Cameco

CAMECO RESOURCES
Smith Ranch-Highland Operation
Mail:
P.O. Box 1210
Glenrock, WY
82637 USA

Tel: (307) 358-6541
Fax: (307) 358-4533
www.cameco.com

December 21, 2011

ATTN: Document Control Desk
Nuclear Regulatory Commission
Washington DC, 20555-10001

CERTIFIED MAIL #7011 0470 0000 7716 1000 RETURN RECEIPT REQUESTED

RE: NRC Inspection Report 040-08964/11-002

Power Resources, Inc. d/b/a/ Cameco Resources is herein responding to NRC Inspection Report 040-08964/11-002 for the routine inspection conducted August 29-September 1, 2011.

In response to the unresolved item regarding the failure to evaluate if wells exceeded injection pressures after an incident (URI-040-08964/1102-03) Cameco Resources commissioned a third party review by, SRK Consulting. The third party review included analysis of information related to the May 3, 2011 in regard to forces placed upon the confined aquifer during the power failure and subsequent spill event as well as the pressure seen by the well heads. One causal factor that led to the spill was that Mine unit 15A, in contrast to other mine units within the Smith Ranch Highland (SRH) project area, has a potentiometric surface of the O-sand production zone aquifer approximately 100 feet below the ground surface, which is about 200 feet shallower than the potentiometric surface at most mine units in the SRH project area.

SRK completed a technical review of subsurface hydraulic response to injection well operation in the absence of pumping, as observed at Mine Unit 15A, header house 15-20 on May 3, 2011. The review was based on operational discussions with Cameco staff, review of all available and relevant information, and the results of groundwater modeling to simulate the power failure event. In conclusion it was determined that the formation fracture pressure nor the injection well head pressures were elevated beyond regulatory limits stated in the facility operating permits.

In addition Cameco Resources conducted mechanical integrity testing (MIT) inspections of all injection wells in the wellfield and found two of 40 Class III wells that did not pass the Cameco Resources MIT inspection criteria. The MIT wells were found to have failed at a joint of the PVC piping and did not appear to be related to the event that occurred on May 3, 2011. The wells (15I-0739 and 15I-0741) were plugged and abandoned on October 21, 2011 after further

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investigation and isolation of the failure location. This information is available at site for your further review during the next inspection.

If you have questions, please contact me at (307) 358-6541, ext. 452

Sincerely,

Brent Berg
General Manager

Attachments: SRK Report

cc:	D. Mandeville, USNRC (2 copies)	CERTIFIED MAIL #7011 0470 0000 7716 1017
	L. Spackman, WDEQ	CERTIFIED MAIL #7011 0470 0000 7716 1024
	File SR 4.6.4.1	
	CR-Cheyenne	

srk consulting

SRK Consulting (US) Inc.
Suite 3000
7175 West Jefferson Avenue
Lakewood, CO 80235

T: 303.985.1333
F: 303.985.9947

denver@srk.com
www.srk.com

Technical Memo

To:	Dave Moody Arlene Faunce	**Date:**	November 26, 2011
Company:	Cameco Resources Smith Ranch Highland Operations	**From:**	Vladimir Ugorets Matt Hartmann Miori Yoshino Terry Braun
Copy to:	Jim Clay, Cameco David Repshire, Cameco	**Project #:**	157200.010

Subject: Technical Review of Solution Release at Mine Unit 15, Header House 15-20

1 Introduction

Power Resources Inc., dba, Cameco Resources (Cameco) requested that SRK Consulting (US) Inc. complete a technical review of potential operational impacts of a reportable release of uranium bearing solutions to the ground surface at the Smith Ranch Highland Uranium In Situ Recovery (ISR) Mine located in Converse County, Wyoming. This technical memo summarizes the event analysis completed by SRK.

