CHARACTERIZING HYDROGEOLOGICAL CHANGE FROM OIL AND GAS DEVELOPMENT IN THE WESTERN CANADA SEDIMENTARY BASIN

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ABSTRACT
The Western Canada Sedimentary Basin (WCSB) has been extensively developed for oil and gas production and still hosts large reserves of oil and gas. Remaining reserves are likely to require various stimulation techniques. The WCSB also has significant potential for carbon sequestration, waste isolation and geothermal energy and contains large stores of fresh groundwater. Future development needs to consider how historical development both informs and constrains future developments. Oil and gas development may provide key hydrogeological data for these projects but legacy impacts, such as hydraulic fracturing, leaky wells and injection of produced water, create challenges with subsurface characterization and engineering design.

Legacy impacts can be grouped into four main areas of impact: changes in pressure, changes in temperature, changes in chemistry and changes in permeability. Changes in pressure, temperature and chemistry are results of production and injection, with injection mainly affecting temperature and chemistry. The amount of production and injection in the WCSB has been substantial. Approximately 23 km^3 of water has been injected into the WCSB. Spread out over the geographic area of Calgary (825.3 km^2), the injected water would form a lake of 29.1 m depth, approximately the height of a 10-storey building. Increasing the area to the Calgary-Edmonton Corridor, a 38 323 km^2 region encompassing the metro areas of Calgary and Edmonton and the area in between, this is equivalent to a water depth of 63 cm. The bulk of the injected water is produced water, with a volume of 20 km^3. Monthly production and injection volumes are available through various databases but the associated changes in pressure, temperature and chemistry are not well understood at the regional scale. Details of chemistry and temperature of injected water are not well known. Here, we provide a preliminary analysis of this issue at the basin scale and for selected local areas. Issues appear minor at the basin scale but may create significant risk at the scale of individual developments.

Pressure changes at individual wells are not documented in commercially available databases for the WCSB. Most previous efforts to map pressures or hydraulic head in various formations have used screening procedures to eliminate wells affected by production or injection in order to provide maps of background conditions. The current project will examine changes in pressure over time. Preliminary findings indicate that these will not be significant at the basin-scale but will have significant effects on individual pools and could be an important factor in changing cross-formational flow.

Injection of water is likely to result in temperature changes at depth. Water is often injected into formations to stimulate further oil production. The water is used to increase the pressure in the formation and drive oil towards the producing well. Injected water is often sourced from production water, a byproduct of oil and gas extraction, and is stored on the surface prior to injection, losing heat over time. Produced water is often not enough, so other sources of water are employed. This makeup water is often sourced from surface water bodies and mixed with produced water before injection, further reducing the temperature of the injected water. The injection of water into formations can potentially alter the thermal regime within the formation, impacting future potential uses including geothermal energy and heat extraction. Calculating the radius of thermal influence around a well from injected water showed that the effects are felt most prominently at the local scale, especially in a dense well field such as the Redwater field. Here, we provide an analysis of the thermal impacts of injected water within the Redwater field.

The chemistry of injected water is largely unknown in the WCSB. While injected water is often produced water from the same formation, this is not always the case. Use of surface water or shallow groundwater will result in dilution of brines typically associated with oil and gas production. There has also been an increase in the use of brackish and saline water for enhanced oil recovery and hydraulic fracturing, which will cause changes to water chemistry in the subsurface. Finally, flowback and produced water from hydraulic fracturing is typically injected into higher permeability reservoirs. The implication of mixing these waters with different chemistry has not been assessed at the regional scale.

There have been approximately 700 000 wells installed in the WCSB, of which over 200 000 have been abandoned at various construction and abandonment procedures, potentially resulting in leaky wells. The spatial density of wells in the

WCSB varies from <1/km^2 over most of the basin to local areas of over 15/km^2 in Alberta. Higher densities of wells tend to amplify the effects of legacy impacts. The permeability of the formation may have changed due to fracking and leaky wells. Effective permeabilities were estimated using the Raleigh Equation and show that permeabilities may rise an order of magnitude at the basin scale and several orders of magnitude locally. Thus, the change in permeability due to leaky wells is not likely to be significant at the basin scale, but likely to be important locally for transport problems.

The Redwater Field northeast of Edmonton is a depleted oil reservoir where some of the wells have been converted to water disposal wells, including sour water. Injection occurs into the Leduc Formation Redwater reef, a Late Devonian carbonate reef with a thickness of 160 to 200 m in the injection area. Average porosity is 7% and formation temperature is around 34°C. Since 1948, 1074 wells have been drilled in the field, of which 543 are now abandoned, resulting in a well density of approximately 5.5/km^2. The field produced approximately 0.13 km^3 of oil and 1.71 km^3 of water, while approximately 1.77 km^3 of water (~1.22 times the volume of Abraham Lake, Alberta at full capacity) was injected into the field through 58 injection wells, of which 47 are sour water injection. Although most of the injected water is mainly produced water from the Redwater reef, changes in temperature and chemistry occur as the water is brought to and stored on the surface. The dissolution of acid gas into the produced water to create sour water, as well as the mixing with makeup water, also alters the chemistry. Here, we provide an analysis of legacy impacts, including changes in pressure, temperature, chemistry and permeability, on the Redwater Field through analytical and numerical models, with a discussion on the broader implications of our results.