BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

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IN THE MATTER OF THE PETITION OF TRANSCANADA KEYSTONE PIPELINE, LP FOR ORDER ACCEPTING CERTIFICATION OF PERMIT ISSUED IN DOCKET HP09-001 TO CONSTRUCT THE KEYSTONE XL PROJECT	: : : : :	HP 14-001 REBUTTAL TESTIMONY OF HEIDI TILLQUIST

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Pursuant to the Commission's Order Granting Motion to Define Issues and Setting Procedural Schedule, Petitioner TransCanada Keystone Pipeline, LP, offers the following rebuttal testimony of Heidi Tillquist.

1. Please state your name and occupation.

Answer: Heidi Tillquist, Director of Oil and Gas Risk Management, Stantec Consulting Services Inc., Fort Collins, CO.

2. Did you provide direct testimony in this proceeding?

Answer: Yes.

3. To whose direct testimony are you responding in your rebuttal testimony?

Answer: I am responding to the direct testimonies of Richard Kuprewicz of Accufacts Inc., Ian Goodman and Brigid Rowan of The Goodman Group, Ltd., and Arden Davis, Ph.D., P.E.

4. Kuprewicz (p. 4) and Goodman and Rowan (p. 22, 23, 24, 25, 34, 35, and 50) question the use of historical incident databases to conduct the 2009 Keystone XL Risk Assessment included as part of the Department of State Final Supplemental Environmental Impact Statement (FSEIS). Can you comment on the use of historical incident databases, such as the PHMSA database, as industry practice? Additionally, please explain how the PHMSA database was used to determine risk as part of the permitting process for the Keystone XL pipeline.

Answer: During the environmental permitting process, Keystone elected to provide an estimate of failure frequencies and range of probable spill volumes based on historical data since no operational data is available for the proposed project. These statistics are then combined with environmental data to assess the reasonable range of environmental impacts that may occur in the event of a release.

The PHMSA database was used in the development of the 2009 Keystone XL Risk Assessment. While future events cannot be known with absolute certainty, historic incident frequencies are an appropriate basis on which to estimate the number of events that might occur over a period of time. The 2009 Keystone XL Risk Assessment was developed as a part of the State Department's environmental review under the National Environmental Policy Act (NEPA) during its permitting process. The purpose of this Risk Assessment is to provide a conservative range of anticipated effects from the operation of the Project that is sufficient for the purposes of federal permitting requirements. Additionally, the 2009 Keystone XL Risk Assessment provides a preliminary evaluation of potential risk during the pipeline's design phase and provides an initial basis for emergency response planning.

A two-year independent review of Keystone XL's design and the 2009 Keystone XL Risk Assessment was conducted by Battelle Memorial Institute (Battelle) and E^{x}ponent Inc. (E^{x}ponent) under the direction of the US Department of State (DOS), Pipeline and Hazardous Materials Safety Administration (PHMSA), and the US Environmental Protection Agency (USEPA) to address concerns raised by the USEPA in the NEPA review of the proposed project. Battelle (2013) concluded that "*because historic data provide a sound basis to assess risk from a historic perspective, it is customary to do such analysis based on the historic record. As stated in the [2009] Keystone [XL] Risk Assessment, the Project is being weighed relative to the US portion of the system; therefore, their assessment focused exclusively on the US database, which is maintained by the PHMSA…As has been noted by Keystone, all data available were used with the exception of information involving terminals and tanks, with a rationale noted for that decision. As needed, gaps were bridged or adjustments were made in the context of judgment, which has been a usual practice since risk analysis emerged in the early 1990s as a viable assessment under the auspices of a joint industry-government task force…Much of what has been done is usual and consistent with industry practices as part of the procedure for obtaining PHMSA approval to commission a pipeline.* ***However, the Risk Assessment presented does go beyond the process typically followed for the National Environmental Policy Act (NEPA) stage of the Federal process*** [emphasis added]" (Battelle 2013).

5. Kuprewicz (p. 4) and Goodman and Rowan (p. 23, 25, 50, and 52) suggest that PHMSA data have significantly changed since the 2009 Keystone XL Risk Assessment due to the "recent growth in North America crude oil production, the accompanying increase in terrestrial transport of more hazardous non-conventional crudes, as well as the unfortunate advent of very large spills." Based on your analysis, has the PHMSA incident

database significantly changed such that the findings and conclusions of the 2009 Keystone XL Risk Assessment are no longer valid?

Answer: No. For consistency, the values presented in this testimony are based on the same database used for the 2009 Keystone XL Risk Assessment. Nonetheless, the risk statistics presented in the 2009 Keystone XL Risk Assessment are highly comparable with current PHMSA data. Recent high profile spill events remain extremely uncommon and are not representative of the majority of spills. Spill volume data continue to reflect a highly skewed distribution, with the spill distribution for very large spills decreasing by one tenth of one percent (i.e., spills greater than 10,000 barrels now account for 0.4% of all spills, as compared to 0.5% of all spills as reported in 2009 Keystone XL Risk Assessment).

6. Goodman (p. 23) states "[m]ost of the data is provided by industry, which tends to underreport spills, particularly the serious ones, which are of greatest concern." Please comment on this assertion.

Answer: Goodman's assertion that operators do not comply is contrary to federal regulations is unsupported by data. Since 2002, pipeline operators are required by federal regulations (49 CFR Sections 195.50 and 195.54) to file accident reports for a release of 5 gallons or more. Failure to report incidents constitutes a noncompliance violation and PHMSA can impose fines and other punitive measures. PHMSA regularly audits pipeline operators for compliance. Questions regarding compliance with incident reporting are identified on two separate auditing forms provided by PHMSA. These forms allow operators to conduct internal audits to ensure compliance and provide companies with the minimum documentation that they will be required to produce during an audit.

