BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

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 PIPELINE	)))))))	Docket 14-001 **DAKOTA RURAL ACTION'S POST-HEARING BRIEF**

To say that these proceedings have been contentious risks making a gross understatement. The permitting process for TransCanada Keystone Pipeline LP's ("TransCanada") proposed Keystone XL Pipeline (the "KXL Pipeline") has been a classic example of long-held privileges afforded the global fossil fuel industry arrayed against the interests of a public that is increasingly concerned about the effects of fossil fuel on our environment. This post-hearing brief is submitted on behalf of Dakota Rural Action ("DRA"), a nonprofit organization that represents the interests of South Dakota's farming and ranching families – individuals whose lands have been negatively affected by TransCanada's base Keystone pipeline, and who will bear the burden and effects of the proposed KXL Pipeline should it ever be constructed.

INTRODUCTION

Nine days of regulatory hearings before the South Dakota Public Utilities Commission (the "Commission") were barely enough to permit a thorough examination of the risks to the public that would be posed by the KXL Pipeline. These challenges were exacerbated by a clear power imbalance – a multinational corporation with tremendous resources arrayed against a small group of individuals, nonprofit organizations, and indigenous tribes, all of whom lacked the resources to do very basic things, such as engage much-needed expert witnesses to counter the paid-for narrative presented by TransCanada. Compounding these challenges was the Commission's own unwillingness to permit a thorough discovery process, illustrated by its order of December 17, 2014, limiting the scope of the proceedings and discovery. Additionally, TransCanada's obfuscation in responding to discovery requests – and the lack of resources by intervening parties to hire experts to fully analyze and interpret the information ultimately provided by TransCanada – further exacerbated the challenges. These circumstances left many intervenors, including DRA, with the clear impression that when challenging the economic privilege and power of the entrenched fossil fuel industry, the deck is stacked against citizens. With this institutional imbalance embedded in the overall process, intervenors such as DRA and the general public has no choice but to rely upon the Commission to carefully scrutinize claims made by well-funded corporations such as TransCanada in order to proactively protect South Dakota's water and land resources. We would suggest that the Commission's obligation to do so rises to the level of a fiduciary duty owed to the citizens of South Dakota in order to fulfill the public trust with which it is entrusted. The Commission is the only entity that can offset structural imbalances faced in proceedings such as this.

Even in the face of the tremendous power and resource imbalance DRA and the other intervenors faced, a remarkable thing happened during the course of these proceedings. Perhaps overly-confident in its political and economic power, TransCanada made a significant error fatal to its case for recertification of the permit for the KXL Pipeline. TransCanada failed to put on a case that even touched upon the majority of the conditions it had to demonstrate that it could meet. Instead, TransCanada simply believed that it could get by with saying "trust us, we'll comply." Time and time again throughout the nine-day hearing, TransCanada's witnesses came up short and the company failed to present evidence that it would or even could comply with permit conditions. TransCanada is asking the Commission to grant recertification on a hope and a prayer, with no substantive evidence that permit conditions can be met. That is not sufficient for TransCanada to prevail. Its petition for certification should be denied.

Even more remarkably, with the lack of substantial evidence to support its petition for certification, TransCanada – with support from Commission staff – argues that the scope of the Commission's authority is severely limited. DRA suggests this attempt to severely restrict the

Commission's authority to consider issues and evidence in the context of certification proceedings is incorrect.

As a final note, DRA would encourage the Commission to carefully examine the transcripts of the proceedings. Commissioner Fiegen, for example, is already examining the transcripts due to her medical absence during the hearing. Commissioner Hansen, who is also facing medical issues, should also be afforded the full opportunity to examine the hearing transcripts as well, perhaps after he is fully healed. The Commission as a whole has ample time to do so, given the statement by TransCanada executive Corey Goulet that no other permits were currently being applied for, in addition to the fact that the proposed KXL Pipeline's fate in Nebraska is still in question, not to mention the fact that no federal permit has been forthcoming. In short, there is no need for the Commission to feel rushed in its evaluation of these matters because time is not of the essence.

PROCEDURAL BACKGROUND

TransCanada was originally granted a permit for construction of the proposed KXL Pipeline through South Dakota on June 29, 2010 via entry by the Commission of its Amended Final Decision and Order (the "2010 Permit"), subject to fifty separate conditions. The conditions imposed on TransCanada by the 2010 Permit ranged from compliance with all federal and state environmental laws, to compliance with a variety of other matters as set forth in the 2010 Permit. Because TransCanada failed to commence construction of the proposed KXL Pipeline within four years of the date of the 2010 Permit, under SDCL § 49-41B-27 it was required to file a petition with the Commission certifying that it could continue to meet the conditions upon which the 2010 Permit was issued. SDCL § 49-41B-27 states:

> Utilities which have acquired a permit in accordance with the provisions of this chapter may proceed to improve, expand, or construct the facility for the intended purposes at any time, subject to the provisions of this chapter; provided, however, that ***if such construction***, expansion and improvement ***commences more than four years after a permit has been issued, then the utility must certify to the Public Utilities Commission that such facility continues to meet the conditions upon which the permit was issued***. (Emphasis added.)

STANDARD OF REVIEW

In rendering a decision the Commission must do so within an appropriate legal framework. This issue gets to the heart of the matter – what is required in order for TransCanada to "certify to the Public Utilities Commission that such facility continues to meet the conditions upon which the permit was issued" under SDCL § 49-41B-27? DRA suggests there are three key principles: (a) TransCanada's burden of proof, (b) the requirement that TransCanada present substantial evidence in support of its petition, and (c) the application of the public trust doctrine, which places a fiduciary duty on the Commission to protect South Dakota's land, water, and environment.

Burden of Proof

There is no question that TransCanada bears the burden of proof in advancing its petition for certification under SDCL § 49-41B-27. This principle is long-standing under South Dakota law, with the South Dakota Supreme Court "affirming the well-established rule that, "He who asserts an affirmative has the burden of proving the same."" *Tripp State Bank of Tripp v. Jerke*, 189 N.W. 514 (S.D. 1922).

Beyond the basic standard articulated by the South Dakota Supreme Court, the Commission's own administrative rules expressly address the question of which party carries the burden of proof in a contested case. The Commission's rules state that "[i]n any contested case proceeding … petitioner has the burden of proof as to factual allegations which form the basis of the … application, or petition …" S.D. Admin. R. 20:10:01:15.01 (2006). The Commission's rules are dispositive of this issue. TransCanada is the petitioner. TransCanada submitted a petition to the Commission pursuant to SDCL § 49-41B-27. The petition asks the Commission to make a factual determination that it can continue to meet the conditions upon which the 2010 Permit was granted. That petition was opposed by the intervenors, including DRA. Hence, TransCanada has the burden of proving that the proposed KXL Pipeline project continues to meet the conditions upon which the 2010 Permit was granted.

These principles were acknowledged prior to the Final Evidentiary Hearing (hereinafter, referenced as "EH" when citing to the hearing transcript), when the Commission and the parties expressed their respective understanding of what areas of inquiry and issues were before the Commission in these highly-contested proceedings. In fact, Chairman Nelson directly instructed the parties as to who had the burden of proof and what that burden was:

> "It is the Petitioner, TransCanada, that has the burden of proof. And under SDCL 49-41B-27, that burden of proof is to establish that the proposed facility continues to meet the 50 Conditions set forth in the Commission's Amended Final Decision. I would like to stress again to all parties here today that this case is about whether the project continues to meet those 50 Conditions." [7/27/15 EH: 10. *Also see*, 7/27/15 EH: 472].

This reality was acknowledged by TransCanada itself in its opening statement to the Commission, where it stated that the burden of proof was limited to the Amended Conditions established as part of the 2010 Permit: "We are here today to meet Keystone's burden of 18 proof. That is, certifying that the project continues to meet the 50 Conditions on which the Permit was issued and that it can be constructed and operated accordingly." [7/26/15 EH: 67]. TransCanada directly stated that it would call seven witnesses to satisfy its burden of proof, "five of whom are direct witnesses, two of whom are rebuttal. We will present exhibits that meet that burden of proof." [7/26/15 EH: 67].

Finally, TransCanada's burden of proof was articulated by the Commission's counsel, John Smith who, after opening statements had been completed, launched the presentation of evidence by stating: "And the party having the burden of proof, the Petitioner, TransCanada Keystone Pipeline, LP, please proceed with your case in chief." [7/26/15 EH: 148]. Extending this burden further, Commission counsel even determined that since TransCanada's witnesses were describing the nature and purpose of the proposed changes in the Findings of Fact (Exhibit C to TransCanada's petition for certification), cross-examination would be permitted in those areas, despite the fact they were "not part of Conditions that I know of." [7/26/15 EH: 212-213]. Given that TransCanada advanced that proposition in its petition for certification, even the proposed changes to the Findings of Fact as to the 2010 Permit were to be used as a guideline at the hearing, per Chairman Nelson's suggestion. [7/26/15 EH: 213].

Substantial Evidence

With the burden of proof squarely on TransCanada, it has the obligation to demonstrate that it can meet that burden through the presentation of substantial evidence in support of its petition. While South Dakota's courts are obligated to give broad deference to the decisions of administrative agencies, including the Commission, judicial deference is not absolute, and courts may reverse or modify agency decisions if "…substantial rights of the appellant[s] have been prejudiced because the administrative findings, inferences, conclusions, or decisions are...(5) [c]learly erroneous in light of the entire evidence in the record; or (6) [a]rbitrary or capricious or characterized by abuse of discretion or clearly unwarranted exercise of discretion." SDCL § 1-26-36.

When deciding whether a decision by the Commission is "clearly erroneous" courts will examine whether "substantive evidence" exists in the record upon which the Commission based its decision. *Helms v. Lynn's, Inc.*, 542 N.W.2d 764 (S.D. 1996); *Therkildsen v. Fisher Beverage*, 545 N.W.2d 834 (S.D. 1996) (citing *In re Establishing Certain Territorial Elec. Boundaries*., 318 N.W.2d 118 (S.D. 1982)); *Helms v. Lynn's, Inc.*, 542 N.W.2d 764 (S.D. 1996) (stating '[t]he issue we must determine is whether the record contains substantial evidence to support the agency's determination.'); *Abilb v. Gateway 2000, Inc*., 547 N.W.2d 556 (S.D. 1996) (stating '[t]he question is not whether there is substantial evidence contrary to the findings, but whether there is substantial evidence to support them.'); *see also Westergren v. Baptist Hosp. of Winner*, 549 N.W.2d 390 (S.D. 1996); *Zoss v. United Bldg. Centers, Inc*., 566 N.W.2d 840 (S.D. 1997); *Jackson v. Lee's Travelers Lodge, Inc.*, 563 N.W.2d 858 (S.D. 1997); *Rohleck v. J & L Rainbow, Inc.*, 553 N.W.2d 531 (S.D. 1996) (each case cites to and applies the substantive evidence test described in *Therkildsen*, *Helms*, and *Abilb*). Of note, the substantive evidence standard explicitly applies to decisions by the Commission. See *In re Establishing Elec. Boundaries*, 318 N.W.2d at 121.

Substantive or substantial evidence is much more than a mere promise, hope, or conclusory statement. SDCL § 1-26-1(9) defines the term as "…such relevant and competent evidence as a reasonable mind might accept as being sufficiently adequate to support a conclusion." South Dakota's Supreme Court delved into the meaning of this requirement in *M.G. Oil Co. v. City of Rapid City*, 793 N.W.2d 816 (S.D. 2011). The *M.G. Oil. Co*. case involved an application for a conditional use permit to operate a video lottery casino. *Id*., at 817. Rapid City's City Council could deny issuing a permit if it concluded that the permit would cause an undue concentration of similar uses, resulting in blight, deterioration or substantially diminished or impaired property value. *Id*. at 822. The "evidence" at a public meeting consisted of vague conclusory statements as to the potential impact of granting the permit – mainly, allegations that an increase in crime would occur. Additionally, a City Alderman expressed his belief that real estate values might fall as a consequence of issuing the permit. *Id*., at 821-22. As a result the City Council voted to deny the permit. The applicant appealed arguing that the City's decision was arbitrary and capricious and an abuse of discretion. *Id*., at 820.

In looking at the substantial evidence requirement, the Court examined whether the testimony and comments submitted during City Council meetings constituted substantial evidence upon which the Council could base its decision. *Id*., at 822-23. Its conclusion was that it was not. The Court held that "[v]ague reservations expressed by [Council] members and nearby landowners are not sufficient to provide factual support for a Board decision." *Id*., at 823 (citing *Olson v. City of Deadwood*, 480 N.W.2d 770, 775 (S.D. 1992)). Of note, the Court also stated that the City's failure to link specific and substantive testimonial evidence to the governing statute resulted in nothing more than simply repeating the language of the ordinance as a basis to deny the permit. *Id*. 823-24. That did not constitute substantial evidence in the Court's eyes.

TransCanada's case presents the same issue. Its witnesses' testimony largely consisted of conclusory, unsupported statements that it would comply with the conditions of the 2010 Permit. That is insufficient and does not constitute the substantial evidence necessary to support granting its petition.

Public Trust Doctrine – Commission has a Fiduciary Duty

In addition to determining whether TransCanada has presented substantial evidence demonstrating that it continues to meet the conditions of the 2010 Permit, in making its decision whether or not to grant TransCanada's petition for certification under SDCL § 49-41B-27, the Commission is held to a higher standard under the principles of the public trust doctrine. The public trust doctrine holds that certain natural resources belong to all and cannot be privately owned or controlled because of their intrinsic value to each individual and society. Public governmental bodies such as the Commission are, in effect, held to be trustees, with a fiduciary duty owed to the public to safeguard those resources. "[T]he Public Trust Doctrine is a critically important reminder of the duty of government to preserve wildlife, to protect the public's right to enjoy and benefit from a diverse ecosystem, and the duty of courts to carefully scrutinize any attempts to abandon the public trust in those resources." *Center for Biological Diversity, Inc. v. FPL Group, Inc.*, 166 Cal. App. 4th 1349 (2008) (quoting Carstens, *The Public Trust Doctrine: Could a Public Trust Declaration for Wildlife Be Next?* (2006) vol. 2006, No. 9, Cal.Envtl. L.Rptr. 1).

