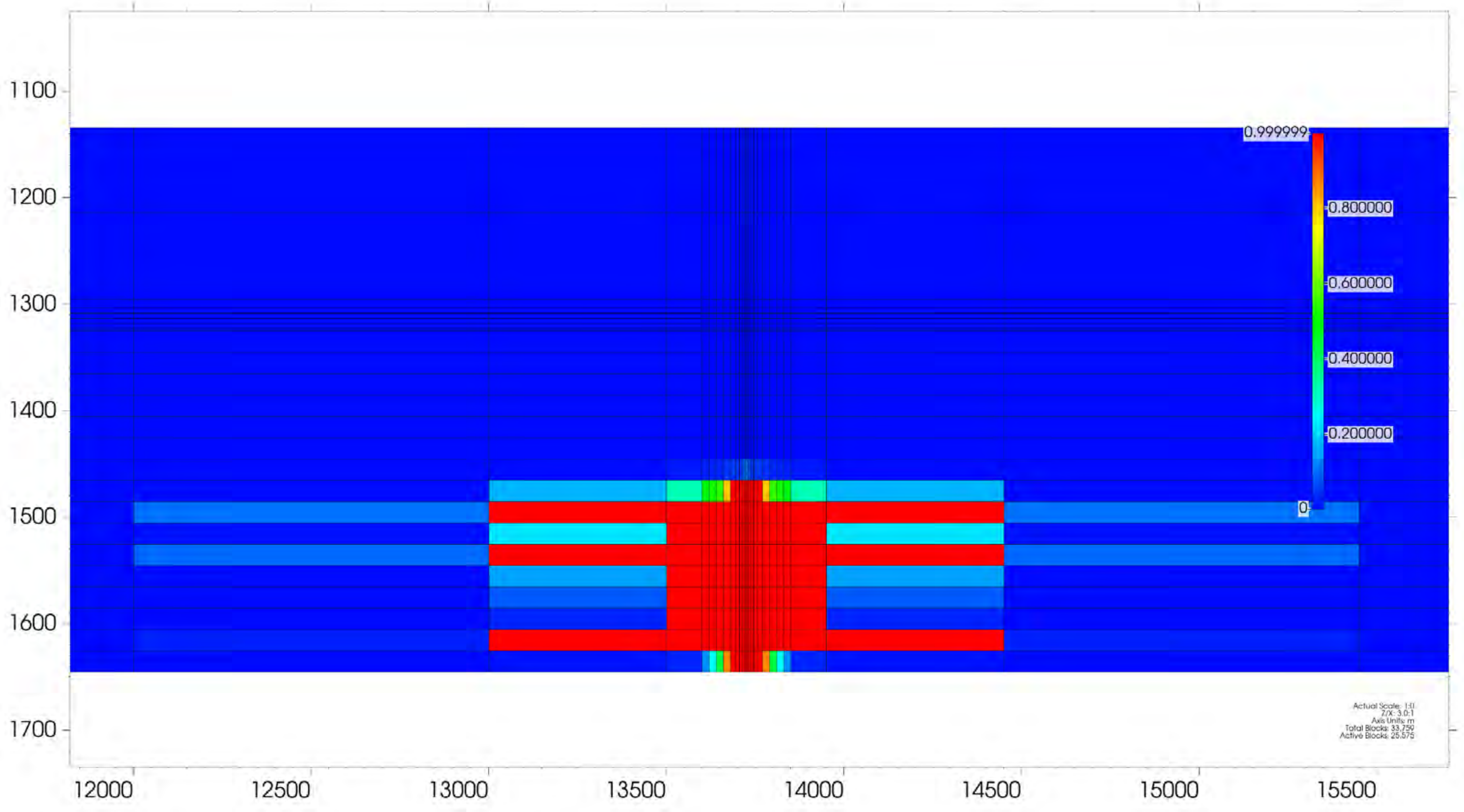
Case3: inject from cooking lake, Rate=0.07 Mpta

Gas saturation @ 15 years



Case3: inject from cooking lake, Rate=0.07 Mpta

CO2 Mole fraction@ 15 years



Case 4: Injection at Leduc, high vertical perm, Kv/Kh=1

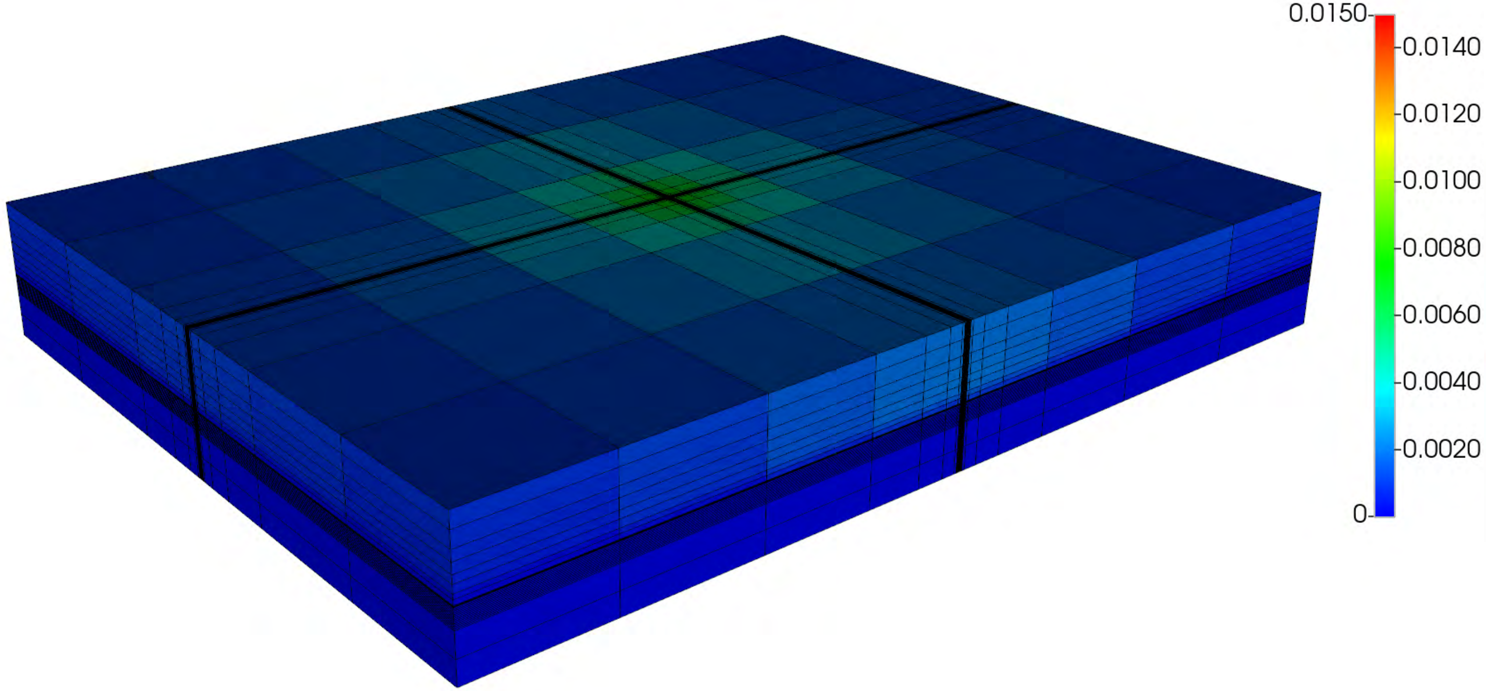
Base case: Case1

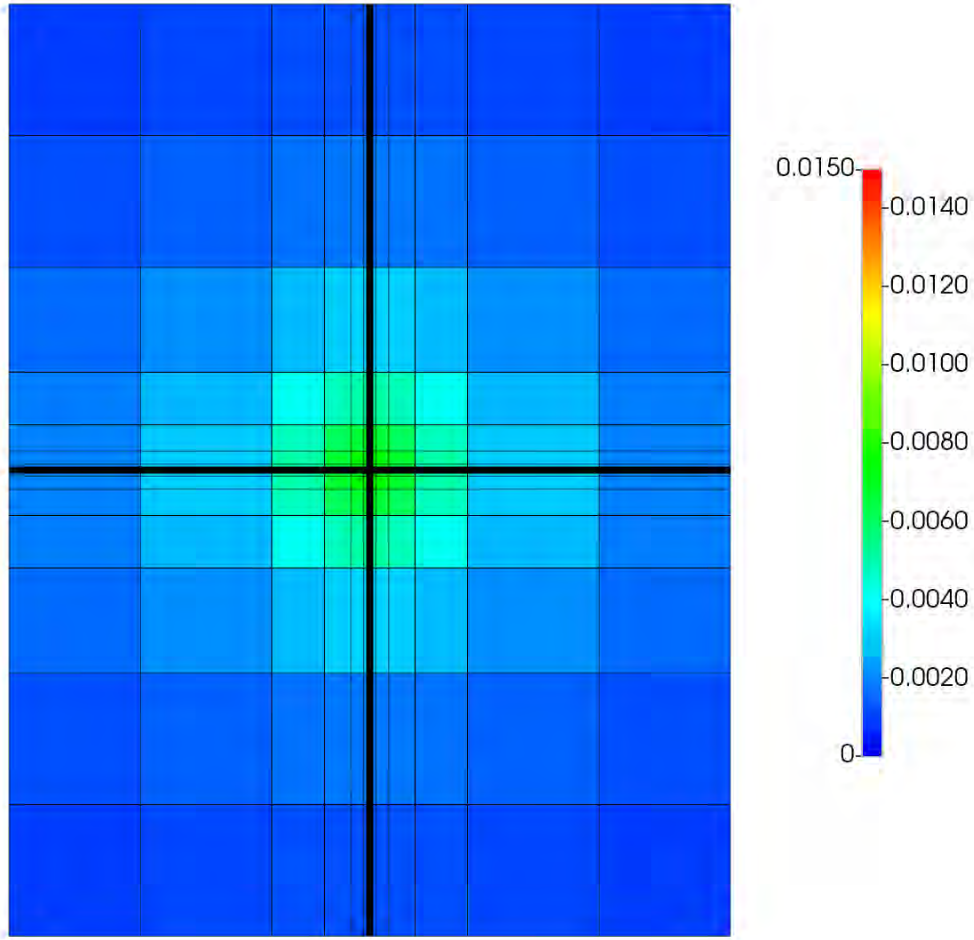
Input file change from Case 1

```
**----------------15---------------------*
 2*265.18 2*171 2*131 80 81 8 5 5 5 4 2 1 16*20 2*400
DTOP
 1023*0.0
XOFFSET           0.0000
YOFFSET           0.0000
ROTATION           0.0000
AXES-DIRECTIONS 1.0 -1.0 1.0
**  0 = null block, 1 = active block
NULL CON          0
 *MOD 1:31 1:33 7:31 = 1

POR KVAR
 15*0.01 0.07 0.1 0.13 0.07 0.1 0.13 2*0.01 0.1 0.01 0.1 0.04 0.07 0.04 0.1 0.01 2*0.01
PERMI KVAR
 15*0.001 3.0 19 50 3.0 19 50 2*0.001 19.0 0.03 19 0.3 3.0 0.3 19 0.03 2*0.001
PERMJ *EQUALSI
PERMK *EQUALSI
 *MOD 1:31 1:33 1:33 * 1.0

TRANSI CON            1
TRANSJ CON            1
TRANSK CON            1
**  0 = pinched block, 1 = active block
PINCHOUTARRAY CON           1
```

Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

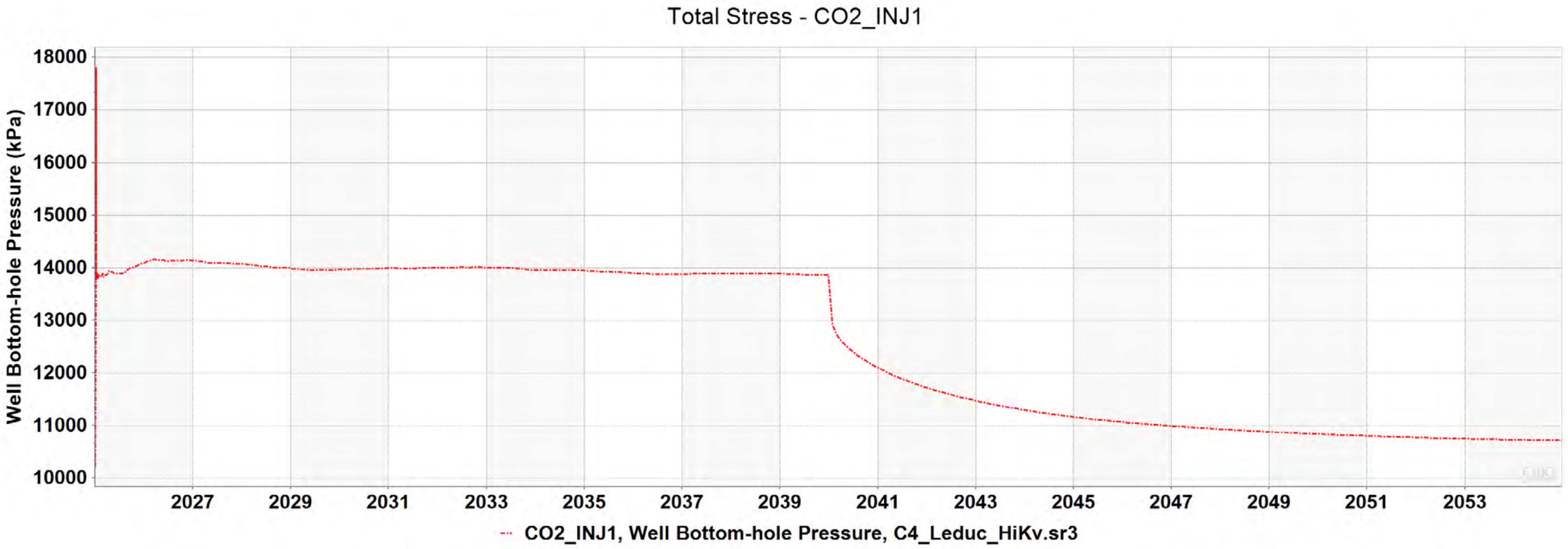
Surface heave @ end of injection 15 years (max. 8mm)





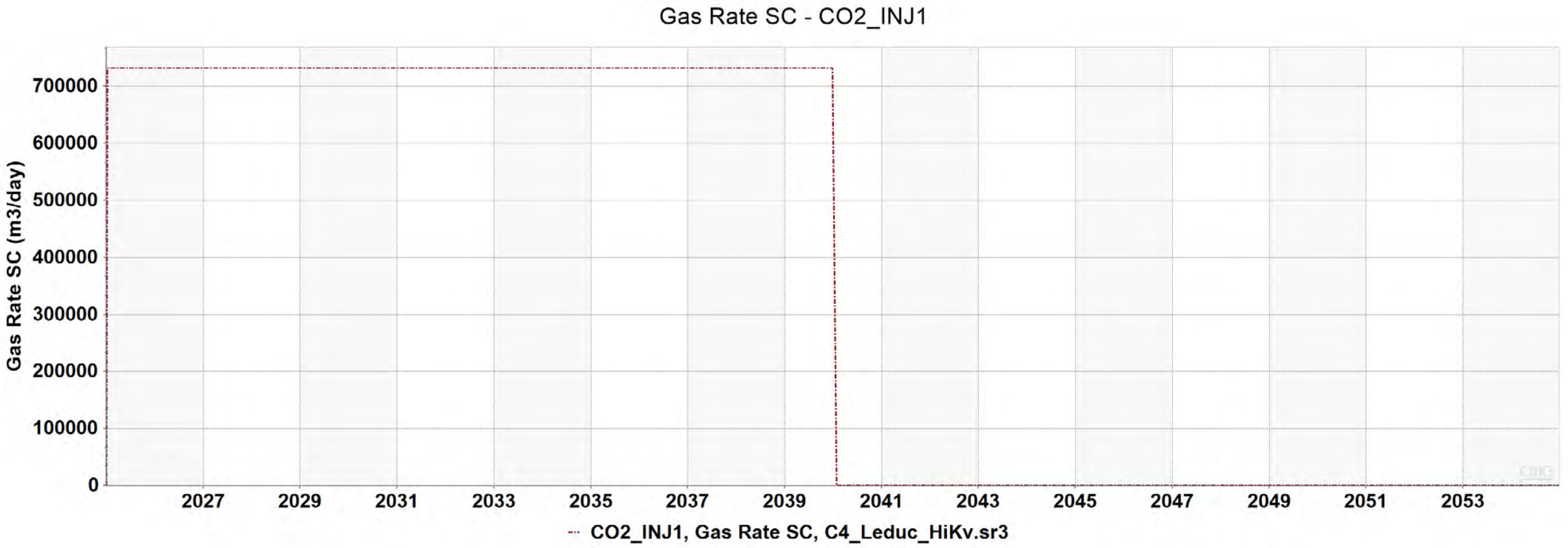
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

Injection pressure (BHP, unit: kPa)



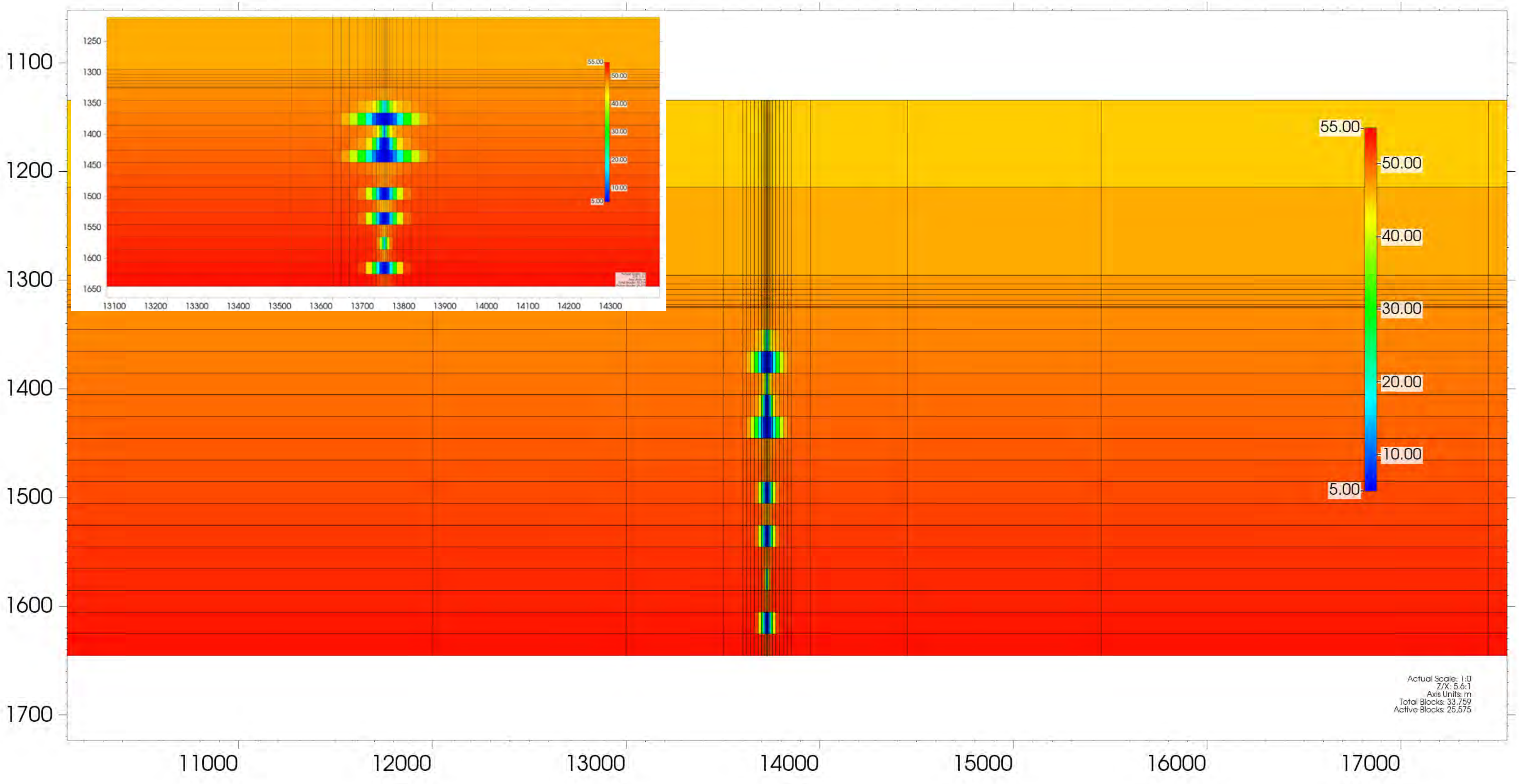
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

Injection rate



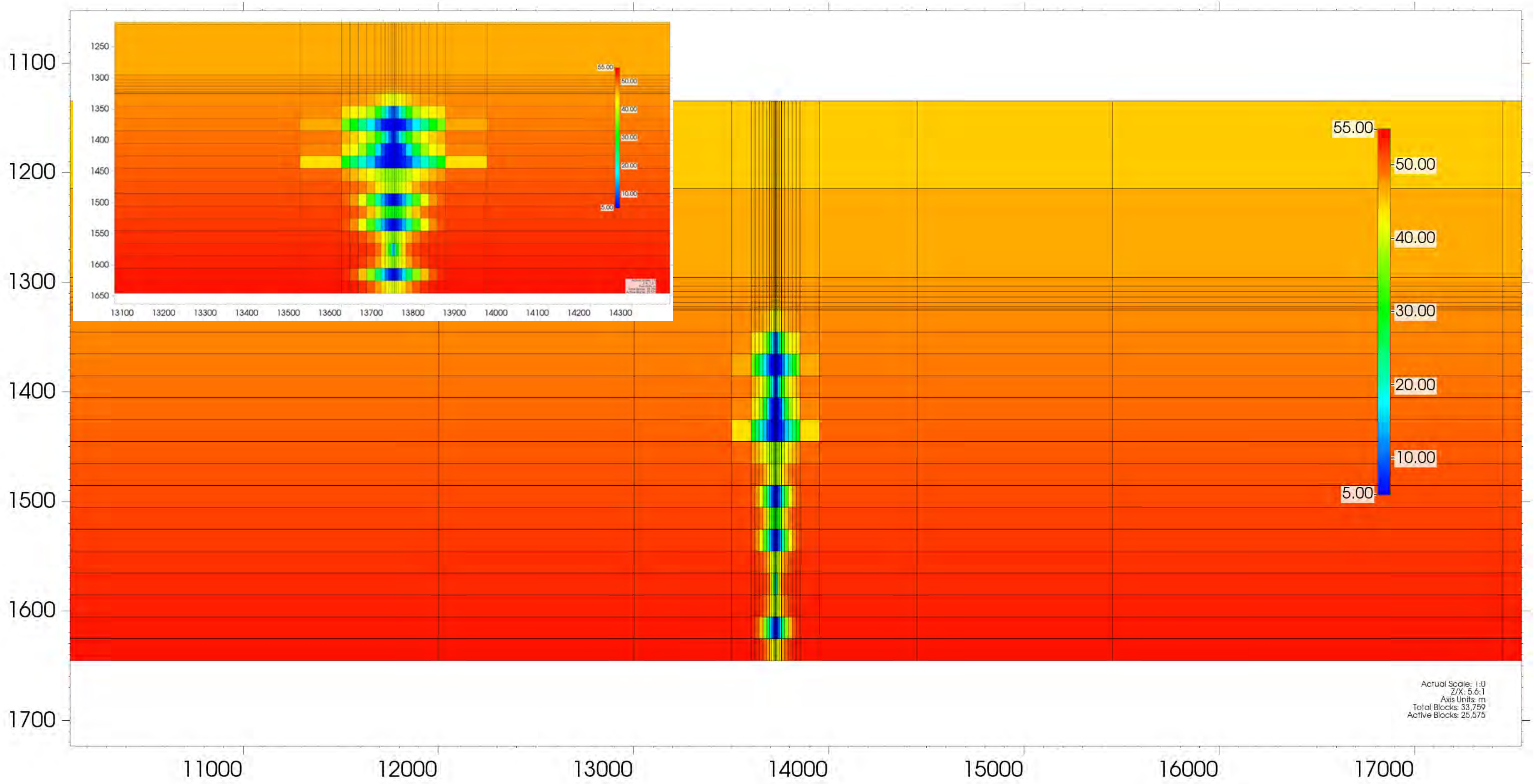
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

Temperature distribution @ 1 year



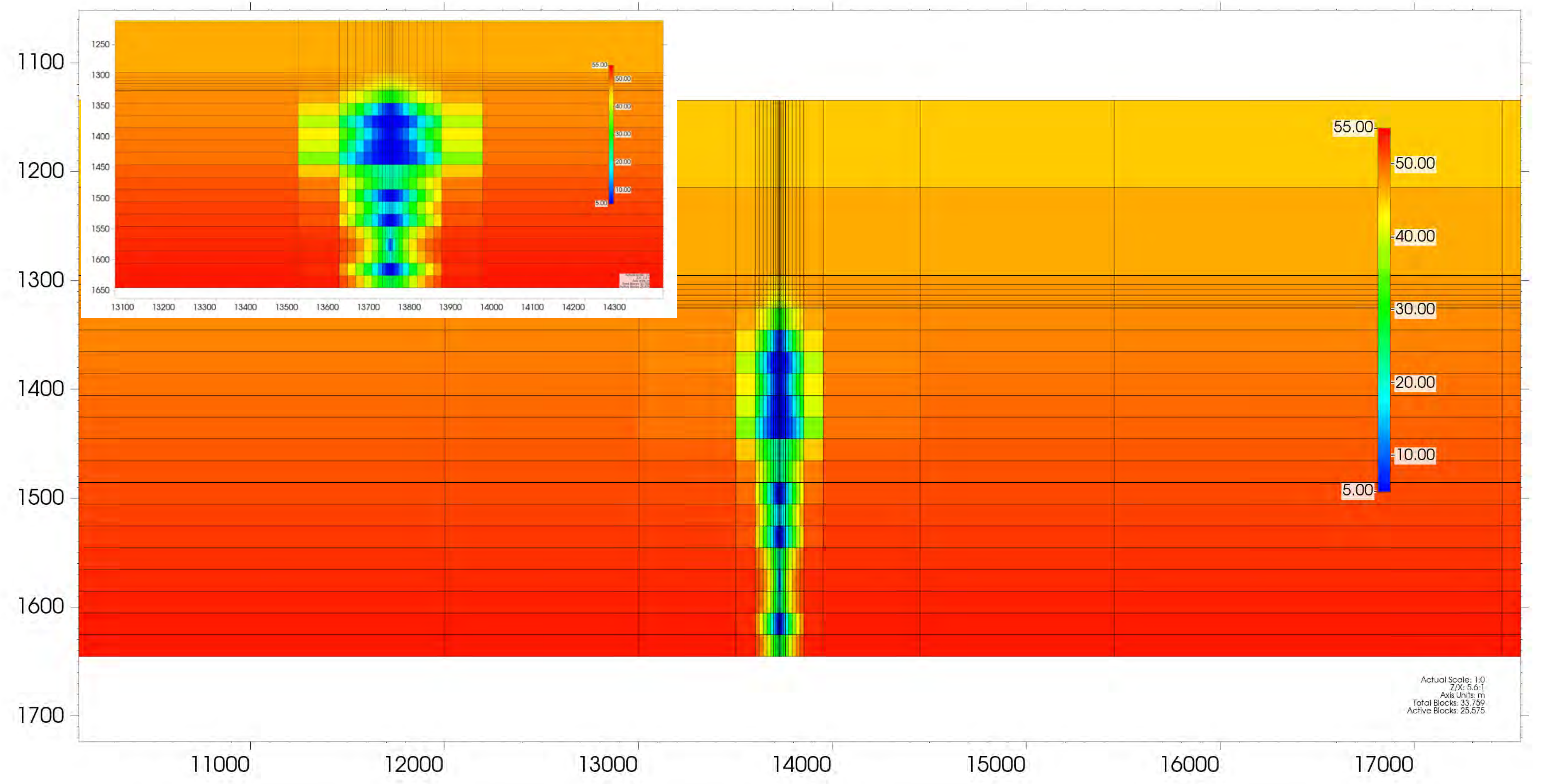
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

Temperature distribution @ 5 years



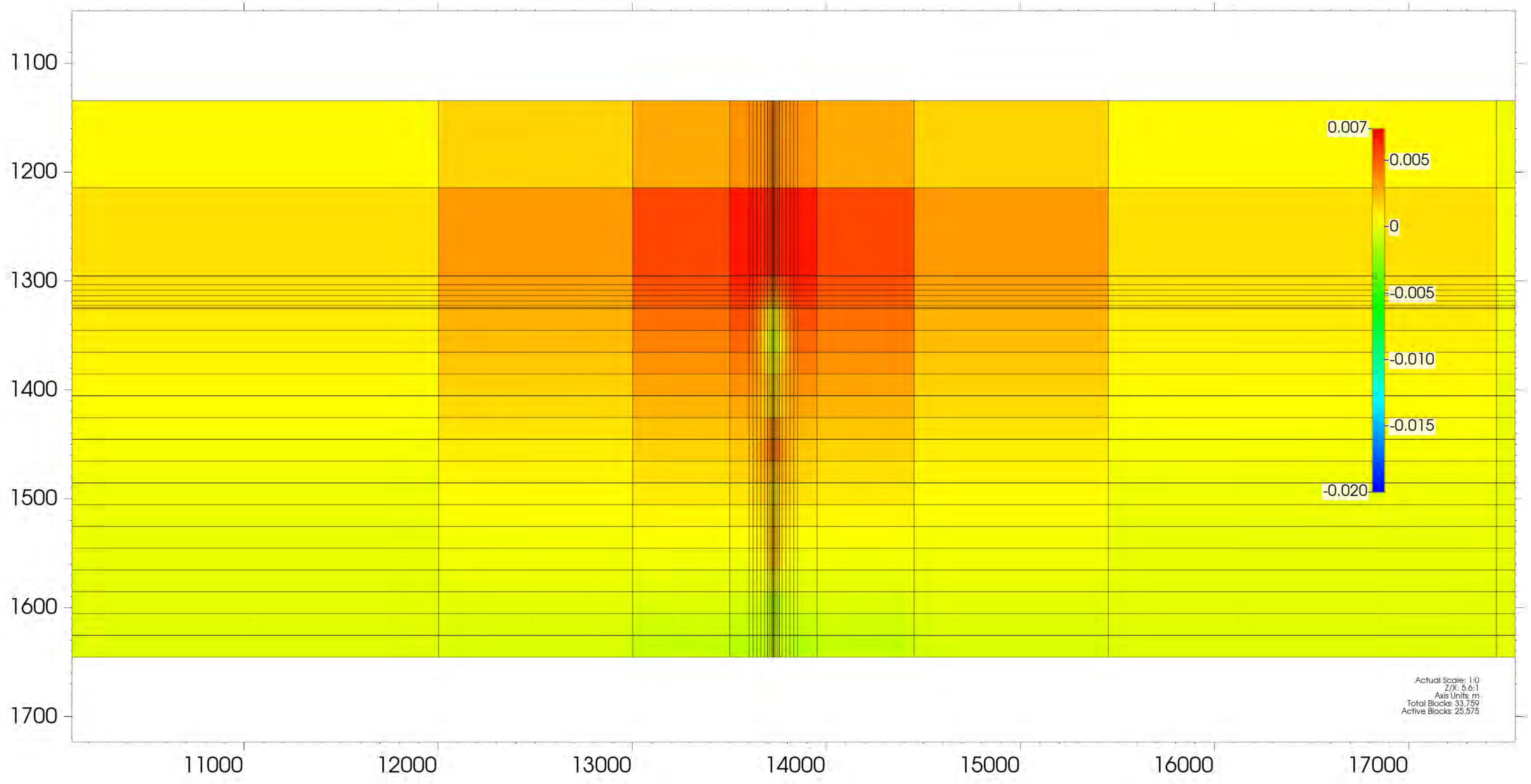
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

Temperature distribution @ end of injection 15 years



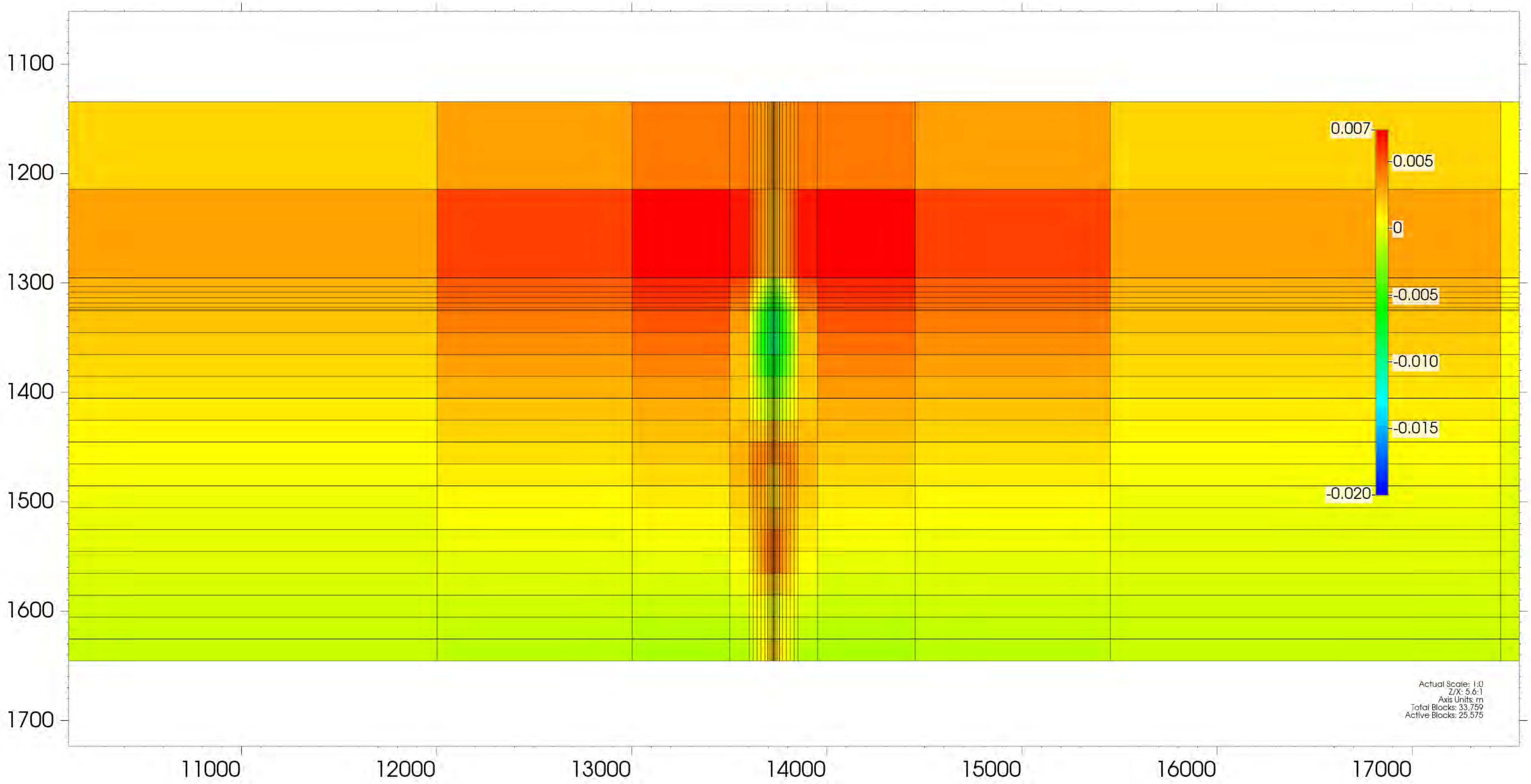
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

Deformation (Uz) @ 1 year



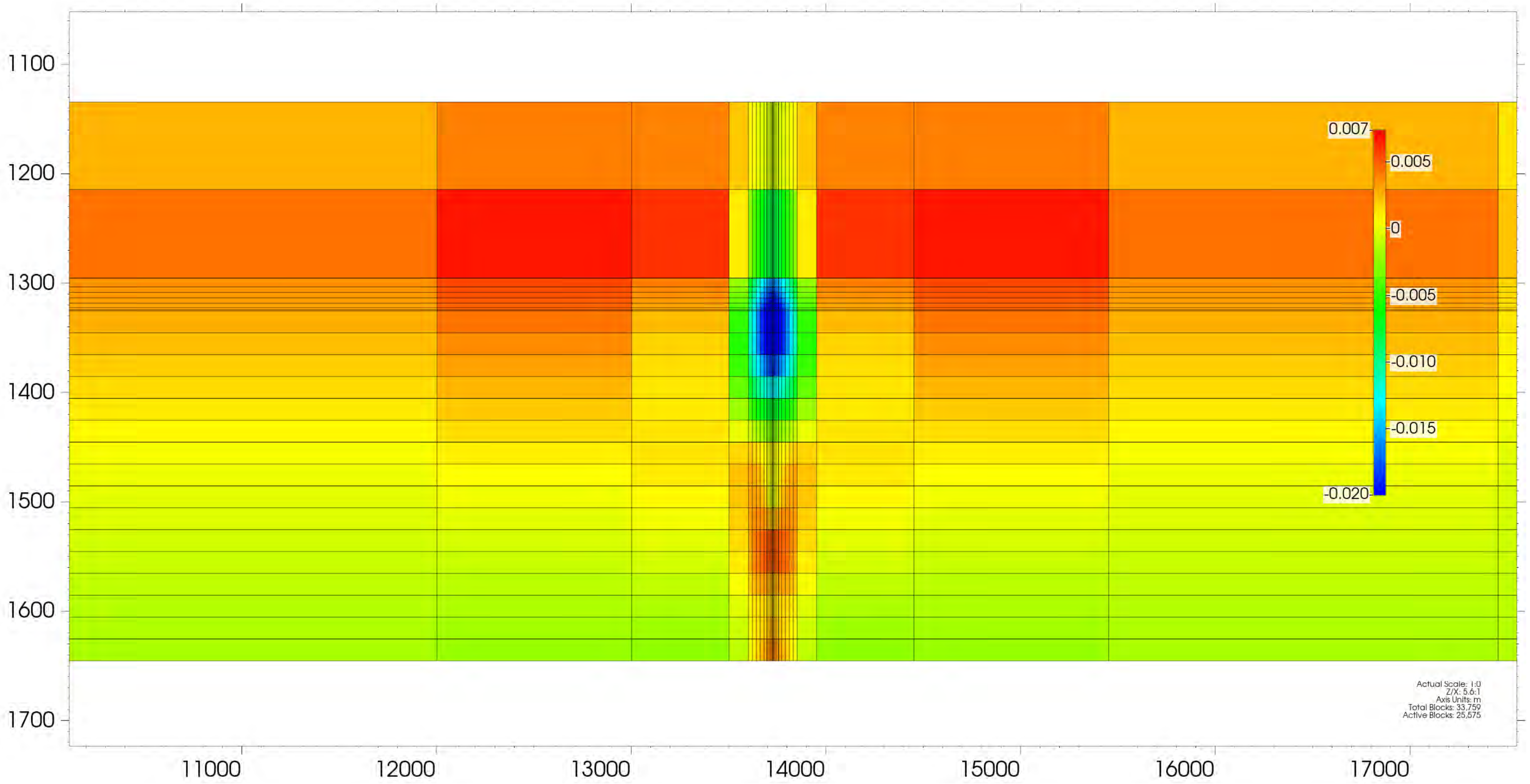
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

Deformation (Uz) @ 5 years



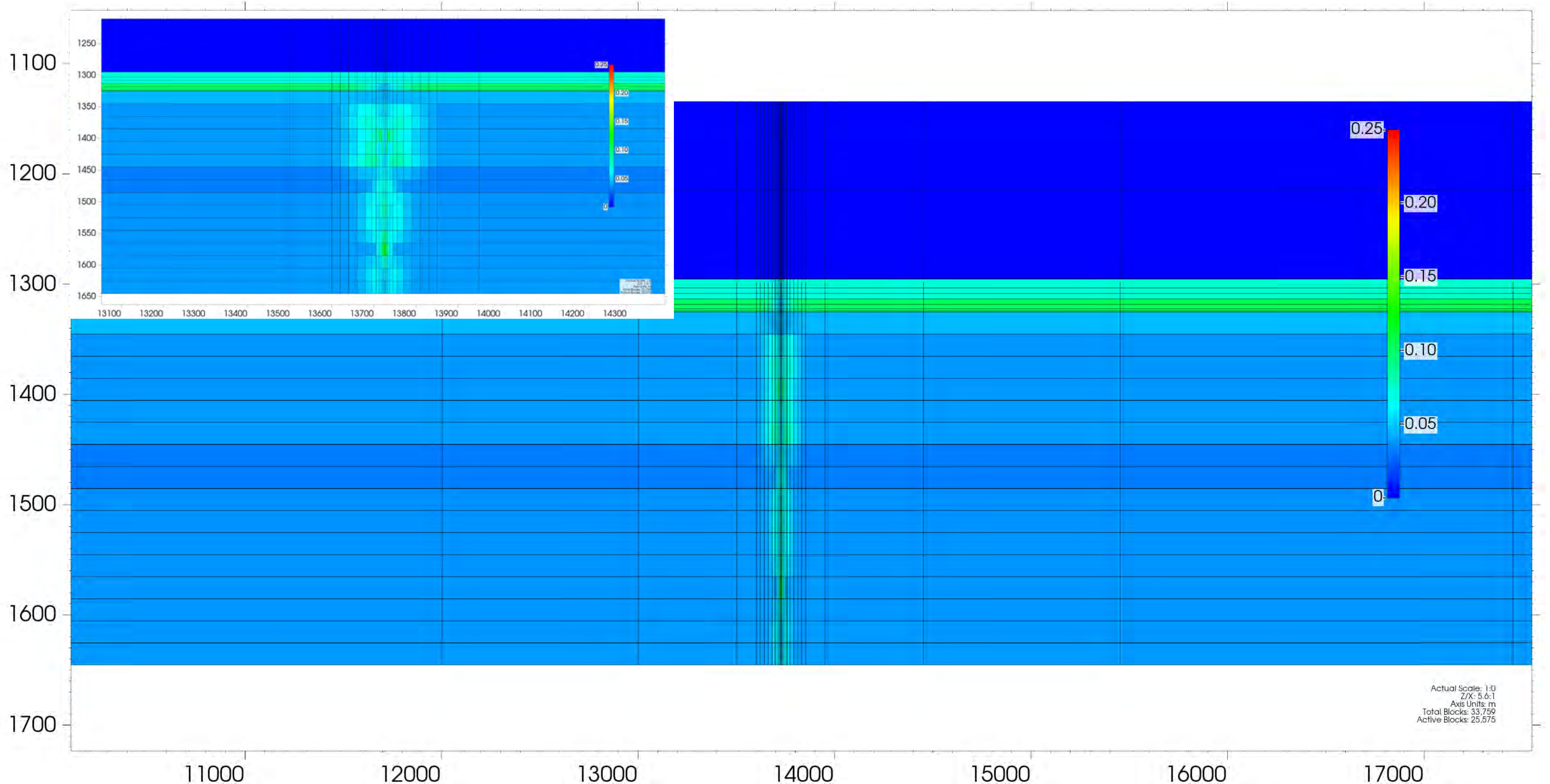
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

Deformation (Uz) @ end of injection 15 years



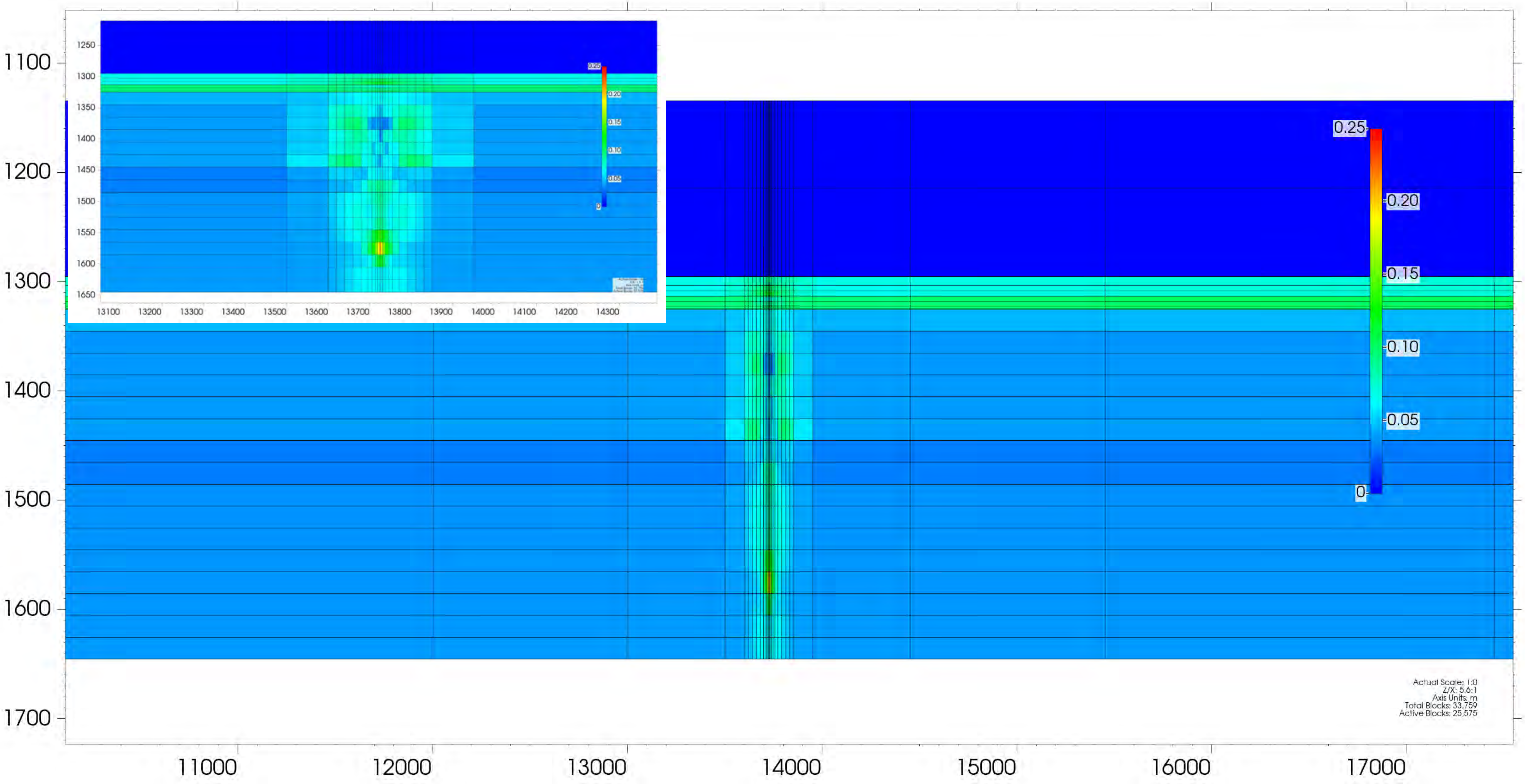
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

SSL at lower Ireton, Leduc and Cooking lake @ 1 year



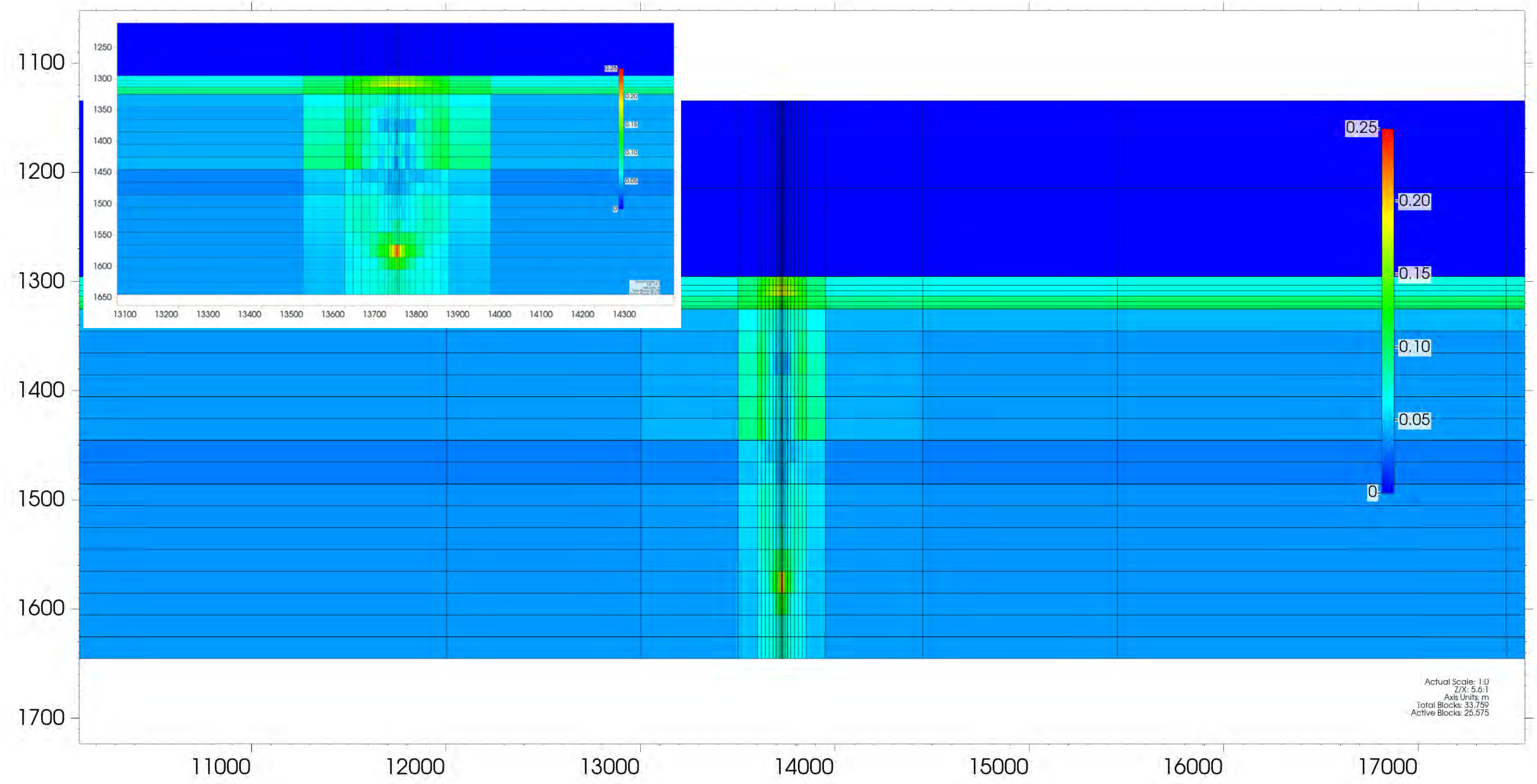
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

SSL at lower Ireton, Leduc and Cooking lake @ 5 years



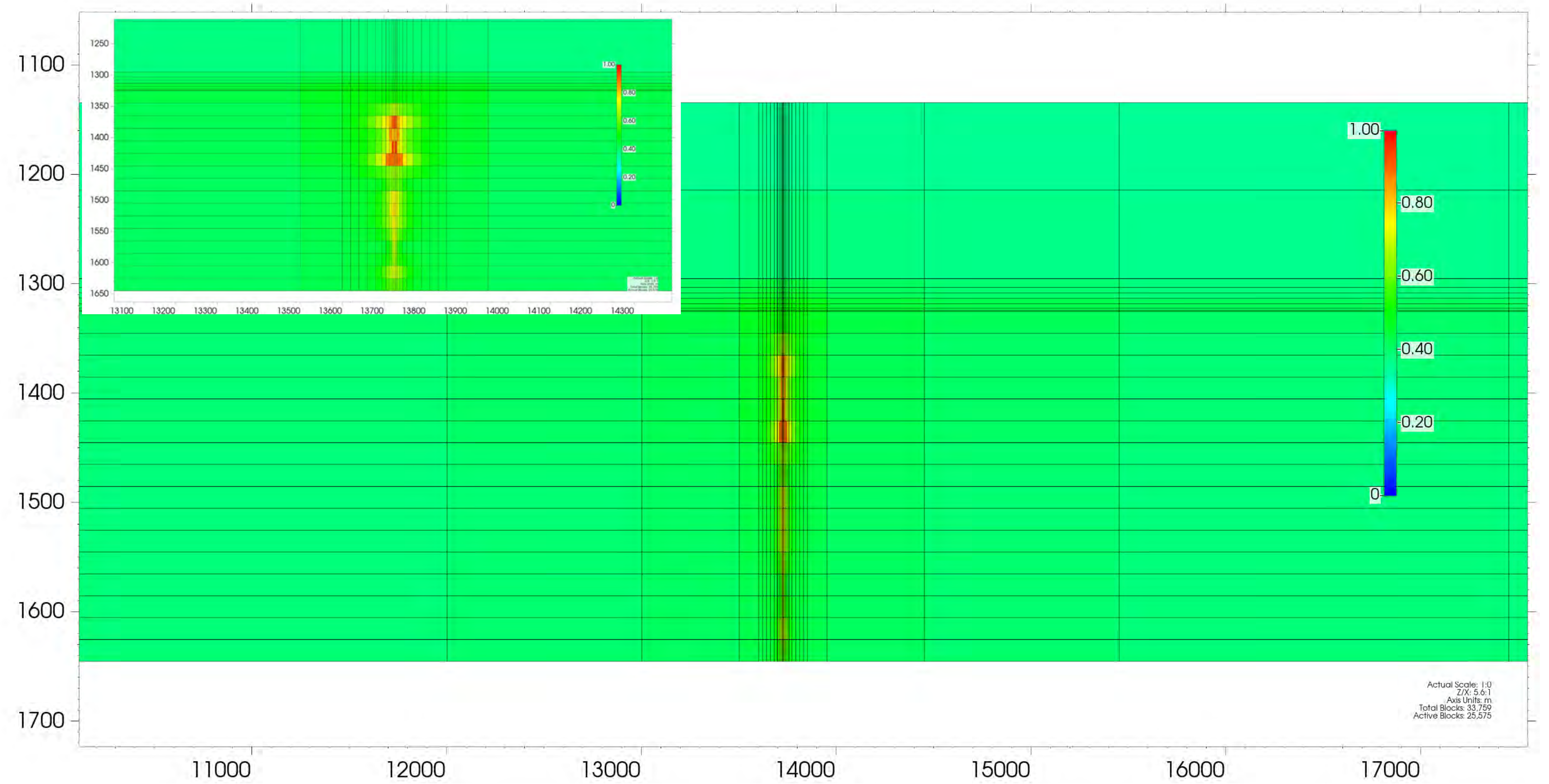
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

SSL at lower Ireton, Leduc and Cooking lake @ 15 years



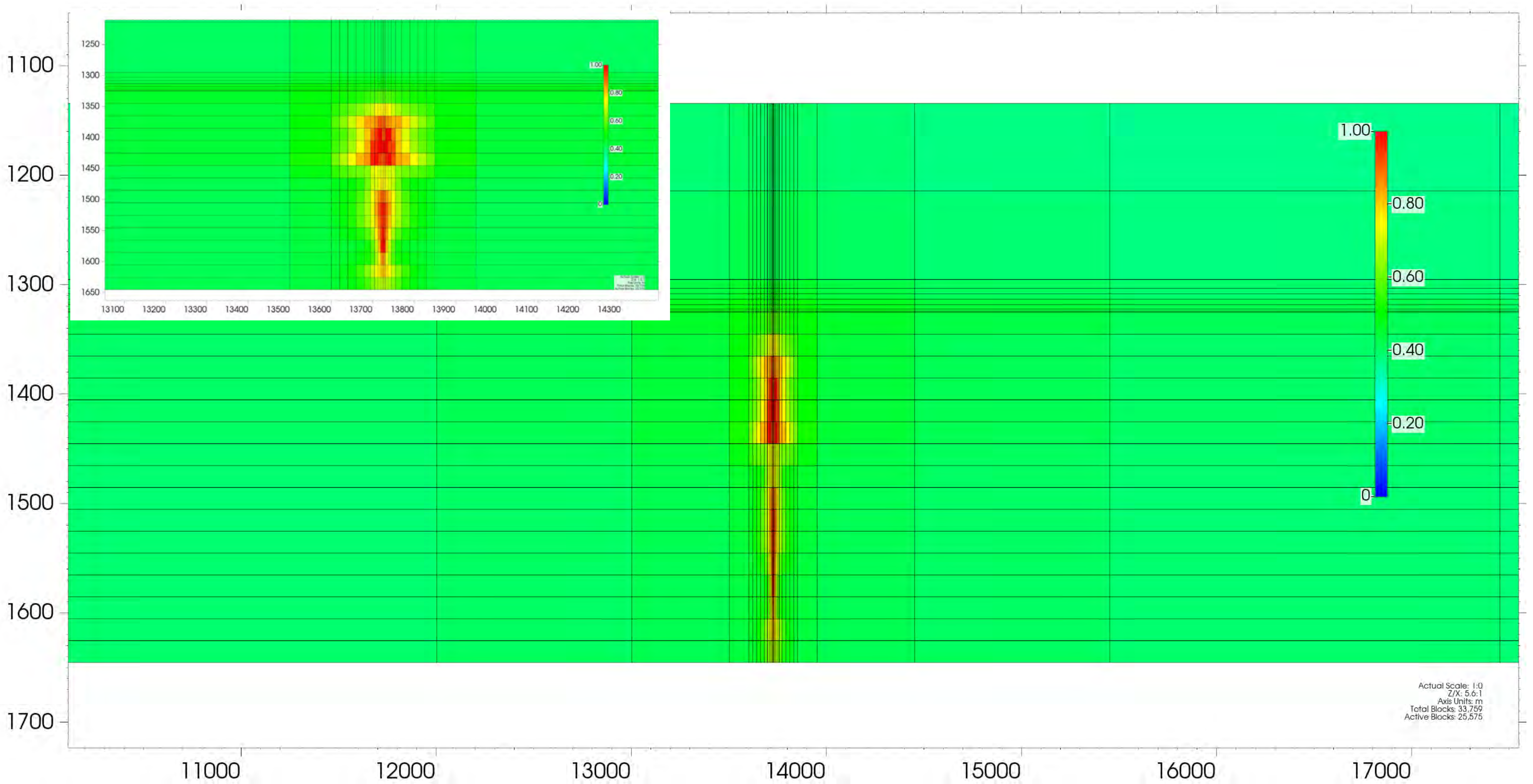
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

TSL at lower Ireton, Leduc and Cooking lake @ 1 year (fractured near wellbore)



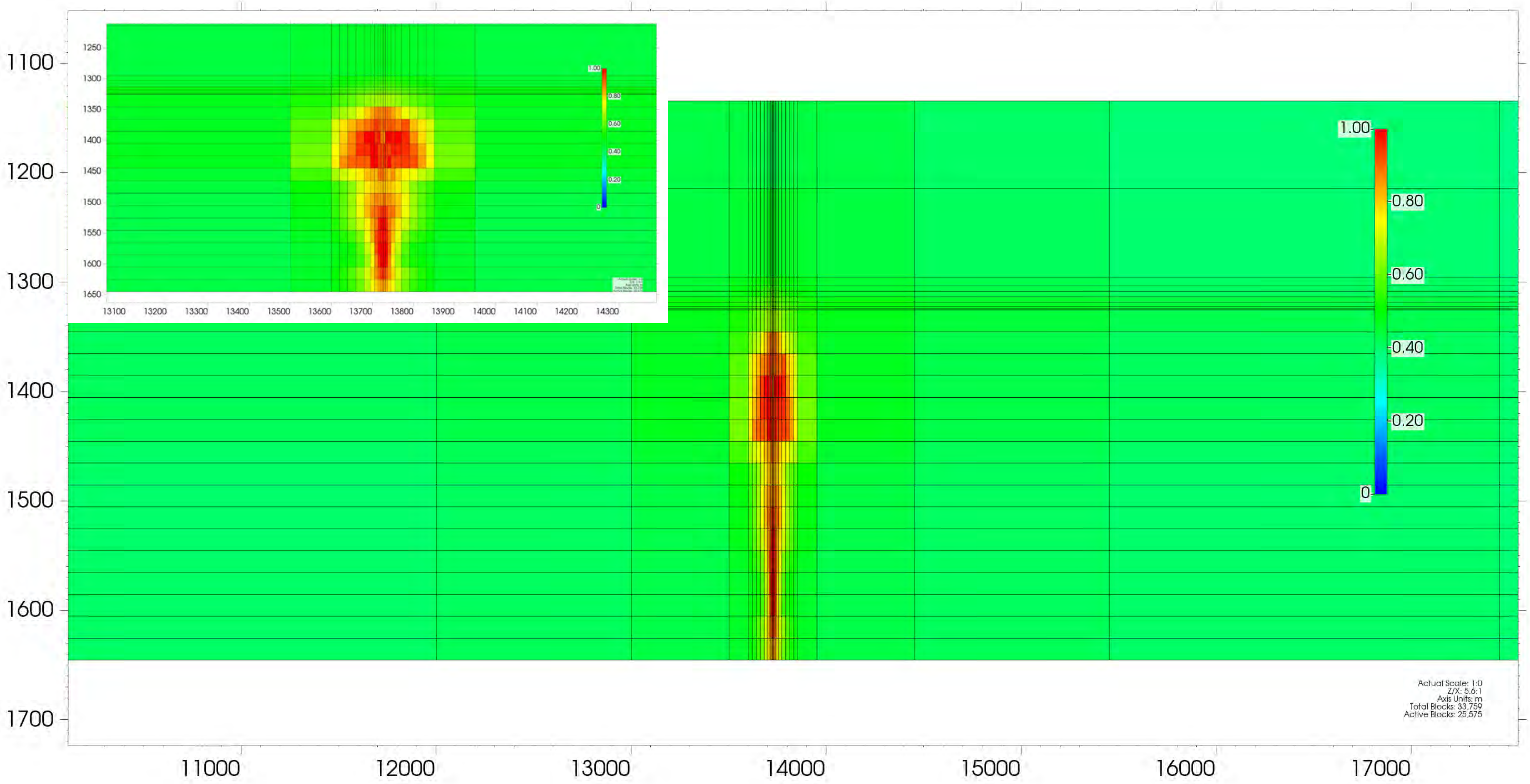
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

TSL at lower Ireton, Leduc and Cooking lake @ 5 years (fractured near wellbore)



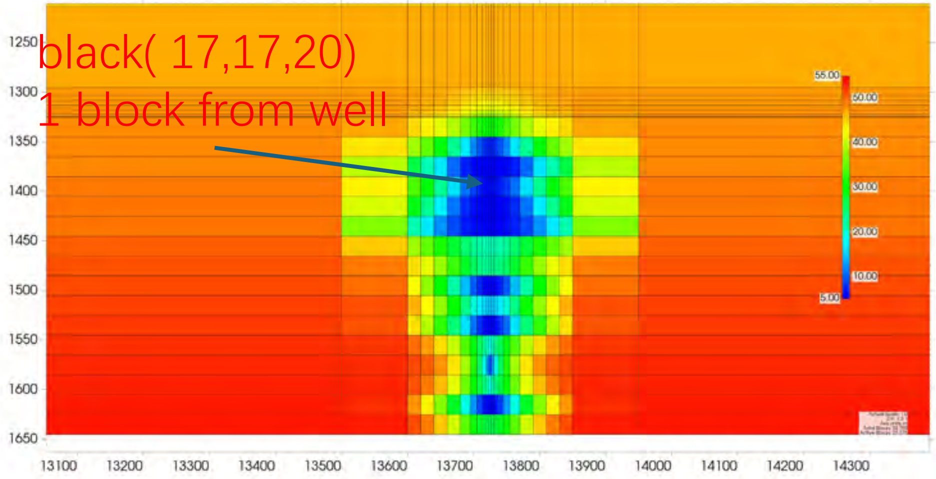
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

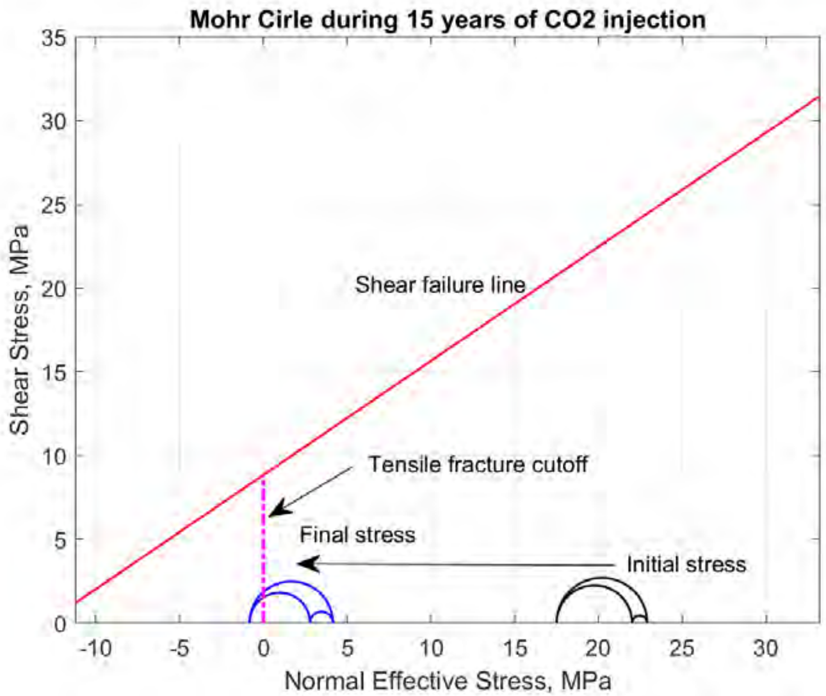
TSL at lower Ireton, Leduc and Cooking lake @ end of injection 15 years (fractured near wellbore)

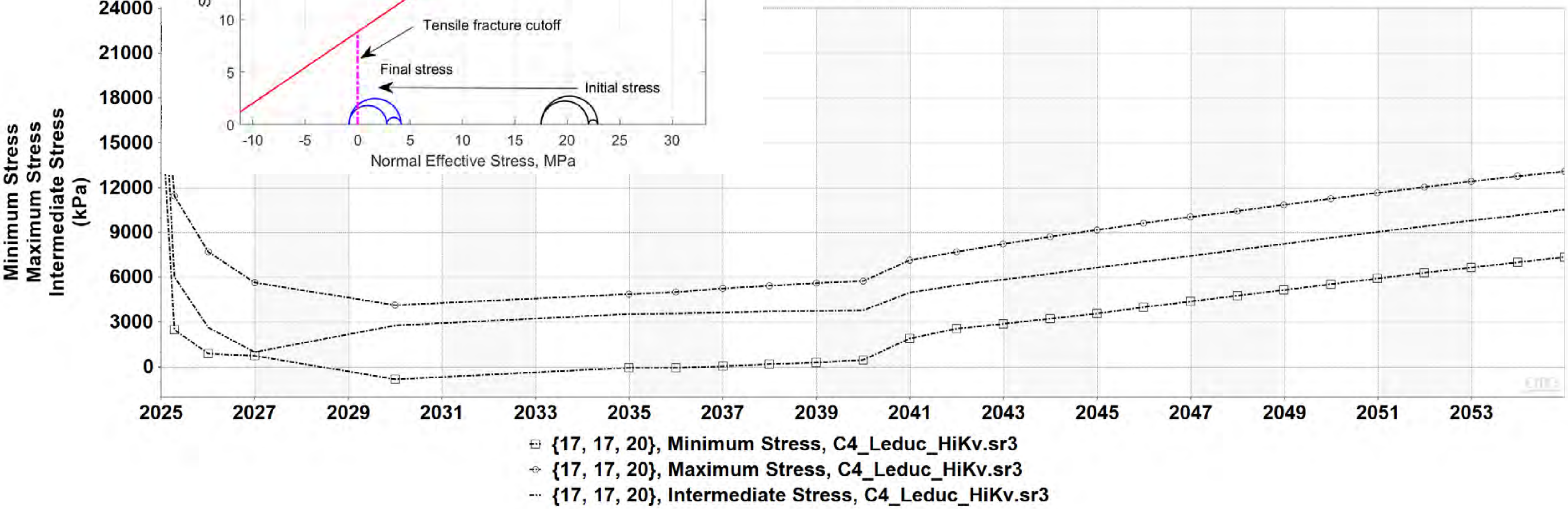


Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

Change of 3 principal effective stresses near wellbore

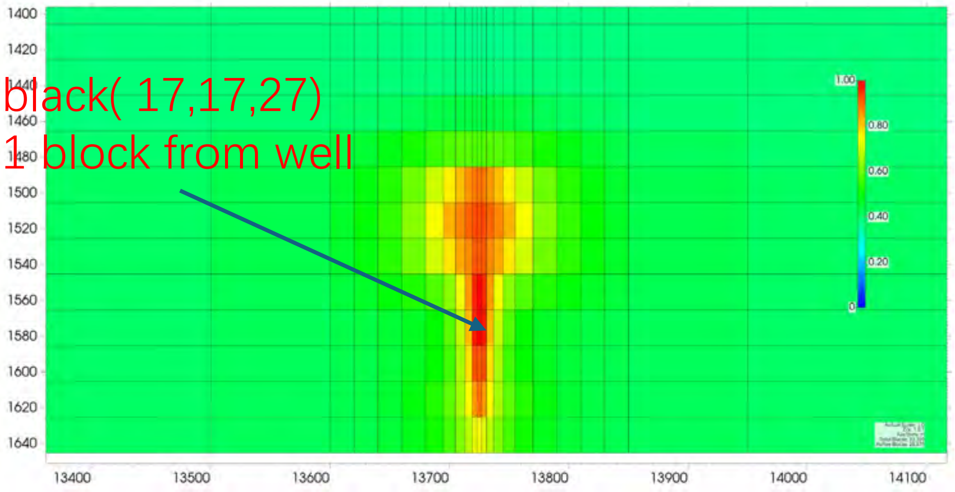


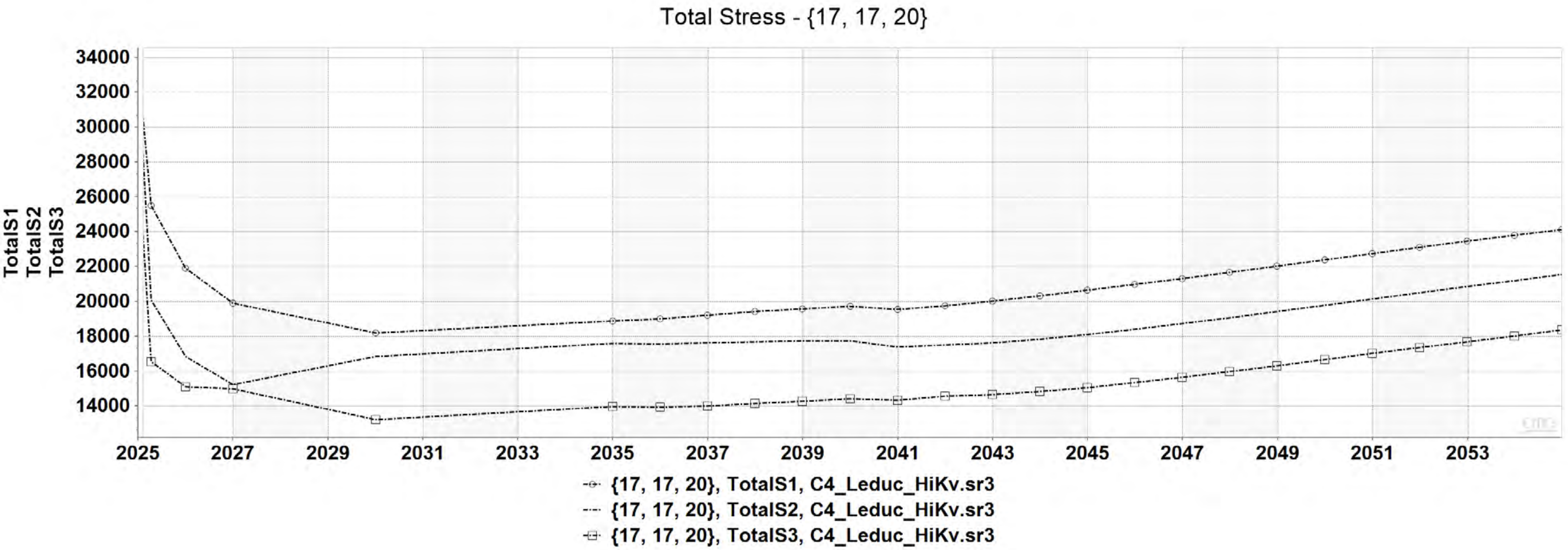




Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

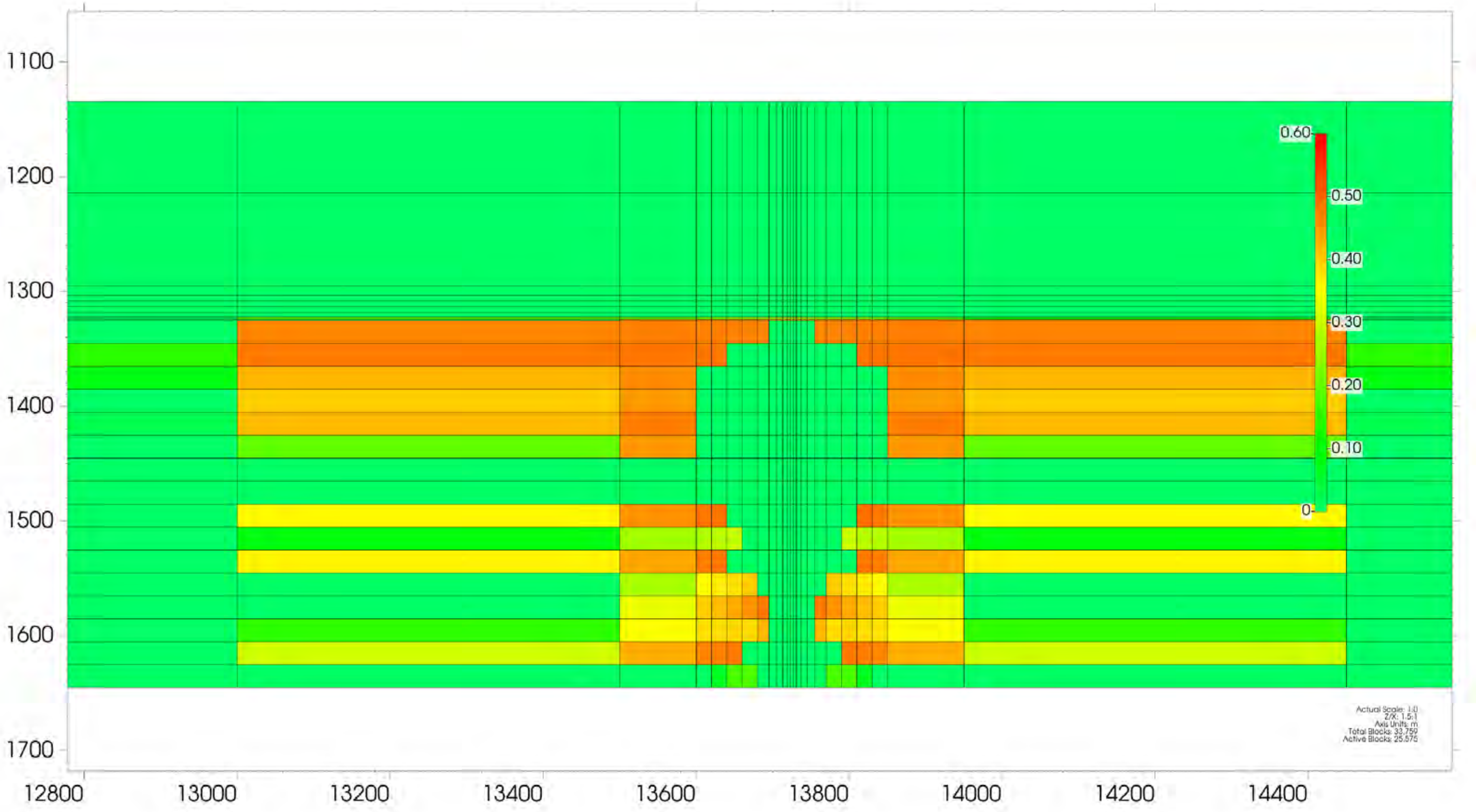
Change of 3 principal total stresses near wellbore





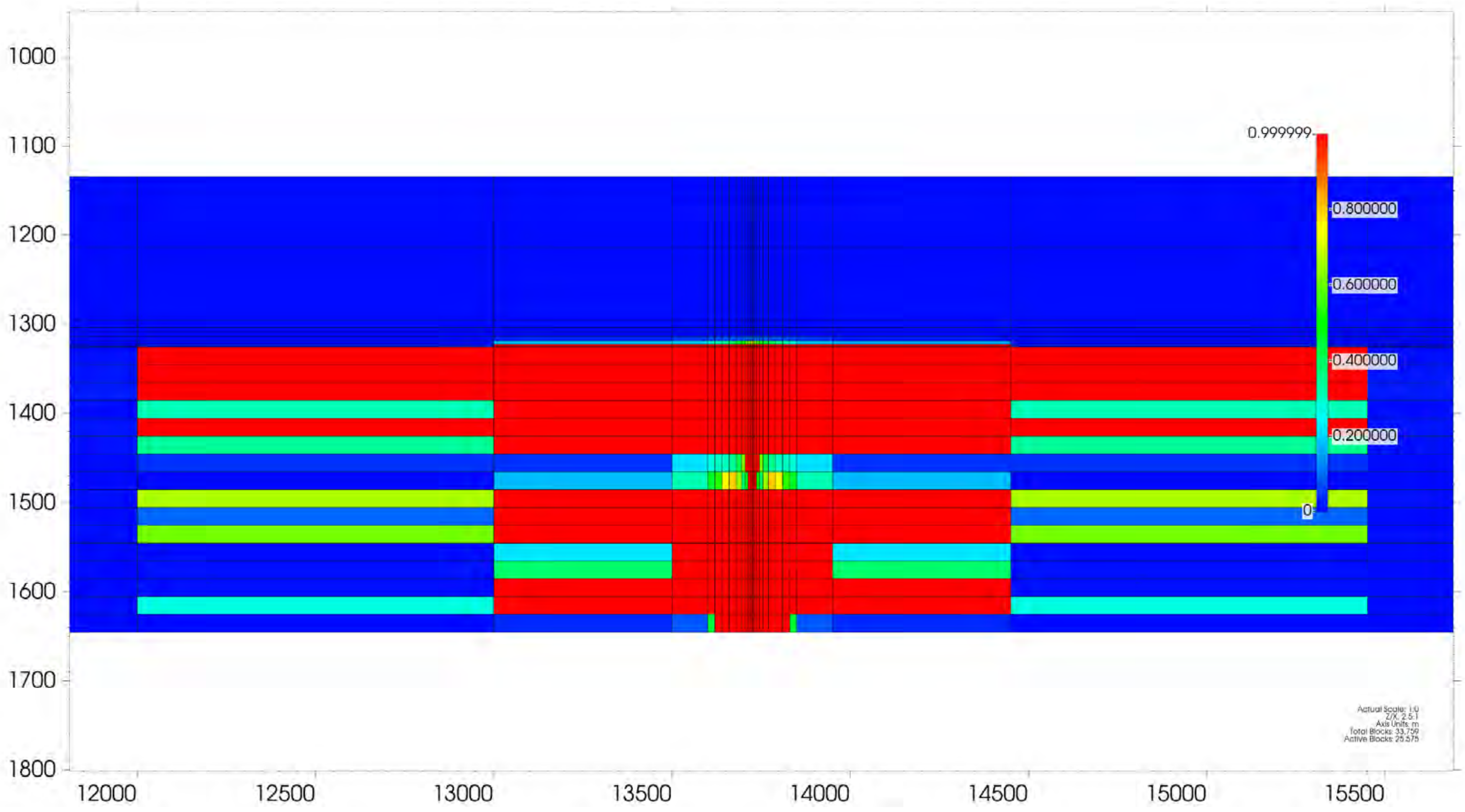
Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