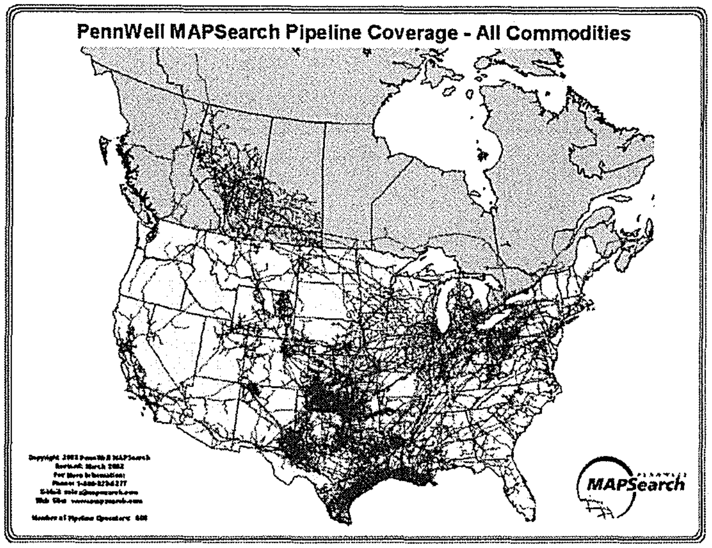
7. Kuprewicz (p. 5) suggests that a "true risk assessment" should be conducted using "specific pipeline" information. Goodman and Rowan (p. 22, 23, 24, and 25) also suggest that a similar site-specific risk assessment using "the elevation profile and other key information" be conducted. Can you comment on these suggestions?

Answer: As described above, the 2009 Keystone XL Risk Assessment was prepared as part of the environmental permitting process and evaluated all "specific pipeline" information identified by Kuprewicz and Goodman and Rowan.

8. Can you comment on the appropriateness of the PHMSA database for determining risk in areas that are "unique" (e.g., areas of reported high landslide risk as mentioned in testimonies of Kuprewicz [p. 2 and 4] and Goodman and Rowan [p. 22])?

Answer: The PHMSA incident database contains historical incident data for approximately 200,000 miles of liquid pipelines. The extent of US liquid pipelines is shown on Figure 1. These pipelines routinely cross discrete areas of high landslide risk, slope instability, soils with high clay content, and other landscape features. Thus, it is reasonable to use the PHMSA database to estimate incident frequencies for a pipeline that crosses several states for permitting purposes.

Figure 1. Pipelines in North America



While geological hazards are addressed at a macro-scale in the 2009 Keystone XL Risk Assessment, actual routing, design, engineering, and operations incorporate site-specific information and analyses to account for terrain, including slope stability issues.

9. Kuprewicz (p. 6) states, "[l]andslides are most likely to be associated with high water/rain events (e.g., flash floods) where rivers and streams will be at higher flow." Can you comment on that assertion?

Answer: While landslides may be associated with high water/rain events, pipeline failures caused by flooding are not associated with landslides. Instead, pipeline failures caused by flooding are almost always due to the loss of cover caused by either vertical scour or lateral stream migration.

While flooding only causes a small fraction of pipeline failures (0.52%) with a median spill volume of 97.0 barrels (PHMSA 2008), under federal regulations (49 CFR Section 195), Keystone's Integrity Management Program is required to monitor and reduce risks from a number of threats, including outside forces due to flooding.

Pipeline failures at river crossings are highly uncommon and almost always are associated with loss of depth of cover. According to the PHMSA Report to US Congress (2012), during the 21-year span between 1991 and 2012, only 20 accidents involving water crossings occurred. "*A depletion of cover, sometimes in the waterway and other times in new channels cut by floodwaters, was a factor in 16 accidents. The dynamic and unique nature of rivers and flood plains was a factor in each accident. These 16 accidents are 0.3 percent of all reported hazardous liquid accidents and 0.5 percent of the hazardous liquid significant incidents*" (PHMSA 2012). A "significant release" is defined by PHMSA as a release of 50 barrels or more, fire, explosion, injury resulting in hospitalization, fatality, or damages of $50,000 or more of cost incurred by operator (PHMSA 2015). PHMSA promulgated 49 CFR Section 195 to establish minimum pipeline safety standards for hazardous liquid pipeline systems. Regulations relevant to depth of cover are found in two subparts: Construction, and Operation and Maintenance.

As part of the 59 Special Conditions developed by PHMSA and set forth in Appendix Z to the State Department's FSEIS, Keystone has committed to a depth of cover of 48 inches in most locations, which exceeds federal regulatory standards. Additionally, as part of the 59 PHMSA Special Conditions, Keystone is required to maintain that depth of cover for the life of the Project.

10. Kuprewicz (p. 6) states that landslides are the "most likely event that could cause rupture" for the Keystone XL pipeline in South Dakota. Goodman and Rowan (p. 28) state that the worst case scenario for the Keystone XL pipeline is "a full bore rupture...caused by a breakaway landslide in areas of steep elevation change." Is the risk of

landslides/ground movement expected to be a leading cause of pipeline failure along the route in South Dakota?

Answer: No. The relevant historical data indicate that the overall probability of an incident related to landslides is very low and unlikely to be the leading cause of pipeline incidents for Keystone XL. Earth movement accounts for approximately 0.56% of pipeline incidents (PHMSA 2008). This is corroborated by Goodman and Rowan on page 27 of their testimony. The majority of earth movement incidents result in relatively small releases, with 50% resulting in releases of 43.5 barrels or less (PHMSA 2008).