2 Background

On May 3, 2011 an estimated 1,500 gallons of water were released from production wells located in Mine Unit 15, in the area of header house 15-20. The release resulted from a three failed transformer fuses that caused a total power outage at header house 15-20 at approximately 0230 hours. The automated Cla-Val flow control valve at the header house failed to close for unknown reason(s). The open control valve allowed continued pressurization of injection wells at an approximate rate of 400 to 600 gpm for a period of approximately 8 hours based on both production and injection pressure data recorded in Smith Ranch Satellite 1 (SR1) and the Central Processing Plant (CPP). Based upon field observations, 8 production wells flowed to the surface with no pumping to relieve injection pressure in the production formation. No surface flow was observed from the 150psi pressure relief valves that seal the injection well heads. Following discovery of release of solutions, the flow of barren lixiviant solution (BLS) to header house 15-20 was manually isolated and stopped. A vacuum truck was dispatched to the site and approximately 200 of the estimated 1,500 gallons released were recovered. Following replacement of the Cla-Val, and restoration of power, header house 15-20 operations resumed in the afternoon of May 3, 2011.

3 Technical Evaluation

In an effort to define the potential effects of the release event, Cameco requested that SRK undertake this technical evaluation to assess:

- The maximum pressure applied to the formation during the event compared to the permit stated fracturing pressure of the formation;
- The maximum pressure applied to the wells during the continued injection in absence to the pumping; and
- The maximum possible pressure experienced at the manifold in HH-20-MU-15 during the power outage event and subsequent contamination of injection in absence of pumping.

3.1 Site Visit

Prior to commencing the technical review, SRK completed a site visit at the Smith Ranch Highland facility on September 6-7, 2011. SRK staff present for the site visit were Terry Braun - SRK Practice Leader, and Vladimir Ugorets - Principal Hydrogeologist. Messrs Braun and Ugorets met with Brent Berg - Mine Manager, David Moody - Well Field Operations Manager Superintendent, Larry Wilbanks – Restoration Superintendent, Jim Clay - Senior Metallurgist, and David Repshire - Staff Engineer to discuss the scope of work, event of interest, and to gather relevant data to complete the technical review.

A second site visit by SRK was completed on November 8, 2011 by Matt Hartmann – Senior Hydrogeologist for the purpose of further discussion, and collection of additional data for assessment of the operational pressure regime of the Mine Unit 15 injection wells during the power failure. Mr. Hartmann met with Arlene Faunce – Radiation Safety Officer, Derek Eager – Well Field Supervisor, and Russel Jannsen – Well Field Services Supervisor, in addition to the aforementioned Cameco staff from the September meeting.

3.2 Formation Fracture Pressure

3.2.1 Analytical Evaluation of Formation Pressurization

Initial analysis of the available data consisted of a pressure evaluation to assess the potential of the continued operation of injection wells, in the absence of pumping well operation, to exceed the fracturing pressure of the formation.

Hydrostatic pressure was simulated as difference between depth to the top/bottom of production zone and depth to the water level. Injection pressure is a measured value prior to the pumping failure. Formation fracturing pressure was estimated base of gradient 0.7psi/ft, the same as that used in all Smith Ranch and Highland permits. The results of simulation of maximum total pressure vs. fracturing pressure of formation are shown in Table 1.

Table 1: Simulation of Maximum Total Pressure vs. Formation Fracturing Pressure

Parameter		Depth	Hydrostatic Pressure		Injection Pressure	Maximum Total Pressure	Formation Fracturing Pressure	Pressure Differential (Frac. – Max)
		ft	ft	psi	psi	psi	psi	psi
Top of Production Zone	Average	451.2	339.2	146.9	110.0	256.9	315.8	59.0
Bottom of Production Zone		471.6	359.6	155.7	110.0	265.7	330.1	64.4
Top of Production Zone	At Minimum Depth	442.0	330.0	142.9	110.0	252.9	309.4	56.5
Bottom of Production Zone		463.0	351.0	152.0	110.0	262.0	324.1	62.1