South Dakota has explicitly recognized the public trust doctrine. The most recent and most discussed case is *Parks v. Cooper*, 676 N.W.2d 823 (S.D. 2004), which held that "as matter of first impression, all water in South Dakota belongs to the people in accord with the public trust doctrine …" This principle in South Dakota extends back to the earlier part of last century, when in *Filsrand v. Madson,* 35 S.D. 457 (1915), the Court held that a riparian owner of water cannot interfere with "navigating, boating, fishing, fowling and like public uses" by the public. Interestingly, while not directly addressing the public trust doctrine, the South Dakota Supreme Court, in *State v. Schwartz*, 689 N.W.2d 430 (S.D. 2004), stated:

> "South Dakota retains a distinctly individual character, evident in its diverse communities, its amalgam of cultures, its mixture of heritages, and its contrasting terrain. Matters unique to South Dakota may generate a reason to view a particular constitutional provision differently. … [O]ur decision in *Parks v. Cooper* exhibits the type of deeply rooted regional issue—preservation of precious water resources through the public trust doctrine—that a court might take into account in examining a disputed provision of our constitution." *Id.*

DRA suggests that the public trust doctrine imposes upon the Commission a heightened fiduciary standard when it comes to protecting South Dakota's environment and resources from damage that could be caused by a pipeline leak or spill. While the Courts have explicitly referenced the public trust doctrine extending to protection of the State's water resources – which, by necessity, would include its surface and groundwater – the same principle applies to protection of the State's land, including its soil, native grasses, and crops. DRA suggests that the application of the public trust doctrine means that the Commission should set a higher bar for companies such as TransCanada, whose activities risk damaging the State's land and water resources.

TransCanada FAILS TO MAKE ITS CASE

With the procedural standards firmly in mind, the Commission must decide whether TransCanada met its burden of proof through the presentation of substantial evidence demonstrating that it could continue to meet the conditions of the 2010 Permit. The entire purpose of having a nine-day evidentiary hearing was to provide TransCanada with an opportunity to present substantial evidence. In the end, TransCanada embodied the classic fairy tale of the emperor who wore no clothes. Its case was sorely lacking. TransCanada's witnesses presented conclusory statements that were largely untied to specific conditions. Where conditions were referenced, TransCanada largely failed to present supporting evidence.

Witness after witness presented by TransCanada agreed that their pre-filed substantive written testimony was not related to showing compliance with any specific condition of the 2010 Permit, but instead, to support TransCanada's proposed amendment of the Findings of Fact.[1] For example, the President of TransCanada's Keystone system, Corey Goulet [7/27/15 (Goulet) EH: 148, 7/29/15 (Goulet) EH: 507] stated: "The changes discussed in FF 24-29 related to demand, do not affect Keystone's ability to meet the conditions upon which the Permit was issued." Direct Testimony of Corey Goulet, HP 14-001, ¶11, p. 5. When asked if this statement referred to Amended Conditions 6, 7, and 37, Goulet could only answer: "I'll just refer to those Conditions, but I believe that that's part of my certificate as well." 7/27/15 (Goulet) EH: 151. Goulet offered no proof showing how TransCanada had been and would be able to continue to do so. See, as further examples of the record: 7/29/15 (Schmidt) EH: 531-532;[2] 7/30/15 (Tillquist) EH: 655-656; Meera Kothari (agrees pre-filed testimony makes no reference to any Amended Condition it purportedly provides evidence for. 7/31/15 (Kothari) EH: 1078). However, while Kothari generally testified that her pre-filed testimony "related" to Amended Conditions 2 and 31 [7/30/15 (Kothari) EH:993, 1064-1065], she made no connection in her oral testimony between any particular testimony as evidence showing TransCanada's history and continued ability to comply with the 2010 Permit.

Demonstrating a remarkable ability to pass the buck, many of TransCanada's witnesses claimed that others could better answer questions being posed. Most of the TransCanada witnesses who said so named Meera Kothari as the person who could answer their questions about:

- Whether representatives of TransCanada's "engineering or construction department" would testify at the hearing: 7/27/15 (Goulet) EH:182.

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[1] Each objection to admission of pre-filed written testimony based only on Findings of Fact and not specific Amended Conditions was overruled by the PUC. 7/28/15 (Goulet) EH: 474; 7/29/15 (Schmidt) EH: 533; 7/30/15 (Tillquist) EH: 658; 7/31/15 (Kothari) EH:1078. DRA respectfully submits such rulings were in error and seeks reversal of the admission of such evidence as being irrelevant to whether TransCanada has been and will continue to comply with the Commission's Amended Conditions, by way of reconsideration.

[2] Although Schmidt responded to TransCanada Attorney White, that such testimony related to Amended Conditions 1-3, 6, 13-16, 20, 22, 26, 41, 43, 44, there was no testimony by Schmidt as to how such evidence showed TransCanada had been and will continue to comply with all or even these specific Amended Conditions. [7/29/15 (Schmidt) EH: 533].

- The length of the proposed KXL Pipeline to be above versus below ground. 7/28/15 (Goulet) EH:335-336.
- Whether there had been consultation with and input from nearby and affected tribes as to routing issues. 7/27/15 (Goulet) EH:182.
- Specifically whether the Yankton Sioux Tribe was notified of proposed local route changes. 7/27/15 (Goulet) EH:170.
- Whether TransCanada provided contact information for its land representative Sarah MeTransCanadaalf to landowners, the designated TransCanada public liaison. 7/27/15 (Goulet) EH:171
- About KXL routing, particularly through John Harter's land. 7/29/15 (Schmidt) EH:628.
- Details about the "89 crossings of pipeline" in the South Dakota portion of the proposed KXL Pipeline and particular waterbody crossing plans. 7/28/15 (Goulet) EH:260-261.
- How large a creek needs to be before TransCanada proposes Horizontal Directional Drilling (HDD) be used for the crossing. 7/28/15 (Goulet) EH:336.
- Details about the HDD process [7/29/15 (Schmidt) EH:545], including open cut and HDD "construction methodologies." 7/29/15 (Schmidt) EH:627.
- Details regarding the proposed HDD Bridger Creek crossing. 7/28/15 (Goulet) EH:279.
- Explanations as to why the Bridger Creek crossing has now be selected by TransCanada for utilization of HDD rather than open cut methods for pipeline installation. 7/29/15 (Schmidt) EH:589.
- What kind of pipe is used by the Mni Wiconi Water system at the location where it is proposed to be crossed over by the proposed KXL Pipeline. 7/29/15 (Schmidt) EH:633.
- Whether planning by TransCanada for the proposed KXL Pipeline includes the occurrence of earthquakes. 7/28/15 (Goulet) EH:336.
- Whether sliding slope soil concerns caused re-routing of KXL. 7/29/15 (Schmidt) EH:577.

- Information about the TransCanada website which had contained a section regarding a South Dakota voluntary evacuation zone. 7/28/15 (Goulet) EH:281-282.

Curiously and significantly, as the Commission weighs any purported claims of compliance with the Amended Conditions of the 2010 Permit, although Kothari was called by TransCanada as a witness "to speak to the engineering design construction for that project" [7/30/15 (Kothari) EH:1010], she was not and has never been licensed to provide engineering services in the United States. 7/31/15 (Kothari) EH:1124. ***Kothari, despite her supervisory work on projects in the United States, never made any effort to become licensed to professionally work in the United States as an engineer.*** 7/31/15 (Kothari) EH:1202. Remarkably, Kothari admitted, "I don't perform any specific services. My role ... as the project engineer is to know the requirements and ensure that we have subject-matter experts and specialty engineers who can fulfill that function." *Id*. This is significant because the record shows that TransCanada failed to call any of the subject-matter experts and specialty engineers on the KXL Pipeline project who could arguably have presented the substantive evidence that was lacking. In short, when it comes to substantial evidence, TransCanada's witnesses largely passed the buck to Kothari, who was ultimately found to be holding an empty bag.

However, although having served as the former lead project engineer for the KXL Pipeline[3] [7/30/15 (Kothari) EH:993], Kothari had overall engineering oversight for the Keystone Pipelines, including the proposed KXL Pipeline [7/30/15 (Kothari) EH:1010, 1083]. That duty involved "oversight of the third-party engineering firm that was responsible for pipeline design," specifically for "routing,"[4] "materials selection," and "interfacing with other disciplines within the project team" [7/31/15 (Kothari)

[3] TransCanada failed to present the current project engineer, hopefully licensed as an engineer in the United States, who could educate the Commission as to his or her duties and actually answer the many questions about the current design plans for the KXL Pipeline, ostensibly showing incorporation of the Commission's 50 Amended Permit Conditions, including PHMSA's 59 Special Conditions. However, choosing not to, TransCanada instead presented the former project engineer who was unlicensed in the United States to perform professional engineering services.

[4] At least prior to her testimony in 2009, Kothari had not looked at any USGS geological maps along the route which the KXL Pipeline was proposed and TransCanada previously made little mention to the Commission of the existence of a lengthy slope slide high hazardous areas at that time. 7/31/15 (Kothari) EH:1103.

EH:1052-1053]. She described herself as having not been "the responsible engineer for the base Keystone so I was not the licensed engineer in charge of authenticating the designs" and "was there to provide company oversight." 7/30/15 (Kothari) EH:1013. Kothari said she provided "engineering construction support to the project management team" during construction of Gulf Coast segment. 7/30/15 (Kothari) EH:1011-1012.

Suggestive of her qualifications as an engineering expert, her engineering skills and value of her testimony, TransCanada was "transitioning" Kothari into a new, non-engineering position in its "business development" department, which would be "non-technical" in nature and not include providing engineering advice to decision makers regarding prospective development projects and the commercial marketing groups. 7/30/15 (Kothari) EH:1009; 7/31/15 (Kothari) EH:1060. Remarkably, this was a position in business development for which Kothari had little training or education. 7/31/15 (Kothari) EH:1091.

For someone proffered as being in an oversight capacity over design and construction of the KXL Pipeline, Kothari displayed a remarkable lack of information and was even dismissive of the specifics of major safety issues clearly within duties. For some examples, Kothari acknowledged that she was unable to answer questions about:

- spills from the base Keystone pipeline system, as leaks during operation of Keystone Base were "not within" her "scope of responsibility."[5] 7/30/15 (Kothari) EH:1011, 1018-1019;
- organic chemistry questions regarding the fusion bonded epoxy (FBE) coating on the pipelines [7/30/15 (Kothari) EH:1019],[6] only "to a certain extent" the vulnerabilities of FBE [7/30/15 (Kothari) EH:1019];

[5] While Kothari later testified: "I believe I'm aware of all the pipeline related issues specifically. That's within my scope" [7/30/15 (Kothari) EH:1030], she previously had said: "I'm not familiar with the details specific to those spills". [7/30/15 (Kothari) EH:1005].

[6] This despite Kothari having had a job as an engineer in the pipeline integrity engineer for asset responsibility for TC for nearly three and one-half years within a department that involved coating. 7/31/15 (Kothari) EH:1088-1089.

- corrosion and cathodic protection issues as a specialist [7/30/15 (Kothari) EH:1027, 1088], including describing and differentiating between AC and DC current corrosion [7/30/15 (Kothari) EH:1031];
- operational aspects of the base Keystone Pipeline [7/30/15 (Kothari) EH:1025]; about any electrical engineering issues [7/30/15 (Kothari) EH:1030];
- corrosion engineering issues [7/30/15 (Kothari) EH:1032];
- the chemistry of crude oil, including the different hydrocarbons contained therein [7/31/15 (Kothari) EH:1051-52];
- "any specific details" about "measures and verification and testing that were done during that integrity program" after a 2009 PHMSA advisory about installation of "lower strength" steel pipe 7/31/15 (Kothari) EH:1055, 1057] - nevertheless, she claimed it was still safe [7/31/15 (Kothari) EH:1058;
- root causes of pipeline deficiencies [7/31/15 (Kothari) EH:1058], and whether it was a chemistry or fabrication problem [7/31/15 (Kothari) EH:1057-1058];
- the type or specific location of the threaded fitting issues causing pump station leaks on Keystone Base in the first year [7/31/15 (Kothari) EH:1058];
- other than changed route in Nebraska, why the first application to the US State Department was denied [7/31/15 (Kothari) EH:1068];
- PHMSA's accusations against TransCanada for failure to adequately monitor pipelines by air patrols ("not specifically aware") [7/31/15 (Kothari) EH:1074-1075].

Kothari agreed, in sum, that there were quite a few skills, training, and experience that she did not have to do her job, which caused her to "rely on my engineering specialty disciplines to provide that additional review and oversight as it comes up through to the management review of those particular issues." 7/31/15 (Kothari) EH:1083. Again, the majority of TransCanada's witnesses deferred to Kothari as the former lead project engineer for the KXL Pipeline, but in the end, she was found lacking. As is

TransCanada's "substantial evidence" of its ability to comply with the Amended Conditions of the 2010 Permit.

Heidi Tillquist was TransCanada's second most deferred-to witness. Although qualified as an environmental toxicologist, Tillquist also failed to show how TransCanada was meeting each of the Amended Conditions of the 2010 Permit and would continue to do so. In fact, Tillquist's testimony revealed that TransCanada not even completed its engineering analysis for the KXL Pipeline. [EH: 825-826].