11. Kuprewicz (p. 2) and Goodman and Rowan (p. 10 and 36) claim that a rupture would result in substantial volumes of oil being released along terrain in South Dakota. Please comment on the probability of a large volume spill occurring along the route.

Answer: Based on the PHMSA dataset, the probability of a 10,000 barrel spill at any 1-mile segment along the Keystone XL pipeline in South Dakota is equivalent to 1 spill every 1.5 million years. The occurrence intervals for a range of spill volumes, including greater than 10,000 barrels, are shown in Table 1.

Table 1 Occurrence Intervals by Spill Volume

	Occurrence Interval (years) by Spill Volume				
Crossing Distance	**All spills**	**3 bbl**	**100 bbl**	**1,000 bbl**	**10,000 bbl**
1 mile	7,407	14,599	48,662	145,985	1,459,854

Source: PHMSA 2008.

Based on the PHMSA pipeline incident database (2002 to 2009), only 3.8% and 3.2% of spills affected surface water or groundwater resources, respectively, and most of those water resources were not drinking water resources. Only 0.16% of spills actually affect drinking water resources. Consequently, the possibility of a spill occurring and affecting drinking water is very remote.

12. Kuprewicz (p. 2) claims that there would be a "remarkably low amount of released oil that will actually be recovered in the event of a spill." Please comment on the fate of released crude oil in the environment in the event of a spill.

Answer: Crude oil released into the environment undergoes weathering (i.e., the loss and degradation of petroleum products). Using ADIOS2, an environmental fate model for crude oil spills, approximately 20 to 60% of the crude oil evaporates within the first 12 hours following a spill. For Western Canadian Select, approximately 20% evaporates in the first 12 hours, consistent with other heavy conventional crude oils. In addition, according to the PHMSA database, approximately 50% of crude oil released is recovered. Therefore, the vast majority of crude oil either evaporates or is recovered following an incident.

13. Goodman and Rowan (p. 28 and 29) claim that "[i]n light the Line 6B spill, there is now substantial evidence that dilbit can sink in water making a dilbit spill to water significantly more difficult to clean up." Please comment on this assertion.

Answer: On July 25, 2012, Enbridge's 6B pipeline failed near Marshall, Michigan, and released over 20,000 barrels of oil into Talmadge Creek. At the time of the accident, Enbridge's 6B pipeline was transporting Cold Lake diluted bitumen. An API of 10 is equivalent to water, which means any oil with an API above 10 will float on water while any with an API below 10 will sink (Petroleum 2015). Keystone's diluted bitumen has an API gravity of 16. In comparison, the API gravities of Western Canadian Select and Bakken crude are 20.6 and 52.9, respectively (Crude Monitor 2013, Shafizadeh 2010). Cold Lake's API value is lower than most diluted bitumen crude oils but is greater than 10 and, therefore, it was expected to float on the water's surface. According to the US Environmental Protection Agency (DOS 2014, USFWS et al. 2015) and PHMSA's on-site coordinator (J. Hess, personal communication, January 2013), the oil did float initially, as expected.

It has been suggested that the type of oil contributed to the severity of the spill and its impacts. Recent evaluations of diluted bitumen (Battelle 2012, Been 2011, National Academy of Sciences [NAS] 2013) found no significant differences in the physical or chemical properties of diluted bitumen and other heavy crude oils. Copies of these reports have been attached as Exhibits 1 through 3 of my testimony.

The behavior of the crude oil in the Kalamazoo spill was similar to that expected for other heavy crude oils; it was not unique. Extenuating factors (flood conditions and emergency response times) allowed time for the crude to weather prior to cleanup. As the oil weathered with time (i.e., light end hydrocarbons evaporated), the remaining oil became heavier until the API gravity was less than 10 and portions of the oil slick became submerged. This process was exacerbated by heavy turbulence caused when the oil passed over an overflow dam and flooding that caused sediment, rocks, debris, and water to become incorporated into the crude oil, forming a heavier-than-water emulsion. The resulting submerged oil formed globules that were transported downstream.

References:

Been, J. 2011. Comparison of the Corrosivity of Dilbit and Conventional Crude. Corrosion Engineering, Advanced Materials, Alberta Innovates Technology Futures. 29 pp. Internet website: http://www.ai-ees.ca/media/6860/1919_corrosivity_of_dilbit_vs_conventional_crude-nov28-11_rev1.pdf

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Petroleum. 2015. API Gravity. Internet website: http://www.petroleum.co.uk/api. Accessed on May 27, 2015.

Shafizadeh, A. (2010, June 10). Bakken [Powerpoint slides]. Retrieved from Crude Oil Quality Association website: http://www.coqa-inc.org/06102010_Shafizadeh.pdf

US Fish and Wildlife Service (USFWS), Nottawaseppi Huron Band of the Potawatomi Tribe, Match-E-Be-Nash-She-Wish Band of the Pottawatomi Indians. 2015. Draft Damage Assessment and Restoration Plan/Environmental Assessment for the July 25-26, 2010 Enbridge Line 6B Oil Discharges near Marshall, MI. May 2015.

14. Following up on Goodman and Rowan's discussion of the Kalamazoo spill (p. 23), can you discuss key differences between Enbridge Line 6B and the proposed Keystone XL pipeline that affect the risk posed by each pipeline.

Answer: A major failure comparable to Enbridge's 6B failure at Kalamazoo is highly unlikely for the Keystone XL pipeline for the following key reasons: i) the quality of the pipe and longitudinal seam welding procedures; ii) corrosion protection systems; iii) the use of in-line inspection tools; and iv) other key materials and construction procedures.