Gas saturation @ 15 years



Case4: inject from Leduc lake, High Vertical Perm, Kv/Kh=1.0

CO_2 Mole fraction@ 15 years



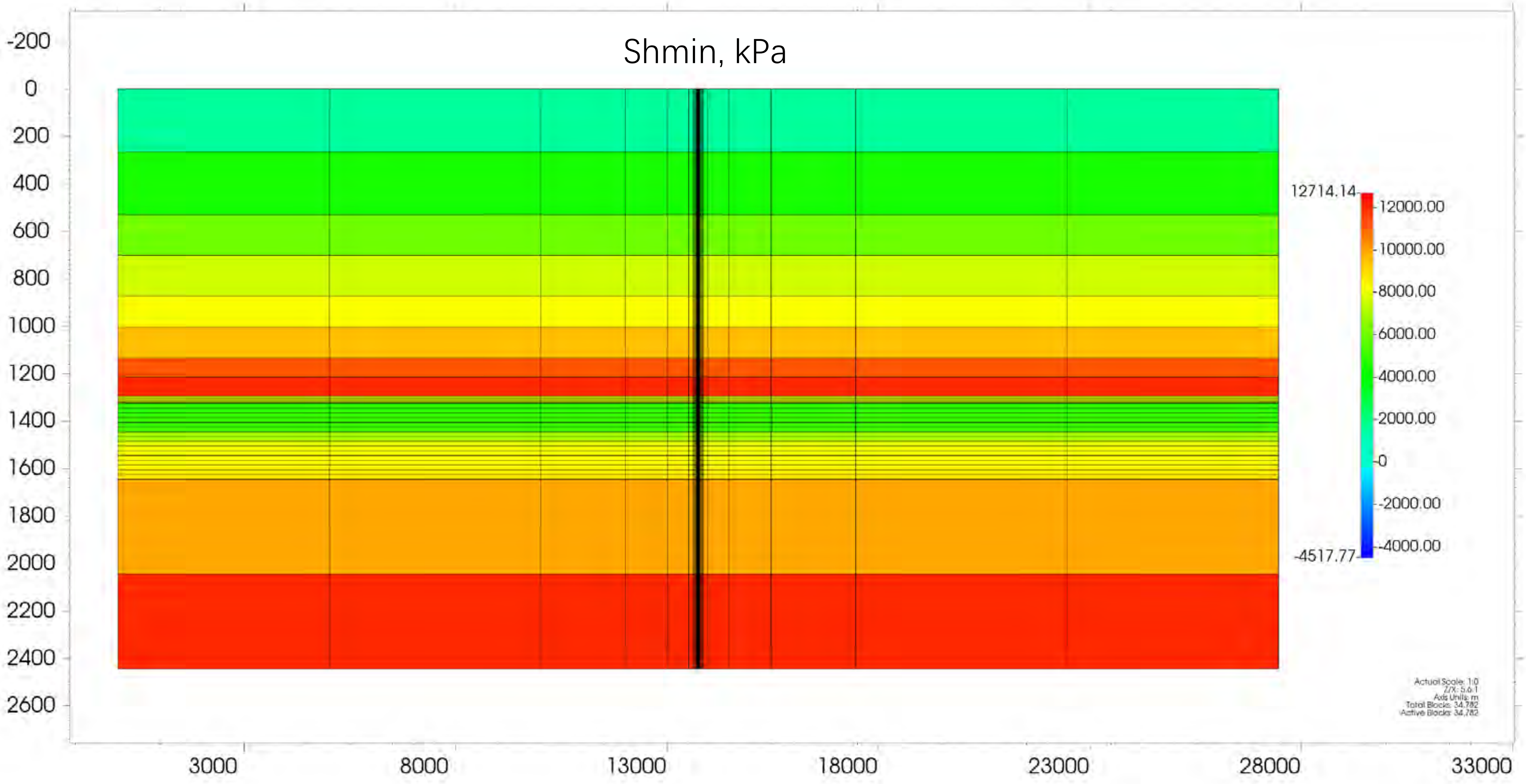
Case 5: Injection at Cooking Lake, Low Initial Stress

Base case: Case2

Case5: inject from cooking lake, Low Initial Stress

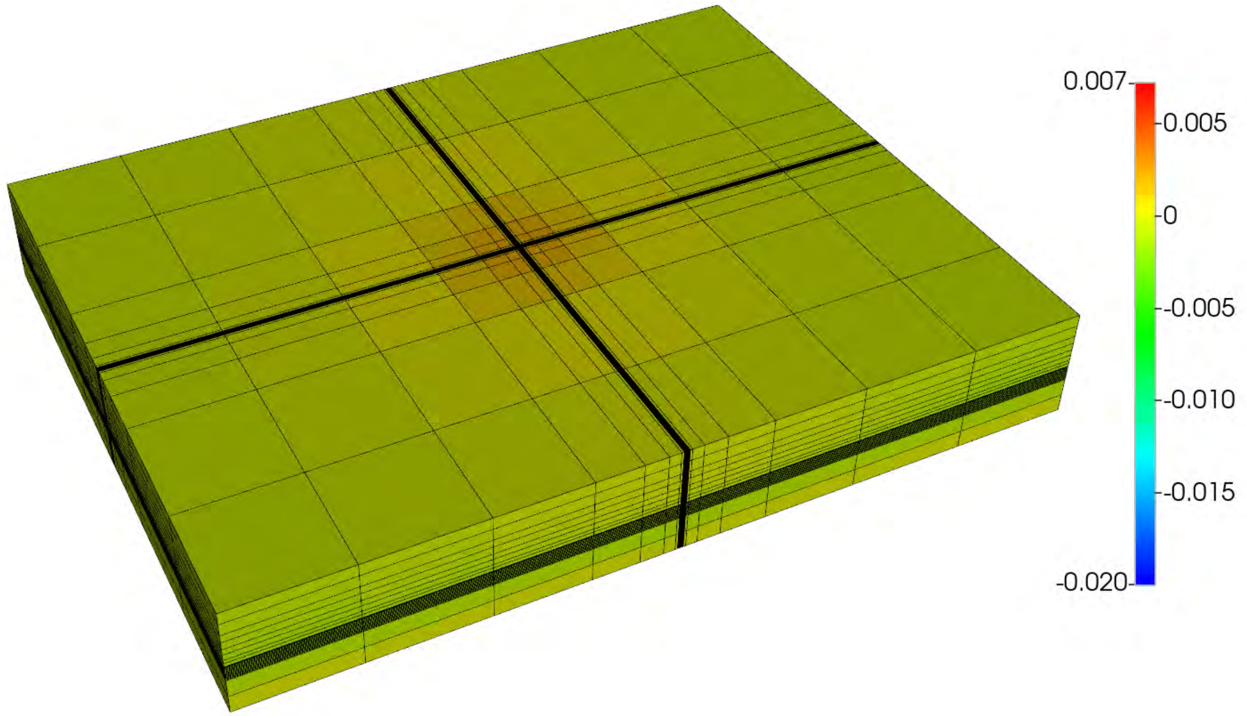
CMG Grid	Formation	Lithology	Elevation (SS)	Depth (m)	Comments	Es, kPa	Pois	Cohesion	Fric_ang	Porp_grad	Sv_grad	Shmin_grac	Shmax_gra
Milk River	Lea Park	shale	347.0	368.4	2 265.18 265.18	8.21E+06	0.37	3.24E+03	25.47	6.6	22.54	17.82	19.62
	Milk River	shale	260.0	455.4									
Colorado	Colorado Gp	shale	185.0	530.4	2 grids 171 171	9.50E+06	0.35	3.40E+03	25.91	7.8	22.79	17.46	19.13
	Second Wh	shale	6.0	709.4									
	Base Fish S	shale	-84.0	799.4									
	Viking	sandstone	-113.0	828.4									
	Joli Fou	shale	-134.6	850.0									
Manville	Manville	sandstone	-157.0	872.4	2 grids, 131 131	1.51E+07	0.32	5.03E+03	29.4	7.3	23.08	16.18	18.01
	Glauconite	sandstone	-297.0	1012.4									
	Ostracod	shale	-319.0	1034.4									
	Ellerslie	sandstone	-345.0	1060.4									
Wabamun	Wabamun	limestone	-419.0	1134.4	2 grids, 80 81	3.91E+07	0.29	1.60E+04	37.57	7	23.26	16.59	20.52
	Graminia	shale	-460.0	1175.4									
	Blueridge	limestone	-468.0	1183.4									
	Calmar	shale	-492.0	1207.4									
	Nisku	dolomite	-495.0	1210.4									
Ireton	Ireton	shale	-580.0	1295.4	H=30, 7 grids, 1 2 4 5 5 5 8	4.18E+07	0.28	3.23E+04	37.96	7	23.58	13.06	16.18
						3.08E+07	0.29	8.83E+03	34.27	7	23.6	12.86	15.07
Reservoir	Leduc	dolomite	-611.0	1326.4	Yes---in the GM model, same as tony's grid size	4.52E+07	0.28	1.93E+04	38.87	7.5	23.66	11.61	14.3
	Lower Ledu	dolomite	-723.0	1438.4	Yes---in the GM model, same as tony's grid size	5.65E+07	0.27	3.10E+04	40.21	7.5	23.76	12.26	14.81
	Cooking Lak	limestone	-772.0	1487.4	Yes---in the GM model, same as tony's grid size	5.55E+07	0.28	2.22E+04	40.48	7.5	24.02	12.86	16.38
Base	Base			2287.36	2 grids, 400 400	4.83E+07	0.26	2.17E+04	40	7.5	23.96	20.47	24.41

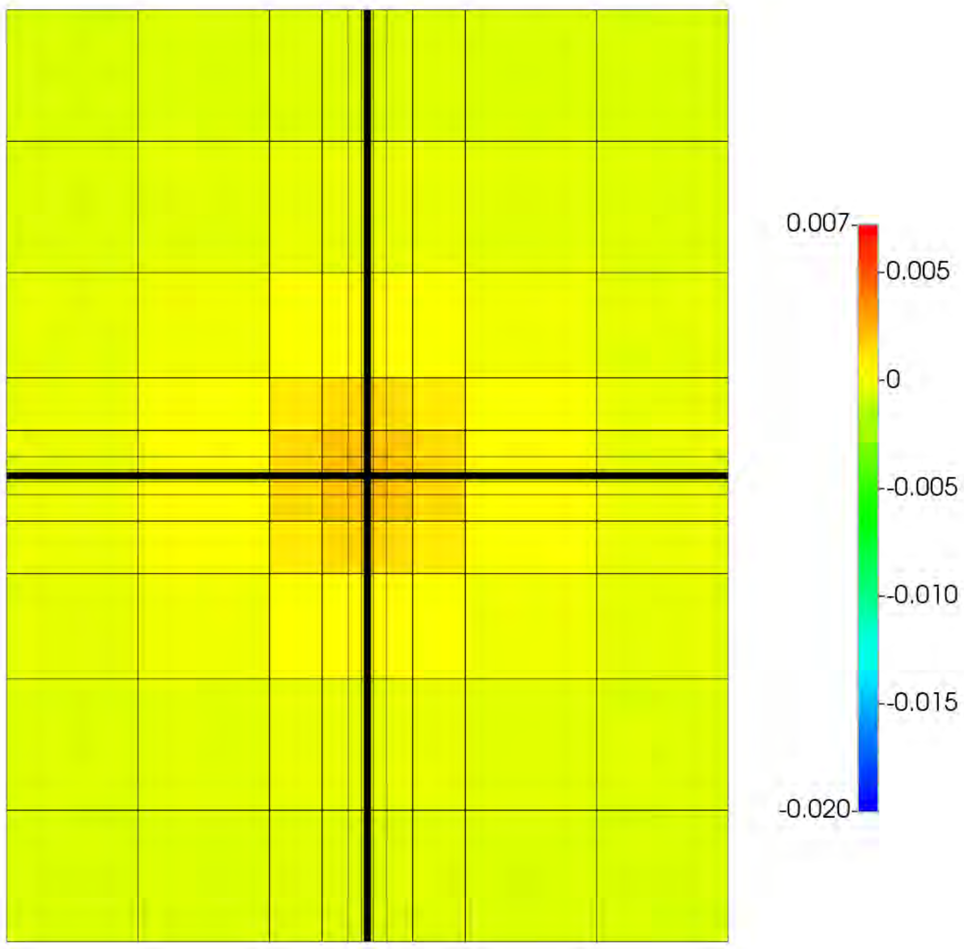
Case5: inject from cooking lake, Low Initial Stress



Case5: inject from cooking lake, Low Initial Stress

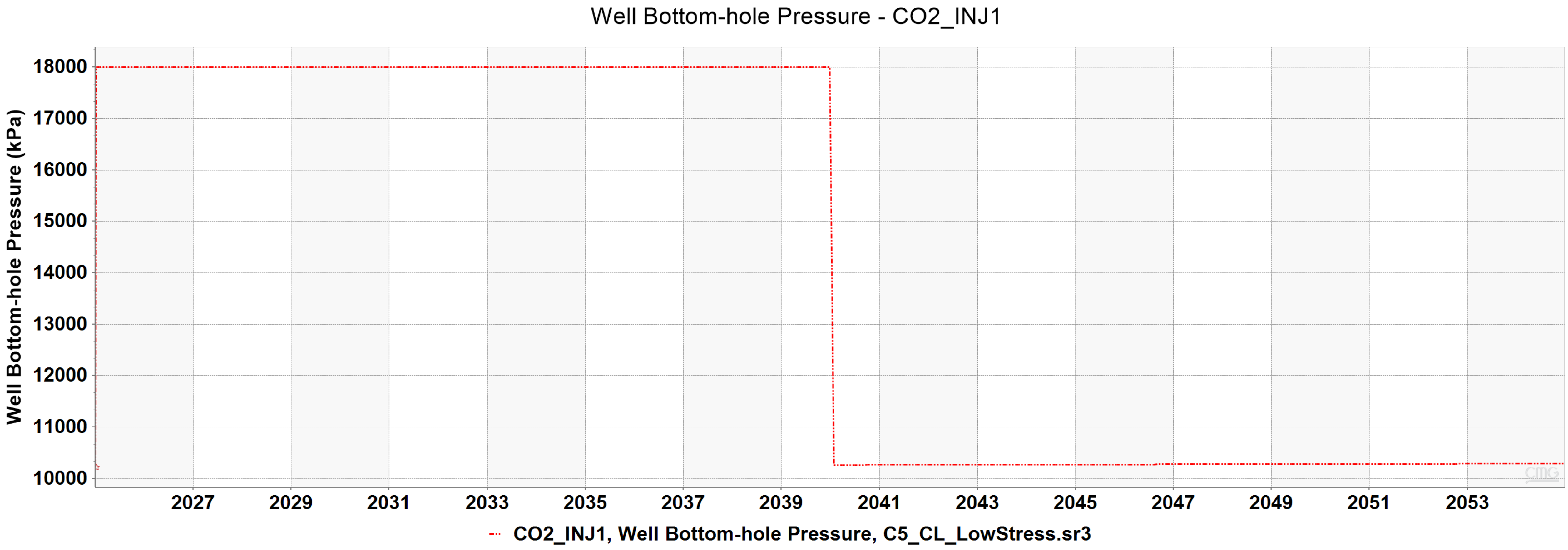
Surface heave @ end of injection 15 years (max. 3mm)





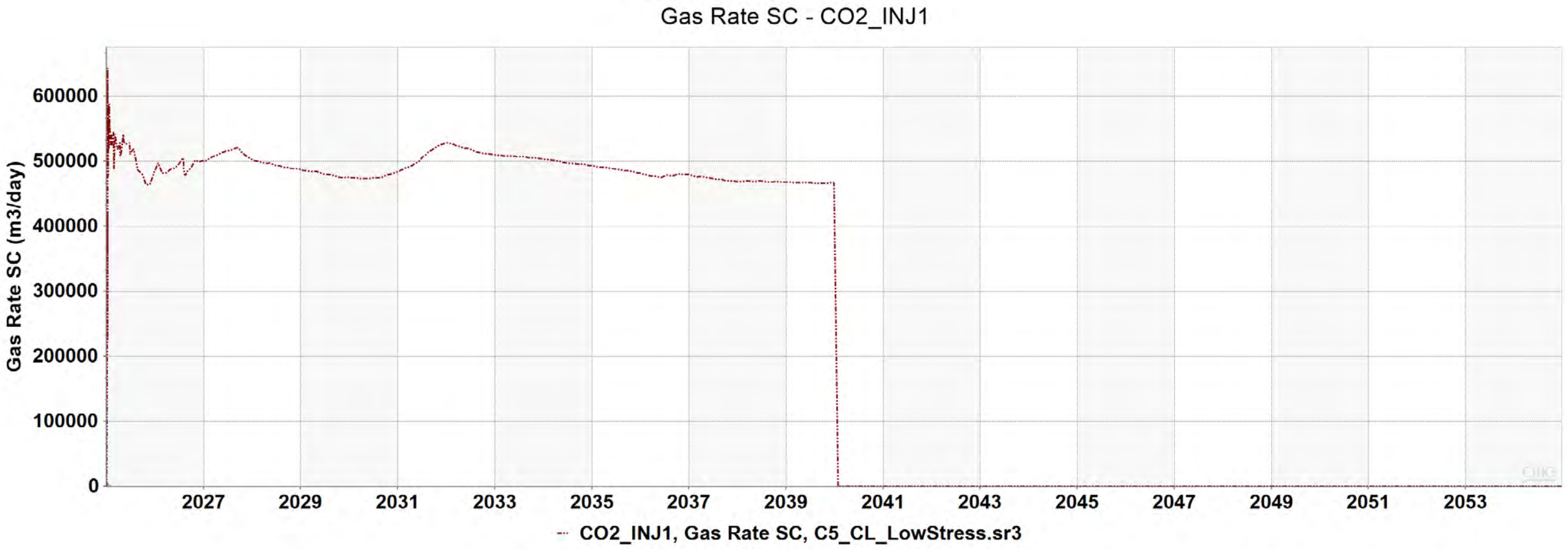
Case5: inject from cooking lake, Low Initial Stress

Injection pressure (BHP, unit: kPa)



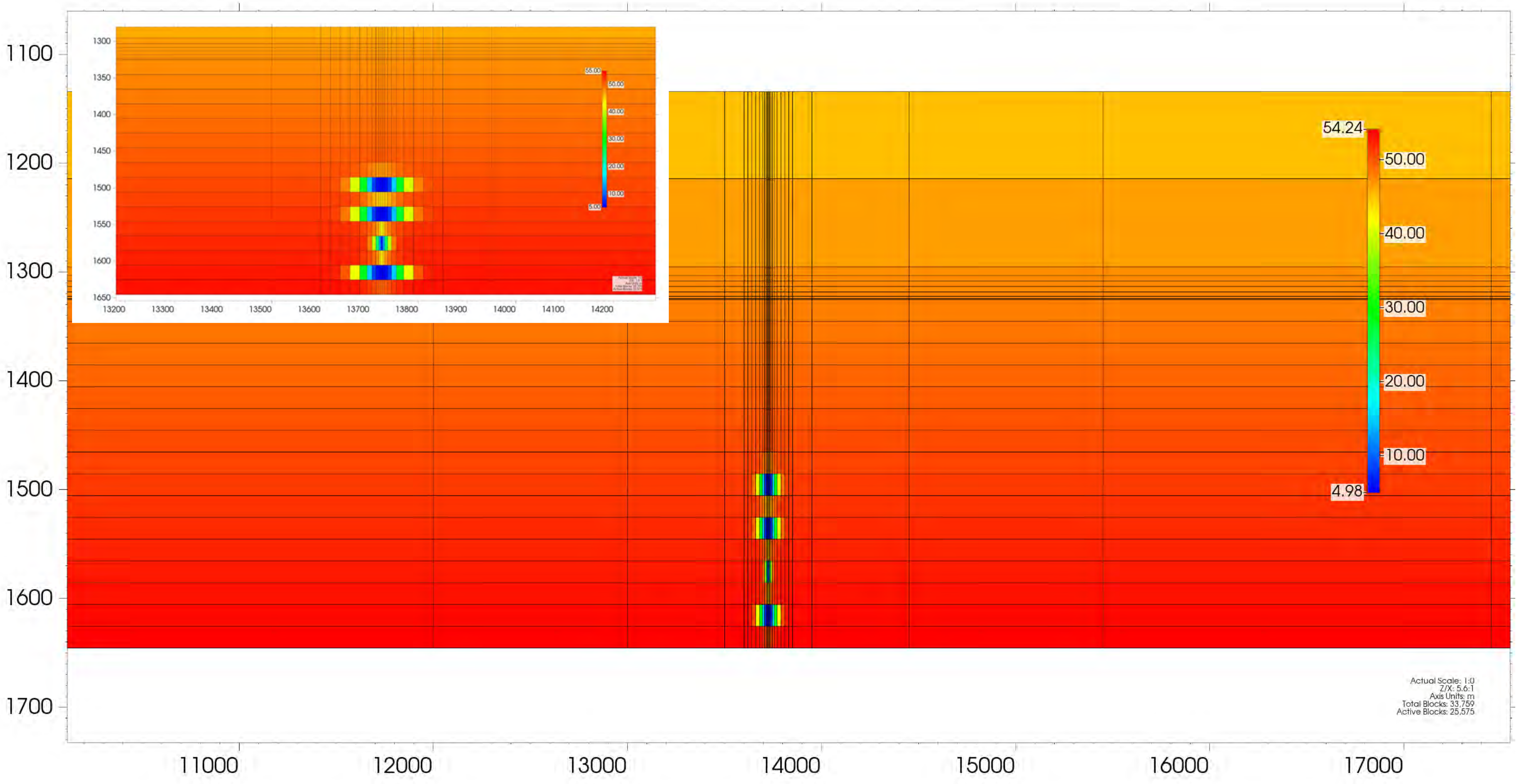
Case5: inject from cooking lake, Low Initial Stress

Injection rate



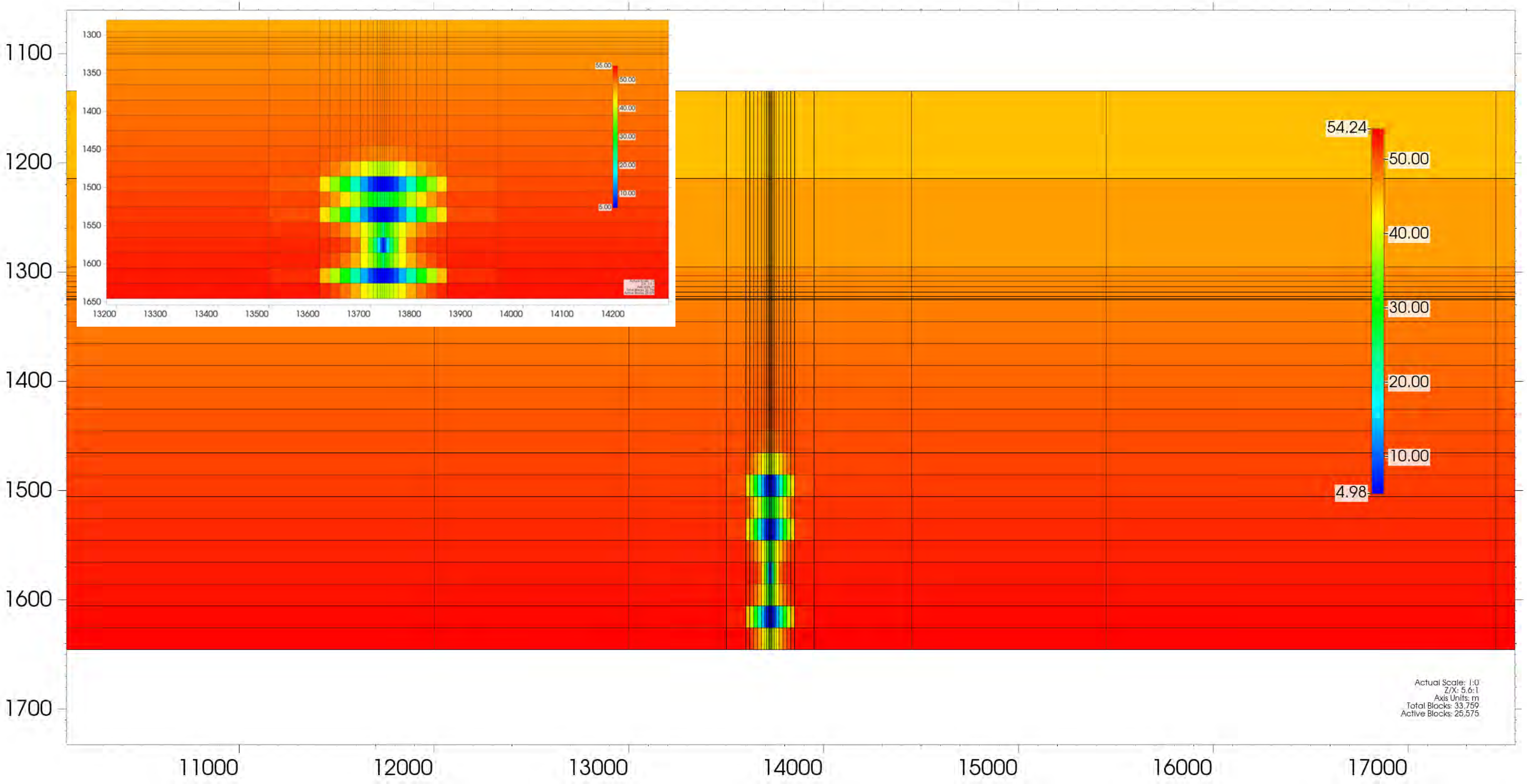
Case5: inject from cooking lake, Low Initial Stress

Temperature distribution @ 1 year



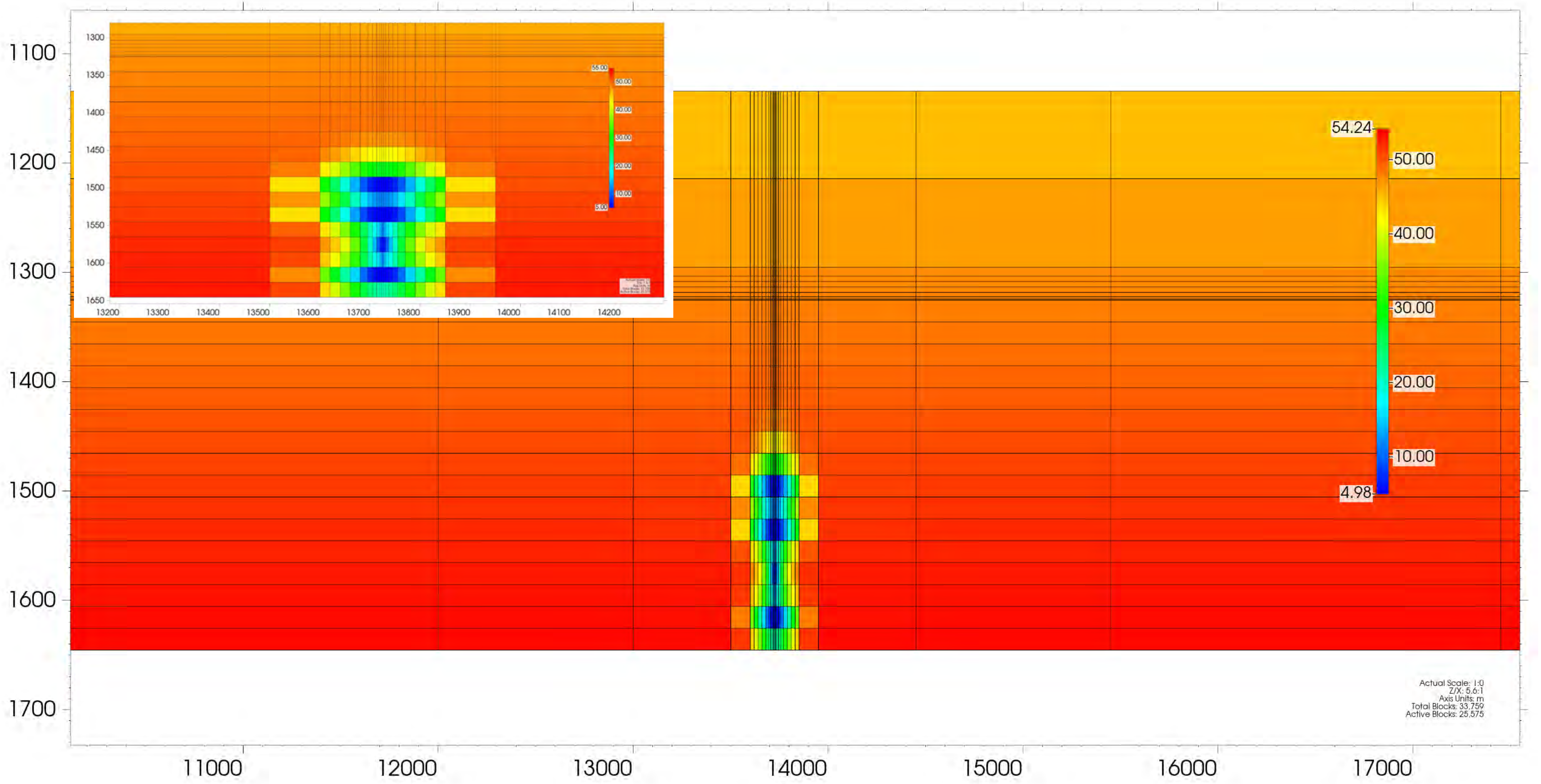
Case5: inject from cooking lake, Low Initial Stress

Temperature distribution @ 5 years



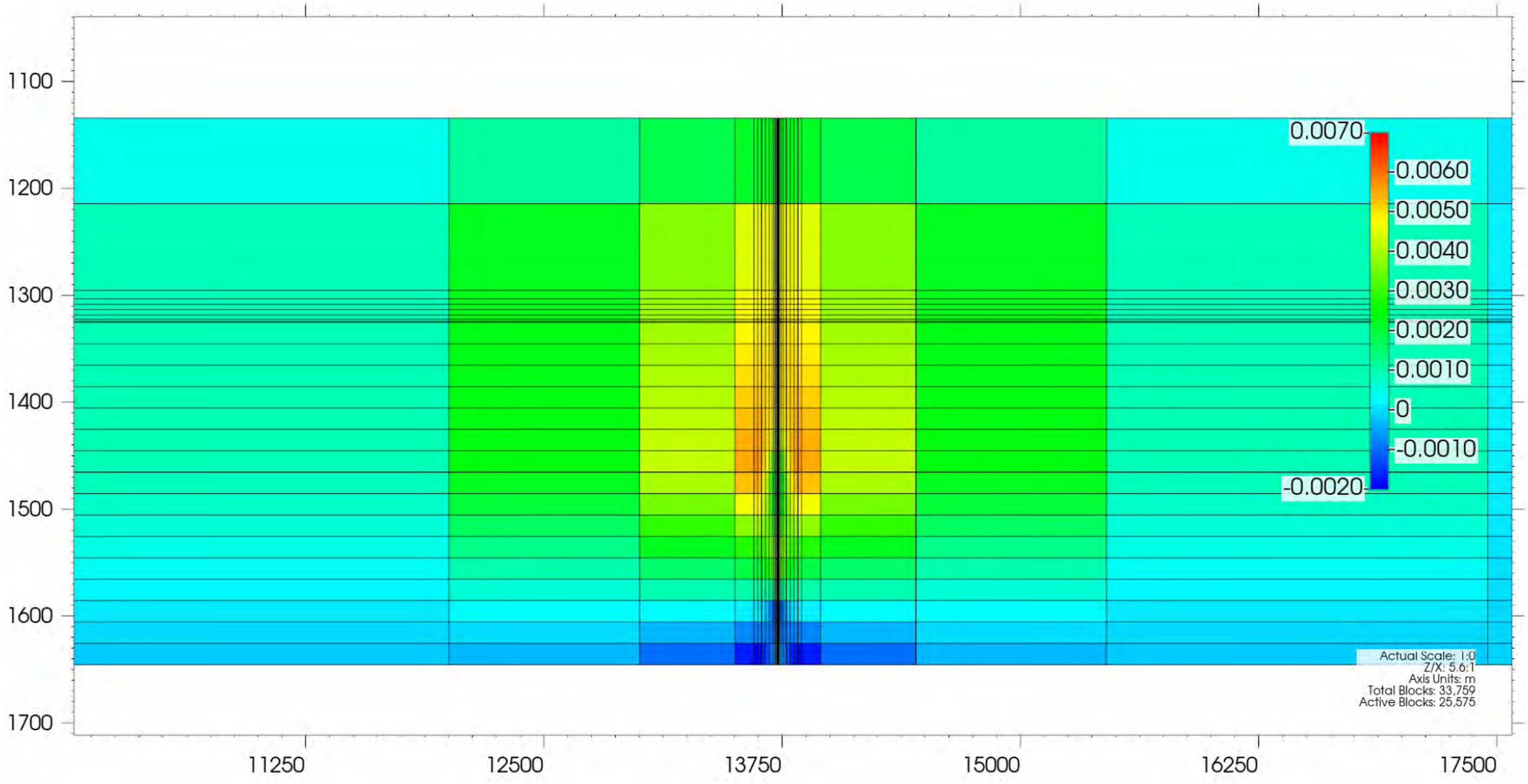
Case5: inject from cooking lake, Low Initial Stress

Temperature distribution @ end of injection 15 years



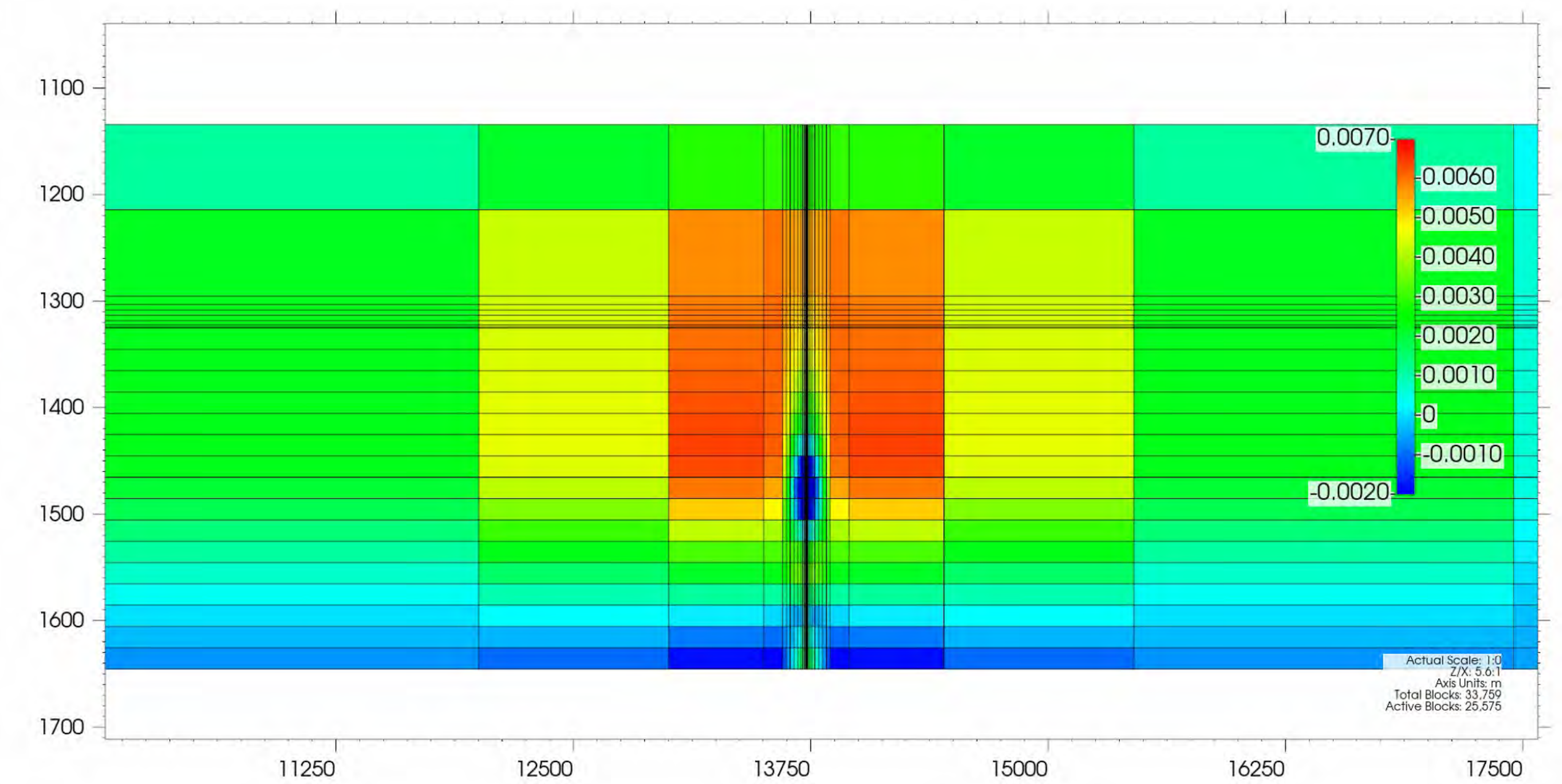
Case5: inject from cooking lake, Low Initial Stress

Deformation (Uz) @ 1 year



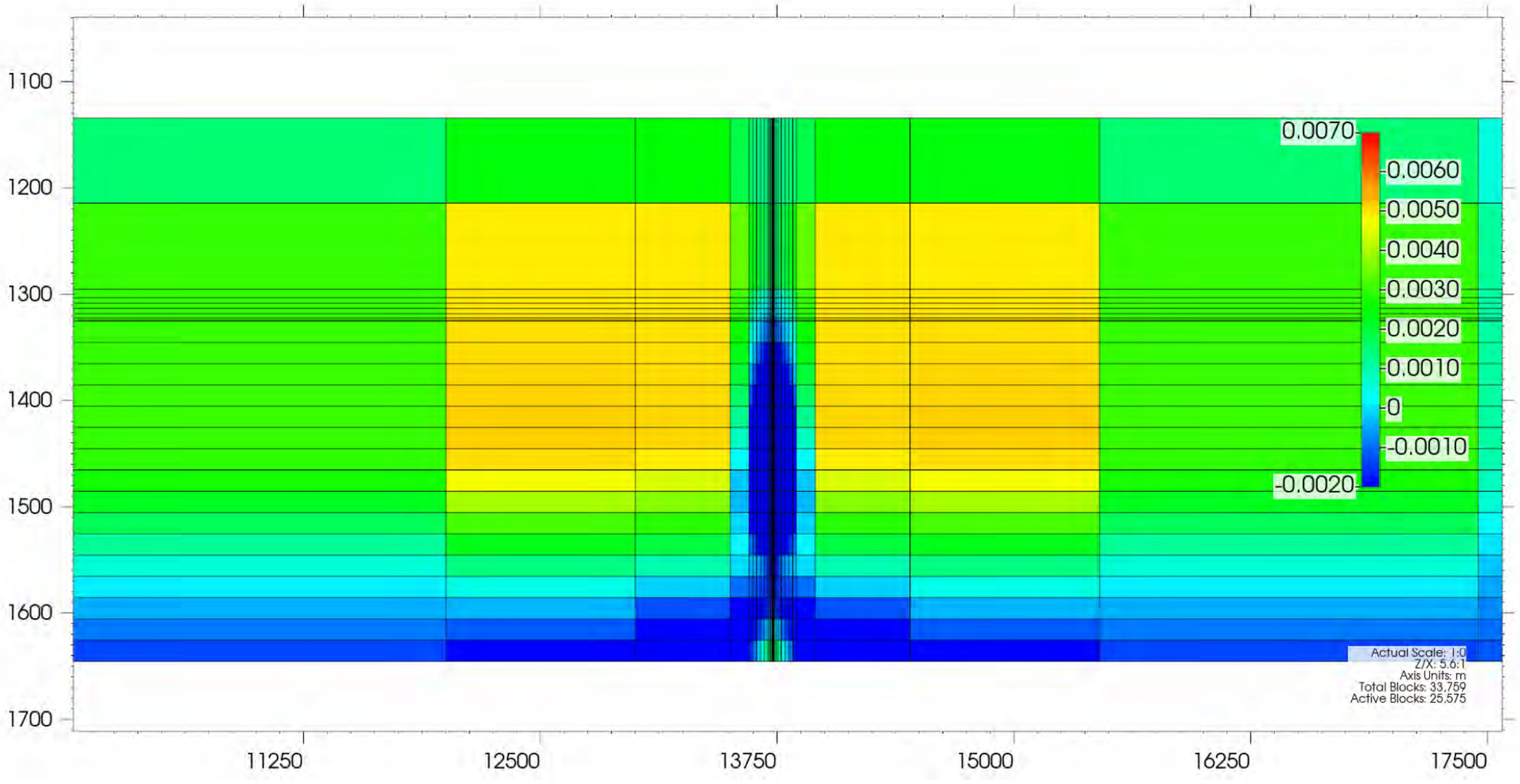
Case5: inject from cooking lake, Low Initial Stress

Deformation (Uz) @ 5 years



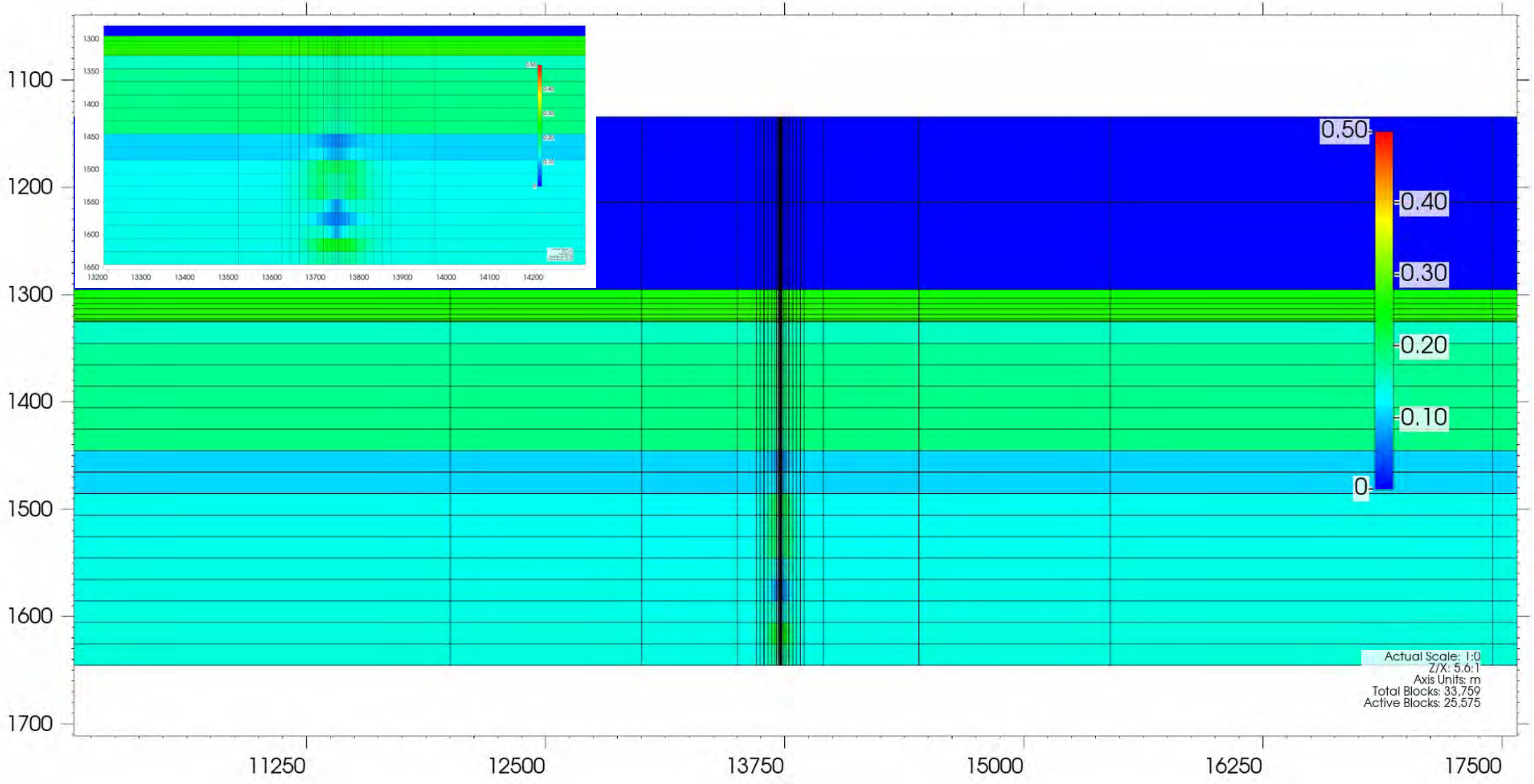
Case5: inject from cooking lake, Low Initial Stress

Deformation (Uz) @ end of injection 15 years



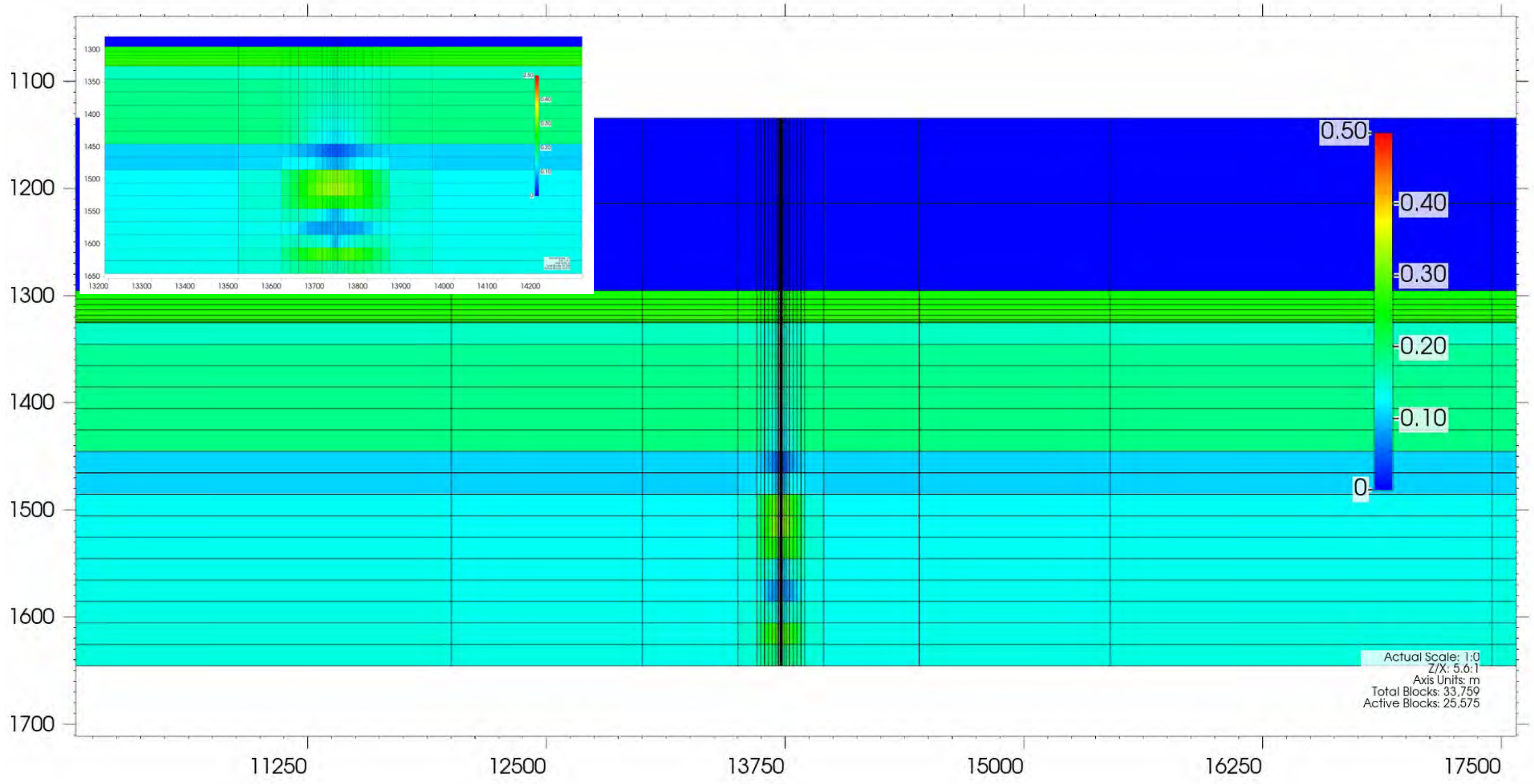
Case5: inject from cooking lake, Low Initial Stress

SSL at lower Ireton, Leduc and Cooking lake @ 1 year



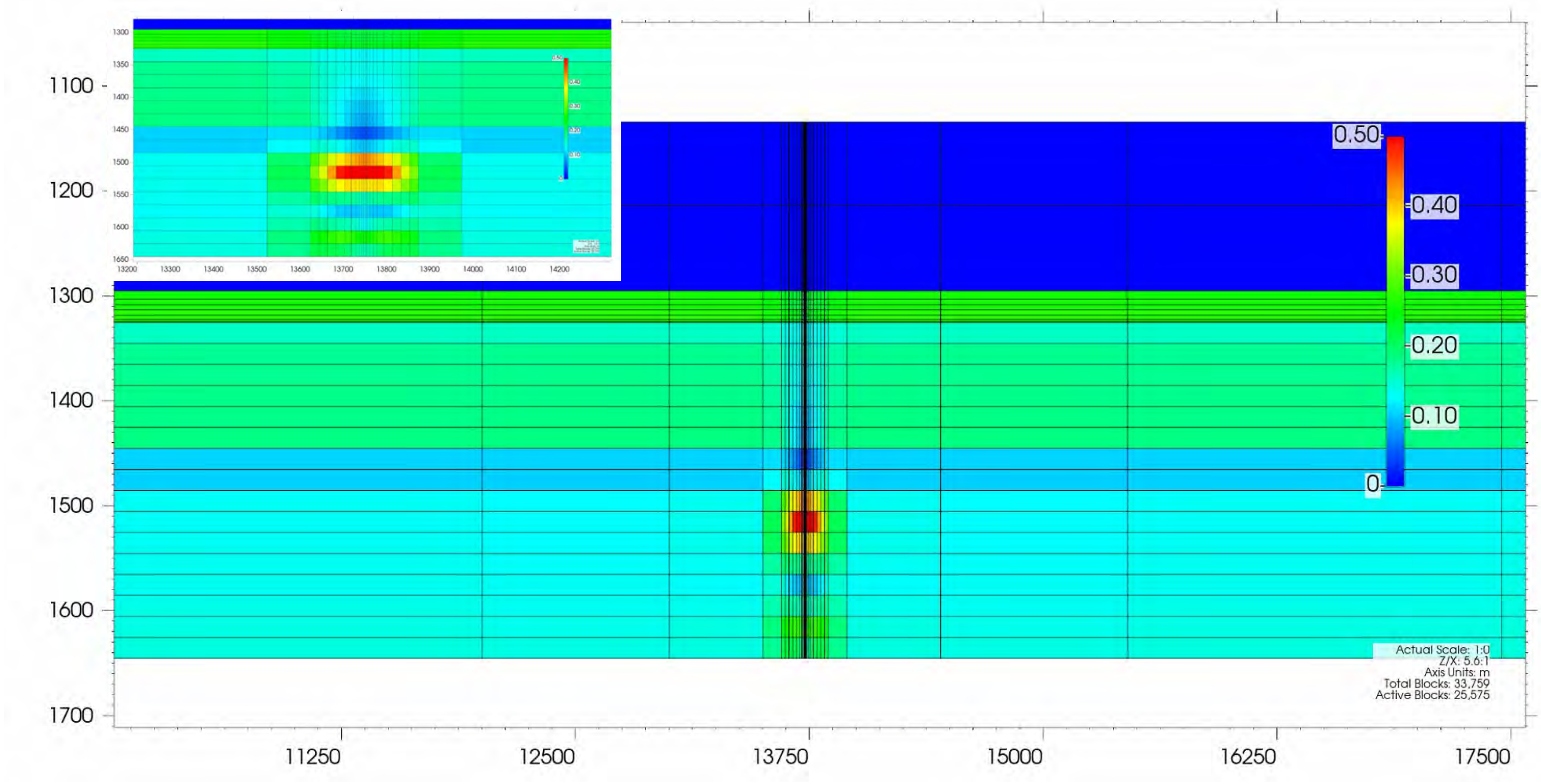
Case5: inject from cooking lake, Low Initial Stress

SSL at lower Ireton, Leduc and Cooking lake @ 5 years



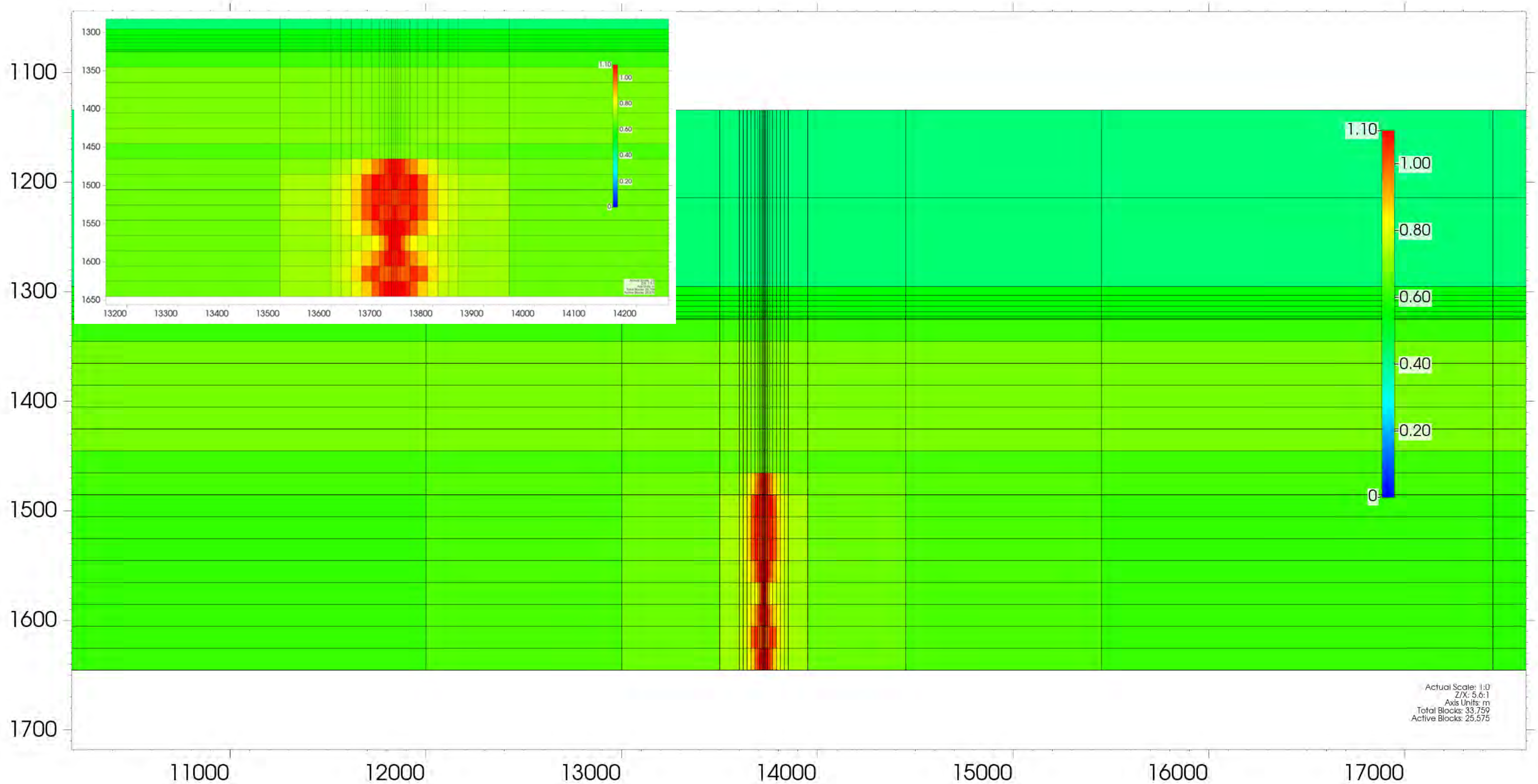
Case5: inject from cooking lake, Low Initial Stress

SSL at lower Ireton, Leduc and Cooking lake @ 15 years



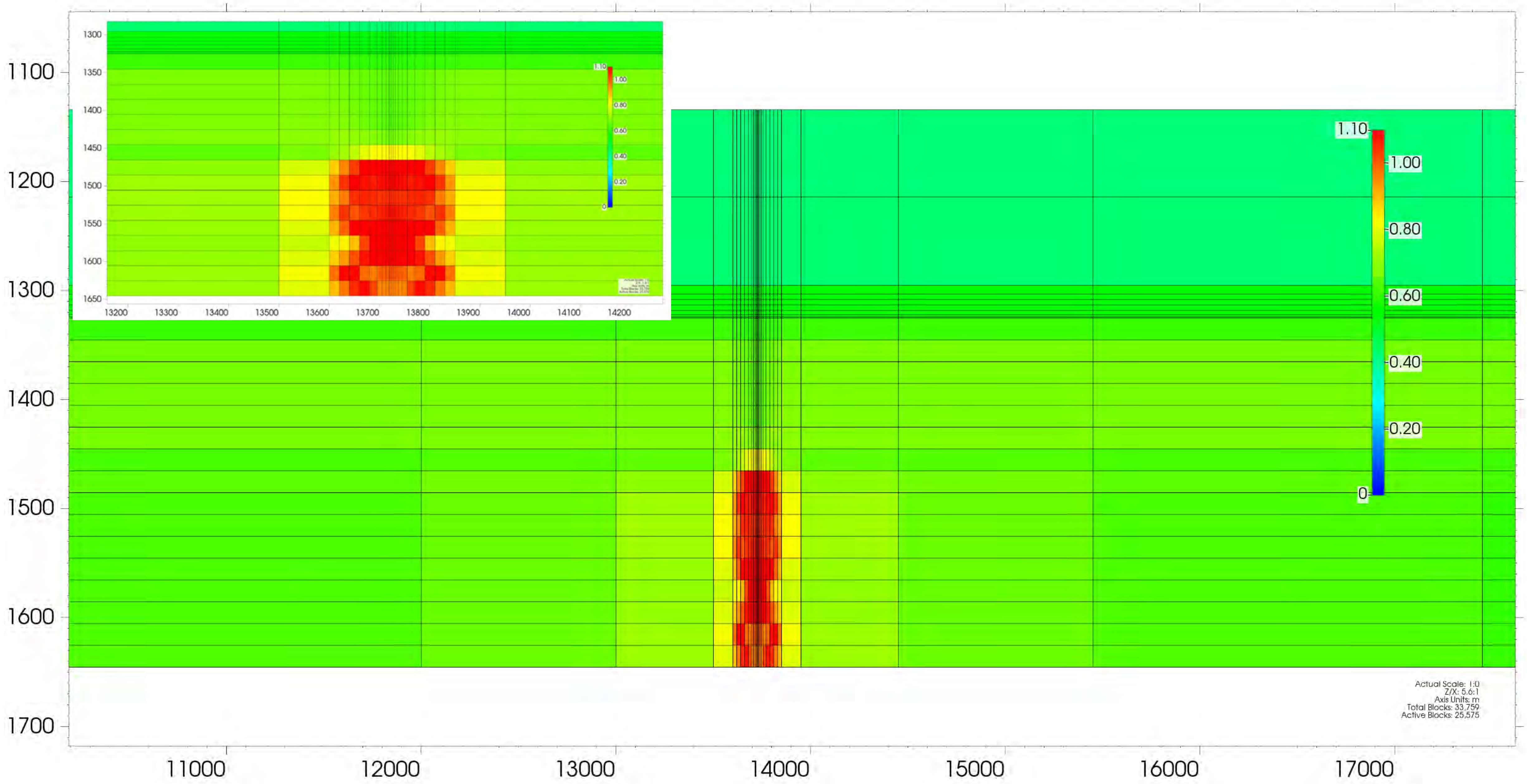
Case5: inject from cooking lake, Low Initial Stress

TSL at lower Ireton, Leduc and Cooking lake @ 1 year (fractured near wellbore)



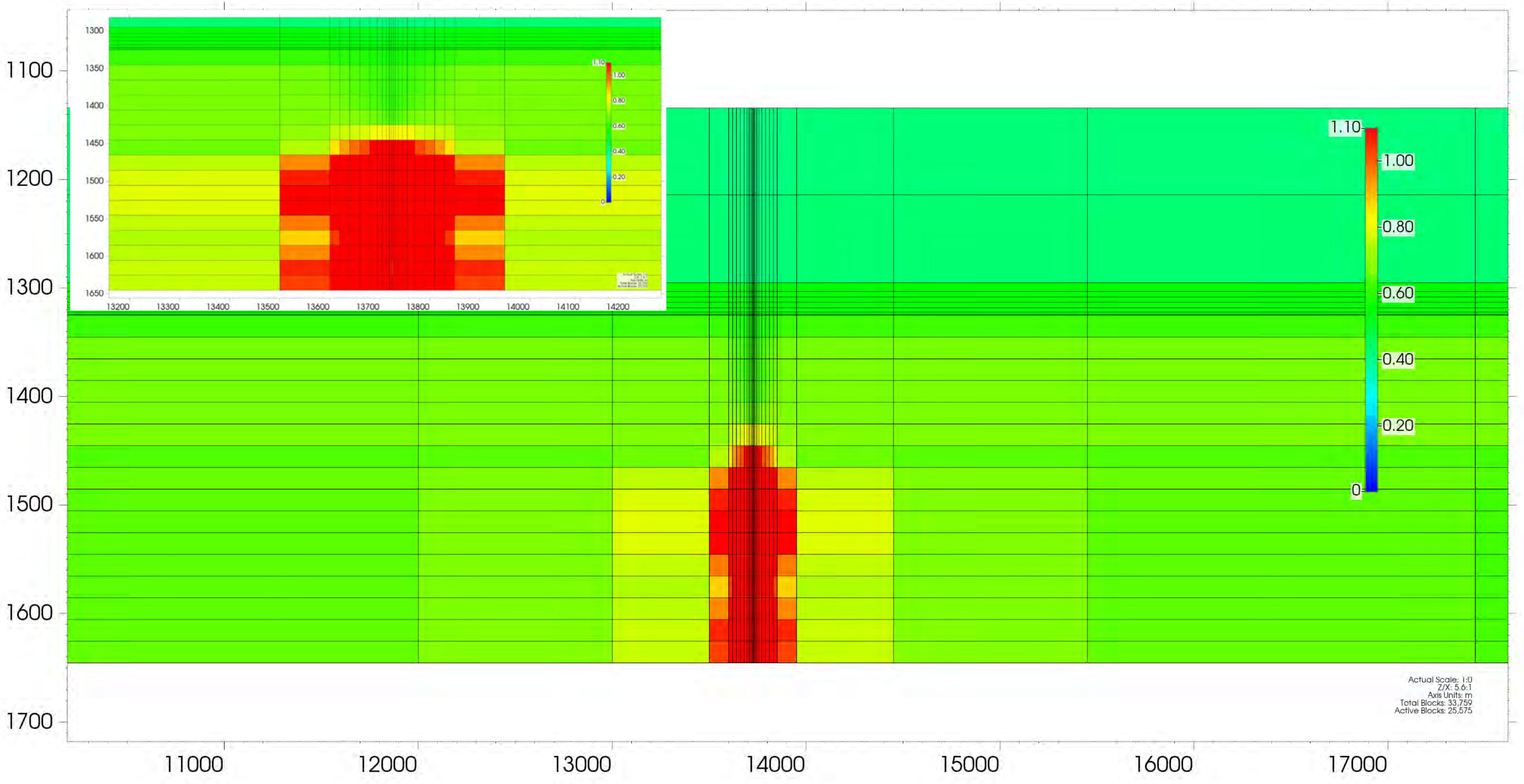
Case5: inject from cooking lake, Low Initial Stress

TSL at lower Ireton, Leduc and Cooking lake @ 5 years (fractured near wellbore)



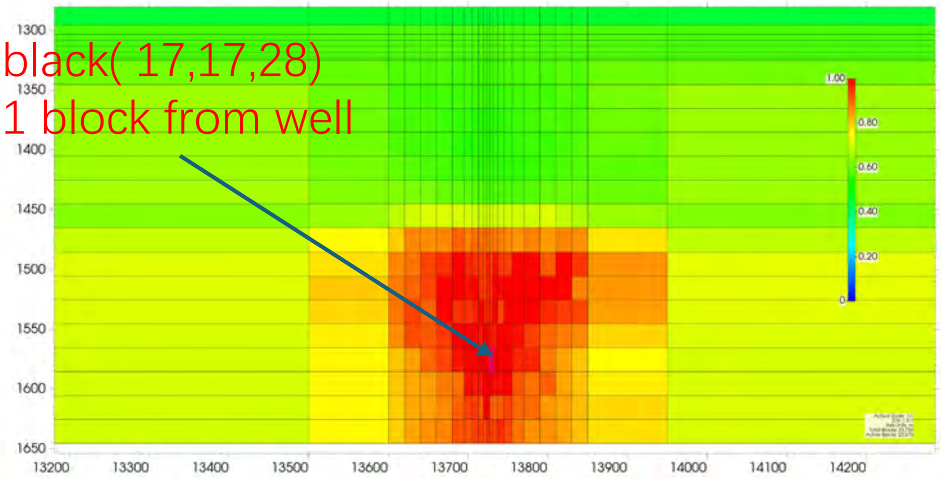
Case5: inject from cooking lake, Low Initial Stress

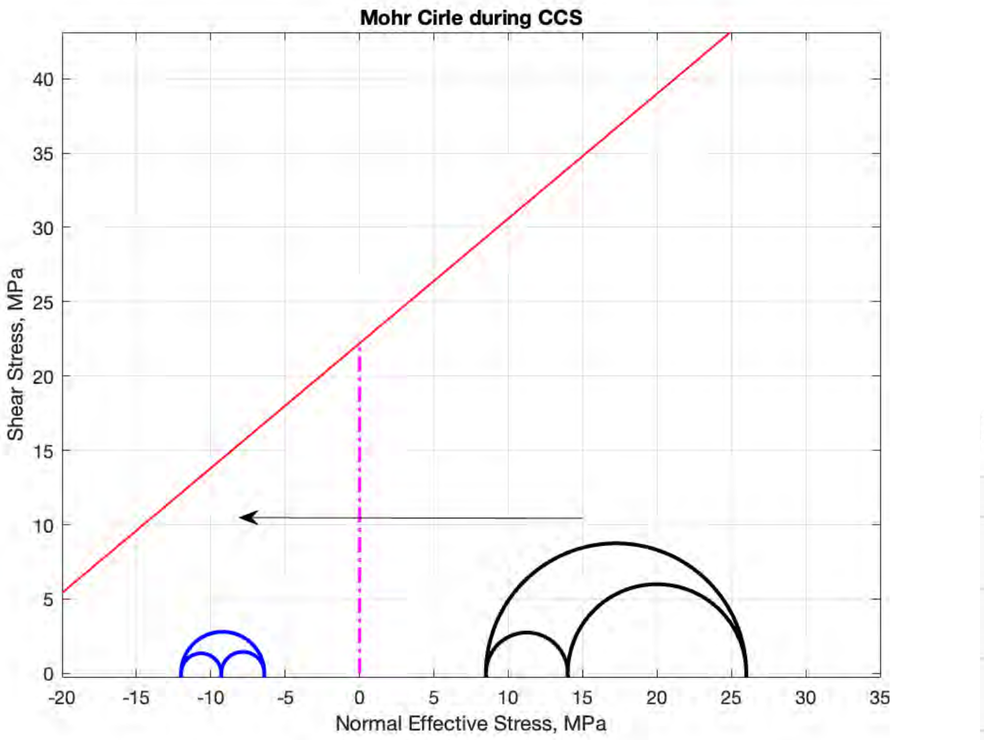
TSL at lower Ireton, Leduc and Cooking lake @ end of injection 15 years (fractured near wellbore)

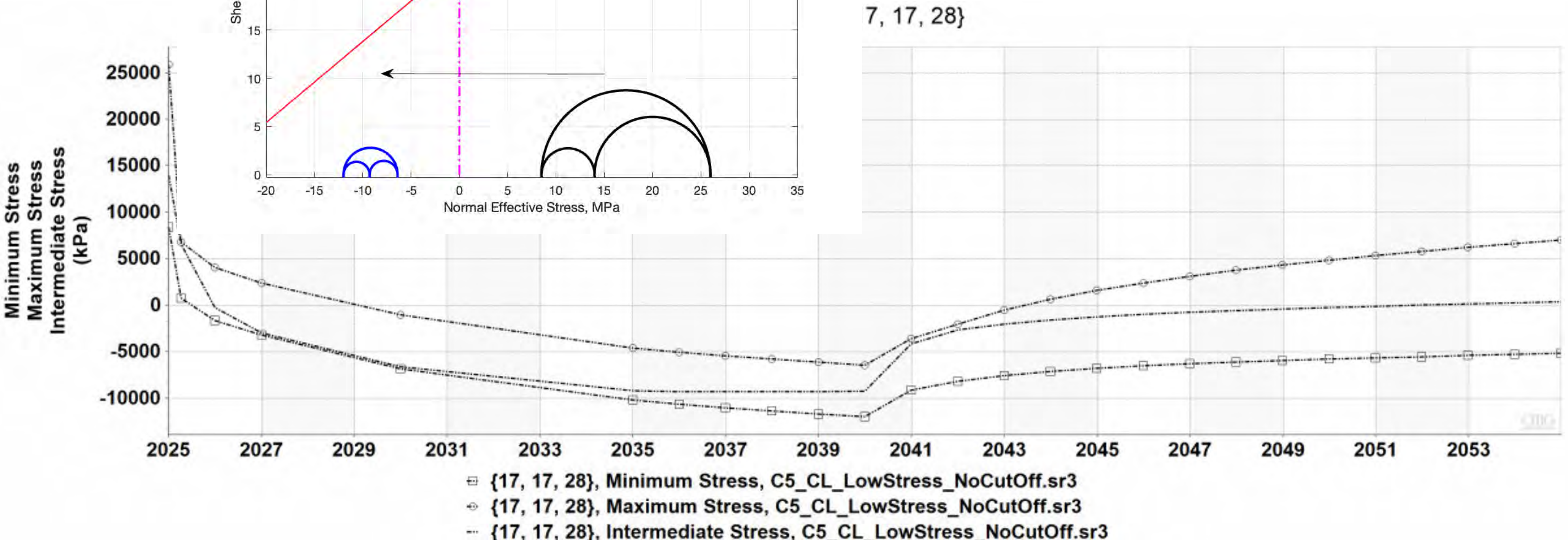


Case5: inject from cooking lake, Low Initial Stress

Change of 3 principal effective stresses near wellbore

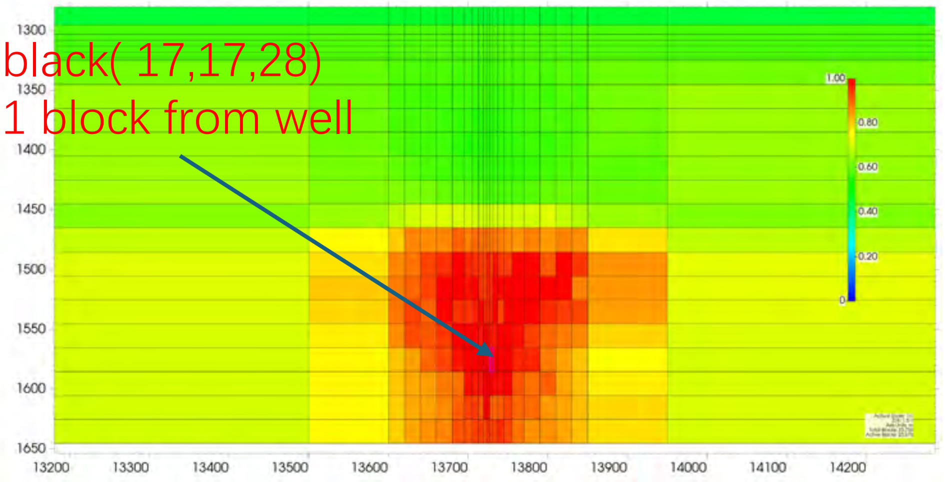


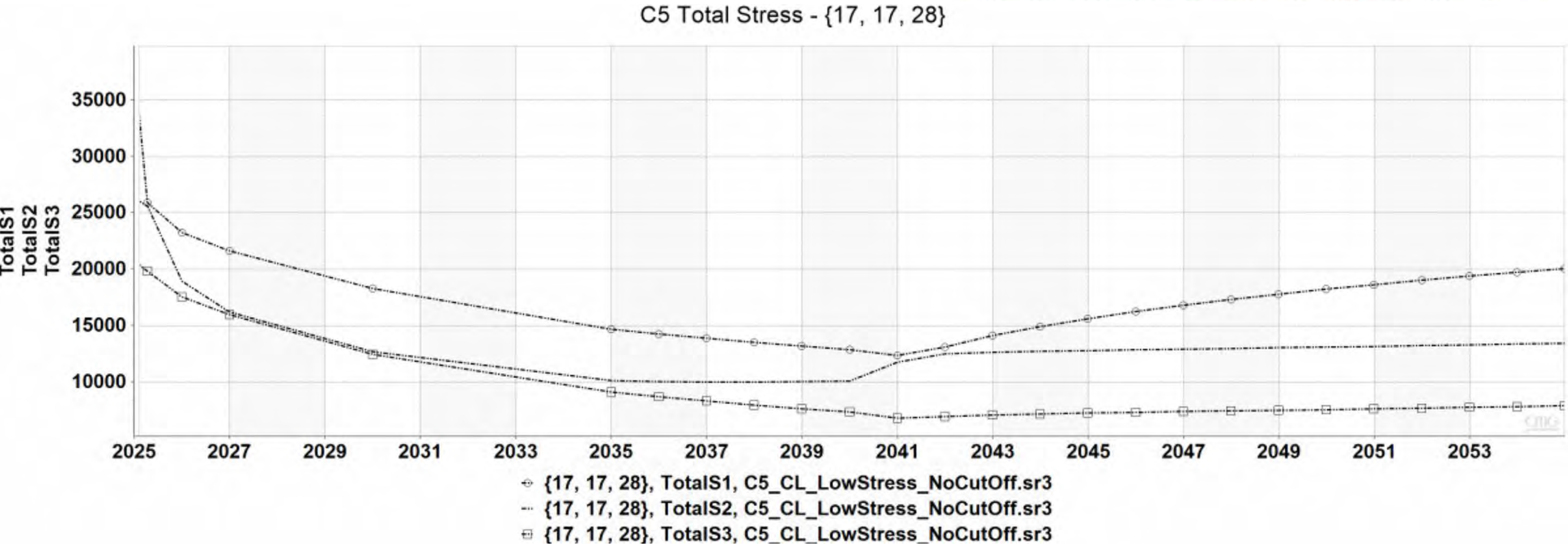




Case5: inject from cooking lake, Low Initial Stress

Change of 3 principal total stresses near wellbore



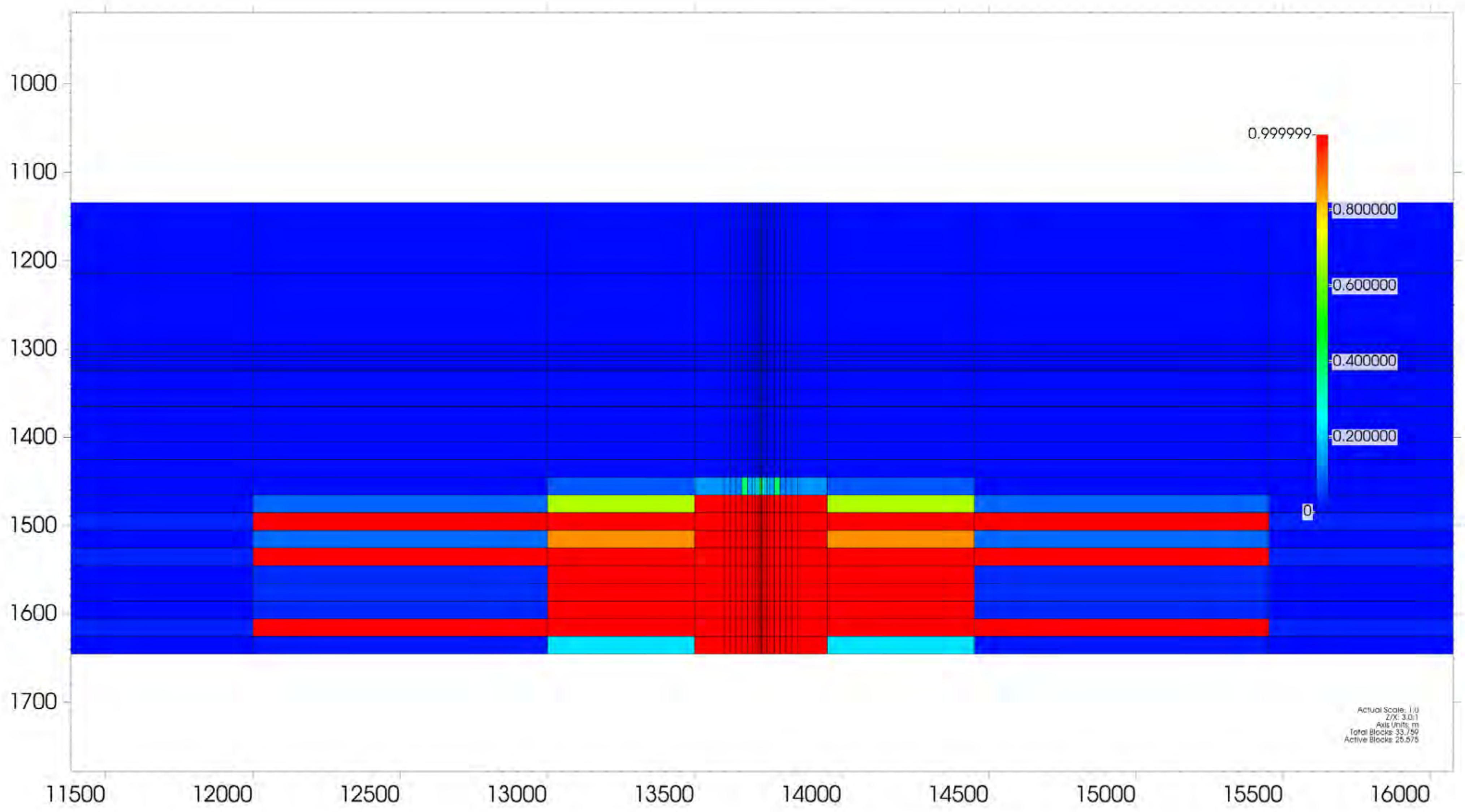


Case5: inject from cooking lake, Low Initial Stress

Gas saturation

Case5: inject from cooking lake, Low Initial Stress

CO2 Mole fraction@ 15 years

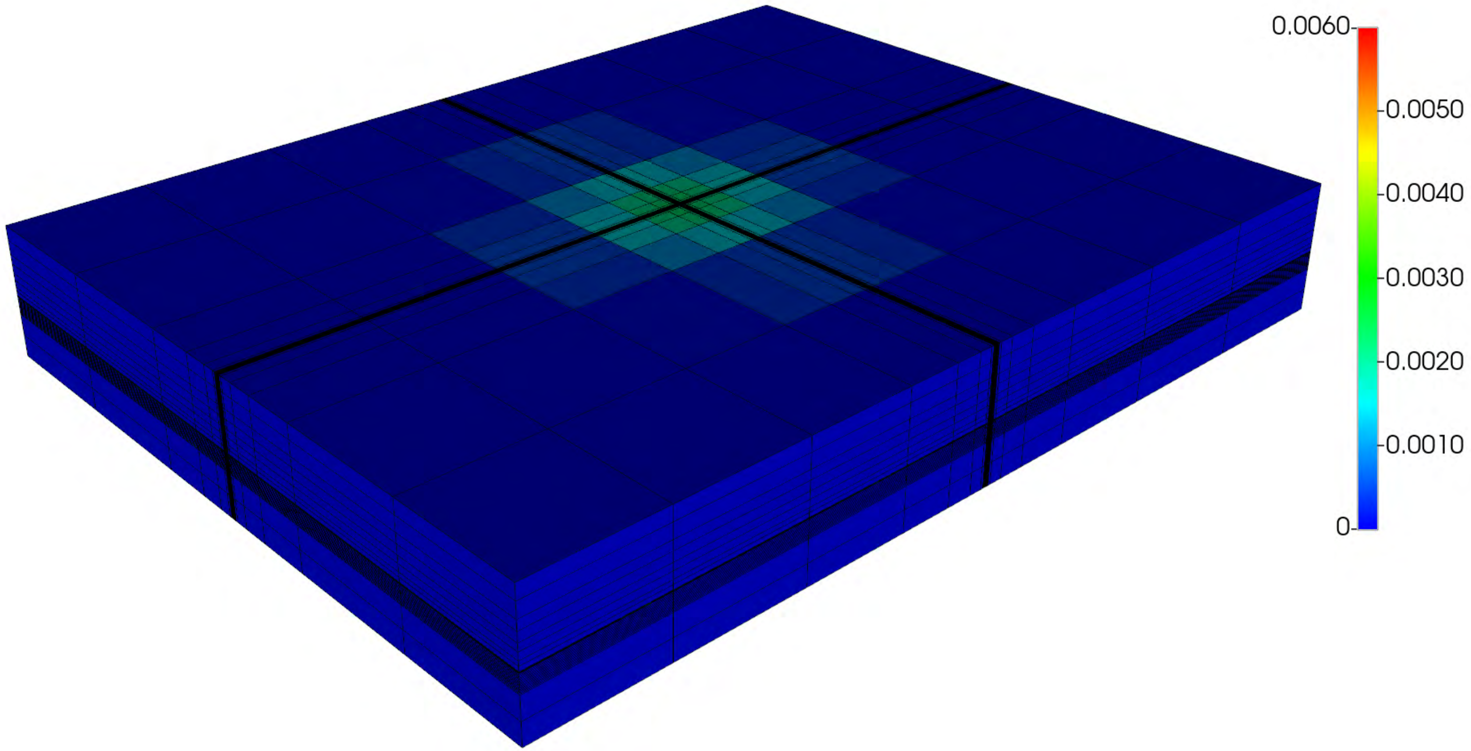


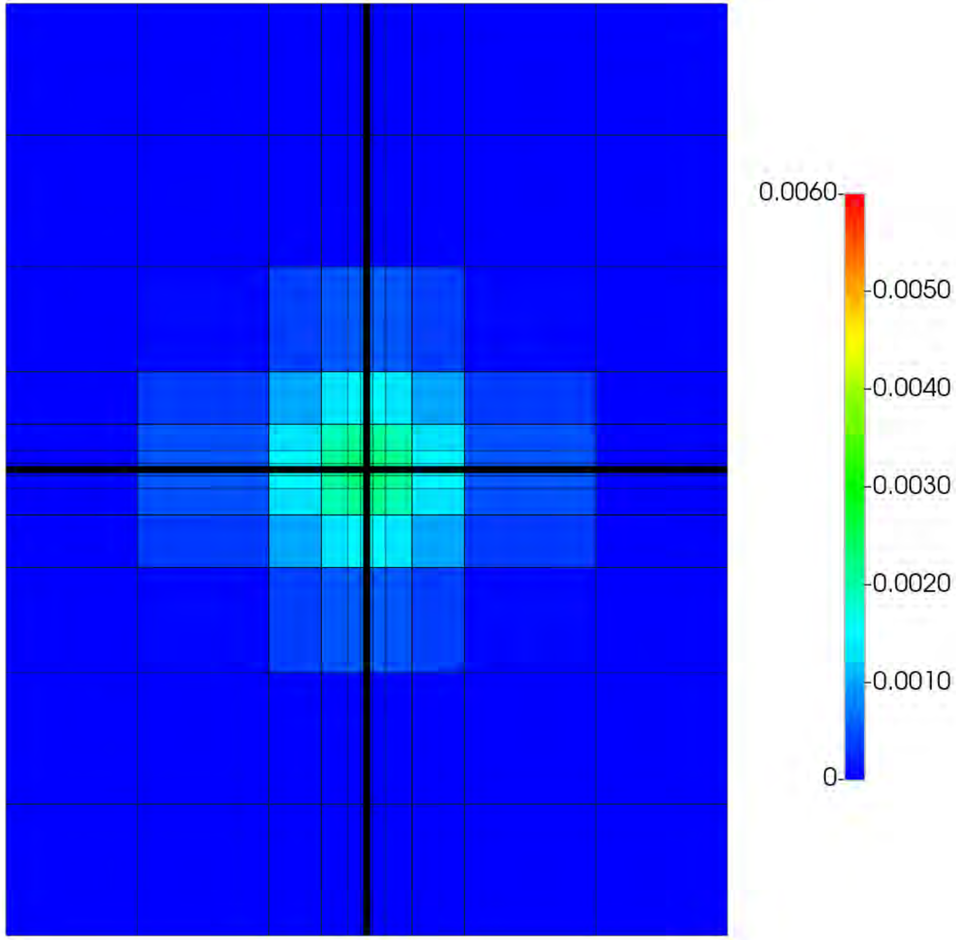
Case 6: Injection at Cooking Lake, High Thermal Expansion