A large portion of Tillquist's testimony focused on her performance of risk analysis with respect to the probabilities of pipeline leaks and spills, as well as possible spill volumes and the environmental effects of a spill. Rather troubling, her testimony exposed serious holes in TransCanada's purported ability to comply with the Amended Conditions of the 2010 Permit, and very possibly a disregard for the safety of South Dakota's residents and environment. This was highlighted by her admission that her choice of statistical methodologies used to calculate the risks posed by the KXL Pipeline were, in part, designed for public relations purposes. [EH: 844-847].

Casting further doubt on TransCanada's presentation of the risks posed by the KXL Pipeline, Tillquist revealed a startling deficiency in her analysis by acknowledging she did not know what a "black swan even" was. [EH: 850]. The black swan theory or theory of black swan events is perhaps one of the more widely-known principles of risk analysis. It is a metaphor that describes an event that comes as a surprise, has a major effect, and is often inappropriately rationalized after the fact with the benefit of hindsight. The theory was developed by Nassim Nicholas Taleb[7] to explain: (a) the disproportionate role of high-profile, hard-to-predict, and rare events that are beyond the realm of normal expectations in history, science, finance, and technology; (b) the non-computability of the probability of the consequential rare events using scientific methods (owing to the very nature of small probabilities); and

[7] Taleb is a bestselling author, is Distinguished Professor of Risk Engineering at the New York University Polytechnic School of Engineering, and as co-Editor in Chief of the academic journal, Risk and Decision Analysis.

(c) the psychological biases that blind people, both individually and collectively, to uncertainty and to a rare event's massive role in historical affairs.

For Tillquist to hold herself out as risk analyst and have no knowledge of a key principle of risk analysis is remarkable. Instead, she admitted that her risk analysis was based largely on analysis of the PHMSA database [EH: 825-828], which she acknowledged only contained domestic data. [EH: 830-831]. She also acknowledged that her risk analysis excluded risk of spills at tanks and terminals [EH: 832], that she did not take geographical variance into account [EH: 861-863], that she was unable to factor in different construction and operation standards between pipeline companies reporting in PHMSA database [EH: 834-835], and that her risk analysis failed factor in increased likelihood of adverse weather events [EH: 867]. This last point was crucial in light of her admission that she did not take into account data on adverse weather events such as the two contiguous hurricanes that caused damage to a TransCanada pipeline in Guadalajara, Mexico [EH: 2380-81].

Tillquist's risk analysis ultimately proved to be folly. She testified that her calculation of a risk of a spills was conservative (2.2 spills over 10 years), yet real-world experience resulted in spills on the base Keystone pipeline that greatly exceeded her estimates (12 spills shortly after being placed in service). [EH: 855-856, 860]. When asked about risks from landslides, Tillquist admitted her risk data was taken from an analysis of the entire PHMSA database and was not localized to areas of high risk. She stated that TransCanada would perform a more detailed engineering analysis, but that had not been completed. [EH: 871-872].

Compliance with environmental laws and regulations designed to protect water and other natural resources from harm is a critical component of the Amended Conditions contained in the 2010 Permit. Given that Tillquist testified that hundreds of High Consequence Areas exist in South Dakota [EH: 886-887], and that the chemical constituents of the diluted bitumen to be transported by the KXL Pipeline, including the BTEX complex of chemicals, are harmful to human health in small quantities [EH: 883-885], instead of bolstering TransCanada's case, her testimony revealed a tremendous lack of substantial evidence that TransCanada can even begin to comply, much less continue to comply, with the Amended Conditions of the 2010 Permit.

Continuing its failure to show how it can comply or continue to comply with the Amended Conditions of the 2010 Permit, including addressing the inadequacies in evaluation and analysis required for a more accurate risk analysis, TransCanada did not even present evidence that it was addressing issues noted by US State Department analysts in the 2014 FSEIS. For example:

- "at...small stream crossings, TransCanada needs to conduct location-specific analysis of fate and effects of spills...consider the use of additional valves &/or noninvasive boring technologies." 2014 FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(24), p. 37]
- E^x^ponent identified "additional potentially sensitive ecological areas and where Keystone's release analysis shows potential exists for medium to very large spills." 2014 FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(24), p. 37.
- Regarding "expressions of average risk, care should be taken when stating a U.S. threat rate, or state level threat rate because downplays the absolute importance of potentially large localized and/or periodic events." [FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(15a), p. 33] and including "overland flow (spreading)" [*Id.*, 3.0(17), p. 34], "4 streams identified by E^x^ponent" [*Id.*].
- TransCanada's risk assessment should include evaluation of potential damage of a spill "at least 10 miles downstream "...for identifying sensitive areas and contributory pipeline segments "during .. final design phase." [2014 FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(18), p. 34]. As the FSEIS pointed out, such studies are needed to determine if "sensitive areas," in order to be "protected," whether still "additional valves would not have a net benefit." *Id.*, 3.0(18a), p. 34.

- "[I]f...PHMSA approves construction" of the KXL pipeline, the FSEIS recommended that TransCanada "should assess incident likelihood considering the benefits of (having) "alternative, preventive, protective, and mitigating features in place." 2014 FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(15a), p. 33.
- TransCanada needs to conduct a "stream-specific scour analysis" for small streams in light of potential for flood events, specifically for small stream crossings identified by E^x^ponent where TransCanada plans to bury pipe through open cut methodology, less than five feet below creek bed. 2014 FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(25), p. 37-38.
- TransCanada used a "query process" which utilized CAUSE and GEN__CAUSE fields "to obtain...cause/threat results." It "appears...their ouTransCanadaomes exclude the facilities which are an essential element of any pipeline system." FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(19b), p. 34. A "better approach" would "capitalize on PHMSA National Pipeline Mapping System to geolocate the historic spill records as the means to better quantify localized threats." 2014 FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(19b), p. 35.

Of note, TransCanada failed to present substantial evidence, much less any evidence at all, as to how it would deal with these crucial risk factors in order to minimize harm to the environment and to water resources.

DRA would also ask the Commission to take administrative notice of Kothari's prior testimony before the Commission in evaluating both her credibility and the significance of prior admissions. For example, by 2007 TransCanada reported some "576" spills from its pipeline system, of which "80%" involved "equipment related spills of "hydraulic oil, lube oil, glycol and fuel." Written Testimony of Meera Kothari, HP 07-001, Ques. 19, p. 5. TransCanada had already experienced 20 "near misses" [*Id*., Ques. 19, p. 6], 28 of which were "serious," meaning "less than 20 gallons" spilled [*Id*.], one was "critical," involving "approximately "100 gal. of various liquids such as lube oil [*Id*.]." In a 1996 incident at one the pump stations on the TransCanada-operated Platte Pipeline, "approximately 220 bbls of oil - were released" of which "none" recovered. Written Testimony of Kothari, HP 07-001, Ques. 21, p. 6.

To estimate the likely number of spills expected from the KXL Pipeline, the FSEIS advised TransCanada that it should include "threat-based sensitivity analysis including scope and results." FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(14), p. 33. The FSEIS found that TransCanada had "not used" "sensitivity analysis to understand the underlying drivers for incidents when estimating spill frequencies" FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(14a), p. 33. The State Department analysts advised TransCanada that Battelle suggested that such "sensitivity analysis could help identify localized threats." *Id*.

Risk assessment is required by PHMSA - Condition 14 and 49 CFR 195.452 for HCAs. FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(14), p. 33. The State Department analysts noted the "large differences" between "system components and facilities that comprise the discrete elements cast uncertainty on the use of aggregated metrics for risk" and equally cast uncertainty on the use of aggregated "professional engineering judgment." [2014 FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(26), p. 38. For example, the 2014 FSEIS further observed that seals and seats have a "higher potential for spills than (on equipment & pumps)" 2014 FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(11)(a), p. 32. Due to "dominance" of risks "associated with mainline pipe and other system components (other than mainline valves or tanks)" the "risk assessment" required by 29 CFR 195.452 should address both "to effectively reduce risk," observing that 97% of risk occurs in mainline pipe and "fixed facilities" (e.g., pumping stations. 2014 FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(20a), p. 35. The State Department reported that it expected TransCanada to be "diligent" in its "material section for" these components. FSEIS,

Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(11)(a), p. 32]. Remarkably, TransCanada provided no substantial evidence during nine days of evidentiary hearings to demonstrate compliance – other than conclusory statements promising compliance.

KXL to be Safest Pipeline?

In response to Commissioner Hanson's statement during the hearing of how he had read and heard "several" times that the KXL will be "the safest pipeline ever built", Goulet gushed how no other pipeline has been requested to incorporate 59 special conditions (referencing Appendix Z of the FSEIS), and as such, other pipelines "don't have the redundancies and safety measures which we will build on KXL." 7/27/15 (Goulet) EH:302. The colloquy continued:

> Hanson: It sounds as if, though, it might be safer to say it's one of the safest pipelines....can you honestly say this is the safest....?
>
> Goulet: ....until we build the pipeline, I suppose we can't say it is ...
>
> 7/27/15 (Goulet) EH:303.

Yet, later during later under cross-examination, Goulet clarified that he "never said it will not leak" ... and "can't predict" whether a leak would be large or small. "I can't predict the future." 7/28/15 (Goulet) EH:354.

Goulet's backtracking is not surprising when seen in the light of Kothari's acknowledgment that, since 2010, TransCanada has not submitted any detailed geologic, biologic, environmental, engineering studies and current designs to the Commission for review as to sufficiency or accuracy, or to show compliance with any of the 50 Amended Conditions. Similarly, TransCanada has not submitted updated or corrected design plans and environmental studies surrounding HCAs [7/31/15 (Kothari) EH:1117], or otherwise presented the Commission with evidence it is in compliance with the many deficiencies in evaluations, analysis, or otherwise completed to address many important issues necessary to show it can safely construct the KXL Pipeline.

TransCanada Admitted It Cannot Meet Condition 3

Significantly, TransCanada's paid corporate expert witness Jon Schmidt agreed during cross-examination that TransCanada cannot meet Amended Condition 3 of the 2010 Permit since the submission and testimony to the Commission in these proceedings were based upon a US State Department Permit Application that had been denied [7/29/15 (Schmidt) EH:542].

In addition to TransCanada's failure to meet its burden of proof to warrant certification, the hearing evidence tends to show the contrary.

Kothari testified she performed "oversight" for TransCanada of the "design and engineering" on the Gulf Coast and Keystone Base pipeline design and construction projects. 7/31/15 (Kothari) EH:1090. However, she quickly attempted to absolve herself of responsibility for any design or construction related flaws in the respective pipelines since she didn't design the pipelines and an authenticating engineer, not her, was responsible to ensure pipeline designed and built correctly. 7/31/15 (Kothari) EH:1090-1091.

Kothari agreed that "preventing leaks is a primary goal because any leak could release product into potentially sensitive ecosystems or critical resource areas" and testified it was a "one of the primary goals". 7/31/15 (Kothari) EH: 1091. However, like other parts of her testimony, her rose-tinted sugar-coated promises to comply with all Amended Conditions of the 2010 Permit can be seriously questioned by the evidence in the record.

What TransCanada would like to transport through South Dakota is a "hazardous liquid". 7/31/15 (Kothari) EH: 1092. And, "modern pipelines can fail in a number of different ways." This includes "internal and external corrosion, third party damage, equipment failure, or outside force type failures." 7/31/15 (Kothari) EH: 1092. Part of Kothari's job was to "review potential pipeline threats to the pipeline and work with our design engineers to ensure that we have safeguards and various design requirements built in to prevent, mitigate, and monitor those particular threats to the pipeline." 7/31/15 (Kothari) EH: 1092-1093.

Despite these assuring words, the evidence in the record shows that TransCanada has a questionable ability or willingness to comply with all applicable design and construction regulations of all agencies which have established permit conditions (Condition 2), should provide, in addition to TransCanada's failure to meet its burden of proof, providing an additional basis for this Commission to deny recertification of the construction permit for TransCanada.

59 Special Conditions "were put out by PHMSA" regarding the proposed KXL pipeline. 7/31/15 (Kothari) EH: 1115. These 59 Special Conditions are eight additional to those PHMSA required on the base Keystone. 7/28/15 (Goulet) EH: 354. Amended Condition 2 provides that TransCanada comply with any conditions imposed by any permitting agency, including PHMSA (see Finding of Fact 22). Yet in a revealing moment for this Commission to consider in terms of TransCanada's willingness to comply with permit conditions, TransCanada has taken the position that the 59 Special Conditions imposed on the KXL Pipeline by PHMSA need only be complied with if the hazardous material transportation company chooses to do so. As Kothari testified, at this point in time, TransCanada has "**voluntarily adopted** to apply those Permit Conditions." 7/31/15 (Kothari) EH:1079-1080, 1105, 1110. See, Direct Testimony of Corey Goulet, HP 14-001, ¶9, p. 3; 7/27/15 (Goulet) EH:215, 216. This despite the admission that there is no correspondence from PHMSA telling TransCanada that the 59 Special Conditions are merely "advisory." 7/31/15 (Kothari) EH:1106. By way of further example, there is no SCADA requirement in Amended Conditions, although TransCanada recognizes there is one from PHMSA in the 59 Special Conditions - Appendix Z to the FSEIS. 7/31/15 (Kothari) EH:1076.

Failure to Recognize Magnitude and Risk of Routing Pipeline through High Hazard Slip Slope Areas.

Dr. (and now Professor Emeritus of geology) Arden Davis of the South Dakota School of Mines [8/3/15 (Davis) EH:1784], testified that from the USGS map in the FSEIS, he estimated the pipeline would travel within "slightly more than 150 miles of Pierre Shale." 8/3/15 (Davis) EH:1784. The Commission has in the record the USGS map of South Dakota with the pipeline drawn through the various geologic formations along its proposed route. The USGS map characterizes a significant portion as a "high landslide Hazard Area." RST EX-4, also contained within the 2014 FSEIS, Volume 2, Chapter 3, 3.1 Geology, Figure 3.l1.2-3, p. 3.1-29.