Pipeline manufacturing processes and regulatory standards have evolved and improving technologies have resulted in demonstrable improvements in pipeline safety performance. The Enbridge Line 6B pipeline was constructed in 1969 when there were different pipe materials and manufacturing processes than today. The Keystone XL pipeline will be manufactured with much higher quality and stronger steel that helps reduce the impacts of external forces, such as excavation and flooding damage.

Federal pipeline regulations have evolved over time and pipeline operators are now required to manage their pipelines actively to reduce the possibility of incidents. Keystone has agreed to implement an additional 59 PHMSA Special Conditions identified in the FSEIS. The State Department, in consultation with PHMSA, has determined that incorporation of the 59 PHMSA Special Conditions "*would result in a Project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in HCAs, as defined in 49 CFR 195.450*" (DOS 2014).

15. Goodman and Rowan (p. 38 and 52) state, "a slow and undiscovered leak is likely to be the more serious threat to the Ogallala Aquifer and RST water resources." Kuprewicz (p. 7 and 8, respectively) states, "leaks are probably the most likely risk of concern to the water wells" and that leaks "could migrate underground possibly delaying discovery." Please comment on the subsurface movement of groundwater plumes and the potential impacts on these specific groundwater resources.

Answer: The proposition that a leak could go undetected for a long period of time that could release thousands of barrels is not realistic. The independent Battelle review (2013) concurred with the conclusions in the 2009 Keystone XL Risk Assessment that a small leak going undetected indefinitely is unlikely. Battelle (2013) estimated that crude oil from a small "pin hole" leak (28 bbl/day) would theoretically reach the ground surface in no more than a few months.

Data from actual pipeline spills demonstrate that substantial leaks do not go undetected for long periods of time. Further, those spills that are not detected within the first 48 hours almost always are small. The data used in the 2009 Risk Assessment indicate that the majority of spills are 3 barrels or less, regardless of detection time. These data also indicate that the majority of spills are detected within 2 hours, with 99 percent of spills detected within 7 days. Of those spills not detected within the first 48 hours, the majority of spills were 15 barrels or less. These data demonstrate that the theory of a leak going undetected for months to years resulting in a release of tens of thousands of barrels is not reasonable or realistic.

In the event of a release, crude oil would spread through the interstitial spaces between soil particles. Often the oil will remain in the trench where soils are less consolidated compared to the adjacent soils as well as move to the soil's surface. Crude oil adheres to soil particles and has very limited mobility. If crude oil was not removed from the environment and crude oil came into contact with groundwater, soluble constituents could begin to form a groundwater plume. Plume formation takes months to years to occur due to the limited subsurface movement of petroleum hydrocarbons. Newell and Connor (1998) summarized the results of four nationwide studies looking at groundwater plumes from petroleum hydrocarbon contamination. The results show that the subsurface movement of petroleum hydrocarbons is very limited, moving 312 feet or less in 90 percent of the cases. Additional studies support this plume transport distance. Copies of these reports have been attached as Exhibits 4 through 9 of my testimony.

Petroleum hydrocarbon plumes do not sink within groundwater as observed with chlorinated solvent plumes (e.g., trichloroethylene [TCE], perchloroethylene [PCE]); instead, they form along the uppermost layer of groundwater. Therefore, contamination of groundwater would be limited to the uppermost volume associated with the groundwater surface. Petroleum hydrocarbons are naturally degraded by microbial communities naturally found within soils. As a result, petroleum hydrocarbon plumes would be expected to result in highly localized effects. Removal of the source oil and remediation actions would help to further minimize groundwater impacts. Kuprewicz reaches the same conclusion (p. 7), specifically stating that impacts to RST groundwater wells are not anticipated due to the slow-moving nature of the groundwater plumes.

16. Goodman and Rowan (p. 32, 37, and 52) also identify groundwater resources associated with the Ogallala Aquifer in Tripp County as being a high value resource. How is Keystone addressing groundwater vulnerability in this region?

Answer: The High Plains Aquifer area in southern Tripp County has been identified as a hydrological sensitive area, as defined by the Public Utilities Commission's June 2010 Amended Final Order in Docket HP09-001. Keystone has elected to treat "hydrologically sensitive areas" as operator-defined HCAs based on a number of factors, including those identified by the Public Utilities Commission Amended Final Order Condition 35.

17. Kuprewicz (p. 3 and 6) states, "[i]t is my understanding that much of the state gets its water from the Missouri River so the impact on the state's overall water supply should the pipeline rupture and threaten this resource needs to be properly evaluated." Please comment on this as it relates to spill distance to this resource and possible impacts.

Answer: The Missouri River is not crossed by the Keystone XL pipeline and is located at least 82 river miles downstream from the Keystone XL pipeline at the closest point. The White River represents the shortest downstream flow path from the pipeline to the Missouri River. The 82-mile distance far exceeds the maximum transport distance observed in even catastrophic pipeline failures during flood conditions. Three major rivers that are tributaries to the Missouri River will be crossed using HDD, thereby reducing the possibility of i) stream scour resulting in pipeline failure and ii) a pipeline release entering the waterbody due to the amount of overburden. All water crossings were evaluated using a vertical and horizontal scour analysis based on a 100-year flood event and the depth of crossings adjusted accordingly.