Base case: Case2

Case6: inject from cooking lake, high thermal expansion

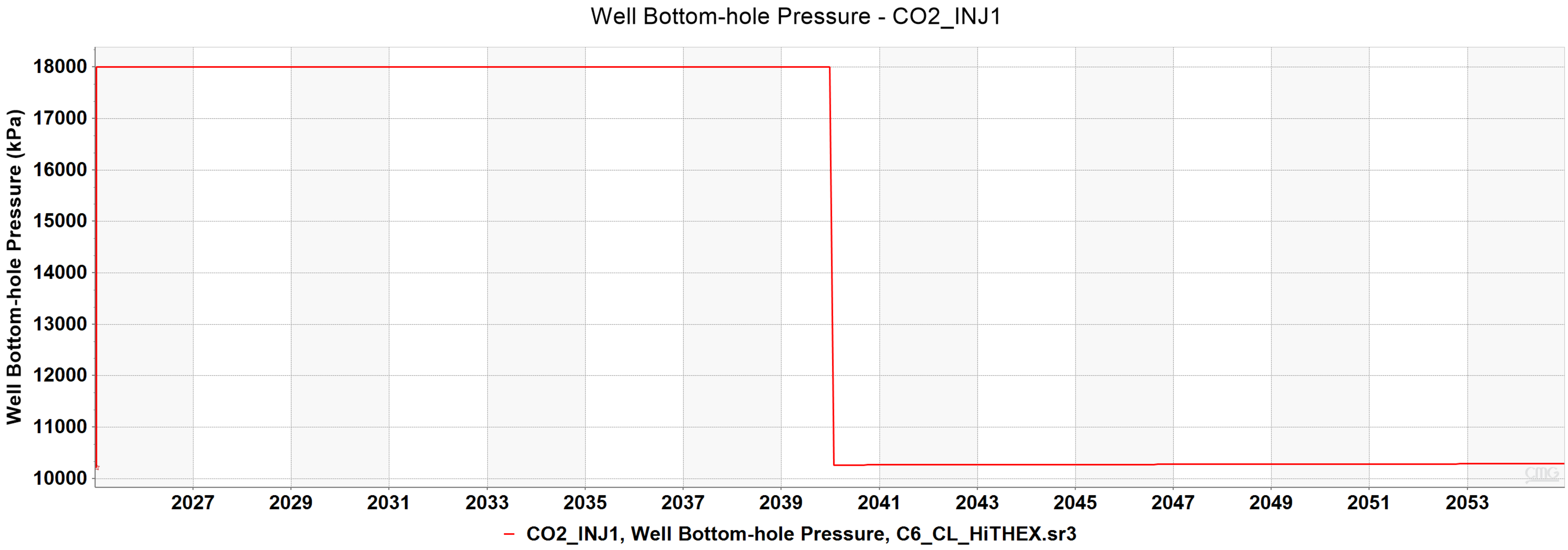
Surface heave @ end of injection 15 years (max. 3mm)





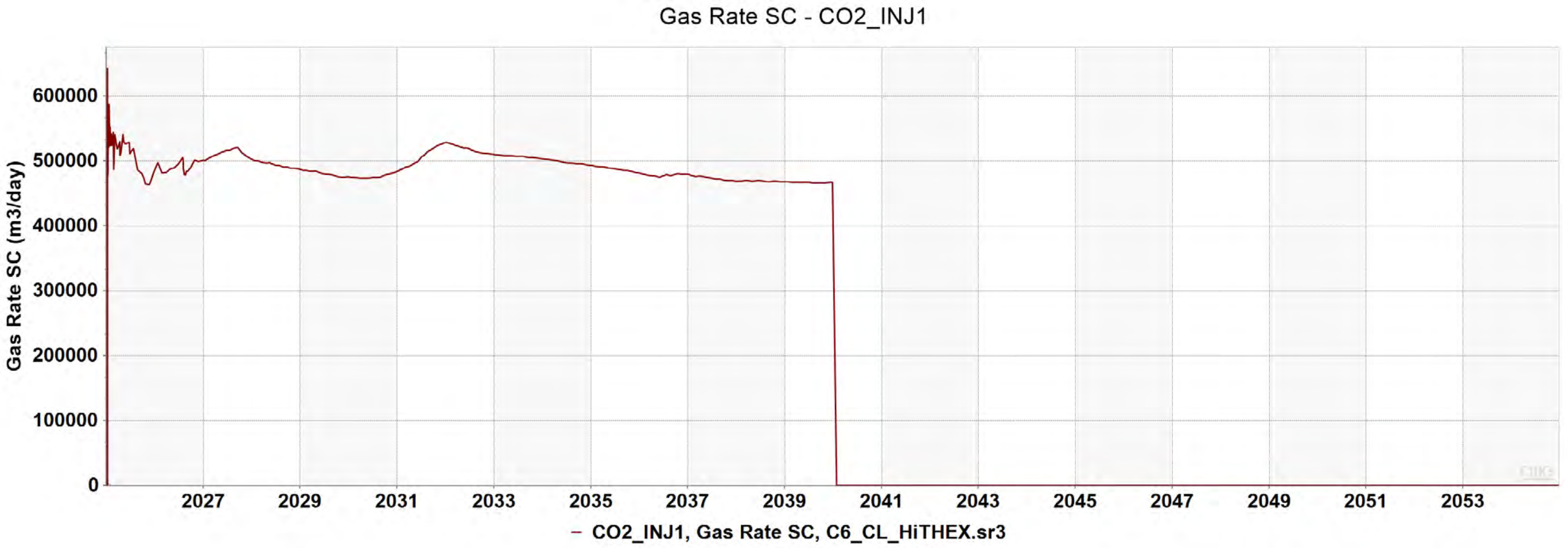
Case6: inject from cooking lake, high thermal expansion

Injection pressure (BHP, unit: kPa)



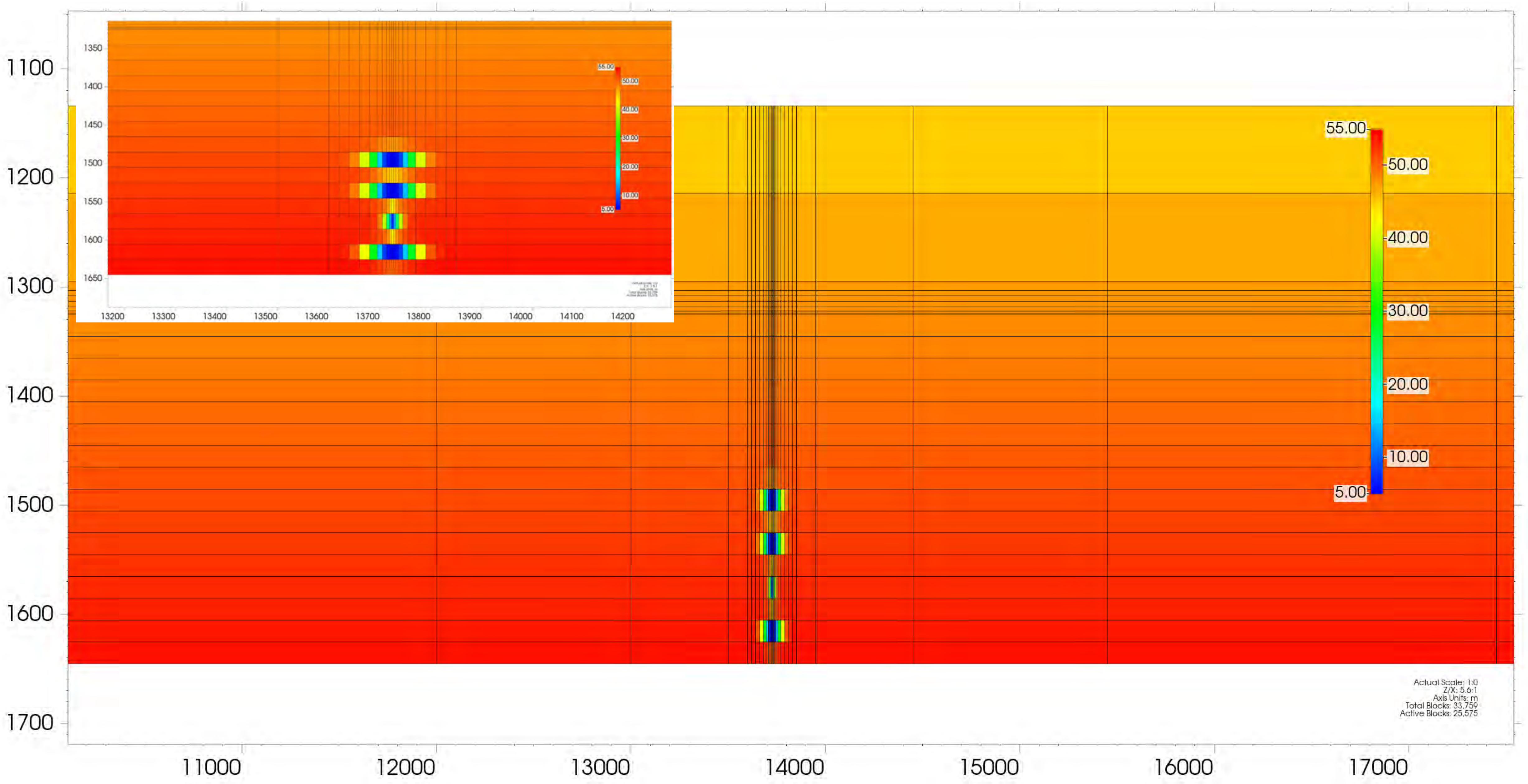
Case6: inject from cooking lake, high thermal expansion

Injection rate



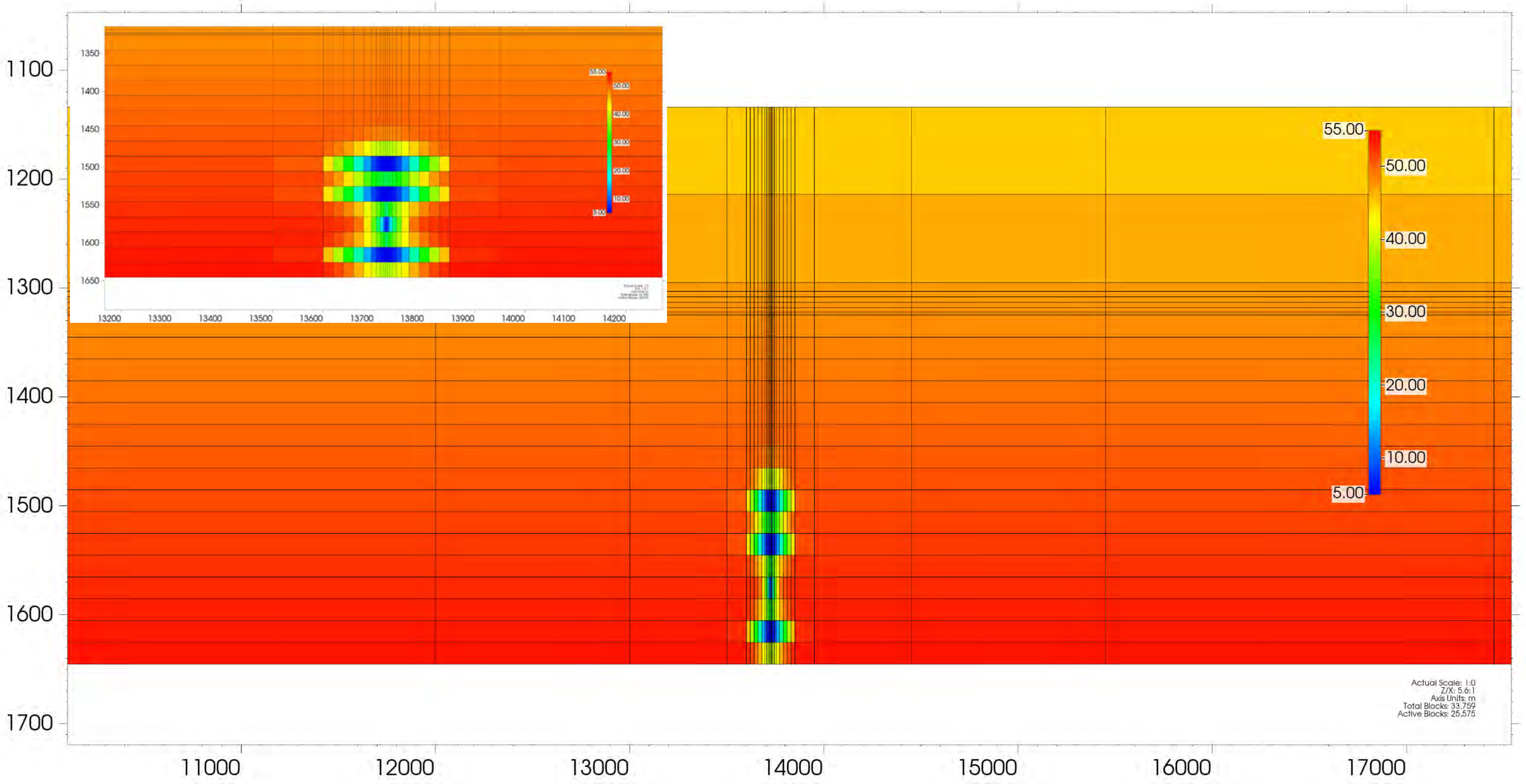
Case6: inject from cooking lake, high thermal expansion

Temperature distribution @ 1 year



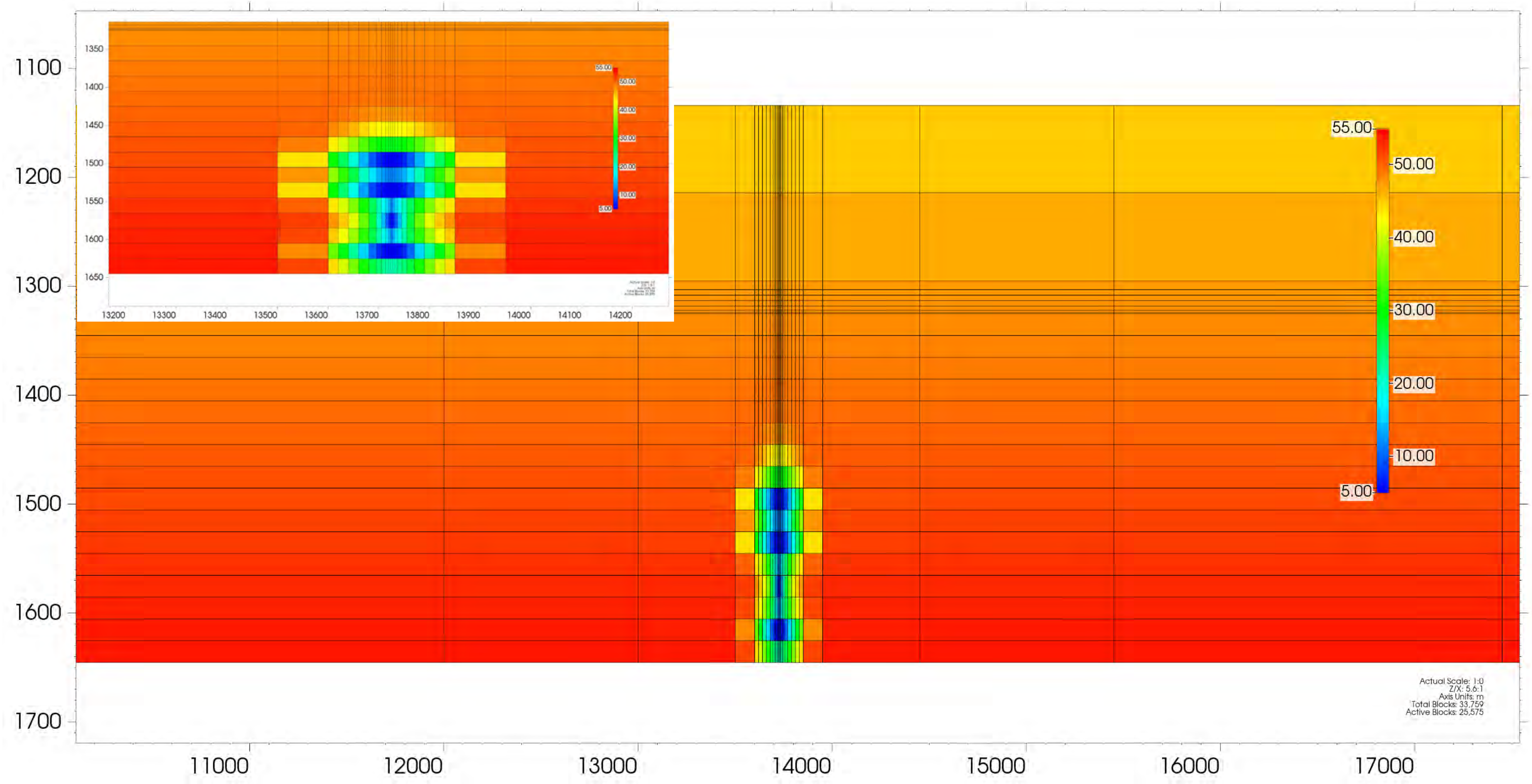
Case6: inject from cooking lake, high thermal expansion

Temperature distribution @ 5 years



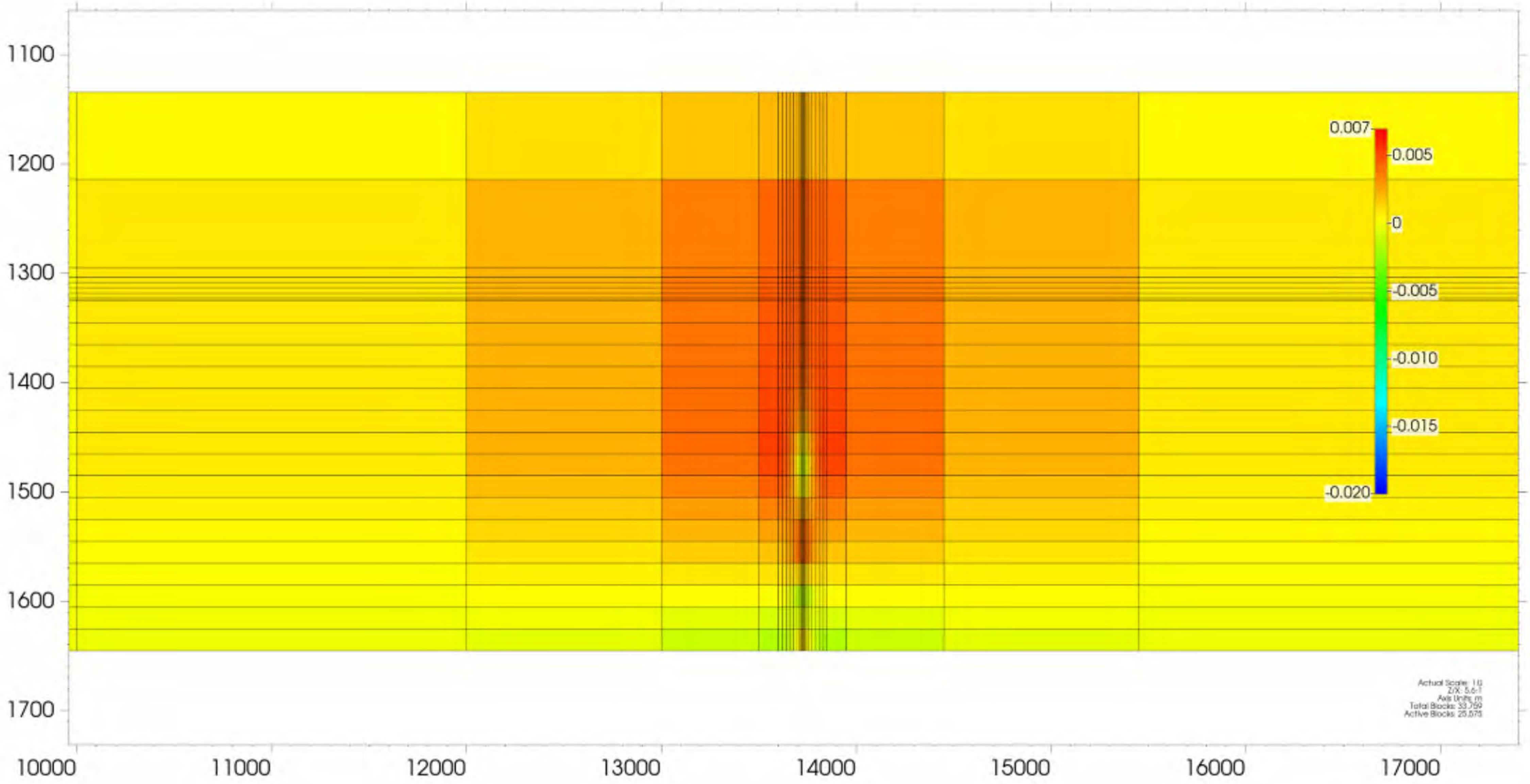
Case6: inject from cooking lake, high thermal expansion

Temperature distribution @ end of injection 15 years



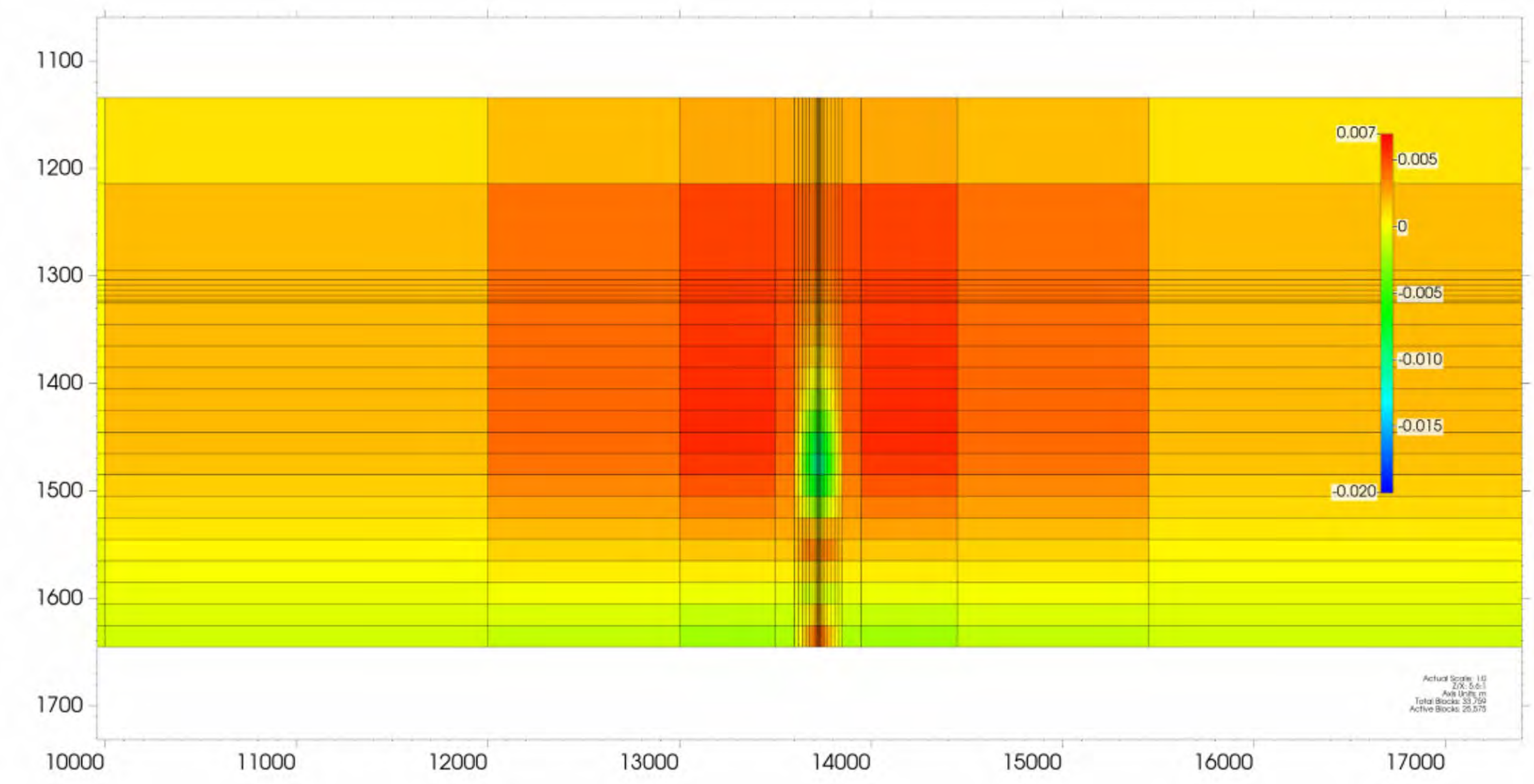
Case6: inject from cooking lake, high thermal expansion

Deformation (Uz) @ 1 year



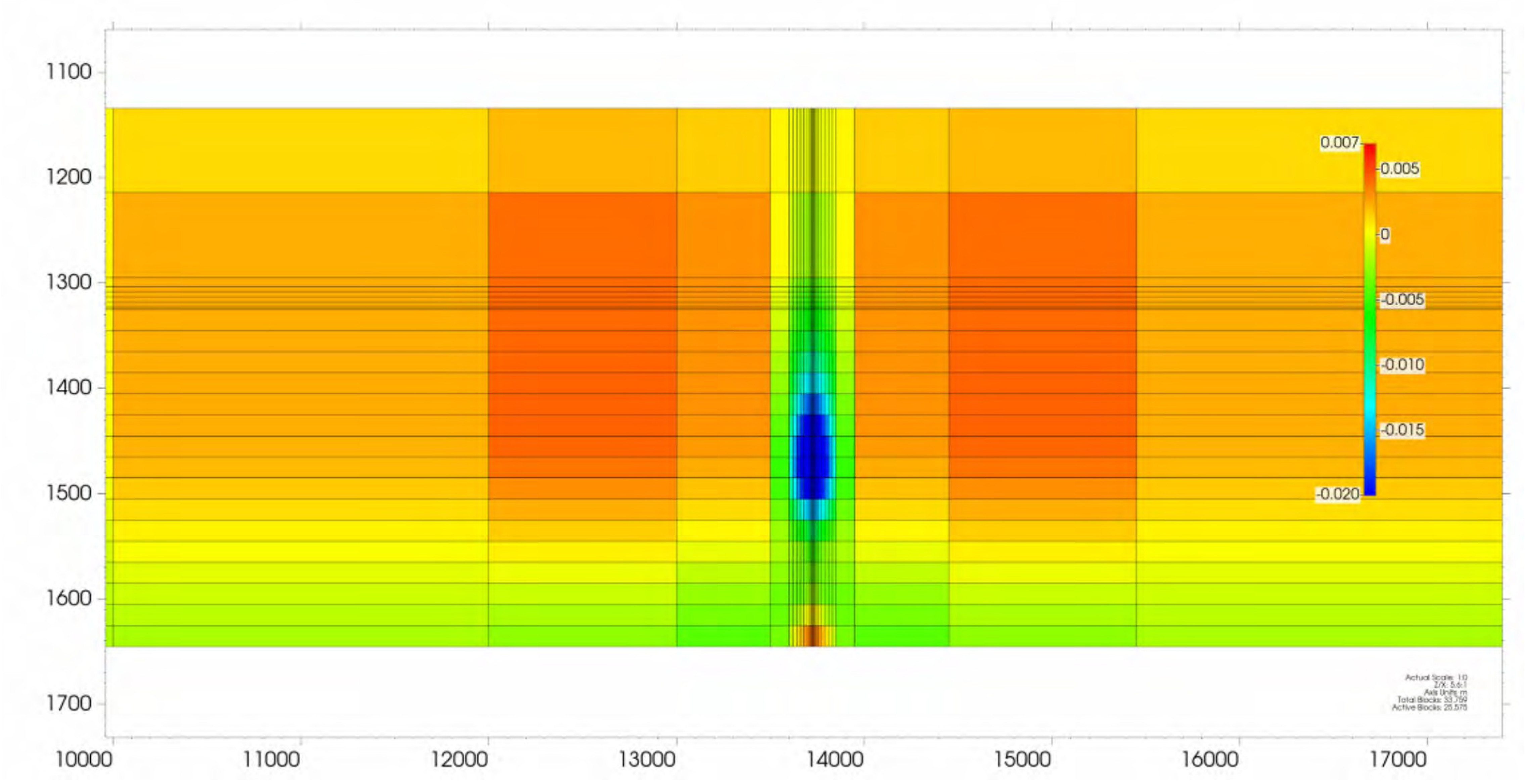
Case6: inject from cooking lake, high thermal expansion

Deformation (Uz) @ 5 years



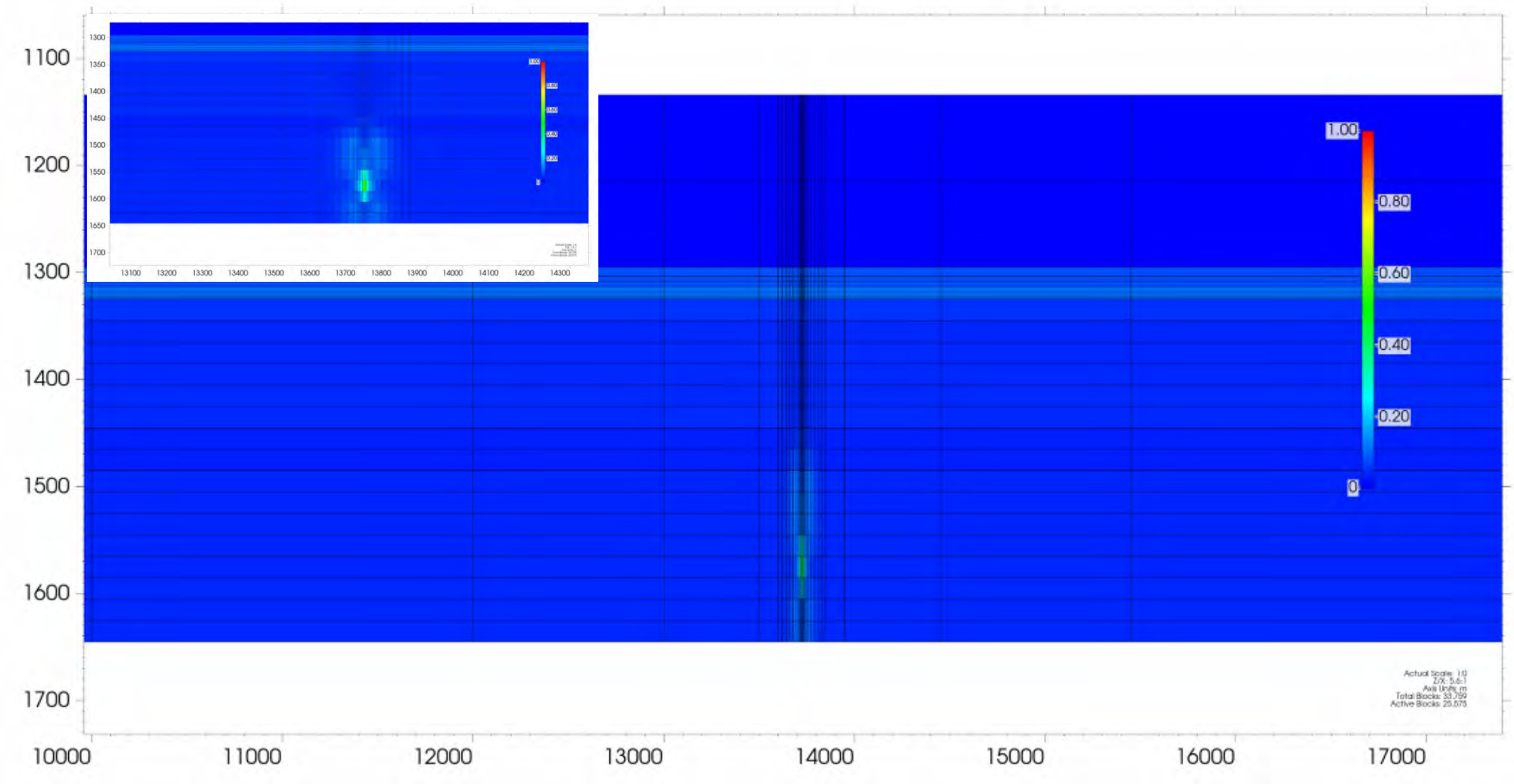
Case6: inject from cooking lake, high thermal expansion

Deformation (Uz) @ end of injection 15 years



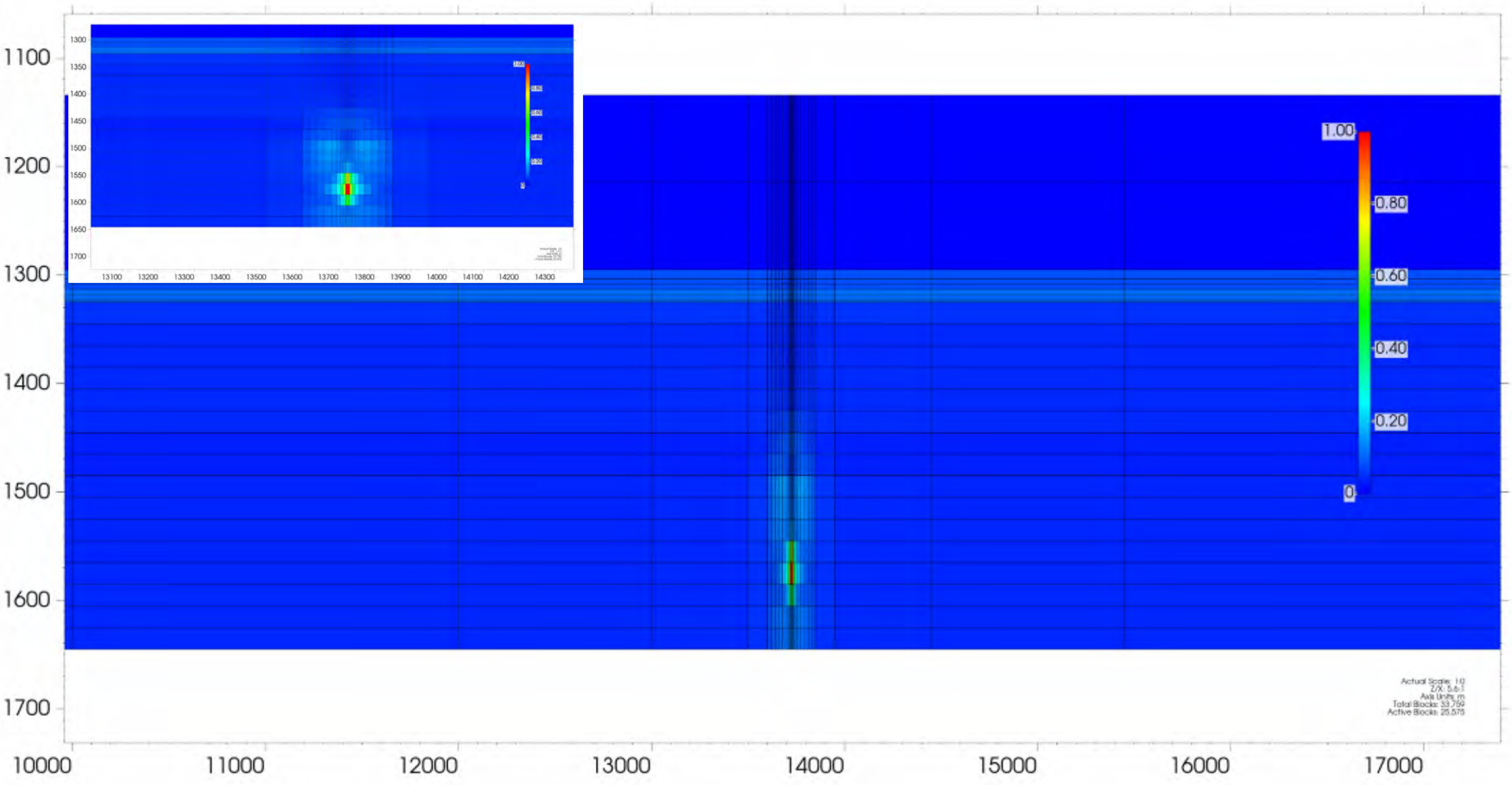
Case6: inject from cooking lake, high thermal expansion

SSL at lower Ireton, Leduc and Cooking lake @ 1 year



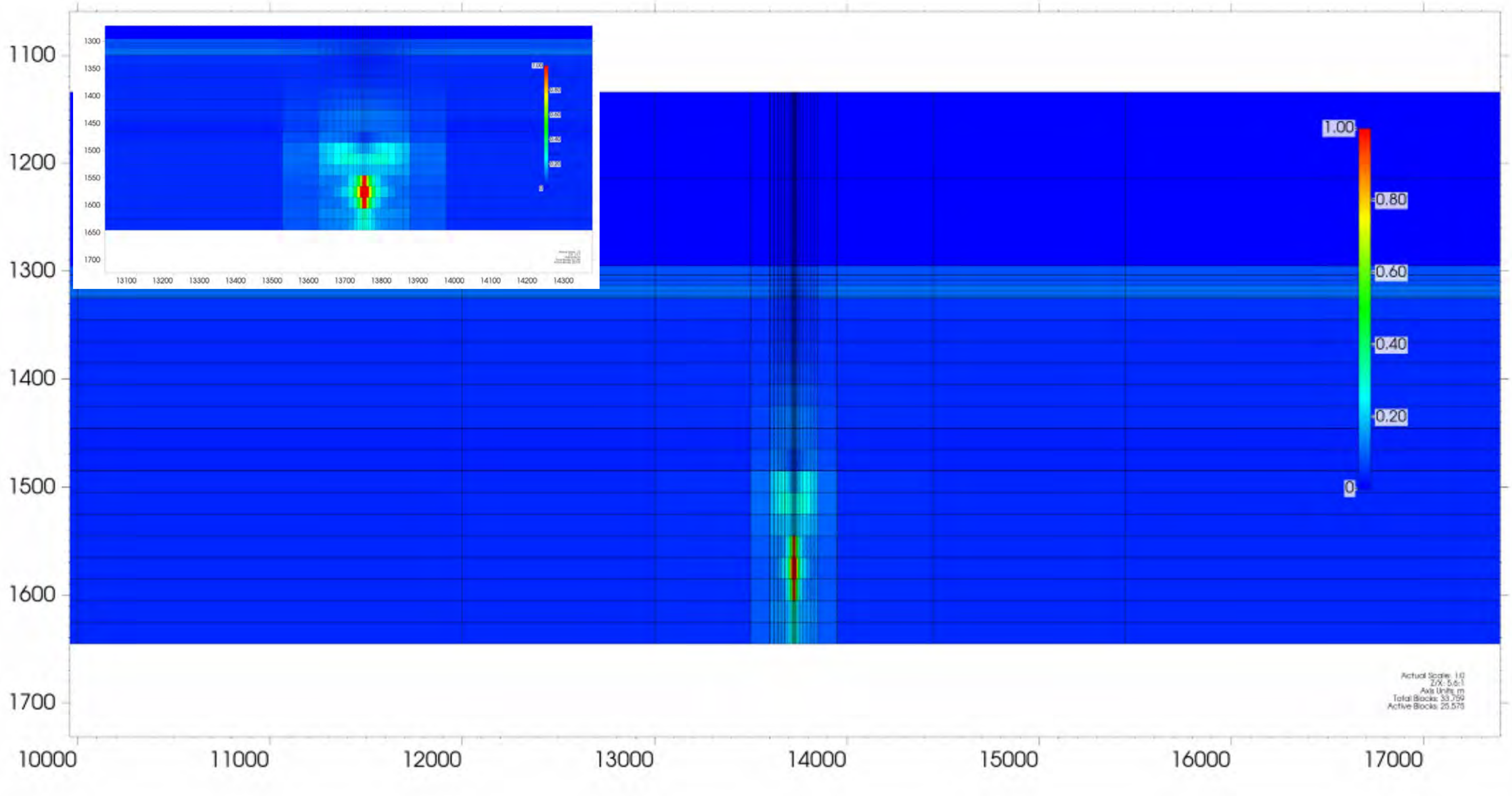
Case6: inject from cooking lake, high thermal expansion

SSL at lower Ireton, Leduc and Cooking lake @ 5 years



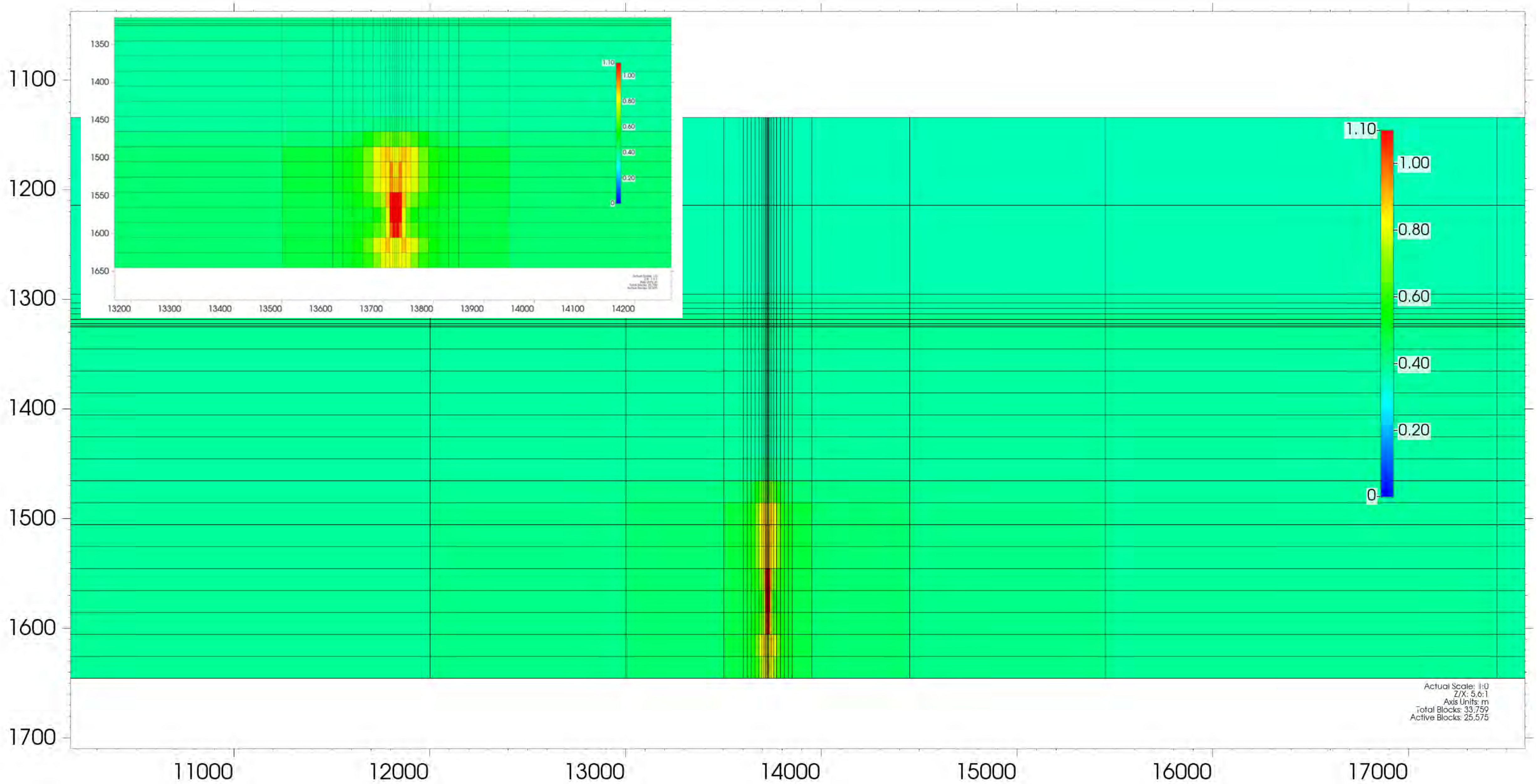
Case6: inject from cooking lake, high thermal expansion

SSL at lower Ireton, Leduc and Cooking lake @ 15 years



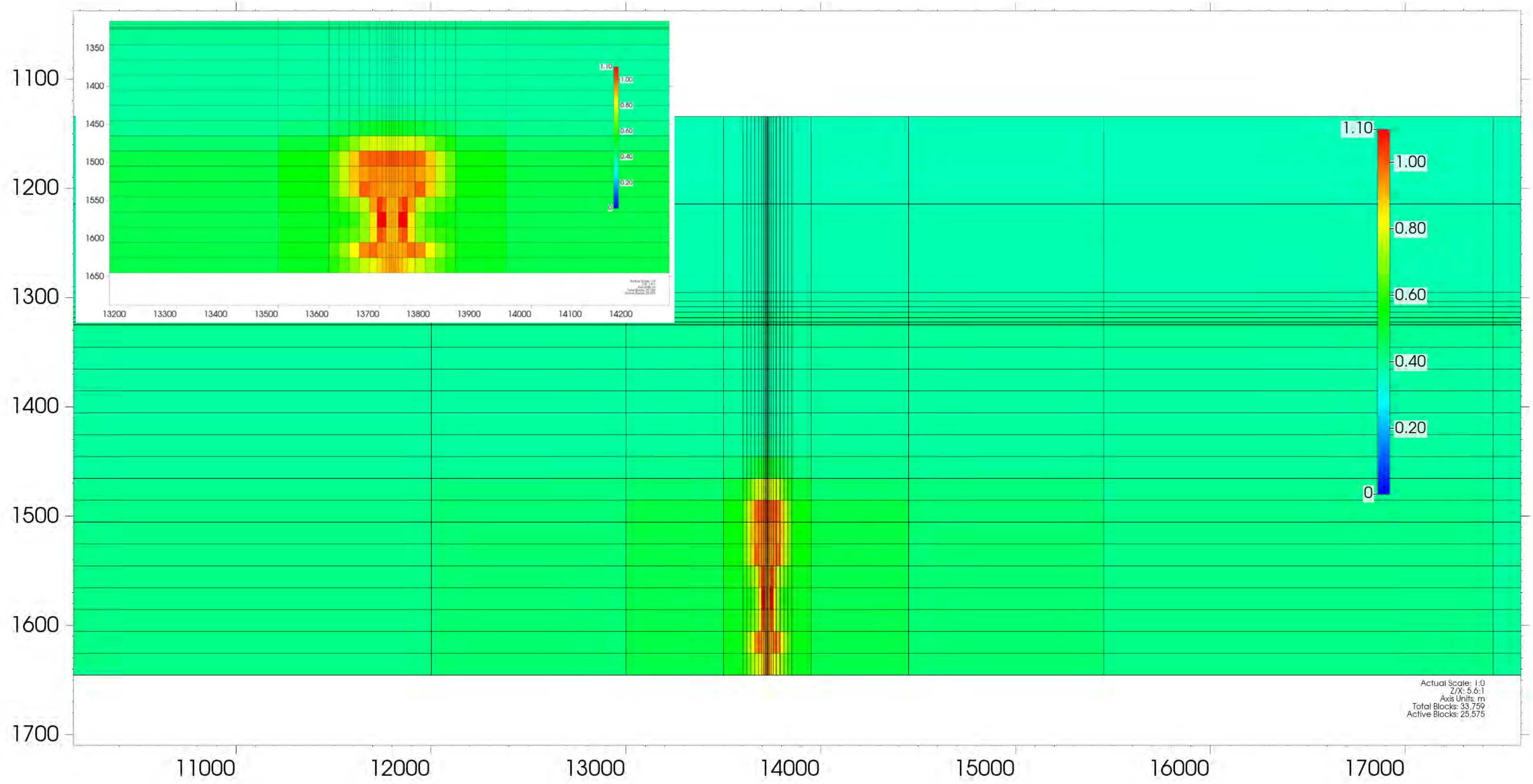
Case6: inject from cooking lake, high thermal expansion

TSL at lower Ireton, Leduc and Cooking lake @ 1 year (fractured near wellbore)



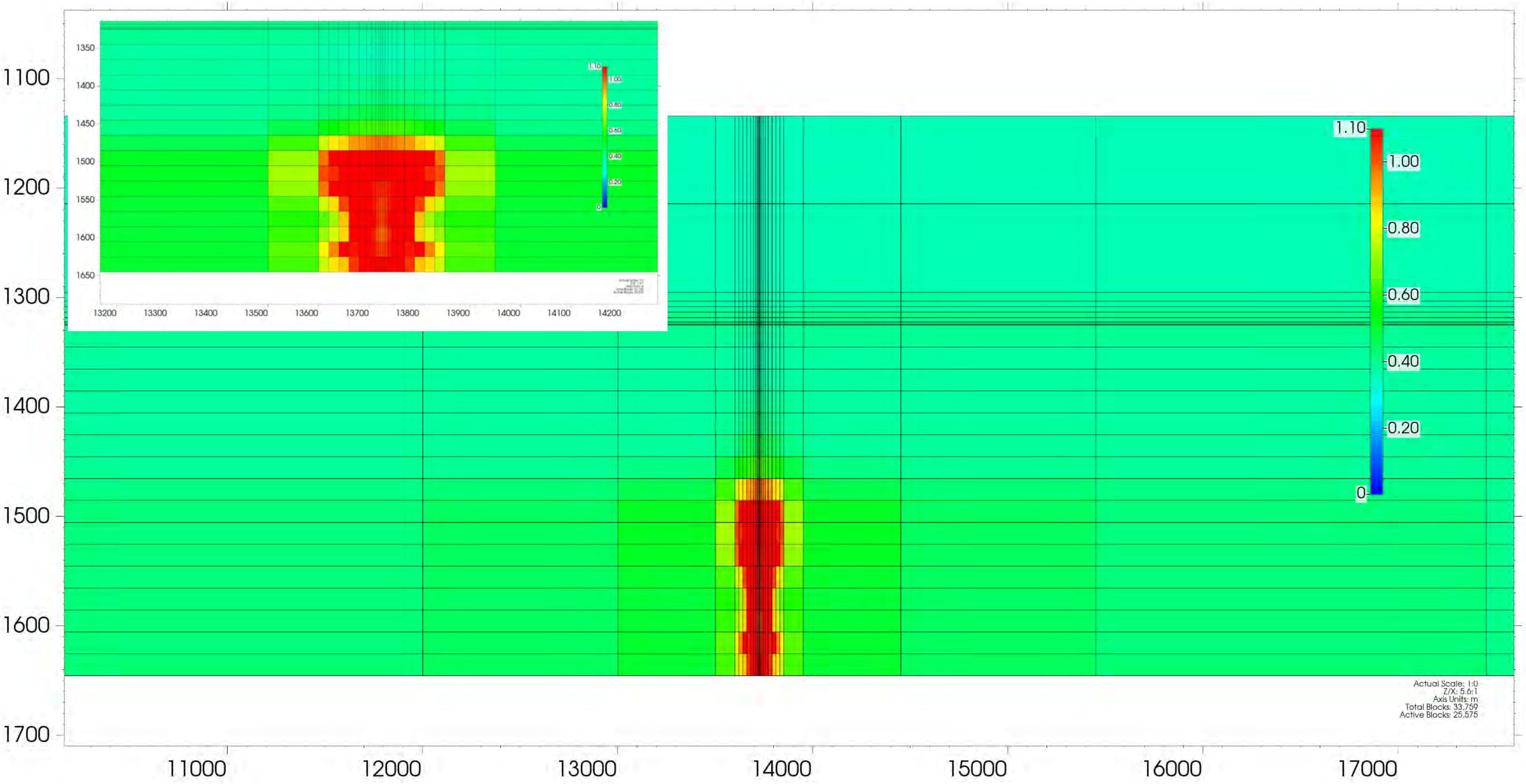
Case6: inject from cooking lake, high thermal expansion

TSL at lower Ireton, Leduc and Cooking lake @ 5 years (fractured near wellbore)



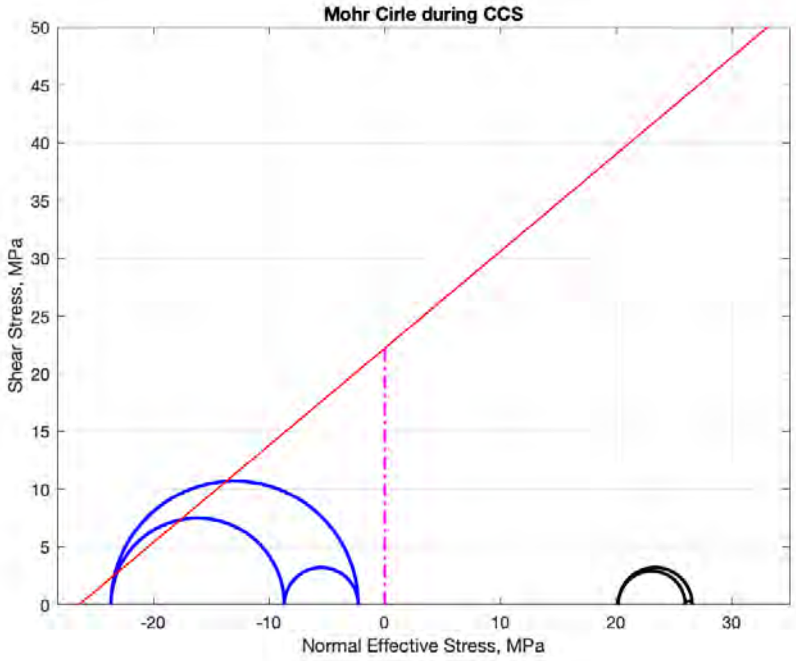
Case6: inject from cooking lake, high thermal expansion

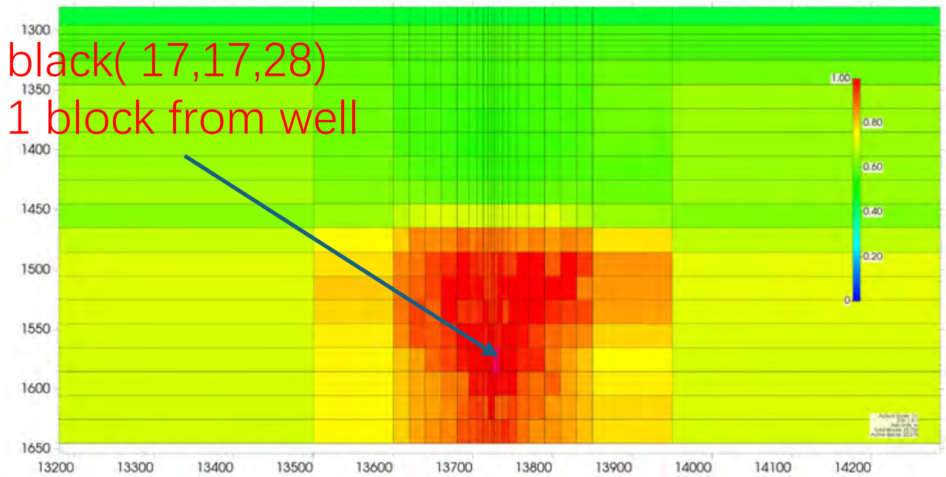
TSL at lower Ireton, Leduc and Cooking lake @ end of injection 15 years (fractured near wellbore)

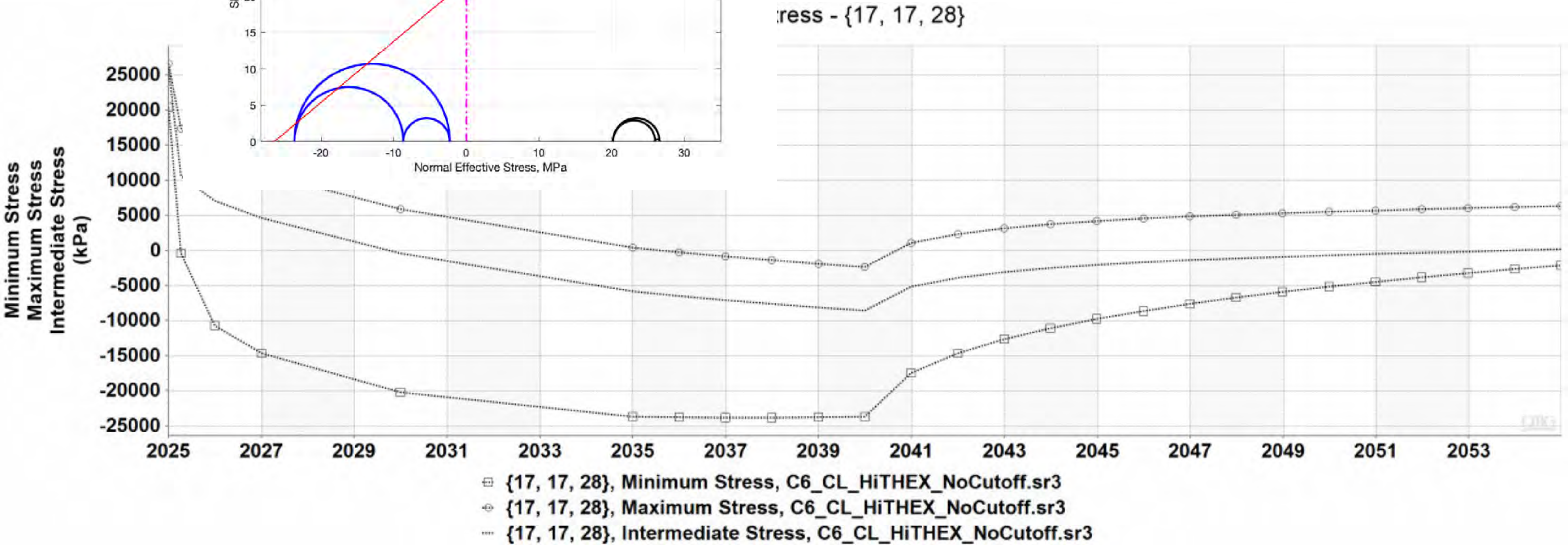


Case6: inject from cooking lake, high thermal expansion

Change of 3 principal effective stresses near wellbore





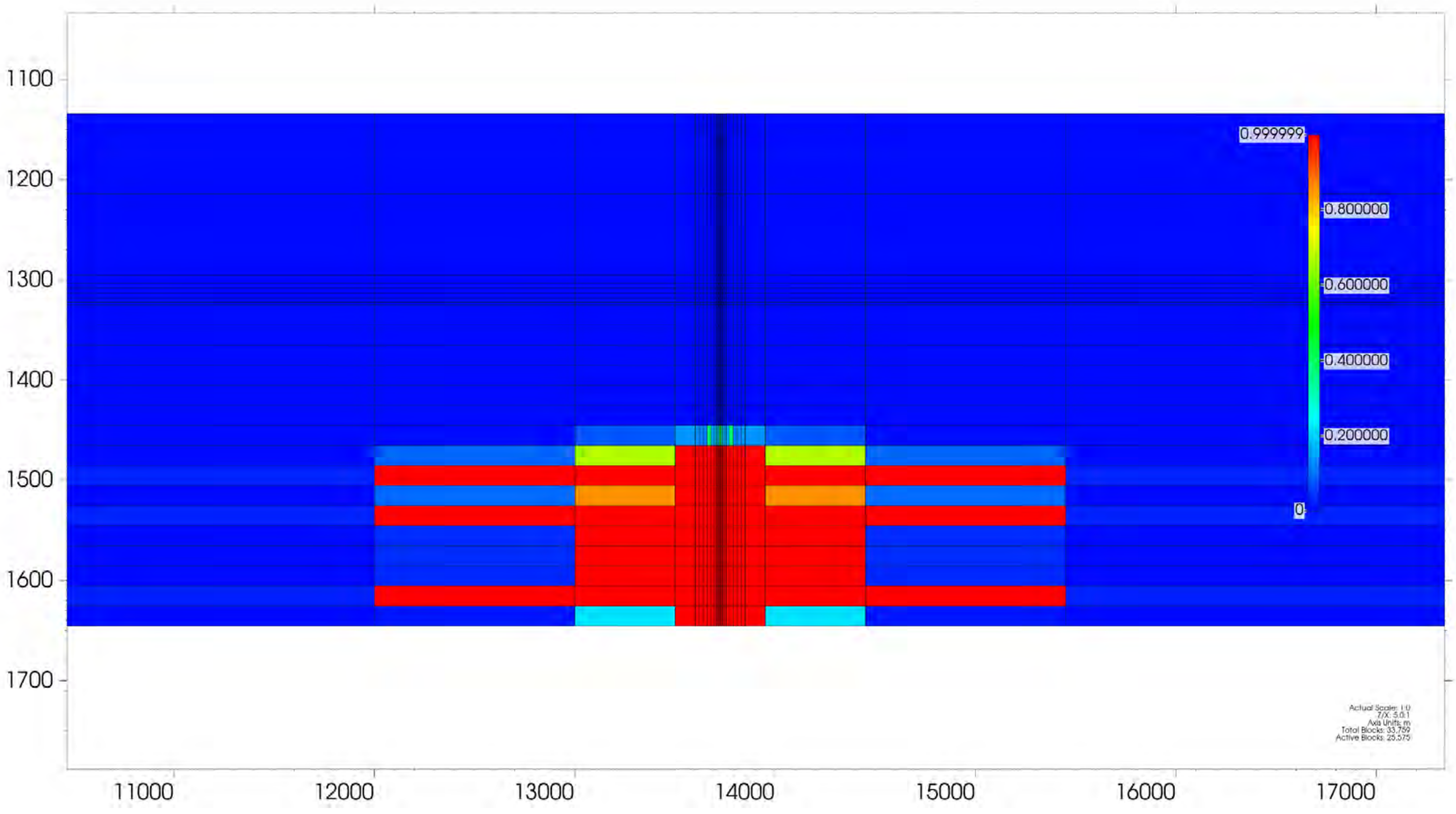


Case6: inject from cooking lake, high thermal expansion

Gas saturation @ 15 years

Case6: inject from cooking lake, high thermal expansion

CO2 Mole fraction@ 15 years

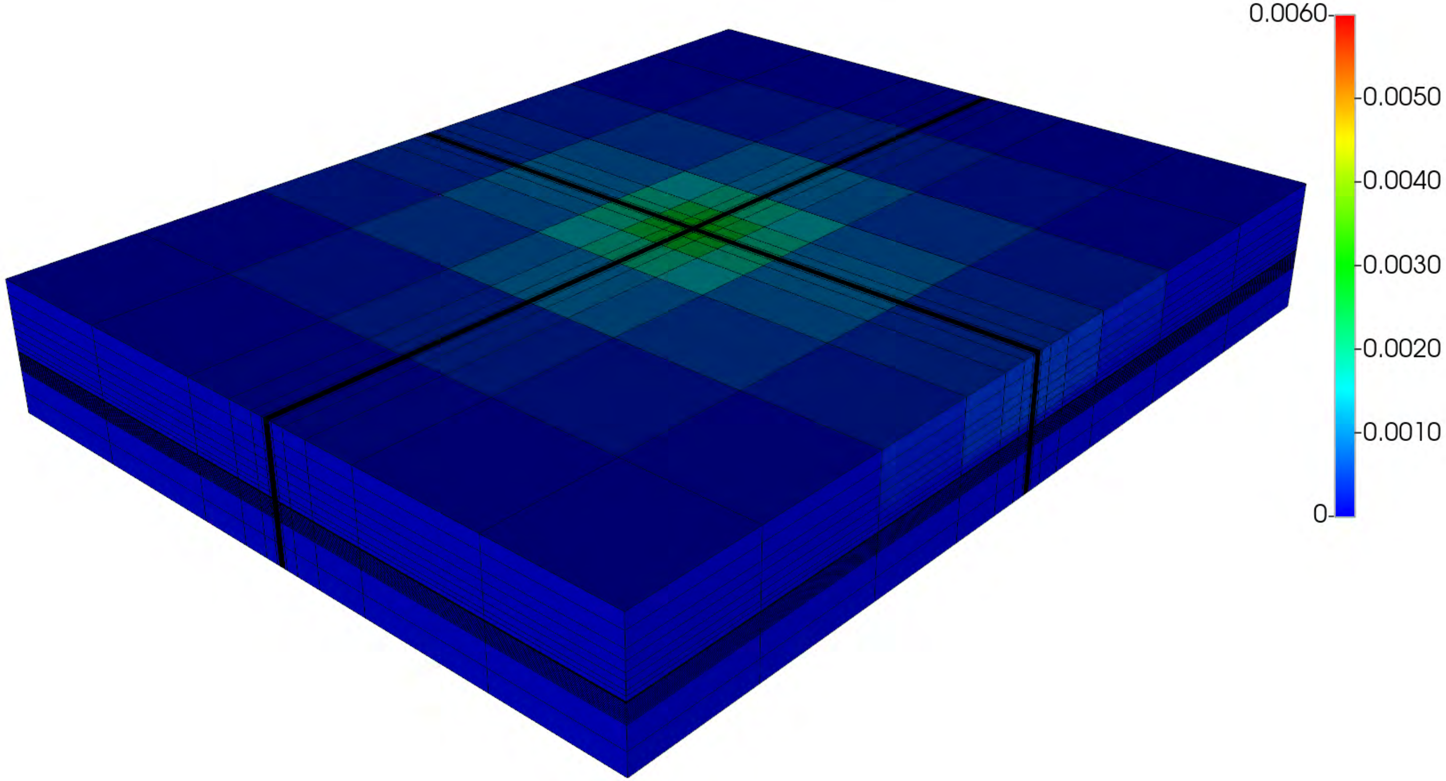


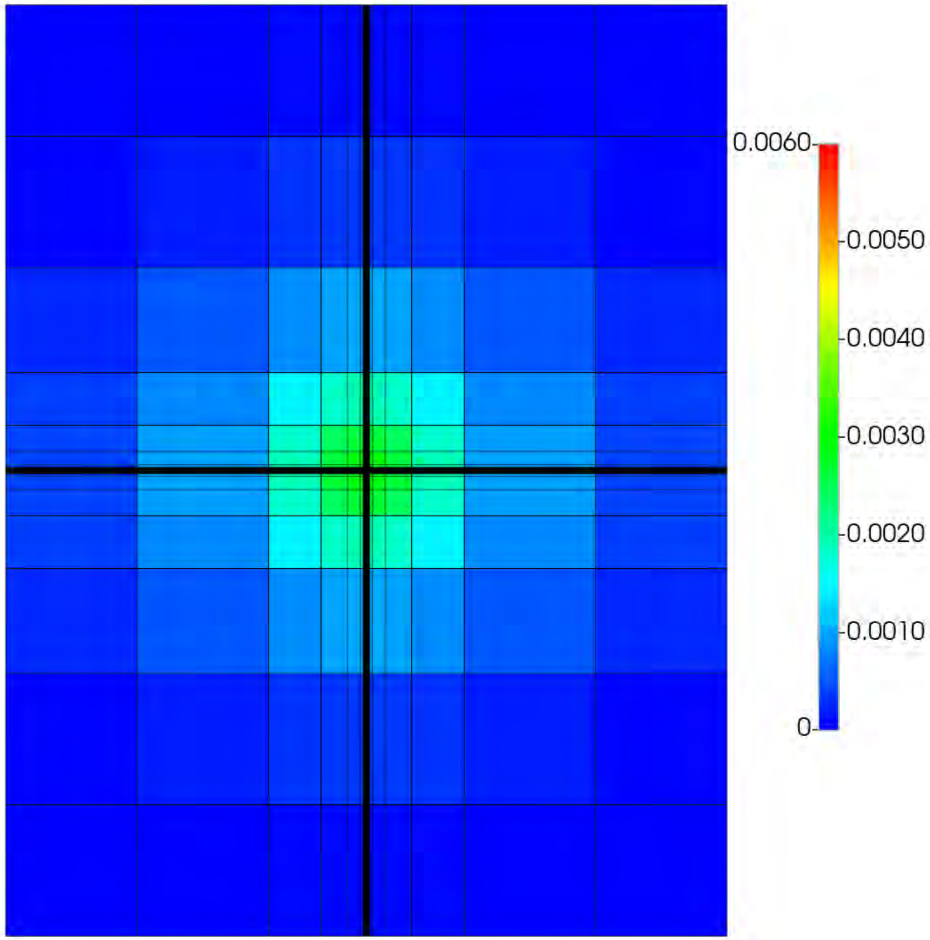
Case 7: Injection at Cooking Lake, Injection temperature=1 degC

Base case: Case2

Case7: inject from cooking lake, injection temp=1 degC

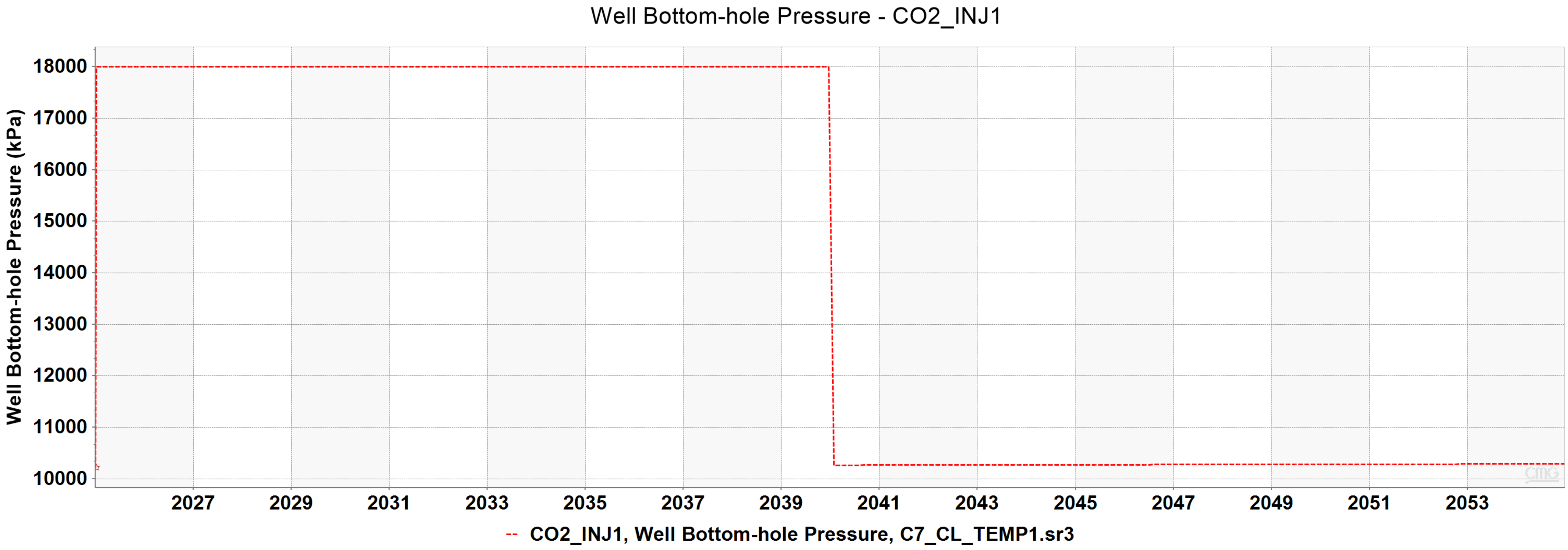
Surface heave @ end of injection 15 years (max. 2.5mm)





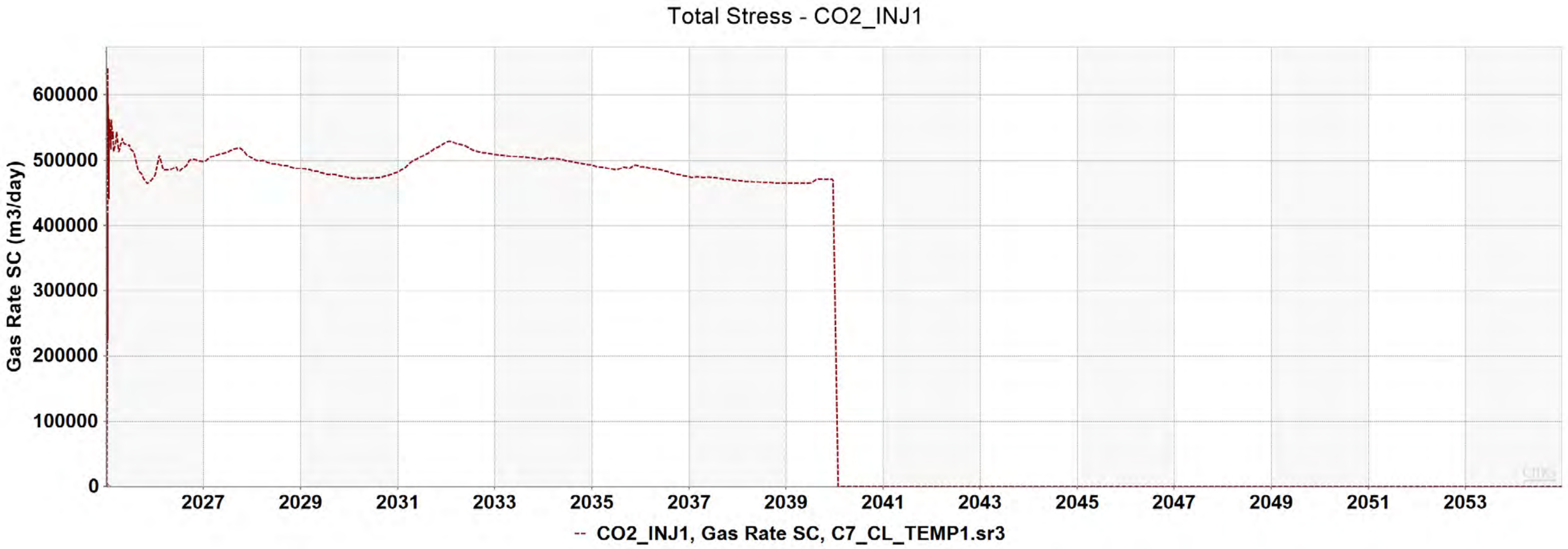
Case7: inject from cooking lake, injection temp=1 degC

Injection pressure (BHP, unit: kPa)



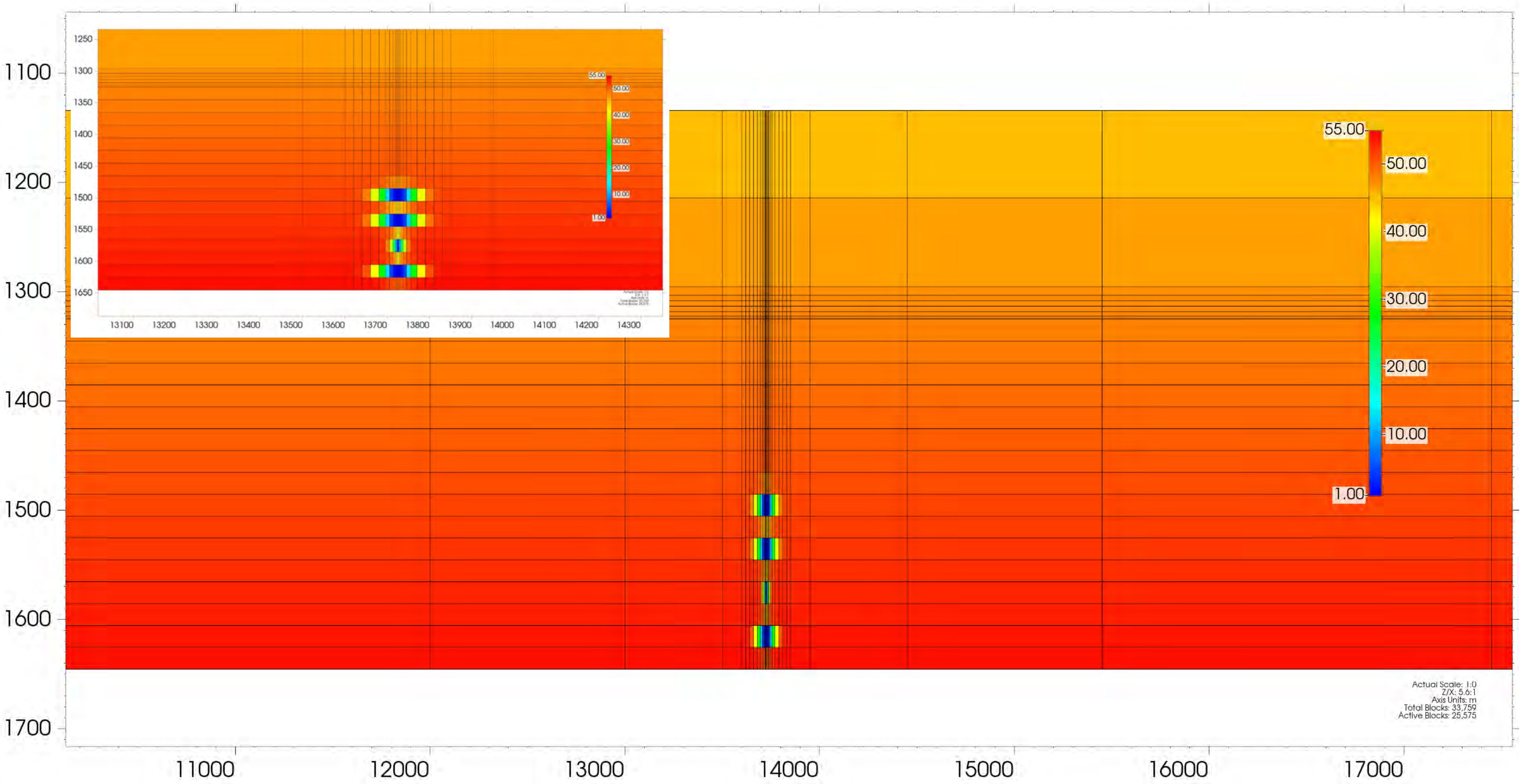
Case7: inject from cooking lake, injection temp=1 degC