Yet, despite such evidence and TransCanada's purported commitment to follow the guidance and recommendations in the FSEIS in the construction of the KXL pipeline, and perhaps reflective of other evidence that regulatory safety requirements are merely voluntary, and defective design or construction issues seem to never involve real pipeline safety issues, just meaningless regulations, this Commission heard testimony that TransCanada considers only 1.6 miles of its proposed route to be "considered in that high hazard, high landslide type scenario." Responded Dr. Arden: "I would be very surprised to hear that." 8/3/15 (Davis) EH: 1796. And what should be of additional concern to the Commission, TransCanada is not sure if even this minute portion of the KXL Pipeline route is really in such a high hazard area. 7/31/15 (Kothari) EH:1094-1097. This despite Kothari's agreement that the USGS map in the FSEIS shows the pipeline traversing up to 150 miles of the high hazard slide topography just between four planned pump stations. 7/31/15 (Kothari) EH:1097.

To his credit, TransCanada witness John Schmidt acknowledged that slope stability is an important consideration as to routing of pipeline. 7/29/15 (Schmidt) EH:578. If "there's slope coupled with erodible...then yeah, you look to try and minimize," claiming it would become a "reclamation issue" following construction, since it would be "difficult to maintain that right of way." 7/29/15 (Schmidt) EH:581. He further agreed that bentonite soils would "potentially" create a "stability problem," especially when "coupled with water source and slope and other factors." 7/29/15 (Schmidt) EH:582.

He agreed ground movement "may" occur in this area of the State due to presence of Pierre Shale, especially the bentonite layers. 7/29/15 (Schmidt) EH:594.

Dr. Davis described the clay nature of bentonite and what should be remembered about construction where it predominates the ground-structure: "It's a platy mineral that can absorb water in betwen the sheetlike layers....up to around 190% of its own weight in water....And when it absorbs water then it's prone to failure." [8/3/15 (Davis) EH:1788].

From his knowledge of the high slide areas depicted on the USGS map, Schmidt agreed the "land forms and topography of the area" the KXL pipeline is routed to go through "is characterized by dissected plateau with river channels that have incised into the landscape" and the each has numerous tributaries that feed water into the major rivers 7/29/15 (Schmidt) EH:586-587. Such are "important" component of "watershed." 7/29/15 (Schmidt) EH:588.

Schmidt also acknowledged that additionally along the KXL Pipeline route, almost all of Haakon, Jones, and portions of Tripp County have potentially unstable "gumbo" soils. 7/29/15 (Schmidt) EH:593. He did "not" know status of any plans to compensate for weather issues during construction, as required by Amended Condition 25 [7/29/15 (Schmidt) EH:623], despite this area and the areas with bentonite soils were susceptible to instability upon weathering [7/29/15 (Schmidt) EH:594], "basic wind, sun, water...those are mainly the erosive forces." 7/29/15 (Schmidt) EH:623

However, as the TransCanada contractor charged with responsibility for "cultural surveys, biological surveys, wetlands, water bodies, things of that nature" [7/29/15 (Schmidt) EH:540], he "wasn't aware" of a recent 500 year flood, then admitting that 2, 3, 4, or 5 inches of rain "could" create a problem for the KXL Pipeline in unstable soils.[8] 7/29/15 (Schmidt) EH:583. He also did not recall seeing information in the 2014 FSEIS he reviewed [7/29/15 (Schmidt) EH:555] that a majority of pipeline through South Dakota is routed through what was described as a "high landslide hazard area," and

[8] Schmidt acknowledged that clay is well-known for absorbing large quantities of water. 7/29/15 (Schmidt) EH:591.

disagreed it did so. 7/29/15 (Schmidt) EH:583-584. He acknowledged TransCanada's proposed re-routing maps did "obviously not" remove the pipeline from such high landslide hazard areas shown on the USGS map. 7/29/15 (Schmidt) EH:584.

So far and fortunately, evidence in this record show that most of the spills from the Keystone pipeline system to the Gulf of Mexico have been relatively minor and there have only been "near misses" of potentially disastrous incidents. By way of the examples discussed below, the DRA respectfully submits that TransCanada's history of safety issues should give further pause by any Commissioner of a thought of granting certification.

2009 Incident

Kothari admitted some knowledge about pipeline integrity issues arising in pipe used by TransCanada. There was a "PHMSA advisory...issued late in 2009 related to low yield materials that potential pipeline operators would be susceptible to." [A]s we moved into operations...integrity management folks developing plans, implementing plans, to meet that advisory requirement." 7/31/15 (Kothari) EH:1055. The advisory "requested operators to verify the integrity of the pipeline" regarding a materials issue. 7/31/15 (Kothari) EH:1055. TransCanada's response included "digs involved ... locations ... identified through high resolution in-line inspection, as per the advisory requirements." 7/31/15 (Kothari) EH:1055.

Reflecting TransCanada's attitude towards safety regulations, Kothari saw nothing "wrong" with below PHMSA regulation "lower-strength" pipe being used in TransCanada's pipelines or it being insufficient to meet safety specifications from PHMSA, claiming, nevertheless, it was "[n]othing that would ensure the ongoing safe operations of the pipeline." 7/31/15 (Kothari) EH:1056-1057.

Pipeline Safety History - Spills

Kothari acknowledge that there were 14 spills in 1st year of operation of TransCanada's Keystone Base pipeline.[9] 7/30/15 (Kothari) EH:1005, 1006. Nevertheless, according to TransCanada, a pipeline which leaks 14 times in its first year is "safe" 7/30/15 (Kothari) EH:1007. Goulet admitted the number but described them all as only "minor" and were "associated with small diameter fittings and seals." 7/28/15 (Goulet) EH:355. Kothari admitted being "familiar generally we had a number of leaks at the pumping stations upon initial operations." 7/31/15 (Kothari) EH:1053.

Ludden spill

The largest spill the first year of operation of the Keystone Base pipeline was at Ludden Pump Station. *See DRA Exhibits 69, 70 and 172, attached hereto as Exhibits A, B and C.* Kothari's understanding was the problem involved a "small above-ground component, such as a fitting...some of the issues were" cause of leaks 7/31/15 (Kothari) EH:1053. "[I]t was threaded fitting," which leaked. 7/31/15 (Kothari) EH:1058. Despite her oversight responsibilities, she "wouldn't know the specific manufacturer" of the fitting. 7/31/15 (Kothari) EH:1058.

As to the Ludden Pump Station spill in May of 2001 of some 400 barrels of crude, Kothari knew that "reports are created" and was "aware there was a spill there, but...not...all the details." 7/31/15 (Kothari) EH:1197. She had not read the reports. 7/31/15 (Kothari) EH:1197-1198. She would not guarantee that a larger spill would not happen if the KXL pipeline was constructed. 7/31/15 (Kothari) EH:1199. Indeed, Kothari was unaware of Exponent's calculations that under the latest detection equipment plan given to the State Department, a spill of some 1,400 barrels of crude could take place within two hours before it was even detected electronically. 7/31/15 (Kothari) EH:1200-1201. See, also, 2014 FSEIS, Appendix B, Potential Releases & Pipeline Safety, Mitigation Measures Recommended, 3.0(1)(g), p. 28. As Kothari agreed, that is a "real lot of crude." 7/31/15 (Kothari) EH:1201.

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[9] Kothari may have been trying to distance herself from hard questions about TC's history of leaks, asserting that such leaks were "not within" her "scope of responsibility." 7/30/15 (Kothari) EH:1011, 1018-1019.

Gulf Coast Pipeline Weld Issues

Goulet testified that he was involved construction of the Gulf Coast segment of the Keystone pipeline system, his job being to make sure TransCanada had on-sight the "proper personnel, processes & systems." 7/27/15 (Goulet) EH:198. He was "accountable" for ensuring construction in compliance with TransCanada plans and agency regulations and conditions. 7/27/15 (Goulet) EH:198. For her part, Kothari was not involved in the detailed design of the Gulf Coast pipeline, "just coming in towards the very end." 7/30/15 (Kothari) EH:1012. Further, so-called operational problems with Gulf Coast were not within her ability to testify. 7/30/15 (Kothari) EH:1011.

Goulet was "personally aware" of two PHMSA warning letters [DRA Exhibits 69[10] and 70[11]]. "One associated with welding" and "one associated with...Coating," acknowledging there "might have even been one more than one feature that was talked about." 7/28/15 (Goulet) EH:344. Goulet denied that the PHMSA communications were "compliance letters," claiming they were mere an expression of "their opinions on some potential issues they've seen during their inspections of the pipeline." 7/28/15 (Goulet) EH:340.

Goulet did acknowledge that PHMSA inspectors had concerns over coating damage due to "weld splatter" and "concern over...welding rejection rate...in the early stages of one of the spreads that was

[10] DRA Exhibit 69 was excluded by the Commission for disclosure three weeks prior to the hearing. It is not a PHMSA warning letter but refers a Warning Letter dated 9/26/13 and the finding of additional PHMSA regulation violations for "failing to perform welding on Spread 3 in accordance with a procedure qualified according to §5 of API 1104" and "failing to properly qualify welders on Spread 3 in accordance with §6 of API 1104." PHMSA Evaluation Report of Liquid Pipeline Construction, "Keystone Gulf Coast Pipeline, Inspection Dates: 2011-2011, p. 2, 5, 6. There was also found to be a failure to properly inspect "all external pipe coating...just prior to lowering the pipe into the ditch." *Ibid*, p. 8. The document noted the 36 inch diameter of the pipeline. *Ibid*, p. 3.

[11] DRA Exhibit 70 was also excluded, for which reconsideration and admission is requested. According to the 9/10/13 PHMSA Warning Letter, it was "as a result of the inspection" by PHMSA representative, that violations of PHMSA regulations were noticed during Gulf Coast construction. "TransCanada did not assure that its Keystone Pipeline was installed in the ditch in a manner that minimizes the possibility of damage to the pipe." These included dents "that appear to be caused by secondary stresses on the pipe." Proffered DRA EX-70, p. 1. "In reviewing the submitted anomaly reports and PHMSA inspections it demonstrates that TransCanada is not following their Construction Specifications." There were also violations related to the failure of TransCanada to "follow its written specification, protecting excisting coating from damage due to welding," particularly "weld splatter." *Ibid*, p. 2.

used in that pipeline," the weld rejection rate being "between 10 and 20 percent in the early stages of the project." 7/28/15 (Goulet) EH:345. He contended there was "no issue with our quality control program" which was "why we found out we had a high incidence of weld failures." 7/28/15 (Goulet) EH:346.

Testified Goulet: "We were using qualified and approved welding procedure" and that "All" of the welders "passed a welding qualification test." The "concern PHMSA had...was...that the welders did not have the skill to be able to perform that welding in a productive manner on a continuous basis."[12] 7/28/15 (Goulet) EH:390.

"Near Miss" Near St. Louis

In pre-filed testimony [¶9], there was only one reference to a Fusion Bonded Epoxy (FBE) problem, being an instance of cathodic protection system interference in the Keystone Pipeline in Missouri, which Kothari testified was only offered to support a proposed Finding of Fact change. 7/30/15 (Kothari) EH:1024. Thus, based upon the Commission's rulings, it fails to show compliance with any condition.

The segment of the Keystone pipeline in involved in the incident was constructed by TransCanada in a pipeline corridor, some 40 feet ("so quite close") from two other metal pipelines, one transporting gas, the other crude oil. 7/30/15 (Kothari) EH:1027

The "near miss" involved discovery on the walls of buried and in-service pipe of a number of corrosion anomalies. "[W]e had corrosion identified through an in-line inspection run." 7/30/15 (Kothari) EH:1026. Although Goulet, despite the duties of his corporate position and the purported

[12] To the contrary, as excluded DRA EX-69 would resolve, PHMSA gave TransCanada "unsatisfactory" ratings for violations of PHMSA regulations requiring that: "Welding must be performed by qualified welders using qualified welding procedures;" "Welding procedures are qualified in accordance with §5 of API 1104;" "Welding procedures must be qualified by destructive testing;" "Each welding must be accorded in detail,...;" "Welders must be qualified...;" "Welders may not weld with a particular welding process unless within the proceeding 6 calendar months, the welder has - (1) engaged in welding in that process and (2) Had one weld tested and found acceptable under §9 of API 1104." (Excluded) DRA EX-69, *supra*, p. 7.

Company ethos of learning from incidents to build better pipelines, was unfamiliar with the not familiar with his Company's own Study of Root Cause and Contributing Factors to the Keystone Pipeline Corrosion Anomaly - Final Report of TransCanada 2-13-13 [7/28/15 (Goulet) EH:362-363, 374]. He further could not even generally estimate how many corrosion anomalies were discovered in the necessary digging up of sections of the hazardous pipeline. 7/28/15 (Goulet) EH:320.

Goulet said he was aware of the cause, however, being "result of interference of another pipeline that runs in parallel to that particular portion of pipeline in Missouri. And, there's also electrical transmission line, I believe, in that area as well." 7/28/15 (Goulet) EH:293-294.

Goulet attempted to absolve himself of responsibility for the "near miss" by telling this Commission that he did "not" have oversight of TransCanada operation of pipeline after closeout of construction and transfer of operations. 7/27/15 (Goulet) EH:200. Kothari testified the "root cause" of the "corrosion anomaly was related to cathodic protection interference" [7/30/15 (Kothari) EH:1026, 1029].