Note: Depth to water level in production zone is assumed to be 112ft

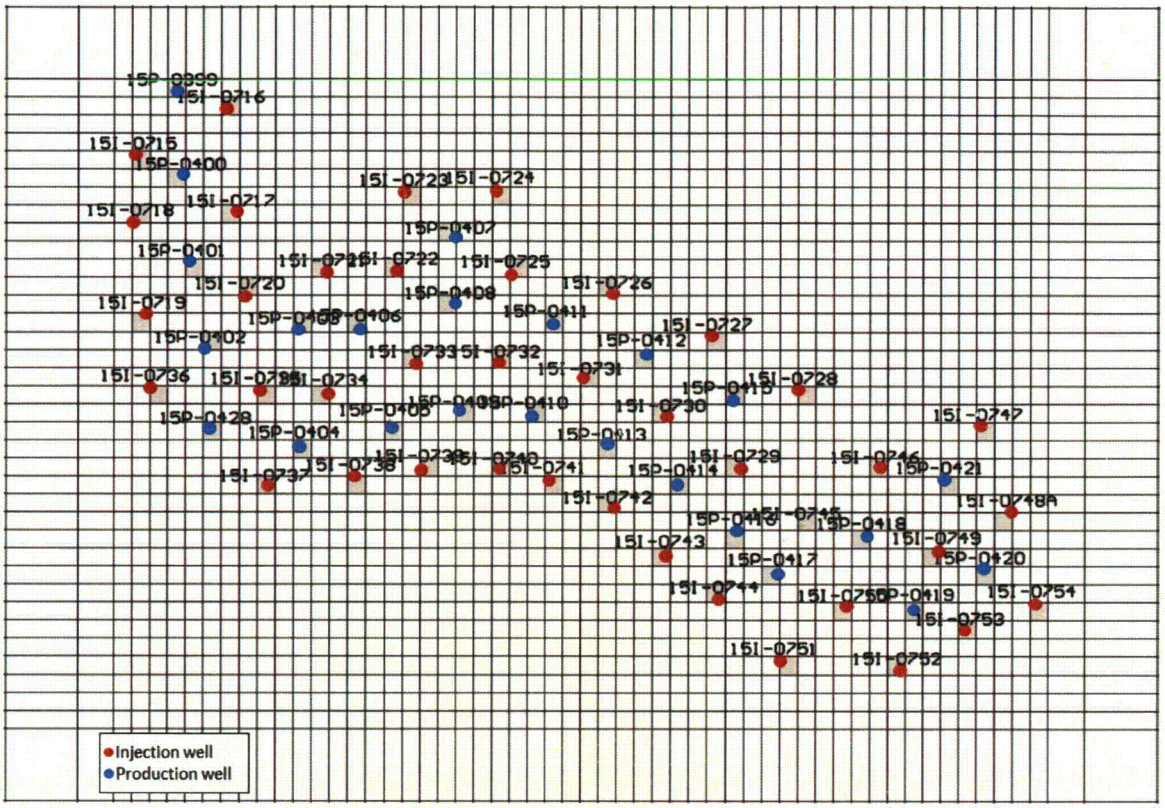
The results of the formation pressure evaluation indicate that:

- Hydrostatic pressures at averaged top and bottom of production zone vary between 147psi and 156psi (143psi and 152psi at the top and bottom of the most elevated part of production zone) assuming an average depth to the water level of 112ft.
- Maximum total pressures applied to formation at averaged top and bottom of production zone vary between 257psi and 266psi (253psi and 262psi at the top and bottom of the most elevated part of production zone).

3.2.2 Groundwater Modeling of Power Failure Event

SRK created a preliminary numerical groundwater model to simulate the PLS discharge from 8 production wells (wells 15P-409 to 15P-416) regulated by Header House 15-20 after the pressure flow control valve failure. Numerical modeling was chosen versus the Theis analytical solution to better estimate initial head distributions that existed during prior-to-failure operating conditions. The approximation for initial hydraulic head distributions was simulated using injection and pumping rates of the Header House 15-20 well field prior to pumping well failure and the model assumed that they were balanced (well field operated under steady-state conditions). These values were then used as initial hydraulic heads in a transient scenario where injection continued while pumping ceased. Visual MODFLOW-SURFACT (SWS, 2010, and HGL, 2006), a 3-D finite-difference code was used to simulate 2-D hydraulic head distributions within the production zone. A plan view of the simulated well field in Header House 15-20 is shown in Figure 1.