Injection rate



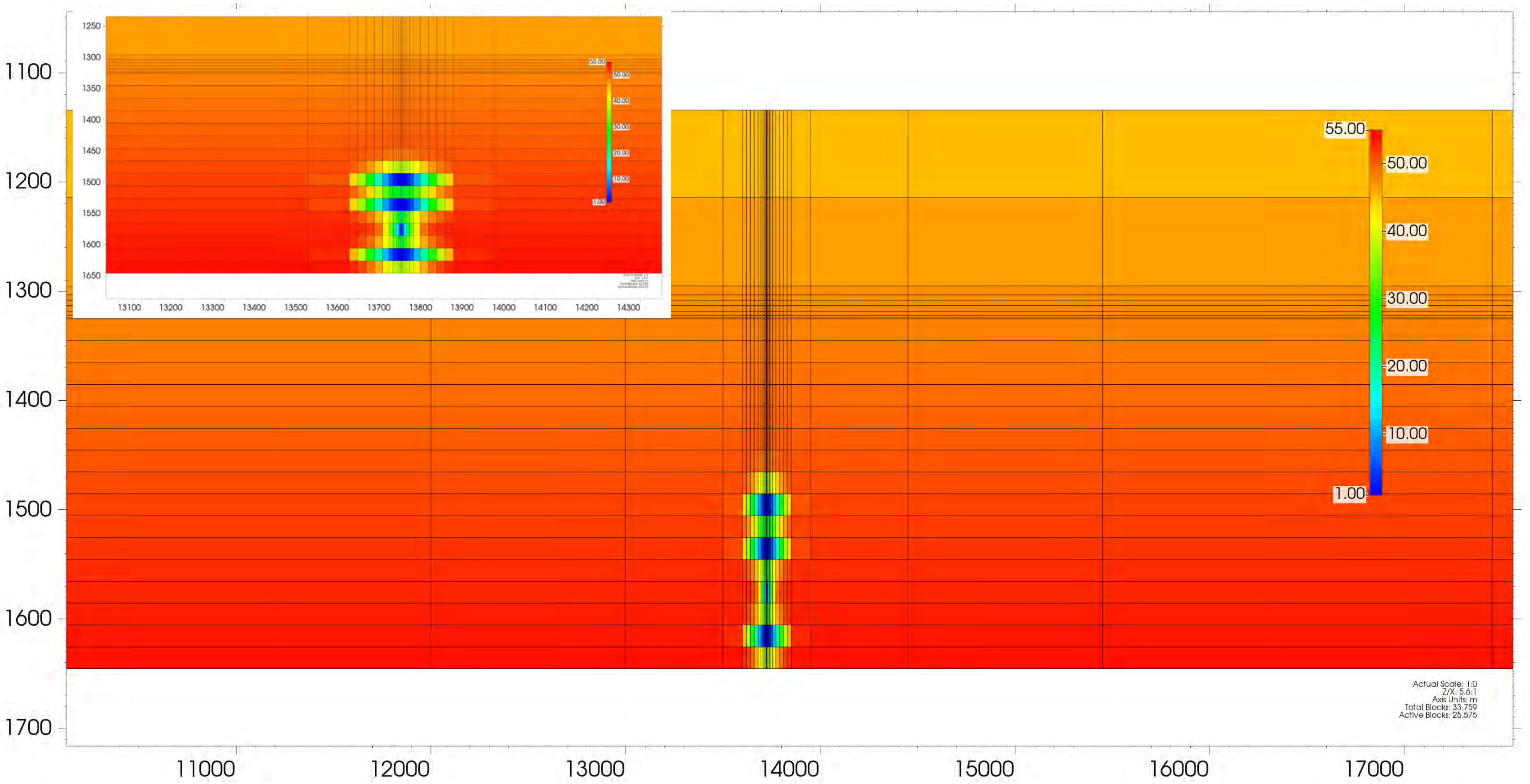
Case7: inject from cooking lake, injection temp=1 degC

Temperature distribution @ 1 year



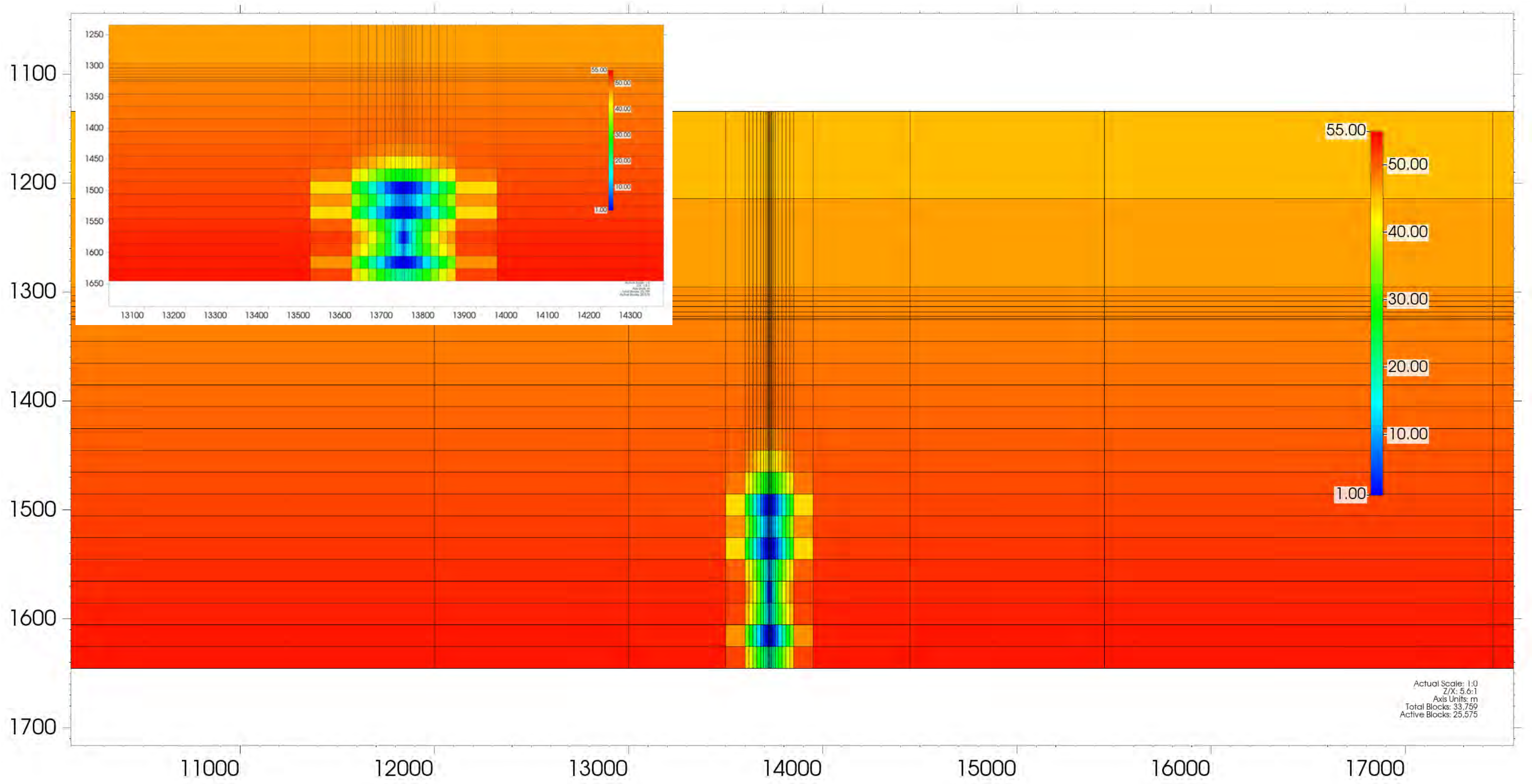
Case7: inject from cooking lake, injection temp=1 degC

Temperature distribution @ 5 years



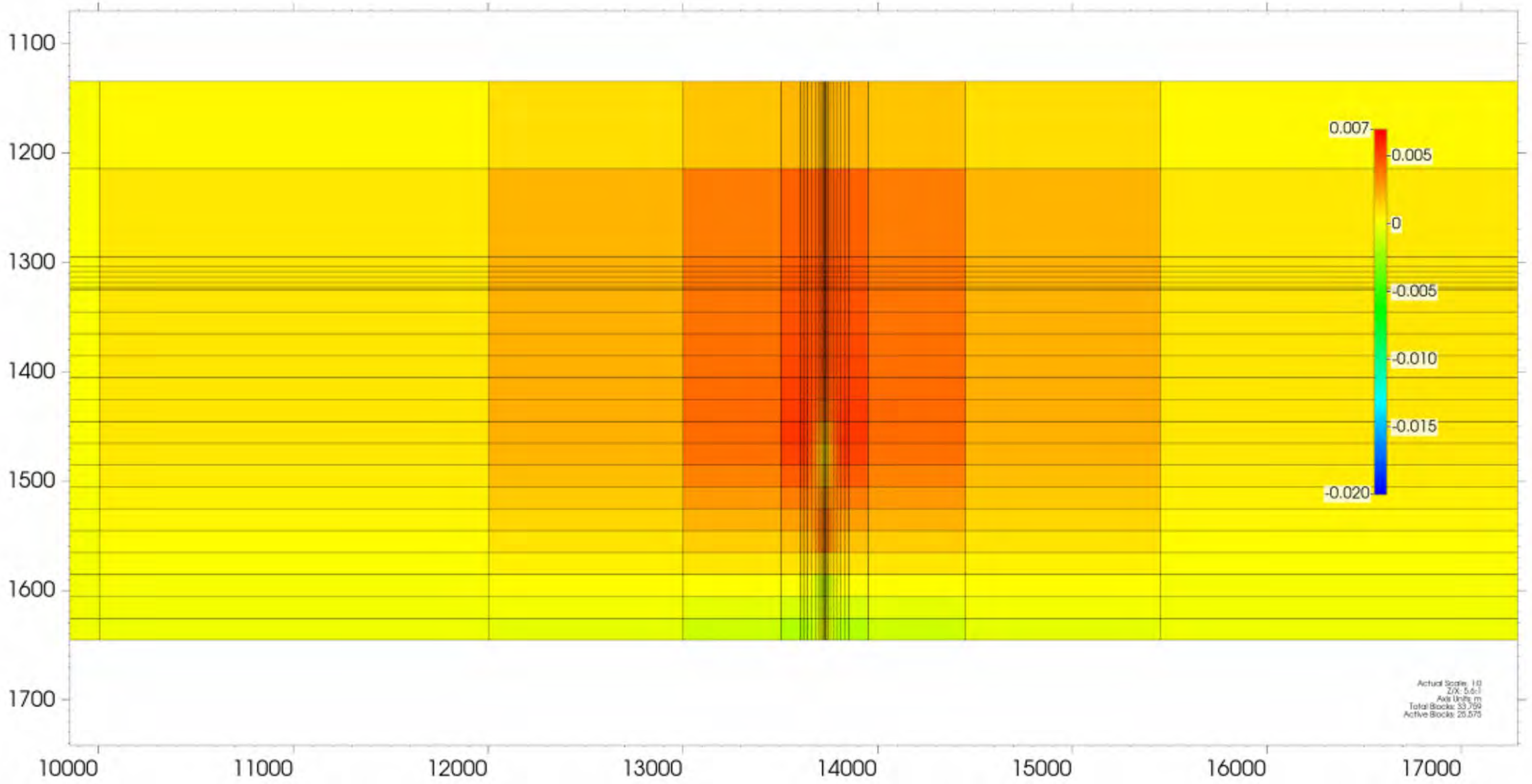
Case7: inject from cooking lake, injection temp=1 degC

Temperature distribution @ end of injection 15 years



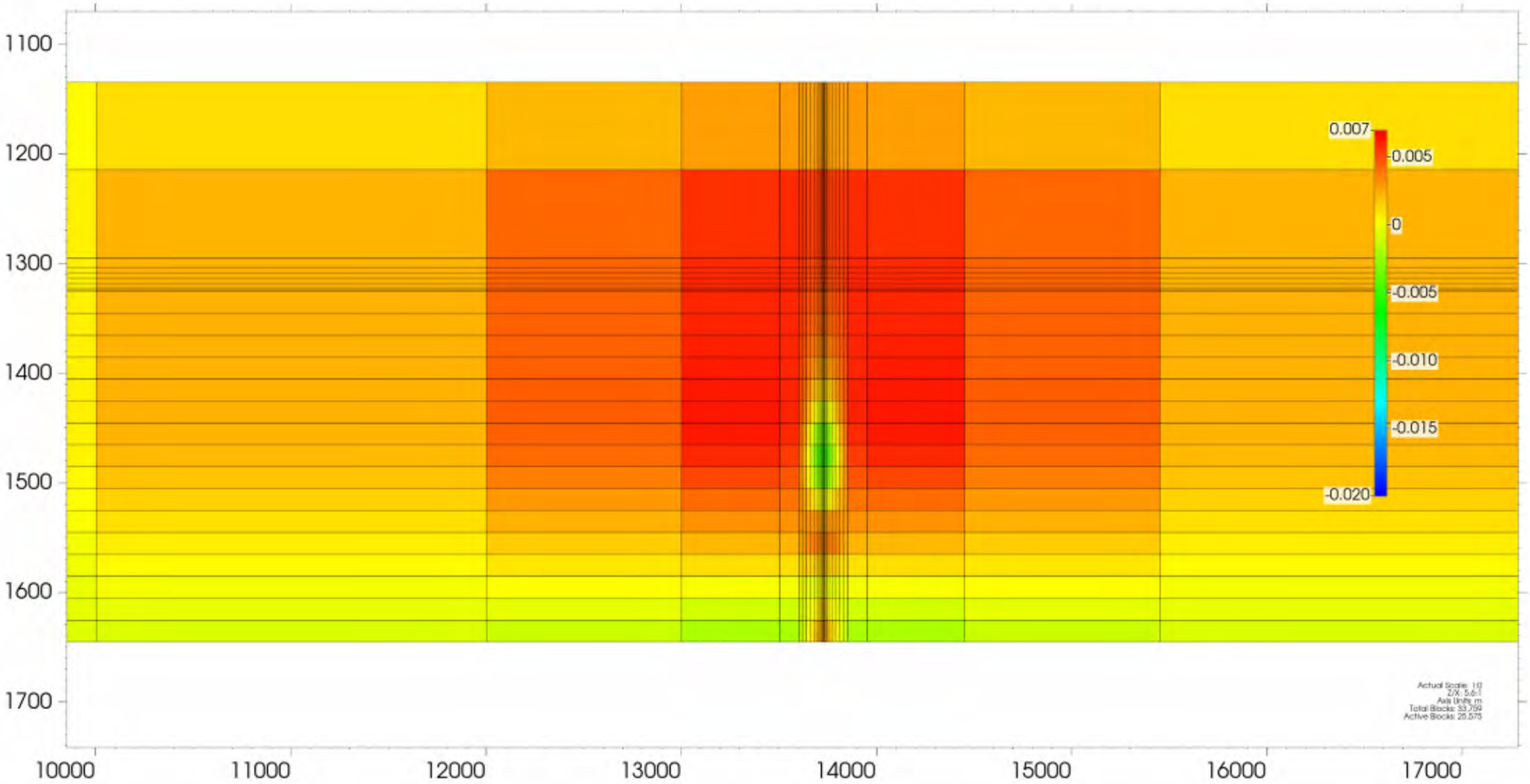
Case7: inject from cooking lake, injection temp=1 degC

Deformation (Uz) @ 1 year



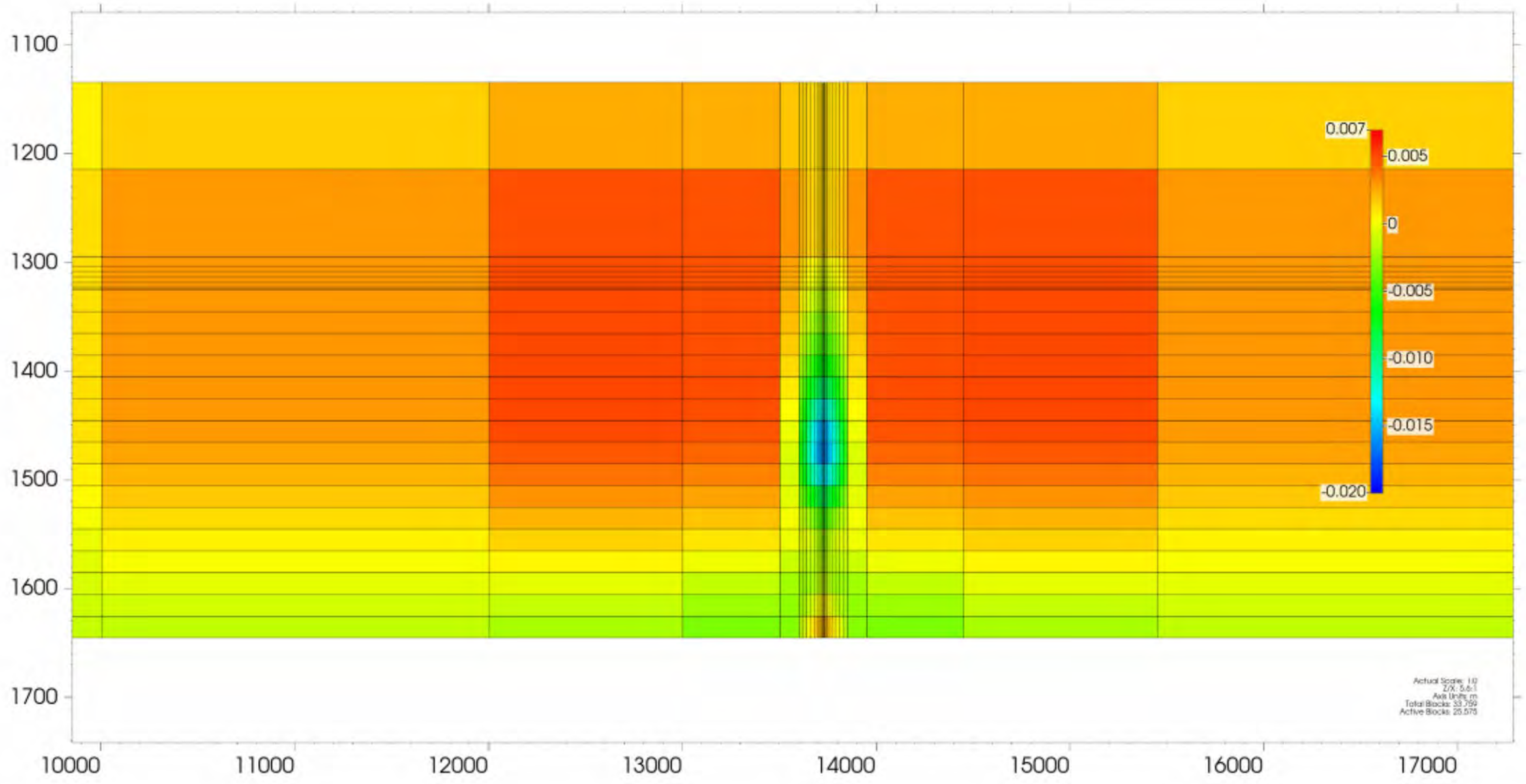
Case7: inject from cooking lake, injection temp=1 degC

Deformation (Uz) @ 5 years



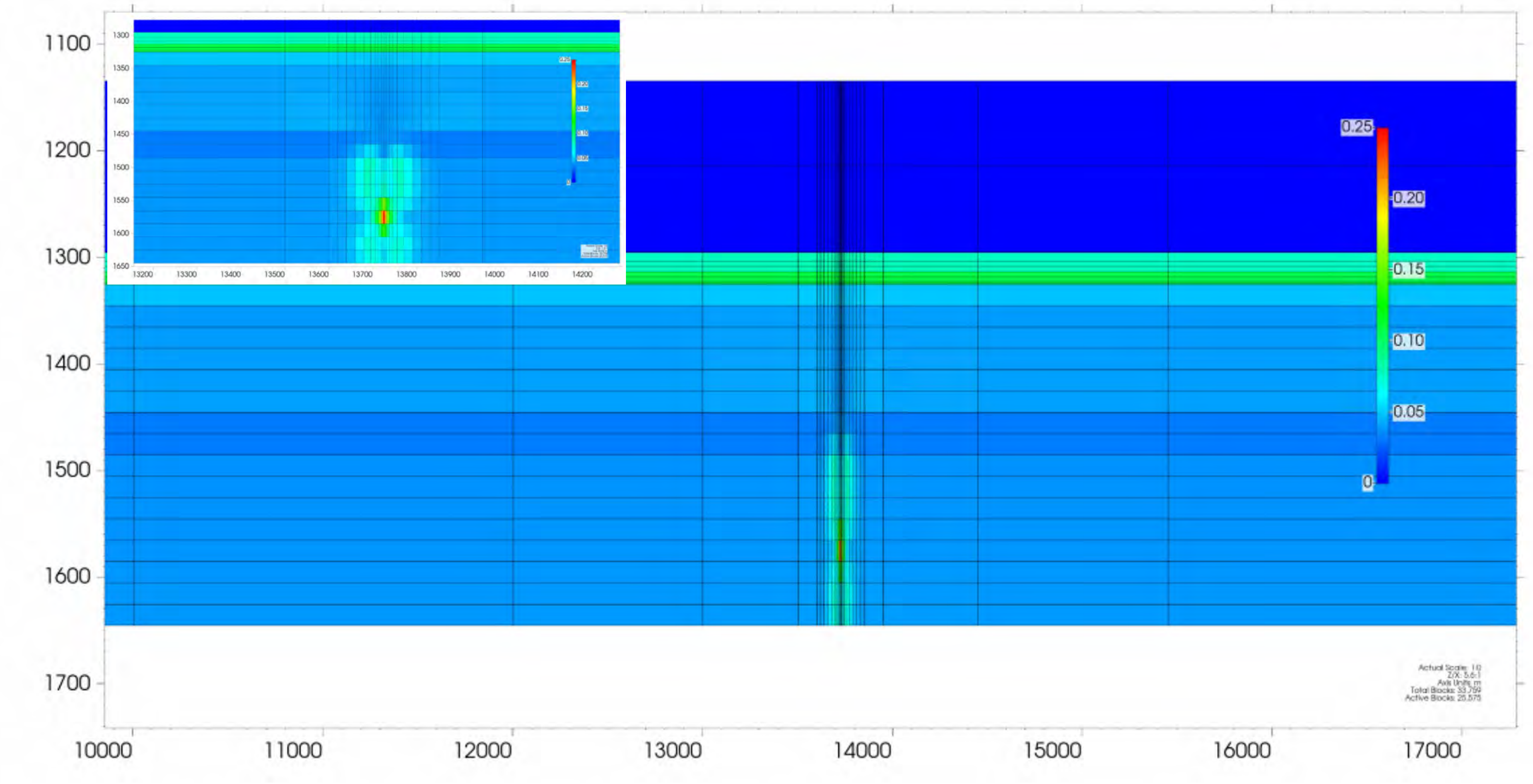
Case7: inject from cooking lake, injection temp=1 degC

Deformation (Uz) @ end of injection 15 years



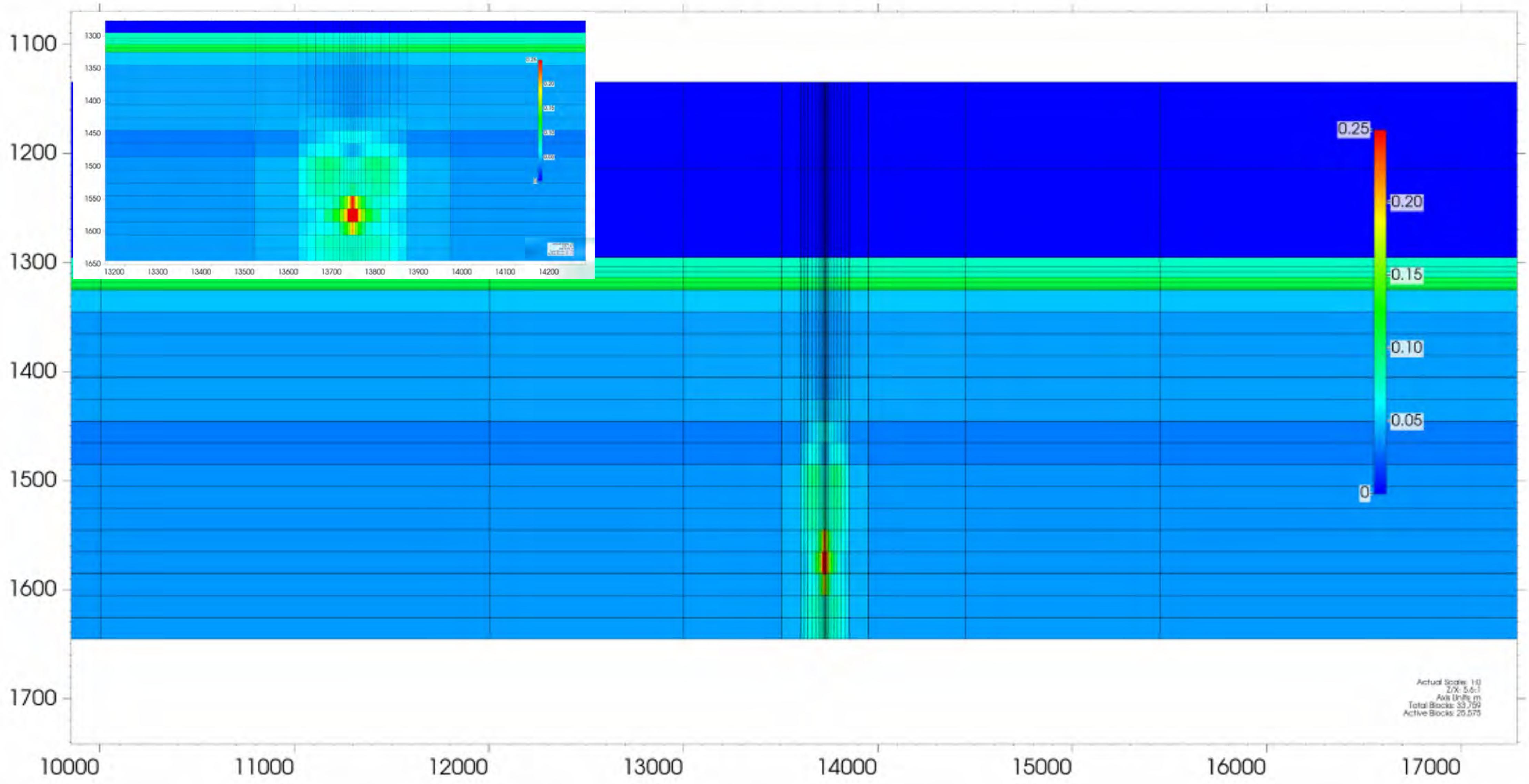
Case7: inject from cooking lake, injection temp=1 degC

SSL at lower Ireton, Leduc and Cooking lake @ 1 year



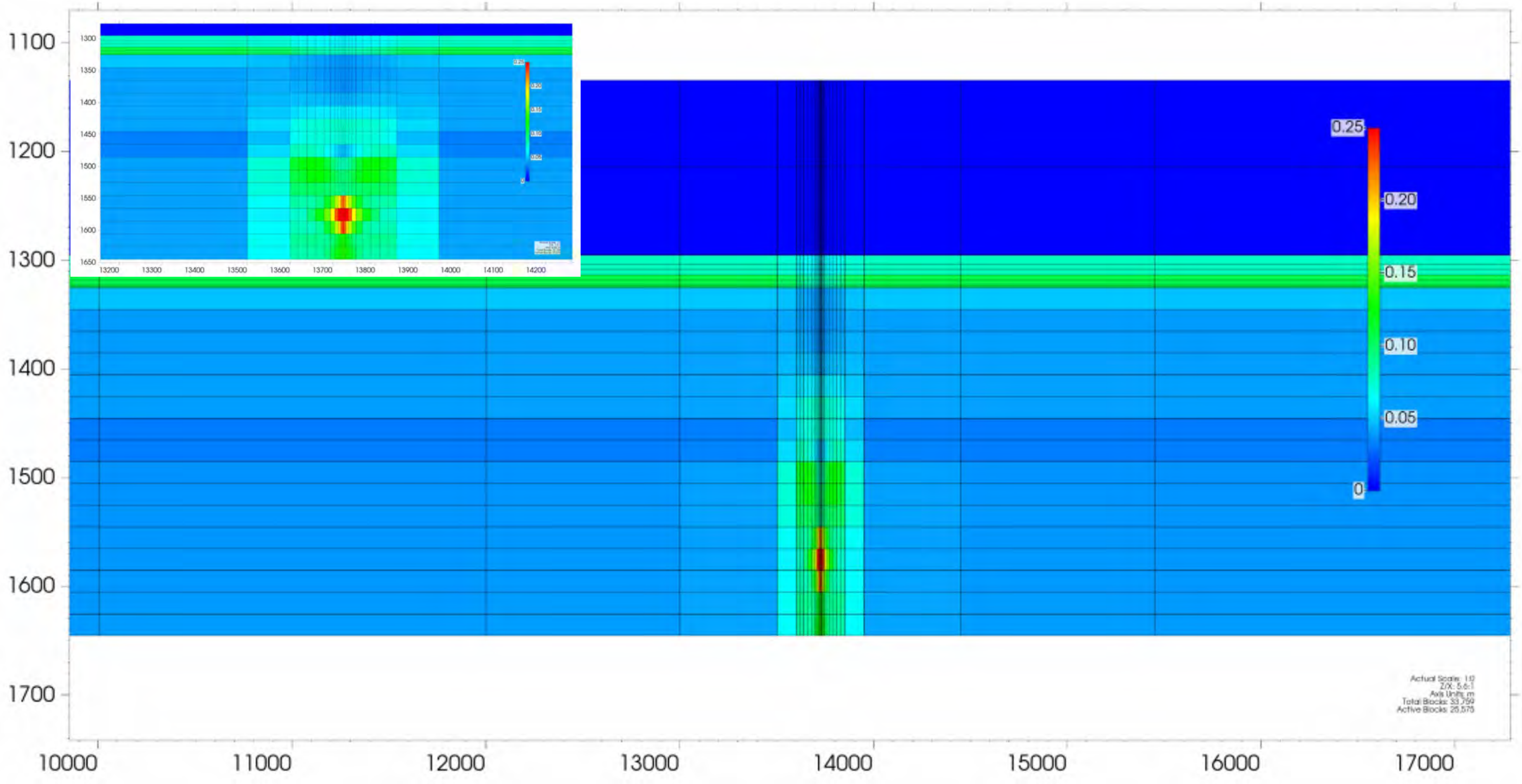
Case7: inject from cooking lake, injection temp=1 degC

SSL at lower Ireton, Leduc and Cooking lake @ 5 years



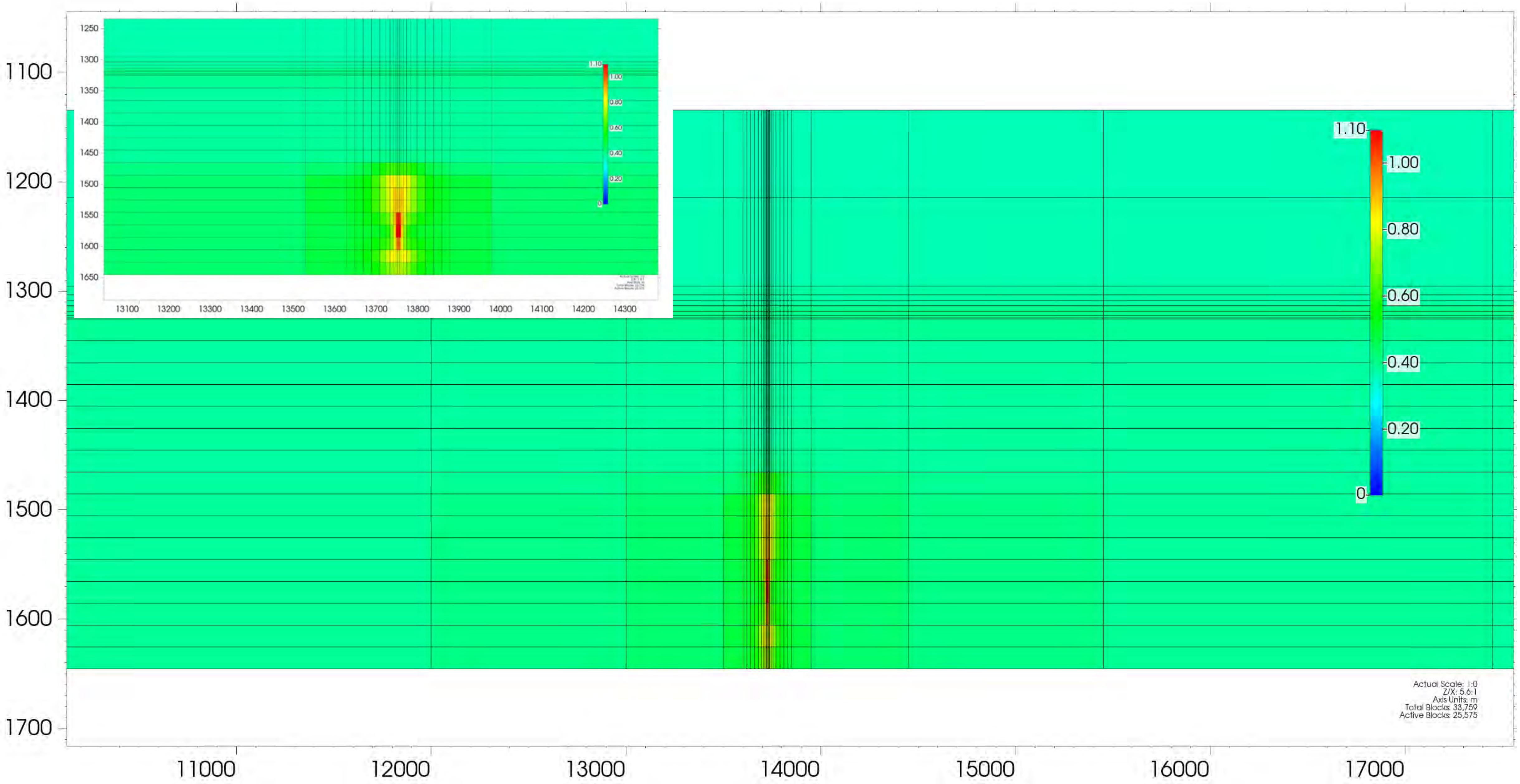
Case7: inject from cooking lake, injection temp=1 degC

SSL at lower Ireton, Leduc and Cooking lake @ 15 years



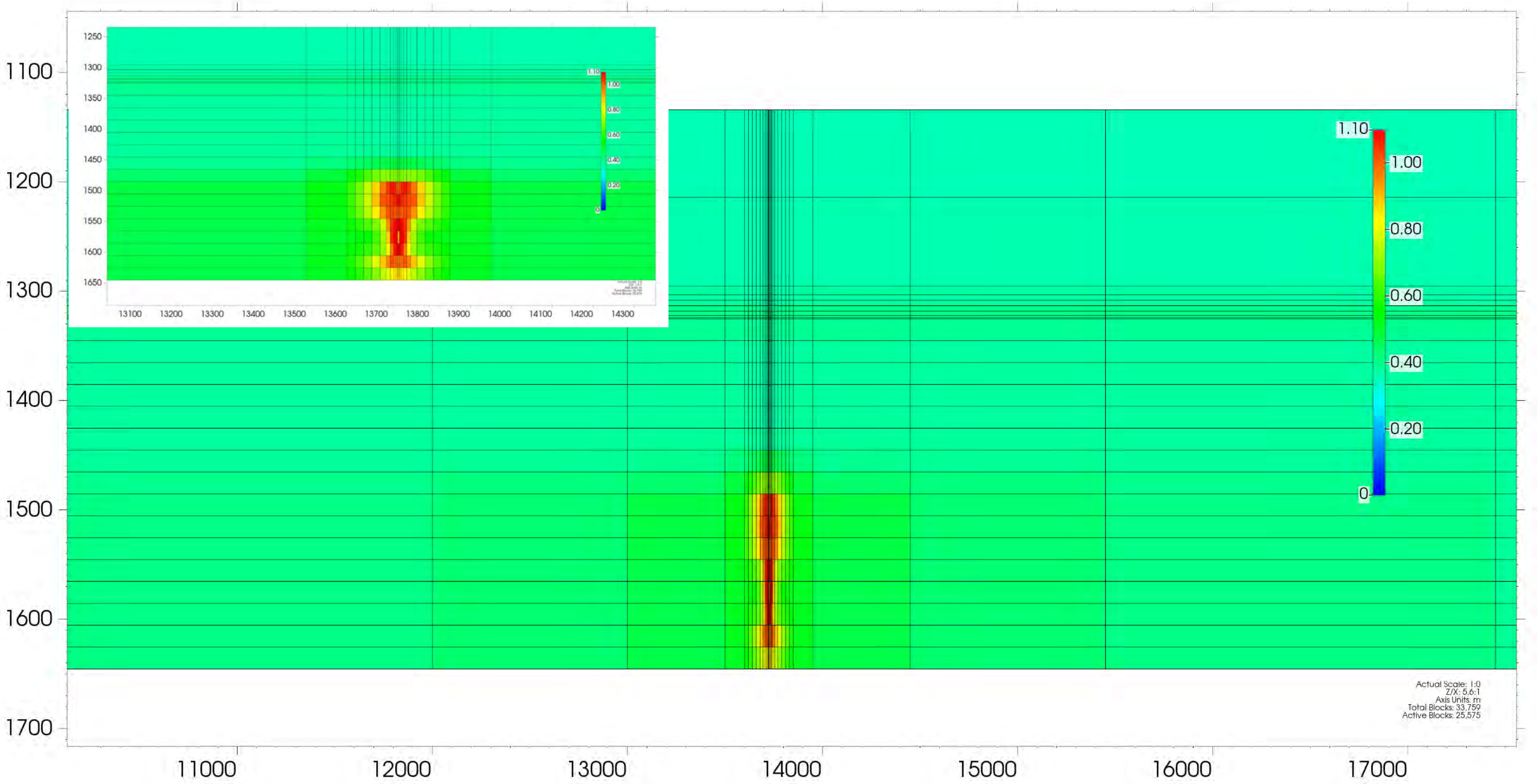
Case7: inject from cooking lake, injection temp=1 degC

TSL at lower Ireton, Leduc and Cooking lake @ 1 year (fractured near wellbore)



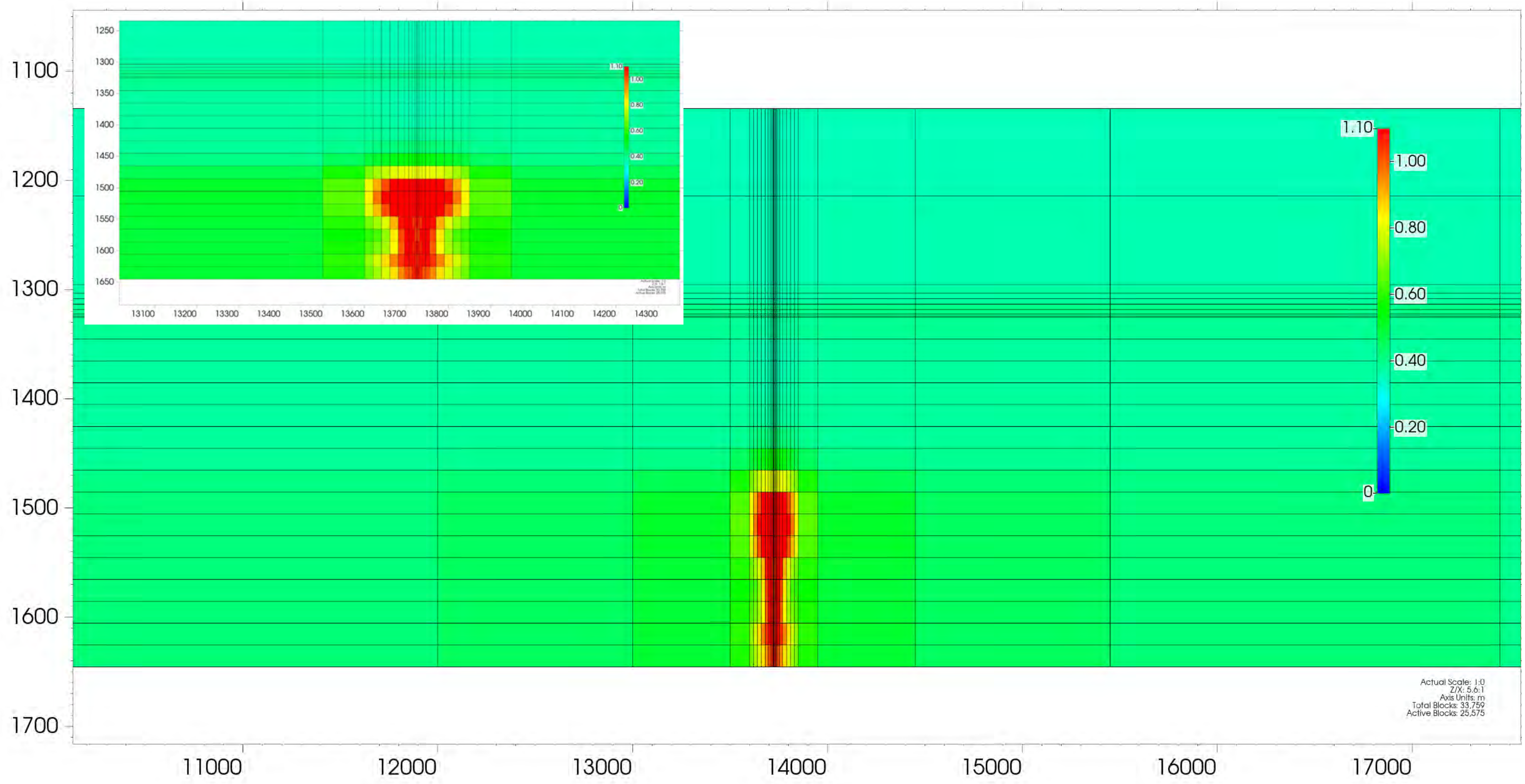
Case7: inject from cooking lake, injection temp=1 degC

TSL at lower Ireton, Leduc and Cooking lake @ 5 years (fractured near wellbore)



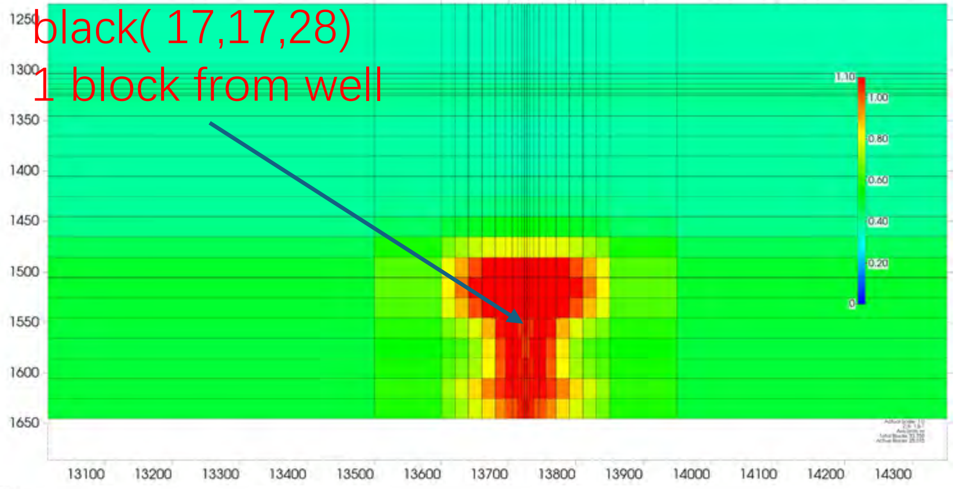
Case7: inject from cooking lake, injection temp=1 degC

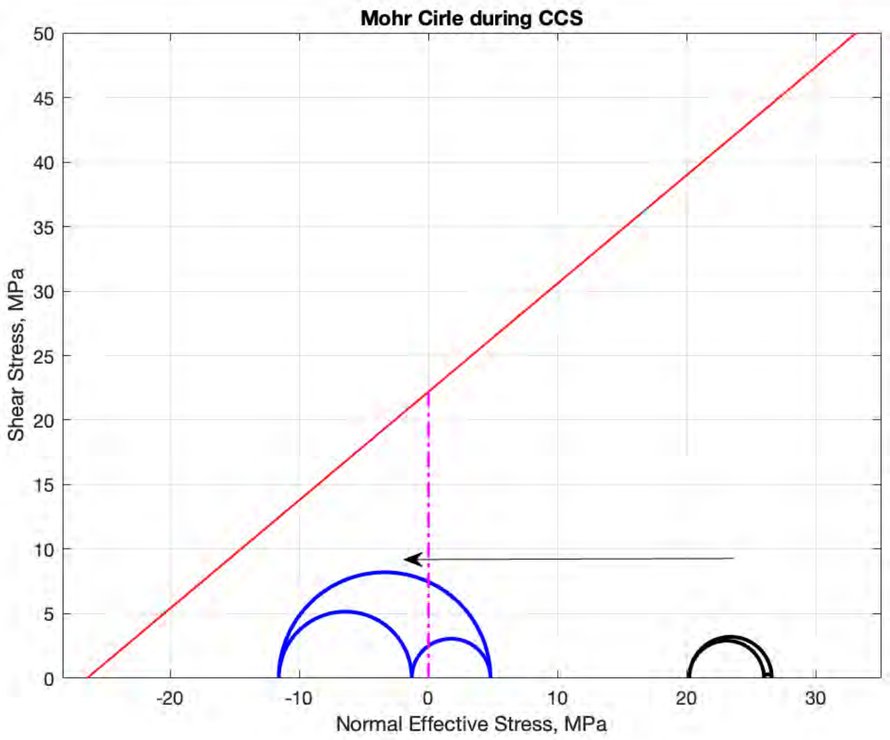
TSL at lower Ireton, Leduc and Cooking lake @ end of injection 15 years (fractured near wellbore)

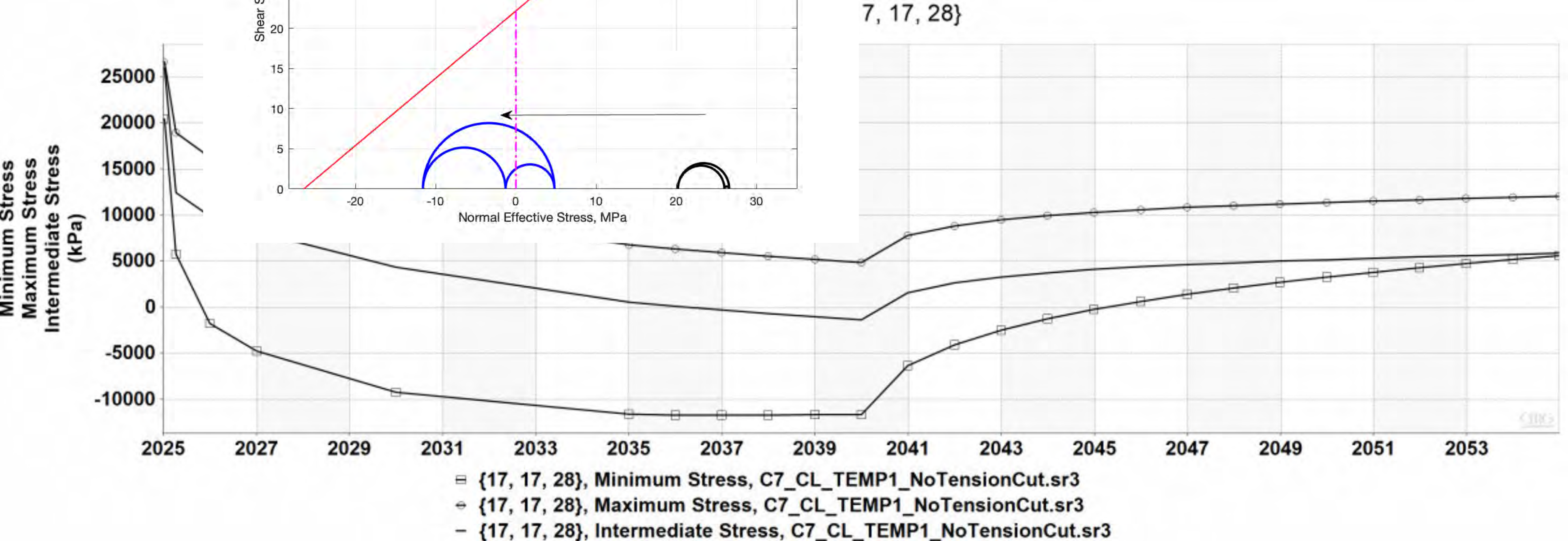


Case7: inject from cooking lake, injection temp=1 degC

Change of 3 principal effective stresses near wellbore

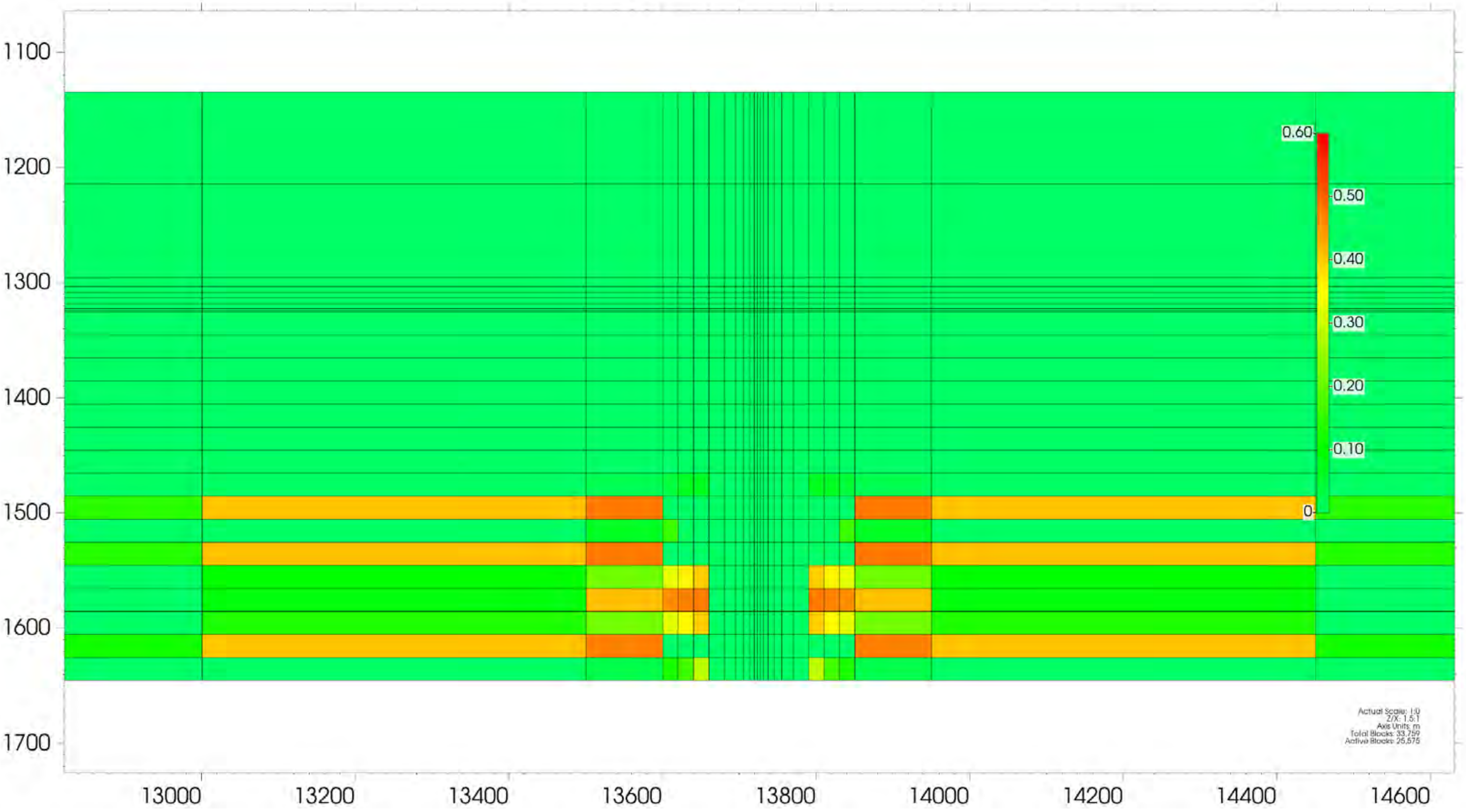






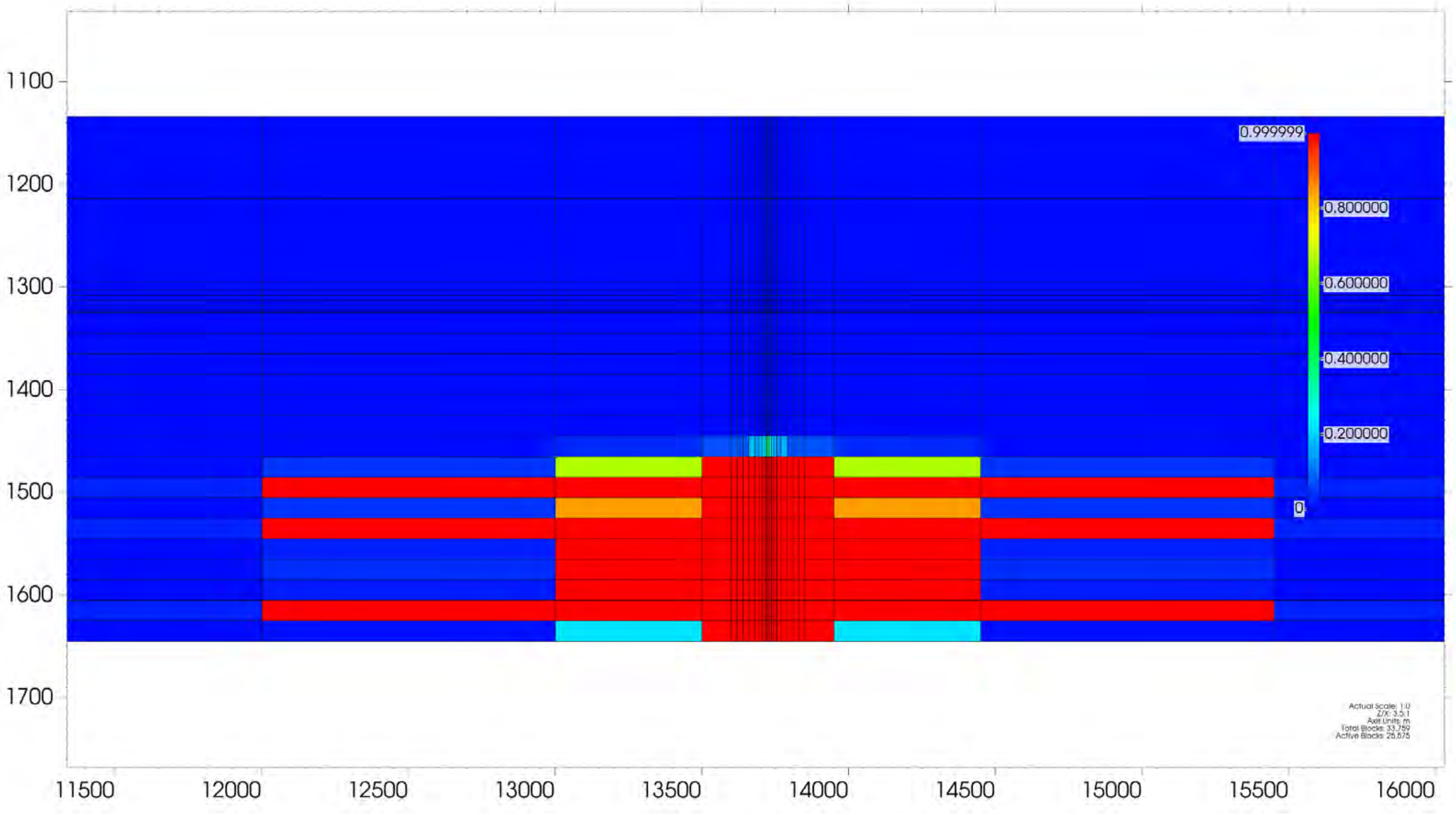
Case7: inject from cooking lake, injection temp=1 degC

Gas saturation @ 15 years



Case7: inject from cooking lake, injection temp=1 degC

CO2 Mole fraction@ 15 years

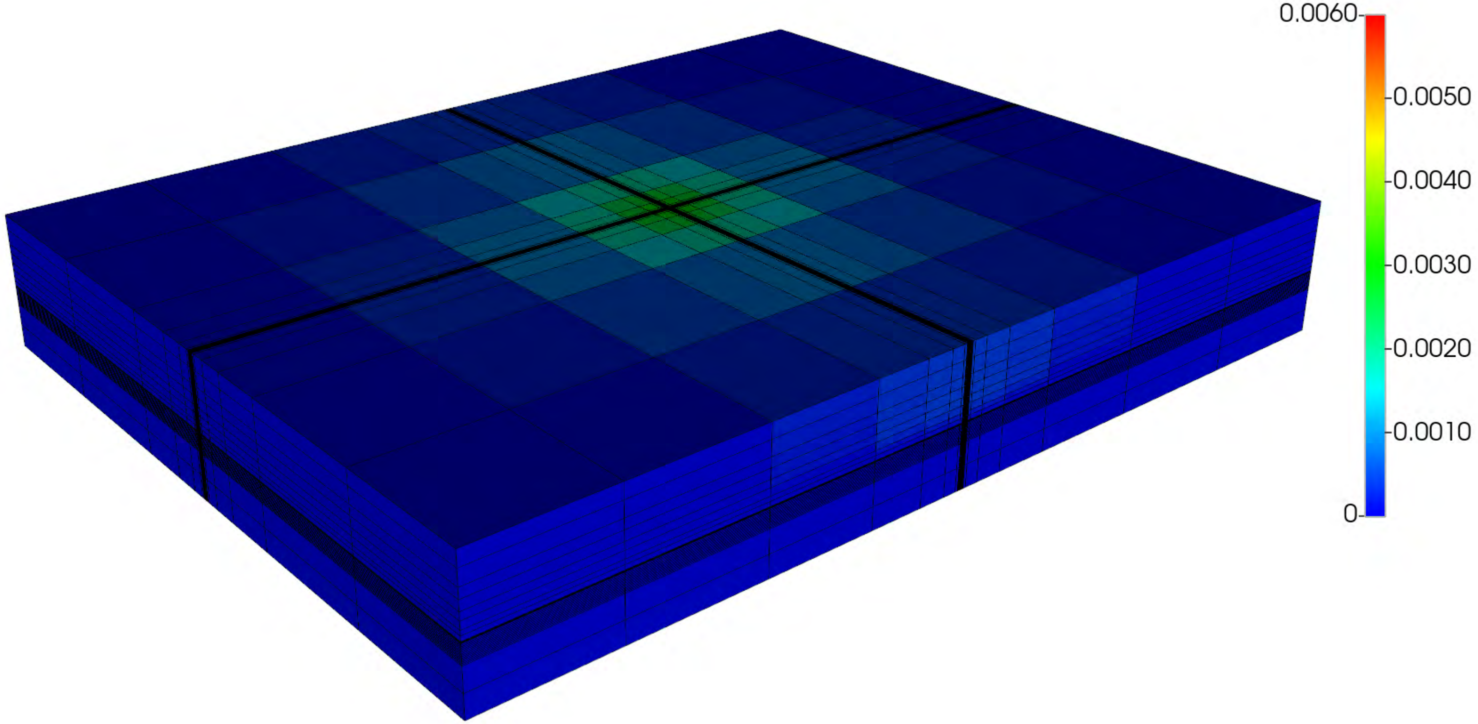


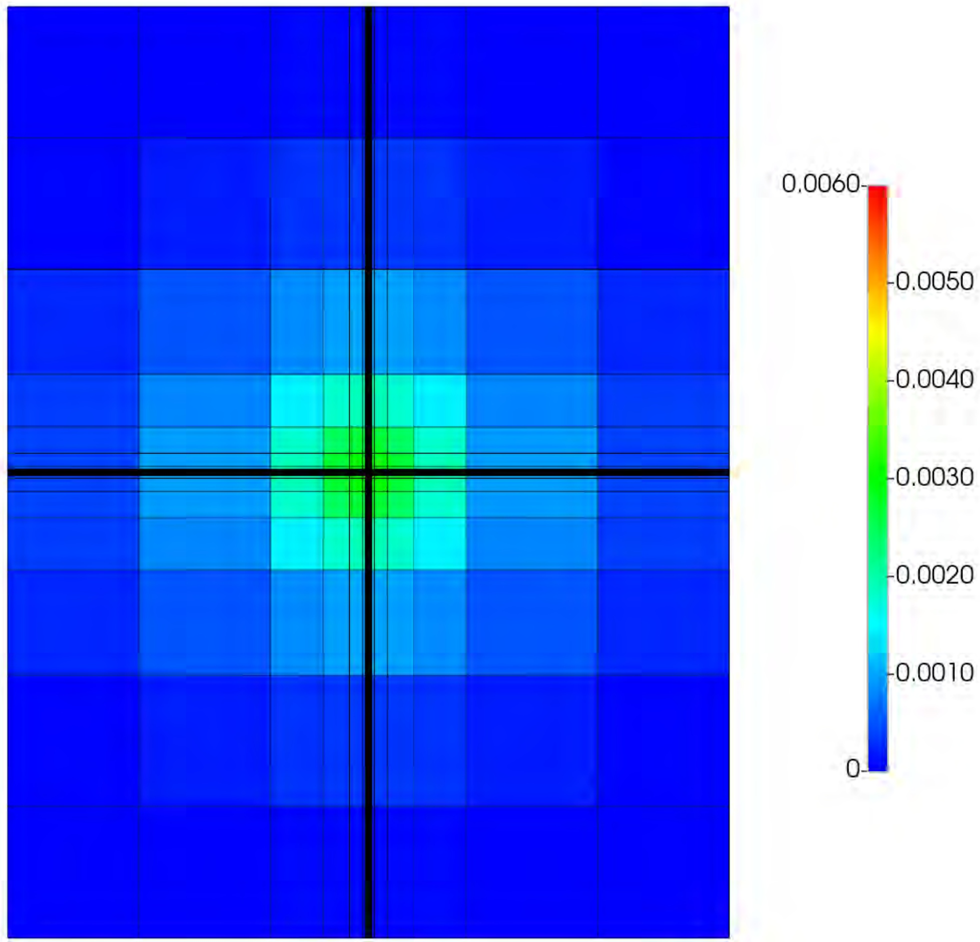
Case 8: Injection at Cooking Lake, Injection temperature=20 degC

Base case: Case2

Case8: inject from cooking lake, injection temp=20 degC

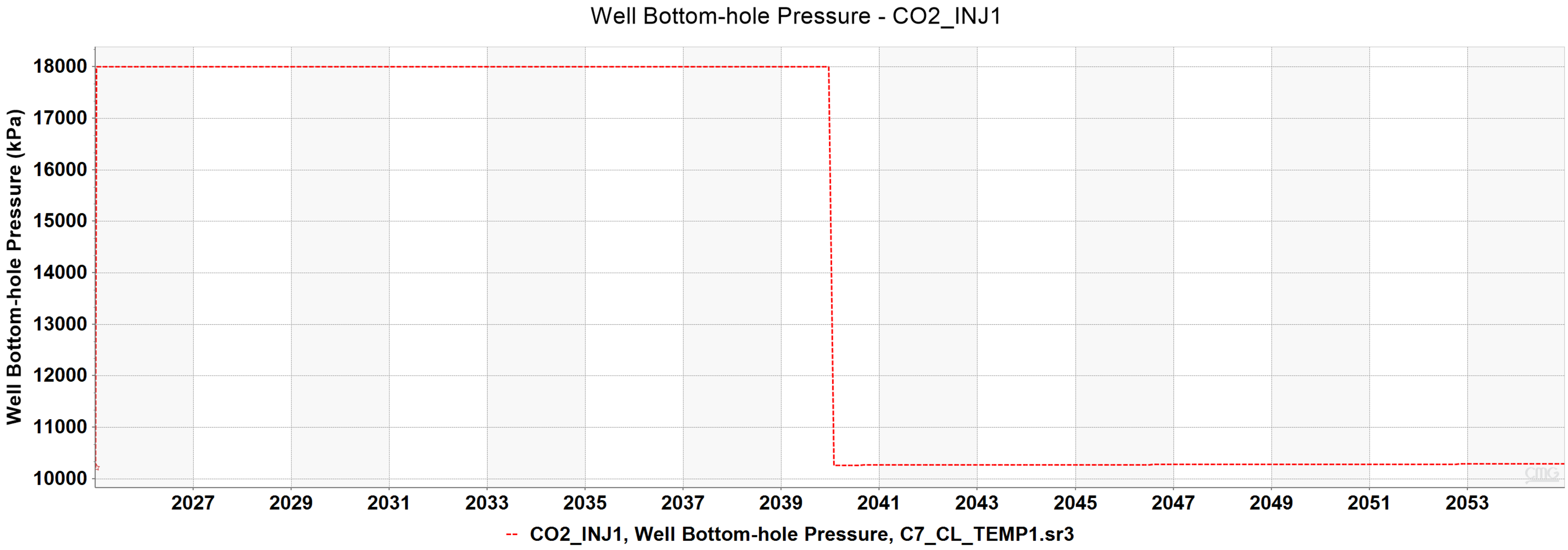
Surface heave @ end of injection 15 years (max. 3.2mm)





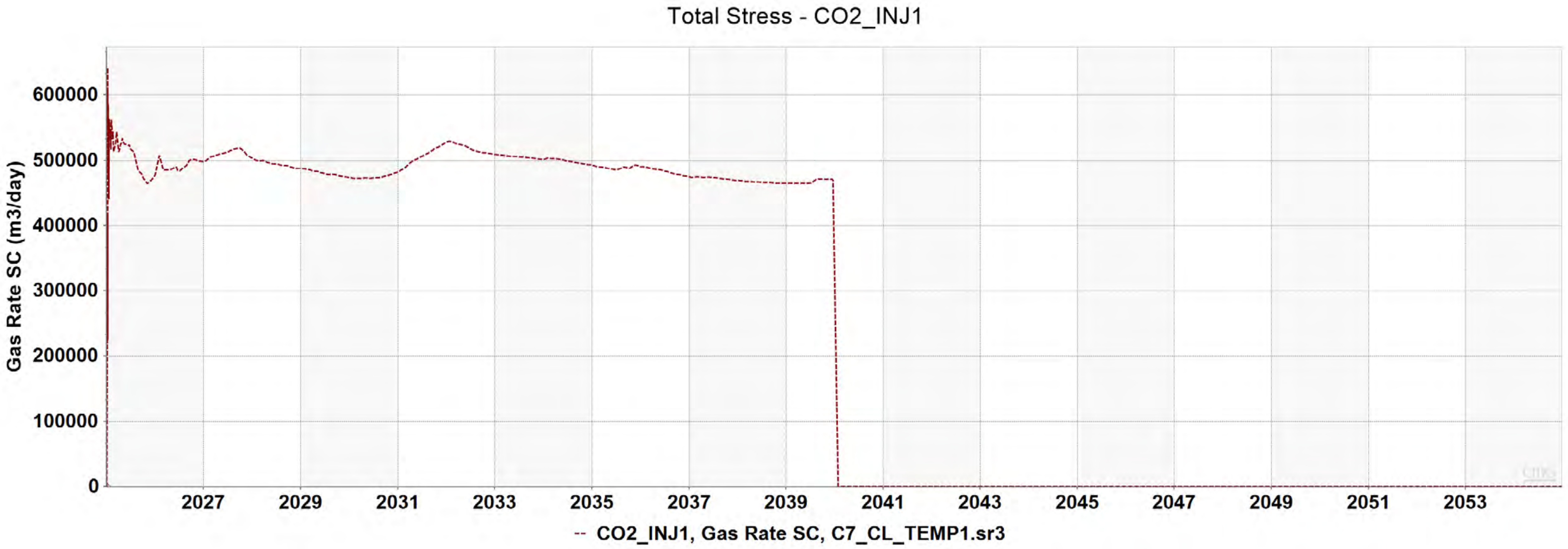
Case8: inject from cooking lake, injection temp=20 degC

Injection pressure (BHP, unit: kPa)



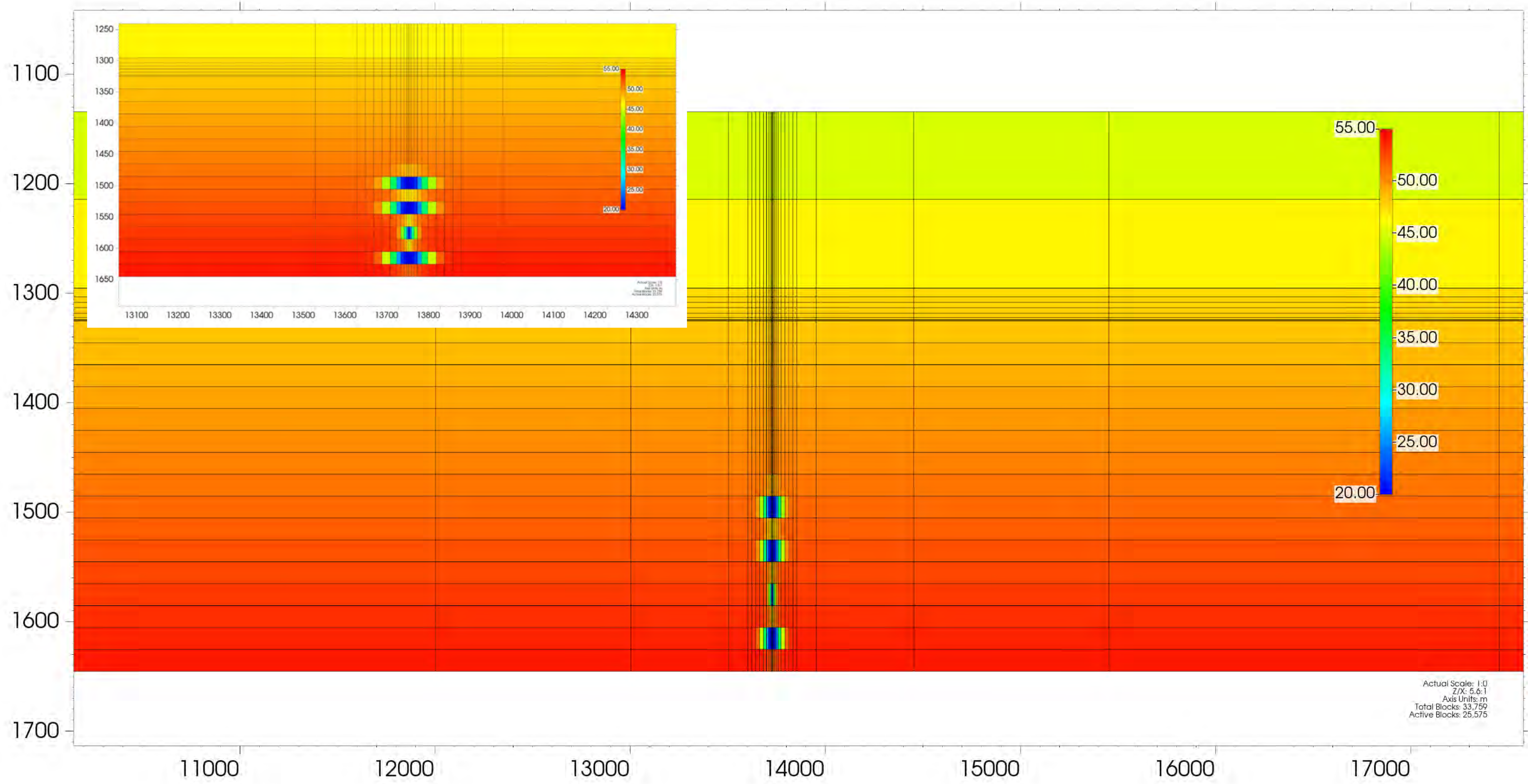
Case8: inject from cooking lake, injection temp=20 degC

Injection rate



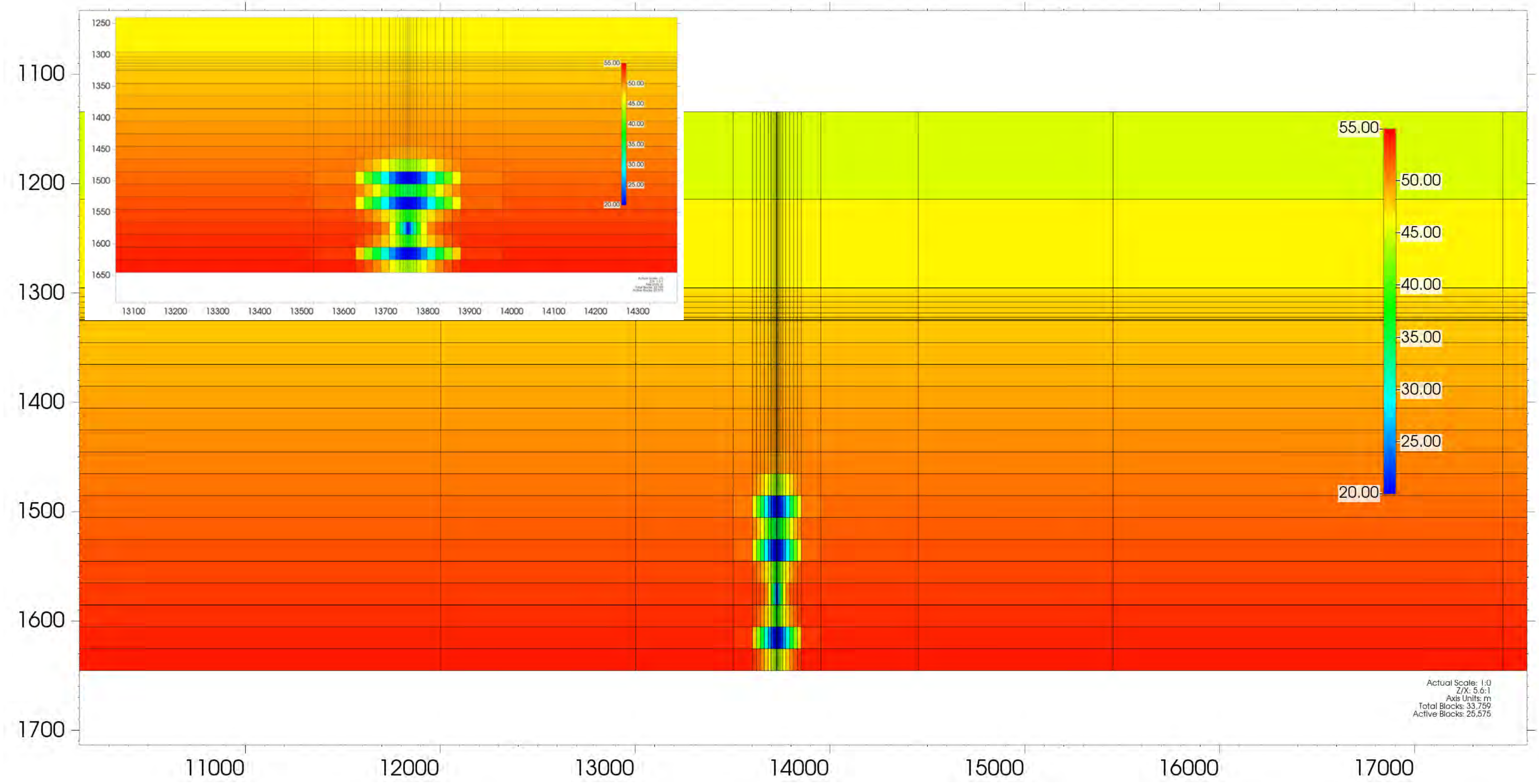
Case8: inject from cooking lake, injection temp=20 degC

Temperature distribution @ 1 year



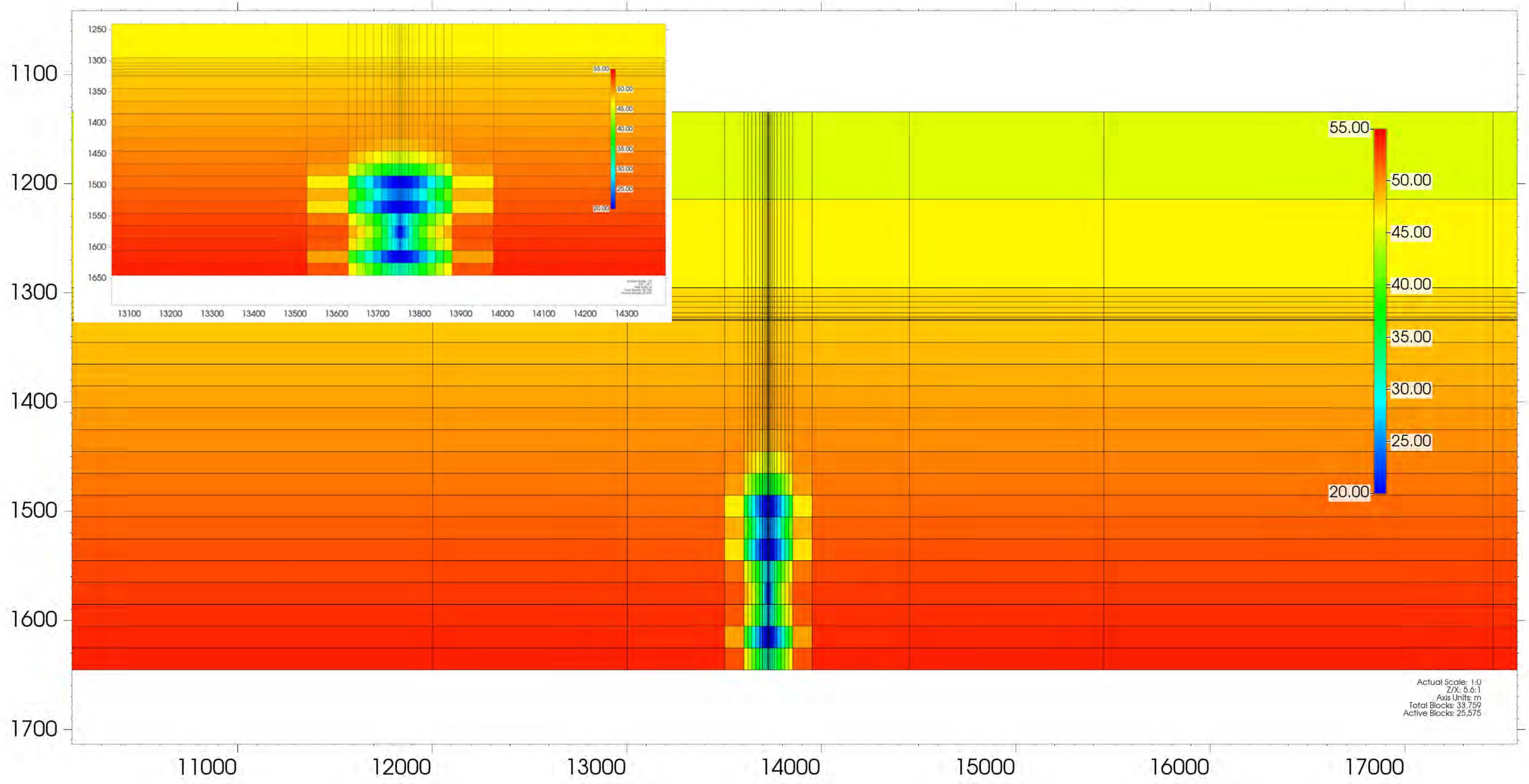
Case8: inject from cooking lake, injection temp=20 degC