When asked whether TransCanada construction oversite included ensuring proper cathodic protection in place when pipeline near foreign pipeline, Goulet responded that "under the regulations, the cathodic protection system doesn't have to be operational when a pipeline goes into service" [7/27/15 (Goulet) EH:222] adding it was "actually required to be in service within 6 months...of placing the project into operation" [7/27/15 (Goulet) EH:223]. He later characterized this as "very early into the operation." 7/28/15 (Goulet) EH:310 It was never explained by any TransCanada witness nor any plan produced that this incident changed TransCanada procedures that at least anywhere near another metal pipeline or high intensity powerline, that a cathodic protection inspection would be done immediately to detect and remedy problematic cathodic interference immediately, and not wait until fortune of timing of an agency required inspection schedule prevents a "near miss."

Goulet expressed that he was "aware" that in the "past", TransCanada buried pipe with line strikes and weld splatters. "But our quality assurance process prevented that system from going into operation and we subsequently repaired those coating problems" 7/27/15 (Goulet) EH:225-226. This evidence reveals, as DRA contends, serious questions about the quality assurance process of the Keystone projects.[13]

When questioned with the pictures and contents of DRA EX-153, Goulet responded that he was "not familiar with all the details" regarding one of the corrosion anomalies which suffered a 97% wall loss.[14] 7/28/15 (Goulet) EH:362. However, he was somehow able to tell this Commission that the most problematic "feature, although it was as thick as a dime, it was also only the size of a dime in diameter." 7/28/15 (Goulet) EH:309. In other words, it was still safe. However, after being confronted with photographs of the anomalies with a ruler included in DRA Ex-153, Goulet agreed the feature shown in Figure 10 of TransCanada Study was "Maybe 1 3/4 average diameter." 7/28/15 (Goulet) EH:372. Challenging the idea of another anomaly having more than a 50% wall loss, he again had to agree that a photo of another anomaly on p.18 of TransCanada Report, Dig Site 2 had a "73.9%" wall loss 7/28/15 (Goulet) EH:375, 381.

TransCanada made limited acknowledgements of the pending impact of a corrosion anomaly(ies) of this depth and size if the last bit of wall went through the outer wall, then "obviously it would create a leak." 7/28/15 (Goulet) EH:362. Goulet said of what it claimed was an abnormal event, it "wouldn't **normally** result in a burst...even a full line pressure. The "feature would have to be...inches, if not feet longer for...burst." 7/28/15 (Goulet) EH:309, 361-362. Attempting to downplay the "near miss" that

[13] In 2012, TransCanada whistle-blower Evan Vokes filed a complaint with the Canadian NEB. In her unrefuted testimony land owner along the proposed KXL pipeline route, individual Intervenor Bonnie Kilmurry told the Commission the NEB found: "Many of the allegations of regulatory noncompliance identified by the complainant were verified by TransCanada's internal audit'." 7/28/15 (Kilmurry) EH:496.

[14] The TransCanada report indicated that a one dig site alone, "Dig Site 1," where the peak depth of one anomaly was "96.8%," there were 6 anomalies caused by external corrosion. 7/28/15 (Goulet) EH:366, 371.

caused an emergency shutdown of the pipeline for four days [7/28/15 (Goulet) EH:374], Goulet said: "I don't know if I'd call it an incident, but it was a feature that was found during the in-line inspection" [7/28/15 (Goulet) EH:318-319]. He then suggested that further questions regarding this incident be directed at TransCanada rebuttal witness King. 7/28/15 (Goulet) EH:319, 320**.**

Kothari encouraged the Commission to not worry, since "no similar situation could exist in South Dakota because there are no shared utility corridors." 7/30/15 (Kothari) EH:1025. Goulet initially gave a similar assurance. 7/28/15 (Goulet) EH:294. However, this was not correct, as Goulet himself apparently forgot, previously acknowledging being "aware" the proposed KXL route crosses a metal pipeline of the major water transportation system, the "Mni Wiconi Project." 7/27/15 (Goulet) EH:223-224; 7/29/15 (Schmidt) EH:633.

Post-Construction Failure to Reclaim Land

Sue Sibson testified on behalf of DRA. Her testimony shows that TransCanada cannot meet its requirements under the Amended Conditions to reclaim land. The Sibsons raise grain and soybeans, and have feeder cattle on a farm in Miner County. [EH: 1949] Native grasses important to how they make a living. The base Keystone pipeline crosses property. [EH: 1950]. The 2009 construction of the base Keystone tore up their land and it is still not fully reclaimed. [EH: 1956-58]. The initial reclamation work was shoddy, as contractors rushed and did not reseed properly. [EH: 1958-59]. In the summer of 2010, mainly noxious weeds and no grasses were growing on the pipeline easement area. [EH: 1959]. Ms. Sibson testified extensively about TransCanada's failures to comply with land reclamation requirements and notes that the same issues affect her neighbors where the pipeline crosses their lands. [EH: 1994]. After six years, the Sibson's property over the easement area has no native grasses. Only weeds and unusable grasses. [EH 2010-2011]. TransCanada's failure to comply with reclamation requirements is indicative of its inability to comply with the Amended Conditions.

Pattern of Regulatory Non-Compliance

Finally, the Commission heard from former TransCanada employee Evan Vokes. We will not repeat his extensive testimony about welding technology and pipeline construction. However, the crucial components of Mr. Vokes's testimony were that on the base Keystone he, worked on inspecting welds. After uncovered problems, he reported to TransCanada management that between 1200-1300 welds had been inadequately inspected. Management reproached Vokes for creating "trouble" and wanted Vokes to ignore problems. [EH: 1619-24]. Critically, Vokes testified that he was asked "many times" by TransCanada management to ignore regulatory violations. [EH: 1627].

CONCLUSION

TransCanada failed to present substantial evidence that it could comply with or even continue to comply with the Amended Conditions of the 2010 Permit. In fact, such an incomplete record was presented that even an attempt at certification is premature. TransCanada has presented its case to the Commission before even being able to begin meeting its burden.

The record is remarkable for what it does not reveal. What is missing from the overall record is substantial evidence of compliance by TransCanada. What is on the record from TransCanada's own witnesses is a lack of willingness to take responsibility, a tremendous amount of buck-passing, and the consistent use of the phrase "that's not my responsibility" and "that's not in my scope."

TransCanada has failed to meet its burden. The Commission should deny its petition for certification.

Respectfully submitted,

/s/ Bruce Ellison

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EVALUATION REPORT OF LIQUID PIPELINE CONSTRUCTION

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If an item is marked U, N/A, or N/C, an explanation must be included in this report.

A completed **Standard Inspection Report** is to be submitted to the Director within 60 days from completion of the inspection. A **Post Inspection Memorandum (PIM)** is to be completed and submitted to the Director within 30 days from the completion of the inspection, or series of inspections, and is to be filed as part of the **Standard Inspection Report.**

Inspection Report		**Post Inspection Memorandum**	
Inspector/Submit Date:	Southwest Region	**Inspector/Submit Date:**	
		Peer Review/Date:	
		Director Approval/Date:	

POST INSPECTION MEMORANDUM (PIM)

Name of Operator:	TransCanada Oil Pipeline Operations Inc.	**OPID #:**	32334
Name of Unit(s):	Keystone Gulf Coast Pipeline North / Keystone Gulf Coast Pipeline South	**Unit #(s):**	74979,83245
Records Location:	Transcanada Sharepoint site, Contractor offices, Transcanada Office	**Activity #**	135840 & 140666
Unit Type & Commodity:	Interstate Liquids (Crude)		
Inspection Type:	Construction	**Inspection Date(s):**	2011-2014
PHMSA Representative(s):	Clint Stephens /Jon Manning /James Arnold / Noah Matthews/Barry Small/ Bill Lowry/ Basim Bacenty/ Joseph Elmer/ David Eng/ John Pepper	**AFO Days:**	165.9

Summary:

The final report consists of three parts:

1. **Form 7**
2. **Appendix A: Construction Summary**
3. **Appendix B: Review of 57 Conditions**

Transcanada Keystone Pipeline LP, notified PHMSA in a letter dated September 30, 2011 of the construction of the Keystone Gulf Coast Pipeline starting in Q1 of 2012. The construction of the Keystone began in 2011 and was commissioned in 2014. Since 2011 until the commissioning of the pipeline on January 22, 2014, PHMSA, Southwest Region conducted onsite inspections and reviewed documents which include construction specifications, construction inspection reports, welding qualifications,etc.,, submitted by Transcanada. A total of 165.9 AFO days and 53.35 non-AFO days were spent on the Transcanada construction project.

In addition, Transcanada ran an in-line inspection caliper/deformation tool and conducted a DCVG survey of their entire Keystone Gulf Coast Pipeline to access any pipeline or coating damage during construction and backfilling activities. Transcanada completed the tool run and DCVG survey and found anomalies which were repaired. PHMSA witnessed part of the tool run and DCVG survey and reviewed the repair methods and records.

Transcanada submitted their Commissioning Plan to PHMSA for review before commencing commissioning/line fill activities. Line fill began in December 2014 and commenced on January 21, 2014. PHMSA engineers/inspectors were onsite to verify commissioning plan was being followed and to witness the testing of pump station alarms, valve operation and SCADA operations. On January 22, 2014 Transcanada commissioned the pipeline.

Daily reports were submitted by each engineer/inspector to document the daily construction activities observed during the inspections. The engineers/inspectors moved around the various construction activities throughout the day depending on the logistics and activities being performed. The primary focus for the engineer/inspector is to observe construction activities and gather and compile all pertinent documentation to assure regulatory compliance with 49 CFR Part 195.

All daily reports, specifications, maps, and any other information gathered by PHMSA is located in the PHMSA “P” drive Construction Folder under “Transcanada Keystone Gulf Coast Pipeline North Final Construction Report”.

Findings:
There were two Warning Letters, 4-2013-5017W and 4-2013-5021W, sent to Transcanada for non-compliance issues. The issues were:

.202- Warning letter 4-2013-5017W was sent to Transcanada on September 10, 2013 for not following their Construction Specifications to protect the coating from damage due to welding spatter.

.246(a) – Warning letter 4-2013-5017W was sent to Transcanada on September 10, 2013 for not following Construction Specifications when installing foam pillows to minimize external stresses on the pipe.

.214(a) and (b) -Warning Letter 4-2013-5021W was sent to Transcanada on September 26, 2013, for failing to perform welding on Spread 3 in accordance with a procedure qualified according to Section 5 of API 1104. Procedure KXL-SMAW-ML had revisions to essential variables which was not requalified.

.222(a) and (b) – Warning Letter 4-2013-5021W was sent to Transcanada on September 26, 2013, for failing to properly qualify welders on Spread 3 in accordance with Section 6 of API 1104. Procedure KXL-SMAW-ML had revisions to essential variables which the welders were not qualified to perform.

Transcanada responded to the Warning Letters and are located in the CPF Southwest Region files.

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Name of Operator:	TransCanada Oil Pipeline Operations Inc.		
OP ID No. [1]	32334	**Unit ID No.** [1]	74979 and 83245
HQ Address:		**System/Unit Name & Address:** [1]	
717 Texas Street Houston, TX 77002		717 Texas Street Houston, TX 77002	
Co. Official:	Mr. Vern Meier	**Activity Record ID No.:**	140666 and 135840
Phone No.:	832-320-5505	**Phone No.:**	832-320-5462
Fax No.:	832-320-6462	**Fax No.:**	832-320-6462
Emergency Phone No.:	800-447-8066	**Emergency Phone No.:**	800-447-8066

Persons Interviewed	Title	Phone No.
Dan Cerkoney	Manager Regulatory Compliance Major	713-693-6466
Transcanada Inspectors		
Michels Pipeline Construction Personnel		
Sunland Construction Personnel		
Meera Kothari	Engineer	713-693-6466

PHMSA Representative(s) [1]	Jon Manning, Jim Arnold, Agustin Lopez, Clint Stephens, Noah Matthews, Barry Small	**Inspection Date(s)** [1]	2011-2014
Company System Maps (Copies for Region Files):	Maps are located in the PHMSA "P" Drive		

Description of Construction [1]

The Keystone Gulf Coast pipeline consists of 485 miles of 36 inch X70 pipe ranging in wall thickness (.465,.515,.572,.618, and .748). The pipeline starts at the TransCanada Keystone Cushing Terminal in Lincoln County Oklahoma and terminates at the Terminal Facilities in Nederland, Jefferson County Texas. The pipeline transports crude oil from Cushing, OK to Nederland, TX where it ties into the Sunoco Terminal.

Spread 1 Contractor- Michels Pipeline Construction, MP 0.00 to 195.00
Spread 2 Contractor- Michels Pipeline Construction, MP 195.00 to 371.70
Spread 3 Contractor- Sunland Construction, MP 371.70 to 484.57

10 Pump Stations
PS-32, Cushing South, MP 0.00
PS-33, Cromwell, MP 49.21
PS-34, Tupelo, MP 95.70
PS-35, Bryan, MP 147.77
PS-36, Delta, MP 194.88
PS-37, Winnsboro, MP 238.96
PS-38, Lake Tyler, MP 284.62
PS-39, Lufkin, MP 338.74
PS-40, Corrigan, MP 380.9
PS-41, Liberty, MP 435.52

The Southwest Region inspected the pipeline in accordance with both the 57 Special Permit conditions and according to 49 CFR Part 195 regulations.

[1] Information not required if included on page 1.

PIPE SPECIFICATIONS			
.51	.112		Steel Pipe
	▪	Manufacturer:	Welspun (Little Rock, AR) – spiral, llva (Taranto, IT) – long seam
	▪	Manufacturing Standard:	API 5L PSL2 X70M 44th Edition
	▪	Pipe Grade:	X70
	▪	Outside Diameter (D):	NPS 36
	▪	Wall Thickness (t):	• 0.465 – Line Pipe (FBE) (PMSA 57 Conditions 1-9) • 0.515 – HCA (FBE) • 0.572 – Downstream of Corrigan Pump Station (FBE) • 0.618 – Road Bore (FBE/ARO) • 0.748 – HDD (FBE/ARO)
	▪	Type of Longitudinal Seam:	Long Seam and Spiral Seam
	▪	Specified Min. Yield Strength (S):	70,000
	▪	Joint Design - Bevel:	V groove
	▪	External Coating:	FBE
	▪	Internal Coating:	N/A
	▪	Minimum Joint Length:	Minimum of 8' typical double joints 76'
	▪	Footage or Miles:	485 miles

Comments:
Pipe was stamped with the specifications and was verified in the construction inspections. Mill test reports were submitted to PHMSA to verify pipe specifications.