Most historic spill incidents are relatively small, are contained in close proximity to the origin of the spill, are cleaned up immediately, and never reach flowing surface water. Most spills would not move significant distances downstream and still be detectable. Under exceptional circumstances, there have been cases where large volume spills have resulted in crude oil being detected miles downstream. Examination of exceptional spill events (e.g., spills into the Coffeyville and Kalamazoo rivers) illustrate that contamination typically does not travel more than 20 miles downstream, with the maximum observed distance of 30 miles. Following a 10,000 barrel release in 2007 from the Coffeyville Refinery in Kansas into the Verdigris River, the USEPA found no detectable concentrations of petroleum products 20 miles downstream at the closest municipal water intake. USEPA samples reported concentration of petroleum hydrocarbons to be below threshold limits at the first sampling point, located 12 downstream miles of the spill. In 2010, an Enbridge 30-inch pipeline ruptured, spilling 19,500 barrels of oil into the Kalamazoo River system. While the majority of contamination occurred in close proximity to the source, USEPA reports that contamination has been documented in localized areas within 30 miles of the spill's origin. I concur with Kuprewicz's conclusion on p. 3 and reiterated on p. 7 that the risks to the two RST water supply line crossings and the Cheyenne River are not significant.

18. Kuprewicz (p. 6) states, "[t]he steepness of the terrain also indicates that a rupture release will result in considerable surface migration, either over the ground surface or via

river transport should a rupture release reach a river that crosses the pipeline." Please comment on river and overland ground transport distances of diluted bitumen.

Answer: Refer to my response to Question 17 for case studies regarding downstream transport distances following large spills. Maximum overland transport distances were calculated using a GIS-based analysis and pipeline product parameters (e.g., transport temperature, dynamic viscosity, and 25,000-barrel spill). Overland transport distances for diluted bitumen are summarized in Table 2.

Table 2 Overland Transport Distances

Slope (%)	Miles of Route	Transport Distance (feet)
Herbaceous Land		
0-20	297	35-218
20-25	13	244
25-30	3	267
30-35	1	289
>35	1	345
Barren Land		
0-20	297	103-655
20-25	13	732
25-30	3	802
30-35	1	866
>35	1	1,035

19. Goodman and Rowan (p. 22 and 24) raise concerns as to whether sufficient attention is being given to these sensitive areas in terms of pipeline safety and oil spill response planning. Please comment on protection of High Consequence Areas.

Answer: Keystone's evaluation of potential impacts to HCAs has been quantified in a confidential appendix for federal agencies. This preliminary analysis is not required by regulation, but assists regulators with understanding the possibility of an incident and its potential impacts. The 2009 Keystone XL Risk Assessment is not intended to replace the more detailed Engineering Assessment required by federal pipeline safety regulations as identified in

49 CFR Section 195.452 and Section 195 Appendix C. That analysis is subject to audit and review by PHMSA, which has regulatory authority over interstate pipelines, including the Keystone XL pipeline.

20. Kuprewicz (p. 7) claims that, in his experience, pipeline incidents are often due to a failure "to incorporate some degree of challenge or reality check to assure spill risk was really low." Please comment on this assertion.

Answer: Key features of Keystone's operational program, where applicable, include the incorporation of industry best practices and participation in industry conferences and forums to exchange ideas and information, as well as involvement with industry research and development programs. Keystone had adopted many of the PHMSA Special Conditions into the Keystone XL pipeline long before they were mandated by regulators. It has been my personal experience that Keystone strives to meet or exceed pipeline safety requirements and often leads the industry in adopting more stringent safety requirements.

The types of errors Kuprewicz refers to can be minimized by independent third-party review of Keystone's policies and practices. In addition to the regulator auditing conducted by PHMSA, the design basis and risk assessment process were reviewed by independent, third-party contractors (Battelle and E^{x}ponent) during a two-year review process that was conducted on behalf of the DOS to address similar concerns expressed by the USEPA. Battelle concluded that the 2009 Keystone XL Risk Assessment was appropriate for the permitting process and that the design of the Project meets or exceeds current regulatory requirements. If approved, the Keystone XL pipeline will be required to meet more stringent requirements than any other pipeline built to date. Thus, the review recommended by Kuprewicz has already been conducted.

21. Dr. Davis' testimony (p.1) states that "the proposed Keystone XL pipeline would cross the recharge areas of several shallow aquifers in the western part of the State, including the Ogallala aquifer and Sand Hills type material, especially in Tripp County." Will the pipeline adversely affect these areas?

Answer: Adverse impacts to these areas are highly unlikely. The Keystone XL pipeline crosses a number of formations in western South Dakota that outcrop in hills, stream cuts, and along mesas. Many of these formations are covered by shallow soil. In Tripp County, the pipeline crosses the Tertiary Ogallala Formation of the High Plains Aquifer system. South of the town of Buffalo, in Harding County, the pipeline crosses a section of wind-blown sand mapped as Qe (Quaternary eolian). As discussed in the State Department's January 2014 Final Supplemental Environmental Impact Statement (FSEIS) for the Keystone XL pipeline project, *"typical recharge rates to the Ogallala Formation and associated alluvial aquifers range from 0.5 to 5 inches per year along the proposed route, with the highest recharge rates in the areas of the aquifer associated with the Sand Hills Unit"* (US Department of State [DOS] 2014). The 50-foot permanent right-of-way for the Keystone XL pipeline will occupy less than 0.1% of the total recharge area associated with the Fox Hills, Hell Creek, and Ogallala formations, as well as areas of wind-blown deposits (Qe), within counties crossed by the pipeline.

22. Dr. Davis' testimony (p. 2) states "the proposed pipeline also would have major stream crossings at water courses...These drainages have associated alluvial aquifers." Will the pipeline adversely affect these areas?

Answer: Adverse impacts to these areas are highly unlikely. The Keystone XL pipeline will cross major drainages with alluvial aquifers in South Dakota. Spills at individual river crossings are rare with occurrence intervals of no more than once in 22,000 years to

830,000 years based on representative stream crossing distances (Appendix P of the FSEIS; DOS 2014). Most spills are less than 3 barrels.