Temperature distribution @ 5 years



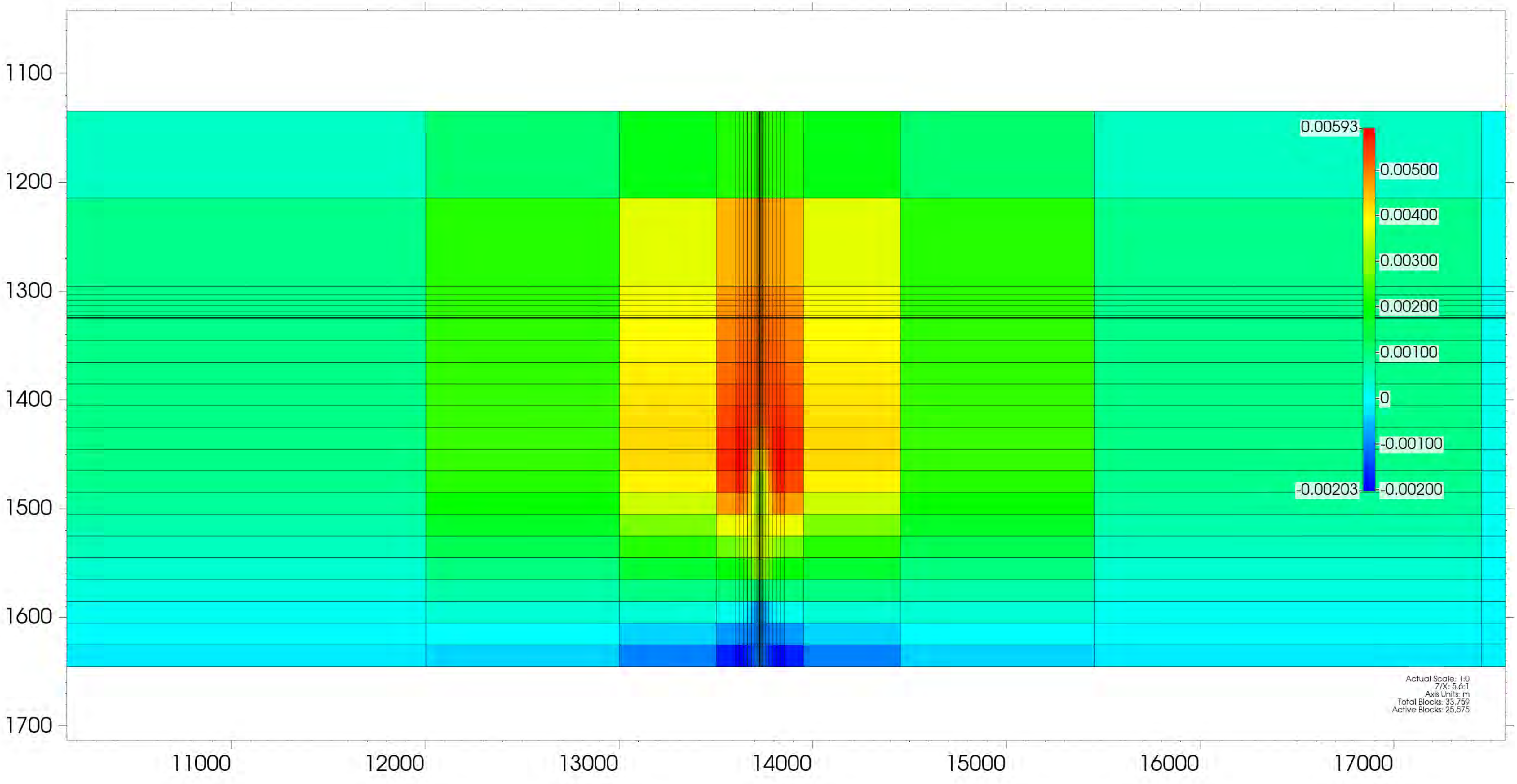
Case8: inject from cooking lake, injection temp=20 degC

Temperature distribution @ end of injection 15 years



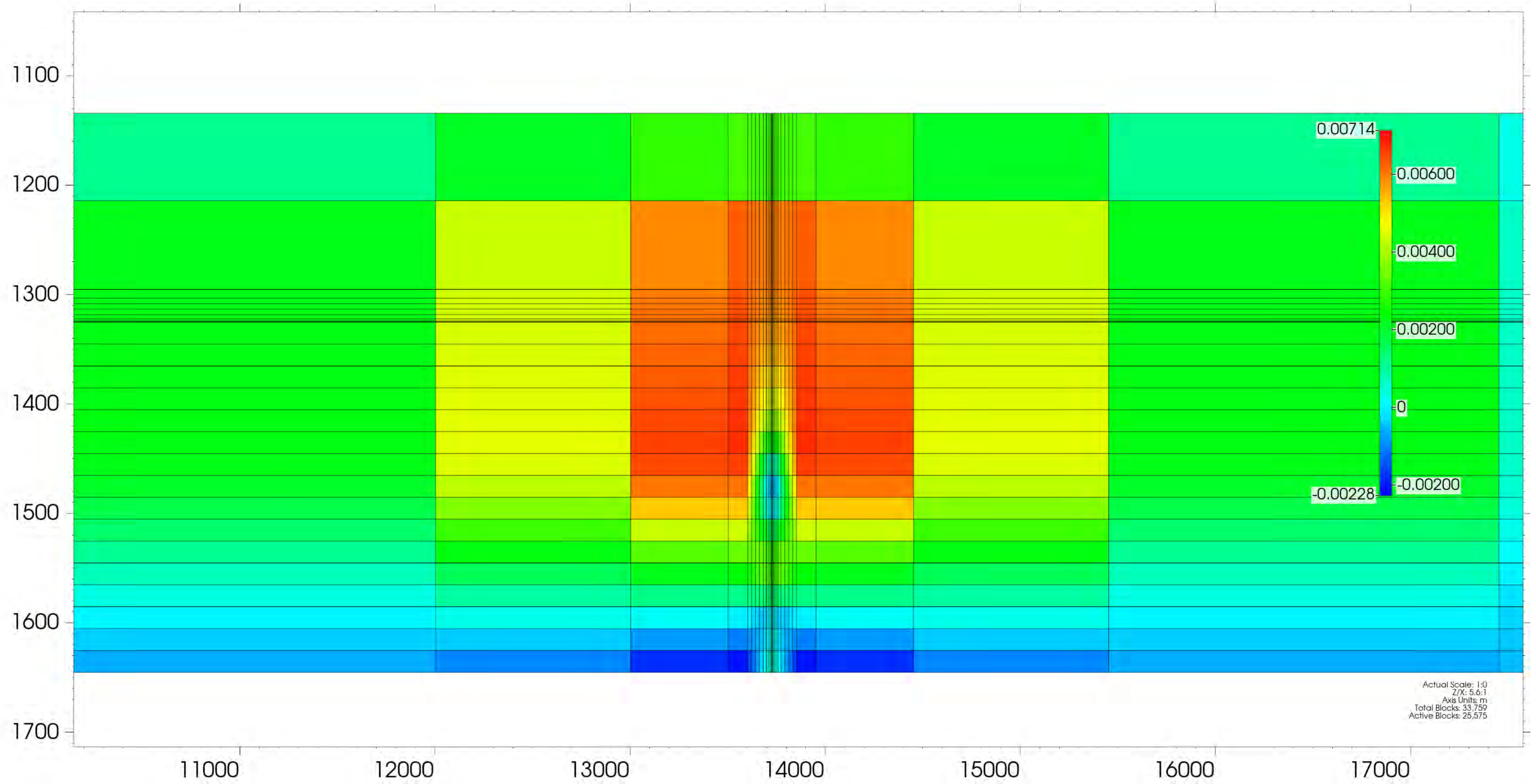
Case8: inject from cooking lake, injection temp=20 degC

Deformation (Uz) @ 1 year



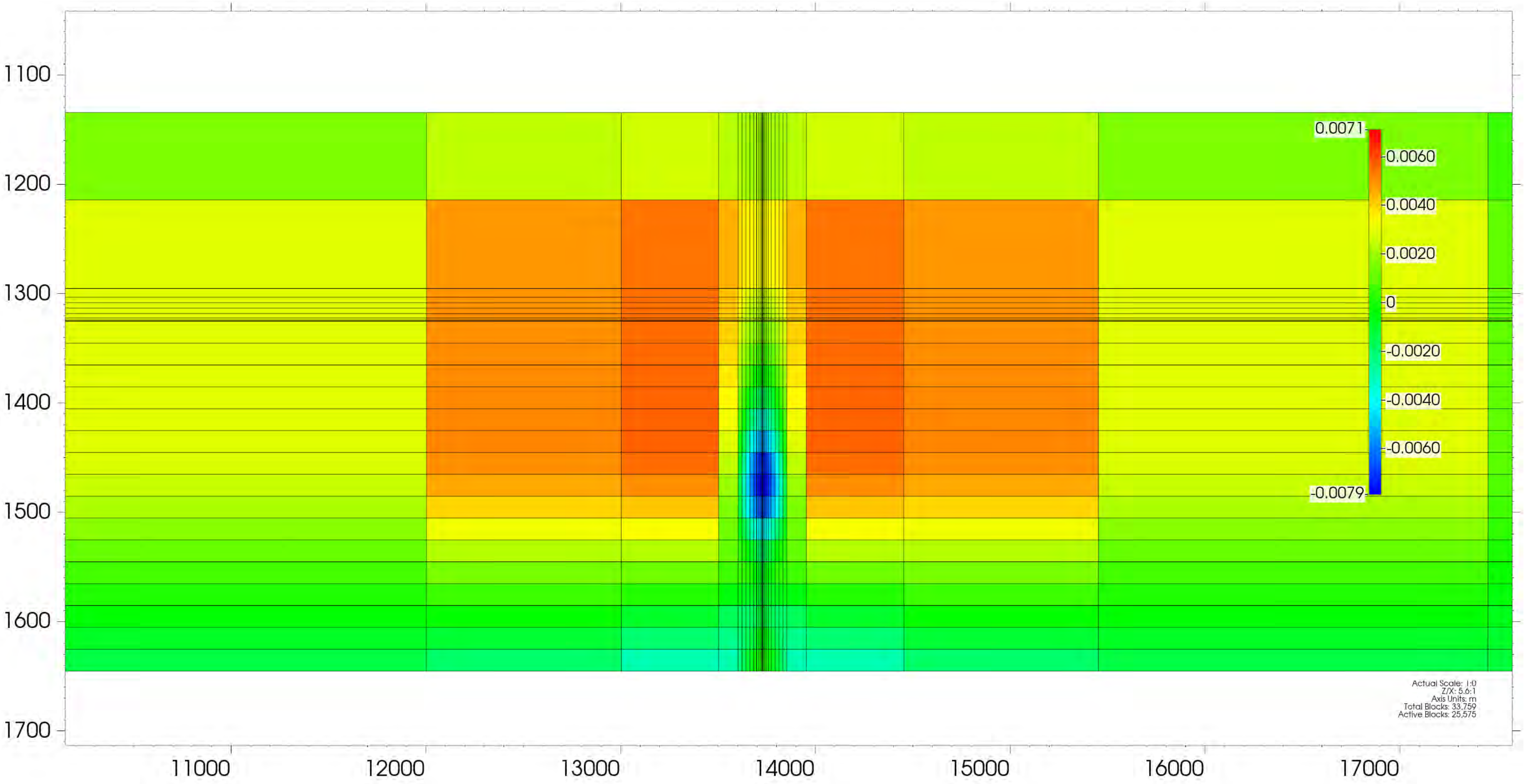
Case8: inject from cooking lake, injection temp=20 degC

Deformation (Uz) @ 5 years



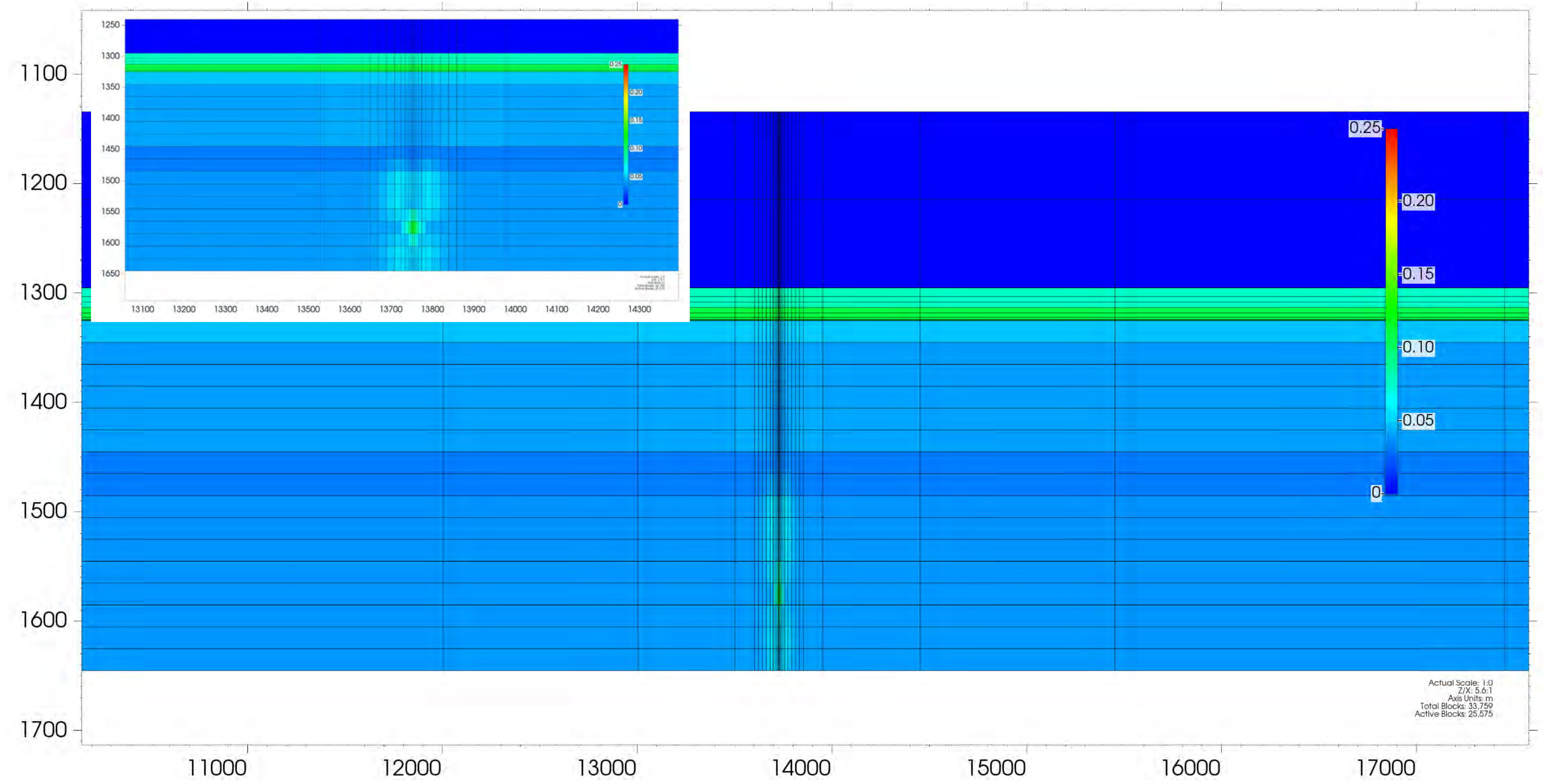
Case8: inject from cooking lake, injection temp=20 degC

Deformation (Uz) @ end of injection 15 years



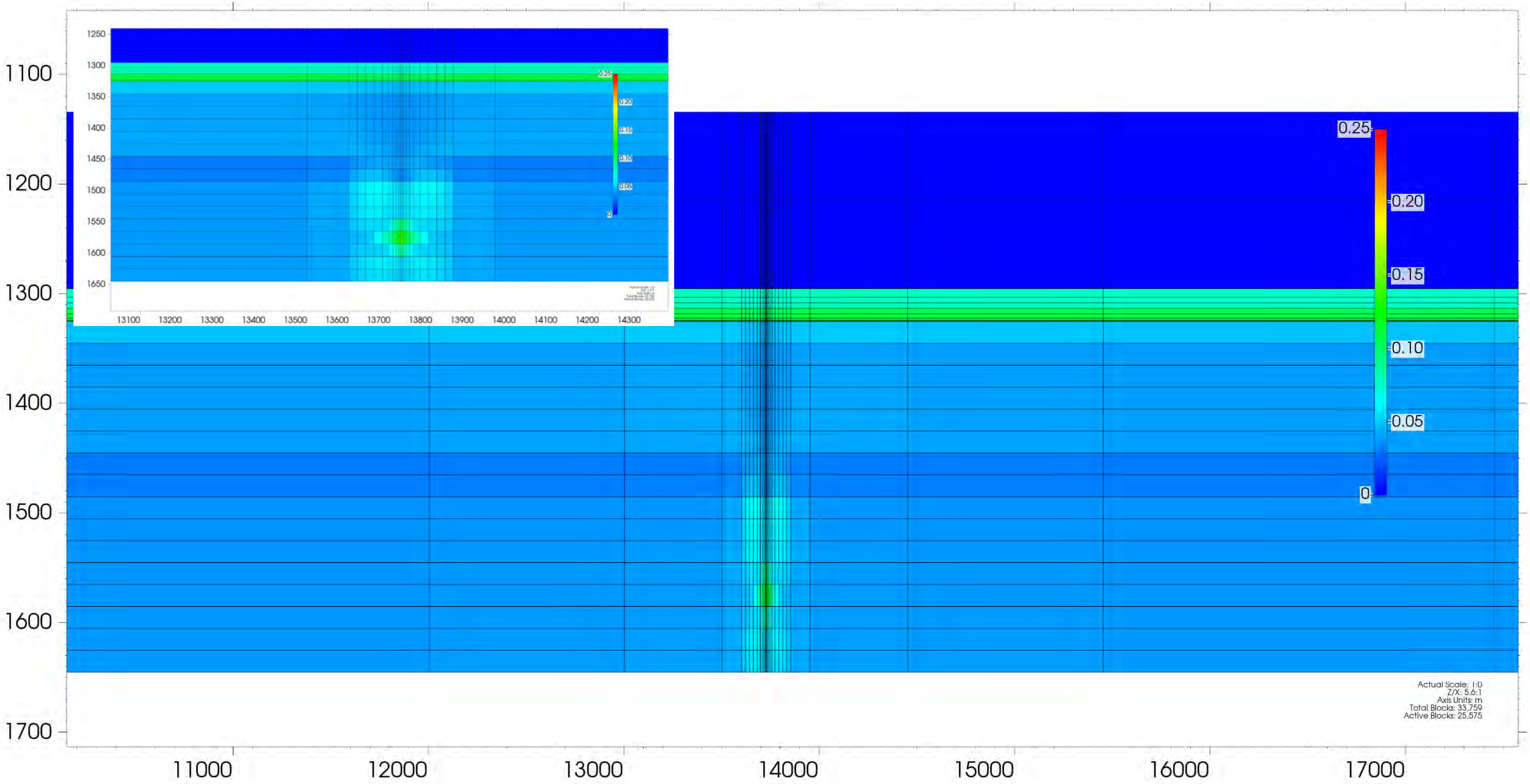
Case8: inject from cooking lake, injection temp=20 degC

SSL at lower Ireton, Leduc and Cooking lake @ 1 year



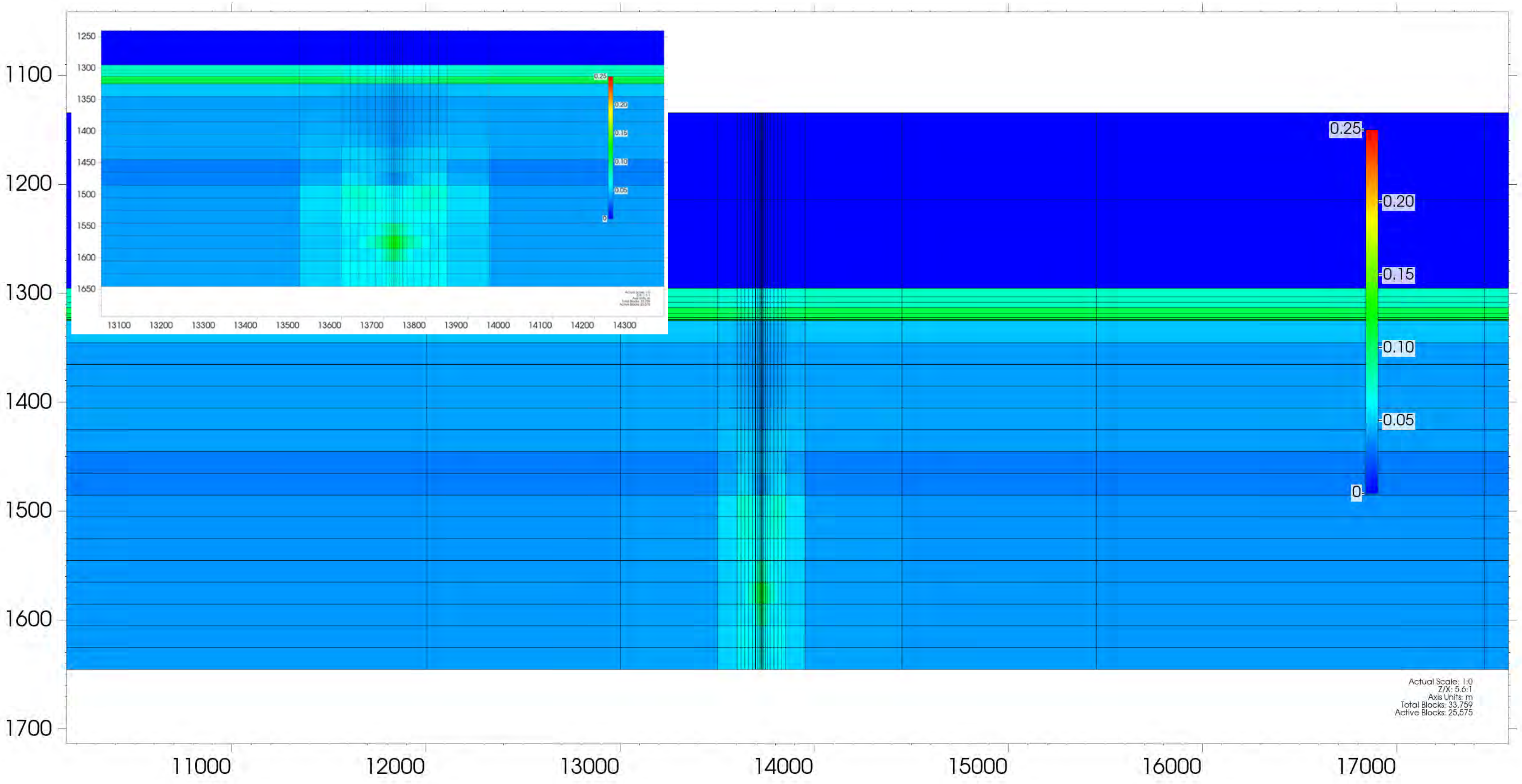
Case8: inject from cooking lake, injection temp=20 degC

SSL at lower Ireton, Leduc and Cooking lake @ 5 years



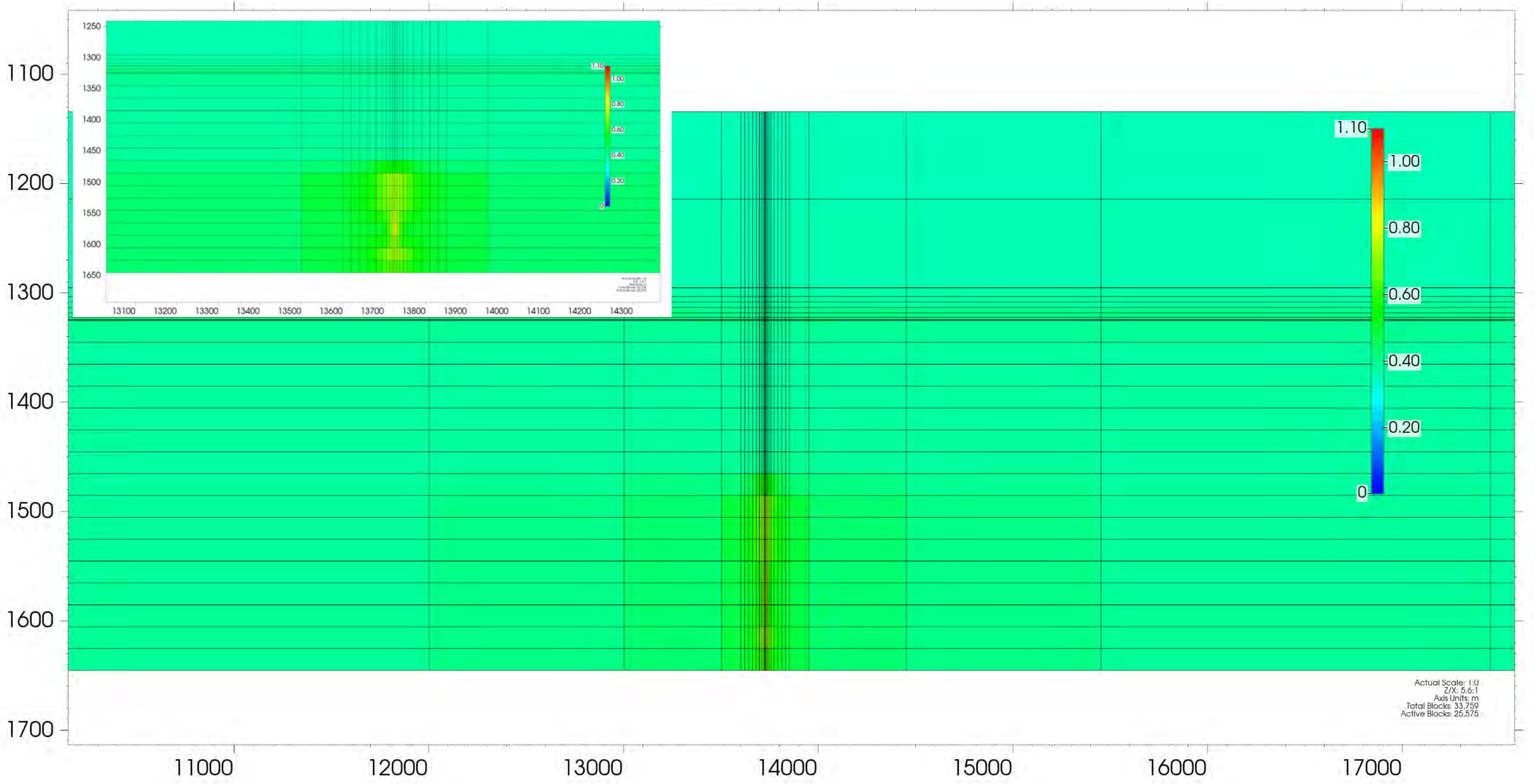
Case8: inject from cooking lake, injection temp=20 degC

SSL at lower Ireton, Leduc and Cooking lake @ 15 years



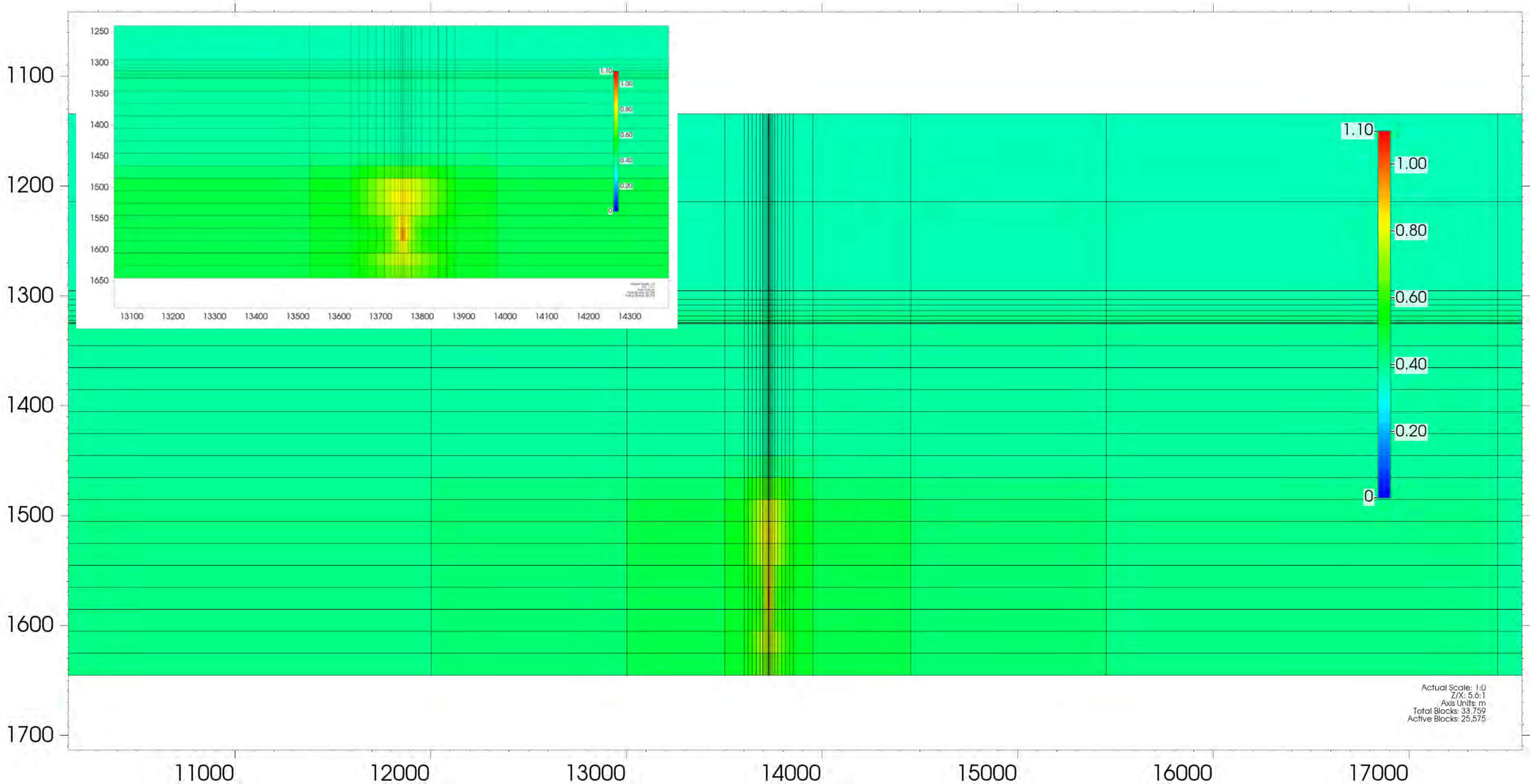
Case8: inject from cooking lake, injection temp=20 degC

TSL at lower Ireton, Leduc and Cooking lake @ 1 year (fractured near wellbore)



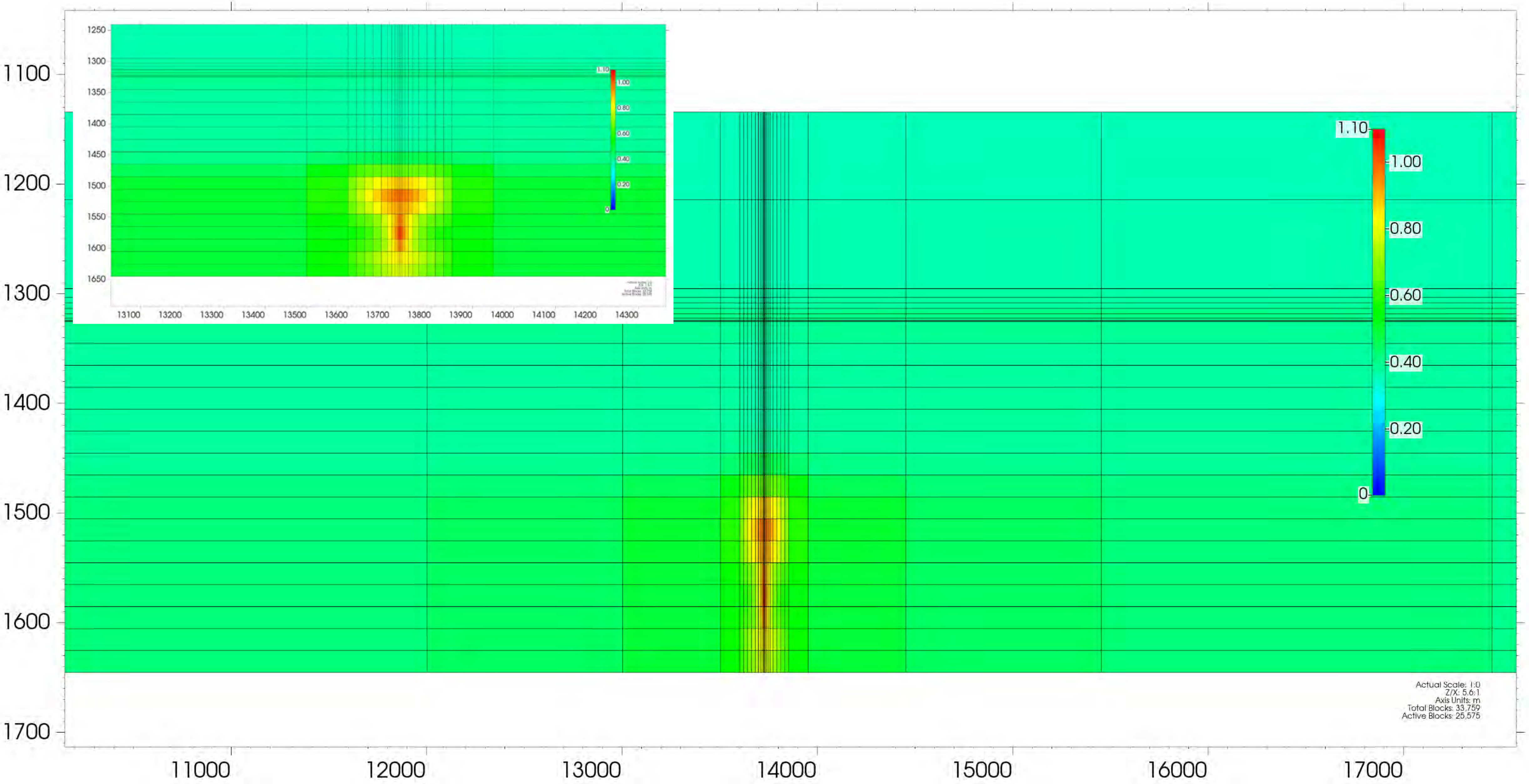
Case8: inject from cooking lake, injection temp=20 degC

TSL at lower Ireton, Leduc and Cooking lake @ 5 years



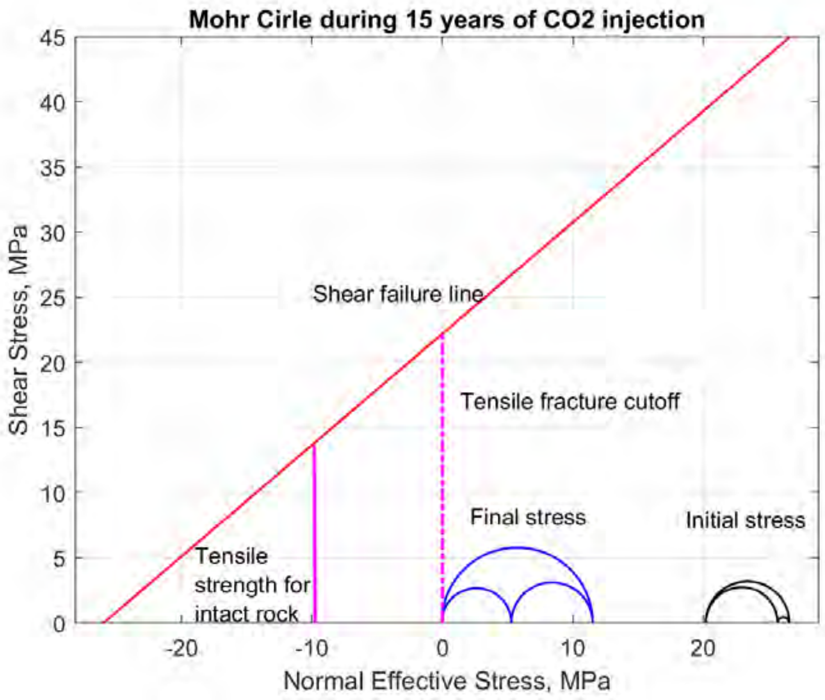
Case8: inject from cooking lake, injection temp=20 degC

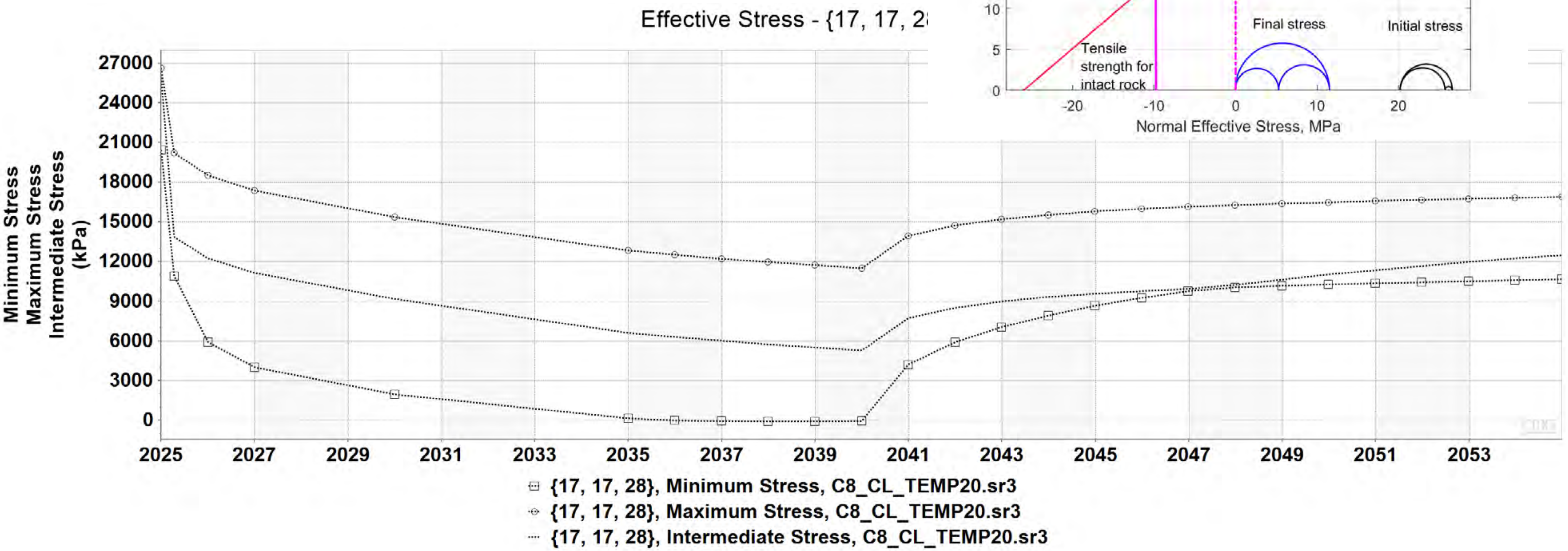
TSL at lower Ireton, Leduc and Cooking lake @ end of injection 15 years



Case8: inject from cooking lake, injection temp=20 degC

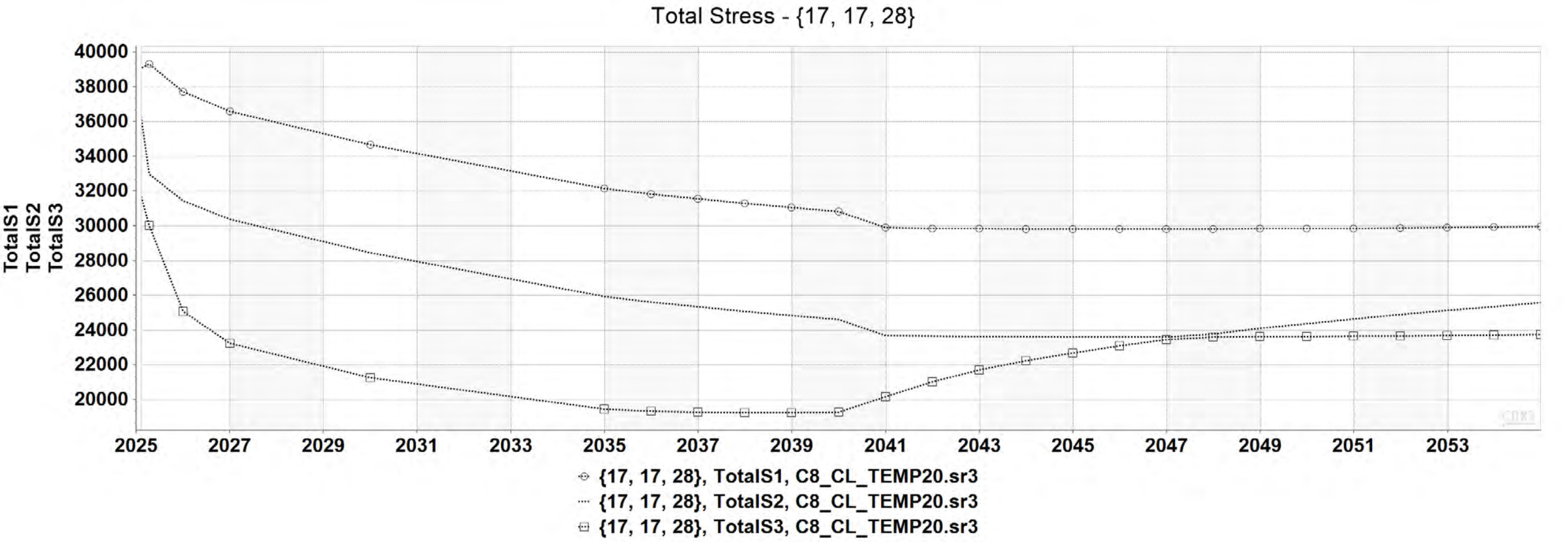
Change of 3 principal effective stresses near wellbore





Case8: inject from cooking lake, injection temp=20 degC

Change of 3 principal total stresses near wellbore

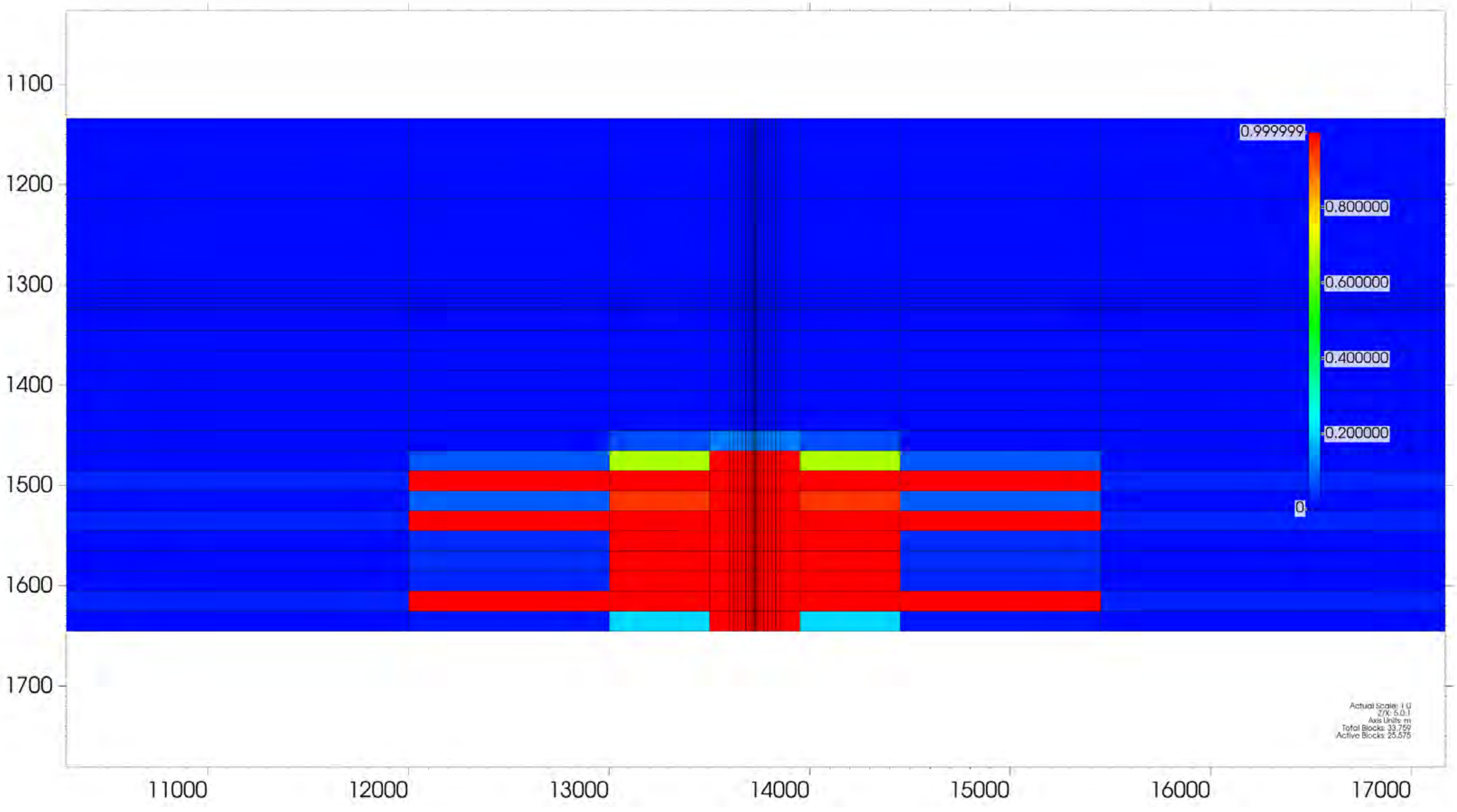


Case8: inject from cooking lake, injection temp=20 degC

Gas saturation @ 15 years

Case8: inject from cooking lake, injection temp=20 degC

CO2 Mole fraction@ 15 years

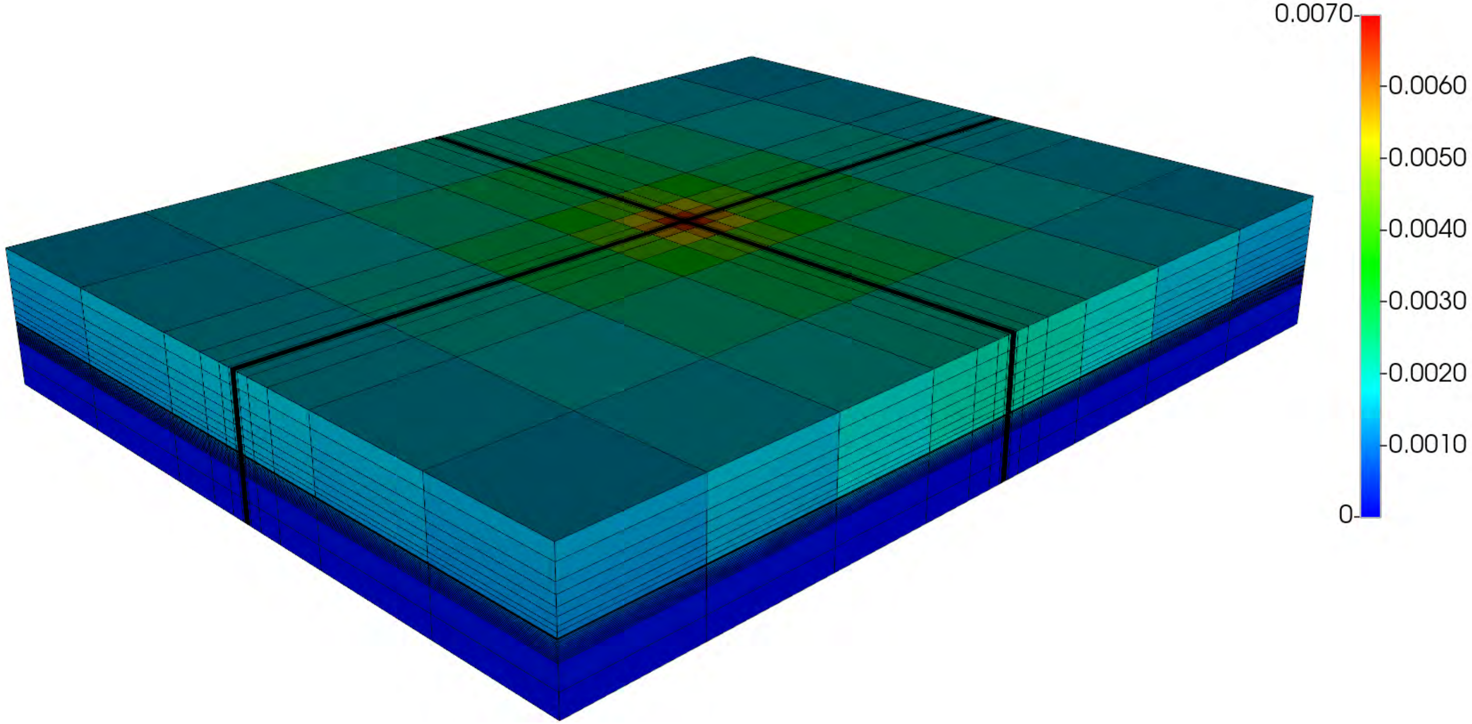


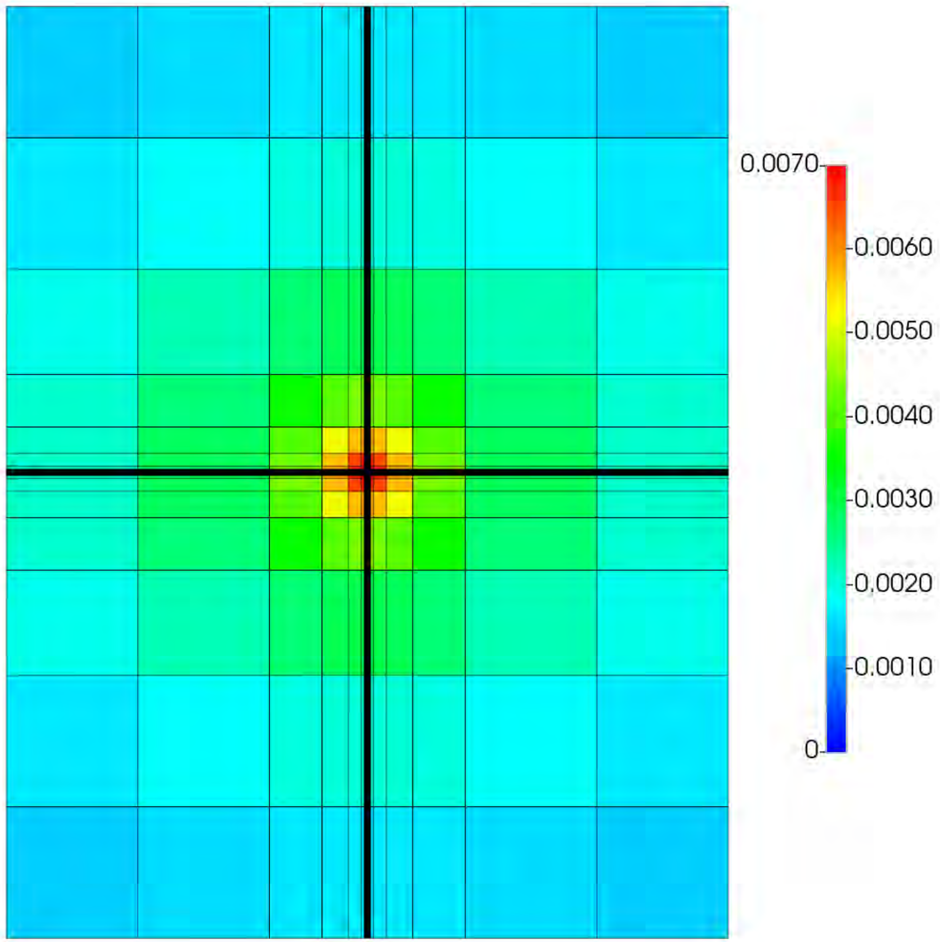
Case 9: Injection at Leduc, Isothermal

Base case: Case1

Case9: inject from Leduc, isothermal

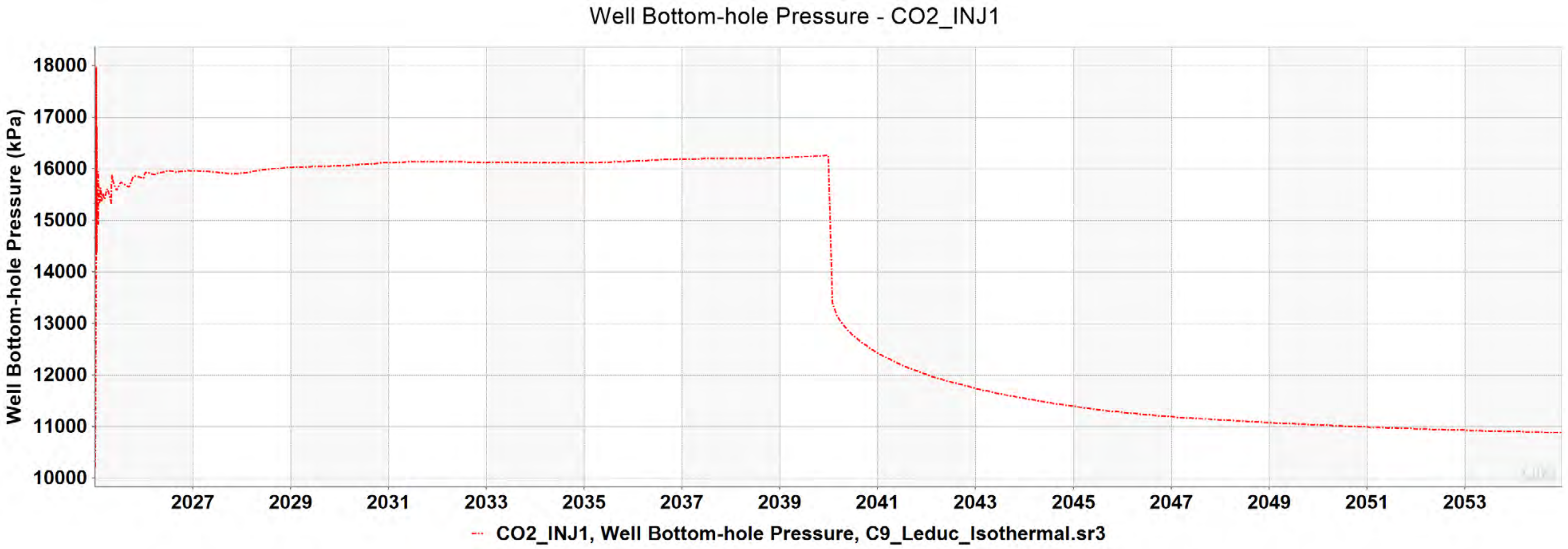
Surface heave @ end of injection 15 years (max. 7mm)





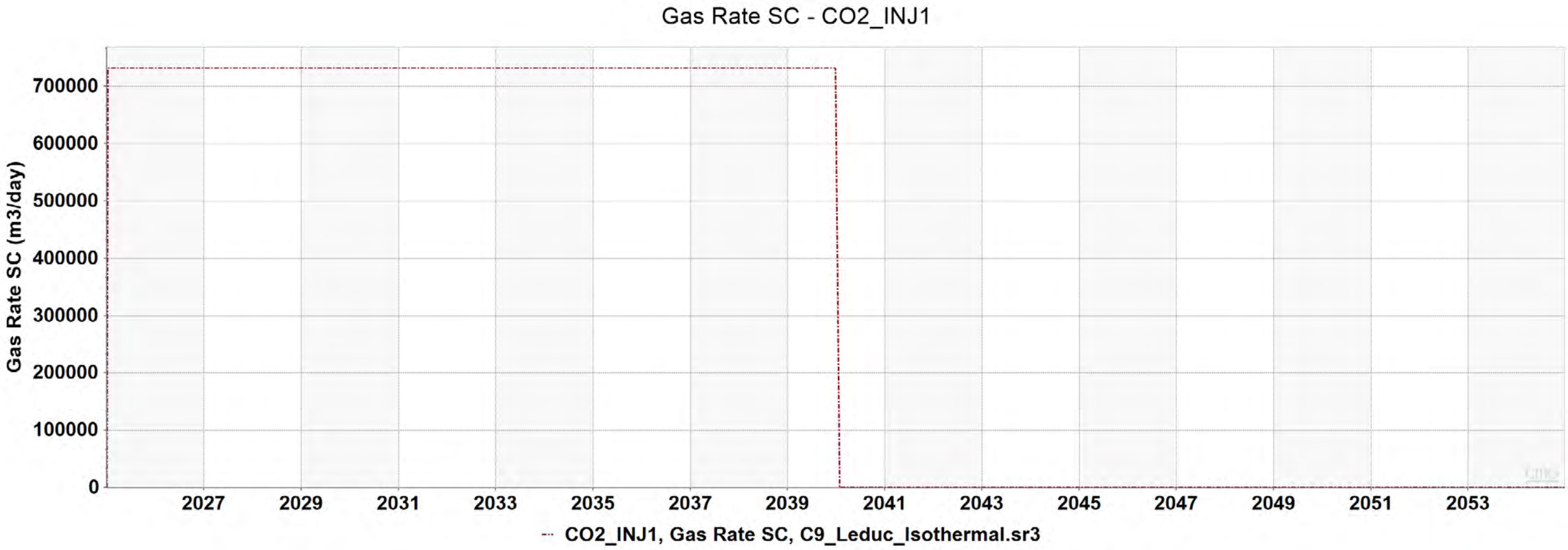
Case9: inject from Leduc, isothermal

Injection pressure (BHP, unit: kPa)