.100		**DESIGN REQUIREMENTS**		**S**	**U**	**N/A**	**N/C**
	.102	Check temperature rating (particularly if this is a CO_2 line).		X			
	.104	All components are consistent with pressure rating. (consider MOP changes along PL)		X			
	.106	Pipeline design formula: **P = (2St/D) x F x E x T** F = .72 most cases F = other, Special Permit (typically 0.8) F = 0.6 offshore platform, risers, inland navigable waters F = 0.54 cold expanded to meet minimum SMYS		X			
	.108	External design pressure.		X			
	.110(a)	Design pipeline system to anticipated external loads, e.g., earthquakes, vibration, thermal expansion, and contraction. Follow section 419 of ASME/ANSI B31.4 for expansion and flexibility.		X			
	.110(b)	Pipe/components supported in a manner to minimize localized stresses. Compute and compensate for stresses to the pipe wall caused by attachments to the pipe.					
	.111	CO_2 lines must be designed to mitigate fracture propagation				X	
	.112(b)	Pipe manufactured in accordance to API or ASTM.		X			
	.112(c)	Mark each length of pipe ≥ **4½ inches OD** to indicate SMYS or grade, pipe size, and specification.		X			
	.114	Used pipe installed in a pipeline system must comply with **§195.112(a) and (b)** and the following:					
		▪	Known API or ASTM specification, seam joint factor determined IAW .106(e), unknown yield or wall thickness IAW .106(b) or (c) as appropriate.			X	
		▪	Free of buckles, cracks, grooves, gouges, dents, corroded areas, or other surface defects that exceed the maximum depth.			X	
		▪	Depth of the corroded areas - is the remaining wall thickness equal to or greater than the minimum required by the tolerance in specifications, or MOP reduced.			X	
	.116	Valves installed in the pipeline system must comply with the following:					
		(a)	ANSI/API Spec 6D, 23rd edition April 2008, and errata 3 (2009)	X			
		(b)	Compatible with the pipe or fittings to which the valve is attached.	X			
		(c)	Compatible with carbon dioxide or each hazardous liquid the pipeline may carry.	X			

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.100			DESIGN REQUIREMENTS		S	U	N/A	N/C
		(d)	Both hydrostatically shell and seat tested without leakage.(Sect. 11 API 6D)		X			
		(e)	Equipped with a means for clearly indicating valve position (open, closed, etc).		X			
		(f)	Marked on the body or nameplate with the following:					
			(1)	Manufacturer's name or trademark.	X			
			(2)	Class designation or maximum working pressure.	X			
			(3)	Body material.	X			
			(4)	Nominal size.	X			
	.118(a)	Butt-welding type fittings meet marking, end preparation, and bursting requirements of **ANSI B16.9, (December 2007 edition)**, or **MSS SP-75-2004.**			X			
	.118(b)	Fittings must be free of any buckles, dents, cracks, gouges, or other defects that might reduce strength.			X			
	.118(c)	Fittings must suitable for the intended service and at least as strong as the pipe and other fittings in the pipeline system to which it is added.			X			
	.120	New and replaced line pipe, valve, fitting, or other line component designed and constructed to accommodate the passage of instrumented internal inspection devices.			X			

Comments:

.111- Pipeline is not a CO2 line.

.112(b) - Pipe was manufactured to API 5L 44th edition (PSL 2). A portion of the Gulf Coast Pipeline was manufactured at the Welspun facility in Little Rock, AR., and was inspected by PHMSA/Southwest.

.114 – There will be no used pipe installed on the Gulf Coast Pipeline.

Design of fittings and valves were verified during the field inspections. PHMSA examined the fitting and valves in the field at the pipe yard and after installation of the valves.

.200		CONSTRUCTION REQUIREMENTS		S	U	N/A	N/C
		SPECIFICATIONS					
	.202	Comprehensive written construction specifications.			X		
	.204	Qualified inspector performing inspections.		X			
	.206	Materials visually inspected at site of installation for damage or service impairment		X			
	.207	Pipe transported in accordance with API RP 5L1 (6th edition, July 2002), or 5LW (2nd edition effective March 1, 1997), as applicable					X
	.208	Supports and braces not welded to the pipe operating above 100 p.s.i.		X			
	.210(a)	Pipeline ROW selected to avoid areas containing private dwellings, industrial buildings, and places of public assembly.		X			
	.210(b)	Pipeline located within **50 feet** of any private dwelling, industrial building, or place of public assembly provided with at least an **additional 12 inches of cover**.		X			
	.212(b)	Field bends cannot be wrinkle bends and made in compliance with:					
		(1)	Not impair serviceability.	X			
		(2)	Smooth, free from buckles, cracks, or mechanical damage.	X			
		(3)	Longitudinal weld near neutral axis unless - an internal bending mandrel is used; or pipe is **≤ 12 ¾ inches** or **D/t ratio is less than 70%**.	X			
		INSTALLATION OF PIPE					
	.246(a)	Pipe installed to minimize stresses and protect the pipe coating from damage.			X		
	.248(a)	Installed with appropriate cover and below cultivation (refer to table below)		X			

.200			CONSTRUCTION REQUIREMENTS	S	U	N/A	N/C

Location	Cover (inches) For Normal Excavation	Cover (inches) For Rock Excavation[1]
Industrial, commercial, and residential areas	36	30
Crossings of inland bodies of water with a width of at least 100 ft from high water mark to high water mark	48	18
Drainage ditches at public roads and railroads	36	36
Deepwater port safety zone	48	24
Gulf of Mexico and its inlets in water less than 15 ft deep as measured from the mean low tide.	36	18
Other offshore areas under water less than 12 ft deep as measured from the mean low tide.	36	18
Any other area	30	18
Additional cover required by 195.210.	As Above + 12	As Above + 12

[1] Rock excavation is defined as any excavation that requires blasting or removal by equivalent means.

Section		Requirement	S	U	N/A	N/C
.248(b)		If minimum cover prescribed above cannot be attained because it is impracticable to do otherwise additional protection being provided as required	X			
.250		**12 inches** of clearance between the pipeline and any other underground structure.	X			
.252		Backfilling performed in a manner that provides firm support for the pipe and does no damage to the coating	X			
.256		Pipe at each railroad or highway crossing installed so as to adequately withstand the dynamic forces exerted by anticipated traffic loads.	X			
		VALVES				
.258(a)		Install valve in a location, accessible to authorized employees and protected from damage or tampering.	X			
.258(b)		Each submerged valve located offshore or in inland navigable waters must be marked, or located by conventional survey techniques, to facilitate quick location when operation of the valve is required.			X	
.260		Valves installed at each of the following locations:				
	(a)	On the suction end and discharge end of a pump station in a manner that permits isolation of the pump station equipment in the event of an emergency.	X			
	(b)	On each line entering or leaving a breakout storage tank area in a manner that permits isolation of the tank area from other facilities.	X			
	(c)	On each mainline at locations along the pipeline system that minimizes damage or pollution from accidental hazardous liquid discharge, as appropriate for the terrain in open country, for offshore areas, or for populated areas.	X			
	(d)	On each lateral takeoff from a trunk line in a manner that permits shutting off the lateral without interrupting the flow in the trunk line.	X			
	(e)	On each side of a water crossing that is more than 100 feet wide from high-water mark to high-water mark unless a waiver has been granted for a particular case where valves not are justified.	X			
	(f)	On each side of a reservoir holding water for human consumption.	X			

Comments:

.202- Warning letter 4-2013-5017W was sent to Transcanada on September 10, 2013 for not following their Construction Specifications to protect the coating from damage due to welding spatter.

.204 – The qualification records were checked for Chief Welding Inspector Ron Green.

.207 - TransCanada procedures for transporting pipe by rail is outlined in Condition 6 of the 57 Conditions, based on the Association of American Railroads (AAR) standard not API RP 5L1.

Comments:

.246(a) – Warning letter 4-2013-5017W was sent to Transcanada on September 10, 2013 for not following Construction Specifications when installing foam pillows to minimize external stresses on the pipe.

.258(b) - There are no offshore or submerged valves installed in the entire pipeline system.

.200		**WELDING**	**S**	**U**	**N/A**	**N/C**
	.214(a)	Welding must be performed by qualified welders using qualified welding procedures.		X		
		Welding procedures are qualified in accordance with Sec. 5 of API 1104 or Section IX of ASME Boiler & Pressure Code		X		
		Welding procedures must be qualified by destructive testing.		X		
	.214(b)	Each welding procedure must be recorded in detail, including results of qualifying tests.		X		
	.222(a)	Welders must be qualified in accordance with **Section 6 of API Standard 1104** (20th edition 2007, including errata 2008**)** or **Section IX of the ASME Boiler and Pressure Vessel Code** (2007 edition), except that a welder qualified under an earlier edition than listed in **' 195.3** may weld, but may not requalify under that earlier edition.		X		
	.222(b)	Welders may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder has – (1) Engaged in welding with that process; and (2) Had one weld tested and found acceptable under Section 9 of API 1104.		X		
	.224	Welding operations protected from weather conditions.	X			
	.226(a)	Arc burns require repair.	X			
	.226(b)	If a notch is not repairable by grinding, a cylinder of the pipe containing the entire notch must be removed. Do arc burn repair procedures require verification of the removal of the metallurgical notch by nondestructive testing? **(Ammonium Persulfate)**.	X			
	.226(c)	Ground not welded to pipe.	X			
	.228(a)	Welding must be inspected to insure compliance with the requirements of this subpart (line-up, pipe not in a bind, API 1104 requirements, welding procedures followed, etc). Visual inspections must be supplemented by nondestructive testing.	X			
	.228(b)	Except for cracks, acceptability of welds per **Section 9 or Appendix A, API 1104.**	X			
	.230(a)	Remove or repair cracks ≤ **8%**, remove cracks longer than **8%**.	X			
	.230(b)	Welds repaired, remove defect down to clean metal, preheat pipe, and assure acceptability.	X			
	.230(c)	Repairs in a previously repaired area must be in accordance with qualified written welding procedures and mechanical properties of the repaired weld equal to those specified for the original weld.	X			

Comments:
.214(a) and (b) -Warning Letter 4-2013-5021W was sent to Transcanada on September 26, 2013, for failing to perform welding on Spread 3 in accordance with a procedure qualified according to Section 5 of API 1104. Procedure KXL-SMAW-ML had revisions to essential variables which was not requalified.

.222(a) and (b) – Warning Letter 4-2013-5021W was sent to Transcanada on September 26, 2013, for failing to properly qualify welders on Spread 3 in accordance with Section 6 of API 1104. Procedure KXL-SMAW-ML had revisions to essential variables which the welders were not qualified to perform.

Welding qualifications, welder qualifications, and welding activities were reviewed by PHMSA either at the office or during the field inspections. Many locations were inspected during the construction of the pipeline in which welding was being performed.

.200	**NONDESTRUCTIVE TESTING OF WELDS**		**S**	**U**	**N/A**	**N/C**
	.228/.234	Detailed written procedure established and qualified for nondestructive testing.	X			
	.234(b)	Nondestructive testing of welds must be performed:				
		(1) In accordance with written procedures for **NDT.**	X			

.200		**NONDESTRUCTIVE TESTING OF WELDS**	**S**	**U**	**N/A**	**N/C**
		(2) Radiographer trained and qualified. (Level II or better).	X			
		(3) By a process that will indicate any defects that may affect the integrity of the weld	X			
	.234(c)	Procedures established for proper interpretation.	X			
	.234(d)	Nondestructively test **10%** of each welder's welds per day.	X			
	.234(e)	Test **100%** or **90%,** if impractical.				
		(1) Stream, river, lake, reservoir, or other body of water.	X			
		(2) Within railroad or public road ROWs.	X			
		(3) Overhead road crossings and within tunnels.	X			
		(4) Within the limits of any incorporated subdivision.	X			
		(5) Within populated areas such as residential subdivisions.	X			
	.234(f)	**100%** of all girth welds nondestructively tested on used pipe.			X	
	.234(g)	Test **100%** of girth welds at tie-ins.	X			

Comments:
.234(f) There is no used pipe being installed.
All welds were NDT. PHMSA inspected the NDT of many welds during the field inspections. Records were also reviewed during field inspections, office visits, and in the office.

			CORROSION PROTECTION REQUIREMENTS	**S**	**U**	**N/A**	**N/C**
		.557	Buried or submerged pipelines (constructed, relocated, replaced, or changed) must be externally coated prior to placing in service. See code for exceptions.	X			
		.561(a)	All external pipe coating inspected just prior to lowering the pipe into the ditch		X		
		.561(b)	Repair any coating damage discovered.	X			
		.563(a)	Adequate cathodic protection of the system.	X			
			Cathodic protection system installed **1 year**. (refer. ADB note below)	X			
		.567	Sufficient number of test leads properly installed.	X			

Comments:
Transcanada reported to PHMSA that there were some pipe sections that may have had coating damage due to welding spatter when the pipe was lowered into the ditch. Transcanada became aware of the problem by reviewing Transcanada inspector reports. Transcanada excavated the approximately 23 identified pipe sections which may have had the damage and were examined. Transcanada examined the pipe sections and made appropriate repairs to the coating in accordance to their specifications. PHMSA witnessed some of the excavations and repairs. PHMSA issued Warning Letter-4-2013-5017W for not following their specifications.