Figure 1: Plan-view of Well Field Controlled at Header House 15-20 Simulated by Numerical Groundwater Model



The results of completed modeling show that under the observed injection and pumping rates, the measured hydraulic conductivity and storativity, and given geology of the area, it was possible to model pressure increases in the production zone that resulted in water levels in inactive pumping wells to rise above the ground surface. The model set up and assumptions included:

- One numerical layer (26ft in thickness) and 89 rows and 103 columns, representing productive sand unit within an area approximately 5mi x 5.25mi;
- Grid cell discretization ranged from 62.5ft x 62.5ft in the well field area to 6,350ft x 6,220ft in peripheral areas of the model;
- The productive layer was modeled as a confined system limited by upper and lower aquitards with storativity and transmissivity constant in time;
- Boundary conditions included zero recharge (from overlying and underlying units) and Constant Head cells along the perimeter of the model, simulated by constant hydraulic head values 112ft below ground surface. This value was obtained from the average depth to water measurements in surrounding monitoring wells. The distances from the well field to the lateral model boundaries are about 2.3mi;
- Hydraulic conductivity of 3ft/d, rounded from the original value of 2.83ft/d from the completed pumping test, using 10:1 anisotropy ratio (vertical hydraulic conductivity of 0.3ft/d);

- Specific storage was varied from 10^{-5}/ft to 10^{-7}/ft, based on the reported storativity of $2.3x10^{-4}$; Specific storage of $2.35x10^{-6}$/ft was chosen for the base case simulation which allows for the reproduction of the 1,500gal spillover during pumping well failure;
- Locations of wells were imported into the model from real world data;
- Pumping and injection rates prior to the failure of production wells were used to simulate steady state mining conditions assuming total rate of 642gpm. Injection rates were continued for the transient simulation of 8hrs of pumping well failure. Pumping was turned off for the duration of the 8-hour simulation;
- All wells were simulated approximately using a screen interval thickness of 26ft (fully penetrating the pumped production layer);
- Drain cells were used to calculate discharge (spillover) volume from each production well. Drain cell elevation was set to the elevation of the ground surface (the point at which discharge from the well will occur);

Model results show discharge from 8 wells after pumping wells have been turned off. On May 3, 2011 wells 15P-409 to 15P-416 were reported to have discharged solution at the well head. In the model simulation, wells 15P-405, 15P-406, 15P-408, 15P-409, 15P-410, 15P-411, 15P-413, and 15P-414 discharged at the surface. Discrepancies between reported overflow wells and model-simulated overflow wells occurred at wells 15P-405, 15P-406, 15P-408, where the model simulation produced discharge at the surface, and at wells 15P-412, 15P-415, and 15P-416, where the model simulation did not reproduce discharge at the surface. This difference in discharge wells may be due to factors including a difference in screen interval thickness, production zone thickness, localized differences in hydraulic conductivity, variation in ground surface elevation from top of casing elevation, and injection rates that may have changed during the 8-hour period that were not accounted for in the model. Figure 2 displays the production wells with modeled spill over, as well as the surveyed extent of observed solutions on the surface of the well field post event.

The simulated increase of the hydraulic heads in production wells during power failure is shown in Figure 3. Total simulated discharge from all wells was 1,585gal at the end of the pumping failure period and shown in Figure 4.

Figure 2: Location of Simulated vs. Observed Spillover in Header House 15-20 Area