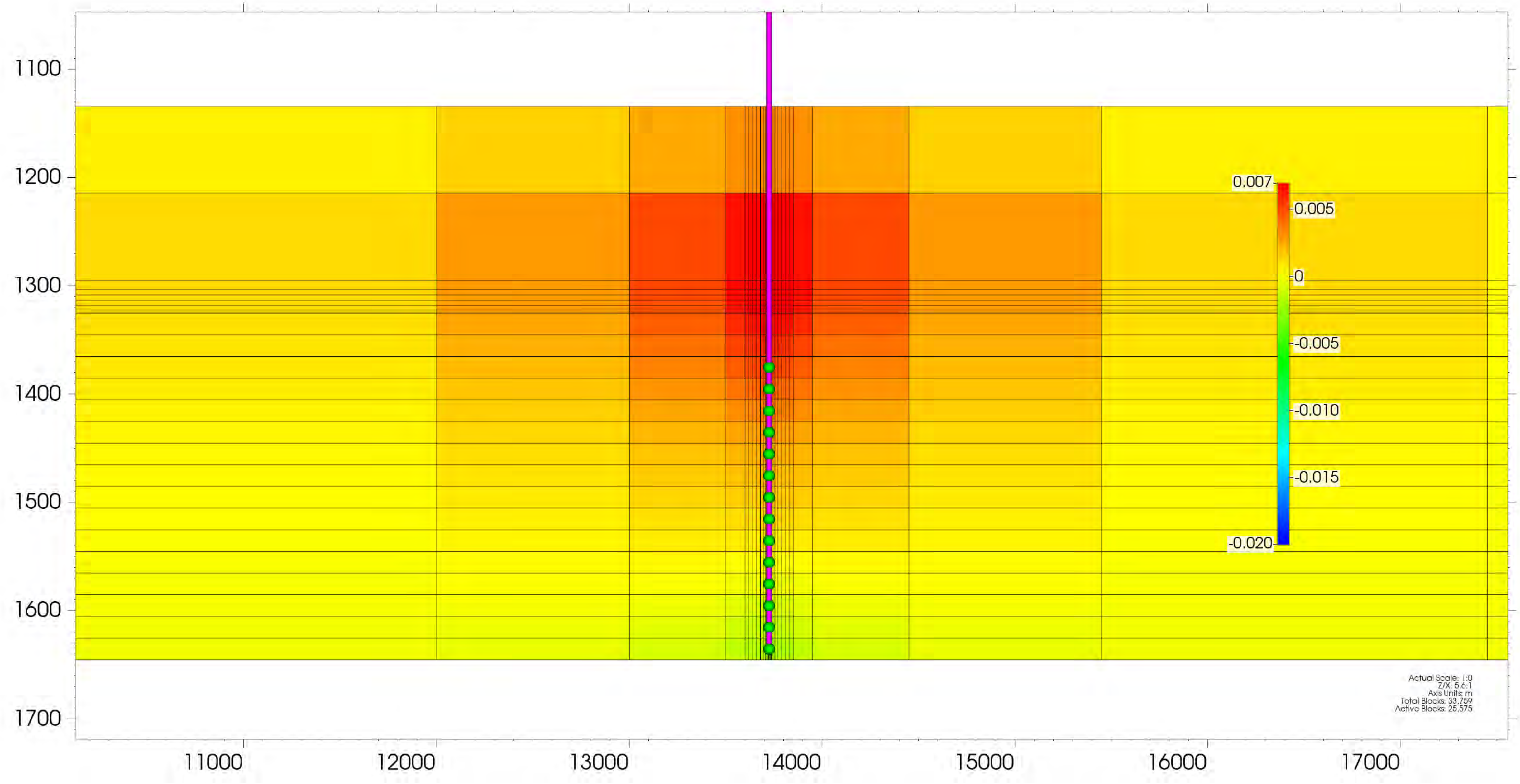
Case9: inject from Leduc, isothermal

Injection rate



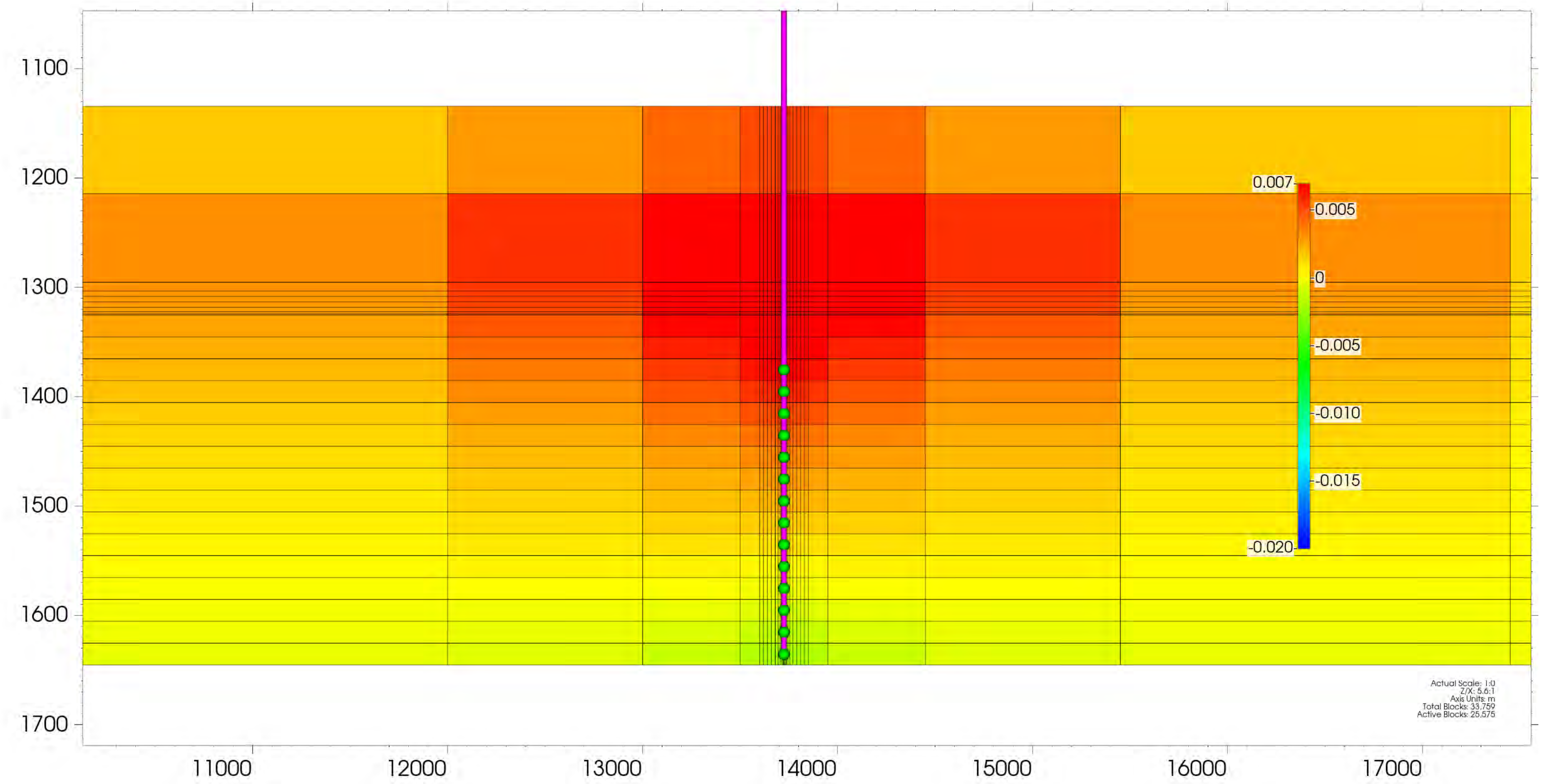
Case9: inject from Leduc, isothermal

Deformation (Uz) @ 1 year



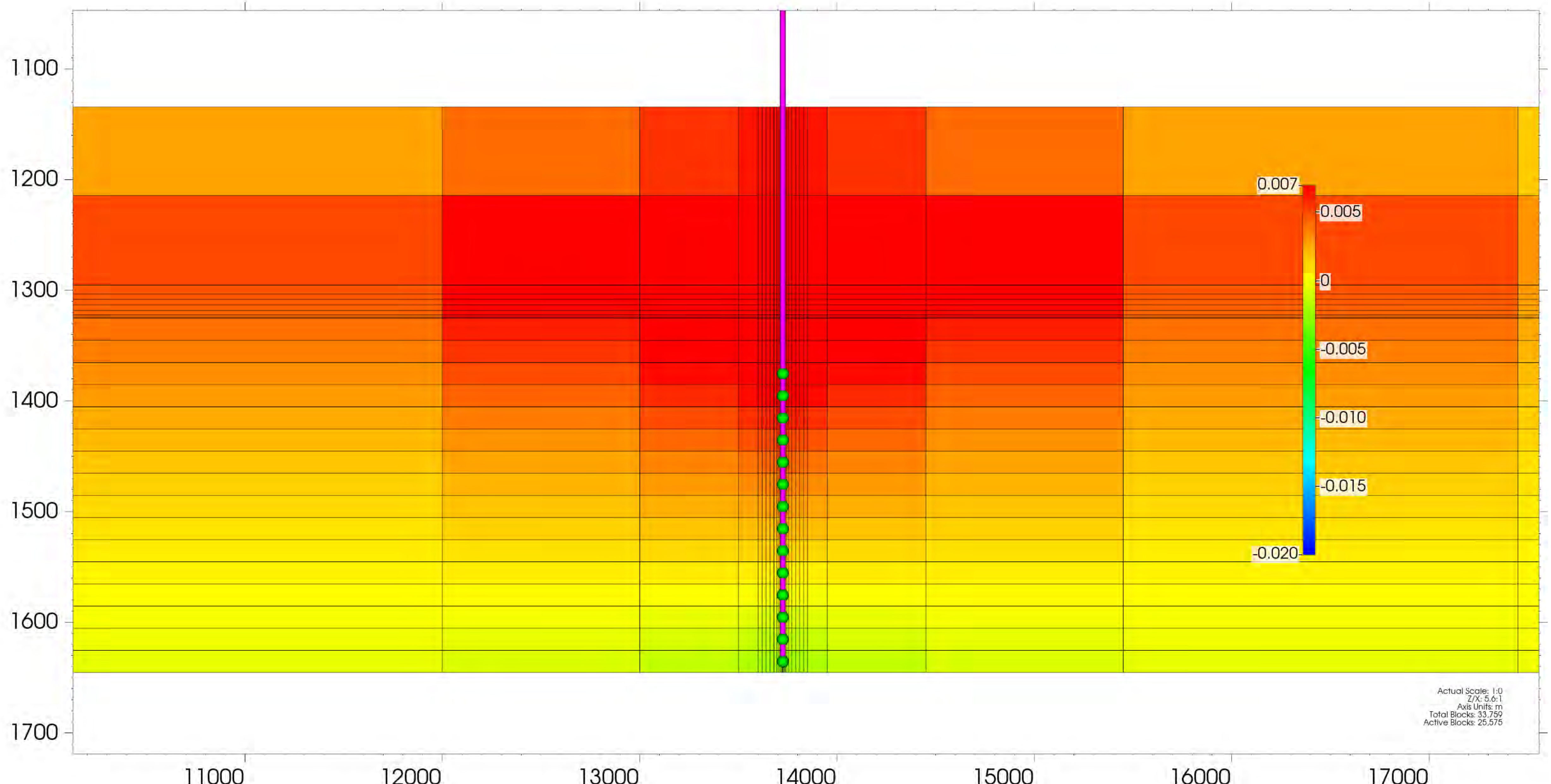
Case9: inject from Leduc, isothermal

Deformation (Uz) @ 5 years



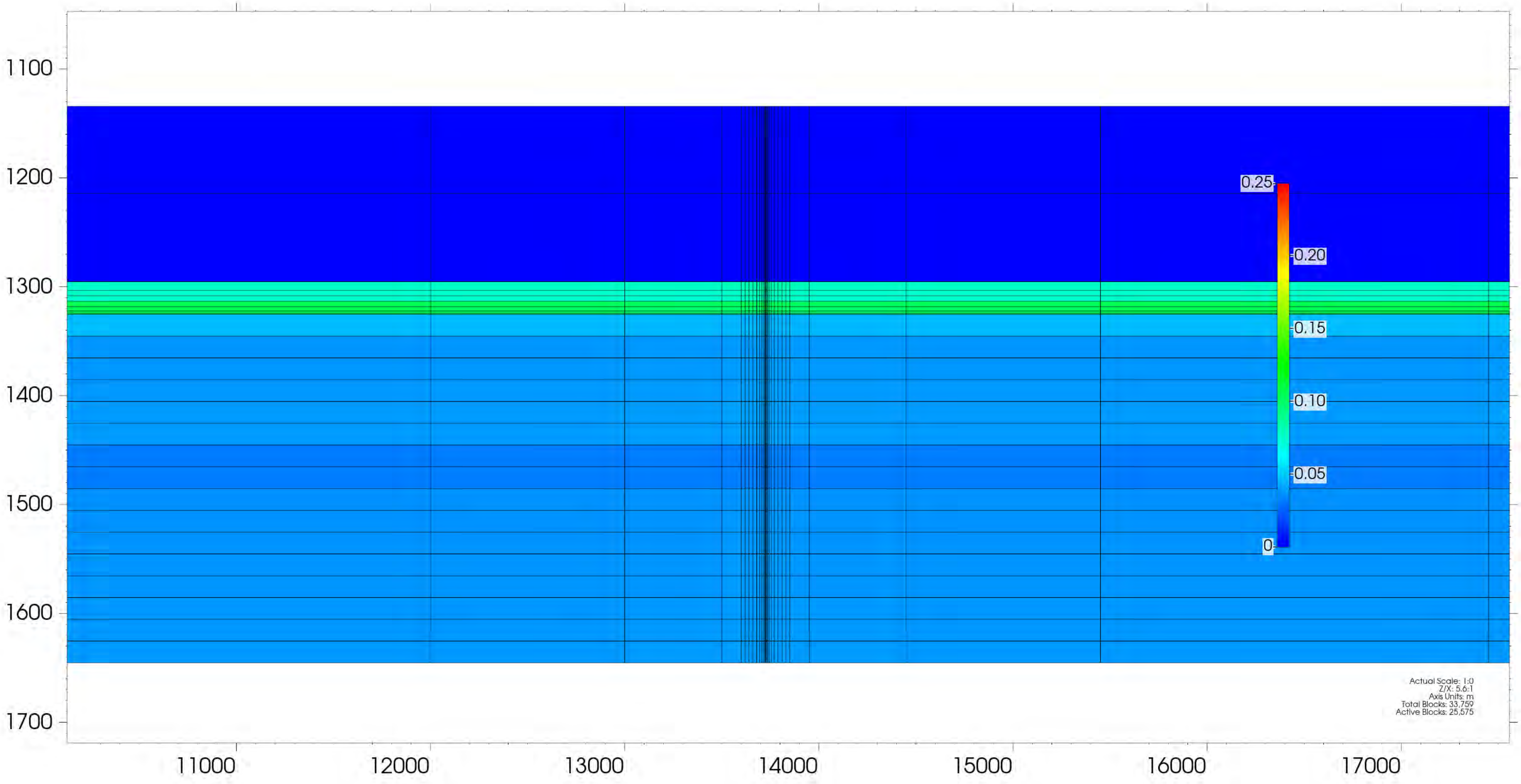
Case9: inject from Leduc, isothermal

Deformation (Uz) @ end of injection 15 years



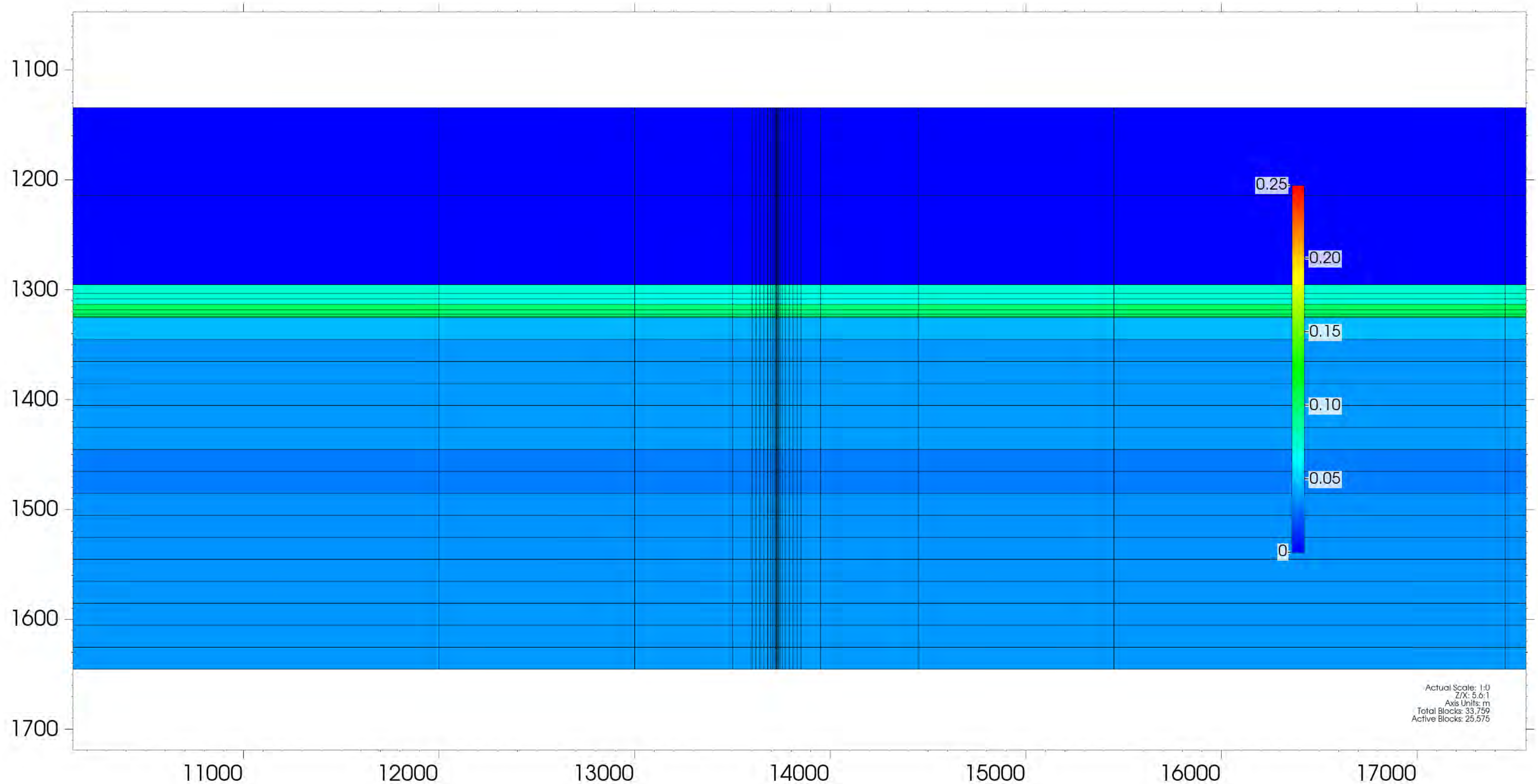
Case9: inject from Leduc, isothermal

SSL at lower Ireton, Leduc and Cooking lake @ 1 year



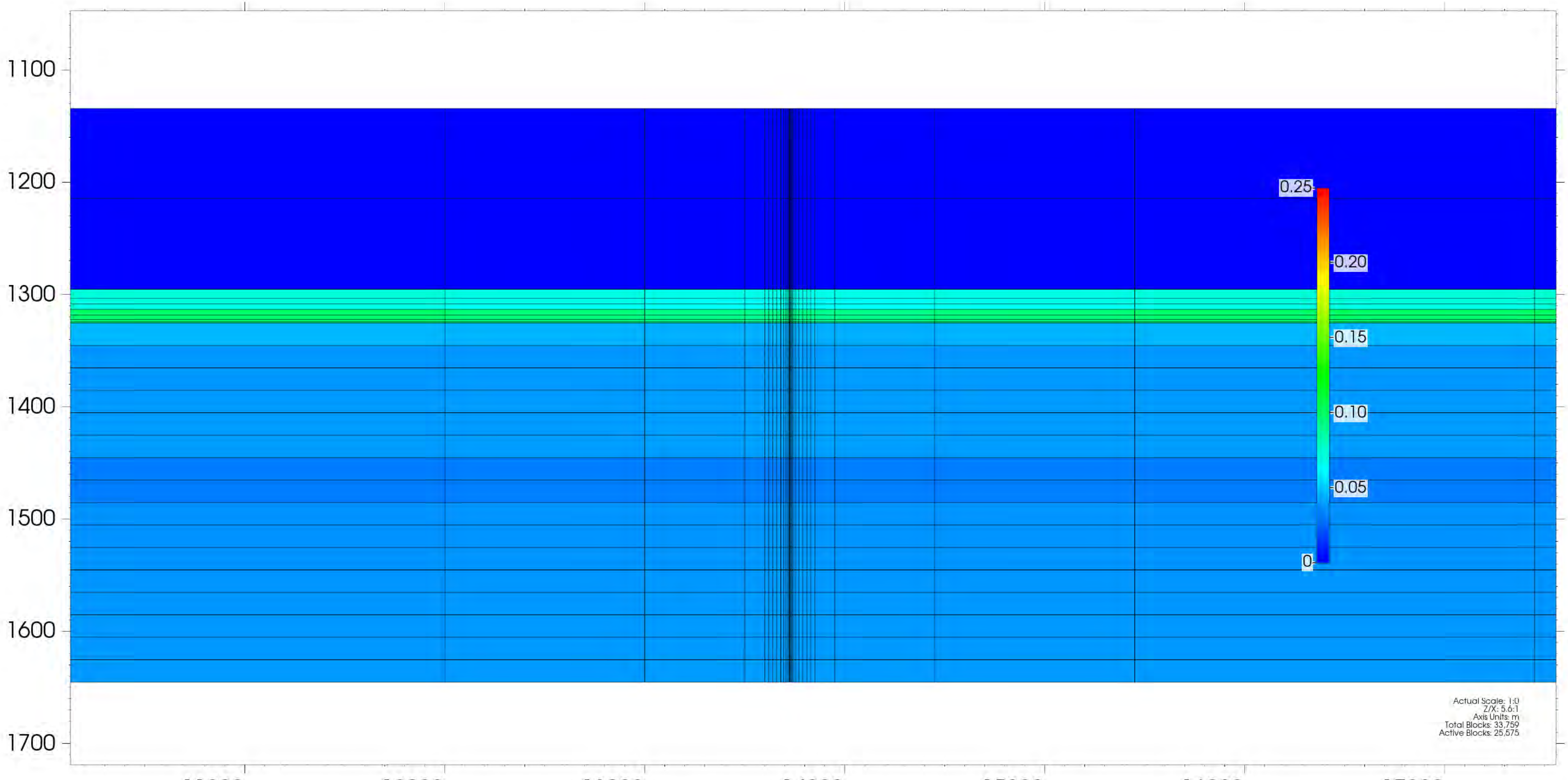
Case9: inject from Leduc, isothermal

SSL at lower Ireton, Leduc and Cooking lake @ 5 years



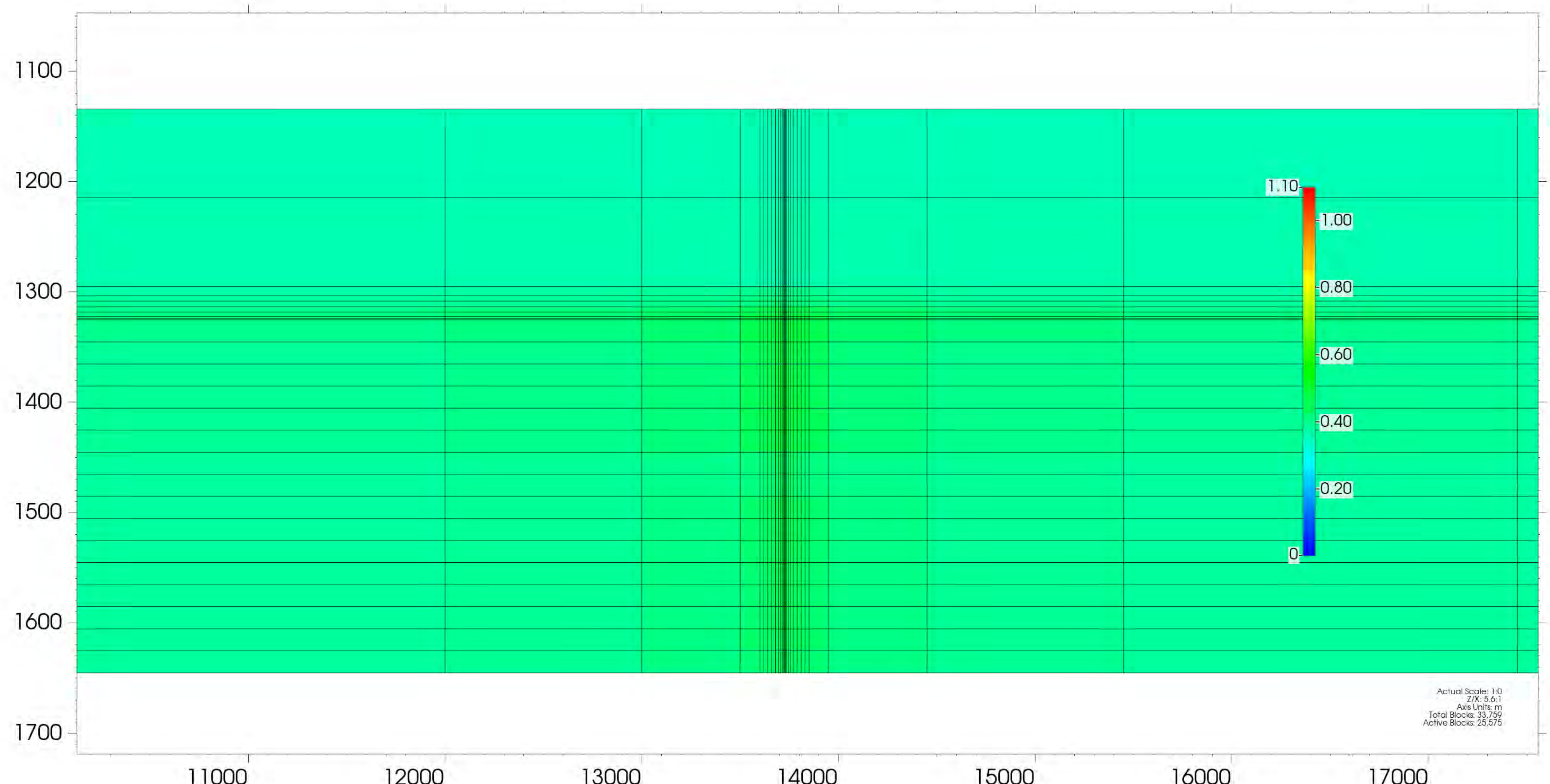
Case9: inject from Leduc, isothermal

SSL at lower Ireton, Leduc and Cooking lake @ 15 years



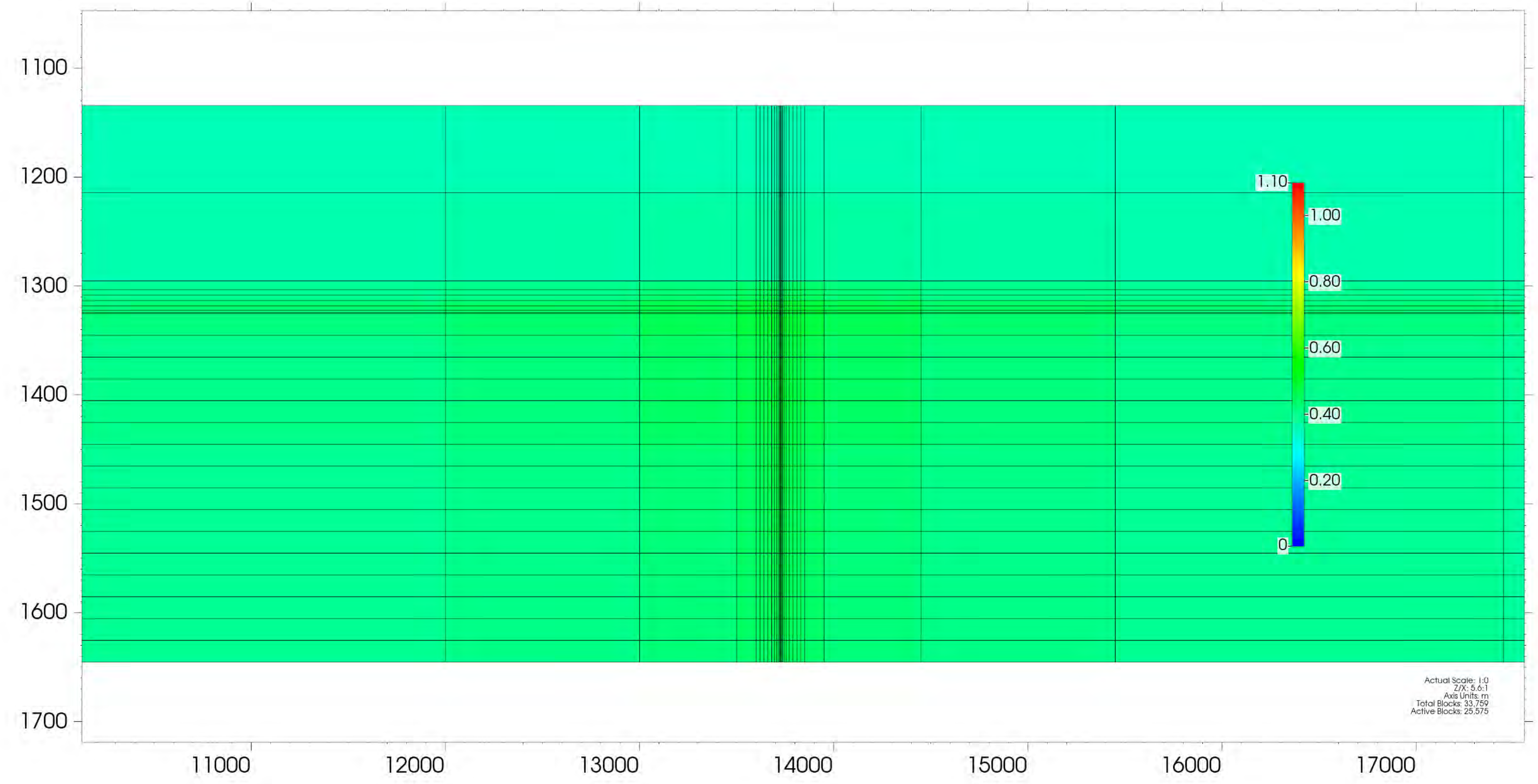
Case9: inject from Leduc, isothermal

TSL at lower Ireton, Leduc and Cooking lake @ 1 year



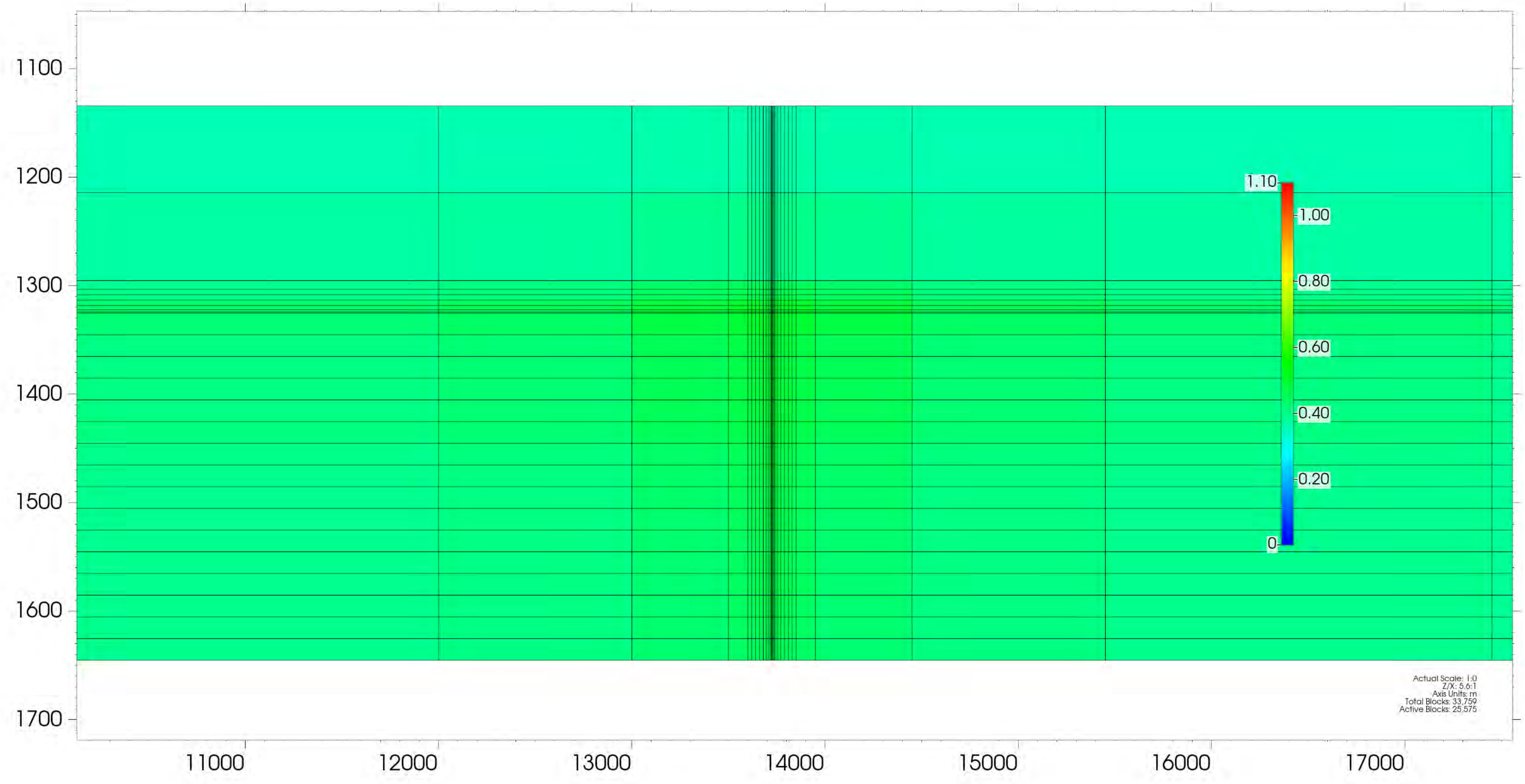
Case9: inject from Leduc, isothermal

TSL at lower Ireton, Leduc and Cooking lake @ 5 years



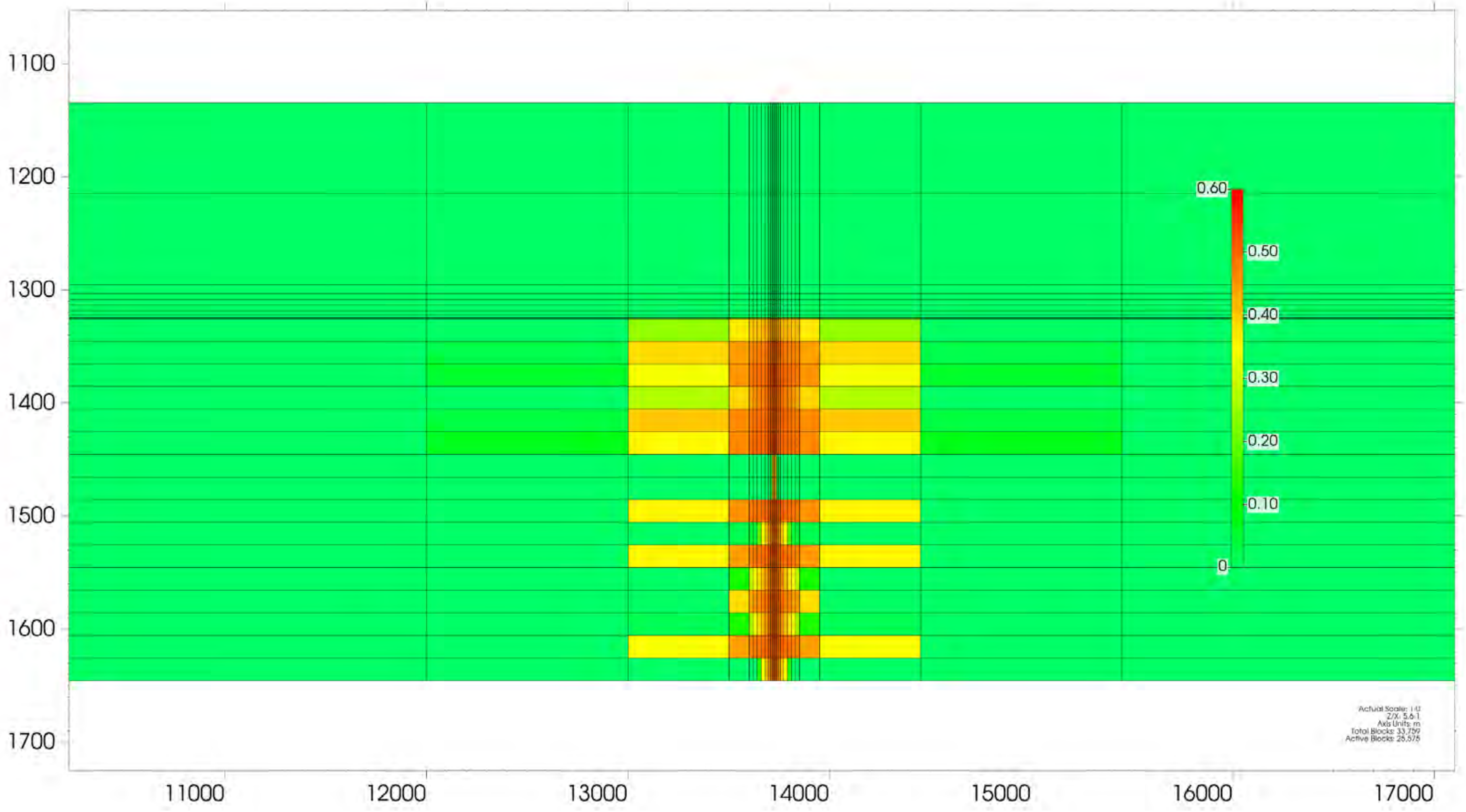
Case9: inject from Leduc, isothermal

TSL at lower Ireton, Leduc and Cooking lake @ end of injection 15 years



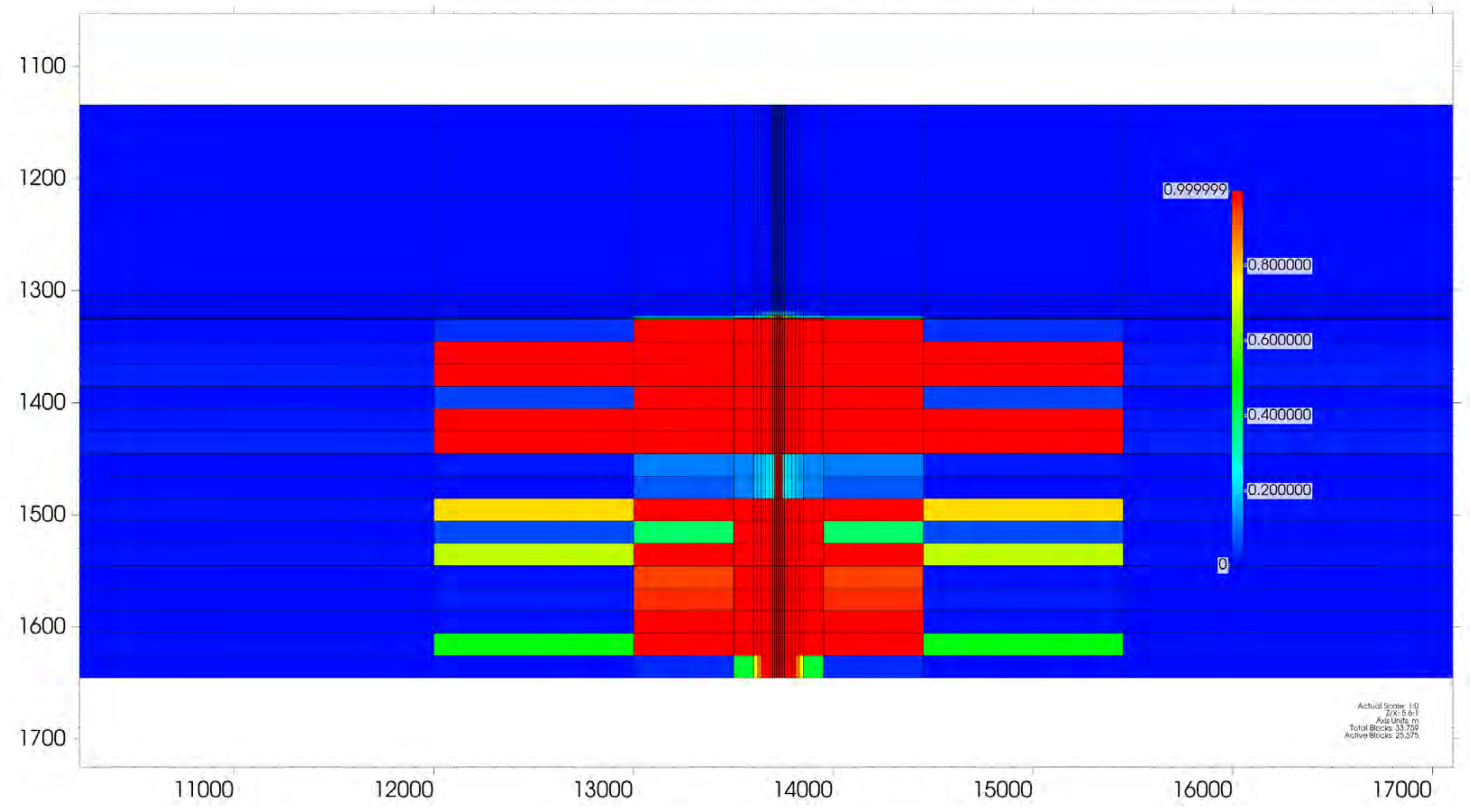
Case9: inject from Leduc, isothermal

Gas saturation @ 15 years



Case9: inject from Leduc, isothermal

CO2 Mole fraction@ 15 years

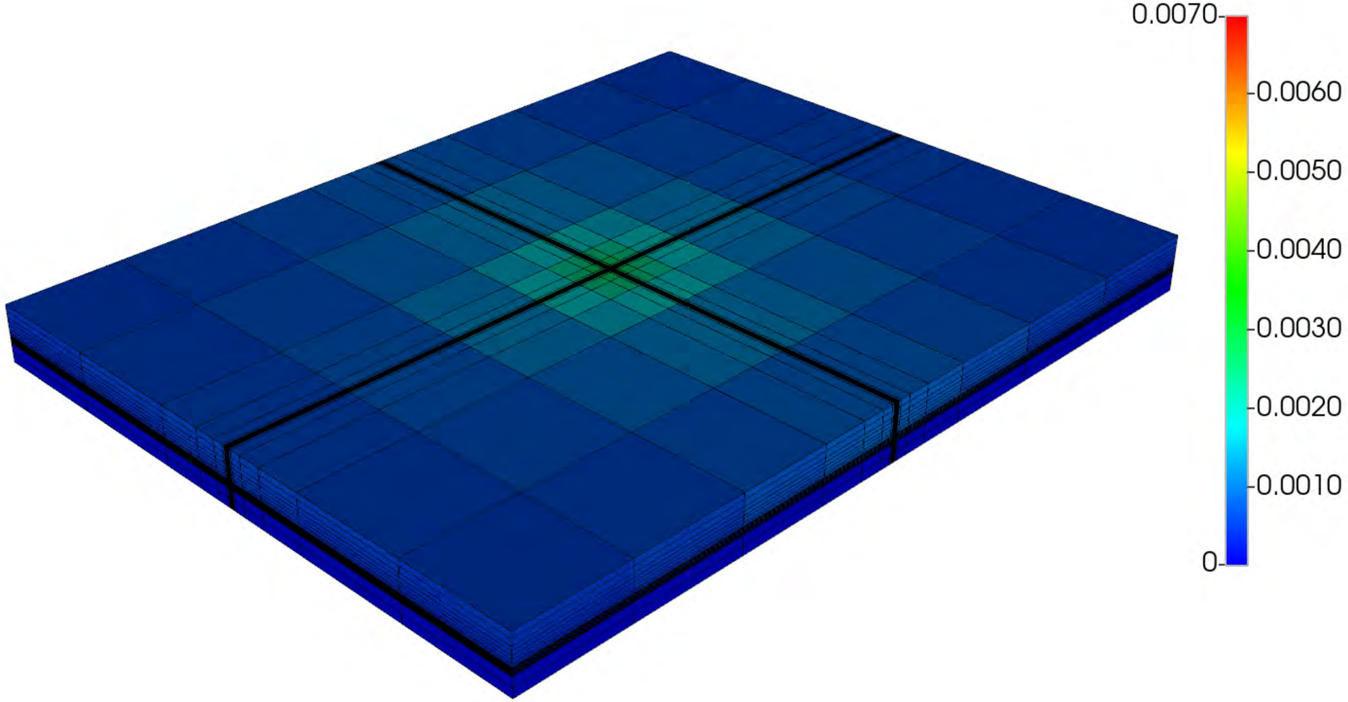


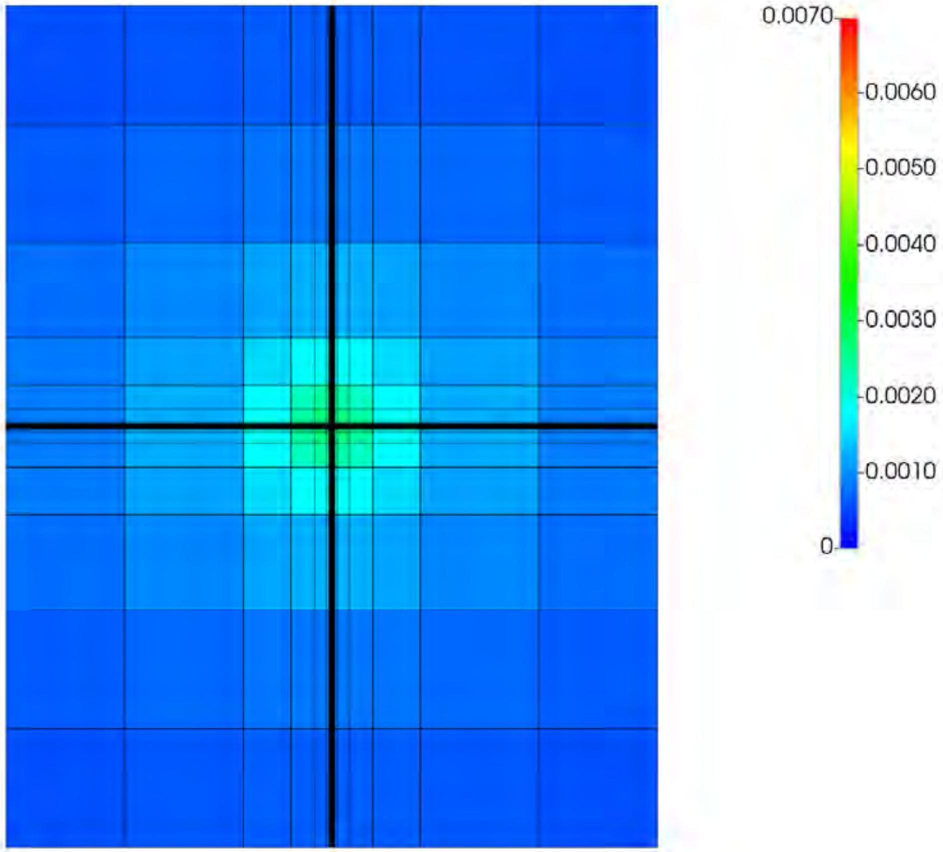
Case 9_1: Injection at Cooking Lake, Isothermal

Base case: Case1

Case9_1: inject from Cooking Lake, isothermal

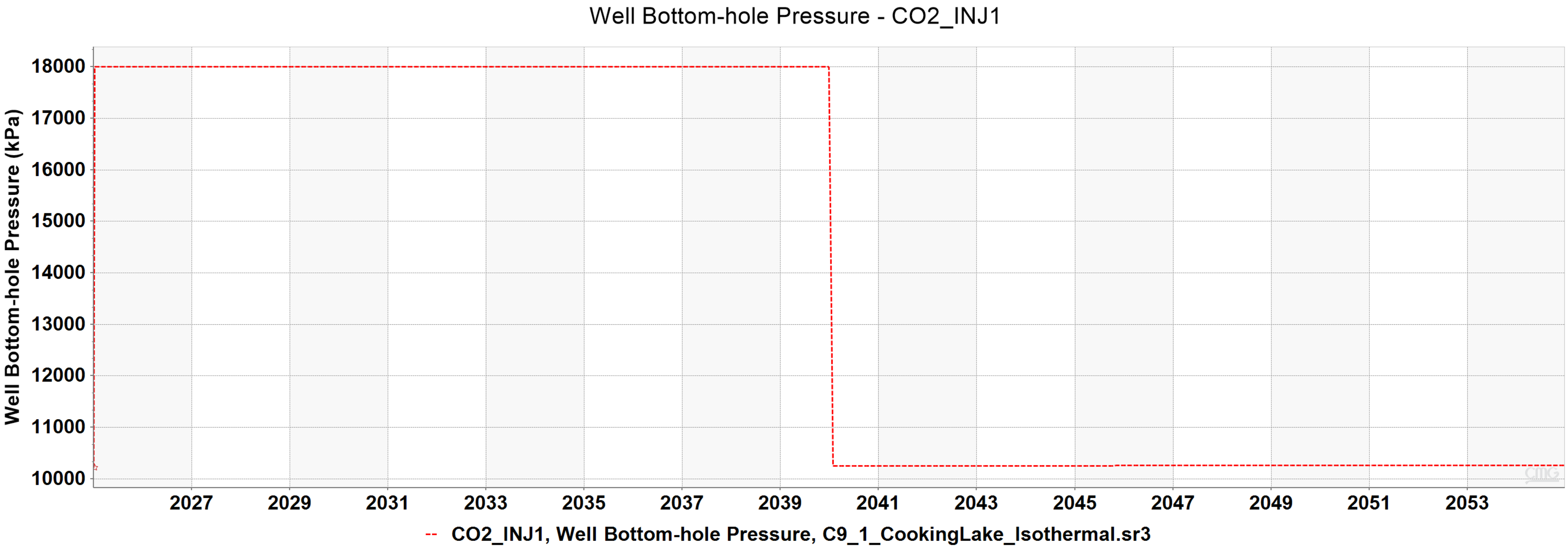
Surface heave @ end of injection 15 years (max. 7mm)





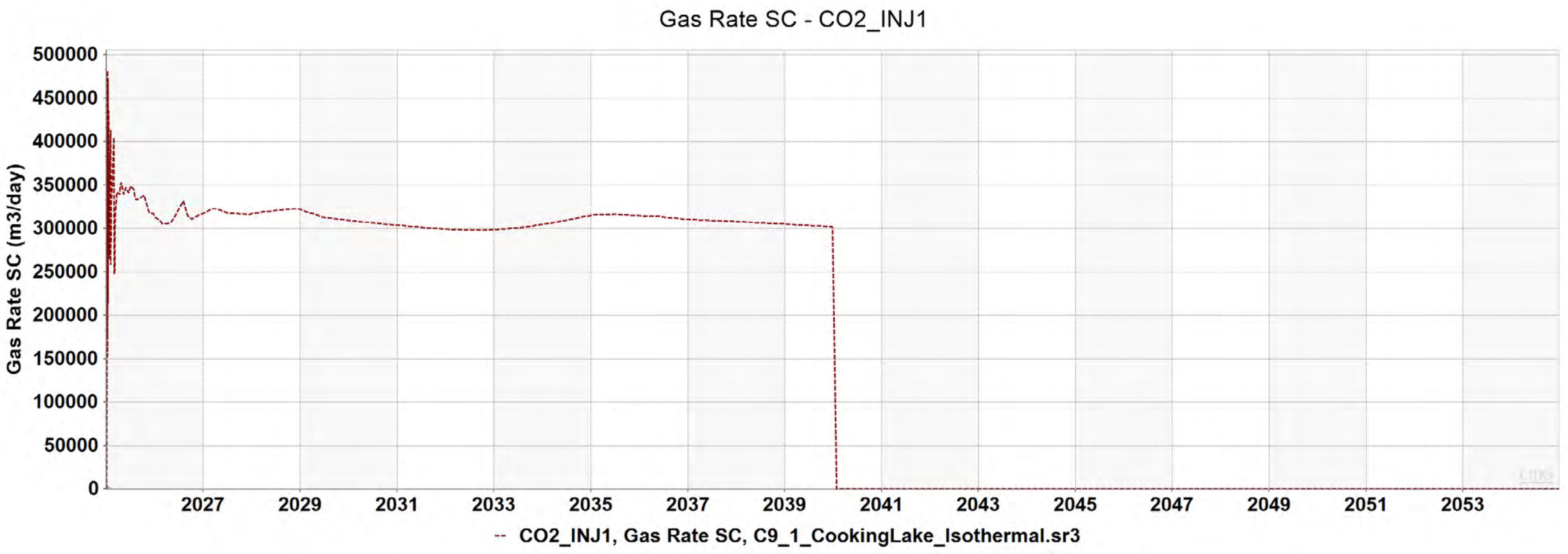
Case9_1: inject from Cooking Lake, isothermal

Injection pressure (BHP, unit: kPa)



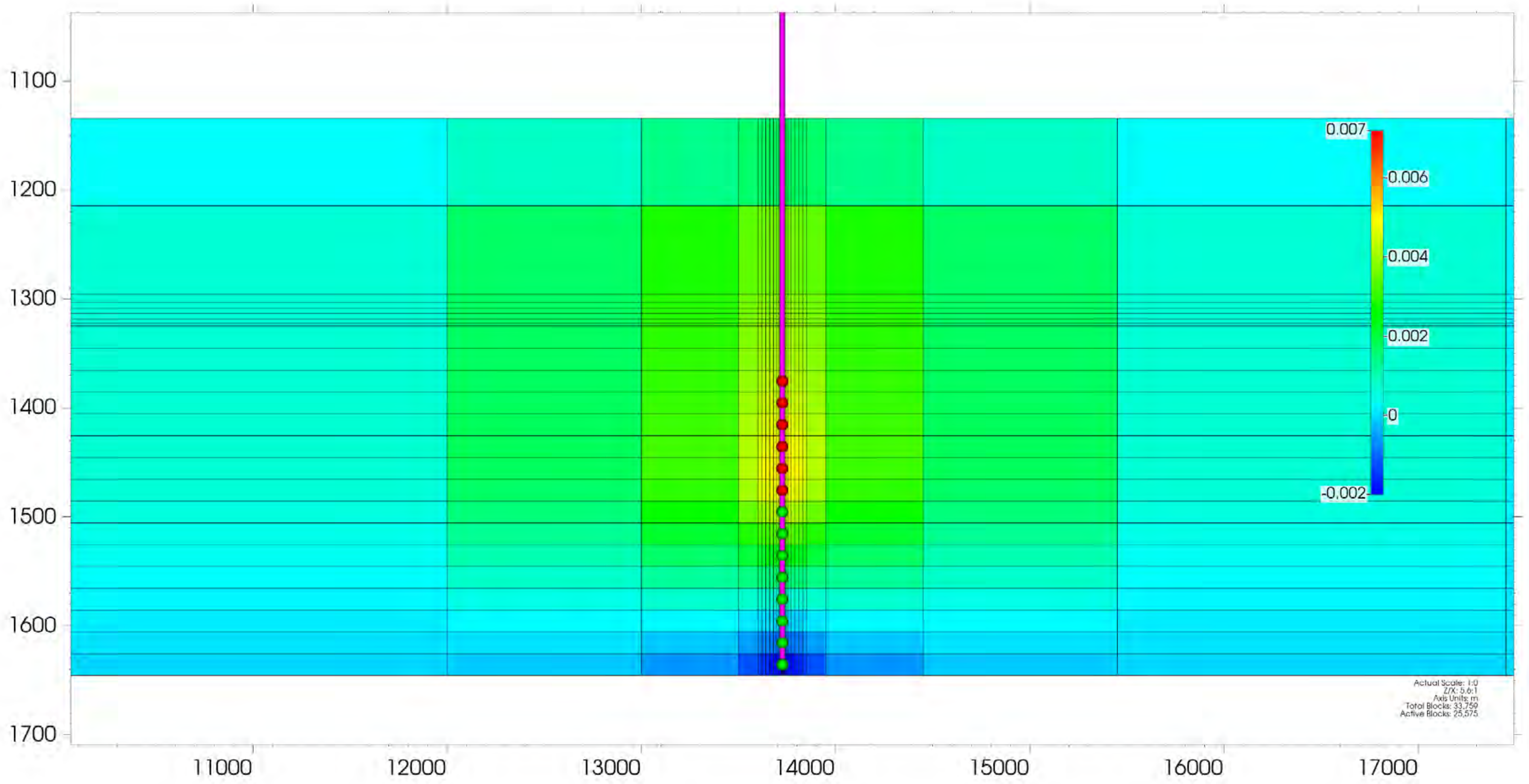
Case9_1: inject from Cooking Lake, isothermal

Injection rate



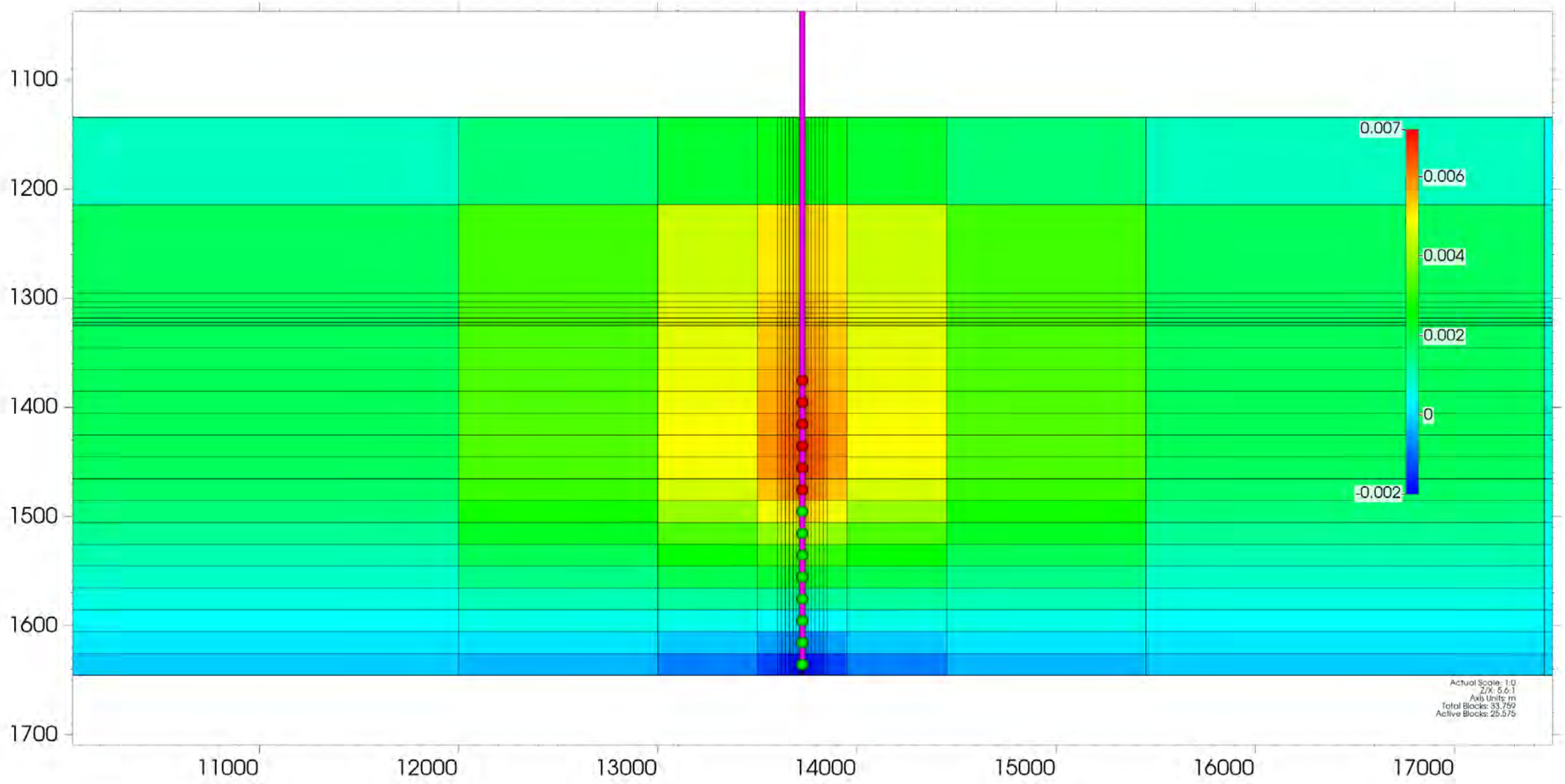
Case9_1: inject from Cooking Lake, isothermal

Deformation (Uz) @ 1 year



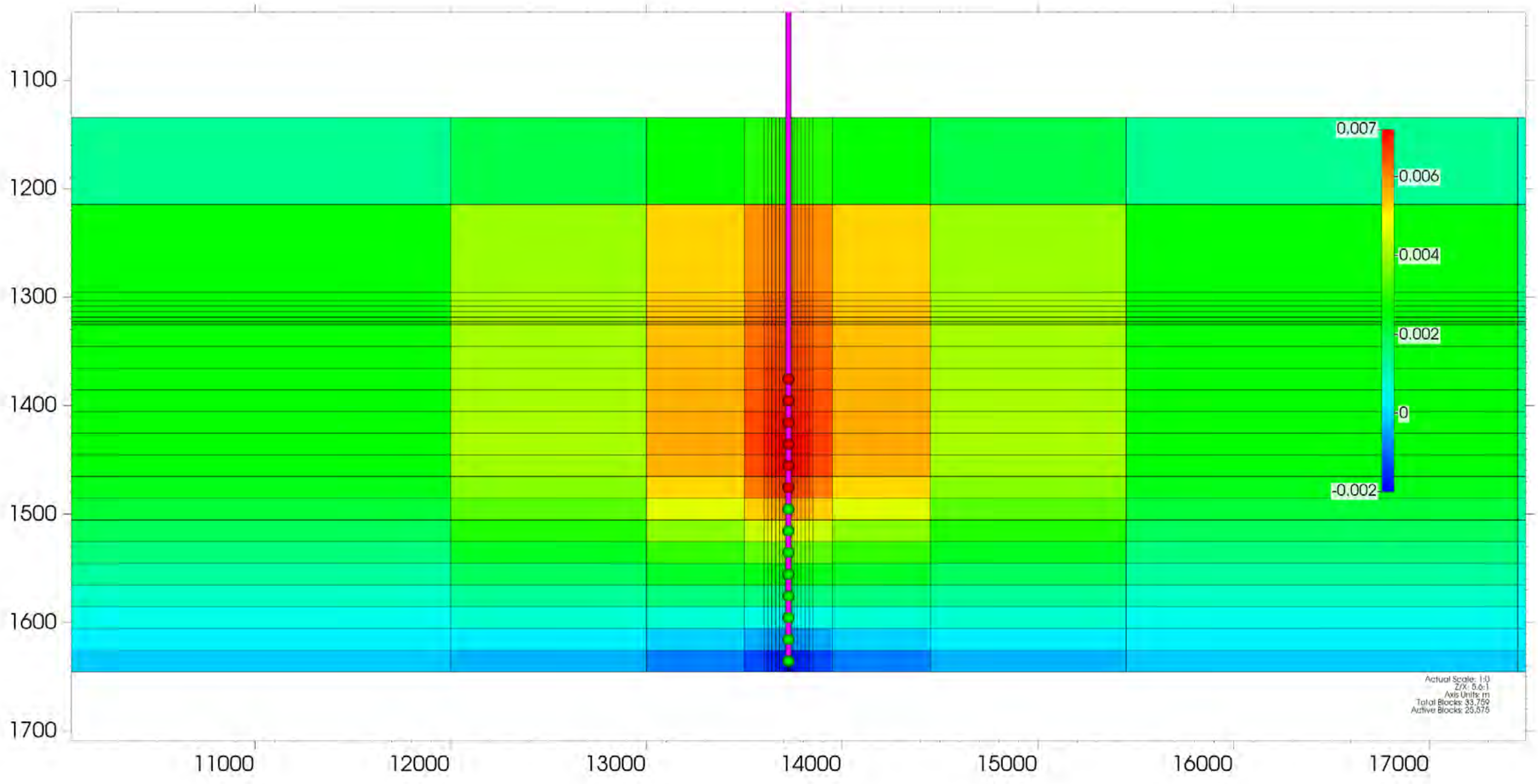
Case9_1: inject from Cooking Lake, isothermal

Deformation (Uz) @ 5 years



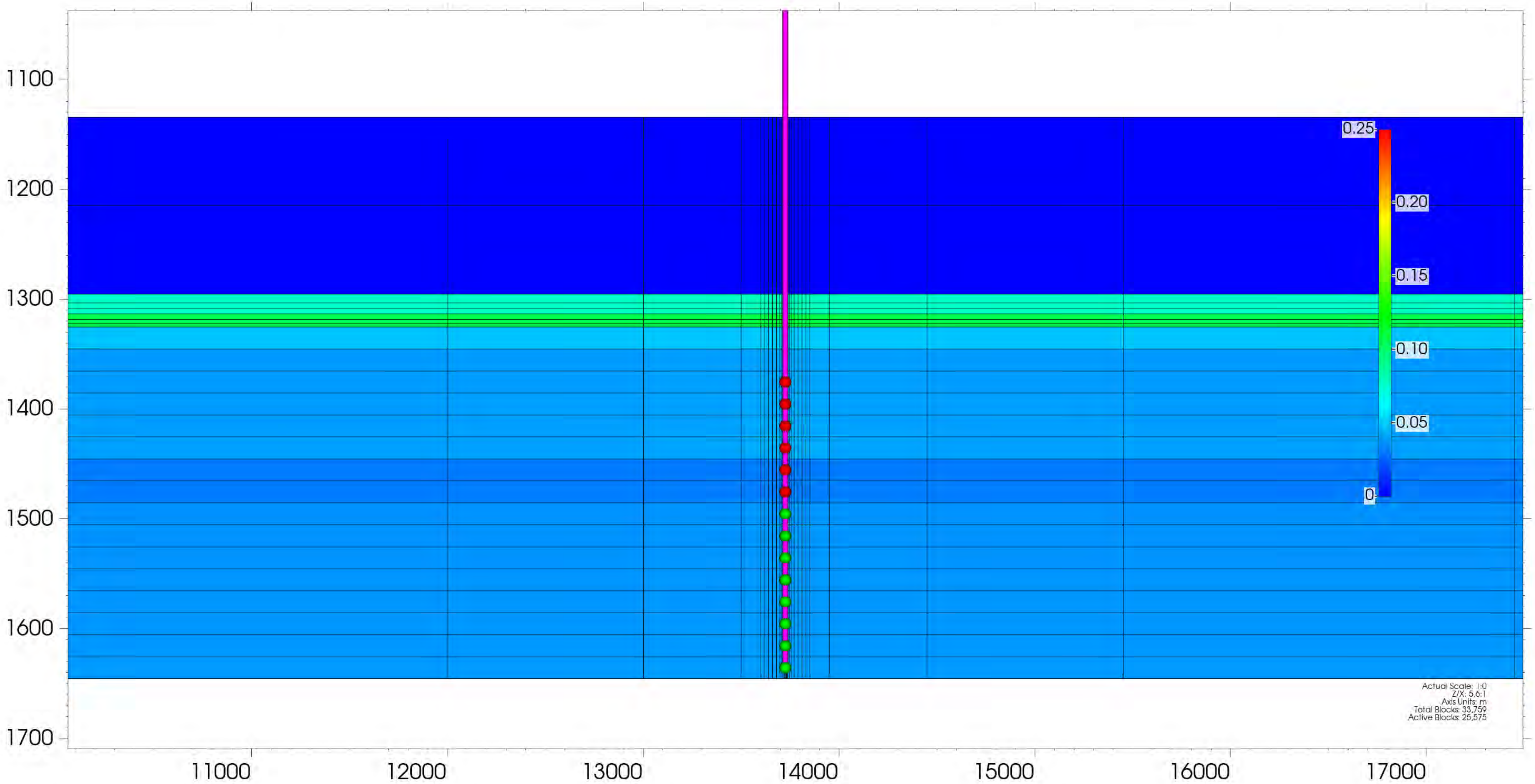
Case9: inject from Leduc, isothermal

Deformation (Uz) @ end of injection 15 years



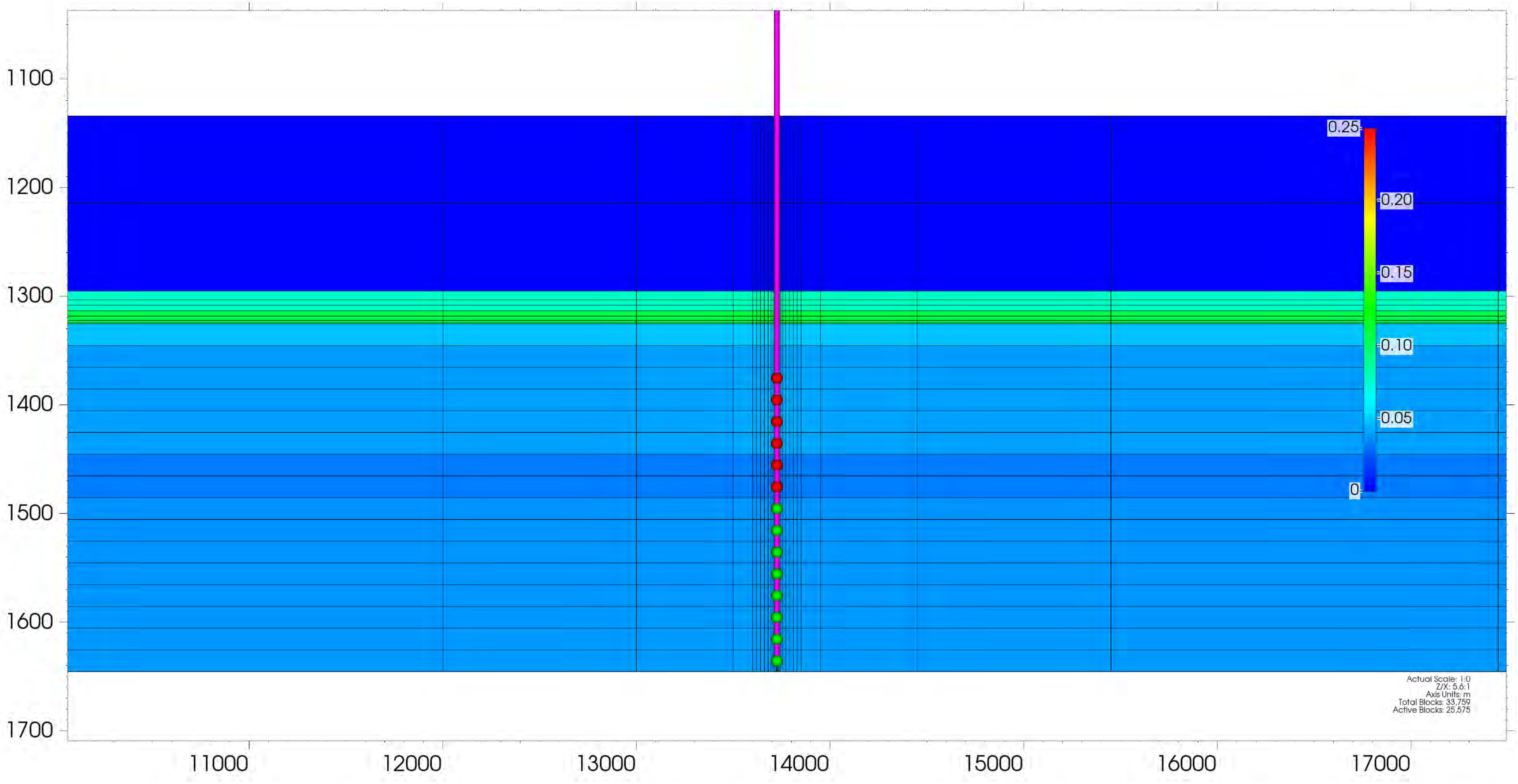
Case9_1: inject from Cooking Lake, isothermal

SSL at lower Ireton, Leduc and Cooking lake @ 1 year



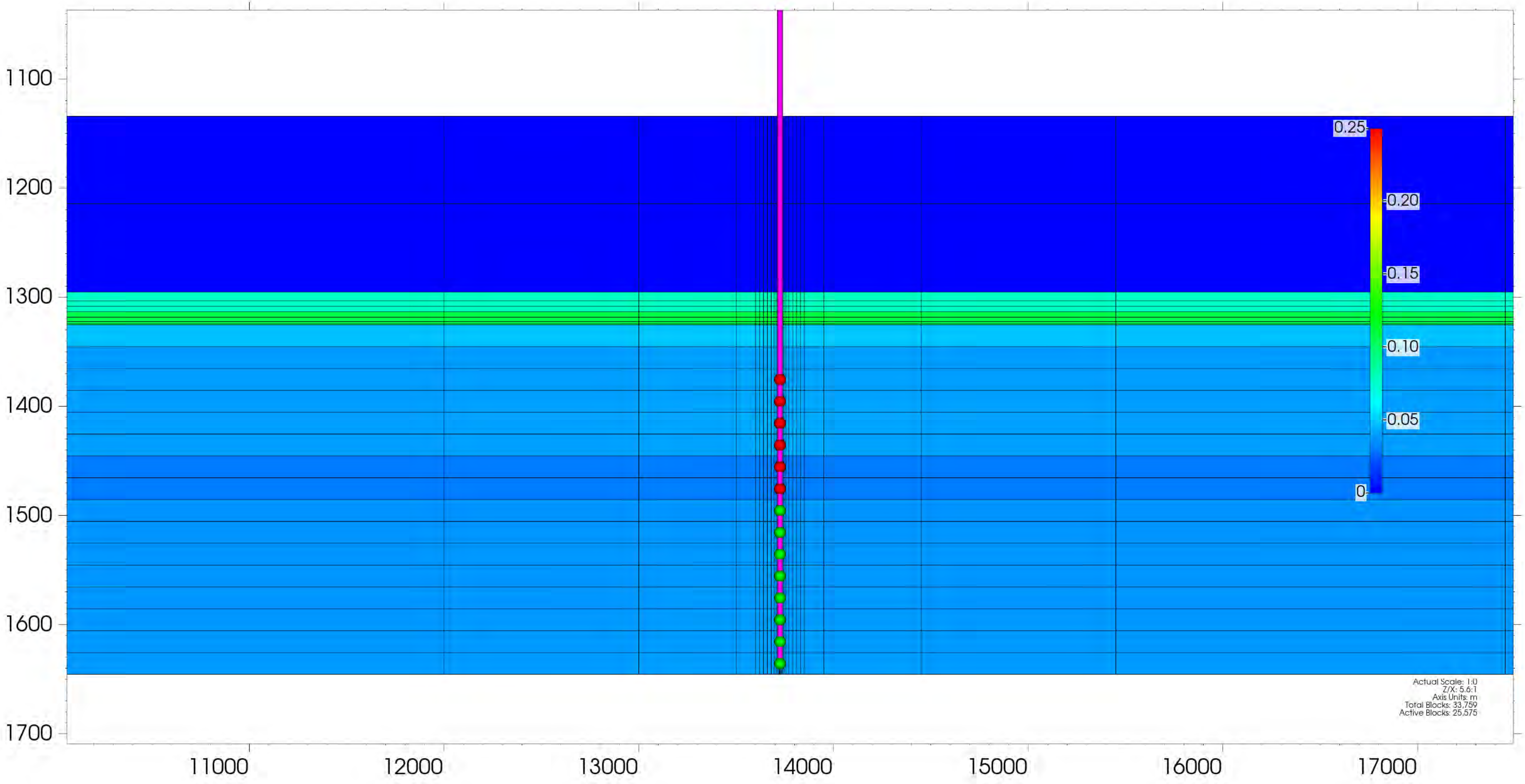
Case9_1: inject from Cooking Lake, isothermal

SSL at lower Ireton, Leduc and Cooking lake @ 5 years



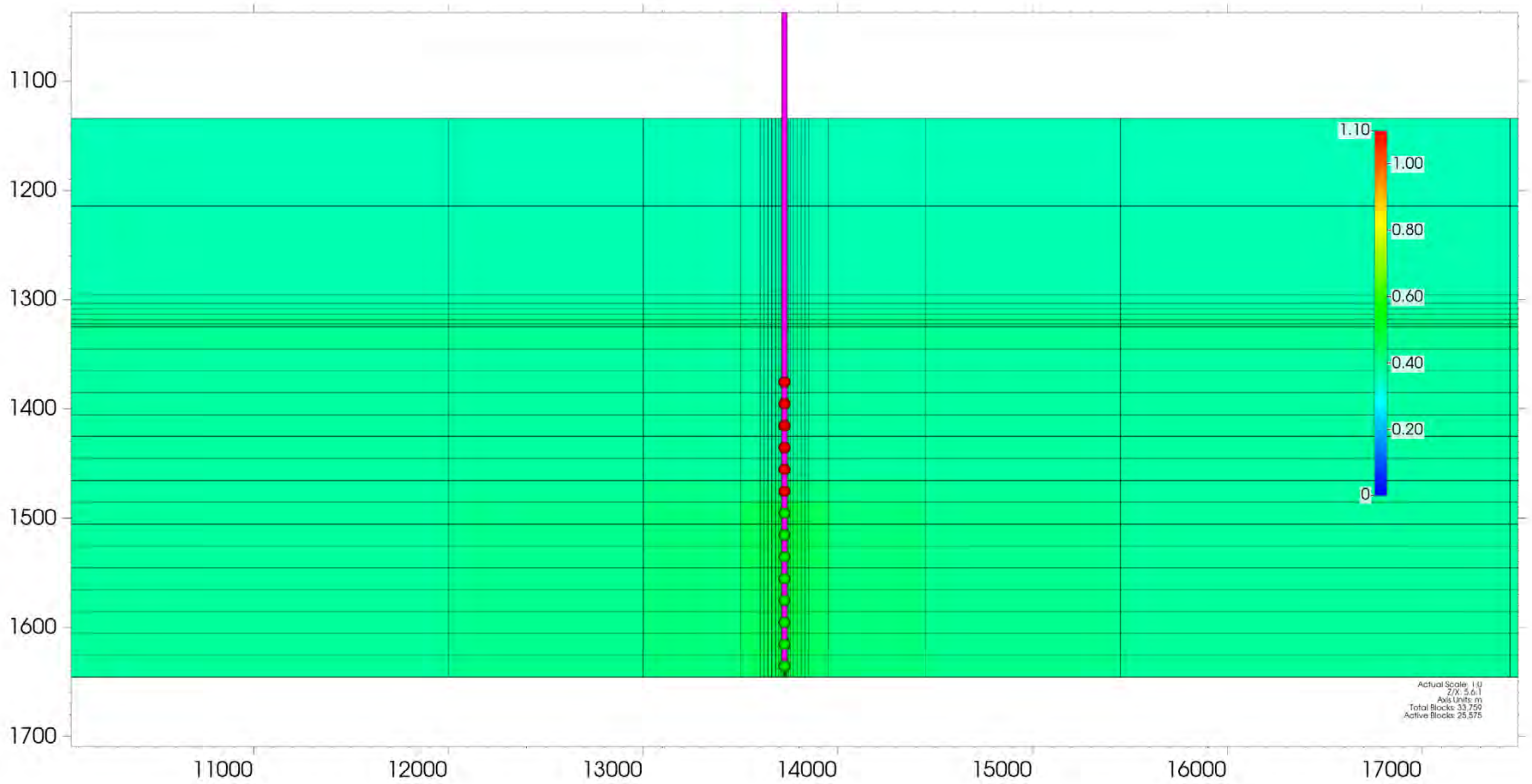
Case9_1: inject from Cooking Lake, isothermal

SSL at lower Ireton, Leduc and Cooking lake @ 15 years



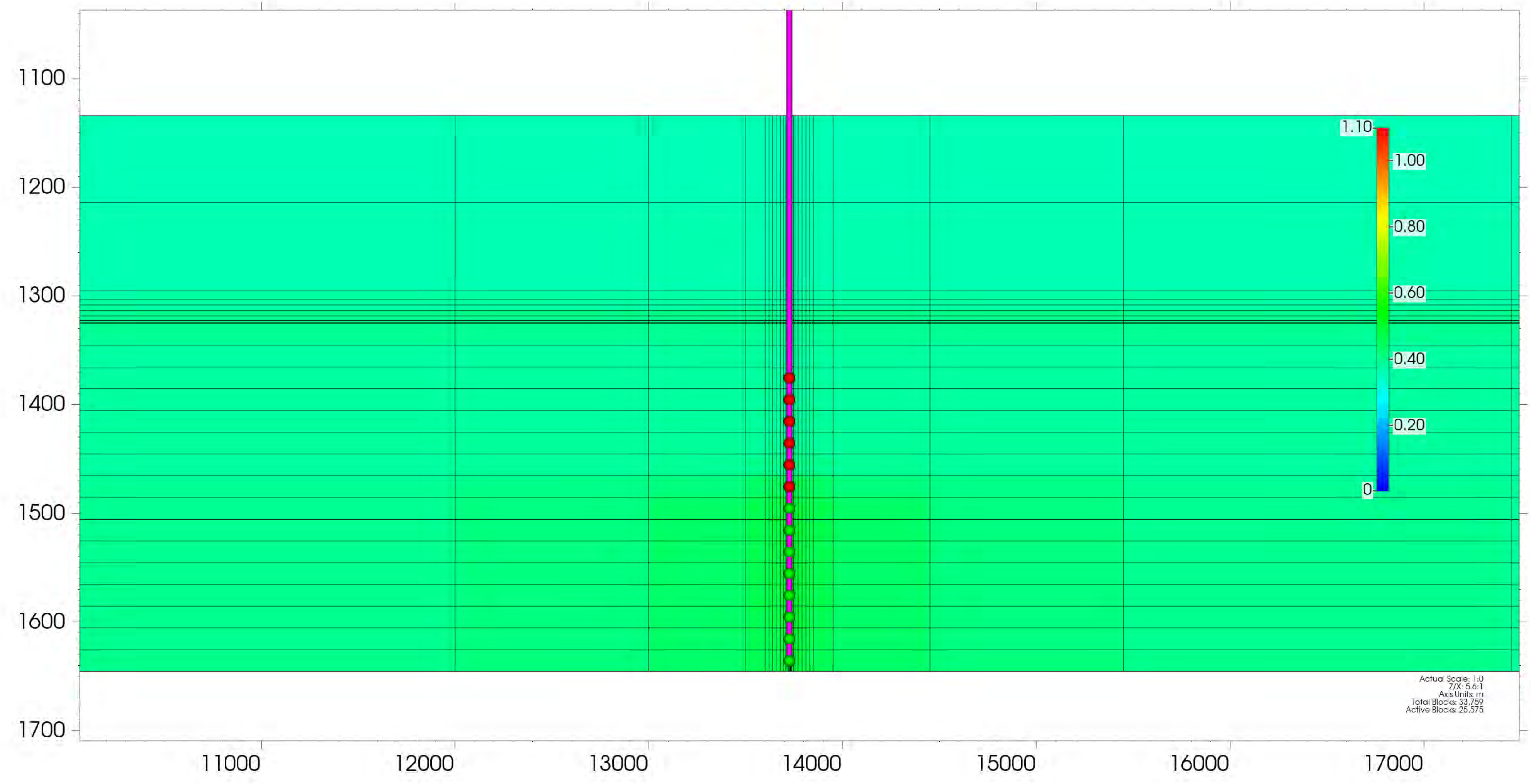
Case9_1: inject from Cooking Lake, isothermal

TSL at lower Ireton, Leduc and Cooking lake @ 1 year



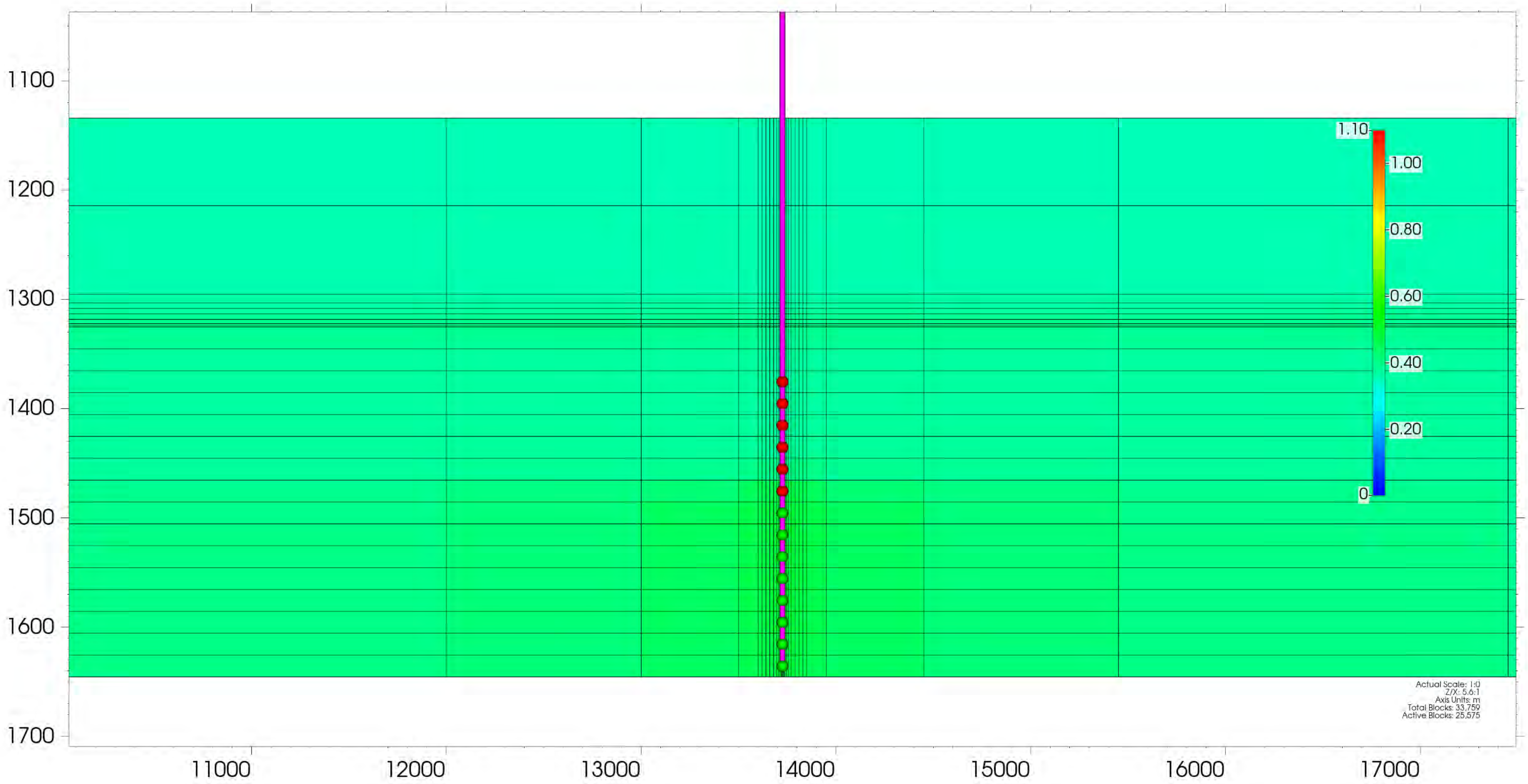
Case9_1: inject from Cooking Lake, isothermal

TSL at lower Ireton, Leduc and Cooking lake @ 5 years



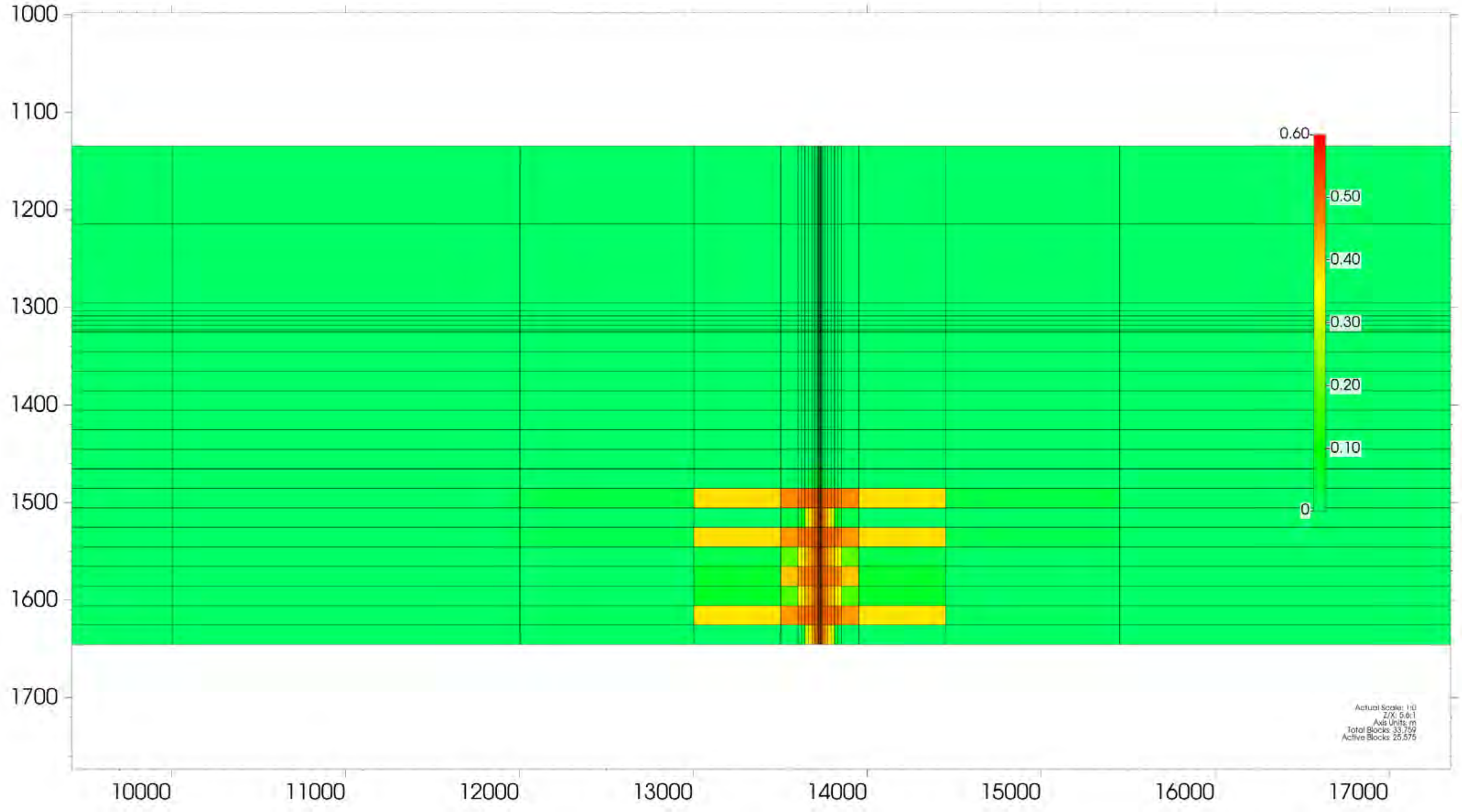
Case9_1: inject from Cooking Lake, isothermal

TSL at lower Ireton, Leduc and Cooking lake @ end of injection 15 years



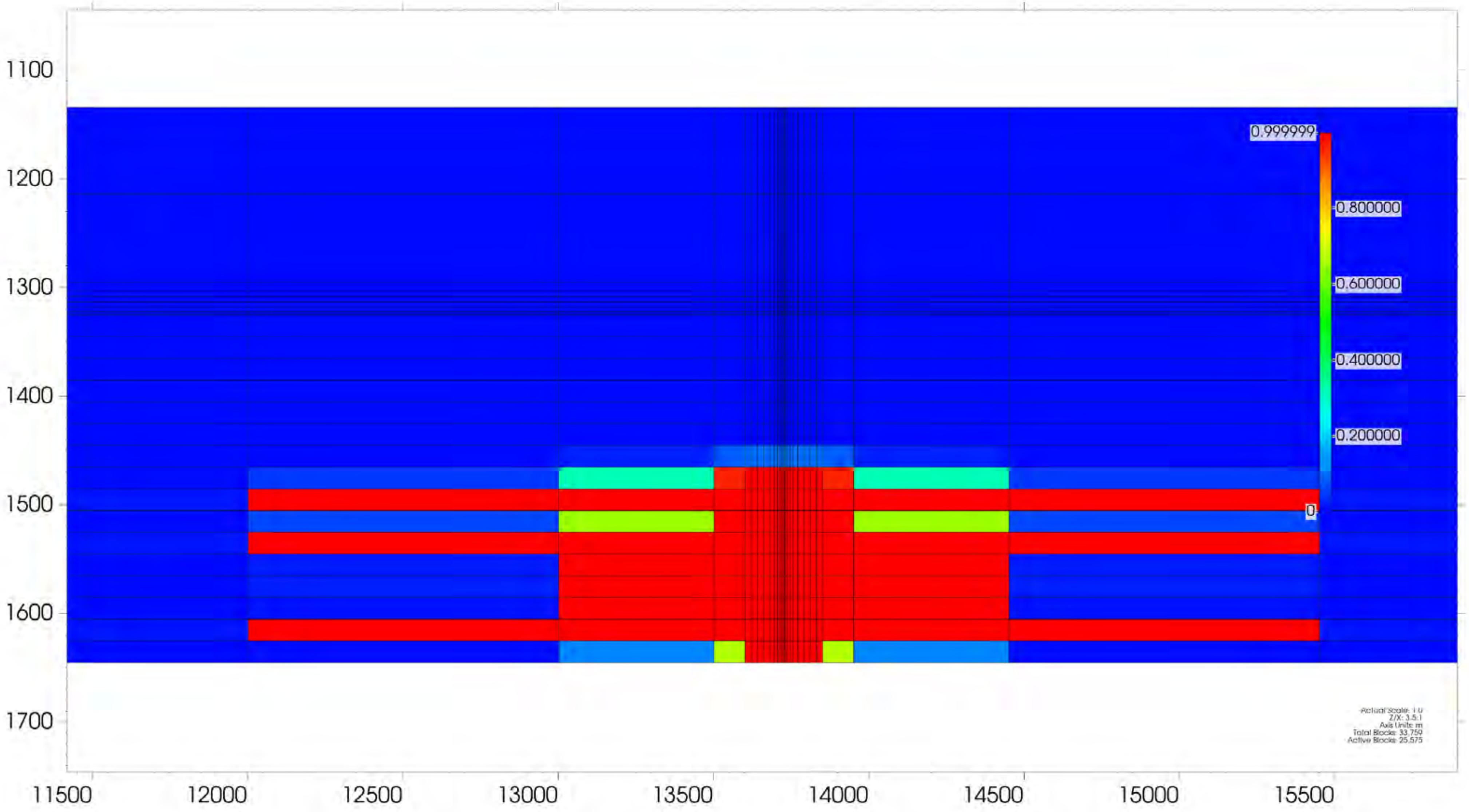
Case9_1: inject from Cooking Lake, isothermal

Gas saturation @ 15 years



Case9_1: inject from Cooking Lake, isothermal

CO2 Mole fraction@ 15 years



Appendix 11 – Mechanical Earth Model and Wellbore Stability Analysis

BISON LOW CARBON VENTURES INC.
BLCV LEGAL 16-29-57-25
Geomechanics Study

1D MEM (Mechanical Earth Model) & WBS (Wellbore Stability Analysis)

Nistha Mukherjee, Petrophysicist & Geomechanics Engineer &
Chandreyi Chatterjee, Senior Geomechanics Engineer

Peer-reviewed by
Safdar Khan, Senior Geomechanics Engineer
08 April 2024

Agenda

- → Summary
- → Recommendations
- → Introduction- Background & Objectives
- → 1D-MEM
  - – Workflow
  - – Data Audit
  - – Overburden Stress
  - – Mechanical Stratigraphy
  - – Pore Pressure
  - – Elastic Properties & Rock Strength
  - – Horizontal Stresses
  - – Wellbore Stability
- → Appendix

Summary- Mechanical Earth Model

→ A 1D-MEM is constructed which contains elastic properties, rock strength, pore pressure, and in-situ stresses (vertical stress, minimum and maximum horizontal stress) along the well profile BLCV LEGAL 16-29-57-25.

→ Lithology-based correlations were used for static elastic properties and rock strength.

- **Static Young's Modulus:** Eissa and Kazi correlation for **Clastics** with a multiplier of 1.15 and Sayers correlation for **Carbonates.**
- **Static Poisson's Ratio:** considered to be same as dynamic PR.
- **UCS:** DT-based Horsrud correlation with a 0.65 multiplier for Clastics and Chang's porosity-based for Carbonates
- **Tensile strength** as 10% of UCS
- **Friction Angle:** DT-based Lal's correlation with a multiplier of 0.9 for both Clastics and Carbonates

→ These properties were not calibrated due to lack of core data. However, regional published HARP model was used as a guide and integrated model was constrained with wellbore stability.

→ Pore pressure was calibrated with provided MDT results and the HARP model, which is sub-hydrostatic.

→ Horizontal stresses were calculated using poro-elastic horizontal strain method and calibrated to acoustics based Integrated Stress Analysis (ISA) and further constrained by the wellbore stability analysis calibrated to caliper and breakout observed from images. Stress- regime was found to be normal to strike slip.

Summary- Mechanical Earth Model

- To account for uncertainty in horizontal stresses, two sensitivity cases on tectonic strains and Biot's coefficient were run, Base-Case and Lower bound case.
  - Base-Case: Tectonic strains, Ehmin = 0.0001, Ehmax=0.00024, Biot's coefficient, Alpha = 1.0
  - Lower bound-case: Tectonic strains, Ehmin = 0.00005, Ehmax=0.0002 and Biot's coefficient, Alpha = 0.8
- The Clastics (Lea Park to Ellerslie) formation show softer, lower rock strength properties, higher tendency of shear failure and are in the normal stress-regime. Whereas the Carbonates, mainly dolomitic (Wabamun to Cooking Lake) are stiffer rocks with higher rock strength, tend to be in strike-slip stress regime which is inline with the observed regional wrench faults.

Observations- CO_2 storage standpoint

- → Leduc formation is targeted for CO_2 injection, Ireton is caprock.
- → Leduc formation has good porosity and possibly good injectivity (need to be confirmed with dynamic simulations).
- → Fracture gradient in injection zone is ~19.7 Kpa/m (Base Case) and 16.5 (Lower bound case). Proposed injection rate of 13 Kpa/m is way below the lower bound fracture gradient – doesn't pose any risk of fracturing while injection.
- → Fracture gradient in confining zone (Ireton caprock) is ~19.1 Kpa/m (Base Case) and 16.1 (Lower bound case) with high rock strength of 125 Mpa. Nisku formation above Ireton has even higher fracture gradient, 20.9 Kpa/m (Base case) and 17.5 Kpa/m (lower bound) which can act as an additional containment layer (secondary caprock). However, caprock integrity needs to be assessed with proposed injection plan dynamic simulation results (elevated pressure) against both tensile and shear failure.
- → Image log showed induced-fractures, mud weight used was low compared to fracture gradient, hence, induced-fractures couldn't be due to overbalance, possibly due to cooling effect (cold mud fluid into hot formation). There is a possibility of thermal fractures being created in injection zone due to cold CO_2 injection (formation cooling effect) which needs to be investigated with thermal stresses depending on the temperature of CO_2 being injected.
- → One of the key advantages of Ireton is that it has shaly section right above Leduc which can not only as act static seal (low perm) but also as being potential ductile zone which can anneal discontinuities and any inadvertent fractures extending into this zone from injection zone.

Recommendations

- → Geomechanical core testing is recommended to be able to calibrate elastic properties and rock strength.
- → Static Young's Modulus and Linear thermal expansion coefficient (LTEC) are two key parameters in calculation of thermal stress. These needs to be calibrated for more accurate thermal stress modeling which require core data.
- → Calibration of stress in injection zone as well as caprock is critical for caprock integrity and fault reactivation potential. It is recommended to acquire stress measurement via extended LOT or mini-frac.
- → Stresses and rock properties change due to injection of CO_2, these changes need to be evaluated with coupled reservoir-geomechanics simulations. Caprock integrity and fault reactivation potential should be assessed corresponding to post-injection pressure and temperature. It is recommended to run coupled reservoir-geomechanics simulations to estimate stress evolution with time or stress path.

Introduction

→ Well: BLCV LEGAL 16-29-57-25
→ Field: LEGAL
→ UWI: 103162905725W400

- Vertical well drilled in Eastern Alberta.

- The logged section encounters the Cooking lake, Lower Leduc, Leduc and Ireton in TD Section. Along with Nisku, Calmar, Blueridge, Graminia, Wabamun, Ellerslie, Ostracod, Glauconite, Manville, Joli Fou, Viking , Base Fish Scales, Second white specs, Colorado and Milk river.

- FMI and SonicScanner data aquisition
- Will be utilized to for characterizing Carbon capture and sequestration site.