.266	**CONSTRUCTION RECORDS**	**S**	**U**	**N/A**	**N/C**
	Complete records showing the following:				
	(a) Number of girth welds and number of nondestructively tested welds, including number and disposition of each rejected weld.	X			
	(b) The amount, location, and cover of each size of pipe installed	X			
	(c) The location of each crossing of another pipeline	X			
	(d) The location of each buried utility crossing	X			
	(e) The location of each overhead crossing	X			
	(f) The location of each valve and corrosion test station	X			

Comments:
PHMSA reviewed Transcanada's welding records and witnessed the NDT of many girth welds. Transcanada submitted documents and maps which displayed any pipe crossings, utilities and the size of pipe installed. Test stations are installed in accordance with Specification TES-CP-CS and standard drawings.

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.300				PRESSURE TESTING	S	U	N/A	N/C
		.302(a)	Hydrostatic testing required:					
			1.	The entire buried portion tested without leakage for **8 hours**	X			
			2.	The above ground portion tested for at least **4 hours** (if visually inspected)	X			
		.304	Test pressure at least 4 continuous hours at a pressure equal to 125 percent, or more, of the MOP. If not visually inspected, at least an additional 4 hours at 110 percent of MOP.		X			
		.305	Hydrostatically test all pipe and attached fittings, including components, (unless - if a component is the only item being replaced or added - manufacturer certifies hydrostatically tested at the factory)		X			
		.306	Appropriate test medium		X			
		.308	Pipe associated with tie-ins either pretested or hydrostatically tested in place		X			
		.310(a)	Hydrostatic test records retained for the life of the facility tested		X			
		.310(b)	Do the hydrostatic test records include the following:					
			(1)	Pressure recording charts	X			
			(2)	Test instrument calibration data	X			
			(3)	Operator’s name, name of the person responsible for making the test, and the name of the test company used, if any	X			
			(4)	Date and time of the test	X			
			(5)	Minimum test pressure	X			
			(6)	Test medium	X			
			(7)	A description of the facility tested and the test apparatus	X			
			(8)	An explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts	X			
			(9)	Where elevation differences in the test section exceed **100 feet**, a profile of the pipeline showing the elevation and test sites over the entire length of the test section	X			
			(10)	Temperature of the test medium or pipe during the test period	X			

Comments:
Pressure testing was conducted in accordance with Specification TES-PROJ-LPCS-US. PHMSA inspected the hydrostatic testing during the field inspections and reviewed records at the Transcanada office.

.501-.509	OPERATOR QUALIFICATION (OQ) FIELD VERIFICATION	S	U	N/A	N/C
	Operator Qualification - Use PHMSA Form 15 OQ Field Inspection Protocol Form if applicable.	X			

Appendix A Construction Summary Report.

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CONSTRUCTION SUMMARY

TransCanada Keystone Pipeline LP, notified PHMSA in a letter dated September 30, 2011 of the construction of the Keystone Gulf Coast Pipeline starting in Q1 of 2012. PHMSA's construction oversight of the Keystone began in 2011 and the pipeline was commissioned in 2014. The Keystone Gulf Coast pipeline consists of 485 miles of 36 inch X70 pipe ranging in wall thickness .465, .515, .572, .618, and .748. The pipeline begins at the TransCanada Keystone Cushing Terminal in Lincoln County, Oklahoma and terminates at the Terminal Facilities in Nederland, Jefferson County Texas. The pipeline transports crude oil from Cushing, OK to Nederland, TX.

Since 2011 until the commissioning of the pipeline on January 22, 2014, PHMSA Southwest Region conducted onsite inspections and inspected documents which include: construction specifications, construction inspection reports, welding qualifications, pipe mill reports, hydrostatic test results, etc., submitted by TransCanada. A total of 165.9 AFO days and 53.35 non-AFO days were spent on the TransCanada construction project.

Daily reports were submitted by each engineer/inspector to document the daily construction activities observed during the inspections. The engineers/inspectors moved around the various construction activities throughout the day depending on the logistics and activities being performed. The primary focus for the engineer/inspector is to observe construction activities and gather and compile all pertinent documentation to assure regulatory compliance with 49 CFR Part 195.

All daily reports, specifications, maps, and any other information gathered by PHMSA are located in the PHMSA "P" drive Construction Folder under "TransCanada Keystone Gulf Coast Pipeline North Final Construction Report".

TransCanada submitted their Commissioning Plan to PHMSA for review prior to commencing commissioning line fill activities. Line fill began in December 2014 and concluded on January 21, 2014. PHMSA engineers/inspectors were onsite to verify that the commissioning plan was being followed and to witness the testing of pump station alarms, valve operation and SCADA operations. On January 22, 2014 TransCanada commissioned the pipeline.

CONSTRUCTION OVERVIEW

The Southwest Region performed a construction inspection of the TransCanada Keystone Gulf Coast Pipeline from 2011 to 2014. The construction inspection consisted of multiple visits to TransCanada's office for review of specifications, procedures, records and to discuss ongoing construction activities. TransCanada provided a link to their external SharePoint to PHMSA to review records and specifications. In addition, the construction inspection consisted of onsite field inspections of ongoing construction activities. Several SW Region Engineers/inspectors visited the pipeline construction from Cushing, OK to Nederland, TX.

Design Requirements

The pipeline used for the construction of the Keystone Gulf Coast project was manufactured by ILVA and Welspun in India and Little Rock, AR. PHMSA engineers/inspectors visited the Welspun pipe mill in Little Rock, AR to verify that the pipe was manufactured in accordance with API 5L and TransCanada's specifications. The inspection included a review of TransCanada's specifications and procedural QA/QC for pipe materials from the vendor (Welspun) at the mill location. Specifications, procedures & records were reviewed for completeness and compliance to pertinent regulatory and/or industry requirements/guidelines. TransCanada's specifications for coating, submerged arc welded pipe and double joined pipe were reviewed. The inspection team met with and directly observed TransCanada personnel and their assigned agents conducting third party monitoring on their behalf (D M Professional Services), who provided QA/QC for pipe materials being produced at the mill for the Keystone Gulf Coast project.

During the field inspections, the pipeline was verified for design specifications by examining the pipe for manufacturer stamping and reviewing manufacturer test reports (MTRs). Each pipe joint was marked with length, grade, pipe size, and specification. See Figures 1 and 2 for examples.

Figure 1: Pipe Specification Markings

Figure 2: Pipe Specification Markings

Pipe used for the construction had different wall thicknesses for different application locations such as: 0.465" for line pipe, 0.515" for HCAs, 0.572" downstream of pump station, 0.618" for road bores, and 0.748" for HDDs. HDD and road bore pipe also had abrasion resistant overcoat (ARO) which was verified during the field inspections as seen in Figure 3. Pipe joints were marked with the appropriate specifications, for example, API 5L PSL2 36", 0.465", X70.

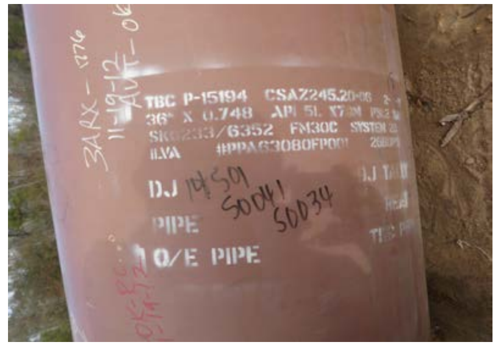

Figure 3: ARO Pipe with specification markings.

Valves and other pipeline components were also verified in the field. Valves were manufactured in accordance with API 6D and were stamped with manufacturer's name, maximum pressure rating, temperature rating, nominal size and body material. Fittings were


Figures 4, 5, 6: Manufacturer Stamp on Valve, and Flange

examined for damage such as buckles, dents, gouges, cracks or other defects that might reduce the strength. Pipe joints were tracked by a labeling system with a bar code. See Figures 4-6.

Figure 7: Pipe Label

Labels were checked in the field for damage or non-readable labels. See Figure 7. All components inspected were consistent with the pressure rating and in accordance with the established MOP.

Construction Requirements

Written Specifications

PHMSA SW Region reviewed TransCanada's construction specifications throughout the construction project. Specifications were reviewed in PHMSA's or TransCanada's offices, through the SharePoint site, and during the field inspections. The field inspections focused on verification that the specifications were being applied and followed during the construction of the pipeline. These field verifications help assure PHMSA that the pipeline was being construction according to Part 195 and the operators specifications.

During the onsite construction inspections there were some potential non-compliance issues identified by PHMSA. The first involved TransCanada not following their specification dealing with backfilling and sand padding of the ditch/trench which was in violation of §195.246. This will be further discussed later in the report.

Installation of Pipe

During the field inspections, PHMSA inspected the pipeline ROW for any private dwellings, industrial buildings, and places of assembly. The ROW of the pipeline avoided and was not in close proximity to any of these structures or locations. The inspection of soil cover and depth of pipe was in compliance with the regulations. The pipeline had a cover of at least the minimum cover required at all locations inspected during the field inspections. Figure 8 shows the depth of the pipe. The Figure demonstrates the cover and depth of the pipeline and the remoteness of the pipeline ROW. Figure 9 shows the depth of pipeline is verified with a GPS system.

Figure 8: Typical Right of Way depicting Depth of Cover.

Figure 9: Depth of Cover check with GPS

To avoid many road and railroad crossings, other pipeline, bodies of water and any other encroachments, TransCanada horizontally directional drilled (HDD) the pipeline at these locations. The depth of the HDDs well exceeded the depth of cover required by the regulations. PHMSA witnessed and inspected HDD construction activities for any issues and to assure specifications were followed. The Figures demonstrate the inspection of the HDDs. Figure 10 shows pipe is being supported by a boom as it is being pulled into the drill.

Figure 10: Boom holding Pipe

Field pipe bends were observed by PHMSA during many field inspections. There were no wrinkle bends identified during these inspections. Pipe bends were performed by a bending machine which utilized an internal bending mandrel to achieve smooth and undistorted bends. PHMSA witnessed pipe bending activities which are shown in Figures 11 and 12. There was no mechanical damage identified during the pipe bending activities.

Figure 11: Bending Machine

Figure 12: Bent Pipe

Valves

Federal regulations require that valves be installed "... at locations along the pipeline system that will minimize damage or pollution ...". PHMSA raised an issue with TransCanada concerning its valve spacing as to whether or not they were being placed to minimize the environmental impact in case of a release. TransCanada submitted additional studies and records which included a Pipeline Assessment and Environmental Consequence Analysis, Keystone Gulf Coast Valve Siting Rationale and Gulf Coast Corridor Schematic. In addition, TransCanada installed remotely operated valves, with back- up generators at all locations mentioned in their study. PHMSA reviewed and met with TransCanada to discuss the locations of the valves which resolved the issue with the valve spacing.

Valve locations and automation equipment were verified during the field inspections by PHMSA.

Figure 13: Typical Valve location

Figure 14: Remote Operation Equipment at Valve site.

Valves were inspected at the pipe yard on several occasions to verify the rating and condition of the valves. Figure 15 shows valves inspected at the pipe yard. Valves were stored away from the pipe to protect from any damage.

Figure 15: Valve Storage at Pipe Yard

Topography maps were submitted to PHMSA showing all water crossings and location of valves. Valves were located at every water crossing and in locations along the pipeline to minimize pollution and damage in populated areas.

There were also valves located at each discharge and suction side of the pump stations. Figure 16 depicts an example of a pump station valve installation.

Figure 16: Valve at Pump Station

All valves are motorized and remotely operational through SCADA. All valves had concrete foundation poured to handle any stresses the weight may put on the pipeline. Figure 17 is an example of concrete supports. Figure 18 demonstrates the protection from unauthorized personnel and vandalism. In addition, the photos show the satellite, electric power and generators for backup needed to operate the valves.

Figure 17: Concrete Pads for Valves.

Figure 18: Typical Fencing around Valve site

Welding

Throughout the construction project, PHMSA reviewed welding procedures, specifications and conducted field observations of welding activities. In addition, PHMSA witnessed the qualification of procedures and welders to assure welding was being performed to a qualified procedure and by qualified welders.

Welding was performed in accordance with API 1104, the federal regulations and TransCanada's specifications. TransCanada utilized automatic welding on spreads 1 and 2 and manual welding on Spread 3. Both automatic and manual welding was being performed while PHMSA was on site.

Figure 19: Welder Qualification Test

Figure20: Automatic Welding Shack

Figure 21: Automatic Welding Set up

Welding inspections also included the inspection of nondestructive testing of all welds. In the field PHMSA observed NDT of the welds and assured that NDT specifications were followed. TransCanada utilized both AUT and X-ray methods for testing welds.

During the PHMSA field inspections and welding qualifications review, there were two issues and concern identified by PHMSA. One concern raised was the high welding repair/rejection rate. From the start of welding, TransCanada experienced a high weld rejection rate on Spread 3. A second issue identified by PHMSA was that TransCanada failed to properly qualify welders on Spread 3 of the

Figure 22: Manual Welding Set up

Keystone Gulf Coast Pipeline project. TransCanada performed welder qualifications using a welding procedure that had not been properly qualified and then allowed these welders to weld on a Part 195 regulated pipeline. These issues will be furthered discussed alter in the report.

Corrosion Protection

During the field inspections by PHMSA, the installation of corrosion control measures was verified. TransCanada provided corrosion control specifications which were reviewed by PHMSA. PHMSA witnessed the installation of many joints of pipe to assure that the coating was in good condition and was inspected (jeeped) for coating damage before burying the pipe. Any damage identified by this inspection technique was repaired. Each weld joint was coated and is seen in Figure 23. PHMSA also verified that there were a sufficient number of test leads installed throughout the pipeline.