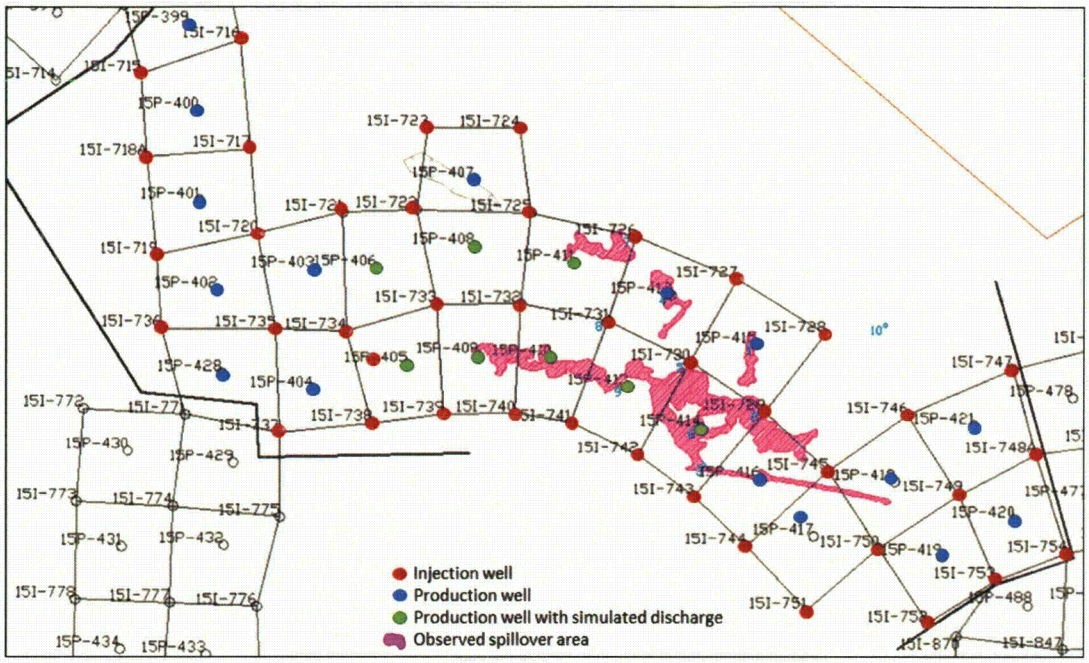


Figure 3: Simulated Increase of Hydraulic Heads in Production Wells During Pumping Failure

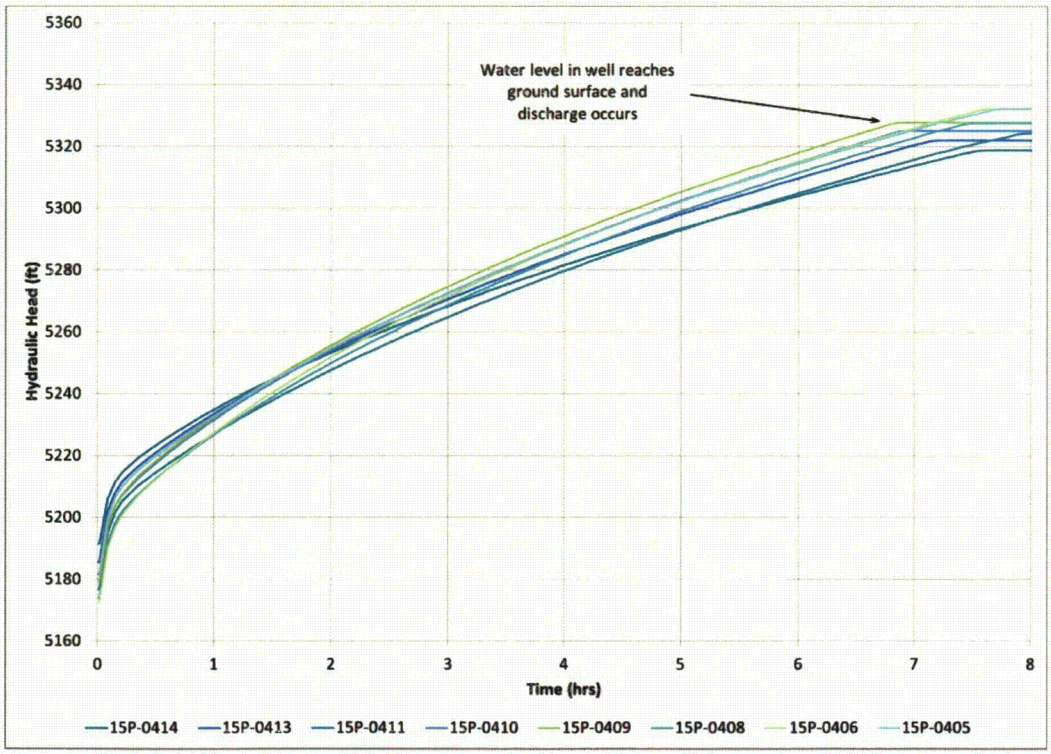
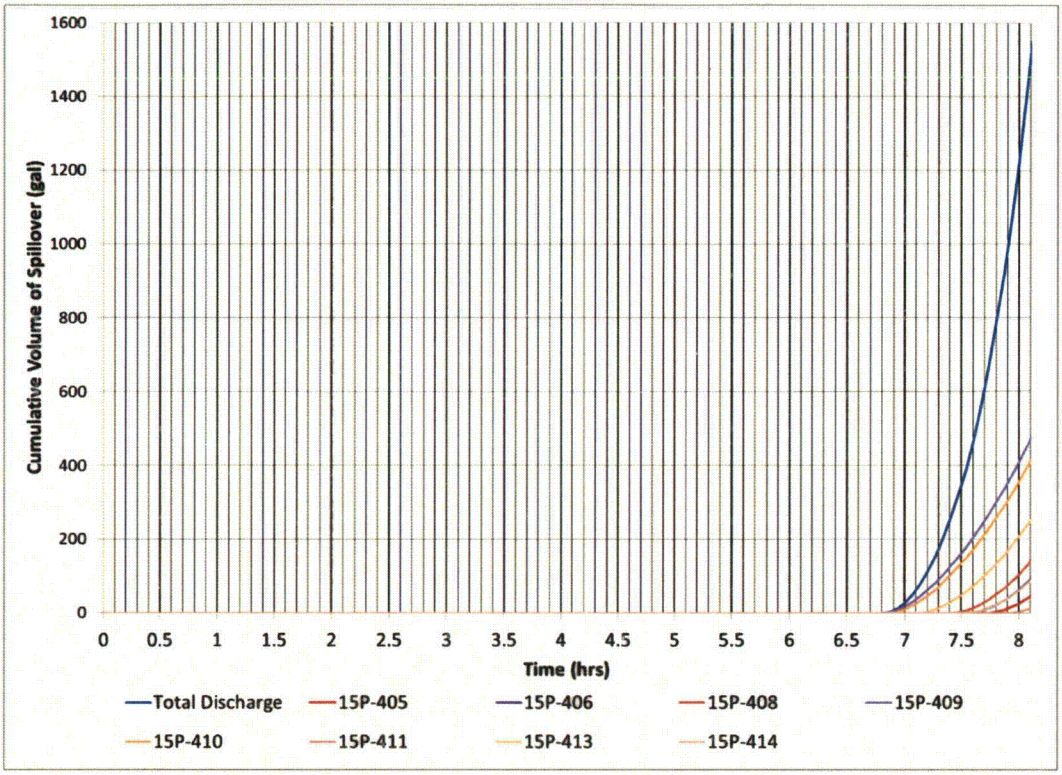