Source: Google Earth

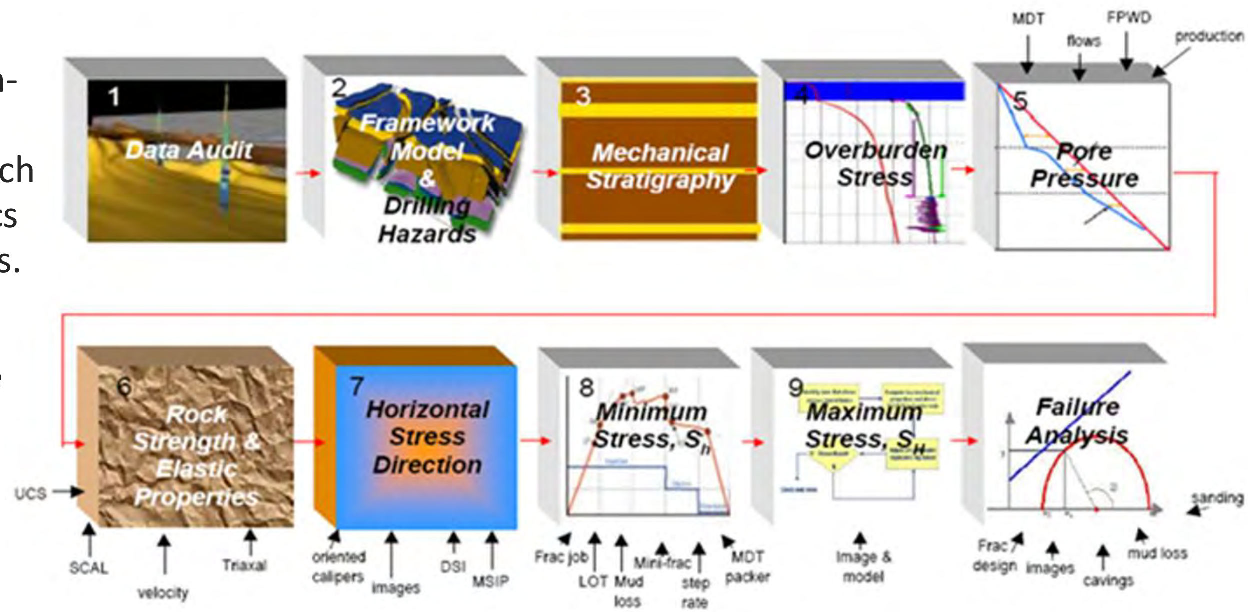
1D-MEM

→ 1D-MEM Workflow

MEM - Workflow

- A 1D-Mechanical Earth Model(MEM) is a numerical representation of the state of in-situ stress and rock mechanical properties along with other relevant information which forms the basis of all further geomechanics analyses such as Wellbore stability analysis.
- 1D-MEM was constructed for BLCV LEGAL 16-29-57-25 well, calibrated with pressure tests, and rock mechanical tests on cores following this 10-steps workflow.

Generalized workflow of 1D-MEM construction



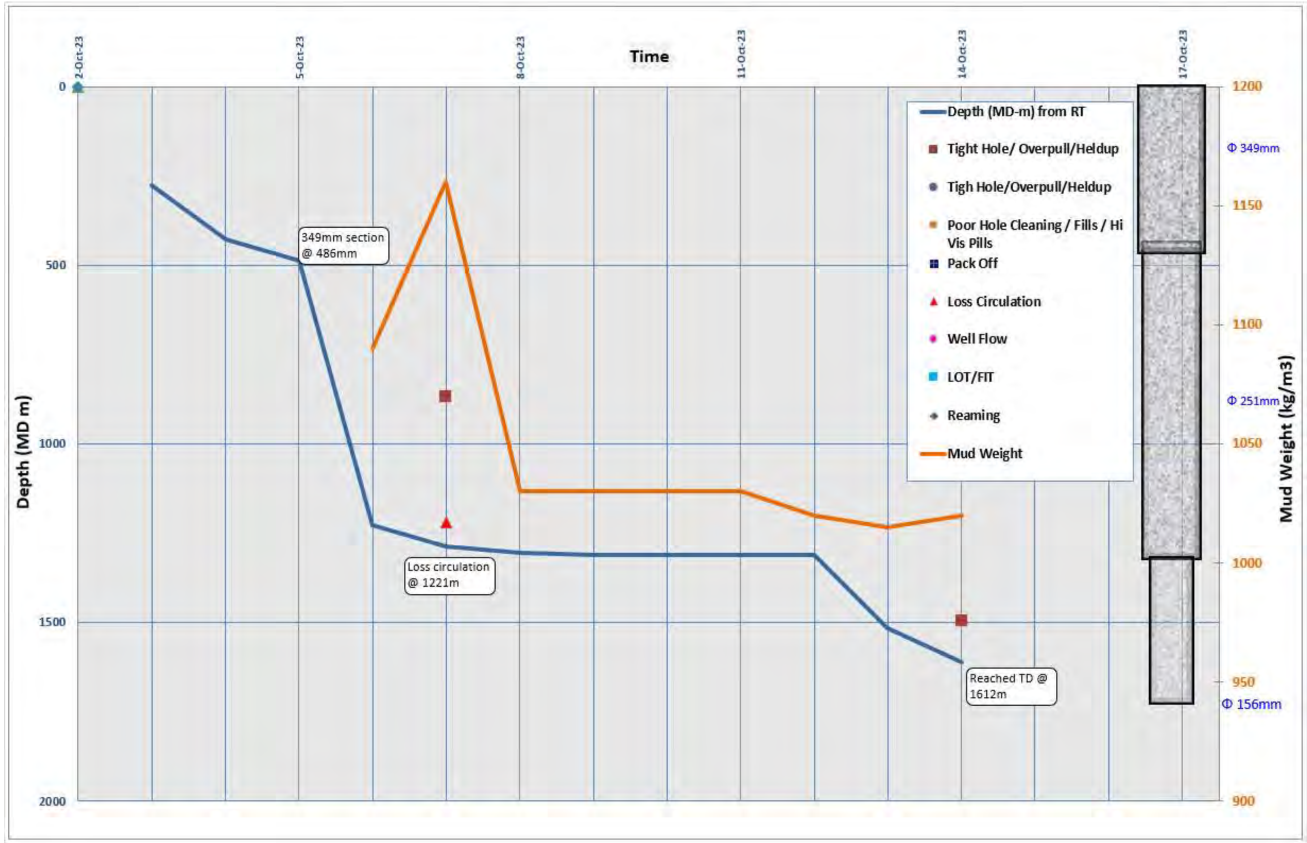
Data Audit- Data Availability

- All "must have" as well as additional "nice to have" data required for 1D-MEM of the well is present.
- An LOT test attempted but due to mechanical failure, test was aborted.

	Data requirement	Remarks		BLCV LEGAL 16-29-57-25
	Geology			
1)	Maps Showing location of offset wells	General Information	Good to have	Not Applicable
2)	Structure of Field and Fault Locations	General Information	Good to have	YES
3)	Mud logs	Calibration data	Mandatory	YES
4)	Formation Tops	Input for modeling	Mandatory	YES
5)	Regional Stress Information	Input for modeling	Mandatory	YES
	Formation Evaluation Data			
1)	Wireline and LWD logs including:			
	Resistivity	Input for modeling	Mandatory	YES
	Sonic DT Compressional	Input for modeling	Mandatory	YES
	Sonic DT Shear	Input for modeling	Mandatory	YES
	Density	Input for modeling	Mandatory	YES
2)	Formation Pressure data (RFT/MDT/StethoScope)	Calibration data	Mandatory	YES
3)	Well Test and production Data	Calibration data	Mandatory	YES
4)	Petrophysical Evaluation (Vshale, SW, and porosity)			
	Drilling Related Data			
1)	End Of Well Reports: Drilling Reports,	Validation	Mandatory	
	a) Drilling Reports,	Validation		YES
	b) Mud Reports	Calibration data		YES
	c) Casing and cementing reports			YES
2)	Leak-Off Tests			
	a) Leak-Off Tests	Calibration data		YES
	d) Formation Integrity Tests	Calibration data		YES
	e) Pressure-Time records of these tests (if available)	Calibration data	Mandatory	YES
3)	Directional Surveys	Input for modeling	Mandatory	YES

Time vs Depth Plot (Drilling events)

- Time v/s depth plot constructed to get an idea of drilling events along drilled depth.
- The well was spudded on Oct 2, 2023, and TD reached on Oct 14, 2023.
- Among the geomechanical issues encountered were tight spots & losses.
  - Tight spots observed during POOH @869m
  - Losses encountered at 1221m (possibly due to vuggy porosity in this section, not due to high MW)



Overburden Stress Computation

→ Overburden Stress Principle

→ Overburden Stress Computation

Overburden Stress

- Overburden stress, also called vertical stress, is induced by the weight of the overlying formations.
- If the overlying formations have an average density of ρ_a, then the overburden stress can be calculated by:

$$\sigma_v = \rho_a g z$$

where g is the acceleration due to gravity.

- If density varies with depth, the vertical stress can be calculated by integration of rock densities from the surface to the depth of interest, z, i.e.:

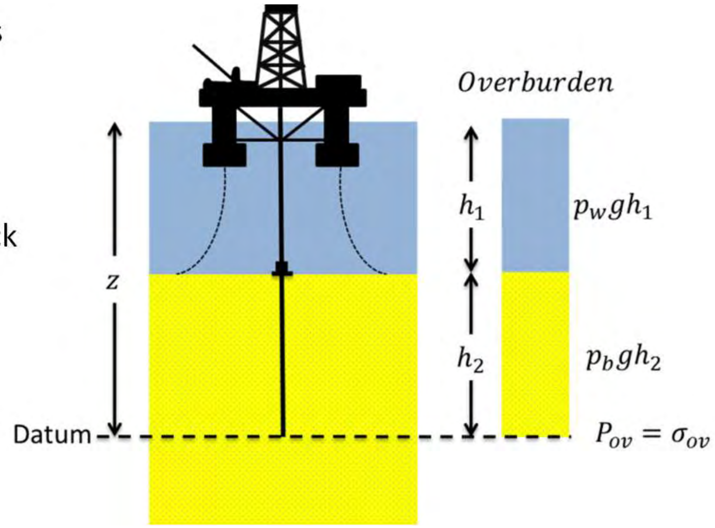
$$\sigma_v = \int_0^z \rho_b(z) g \, \mathrm{d}z$$

where $\rho_b(z)$ is the rock density as a function of depth.

- In offshore areas, water depth (z_w) needs to be considered to calculate the vertical stress, that is:

$$\sigma_v = \rho_w g z_w + \int_{z_w}^{z} \rho_b(z) g \, \mathrm{d}z$$

where ρ_w is the density of water.

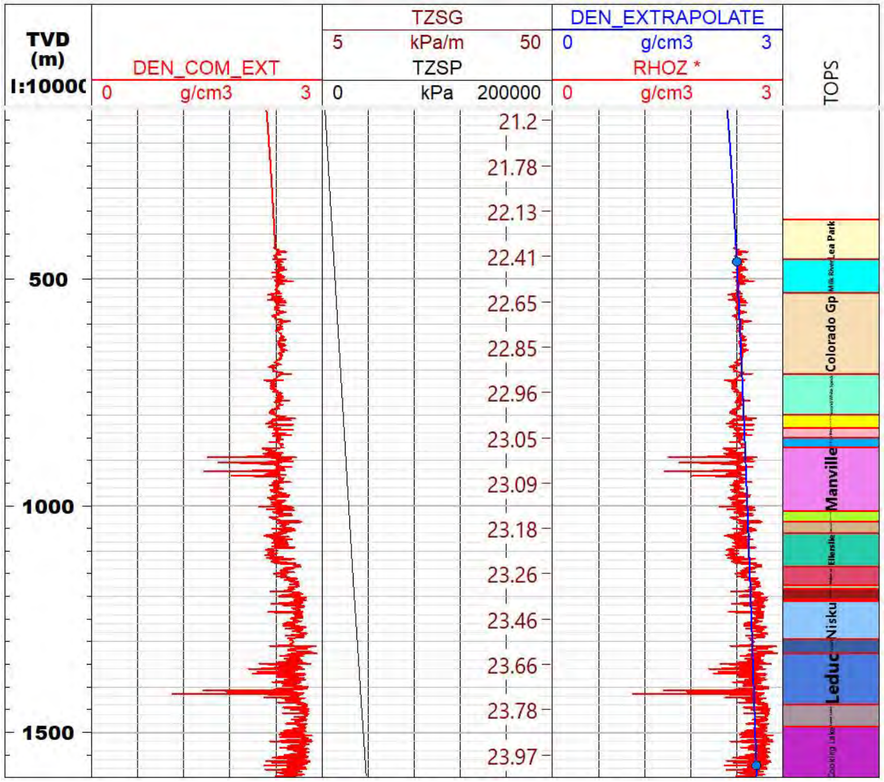


Overburden Stress

- Since the bulk density log is present from LEA Park formation, the density log has to be extrapolated to the mudline.
- The extrapolated density curve is generated using the following formula:

$$\rho_{extrapolated} = \rho_{mudline} + A_0(TVD - Airgap - WaterDepth)^{\alpha}$$

  - where $\rho_{mudline}$ is the density at the shallowest point (mudline) ; A_0 and α are fitting parameters.
- Mudline density ~ 2180 kg/m3
- This density extrapolation method was used to calculate the overburden stress.
- Overburden stress gradient at Leduc ~ 23.5 kPa/m

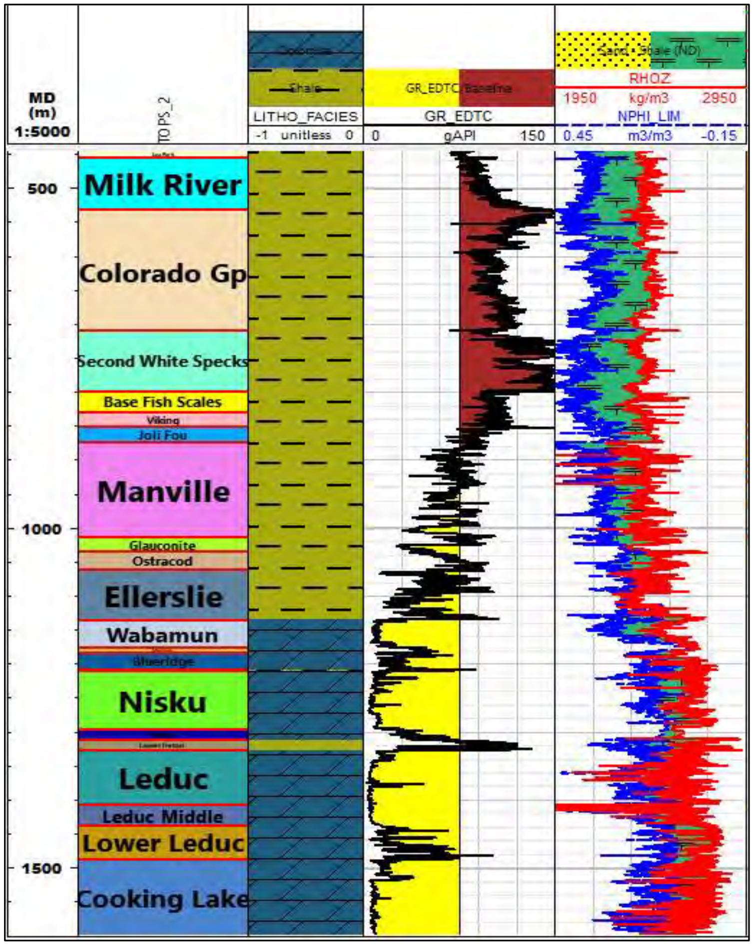


Mechanical Stratigraphy

→ Mechanical Stratigraphy Computation

Mechanical Stratigraphy

- Mechanical litho-stratigraphy is constructed according to the dominant lithology. Spectroscopy and basic logs have been used for its construction.
- Lea Park to Ellerslie formations and Lower Ireton are Clastics.
- Wabamun to Cooking Lake formations dolomite (Carbonates).
- A mechanical stratigraphy log labeled as LITHO_FACIES is created to distinguish Clastics and Carbonates.



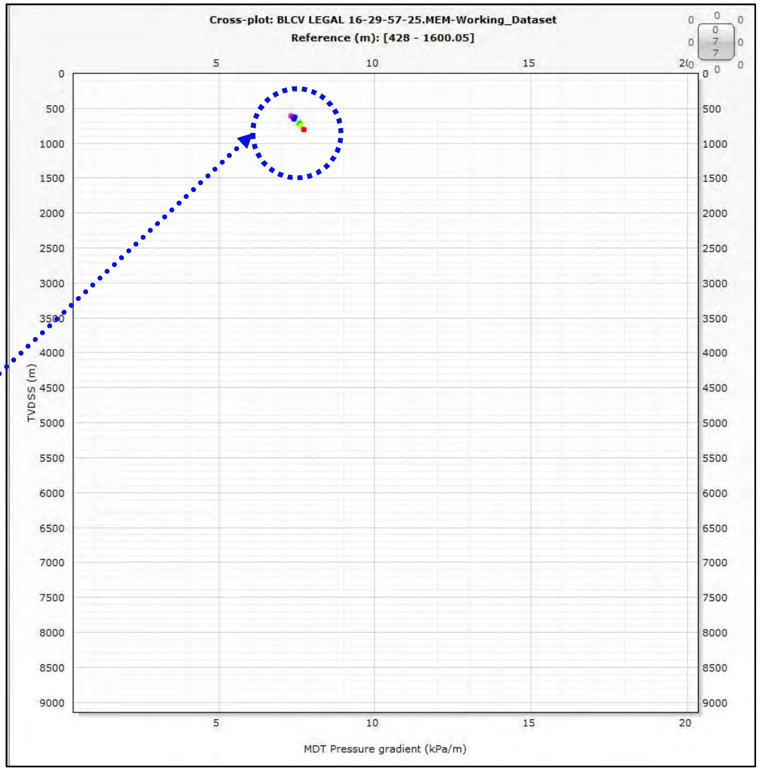
Pore Pressure Computation

→ Pore Pressure Computation

Reservoir Pressures from MDT

- TVDSS-PPG Plot displaying the direct pressure measurements (MDT) for the offset wells.
- The data indicates a sub-hydrostatic pressure gradient.
- Pore pressure from Leduc to Cooking Lake formation are sub-hydrostatic and has been calibrated to MDT pressure points. The gradients that have been used are:
    - Leduc & Lower Leduc = 7.5 kPa/m and
    - Cooking Lake = 7.75 kPa/m
- For Lea Park to Ireton, the HARP model has been used to calibrate the pore pressure.

MDT

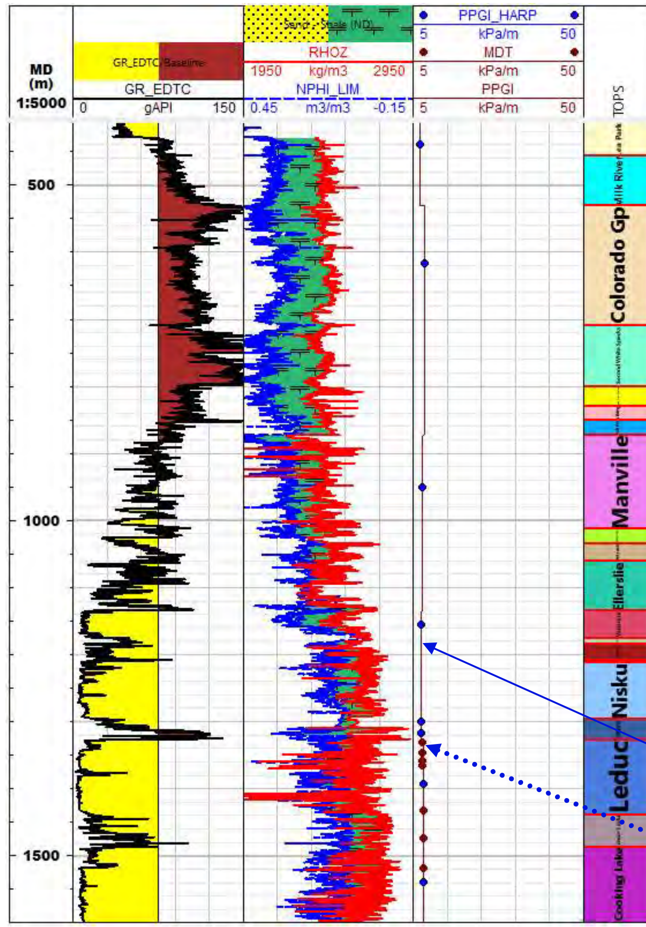


Pore Pressure Estimation

The pore pressure gradient has been used as below by gradient based method.

Zone	Top	Bottom	pressure_gradient	pressure_gradient Unit
Lea Park	368.36	455.36	6.6	kPa/m
Milk River	455.36	530.36	6.6	kPa/m
Colorado Gp	530.36	709.36	7.8	kPa/m
Second White Specks	709.36	799.36	7.8	kPa/m
Base Fish Scales	799.36	828.36	7.8	kPa/m
Viking	828.36	849.96	7.8	kPa/m
Joli Fou	849.96	872.36	7.8	kPa/m
Manville	872.36	1012.36	7.3	kPa/m
Glauconite	1012.36	1034.36	7.3	kPa/m
Ostracod	1034.36	1060.36	7.3	kPa/m
Ellerslie	1060.36	1134.36	7.3	kPa/m
Wabamun	1134.36	1175.36	7	kPa/m
Graminia	1175.36	1183.36	7	kPa/m
Blueridge	1183.36	1207.36	7	kPa/m
Calmar	1207.36	1210.36	7	kPa/m
Nisku	1210.36	1295.36	7	kPa/m
Ireton	1295.36	1326.36	7	kPa/m
Leduc	1326.36	1438.36	7.5	kPa/m
Lower Leduc	1438.36	1487.36	7.5	kPa/m
Cooking Lake	1487.36	1600.048	7.5	kPa/m

** Additionally HARP model has been used where MDT is absent*



Elastic Properties & Rock Strength

- → Dynamic Elastic Properties
- → Static Elastic Properties
- → Rock Strength

Elastic Properties- Dynamic Moduli

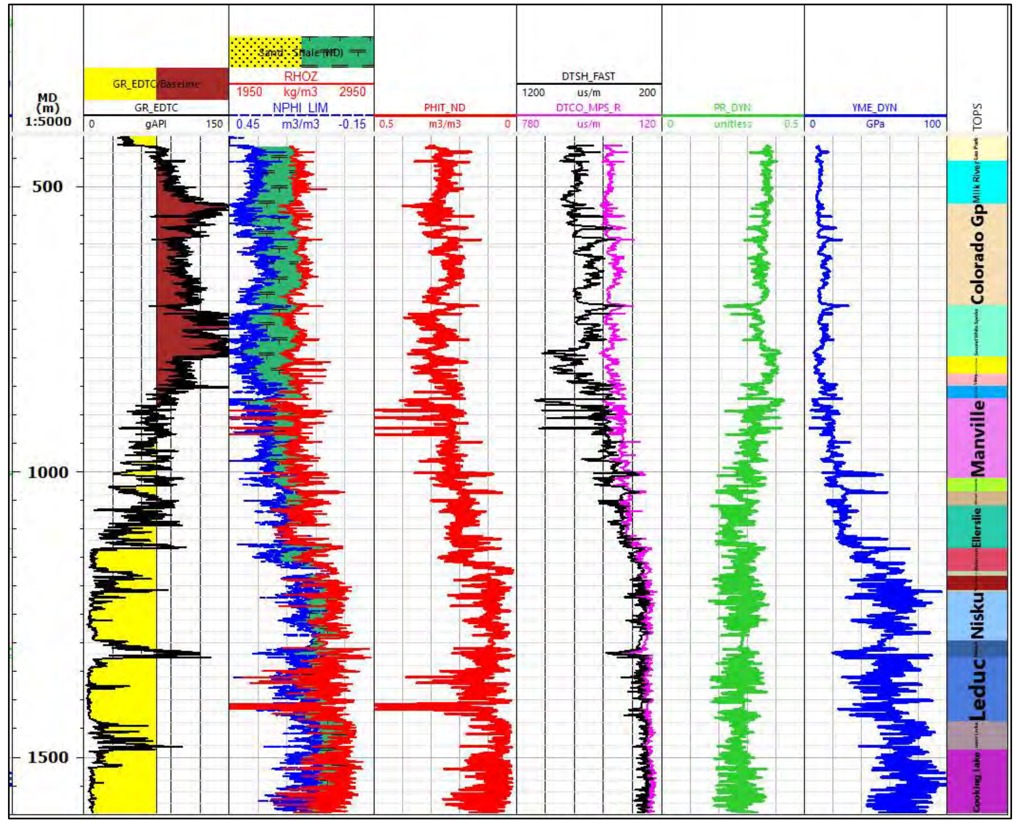
→ The dynamic moduli of rock are calculated from the elastic wave velocity and density.

→ Dynamic Young's Modulus (YME_DYN) & Dynamic Poisson's Ratio (PR_DYN) computed using Bulk density, Compressional (Vc), and Shear (Vs) velocities.

$$E_{dyn} = \frac{\rho V_s^2 (3V_c^2 - 4V_s^2)}{(V_c^2 - V_s^2)}$$

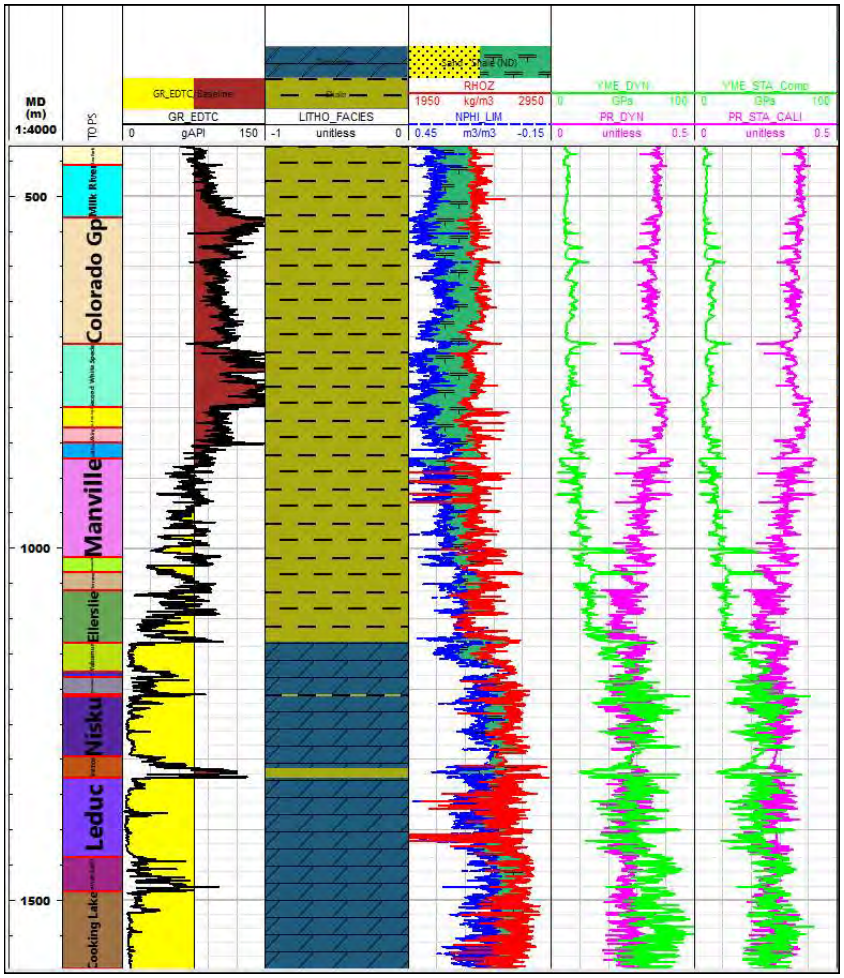
$$\nu_{dyn} = \frac{V_c^2 - 2V_s^2}{2(V_c^2 - V_s^2)}$$

where E_{dyn} is dynamic Young's modulus, ν_{dyn} is dynamic Poisson's ratio, ρ is bulk density, and
compression and shear wave velocity Vp and Vs, (i.e., inverse of compression and shear transit time DTC and DTS from sonic log slowness, respectively.



Elastic Properties- Static Moduli

- → Static properties are used for stress calculations.
- → The static moduli are directly measured on core in a deformational experiment. Core-log correlations are obtained from core data which will be used to calculate static properties along the well profile.
- → No sufficient core data available in this well to develop correlation, hence appropriate lithology-based published correlations are used.
- → For static Young's Modulus, two correlations have been used as follows:
  - **Clastics:** YME_STA = (0.74* YME_DYN -0.82) with a lithology sensitivity multiplier of 1.15 (Eissa and Kazi*)
  - **Carbonate:** YME_STA_Sayers = 0.7792* YME_DYN (Sayers**)
  - These two merged for final composite, YME_STA_Comp profile
- → PR_STA considered to be same as PR_DYN.



References:
** E. A. Eissa and A. Kazi, 1988. Relation between static and dynamic Young's moduli of rocks,1988.*
*** COLIN M. S AYERS, The elastic properties of carbonates, The Leading Edge August 2008*

Rock Strength

→ Rock strength properties are – Unconfined Compressive Strength, Friction Angle, Cohesion and Tensile Strength

→ For UCS, lithology-based correlations are used:

- Clastics: Horsrud* correlation with a 0.65 lithology multiplier

  $$UCS = 0.77\left(\frac{304.8}{DTCO}\right)^{2.93}$$

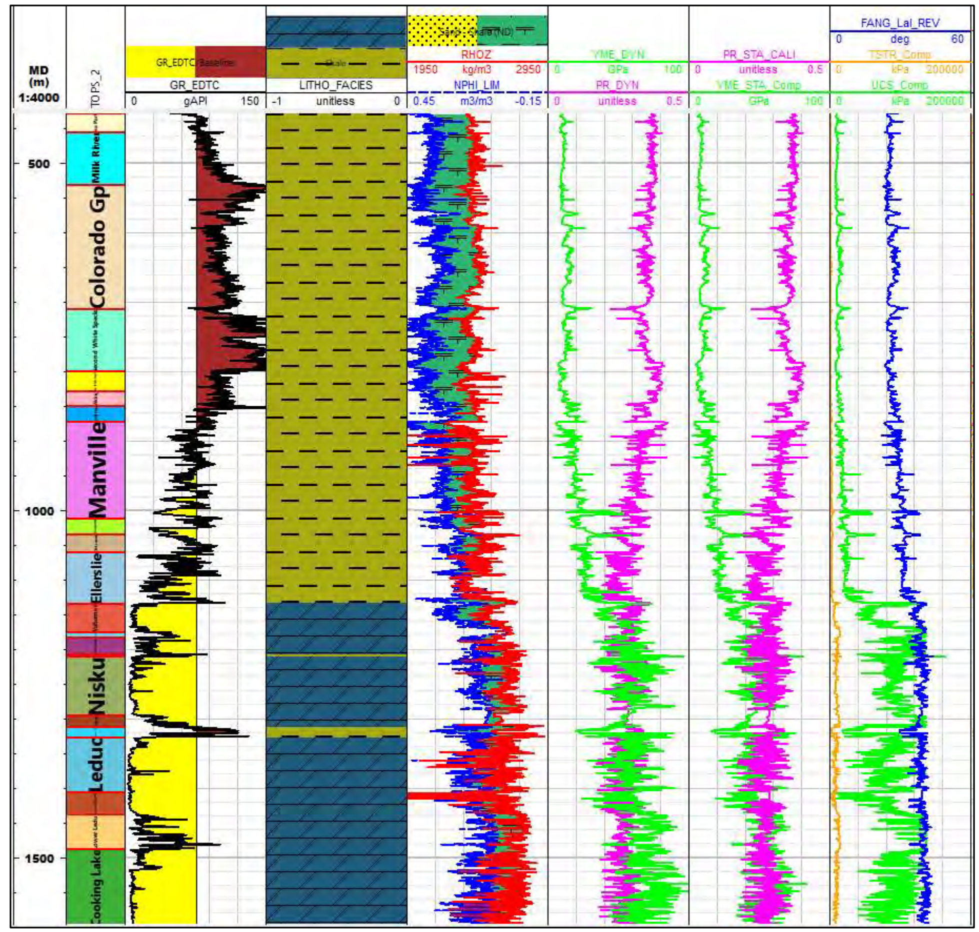
- Carbonates: Chang's** correlation UCS = 135.9*exp(-4.8*PHIE)

- These are merged for composite profile, UCS_Comp

→ Tensile strength (TSTR_Comp) has been kept at 10% of UCS

→ For Friction Angle (FANG_Lal), a DTCO-based correlation *** has been used with a multiplier of 0.9

FANG = (180/3.141592) *sin ((304800-1000*dt)/(304800+1000*dt))



References:
** Horsrud, P., 2001. Estimating mechanical properties of shale from empirical correlations. SPE Drill. Complet. 16, 68 - 73.*
*** Chandong Chang, Mark D. Zoback, at al., 2006. Empirical relations between rock strength and physical properties in sedimentary rocks, Journal of Petroleum Science and Engineering 51 (2006) 223-237*
****Lal, M., 1999. Shale stability: drilling fluid interaction and shale strength. SPE Latin American and Caribbean Petroleum Engineering Conference held in Caracas, Venezuela*

Horizontal Stresses

- Poroelastic Horizontal Strain method
- Horizontal Stress Computations
- Calibration

Horizontal Stresses

→ Poro-Elastic Horizontal Strain Model is the most commonly used horizontal stress calculation method.

→ Assuming flat-layered poroelasticity deformation in the formation rock, a pair of tectonic strains, ε_x and ε_y appropriate for the region are applied to the formation in the directions of minimum and maximum stress respectively. The Poro-Elastic Horizontal Strain Model can be expressed using Static Young's modulus, Poisson ratio, Biot's constant, overburden stress, and pore pressure. We cannot directly measure ε_x and ε_y . By adjusting these strains, you can calibrate the calculated stresses with the measured horizontal stresses (e.g. closure pressure from LOT, mini-frac).

→ The poroelastic horizontal strain equation is:

$$S_{hmin} = \frac{\upsilon}{1-\upsilon}\left(S_V - \alpha P_p\right) + \alpha P_p + \frac{E}{1-\upsilon^2}\varepsilon_x + \frac{\upsilon E}{1-\upsilon^2}\varepsilon_y$$

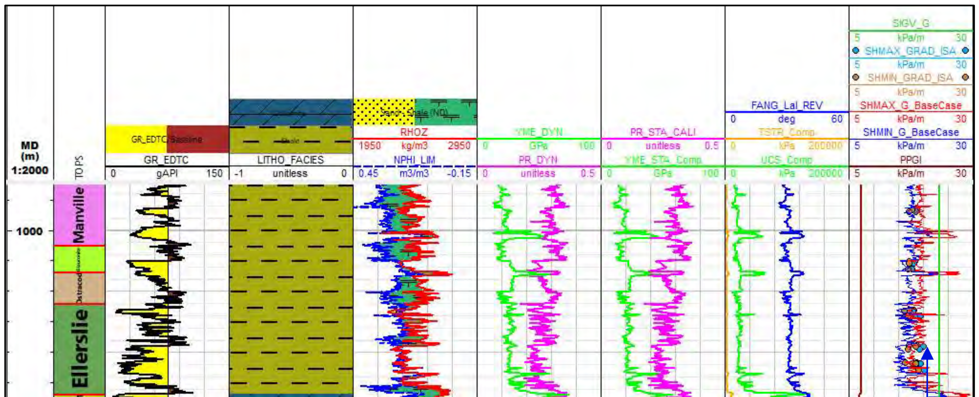
$$S_{Hmax} = \frac{\upsilon}{1-\upsilon}\left(S_V - \alpha P_p\right) + \alpha P_p + \frac{E}{1-\upsilon^2}\varepsilon_y + \frac{\upsilon E}{1-\upsilon^2}\varepsilon_x$$

α = Biot's coefficient; E = Young's modulus; ν = Poisson's ratio

Model Calibration

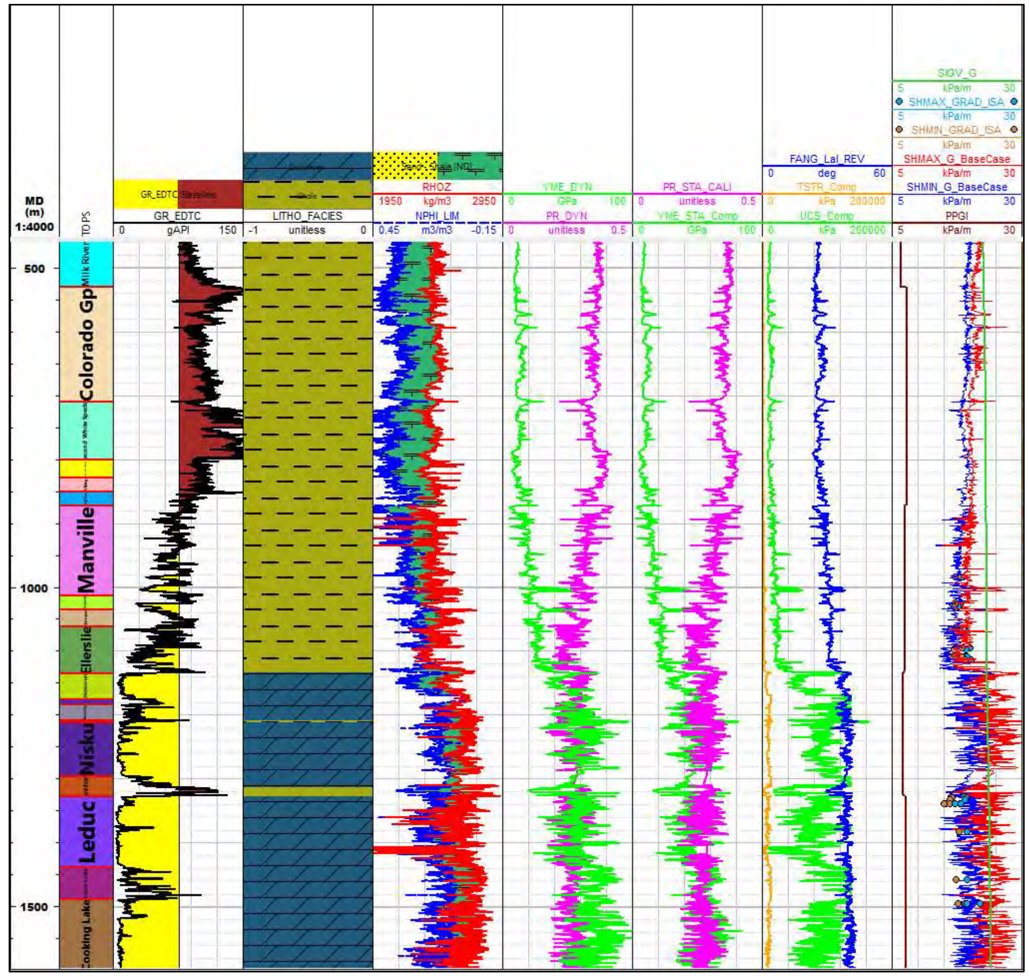
- → No calibration data available for elastic properties, rock strength or horizontal stresses.
- → Carefully selected lithology-based correlations used to compute static elastic properties and rock strength to ensure appropriate values are obtained.
- → A published regional case study from Geomechanical Response to CO2 Injection for the Heartland Area Redwater Project (HARP), Alberta has been used as a guide.
- → Stress model was constrained using results obtained from integrated stress analysis (ISA).
- → Further, wellbore stability assessment was conducted by integrating elastic properties, rock strength and stresses to ensure the model predicts wellbore failure (particularly, breakouts observed in image log).
- → In order to account for uncertainty in horizontal stresses, two sensitivity cases on tectonic strains and Biot's coefficient were run, Base-Case and Lower bound case.
  - Base-Case: Tectonic strains, Ehmin = 0.0001, Ehmax=0.00024, Biot's coefficient, Alpha = 1.0
  - Lower bound-case: Tectonic strains, Ehmin = 0.00005, Ehmax=0.0002 and Biot's coefficient, Alpha = 0.8

Horizontal Stresses (Base Case)

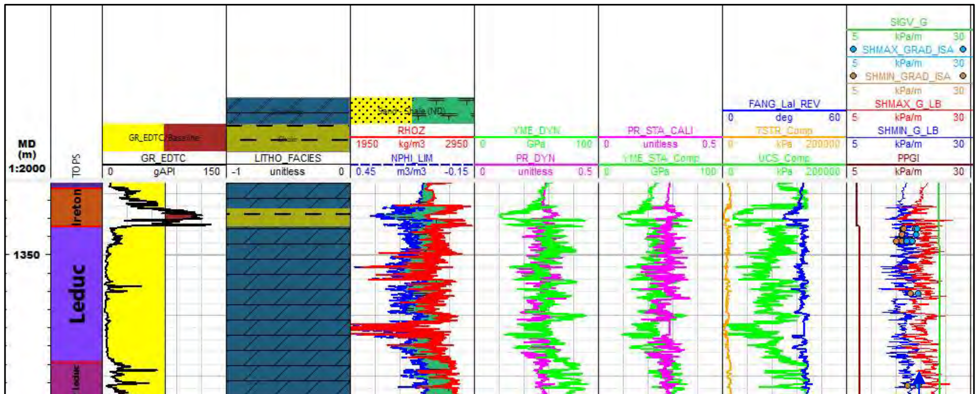


Horizontal stresses calibrated to ISA

- **Stress constrained by ISA.**
- **Stress regime in deeper zones in carbonates is estimated to be strike-slip.**
- **This case is possibly representative of the regional stresses as it confirms to the observed wrench faults in the region.**



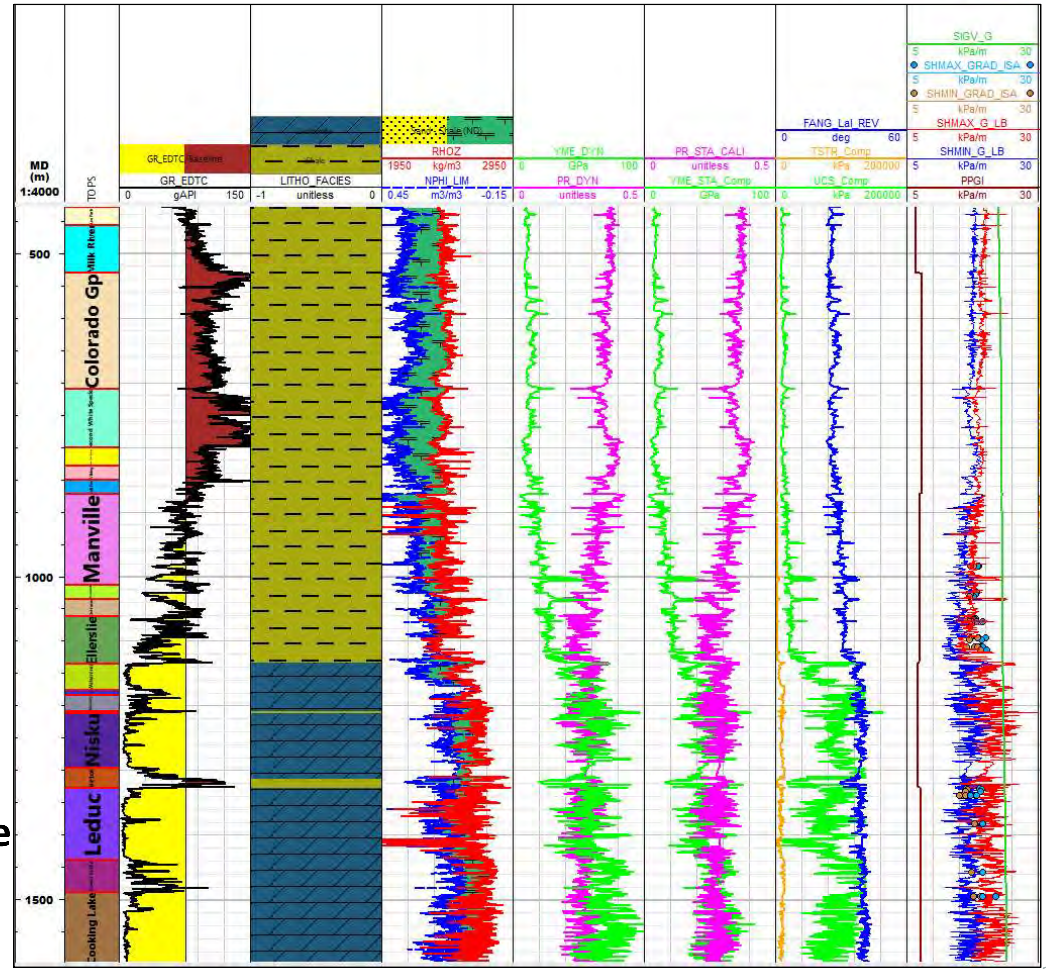
Horizontal Stresses (Lower Bound Case)



Horizontal stresses

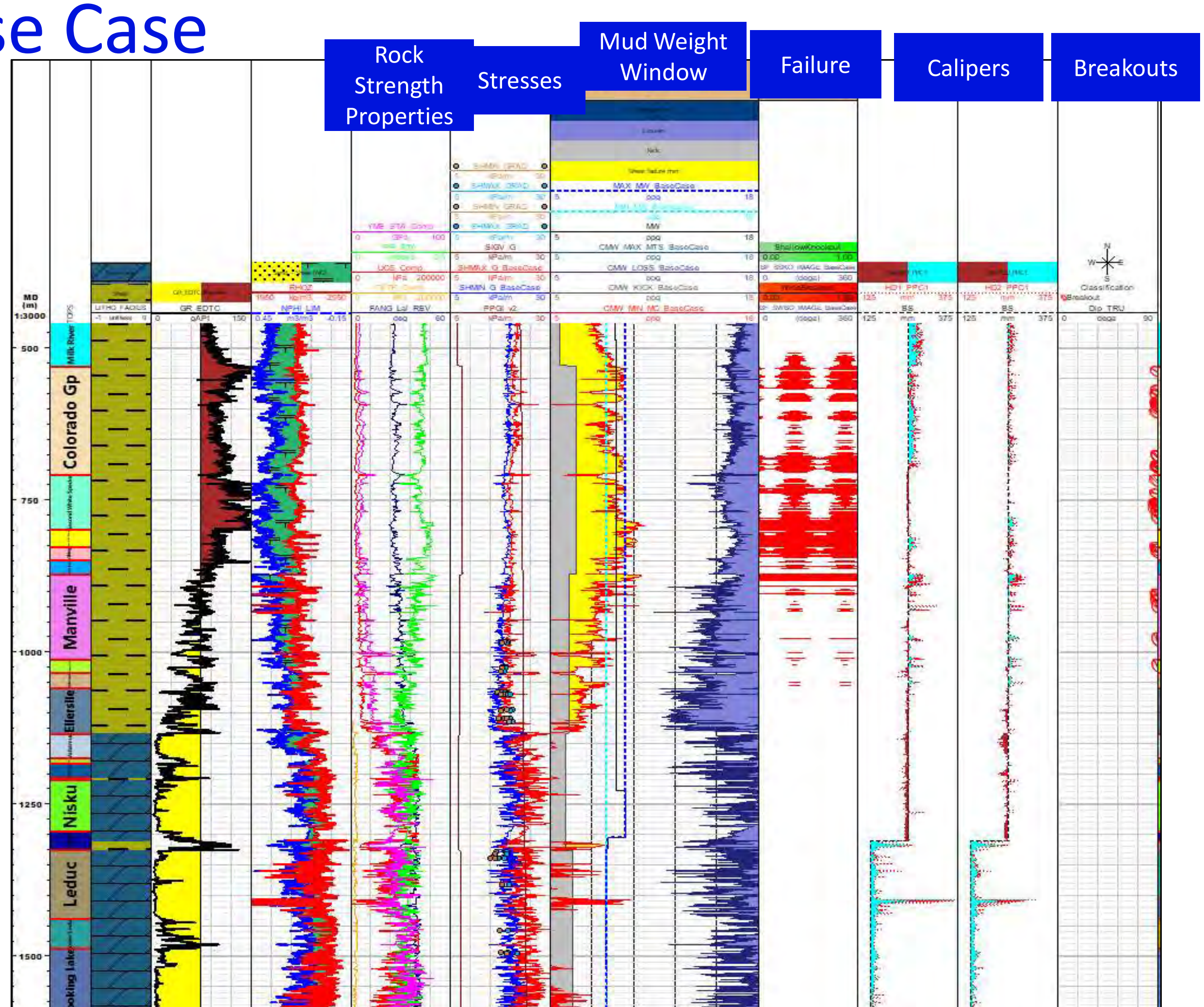
calibrated to ISA

- **Stress constrained by ISA.**
- **Stress regime in deeper zones in carbonates is estimated to be strike-slip.**
- **This case shows a relaxed stress model to account for lower bound stresses as conservative case (lower fracture gradient in injection zone).**



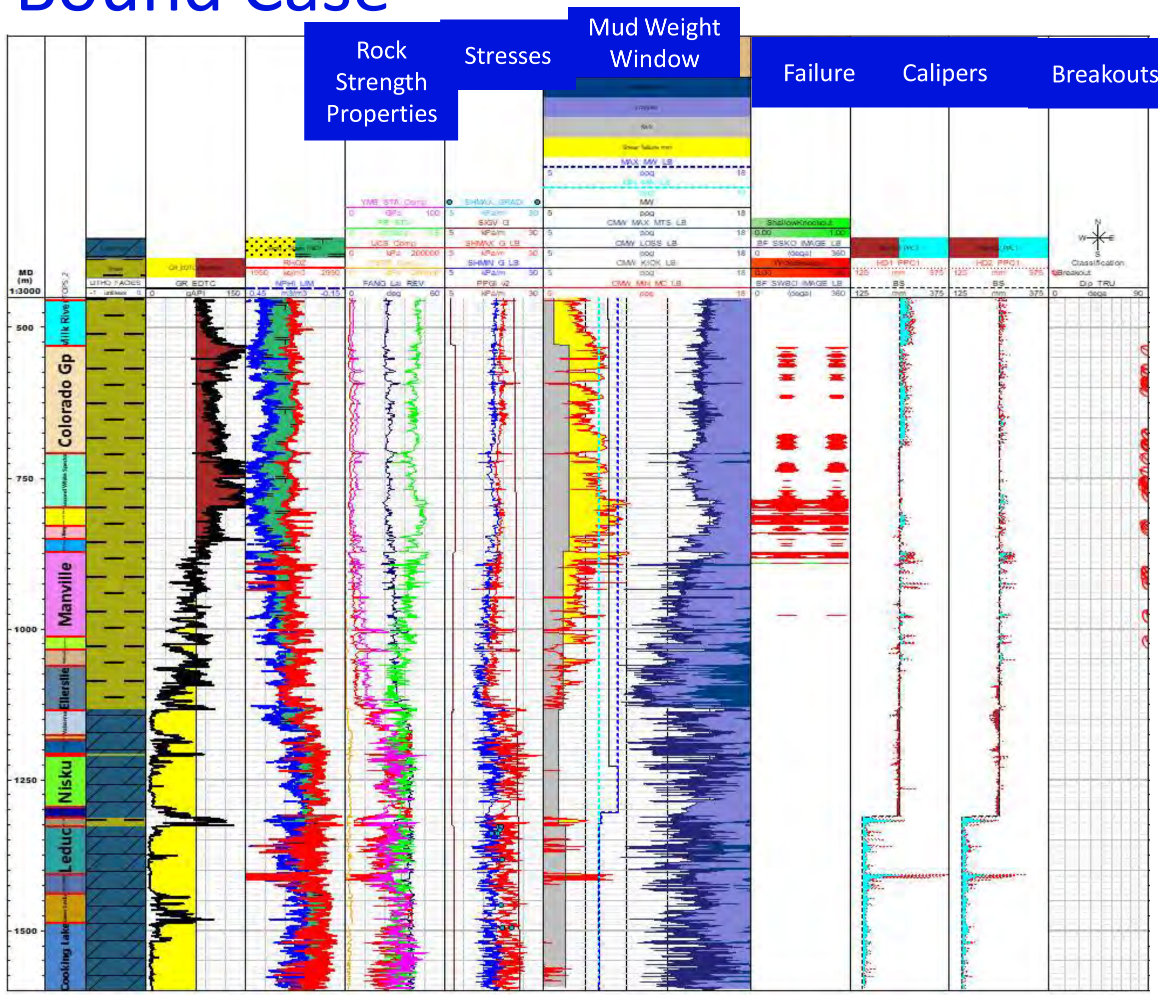
Wellbore Stability – Base Case

- → MEM-WBS validates well with calipers and breakouts
- → Lea Park to Ellerslie shows shear failure as seen in two –armed calipers and dips
- → Lea Park to Ellerslie formation tends towards normal fault regime while Wabamun to Cooking Lake tends more to strike-slip stress regime as seen from the horizontal stresses
- → The carbonate formations (as seen in the litho track) show relatively stiffer rock properties leading to strike-slip stress regime.



Wellbore Stability – Lower Bound Case

- MEM-WBS validates well with calipers and breakouts
- The Lower bound case shows relatively lower stress and lower shear failure compared to Base-case model.
- Lea Park to Ellerslie shows shear failure as seen in two –armed calipers and dips
- Lea Park to Ellerslie formation tends towards normal fault regime while Wabamun to Cooking Lake tends more to strike-slip stress regime as seen from the horizontal stresses.



Zones of Interest –Leduc Formation

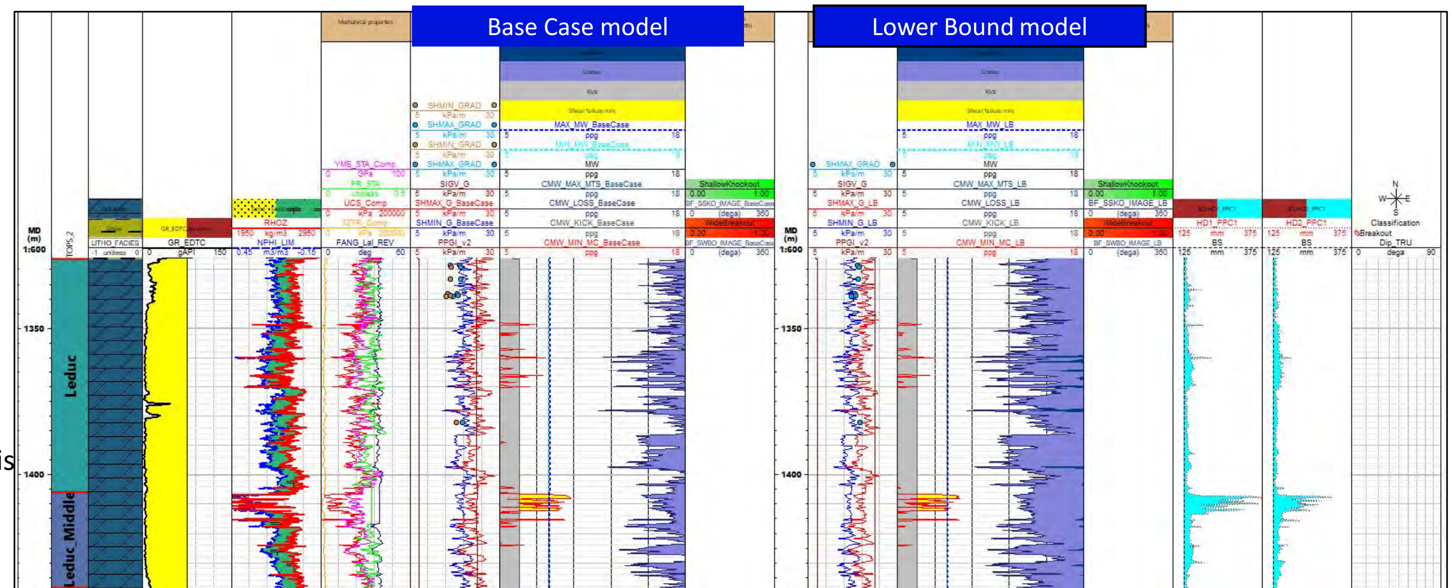
→ The Leduc formation is the main reservoir where CO2 injection is planned.

→ Lithology is dominantly dolostone.

→ The rocks are relatively stiffer, and no shear failure or breakouts seen in caliper and breakouts as well as WBS.

→ The stresses tend to be in a strike-slip regime.

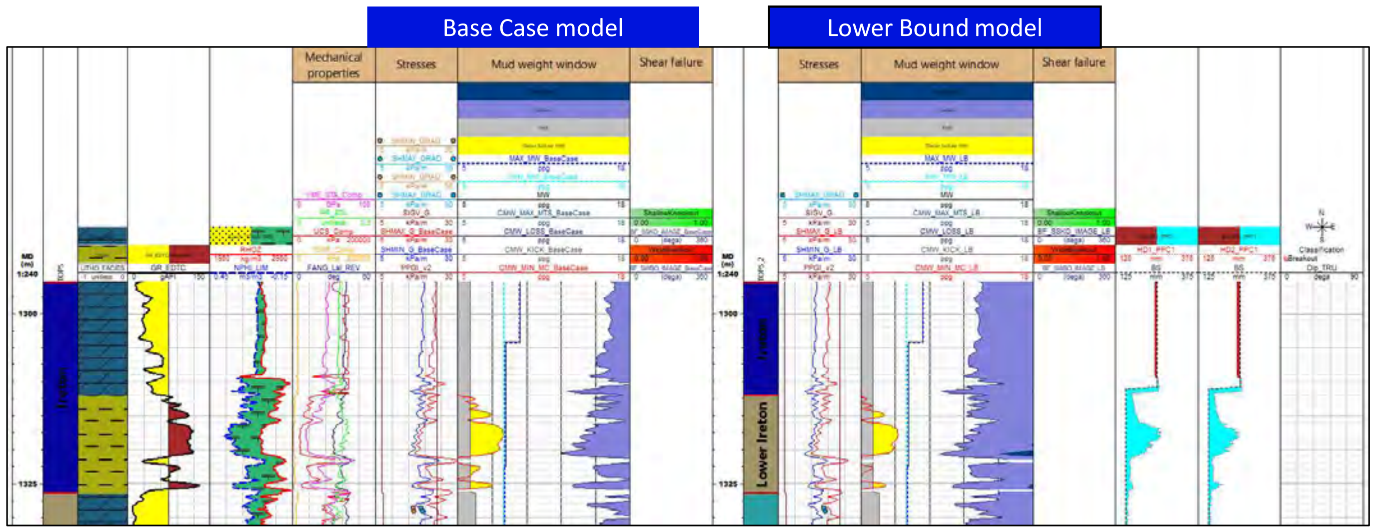
→ Average properties and stress gradients for this zone shown in the table and compared with HARP model.



Property (Leduc)	Unit	Base Case	Lower Bound	HARP
YME_STA_Comp	GPa	45.91	45.91	51.20
PR_STA	unitless	0.27	0.27	0.26
UCS_Comp	MPa	82.29	82.29	N/A
FANG_Lal_REV	deg	38.76	38.76	40.00
PPRG	kPa/m	7.50	7.50	7.50
SIGV_G	kPa/m	23.68	23.68	22.80
SHMIN_G	kPa/m	19.69	16.54	16.60
SHMAX_G	kPa/m	23.39	20.51	21.50
Ratio_SHMAX_MIN	unitless	1.19	1.24	1.30

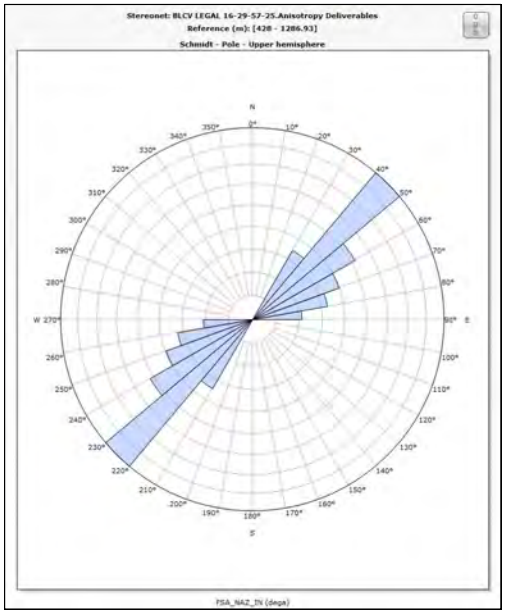
Zones of Interest –Ireton Formation

- The Ireton formation – main caprock above Leduc
- Ireton has two distinct lithological sections – Upper Ireton dolostone (1295m-1311m) and Lower Ireton shale (1312m-1326m).
- Upper Ireton (dolostone) is stiffer than Lower Ireton shale and no shear failure or breakouts seen in caliper and breakouts as well as WBS.
- Lower Ireton is shaly zone with lower stiffness (low YM) can be potential ductile zone which can heal any fractures extending into this zone.
- Average properties and stress gradients for this zone shown in the table and compared with HARP model.

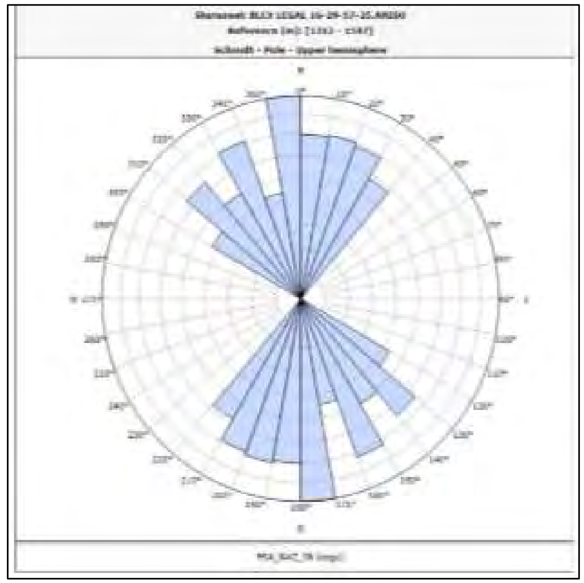


Property (Upper Ireton)	Unit	Base Case	Lower Bound	HARP
YME_STA_Comp	GPa	41.18	41.18	36.50
PR_STA	unitless	0.28	0.28	0.25
UCS_Comp	MPa	125.65	125.65	N/A
FANG_Lal_REV	deg	37.80	37.80	36.00
PPRG	kPa/m	7.00	7.00	7.00
SIGV_G	kPa/m	23.57	23.57	22.50
SHMIN_G	kPa/m	19.06	16.11	16.00
SHMAX_G	kPa/m	22.52	19.82	20.40
Ratio_SHMAX_MIN	unitless	1.18	1.23	1.28

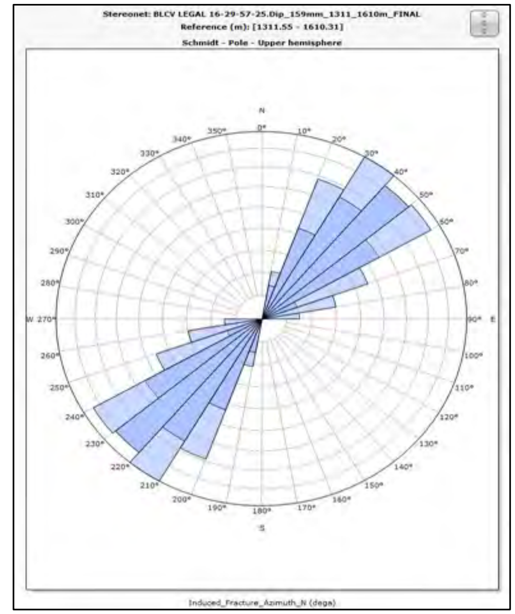
Stress Directions



NE-SW from sonic FSA
(intermediate section)
Max. Stress Azimuth



N-S from sonic FSA (TD section)



NE-SW from Drilling Induced
Fractures images
Max. Stress Azimuth

Maximum stress direction is overall consistent with both sonic and image~45 deg NE

Appendix

→ Nomenclature

→ Key Geomechanical Properties Summary Table

→ References

Nomenclature

Variable	Description
LITHO_FACIES	Litho facies log to distinguish Clastics (value 1) and Carbonates (value 3) - used to distinguish correlations for static Young's Modulus and UCS
PR_DYN	Poisson's Ratio (Dynamic)
PR_STA	Poisson's Ratio (Static) = Dynamic
YME_DYN	Young's Modulus (Dynamic)
YME_STA_Comp	Young's Modulus (Static) Composite: Correlation used Eissa and Kazi (for Clastics) and Sayers (for Carbonates)
UCS_Comp	Unconfined compressive strength- composite: Horsrud DT-based correlation (for clastics) and Chang's porosity-based correlation (for Carbonates). Multiplying factor =0.65 (clastics), 1.0 (for carbonates): UCS_Comp=0.65*UCS_HRD if LITHO_FACIES<3 else UCS_PhieChang
TSTR_Comp	Tensile strength (=0.1*UCS_Comp)
FANG_Lal_REV	Friction angle - compression DT-based correlation by Lal with Multiplying factor =0.90
COHESION_Comp	Cohesional strength (computed from UCS_Comp and FANG_Lal_Rev)
PPRG	Pore pressure gradient
PPRS	Pore Pressure
SIGV_G	Veritcal stress gradient
SIGV	Vertical stress
SHMIN_G_BaseCase	Minimum horizontal stress gradient (using YME_STA_Comp, Tectonic strain Ehmin = 0.0001, Ehmax=0.00024, Biot=1)
SHMIN_BaseCase	Minimum horizontal stres-Base case
SHMAX_G_BaseCase	Maximum horizontal stress gradient(using YME_STA_Comp, Tectonic strain Ehmin = 0.0001, Ehmax=0.00024, Biot=1)
SHMAX_BaseCase	Maximum horizontal stress--Base case
SHMIN_G_LB	Lower Bound Minimum horizontal stress gradient (using YME_STA_Comp, Tectonic strain Ehmin = 0.00005, Ehmax=0.0002, Biot=0.8)
SHMIN_LB	Minimum horizontal stress-Lower Bound
SHMAX_G_LB	Lower Bound Maximum horizontal stress gradient (using YME_STA_Comp, Tectonic strain Ehmin = 0.00005, Ehmax=0.0002, Biot=0.8)
SHMAX_LB	Maximum horizontal stress-Lower Bound
Ratio_SHMAX_MIN_BaseCase	Ratio of Max. and Min.Horizontal stress-BaseCase
Ratio_SHMAX_MIN_LB	Ratio of Max. and Min.Horizontal stress-Lower Bound

Key Geomechanical Properties - Nisku

Property (Nisku)	Unit	Base Case	Lower Bound	HARP
YME_STA_Comp	GPa	47.67	47.67	N/A
PR_STA	unitless	0.29	0.29	N/A
UCS_Comp	MPa	92.99	92.99	N/A
FANG_Lal_REV	deg	39.33	39.33	N/A
PPRG	kPa/m	7.00	7.00	N/A
SIGV_G	kPa/m	23.47	23.47	N/A
SHMIN_G	kPa/m	20.89	17.51	N/A
SHMAX_G	kPa/m	25.03	21.94	N/A
Ratio_SHMAX_MIN	unitless	1.20	1.25	N/A

Key Geomechanical Properties - Ireton

Property (Upper Ireton)	Unit	Base Case	Lower Bound	HARP
YME_STA_Comp	GPa	41.18	41.18	36.50
PR_STA	unitless	0.28	0.28	0.25
UCS_Comp	MPa	125.65	125.65	N/A
FANG_Lal_REV	deg	37.80	37.80	36.00
PPRG	kPa/m	7.00	7.00	7.00
SIGV_G	kPa/m	23.57	23.57	22.50
SHMIN_G	kPa/m	19.06	16.11	16.00
SHMAX_G	kPa/m	22.52	19.82	20.40
Ratio_SHMAX_MIN	unitless	1.18	1.23	1.28

Property (Lower Ireton)	Unit	Base Case	Lower Bound	HARP
YME_STA_Comp	GPa	31.89	31.89	28.60
PR_STA	unitless	0.29	0.29	0.25
UCS_Comp	MPa	36.20	36.20	N/A
FANG_Lal_REV	deg	33.99	33.99	36.00
PPRG	kPa/m	7.00	7.00	7.00
SIGV_G	kPa/m	23.60	23.60	22.40
SHMIN_G	kPa/m	18.47	16.02	16.00
SHMAX_G	kPa/m	21.09	18.83	19.70
Ratio_SHMAX_MIN	unitless	1.14	1.18	1.23

Key Geomechanical Properties - Leduc

Property (Upper Leduc)	Unit	Base Case	Lower Bound	HARP
YME_STA_Comp	GPa	45.91	45.91	51.20
PR_STA	unitless	0.27	0.27	0.26
UCS_Comp	MPa	82.29	82.29	N/A
FANG_Lal_REV	deg	38.76	38.76	40.00
PPRG	kPa/m	7.50	7.50	7.50
SIGV_G	kPa/m	23.68	23.68	22.80
SHMIN_G	kPa/m	19.69	16.54	16.60
SHMAX_G	kPa/m	23.39	20.51	21.50
Ratio_SHMAX_MIN	unitless	1.19	1.24	1.30

Property (Middle Leduc)	Unit	Base Case	Lower Bound	HARP
YME_STA_Comp	GPa	44.21	44.21	51.20
PR_STA	unitless	0.28	0.28	0.26
UCS_Comp	MPa	71.03	71.03	N/A
FANG_Lal_REV	deg	38.88	38.88	40.00
PPRG	kPa/m	7.50	7.50	7.50
SIGV_G	kPa/m	23.74	23.74	22.80
SHMIN_G	kPa/m	19.47	16.49	16.60
SHMAX_G	kPa/m	22.87	20.14	21.50
Ratio_SHMAX_MIN	unitless	1.17	1.22	1.30

Property (Lower Leduc)	Unit	Base Case	Lower Bound	HARP
YME_STA_Comp	GPa	55.38	55.38	51.20
PR_STA	unitless	0.27	0.27	0.26
UCS_Comp	MPa	126.52	126.52	N/A
FANG_Lal_REV	deg	39.94	39.94	40.00
PPRG	kPa/m	7.50	7.50	7.50
SIGV_G	kPa/m	23.81	23.81	22.80
SHMIN_G	kPa/m	20.19	16.76	16.60
SHMAX_G	kPa/m	24.37	21.24	21.50
Ratio_SHMAX_MIN	unitless	1.21	1.27	1.30

slb

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Pore Pressure Theory

- Pore pressure is one of the most important parameters for Geomechanical and geological analyses. One cannot obtain a correct prediction for any geomechanical model without a right pore pressure input for the porous formations.
- Pore pressure varies from hydrostatic (pressure gradient of about ~9.726 kPa/m), which is normal pressure, to severely overpressured (48% to 95% of the overburden stress).
- The abnormal pore pressure is caused by abnormal formation compaction. When sediments compact normally, their porosity is reduced at the same time as pore fluid is expelled. This causes hydrostatic pore pressure. Non-hydrostatic abnormal pressure has many origins. The overburden stress is a major reason to induce abnormal pressure. During burial process, increasing overburden and no fluid expulsion from the pores of the formation causes pore pressure increase, producing overpressured pore pressure.
- Assuming the normally pressured and overpressured formations with identical elastic velocities/resistivities have identical effective stresses, the overpressured pore pressure can be calculated by comparing it to the hydrostatic pressure.

Pore Pressure Theory

Determining the active mechanism(s) within each shale package is critical to pore pressure prediction.

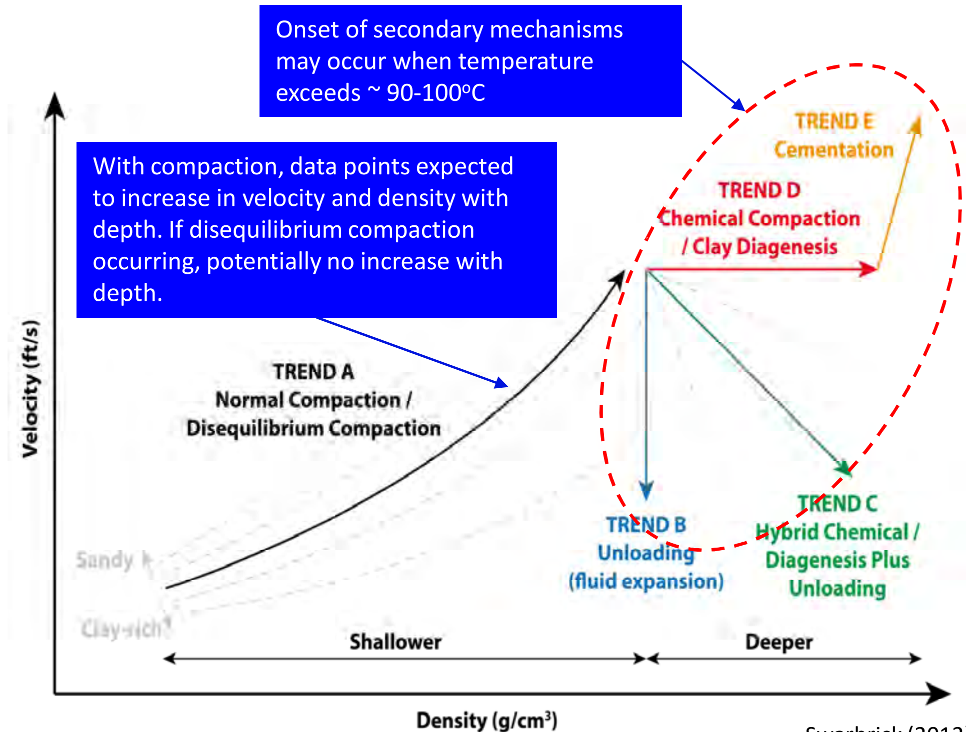
Black (Trend A): Normal compaction trend (also applicable when compaction is reduced or ceases due to disequilibrium compaction).

Blue (Trend B): Fluid expansion trend (significant velocity decrease and negligible increase in density), normally termed 'unloading' (Bowers, 1995).

Green (Trend C): Hybrid trend, (density increase and velocity decrease), due to a combination of chemical diagenesis and consequential unloading as the overburden stress is transferred onto the fluid, due to incomplete drainage.

Red (Trend D): Early chemical diagenesis trend (significant density increase and negligible increase in velocity).

Orange (Trend E): Later diagenetic change at very low porosity (high density) when velocity increases very rapidly due to very low porosity.

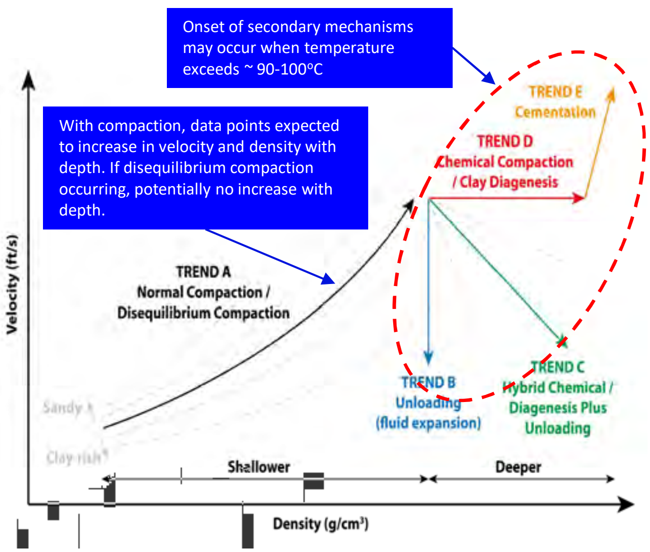


Swarbrick (2012)

Pore Pressure Trend

The velocity – density (Vp – Rho) data from all selected offset wells lie on the Trend A displayed in the Vp-Rhob crossplot for overpressure mechanisms analysis and comparison, indicating a normal compaction/disequilibrium compaction trend.

No secondary overpressure mechanisms (Trends B to E) are observed.



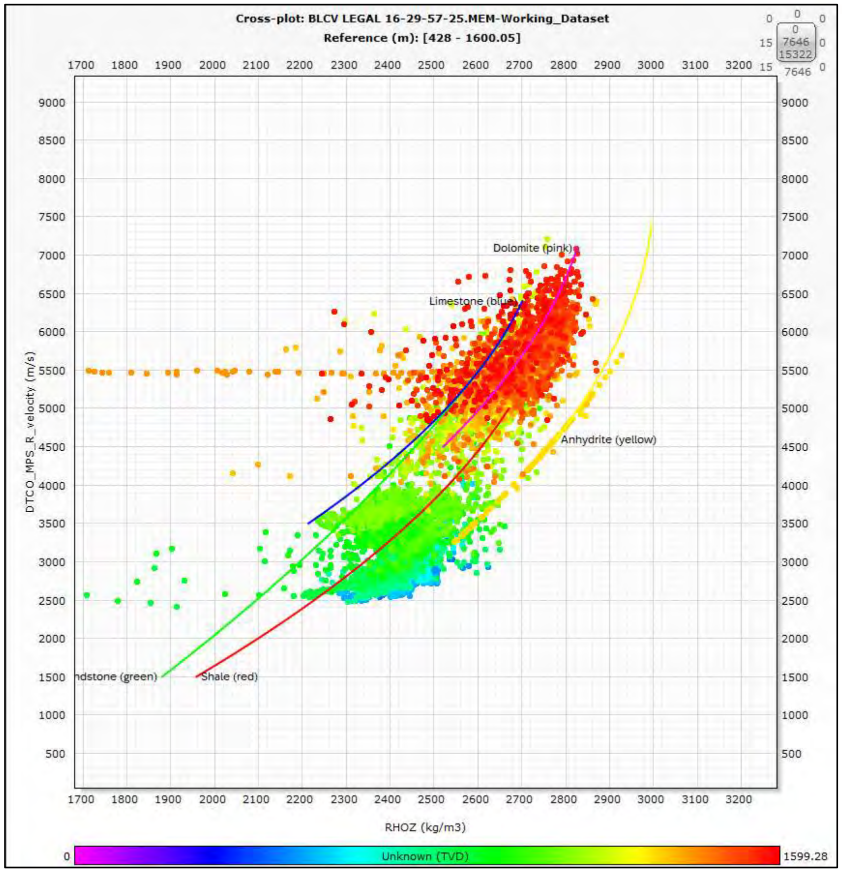
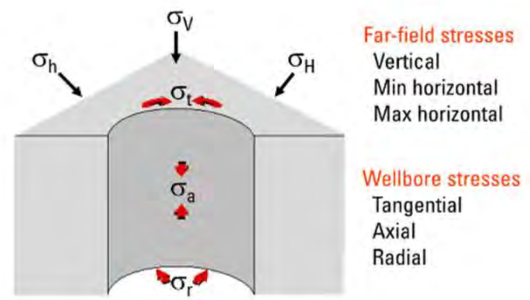
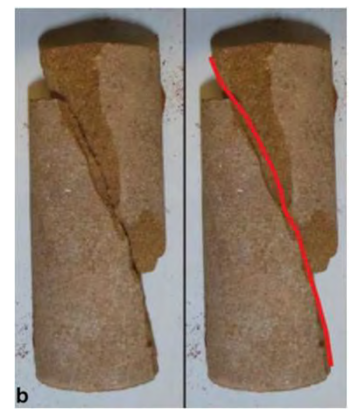


Fig. VP-RHOB Crossplot showing normal compaction trend

Wellbore Stability Assessment

- Elastic and strength rock properties are estimated using regional knowledge and taking inputs of synthetic compressional and shear slowness logs
- Horizontal stresses are estimated using the poro-elastic horizontal strain approach
- Shear failure is estimated using Mohr-Coulomb failure criterion
- Minimum horizontal stress is ideally the upper bound of drilling mud weight window
- Low density intervals have lesser rock strength and subsequently higher shear failure. However, in absence of the actual data, shear failure and other rock mechanical properties should be considered as a qualitative indicator



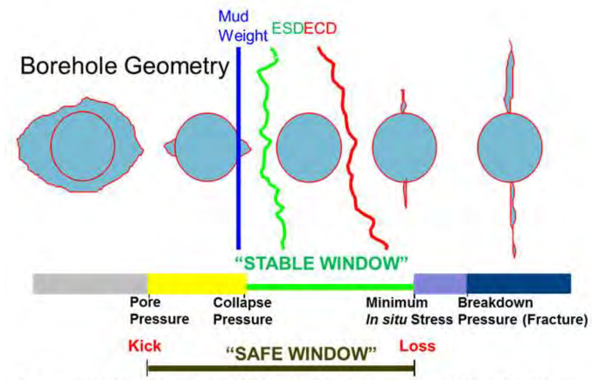


Wellbore Stability- Mud Weight Management

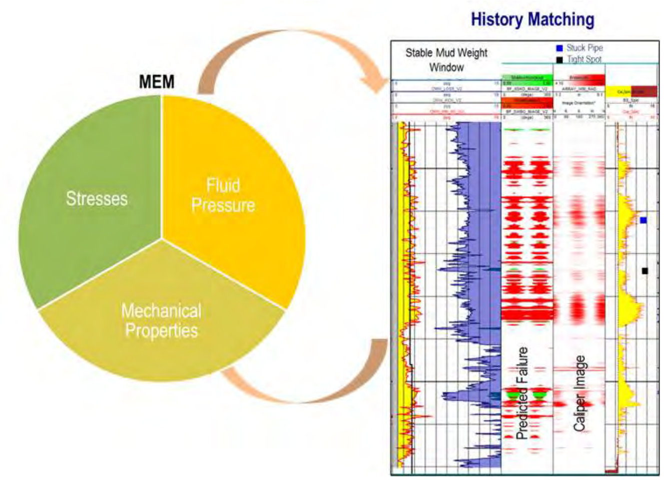
Minimum mud weight for preventing breakout - If the mud weight is less than this value, borehole breakout will happen, because the mud support to the borehole wall is not enough. The lower the mud weight below this value, the more severe the breakout will become. Swabbing, that might reduce the instantaneous hole pressure below this equivalent mud weight, can have a similar effect.