The Keystone XL pipeline is designed with a minimum depth of cover of 5 feet below the bottom of waterbodies and that depth is maintained over a distance of 15 feet on each side of the waterbody, measured from the ordinary high water mark. Depth of cover is an important factor to reduce the threat of outside force damage and stream scour.

The Project's depth of cover meets or exceeds the federal requirements noted in 49 CFR Section 195.248 of 48 inches for inland bodies of water with a width of at least 100 feet from high water mark to high water mark (for normal excavation, 18 inches for rock excavation) and PHMSA Special Condition 19 regarding depth of cover.

23. Dr. Davis' testimony (p. 2) states "in Harding County, the proposed route would cross permeable wind-blown deposits shown as Qe on Figure 4. These wind-blown deposits of silt and sand recharge from rainfall and snowmelt, they are capable of supplying water to shallow wells in the area." Will the pipeline adversely affect these areas?

Answer: Adverse impacts to these areas are highly unlikely. The wind-blown sand south of Buffalo in Harding County has been mapped by Erickson (1956) and Petsch (1956). The deposits are mostly sand overlying the Cretaceous Hell Creek Formation. Erickson (1956) interprets these deposits to be derived from the underlying Hell Creek Formation. Rainfall falling on these sand deposits would infiltrate and form a local, temporary water-bearing zone near the base of the deposits. Because the deposits are found on bluffs and the underlying Hell Creek has a much lower permeability, it is likely that water entering the sand may form temporary springs and seeps at the base of the sand deposits, rather than migrating downward into the Hell Creek Formation.

The Keystone XL pipeline crosses these sand deposits near their eastern edge, where the deposits are thin. Examination of well logs for wells within the 1-mile buffer zone around the pipeline indicates that none of the wells are screened in the wind-blown sands. In the area of the pipeline ROW, the wind-blown deposits are thin and not likely to be water-bearing most of the year. Based on this, along the ROW in areas of wind-blown deposits, a potential release from the pipeline would most likely not encounter permanent groundwater.

References:

Erickson, H.D., 1956. GQ 62K-045. Areal geology of the Buffalo quadrangle, scale 1:62,500 (22 x 17 in. map).

Petsch, B.C., 1956. GQ 62K-052. Areal geology of the Mouth of Bull Creek quadrangle, scale 1:62,500 (22 x 17 in. map).

24. Dr. Davis' testimony (p. 3) states "South of the Cheyenne River in Haakon County, the proposed route would cross permeable Quaternary terrace gravels (Qt on Figure 6) and wind-blown deposits (Qe on Figure 6)...The terrace gravels and wind-blown deposits are permeable and are recharged by precipitation" and in places "are capable of supplying water to wells." Will the pipeline adversely affect these areas?

Answer: Adverse impacts to these areas are highly unlikely. The wind-blown deposits crossed in Haakon County south of the Cheyenne River are relatively thin and not likely to form a major aquifer. Wells within 1 mile of the pipeline ROW are not screened in wind-blown material. The Cheyenne River will be crossed employing the HDD method, whereby the pipe is installed at a depth of 50 feet below the river bottom, thereby eliminating the potential for key threats including excavation damage and outside force associated with potential stream scour.

25. Dr. Davis' testimony (p. 3) states "In Jones and Lyman counties, the proposed pipeline route would cross permeable wind-blown deposits (Qe on Figure 8) and also would cross Quaternary terrace deposits north of the White River (Qt on Figure 8)." The terrace deposits have a shallow water table, are recharged by rainfall, and provide water to springs. Will the pipeline adversely affect these areas?

Answer: Adverse impacts to these areas are highly unlikely. The wind-blown deposits crossed in Jones and Lyman counties associated with the White River are relatively thin and not likely to form a major aquifer. Wells within 1 mile of the pipeline ROW are not screened in wind-blown material. The White River will be crossed employing the HDD method, whereby the pipe is installed at a depth of 70 feet below the river bottom, thereby eliminating the potential for key threats including excavation damage and outside force associated with potential stream scour.

26. Dr. Davis' testimony (p. 3) states "In Tripp County…the route would cross the Ogallala aquifer (To on Figure 9)" and "wind-blown Sand Hills type material (Qe on Figure 9)…The hydrologic situation is similar to the Sand Hills of Nebraska…and therefore deserves consideration for special protection as a high consequence area. As noted by Stansbury (2011), areas with shallow groundwater that are overlain by permeable soils…pose risks of special concern because leaks could go undetected for long periods of time." Please comment on this assertion.

Answer: "The High Plains Aquifer area in southern Tripp County" has been identified as a hydrologically sensitive area, as defined by the Public Utilities Commission's June 2010 Amended Final Order in Docket HP09-001. Keystone has elected to treat "hydrologically sensitive areas" as operator-defined HCAs based on a number of factors, including those identified by the Public Utilities Commission Amended Final Order Condition 35.

The Keystone XL pipeline in South Dakota was routed to reduce impacts to a number of valuable resources, including but not limited to, unconfined aquifers. Keystone has attempted to identify vulnerable aquifers through consultation with State agencies and rural water districts, as well as through the use of data provided by South Dakota Department of Environment and Natural Resources (SD DENR) (http://denr.sd.gov/data.aspx) and published literature. The location of unconfined aquifers is documented in the literature on the hydrogeology of South Dakota. The SD DENR website provides well logs for wells near the pipeline ROW. It is possible that, during construction and through discussion with landowners crossed by the Project, Keystone may identify shallow wells located in unconfined aquifers.