Figure 4: Simulated Volume of Discharge from Production Wells During Valve Failure



Numerical groundwater model calculations show that spill over began approximately 7hrs after pumping ceased.

The results of completed groundwater modeling indicate the possibility of a spillover of about 1,500gal of PLS during the pumping failure period due to raising hydraulic heads in the production zone from continued injection of BLS. The model therefore supports the conceptual system dynamics that led to artesian conditions in production wells, and indicates that the wells acted as a pressure relief for the formation effectively capping further elevation of the hydraulic pressures that would lead to fracturing of the formation. The model also validates the pressures utilized to determine the maximum total pressure exerted on the formation during the event. In addition, the in-field approximation of 1,500gal of solution release is determined to be reasonable.

3.2.3 Formation Fracture Pressure Analysis Conclusions

Presently all operating permits (WDEQ Permit 633, NRC License SUA 1548) for the Smith Ranch Highland facility utilize a formation fracture gradient of 0.7 psi/ft. Numerical groundwater modeling and analytical methods have reasonably replicated the surface discharge observed at the end of the 8hr pumping failure at header house 15-20. The results of this work support a finding that the formation pressure did not exceed the regulatory stipulated formation fracture pressure limits, peaking at approximately 60psi lower than the formation fracture pressure.

3.3 Analysis of Injection Well and Well Field Piping Pressurization

3.3.1 Injection Pressure Data

Under the WDEQ 633 Permit to Mine, the point of compliance for injection pressure is the individual injection well heads within each mine unit. The absolute regulatory limit for injection pressure is based on the mechanical integrity test (MIT) pressure which is 125% of operational pressure. The operating pressure for the injection wells of header house 15-20 is 110psi, the MIT pressure is 140psi. The injection pressure is regulated via Cla-Val and manual controls at the manifold on a header house basis. Individual wells are further regulated at the header house injection manifold through flow rate adjustment. Injection pressure and flow rate data are recorded on 24hr cycles at the header house level. The total loss of power at the header house interrupted continuous data recordings of pressure and flow.