Minimum horizontal stress (Sigh) - If natural fractures or any other conductive fissures exist around the wellbore, or in the presence of a highly permeable thief zone, the mud pressure that is higher than the minimum horizontal stress (known in drilling as fracture pressure P_{frac}) will reopen the natural fractures/fissures and causing drilling fluid losses in the formation. In highly fractured formations, any well pressure more than the minimum horizontal stress can cause geometrical failure and movement (into the hole) of the otherwise intact blocks. Excessive ECD or surging the hole during tripping can have a similar effect.

Formation breakdown pressure (FBP) - When the mud pressure is higher than the formation breakdown pressure, tensile failure can occur in the intact rock and hydraulic fractures will be induced on the borehole wall. This can cause significant mud losses, particularly if the mud pressure is higher than the minimum horizontal stress also.



It is important to keep the mud weight **higher** than the collapse pressure but **lower** than the minimum *in situ* stress to maintain hole stability.



Thank you

Appendix 12 – Legacy Well Review

(refer to Appendix H of D065 application)

Appendix 13 – Wildlife Sweep Report

Wildlife Sweep Report for Wildlife Sweep Report for BISON 103 LEGAL 16-29-57-25-W4M Well Site and Access Road

Bison Low Carbon Venture retained Aurora Land Consulting Ltd. to complete a wildlife sweep of the 16-29-57-25-W4M well site and access road. Field work was completed on September 12, 2023. The site is located within the Central Parkland Natural Subregion of Alberta. Existing disturbances in the area include pre-existing access roads, a pipeline right-of-way, and cultivated lands. A wildlife sweep was completed to document important wildlife features such as nests, occupied dens, hibernacula, and natural mineral licks. The development area and 100 m buffer were swept following the wildlife sweep protocols (AEP, 2020) and a pre-determined grid pattern (Figure 1). Areas with greater habitat potential were assessed more intensely (as needed).

Job: 16-29-57-25-W4M Well Site and Access Road

Completed by: Susan Dahal

Date: September 12, 2023

Figure 1. Wildlife Sweep Walkthrough Design

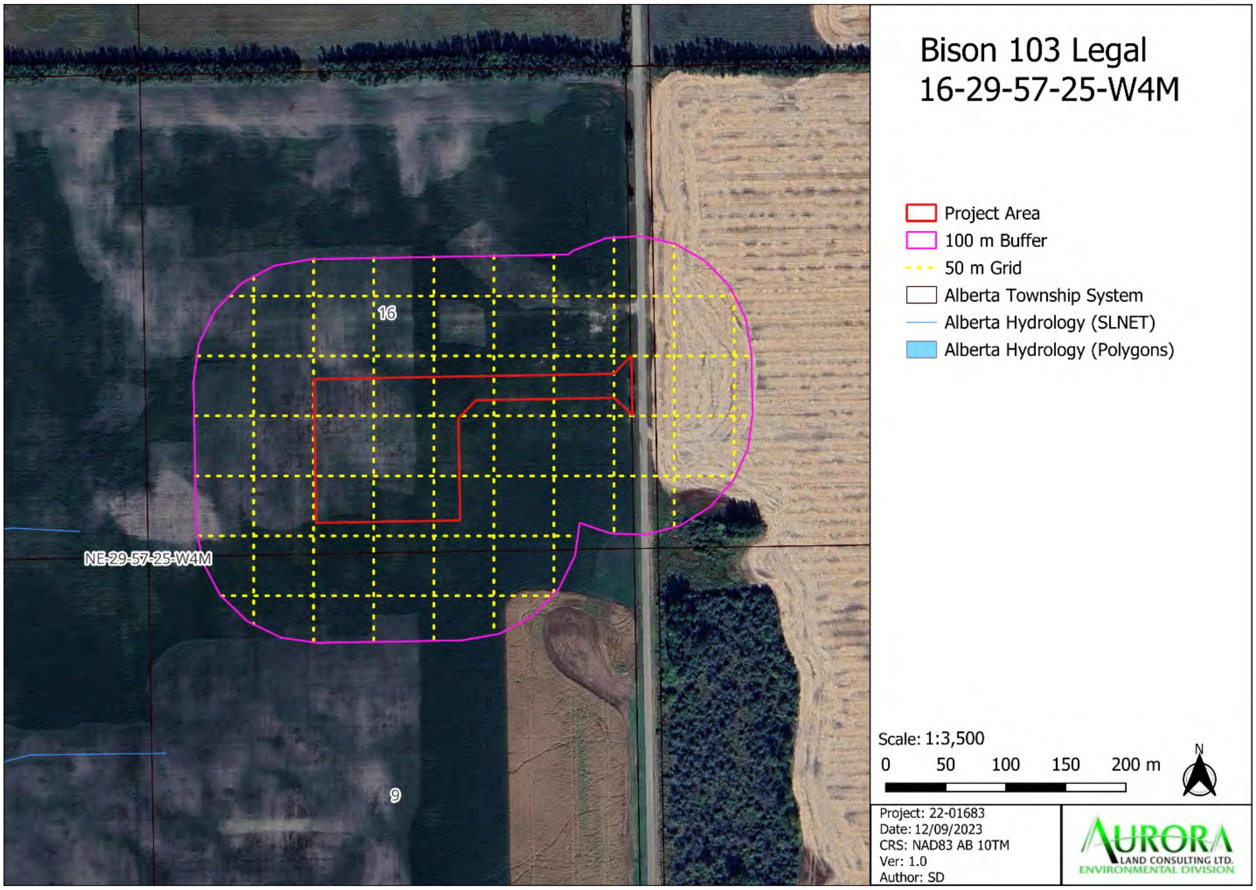
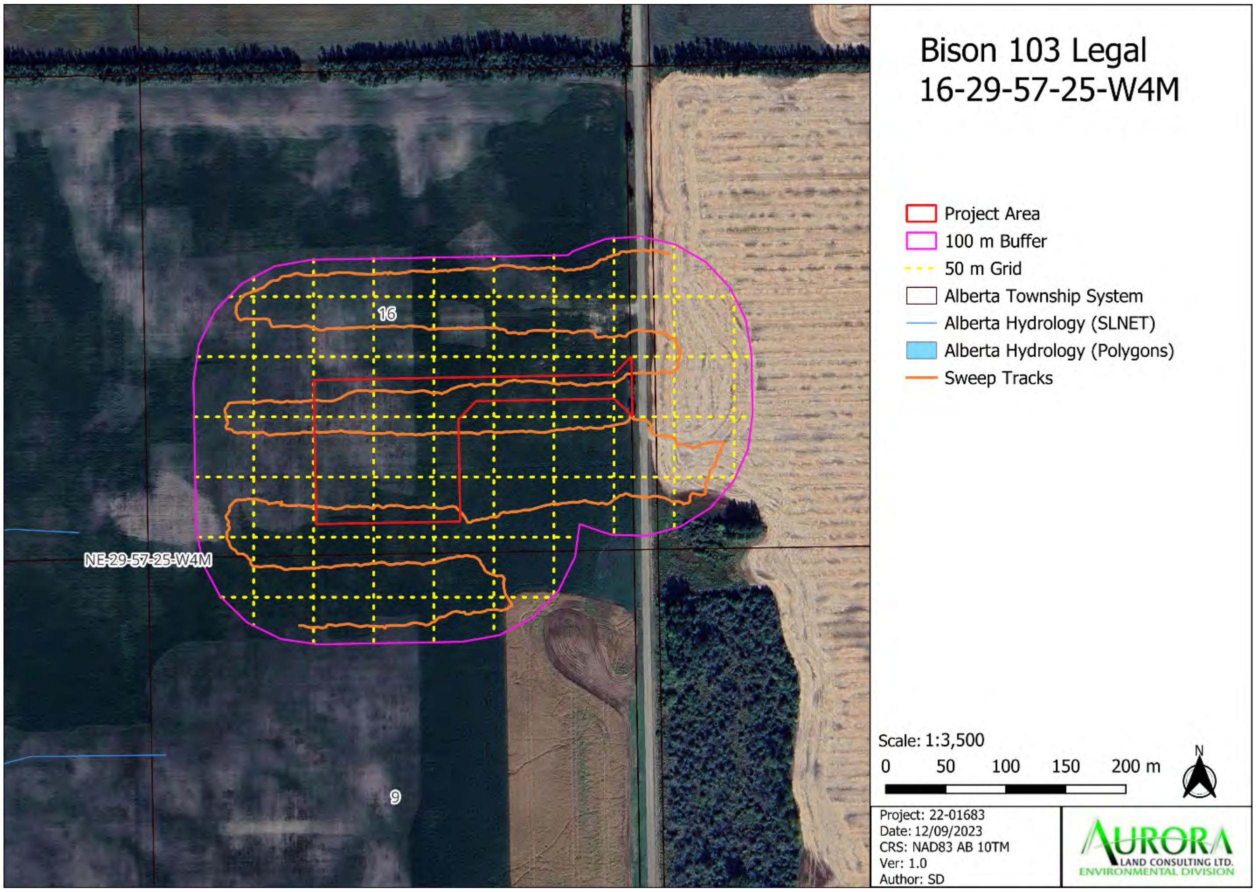


Figure 2. Wildlife Sweep Tracks



Environmental Conditions		
September 12, 2023	**Start**	**End**
Survey Time (24 h)	**9:15**	**10:30**
Temperature (^{0}C)	**14**	**15**
Wind Speed (km/h)	**16**	**20**
Precipitation (mm)	**0**	**0**
Cloud Cover (%)	**90**	**80**
Wildlife Features Identified (Yes/No)		
Occupied Nests	**No**	
Occupied Dens	**No**	
Hibernacula	**No**	
Mineral Licks	**No**	

Wildlife Species:

- American Pipit
- American Robin
- Chipping Sparrow
- Orange-Crowned Warbler
- Savannah Sparrow
- White-tailed Deer

Pic #1 Deer Tracks (53.960391, -113.669020)

Pic #2 Project Area Looking South (53.961734, -113.672987)

Pic #3 Project Area Looking East (53.961005, -113.673715)

Appendix 14 – Geochemistry – Reactive Transport Model

Geochemistry

Geochemical reactive transport modeling can help to understand the CO_2-brine-rock interactions in addition providing data for evaluating injectivity, trapping efficiency of CO_2. The modeling will cover aspects of the geochemistry including:

- changes in the brine chemistry during CO_2 injection
- changes in mineralogy due to CO_2-rock interactions
- total amount of CO_2 sequestered in mineral phases
- effect H_2S present in the water has during CO_2 injection

The geochemical models have been performed using TOUGH2/TOUGHREACT software v.1.2 (Xu and Pruess, 2001) developed by Lawrence Berkeley National Laboratory and licensed to Matrix Solutions.

Reservoir Mineralogy and Water Chemistry

The Leduc formation is observed between 1325 and 1440 m below ground surface with the Lower Leduc observed between 1440 and 1490 m. The Cooking Lake, is observed between 1490 and 1600 m below ground surface. Table 1 shows the properties of the reservoir model used in the simulations. The Leduc formation is overlaid by the Ireton Formation, the caprock. The Ireton was considered to be composed of albite (3.7%), calcite (27.4%), dolomite (5.7%), illite (40.0%), K-feldspar (8.4%), pyrite (0.7%), siderite (9.8%) and chlorite (4.4%) with a permeability of 0.1 mD and a porosity of 5%. The model considered the Leduc formation to be composed of 18% calcite and 82% dolomite with the Cooking Lake being composed of dolomite. The Leduc is modelled to be composed of six layers, each considered to be 20 m thick, with porosity ranging from 7 to 13% and permeability ranging from 8 to 450 mD. The Lower Leduc is considered to be a very tight formation composed of two layers each of 20 m thick each with a porosity of 1% and a permeability of 0.1 mD. The Cooking Lake formation is considered to be composed of eight layers of 20 m thick with a porosity ranging from 1 to 10% and permeability ranging from 0.1 to 58 mD.

Table 1: Properties of the Reservoir Model.

Formation	Depth of Layer (m)	Layer	Porosity (%)	Permeability (mD)
Ireton	0	I	5	0.1
Upper Leduc	-20	UL1	7	8
	-40	UL2	10	58
	-60	UL3	13	450
	-80	UL4	7	8

	-100	UL5	10	58
	-120	UL6	13	450
Lower Leduc	-140	LL71	1	0.1
	-160	LL2	1	0.1
Cooking Lake	-180	CL1	10	58
	-200	CL2	1	0.1
	-220	CL3	10	58
	-240	CL4	4	1
	-260	CL5	7	8
	-280	CL6	4	1
	-300	CL7	10	58
	-320	CL8	1	0.1

The water chemistry considered in the modeling is a Leduc brine from well 100/02-05-058-25W4M, shown in Table 2. It is a NaCl dominated brine with concentrations below halite saturation (~6.3 mol). The charge imbalance, i.e., the ratio of the difference between the positive and negative charge analytes over the total charges is only -0.2%, lower than the generally accepted criterion (i.e., absolute value <5%). This water was allowed to come to equilibrium with the surrounding Ireton, Leduc and Cooking Lake formations for 75 years, which resulted in changes to the concentrations of the analytes. Overall the fluid chemistry did not change significantly, with the exception of the amount of Mg^{2+} and Ca^{2+} present. The Mg^{2+} concentration increased to 0.41 mol/kg in the Ireton and UL1 and to 0.17 mol/kg in the Leduc and Cooling Lake due to dissolution of dolomite. The pH also increased in these 2 regions to 8.3 from 6.4. Ca^{2+} concentrations decreased from 0.18 mol/kg to 0.008 mol/kg in Ireton and UL1 and 0.12 in the remaining Leduc and Cooking Lake. The pH in these lower regions increased to 7.0.

Table 2: Water Chemistry of 100/02-05-058-25W4M

Analyte	Concentration (mg/L)	Concentration (mol/kg)
pH	6.4	
Na^+	35530	1.545
Ca^{2+}	7231	0.180
Mg^{2+}	1886	0.078
K^+	1875	0.048
Cl^-	73600	2.076
$HCO3^-$	852	0.014
$SO4^{2-}$	1263	0.013
HS^-	75	0.002

Modeling of CO_2 injection into the Leduc/Cooking Lake Reservoir

A 2-D radial model was developed representing the Leduc aquifer with the overlying Ireton and underlying Cooking Lake formation. The 2D model is composed of 1700 cells (17 cells in vertical and 100 cells in the radial direction). The 2D model was 100 km in the radial direction and divided into 100 cells with non-uniform spacing. The CO_2 was injected as a supercritical fluid into the bottom of the Leduc formation, UL6, and into the second lowest Cooking Lake layer, UL7, at a constant rate of 15 Mt/y (15.85 kg/s in total, 7.925 kg/s into each formation) for 15 years.

2D radial modeling of CO_2 injection is performed for the CO_2 injection phase (15 years) as well as the long-term post injection period (500 years). The simulation results are presented in 2-D graphical plot as a function of depth and radial distance at discrete time intervals of 1, 5 and 15 years for CO_2 injection simulation and 25, 150 and 500 years for the post injection simulation. The depth shown is the depth below the top of the Ireton formation and radial distance is distance from the injector.

Geochemical reactions

As supercritical CO_2 is being injected, it starts dissolving in the brine. During dissolution of CO_2 in the brine, CO_2 gas phase and CO_2 aqueous phase are assumed to be in equilibrium:

$$CO_2(sc) \leftrightarrow CO_2(aq)$$

where, "sc" and "aq" subscripts denote supercritical and aqueous CO_2, respectively.

The process of dissolution of the injected CO_2 into the brine results in solubility trapping of geological carbon sequestration. The aqueous CO_2 phase, CO_2 (aq) reacts with water, forming a weak carbonic acid (H_2CO_3) and this acid dissociates into a proton (H^+) and bicarbonate ion (HCO_3^-) resulting in a decrease in pH.

$$CO_2(aq) + H_2O \leftrightarrow H_2CO_3$$

$$H_2CO_3 \leftrightarrow H^+ + HCO_3^-$$

Furthermore, carbonic acid reacts with any reactant minerals present in a formation such as calcite producing some metals (for ex: Ca^{+2}) and bicarbonate ion (HCO_3^-). This process leads to ionic trapping of geological carbon sequestration.

$$H_2CO_3 + CaCO_3 \rightarrow Ca^2 + 2HCO_3^-$$

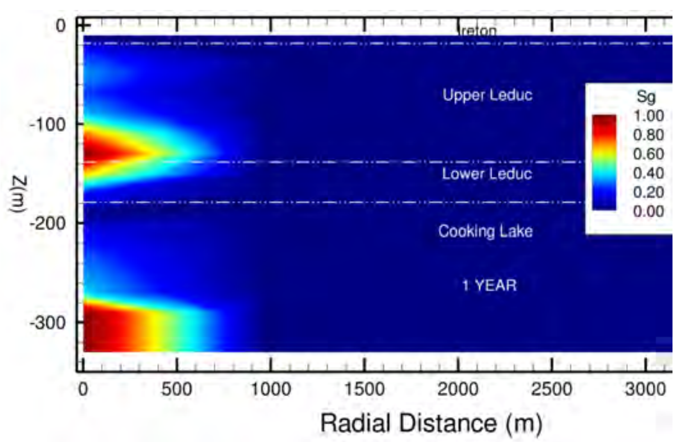
Later on, dissolution of primary minerals may increase the aqueous concentration of cations such as Fe^{+2}, which can lead to secondary precipitation of carbonate minerals. This process results in CO_2 mineral trapping, the most stable, long term form of geological carbon sequestration.

$$Fe^{+2} + HCO_3^- \leftrightarrow FeCO_3 + H^+$$

Even though the gas injected is a supercritical fluid, for convenience the supercritical CO_2 will be referred to as CO_2 gas.

CO_2 Injection Phase

The CO_2 is injected into the UL6 and CL7 layers and migrates up driven by the buoyancy force since the supercritical CO_2 is less dense than the brine. CO_2 injected into UL4 accumulates under the Ireton shale, the caprock of the Leduc aquifer. The CO_2 plume spreads out radially, it reaches out to a radial distance of 2.2 km from the injector at the end of 15 years of injection (Figure 1). CO_2 injected into the CL7 initially remains in that region due to the low permeability of the overlying CL6 layer, 1 mD. After 5 years the CO_2 has migrated vertically into other Cooking Lake regions (Figure 1).



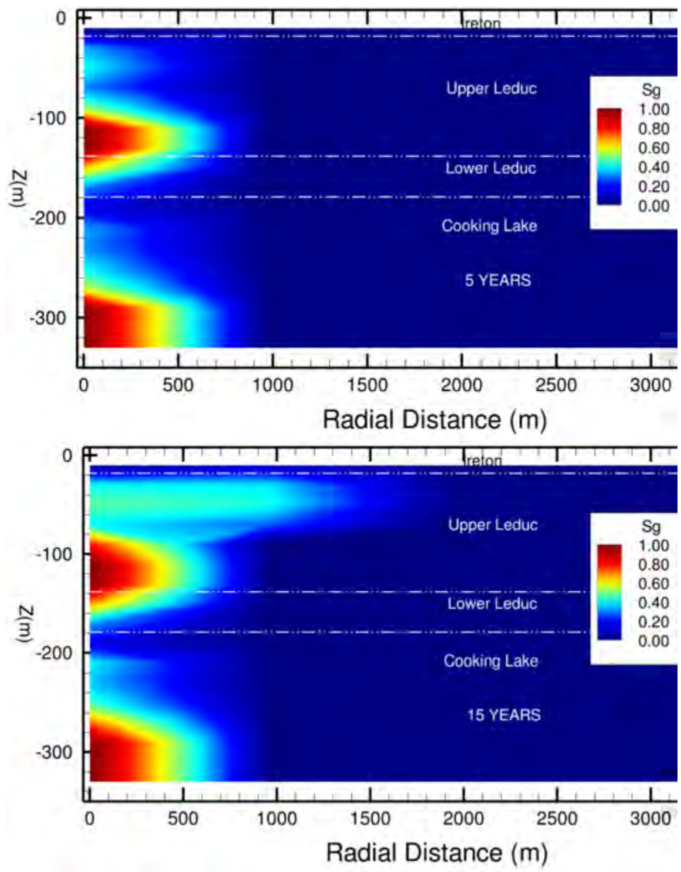


Figure 1: Spatial distribution of CO_2 gas after 1, 5 and 15 years of injection.

Figures 2 and 3 show the spatial distribution of Mg^{2+} and pH for 1, 5, and 15 years of CO_2 injection. Once the injected supercritical CO_2 phase starts dissolving in the brine, producing CO_2 aqueous phase, CO_2 (aq), it reacts with the brine, forming carbonic acid, H_2CO_3. This weak carbonic acid dissociates into bicarbonate ion, HCO_3^- and H^+ ion, decreasing the pH of the formation brine or increasing the acidity of the brine. The pH in the injection regions has decreased from 6.4 to a range of 4.0 to 6.4 in the injection zones (Figure 2). In addition, the carbonic acid dissolves the dolomite resulting in an increase in the Mg^{2+} ion concentration (Figure 3). Initially, the Mg^{2+} concentration at the UL6 injection region increases above and below due to the CO_2 migrating in both vertical directions, forming carbonic acid and reacting with the dolomite. A similar situation occurs at the Cooking Lake injection site. As time progresses the CO_2 plume region increases resulting in the region of high Mg^{2+} disappearing at 5 years and reappearing at 15 years.

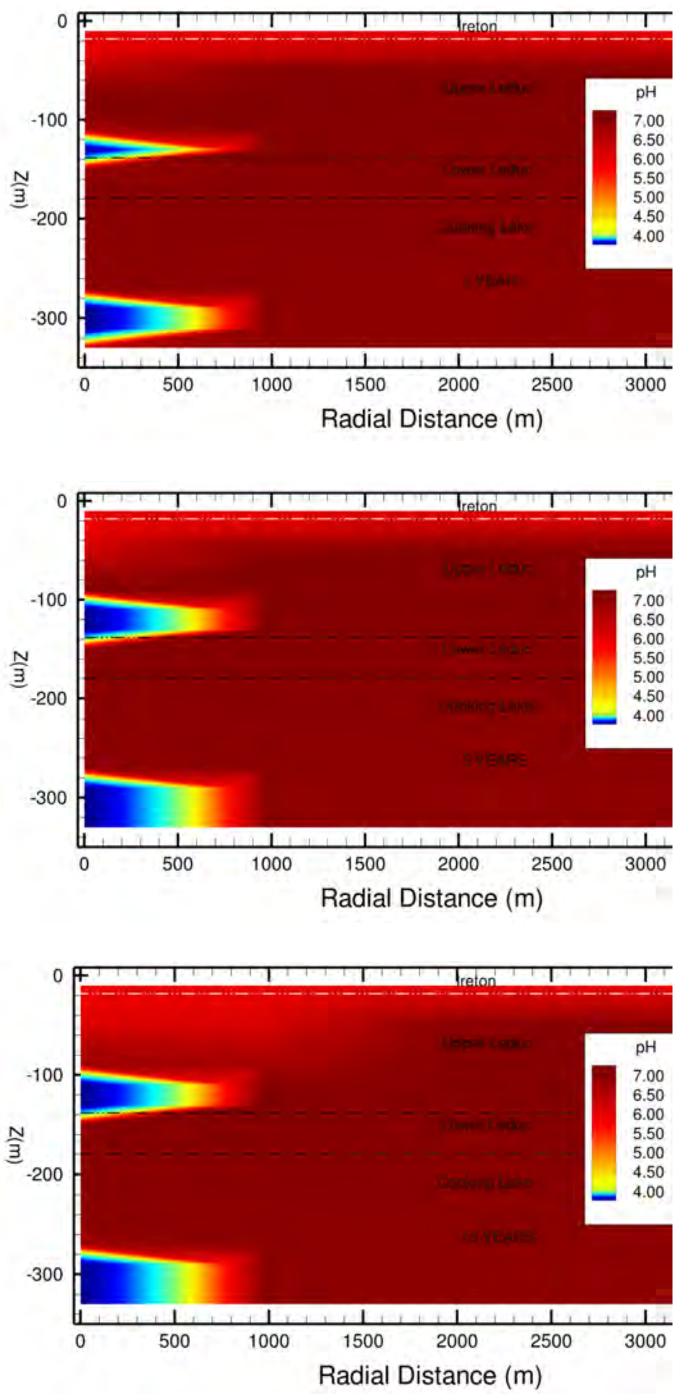


Figure 2: Spatial distribution of pH during 1, 5 and 15 years of injection.

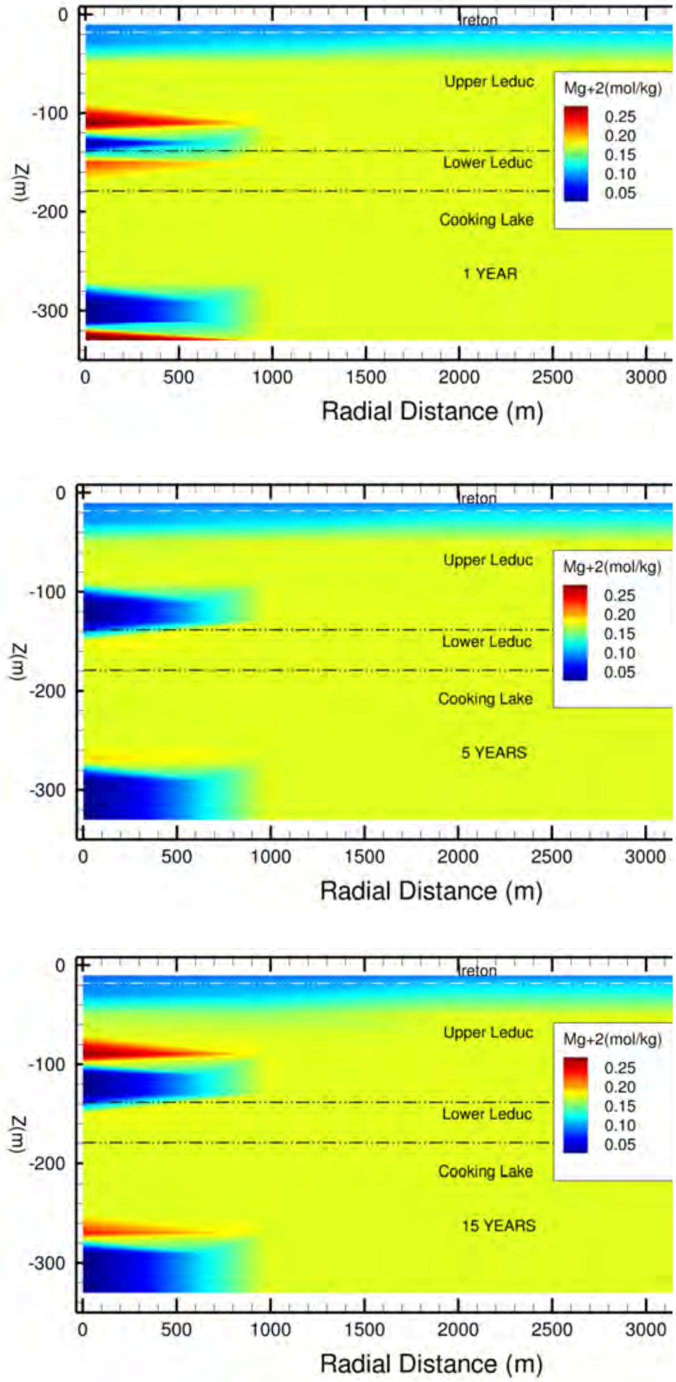


Figure 3: Spatial distribution of Mg^{2+} during 1, 5 and 15 years of injection.

Mineral Evolution during the Injection simulation

More than 80% of the Leduc formation constitutes dolomite. The following show changes in the volume fraction of a mineral of interest. CO_2 injection into the Leduc aquifer caused dolomite to slightly dissolve (shown by a decrease in the volume fraction), with a slight dissolution occurring at in all regions of the Upper Leduc and Cooking Lake(Figure 4). As the system goes into disequilibria as a result of dolomite dissolution, slight calcite precipitation occurs in all regions of the Upper Leduc and Cooking Lake (Figure 5). Halite was also included in the model but no halite precipitation occurred during the injection period.

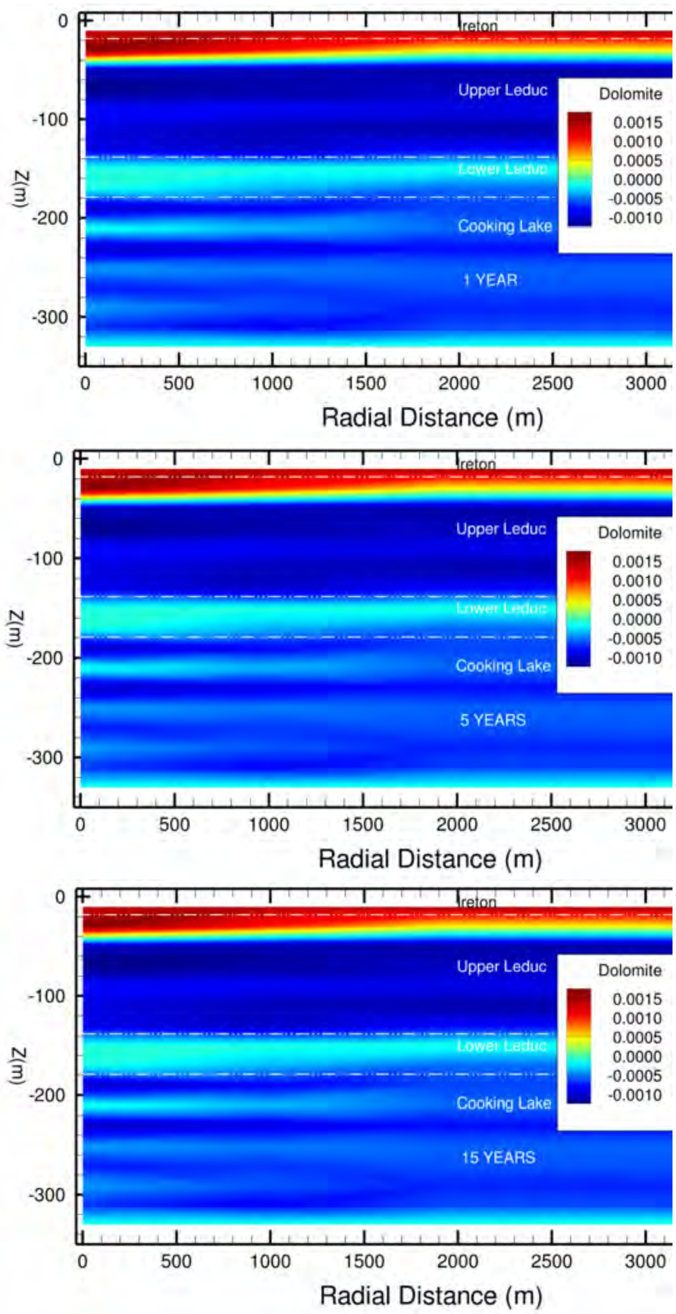


Figure 4: Spatial distribution of the variation in volume fraction of dolomite during 1, 5, 15 years of injection.

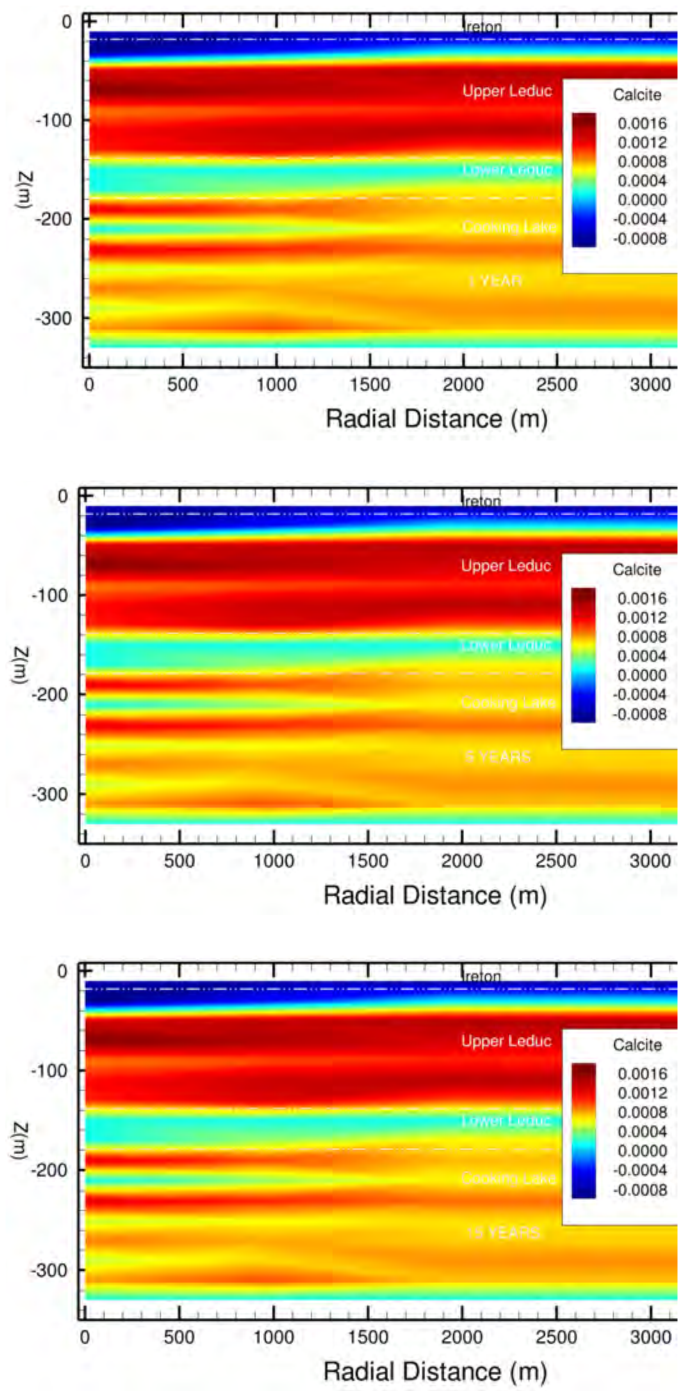
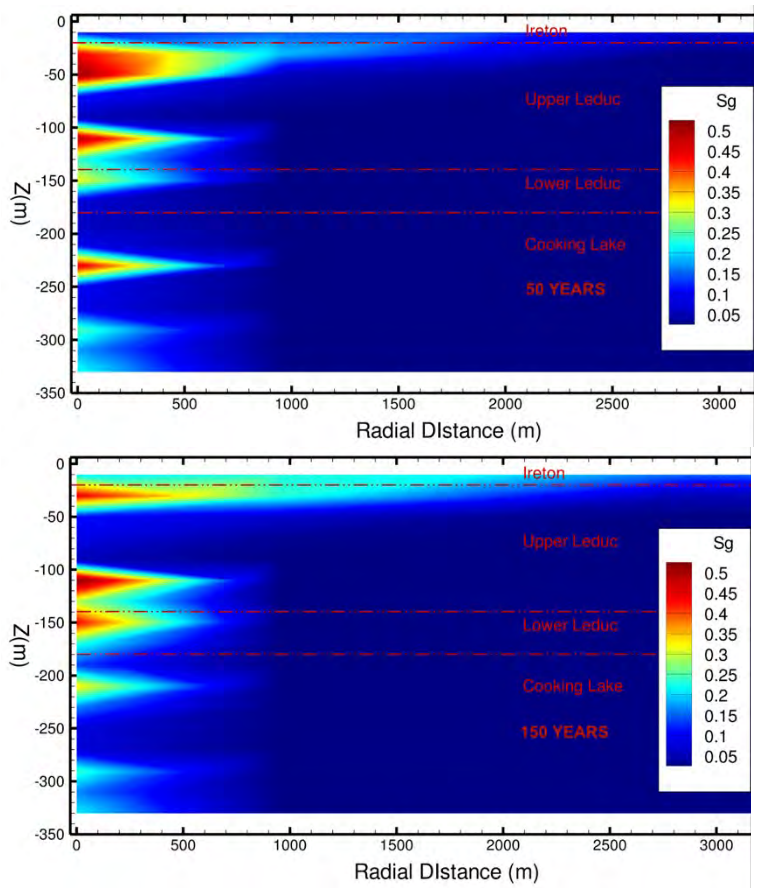


Figure 5: Spatial distribution of the variation in volume fraction of calcite during 1, 5, 15 years of injection.

Post Injection Phase

Fluid Chemistry

It is important to know how long free-phase CO_2 remains in the reservoir and how long complete dissolution of CO_2 into the brine takes because this determines the timescale over which a free-phase CO_2 has a chance to leak from the storage reservoir. For the injected CO_2 in free phase in the reservoir, it can take several thousands years before it completely dissolves in the brine (Lindeberg& Bergmo, 2002). As illustrated in Figure 6, after the CO_2 injection stopped, the hydrodynamic trapping as a free gas decrease with time, CO_2 in free gas phase, with up to a gas saturation of 0.5, exists mainly in the 30 m of upper portion of the Leduc aquifer at the end of 500 years simulation of post injection. It is also observed that, within the lower rest portion of the Leduc, there are small amount of free CO_2 phase at the injection regions UL6 and CL7. However, due to the buoyancy of the CO_2 a significant amount has been trapped under the Ir. The radial extension of the CO_2 plume in the Leduc aquifer, which was around 1 km at the end of 50 years of CO_2 injection, reaching out to 2 km after 500 years of post-injection. In Figure 7, pH is near neutral, pH ~6.9,in most of the reservoir, with the exception of around the injection region where the pH is ~6.5. In the region adjacent to the Ireton, UL1, the pH is ~5.9. Dolomite dissolution around the injection region, where the pH is slightly acidic, has a higher concentration of Mg^{+2} than in the rest of the reservoir for all the post-injection period (Figure 8).



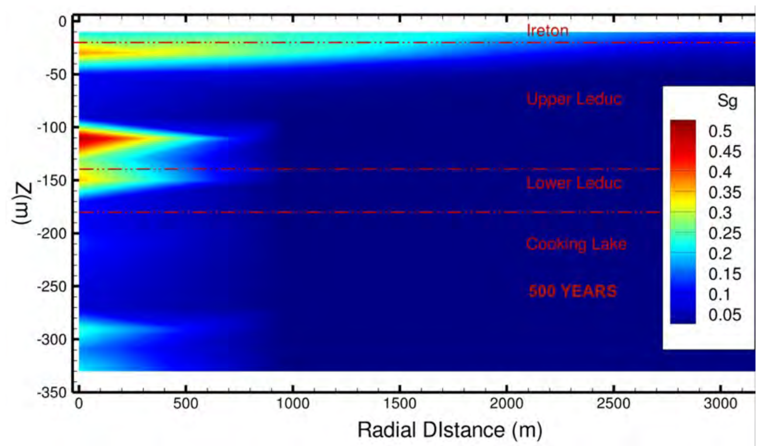
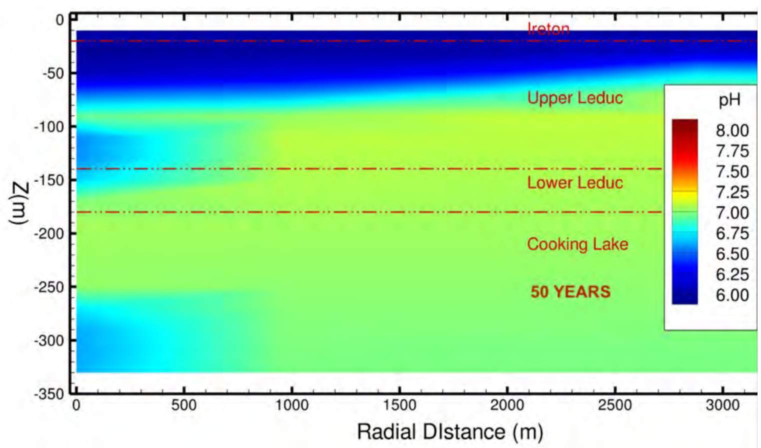
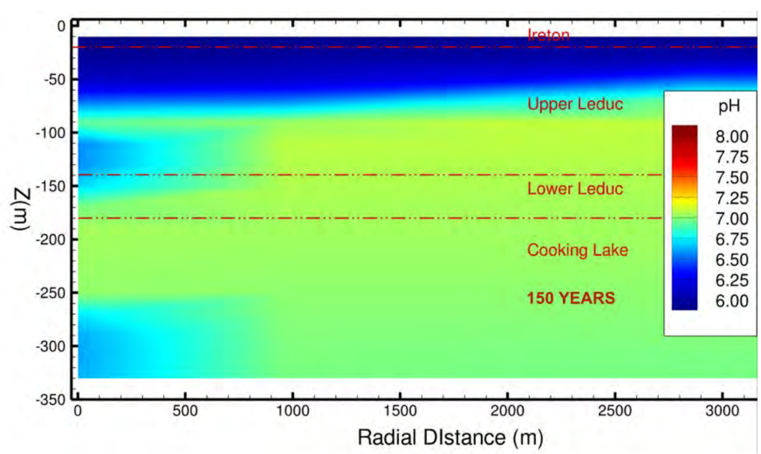


Figure 6: Spatial distribution of CO_2 gas saturation during 50, 150 and 500 years post-injection.





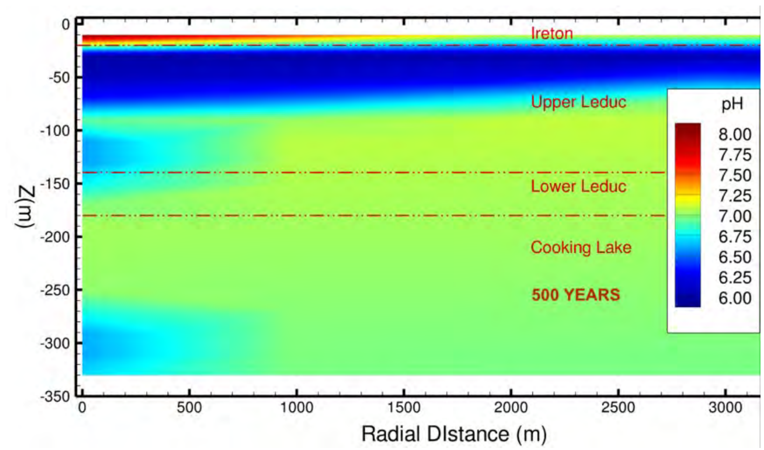
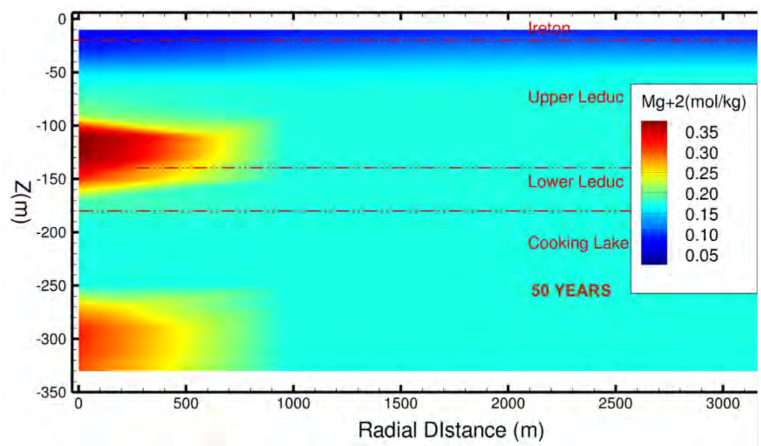
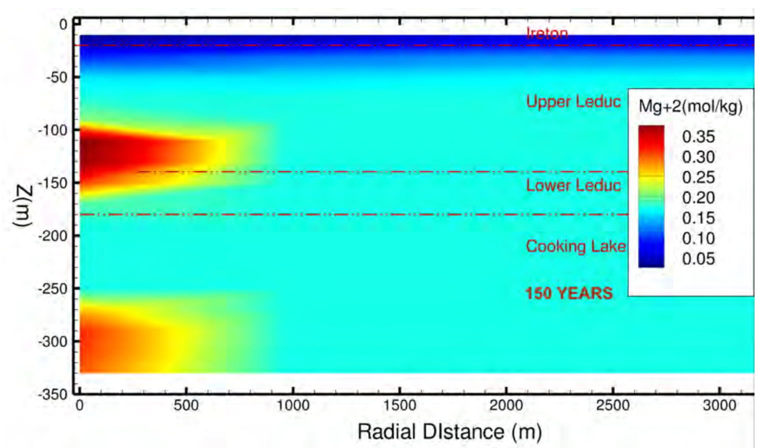


Figure 7: Spatial distribution of pH during 50, 150 and 500 years post-injection.





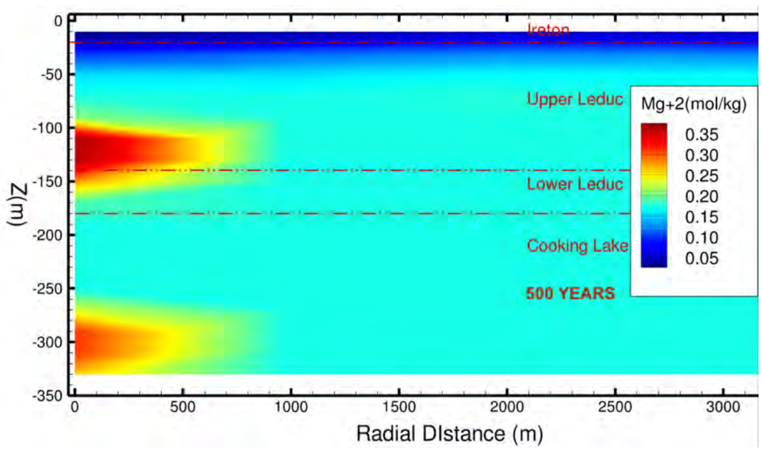
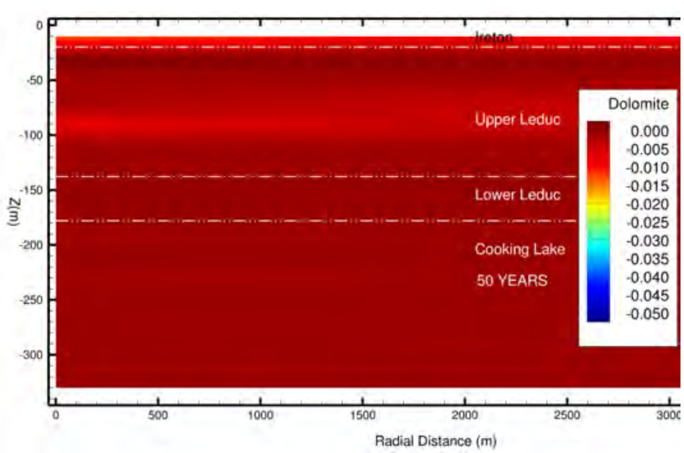


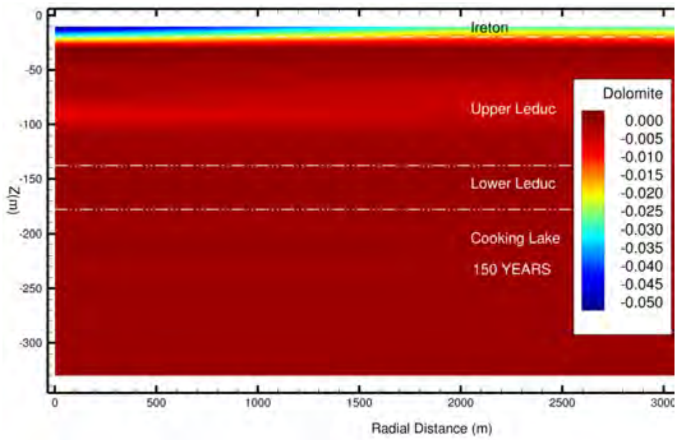
Figure 8: Spatial distribution of Mg^{2+} during 50, 150 and 500 years post-injection.

Mineral Evolution during the post injection simulation

Formations of secondary carbonates such as siderite, dawsonite, halite and magnesite as products of the interaction of the reactive fluid and the rock minerals are defined in the 2-D model but not observed in the simulation results. Dawsonite is one of the minerals that commonly precipitate out as a reaction product in geochemical simulation studies of CO_2 sequestration (Xu et al., 2003; Gauss et al, 2005). However, in this study, negligible amounts form (not shown). Negligible amount of kaolinite and Na-, Ca-smectites are observed during the simulation.

Dolomite is still slightly dissolving in the Leduc and Cooking Lake during the post-injection period (Figure 9). There appears to be in a small amount of calcite precipitation throughout the Leduc and Cooking Lake during the post-injection period (Figure 10).





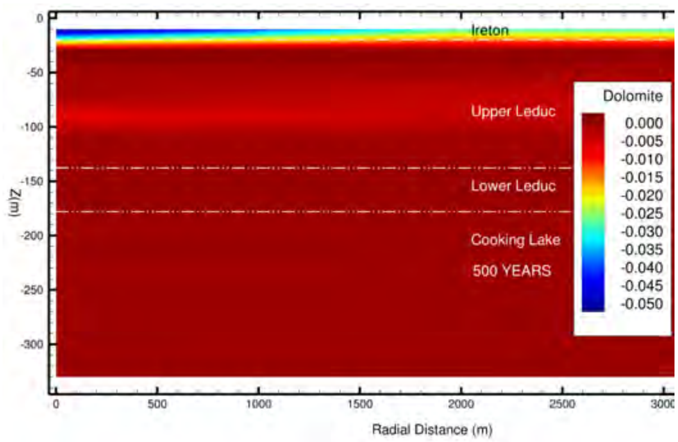
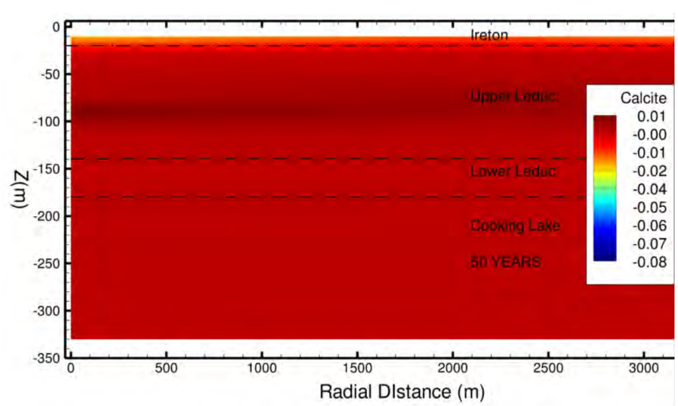


Figure 9: Spatial distribution of the variation in volume fraction of dolomite during 50, 150, and 500 years post-injection.



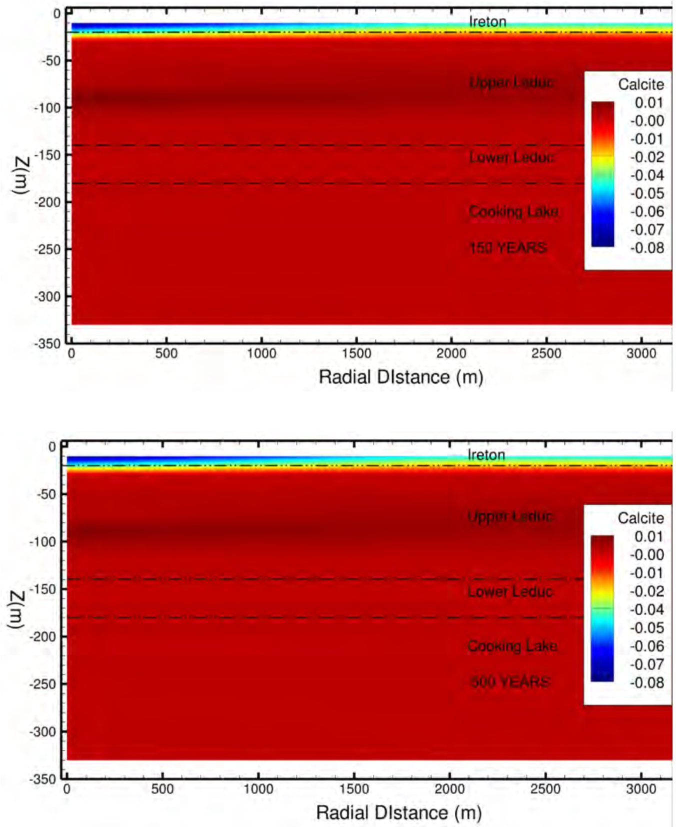
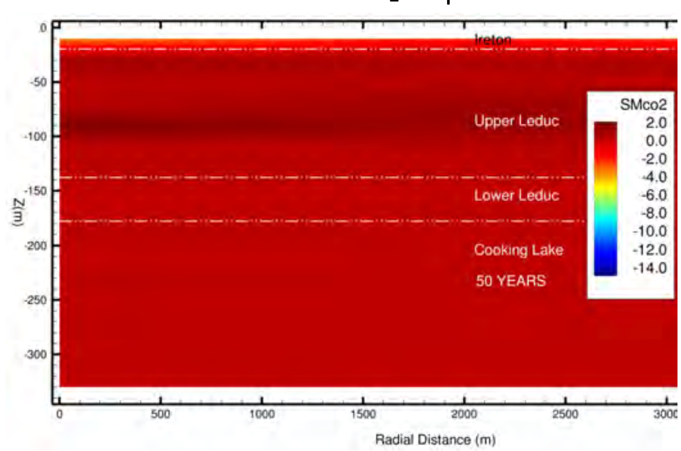


Figure 10: Spatial distribution of the variation in volume fraction of calcite during 50, 150, and 500 years post-injection.

Figure 11 represents the spatial distribution of the CO_2 sequestered in mineral trapping in the model. The amount of mineral trapping is shown in units of kg/m^3. Mineral trapping is important as it represents the best way to sequester CO_2. Negative value shows mineral dissolution and positive value shows mineral precipitation. For the Leduc and Cooking Lake there is a small amount of CO_2 sequestration in the mineral phase, ~1-2 kg/m^3.



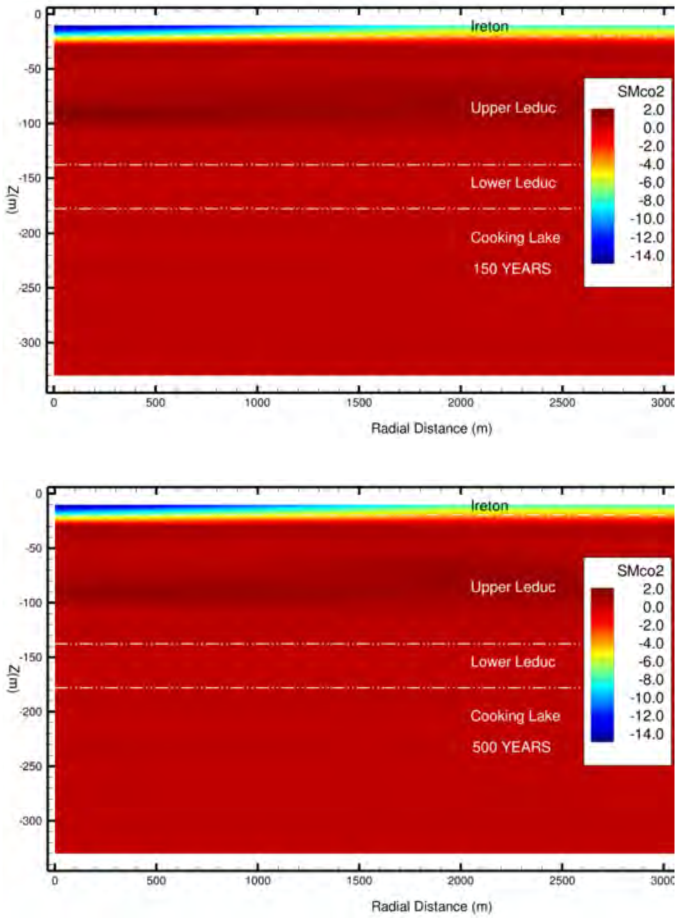
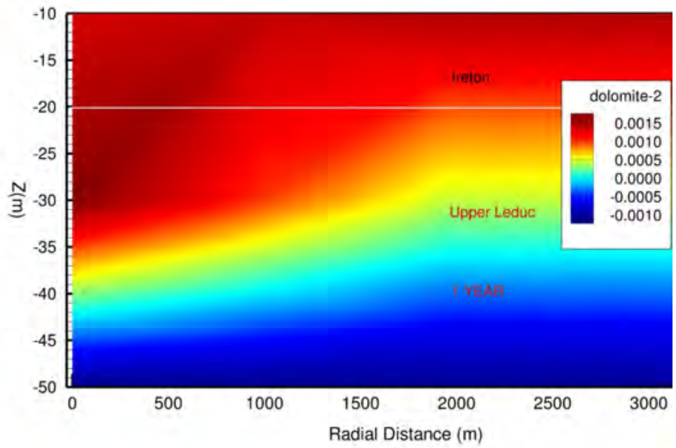


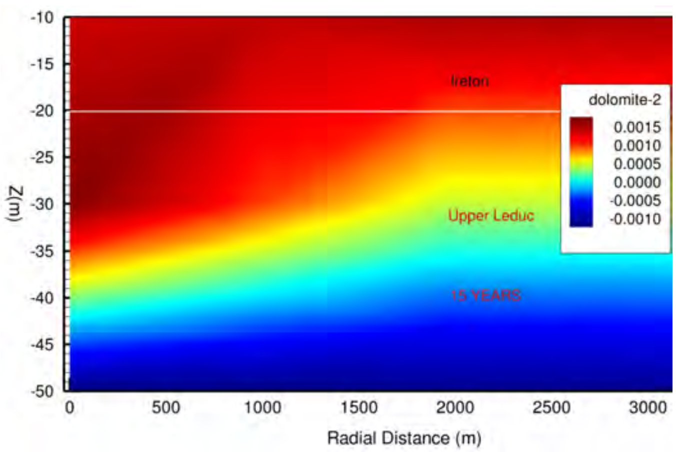
Figure 11. Spatial distribution of CO_2 sequestered (kg/m^3 rock) as minerals (SMco2) 50, 150, and 500 years of post-injection.

Caprock Integrity

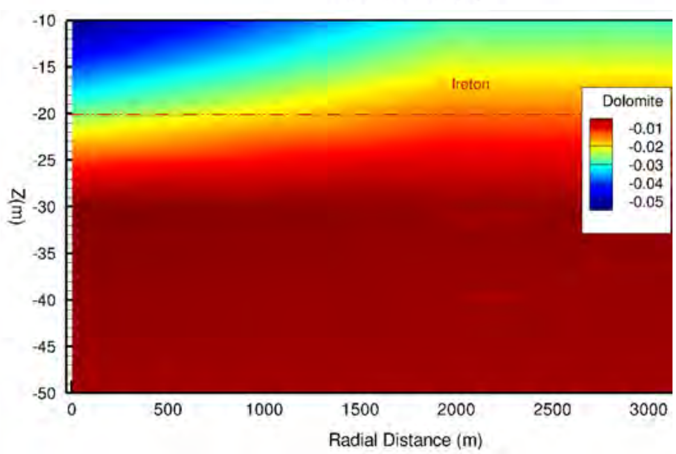
Interaction between the caprock and the injected CO_2 is important in order to determine the integrity of the caprock, i.e., significant changes in the caprock could have an adverse effect on the long-term storage of CO_2. Figure 12 looks at the spatial distribution of dolomite within the Ireton caprock and the Upper Leduc regions, UL1 and part of UL2. From this, it can be seen that there is a small amount of dolomite precipitation within the caprock and both small amounts of dissolution and precipitation in the Upper Leduc, UL1 region during the injection period. Post-injection small amounts of dolomite dissolve. However, given that the volume of dolomite is small, this small change in the volume of dolomite should not affect the caprock integrity. The calcite in the Ireton shows very slight dissolution during CO_2 injection in the Ireton and smaller amounts of dissolution and precipitation occur in the UL1 region of the Leduc during injection. Post-injection there is calcite dissolution in the Ireton and UL1 region of the Upper Leduc.



dolomite-2
0.0015
0.0010
0.0005
0.0000
-0.0005
-0.0010
Ireton
Upper Leduc
1 YEAR
Z(m)
-10
-15
-20
-25
-30
-35
-40
-45
-50
0
500
1000
1500
2000
2500
3000
Radial Distance (m)



dolomite-2
0.0015
0.0010
0.0005
0.0000
-0.0005
-0.0010
Ireton
Upper Leduc
15 YEARS
Z(m)
-10
-15
-20
-25
-30
-35
-40
-45
-50
0
500
1000
1500
2000
2500
3000
Radial Distance (m)



Dolomite
-0.01
-0.02
-0.03
-0.04
-0.05
Ireton
Z(m)
-10
-15
-20
-25
-30
-35
-40
-45
-50
0
500
1000
1500
2000
2500
3000
Radial Distance (m)

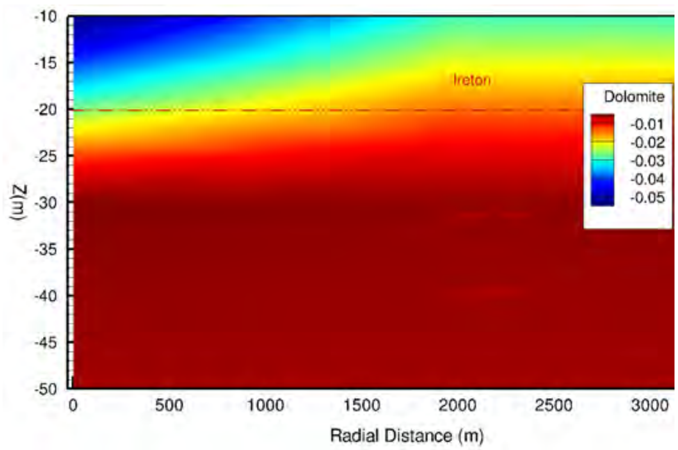
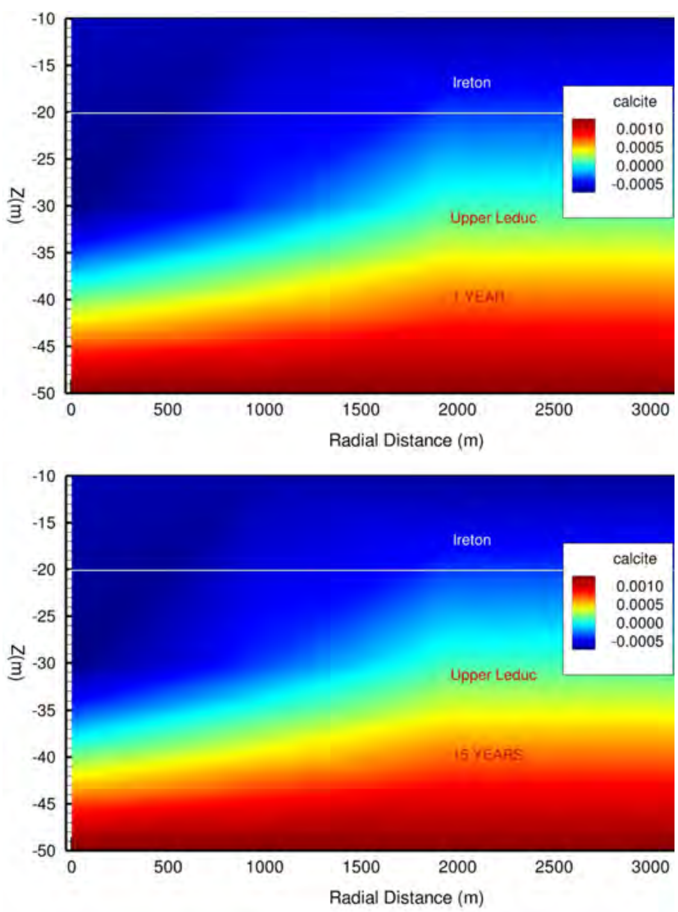


Figure 12: Spatial distribution of the variation in volume fraction of dolomite during 1, 15 years of injection, 150, and 500 years post-injection.



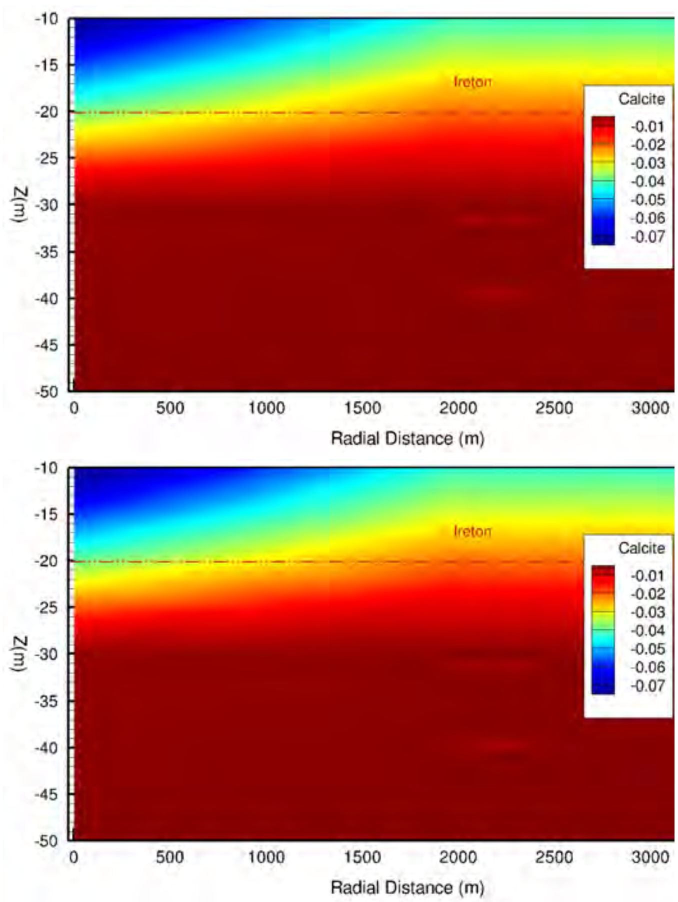


Figure 13: Spatial distribution of the variation in volume fraction of calcite during 1, 15 years of injection, 150 and 500 years post-injection.

The only other minerals that has a significant change in volume are ankerite and siderite. While ankerite is not present in the initial Ireton or Leduc mineralogy, it does begin to precipitate post-injection mainly in the Ireton, but also in the UL1 region of the Leduc (Figure 14). Figure 15 shows changes in siderite, found in the Ireton, with changes occurring post-injection. Siderite dissolution occurs in the Ireton. Given that the changes in the observed changes in the mineral volumes for ankerite and siderite are small, it it was found that there are no significant changes in the porosity or permeability of the caprock (not plotted).

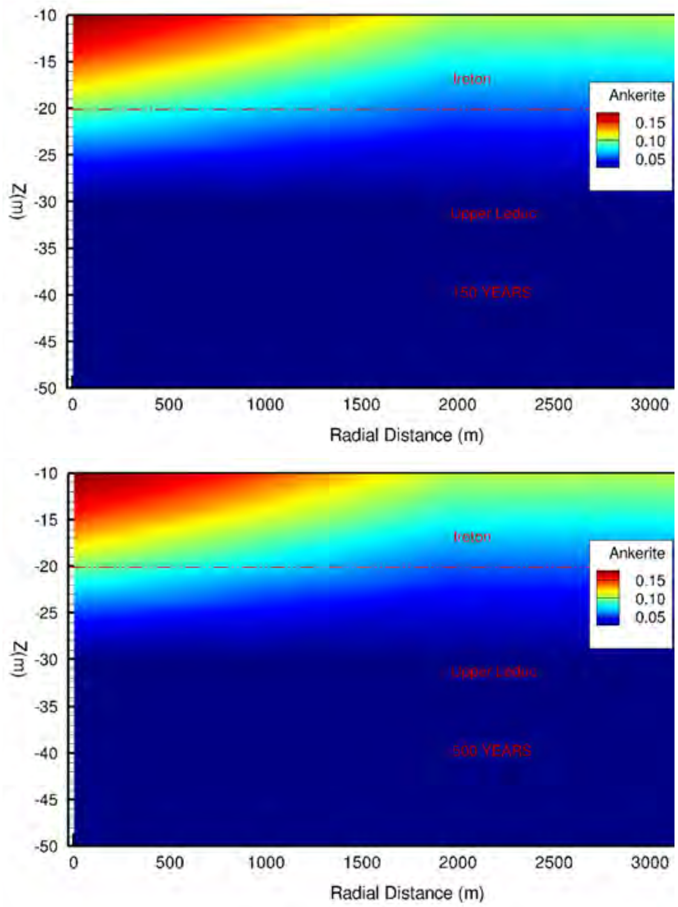
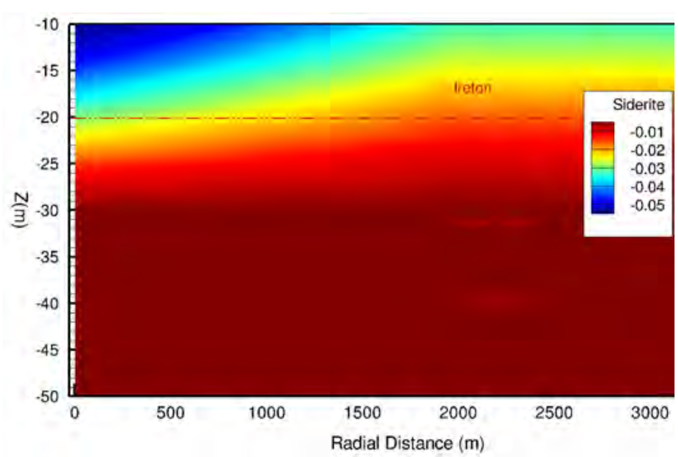


Figure 14: Spatial distribution of the variation in volume fraction of ankerite during 150 and 500 years post-injection.



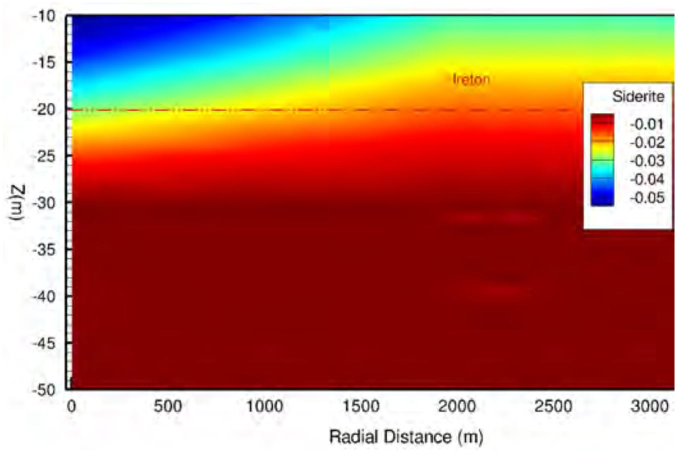


Figure 15: Spatial distribution of the variation in volume fraction of siderite during 150 and 500 years post-injection.

H_2S in Fluid

There is a small amount of H_2S naturally occurring in the waters, there is a question as to what happens to the H_2S as CO_2 is injected into the system. The modelling software tracks HS-, so the concentration of HS- in the Leduc waters was calculated, 75 mg/L, and when this water was equilibrated with the minerals the resulting concentration was 45 mg/L, and this was used in the model. As CO_2 is injected the HS^-, the concentrations decreased around the injection plume as shown in Figure 16. The decrease in HS^- can be explained by the acidification of the waters by the CO_2, resulting in $H_2S_{(aq)}$ forming. Unfortunately, the modeling software, TOUGHREACT v. 1.2, is unable to track the $H_2S_{(aq)}$ aqueous species.

However, the software can track the partial pressure of $H_2S_{(g)}$ which is exsolved due to the increasing amounts of CO_2 present in the water during injection. As the $H_2S_{(g)}$ is exsolved it collects at the front of the CO_2 plume. Figure 17 show that initially the highest partial pressure of $H_2S_{(g)}$ is located in the injection plume. As injection progresses, the injection region maintains the highest partial pressure of $H_2S_{(g)}$ but the partial pressure in the regions farther from the injection region increases. By 15 years the partial pressure of $H_2S_{(g)}$ in the injection region has dropped to less than 0.005 bars from a high of 0.065 bars during the initial injection. The $H_2S_{(g)}$ has been moved out into the main reservoir region is beginning to migrate towards the Ireton caprock due to the buoyancy of the $H_2S_{(g)}$.

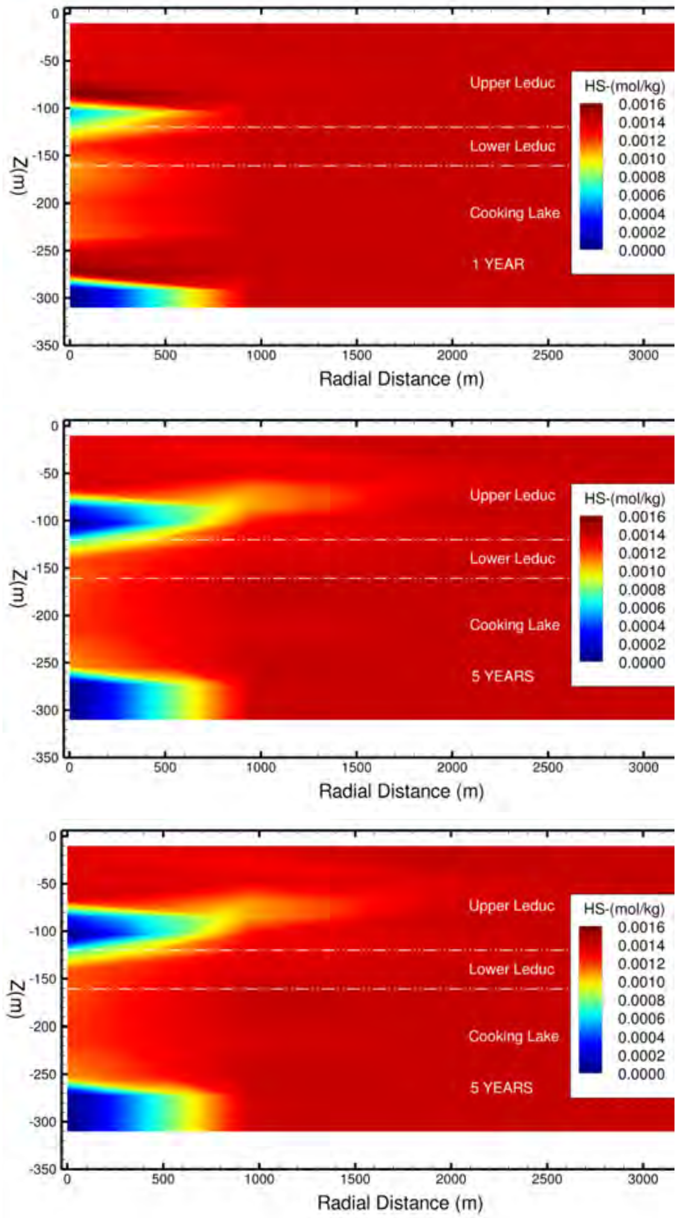
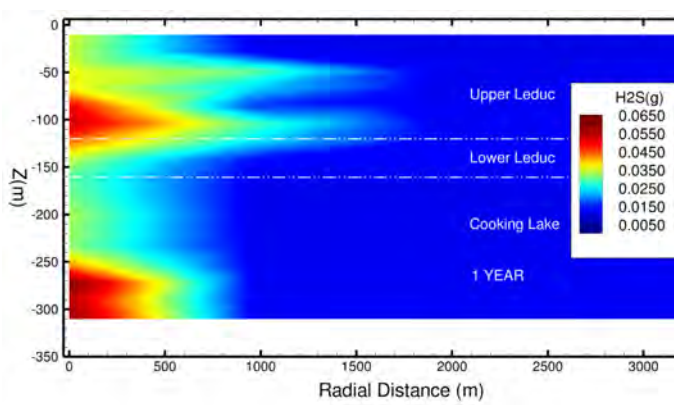


Figure 16: Spatial distribution of HS^- during 1, 5, and 15 of injection.



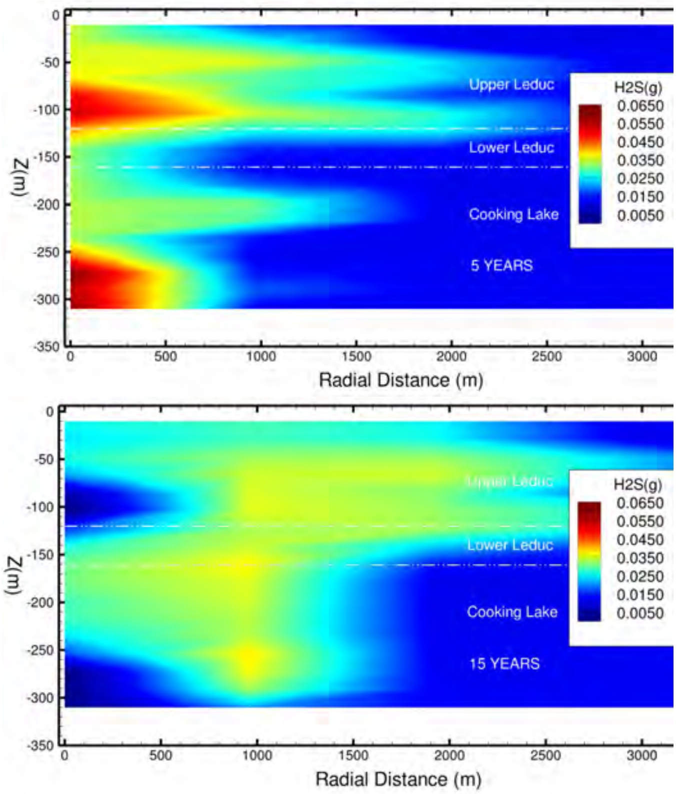


Figure 17: Spatial distribution of $H_2S_{(g)}$ during 1, 5, and 15 of injection. The gas pressure is in bars.

Summary

2D radial modeling was conducted for a 15-year CO_2 injection phase followed by a 500-year long-term storage period. Beside the storage Leduc and Cooking Lake aquifers, the overlying Ireton shale cap rock were considered in the 2-D model. The CO_2 was injected into the two regions, one at the bottom of the Upper Leduc, the UL6 region, and the second injection near the bottom of the Cooking Lake, the CL7 region. at the rate of 0.5 Mt/y (15.85 kg/s) for 15 years.

During CO_2 injection there was a slight dissolution of dolomite and slight precipitation of calcite. No other minerals had any significant effect on the reservoir. The porosity of the system did not change significant even with the dolomite dissolution and calcite precipitation. The water chemistry changed slightly during injection, the main result being a decrease in pH, due to the formation of the weak carbonic acid, which resulted in the aforementioned dolomite dissolution.

During the post-injection period the system is in relative equilibrium, with the pH remaining relatively constant at 6.4. There are small amounts of dolomite dissolution and calcite appearing precipitation. In addition, small amounts ankerite Within the Leduc and Cooking Lake a small amount of CO_2 is sequestered as a mineral, between 1 and 2 kg/m^3.

The caprock is where most of the reactions are occurring, due to its diversity of minerals present. There is dolomite dissolution and calcite precipitation, but with relatively small changes in the volume fraction of each mineral. There are small changes in the volume due to the dissolution of siderite with small amounts of ankerite precipitating. There is no significant changes in porosity or permeability within the caprock region.

The H_2S present in the waters are minor, ~45 mg/L of HS^- present. As CO_2 is injected, the concentration of HS- in the CO_2 plume region decreases. The acidification of the water due to CO_2 injection results in $H_2S_{(aq)}$ forming with small amounts of $H_2S_{(g)}$ being exsolved from the fluid. It is present in the front region of the CO_2 plume and migrates through the water in both the Leduc and Cooking Lake.

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