There are multiple leak detection processes that help identify small leaks, as stated in the Public Utilities Commission Amended Final Order Finding of Fact 94. While detection of a smaller leak may require additional confirmation time, examination of historical incident data confirms that small leaks do not remain undetected for long periods of time. PHMSA records (2001 through 2009) indicate that the majority of spills are 3 barrels or less, regardless of detection time. These data also indicate that the majority of spills are detected within 2 hours, with 99 percent of spills detected within 7 days. Of those spills not detected within the first 48 hours, the majority of spills were 15 barrels or less. These data do not support the contention that small leaks remain undetected for long periods of time.

27. Dr. Davis' testimony (p. 3) states that diluted bitumen is "more corrosive than conventional crude oil transported in existing pipelines." Do you agree with this statement?

Answer: No. A number of recent studies have investigated the claim that diluted bitumen is more corrosive to pipelines than conventional crude oil, but none found evidence of corrosion that is unique to the transportation of diluted bitumen. Although some diluted bitumen contains higher concentrations of naphthenic acids than conventional crude oils, these compounds are only corrosive at temperatures above 200 degrees Celsius (392 degrees Fahrenheit). These temperatures do not occur in pipelines (Been 2011). The Keystone XL pipeline will not exceed temperatures of 150 degrees Fahrenheit per PHMSA Special Condition 15. Other compounds within diluted bitumen that are capable of causing corrosion, including water and sediments, occur at very low levels that are consistent with or lower than levels found in other crude oils (NAS 2013). Copies of these reports have been attached as Exhibits 2 and 3 of my testimony.

References:

Been, J. 2011. Comparison of the Corrosivity of Dilbit and Conventional Crude. Corrosion Engineering, Advanced Materials, Alberta Innovates Technology Futures. 29 pp. Internet website: http://www.ai-ees.ca/media/6860/1919_corrosivity_of_dilbit_vs_conventional_crude-nov28-11_rev1.pdf

National Academy of Sciences (NAS). 2013. Special Report 311: Effect of Diluted Bitumen on Crude Oil Transmission Pipelines. 110 pp.

28. Dr. Davis' testimony (p. 3) states benzene is "known to produce leukemia in humans." Please comment on this assertion.

Answer: While benzene is a known human carcinogen, cancer formation is associated with long-term chronic exposure, not the short-term exposure that could occur following an oil spill. For instance, a cohort study of 79 individuals exposed to benzene through their work in the Australian petroleum industry found an increased risk of leukemia following cumulative exposures above 2 ppm-years (Glass et al. 2003). This is equivalent to being exposed to 1 ppm of benzene for 8-hours per day for two working years (500 days). Exposures such as these would not be expected to occur following a crude oil spill due to the low persistence of benzene and preventative actions such as localized evacuations. Further, emergency response personnel would evacuate the area if there were concerns for human health effects. A copy of this report has been attached as Exhibit 10 of my testimony.

Reference:

Glass, Deborah C.; Gray, Christopher N.; Jolley, Damien J.; Gibbons, Carl; Sim, Malcolm R.; Fritschi, Lin; Adams, Geoffrey G.; Bisby, John A.; Manuell, Richard. 2003. Leukemia Risk Associated with Low-Level Benzene Exposure. Epidemiology. 2003;14: 569-577.

29. Dr. Davis's testimony (p. 3 and 4) discusses concerns with benzene being "transported downgradient toward receptors, such as public water-supply wells, private wells, and springs or seeps" as well as pipeline releases that have occurred in the past that have threatened groundwater supplies. How will Keystone address these concerns?

Answer: With regard to surface water intakes, Keystone's Emergency Response Plan would identify downstream public water intakes and associated contact information. In the event of a release, Keystone would immediately notify downstream water users so that the intakes can be proactively shut down. With regard to groundwater, municipal and residential intake users would be notified through the implementation of Keystone's Emergency Response Plan. Potential impacts would take months to years to occur.

In terms of the potential effects from a release to groundwater, the following points demonstrate why a release would not threaten groundwater sources:

- The subsurface movement of petroleum hydrocarbons is very limited, moving 312 feet or less in 90 percent of the cases (Newell and Connor 1998, as presented in Exhibit 4 of my testimony). Additional studies support this plume transport distance, as presented in Exhibits 4 through 9 of my testimony.
- A plume of dissolved petroleum hydrocarbons could begin to develop if crude oil reached groundwater and was allowed to remain in contact with the groundwater for a period of months.
- The plume would then move in the direction of the groundwater; however, plume movement would be slower than for groundwater.
- The plume would form along the uppermost surface of groundwater; they do not sink within groundwater as observed with solvent plumes. As such, contamination of groundwater would be limited to the volume associated with the groundwater surface.
- Petroleum hydrocarbons are degraded by microbial communities naturally found within soils, and as a result, only highly localized effects would be expected.
- Removal of the source oil and remediation actions would help to minimize groundwater impacts further.

Based on the PHMSA pipeline incident database (2002 to 2009), only 3.8% and 3.2% of spills affected surface water or groundwater resources; however, only 0.16% of spills actually affect drinking water resources. Consequently, the possibility of a spill occurring and affecting drinking water is very remote.

Data from actual pipeline spills demonstrate that substantial leaks do not go undetected for long periods of time. Further, those spills that are not detected within the first 48 hours are typically relatively small. PHMSA records (2001 through 2009) indicate that the majority of spills are 3 barrels or less, regardless of detection time. These data also indicate that the majority of spills are detected within 2 hours, with 99 percent of spills detected within 7 days. Of those spills not detected within the first 48 hours, the majority of spills were 15 barrels or less. In summary, large spills do not remain undetected for substantial periods of time.