The only recorded pressure data for the injection side of the 15-20 header house during the power failure was recorded on the BLS pipeline leaving SR1 and the CPP. The pressure data for BLS leaving these facilities is variably logged and available for review of historical events. The pressure logs for the BLS leaving SR1 and the CPP was reviewed by SRK. BLS leaving SR1 indicated an overall pressure drop of 17psi during the 8hr event, while the BLS leaving the CPP indicated a pressure drop of 15psi during the same period. The recorded pressure drop also confirms an approximate 8hr event duration. The drop in pressure is consistent with a balanced mine unit operation, where the pressure of the incoming pregnant lixiviant solution (PLS) directly dictates the pressure of the outgoing BLS. In this instance, the loss of production from the 15-20 header house lowered the incoming pressure, therefore decreasing the outgoing pressure as controlled through fixed speed pumping boosters at SR1 and the CPP.

The last point of pressure modulation between SR1 and the CPP and the 15-20 header house is Injection Booster 8 (IB8). The injection boosters are a combination of several fixed speed pumps and one variable frequency drive (VFD) booster pump that regulates the discharge pressure. IB8 has a max outlet pressure of 170psi, and a maximum pressure differential between incoming and outgoing fluid of 60psi. During the event, BLS pressure from SR1 dropped to approximately 56psi, and to 116psi from the CPP. It is believed that the discharge pressure from IB8 was relatively consistent through the power failure event in header house 15-20.

Pressure control into the header house injection manifold is regulated by the Cla-Val pressure control valve during normal operation. The standard Cla-Val is a hydraulically operated, pilot controlled, diaphragm valve. The pilot is activated by the differential pressure across the valve to regulate incoming pressure/flow into the header house and limit pressure to a determined preset value. The addition of a solenoid to the valve allows for the potential to override the differential control and close the valve. During the power failure event it is assumed that the Cla-Val pressure regulation continued to operate as normal, reducing the distribution pressure from IB8 to the preset pressure of the valve. The solenoid failed to activate during the power failure for unknown reasons, and therefore the BLS continued to enter into the distribution manifold of the header house at a regulated pressure of approximately 110psi. Due to the hydraulically controlled pressure regulation at the Cla-Val valve, an injection pressure increase at the manifold would be unlikely; however, flow rates would decrease as the hydraulic head in the formation increases. This decrease in total flow rate to MU-15 was reflected in the 24hr interval injection data logs for the mine unit.

The final point of control for injection well pressure is an air pressure relief valve located in the well head of each injection well. Although designed to prevent excess air (oxygen) pressure in the injection well, the relief valve would also release an excess hydraulic pressure. The pressure relief valves utilized in the Mine Unit 15 injection wells are American Society of Mechanical Engineers (ASME) certified, and come from the manufacturer preset to 150psi. The drip trays at each injection well tied to header house 15-20 were dry at the end of the event, indicating that no pressure had been released by a relief valve, and therefore it is unlikely that injection pressures increased above 150psi.

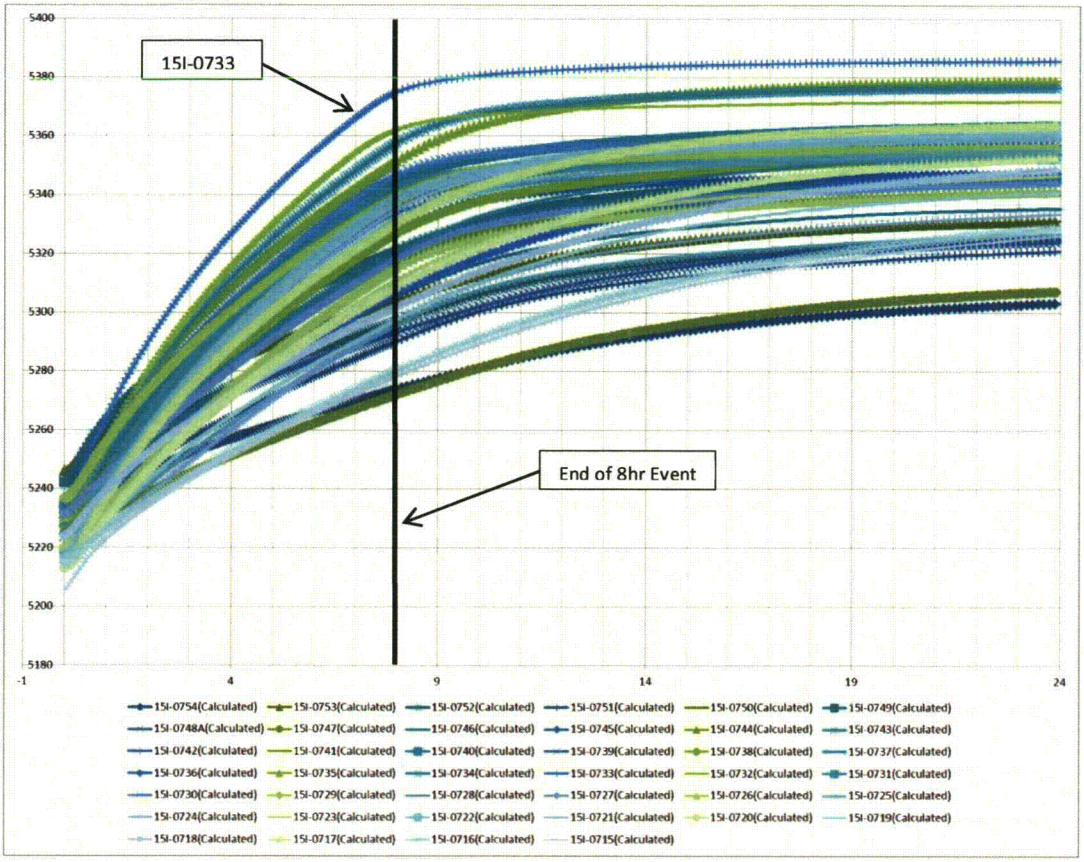
3.3.2 Modeled Injection Well Hydraulic Head