Keystone will utilize an integrated leak detection system as stated in the Public Utilities Commission Amended Final Order Finding of Fact 94. Keystone also will have an Emergency Response Plan (ERP) in place to respond to incidents. The ERP contains comprehensive manuals, detailed training plans, equipment requirements, resource plans, and auditing, change management and continuous improvement processes. The Integrity Management Program (IMP) (49 CFR Section 195) and ERP will ensure Keystone will operate the pipeline in an environmentally responsible manner.

Reference:

Newell, C. J. and J. A. Connor. 1998. Characteristics of Dissolved Petroleum Hydrocarbon Plumes: Results from Four Studies. American Petroleum Institute Soil / Groundwater Technical Task Force. December 1998.

30. Dr. Davis' testimony (p. 5) restates Stansbury (2011) concerns regarding questionable assumptions and calculations by TransCanada of expected frequency of spills. Do you agree with that analysis?

Answer: No. The majority of pipeline infrastructure in North America was constructed many decades ago at a time when the materials, coating systems, and ongoing inspection capabilities that will be used for Keystone XL were not available. Studies show the benefits of these technologies in reducing pipeline incidents. Approximately two thirds of the pipelines in the US were constructed prior to 1970. It is therefore entirely appropriate to use an incident frequency for Keystone XL that is derived from pipelines of its class. This is corroborated by observations included in the FSEIS, "*[i]t is reasonable to conclude that modern and larger-diameter pipelines would experience a lower spill rate than older pipelines. Modern pipelines have built-in measures to reduce the likelihood of a spill (e.g., modern protective coatings, SCADA monitoring)...with the application of the Special Conditions and various studies that indicate more modern pipelines are less likely to leak, it is reasonable to expect a sizable reduction in spills when compared to the historic spill record*" (DOS 2014).

31. Dr. Davis' testimony (p. 5) restates the Stansbury (2011) argument that "worst-case spill volumes from the proposed Keystone XL pipeline are likely to be significantly larger than those estimated by TransCanada." Do you agree with that analysis?

Answer: No. Stansbury's estimate of worst case discharge was based on incorrect assumptions. Keystone has calculated the worst case discharge for the Keystone XL pipeline in accordance with 49 CFR Section 194.105. The Stansbury document suggests that, because shutdown on another pipeline took longer, that increased time should be used as the shut down time assumption for the Keystone XL pipeline. The referenced Enbridge pipeline was constructed in 1969, while the Keystone XL pipeline would be constructed to meet or exceed current regulatory standards. Stansbury does not take into account that the Keystone XL pipeline is instrumented at every mainline valve, which enhances the leak detection system, and that Keystone has incorporated API's recommended practices for computational pipeline monitoring as well as ASME's Pipeline Personnel Qualification standards per Special Conditions 27 and 30.

This makes it unlikely that Keystone operators would experience difficulty detecting a leak. Nor does he address industry information sharing or the workings of the regulatory regime, both of which serve to make it unlikely that alleged operational errors on one system are repeated on another system. For example, TransCanada requires the pipeline be shut down if an operator cannot definitively determine the cause of an alarm within a 10-minute validation period.

In addition, Stansbury does not take into account the fact that worst case discharge is determined using a large leak that would be instantaneously detected by the leak detection system resulting in immediate initiation of shutdown procedures. Nonetheless, in determining its worst case discharge, Keystone conservatively assumed a 10-minute leak confirmation period, plus 9 minutes for pump shut down, plus a 3-minute valve closure time, for a total of 22 minutes. While detection of a smaller leak may require additional confirmation time, the small volumes released would not approach worst case discharge amounts. As discussed in my response to Question 26, it is incorrect to assume that there could be a small leak that remained undetected for an extended period of time, as suggested by the Stansbury document. A copy of this report has been attached as Exhibit 11 of my testimony.

32. Dr. Davis' testimony (p. 5) states concerns regarding transport distance (e.g., up to 120 miles downstream) of petroleum contaminants if a release were to occur at a major water course. What is your response to these concerns?

Answer: Dr. Davis' testimony does not account for containment and cleanup efforts by the operator that limit downstream movement. As discussed in my response to Question 29, most spills do not affect water resources. Exceptional spills that occur during flood conditions represent the worst case for downstream transport, but these do not support a 120-mile downstream transport distance. For example, following a 10,000 barrel release in 2007 from the

Coffeeville Refinery in Kansas into the Verdigris River, the USEPA found no detectable concentrations of petroleum products 20 miles downstream at the closest municipal water intake. USEPA samples reported concentration of petroleum hydrocarbons to be below threshold limits at the first sampling point, located 12 downstream miles of the spill. In 2010, an Enbridge 30-inch pipeline ruptured, spilling 19,500 barrels of oil into the Kalamazoo River system. While the majority of contamination occurred in close proximity to the source, USEPA reported that contamination had been documented in localized areas within 30 miles of the spill's origin. The material downstream was sedimented oil, which lost most of its BTEX compounds through weathering and consisted primarily of asphaltenes and other heavy molecular weight petroleum hydrocarbons. As a group, these compounds tend to have low environmental toxicity, adhere to sediments, have low bioavailability, and do not biomagnify in food chains. The BTEX values at these locations did not exceed EPA human heath exposure thresholds. Sedimented oil was removed by dredging due to their environmental persistence.

As part of its Integrity Management Program and consistent with Federal pipeline safety regulations (49 CFR Section 195), Keystone has evaluated the downstream transport of a spill to identify those pipeline segments with the potential to affect High Consequence Areas.

Dated this 15 day of June, 2015.

Heidi Tillquist