The same model used to analyze the formation pressure can also be used to recreate the hydraulic head in each individual injection well throughout the event. During the event the hydraulic head in the formation reached pressures that equaled a groundwater elevation at or above the ground surface. Where the hydraulic head is greater than ground surface, the total injection pressure is equal to this pressure in addition to the injection pressure transmitted from the header house where:

Hydraulic Head Above Ground Surface (psi)
+ Header House 15-20 Injection Pressure (psi)
= Total Injection Pressure at Well Head (psi)

Using this basic pretense, the hydraulic head at each injection well was extracted on an hourly basis from the groundwater model to determine the maximum hydraulic head above ground surface during the 8hr event period. The highest hydraulic head modeled was in injection well 15I-0733, where hydraulic head equated to a groundwater level 42.4ft above ground surface at the end of 8 hours of injection with no extraction. This hydraulic head equates to a pressure of 18.4psi. When this pressure is added to assumed standard injection pressure from the header house of 110psi, the resultant total injection pressure is 128.4psi. This is 11.6psi below the regulatory limit of 140psi as dictated by WDEQ Permit 633 and Smith Ranch MIT procedures. The four injection wells with the highest resultant hydraulic head: 15I-0730, 15I-0732, 15I-0733, and 15I-0734 are centrally located within the mine unit and the results are consistent with the concept of rapidly increasing pressures in the center of the mine unit, and slow building pressures in the perimeter of the mine unit where there is greater relief of hydraulic pressure laterally. Graphs of groundwater elevation versus time are shown in Figure 5 and plotted out over a theoretical 24hr event to how the pressure approaches steady state conditions.

Figure 5: Modeled Groundwater Elevation vs. Time



3.3.3 Injection Well and Piping Pressure Analysis Conclusions

Based on the review of all available data, the following conclusions can be made:

- No information supports an increase in BLS pressure ahead of header house 15-20;
- It is believed that the Cla-Val valve continued to modulate the incoming pressure, regulating it to 110psi;
- Groundwater modeling suggests a maximum injection pressure of 128.4psi in any injection well tied to header house 15-20; and
- There is no evidence that BLS was released through the well head pressure relief valve in the header house 15-20 injection wells.

Based on this evidence, SRK does not believe that the injection pressure of any wells tied to header house 15-20 was greater than the regulatory limit of 140psi.

4 Summary

SRK completed a technical review of subsurface hydraulic response to injection well operation in the absence of pumping, as observed at Mine Unit 15, header house 15-20, Smith Ranch Highland facility on May 3, 2011. Based on operational discussions with Cameco staff, review of all available and relevant information, and the results of groundwater modeling to simulate the power

failure event, there are no indications that the formation fracture pressure or the injection well head pressures were elevated beyond regulatory limits stated in the facility operating permits.