Figure 23: Coating of field Joint

Figure 24: Typical Test Station

TransCanada conducted a Direct Current Voltage Gradient (DCVG) survey of the entire Keystone Gulf Coast Pipeline to check for any coating damage. After the survey, TransCanada submitted the findings of any coating damage found along with repairs made on anomalies. There were a total of 127 anomalies on Spread 1, 83 anomalies on Spread 2, and 43 anomalies on Spread 3 found by the survey. None of the anomalies found met the repair criteria of 35% IR, the highest was 32%. TransCanada performed verification digs on the highest IR readings on all three spreads to assure accuracy of the DCVG Survey. They made 8 digs in Spread 1, 8 digs in Spread 2, and 4 digs in Spread 3 and made repairs accordingly. The reports were reviewed by PHMSA to assure compliance with their procedures and the regulations. PHMSA conducted field inspections to verify dig sites identified by the DCVG survey. Figures 25 and 26 depict two locations identified by the DCVG survey during a PHMSA field inspection.

Figure 25 and 26: DCVG dig site (recoated)

Pressure Testing

Pressure testing of the TransCanada was performed in accordance with their Specification TES-PROJ-LPCS-US and with CFR 195. The specification and records of all hydrostatic pressure tests conducted by TransCanada were reviewed by PHMSA. In addition, PHMSA conducted field inspections of the hydrostatic testing on various locations of the pipeline.

Figure 27: Hydrotest in Progress

Figure 28: Hydrotest in Progress

The entire pipeline was hydrotested to at least 8 hours for all buried pipelines. In addition, TransCanada conducted a one hour pressure test on all HDD piping before pulling the pipe section. The one hour test is part of TransCanada's procedures to verify the integrity of the HDD pipe before pulling it through the drilled hole. The test medium used for all testing was water. All records reviewed had documented the appropriate pressure of 125% or more of MOP, test medium, instrument calibration, pressure recording charts, temperature, date and time and description of the facility being tested. TransCanada also provided elevation profiles of all test sections with hydraulic pressure profiles. There were no leaks or failures detected in the records review and during the field inspections.

Figure 29: Drying process after hydrotest

Commissioning

TransCanada notified PHMSA in December 2013 of the intent to start line fill and commissioning of the Keystone Gulf Coast Pipeline from Cushing, OK to Nederland, TX. TransCanada submitted their Commissioning Plan for approval from PHMSA to commence commissioning activities. PHMSA reviewed the commissioning plan and had no objections to start the commissioning process.

On December 7, 2013, TransCanada started line fill activities starting from the Cushing facility to their Nederland facility. TransCanada followed their commissioning plan and coordinated with personnel to monitor the line-fill to ensure the pipeline was operating safely and reliably. The plan included the commissioning of 485 miles of pipe, six pump stations and the Nederland Delivery Station. Product was tracked utilizing three batch pigs to assure the location of the product. Each pig was tracked by Corrpro personnel and predetermined above ground markers (AGM). During the commissioning phase, each mainline valve was operated to assure no leaks and satisfactory operation of the valve. In addition each pump station was started up in stages. Each stage consisted of testing each leak detection system and alarms per pump before starting up the next pump(4 pumps per station) at each station. On January 21, 2014 TransCanada notified PHMSA of the completion of the line-fill activities and the intent to start in-service operations. On January 22, 2014 TransCanada commissioned the pipeline and started in-service operations.

Figure 30: Pigs used during commissioning.

PHMSA received daily updates throughout the commissioning phase of all ongoing activities. In addition, PHMSA engineers/inspectors were onsite during the commissioning phase to witness and assure procedures were being followed by TransCanada personnel. PHMSA witnessed the line fill, testing of pump alarms and leak detection, valve testing and pig tracking operations. The Figures demonstrate the observations of the activities witnessed during the commissioning. The Figure 43 shows the pigs used to track the product while filling line. Figure 44 shows how the pigs were tracked from above ground.

Figure 31: Commissioning at Pump Station

Issues identified during Construction

Welding

TransCanada performed welder qualifications using a welding procedure that had not been properly qualified and then allowed these welders to weld on a Part 195 regulated pipeline.

During the first weeks of construction of spread 3 significant welding issues were noted. Approximately 26.8% of the welds required repairs in one week, 32.0% the second week, 72.2% the third week, and 45.0% the fourth week. On September 25, 2012, TransCanada stopped the Spread 3 welding after 205 of the 425 welds, or 48.2% required repairs. Through the welding procedure review, PHMSA found that TransCanada failed to perform welding on construction Spread 3 of the Gulf Coast Pipeline project in accordance with a procedure qualified according to Section 5 of API 1104.

A comparison of the procedure being used to weld the pipe on Spread 3 (KXL-SMAW-ML, revised February 10, 2011) with the PQR revealed inconsistencies between at least two essential variables as defined by API 1104, the Joint Design and the Speed of Travel. The joint design on the document KXL-SMAW-ML being used to weld the pipe on construction Spread 3 specified a Root Opening of 1/16" ± 3/32" between pipe joints at the girth weld and the welding Speed of Travel for the Cap Pass to be 8.6 – 16.2 inches per minute. The PQR for the procedure that was actually qualified by destructive testing (PQR# KPS-RMS-SMAW-ML-PQR Rev 2) showed the root opening to be 1/16" to 3/32" and the Speed of Travel for the Cap Pass to be 6.6 – 16.2 inches per minute. The difference between the PQR and the welding procedure constituted a change in essential variables.

As a result, the welding procedure being used by TransCanada on Spread 3 of the Keystone Gulf Coast Pipeline project (KXL-SMAW-ML) had changes to essential variables that caused it to be different than the Procedure Qualifying Record. Because the procedure used to weld Spread 3 pipe was not re-qualified, TransCanada was using an unqualified procedure to weld Part 195 regulated pipeline.

A second issue identified by PHMSA was that TransCanada failed to properly qualify welders on Spread 3 of the Keystone Gulf Coast Pipeline project. TransCanada performed welder qualifications using a welding procedure that had not been properly qualified and then allowed these welders to weld on a Part 195 regulated pipeline. Paragraph 6.1 of API 1104, incorporated by reference states "the purpose of the welder qualification test is to determine the ability of welders to make sound butt or fillet welds using previously qualified procedures." Procedure KXL-SMAW-ML, Revised February 10, 2011 had changes to the essential variables of Joint Design and Speed of Travel from the Procedure Qualification Record, KPL-RMS-SMAW-ML-PQR Rev 2 but had not been re-qualified. Consequently, the welder qualification was not performed using a previously qualified procedure as required by Section 6 of API 1104.

PHMSA issued Warning Letter 4-201305021W for both issues identified during the construction inspection. TransCanada responded to the Warning Letter stating that after more than twelve months of extensive meetings and discussion, comprehensive supplemental destructive testing and exhaustive records reviews, on November 25, 2013 a meeting held between PHMSA and TransCanada resulted in confirmation that the welder qualifications and manual welding procedures. In addition, The results of a root cause analysis performed by TransCanada to identify the cause of the high weld rejection rate on Spread 3 were documented in a paper titled "Girth Weld Repairs Due to Lack of Fusion in Root Pass," dated November 15, 2012. This analysis identifies the criticality of the essential variables of Joint Design and Speed of Travel by stating, "Weld fit up was increased to 3/32" which allowed the welders to decrease their travel speeds and welding amperages which is a key factor in reducing internal under cut and lack of fusion defects during the welding process. This modification improved the weld quality and reduced the overall weld defects. PHMSA witnessed the re-testing of the welding procedure to verify the modification of the procedure reduced the internal under cut and lack of fusion defects, at the RMS lab in Edmonton, Alberta, Canada.

Dents

TransCanada did not assure that its Keystone Pipeline was installed in the ditch in a manner that minimizes the possibility of damage to the pipe. The deformation tool identified dents on the pipe that appear to be caused by secondary stresses on the pipe. The ILI tool identified a total of 421 anomalies which required investigation per the specifications. There were a total of 236 dents, 56 pipe ovality and 129 anomalies with both dent and ovality. TransCanada verified the locations by excavating the anomalies and made repairs in accordance with their specifications. After excavating and examining the anomalies, there were a total of 350 anomalies within the specifications, 37 anomalies which required being cut-out and 34 anomalies with no indications of a dent or ovality. During the field inspections, PHMSA witnessed and examined anomaly investigations being conducted by TransCanada due to the results of the deformation tool run. In this report you can see examples of the types of dents identified with the inspection tools. Each dent was examined

Figure 32, 33, 34 Examples of dents found with inspection tool.

and measured and nondestructively tested with ultrasound testing equipment to check for cracks. All dents were either cutout or were below the repair criteria. Several anomaly reports stated that foam pillows and rocky terrain were present at the dig sites which may attribute to the dents on the pipe. During the field inspections the PHMSA inspector verified the locations of several dents which were located in the same vicinity as the foam pillow supports.

TransCanada's TES-PROJ-LPCS-US Onshore Liquid Pipeline Construction Specification, Section 22.4 states "when foam pillows are installed, approved fill will be supplied to provide a uniform support along the underside of the pipe." Assuring a uniform fill underneath the pipe at all foam pillow locations will minimize external stresses on the pipe. In addition, Section 22.5 states that "rock, stone laden soil, or frozen material shall not be backfilled into the trench until the pipe has been surrounded by stone free soil."

In reviewing the anomaly reports and PHMSA inspections it demonstrated that TransCanada was not following their Construction Specifications, Section 22.4 and 22.5. PHMSA SW Region issued a Warning Letter, CPF 4-2013-5017W warning TransCanada to follow their procedures/specifications and assure that backfill is free of large rocks and have sufficient support at the foam pillows to minimize the external stresses on the pipe to be in compliance with 195.246.

Coating Damage

Another issue identified involved TransCanada not following their specifications during welding of the pipeline.

TransCanada did not follow its written specification, specifically, protecting existing coating from damage due to welding. In an email dated June 7, 2013, TransCanada notified PHMSA of a non-conformance issue involving coating damage on Spread 3 which TransCanada was in the process of investigating. The problem only occurred in Spread 3 due to the manual welding process with stick rods being utilized. Manual welding was used mainly due to the terrain and the number of water crossings. Spread 1 and 2 utilized the semiautomatic welding process. There were several locations in which the contractor did not follow TransCanada's coating specifications. Specifically, weld blankets were not being utilized to protect the existing coating on the pipe to prevent weld splatter from damaging the coating. TransCanada's specification TES-WELD-PL- US Welding of Pipelines and Tie-ins, Section 8.11 states that "existing coatings on piping shall be protected to minimize damage that may result from the welding operations" which was not being followed by the contractor. After investigating 23 suspected locations, TransCanada confirmed the coating damage and repaired the coating per the specifications.

Figure 35: Repair of coating due to weld splatter.

During the field inspections, PHMSA observed several girth welds had coating damage due to weld splatter. Figure 35 shows the coating repair on the girth welds due to damage of the weld splatter. The coating repair was made after the pipeline was exposed and examined. The pipe was coated and backfilled per the specifications. There were a total of 130 identified locations excavated in which TransCanada examined for damage and made repairs were necessary. All discovered damage was inspected and repaired to original specification criteria.

PHMSA issued a Warning Letter, CPF #4-2013-5017W, warning TransCanada to follow their specifications/procedures and assure that specification 8.11 is followed to be in compliance with 195.202.

TransCanada responded to the Warning Letter and assured that they were taking steps to enhance its design, specifications and inspection practices, by conducting a thorough review of their inspection practices, design, and construction specifications, and would implement changes to try to reduce the number of inspection digs that are required after the pipeline has been backfilled going forward, which included, but not limited to restricting the use of foam pillows, increased use of bedding material in rocky or hard pan conditions, and specifying the minimum size of weld splatter protection devices.

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

September 10, 2013

Mr. Vern Meier
Vice President, Field Operations
TC Oil Pipeline Operations, Inc.
717 Texas Ave.
Houston, TX 77002

CPF 4-2013-5017W

Dear Mr. Meier:

During the months of June and July 2013, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected the construction of the Keystone Gulf Coast Project.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

1. §195.246 Installation of pipe in a ditch.

(a) All pipe installed in a ditch must be installed in a manner that minimized the introduction of secondary stresses and the possibility of damage to the pipe

Transcanada did not assure that its Keystone Pipeline was installed in the ditch in a manner that minimizes the possibility of damage to the pipe. During the field inspections, PHMSA witnessed and examined anomaly investigations being conducted by Transcanada due to the results of a deformation tool run. The deformation tool identified dents on the pipe that appear to be caused by secondary stresses on the pipe. Several anomaly reports state that foam pillows and rocky terrain were present at the dig sites which may attribute to the dents on the pipe. During the field inspections the PHMSA inspector verified the locations of several dents which were located in the same vicinity as the foam pillow supports.

Transcanada's TES-PROJ-LPCS-US Onshore Liquid Pipeline Construction Specification, Section 22.4 states "when foam pillows are installed, approved fill will be supplied to provide a uniform support along the underside of the pipe." Assuring a uniform fill underneath the pipe at all foam pillow locations will minimize external stresses on the pipe. In addition, Section 22.5 states that "rock, stone laden soil, or frozen material shall not be backfilled into the trench until the pipe has been surrounded by stone free soil."

In reviewing the submitted anomaly reports and PHMSA inspections it demonstrates that Transcanada is not following their Construction Specifications, Section 22.4 and 22.5. Transcanada needs to assure the backfill is free of large rocks and have sufficient support at the foam pillows to minimize the external stresses on the pipe to be in compliance with 195.246.

2. §195.202 Compliance with specifications or standards.

Each pipeline system must be constructed in accordance with comprehensive written specifications or standards that are consistent with the requirements of this part.

Transcanada did not follow its written specification, specifically, protecting existing coating from damage due to welding. In an email dated June 7, 2013, Transcanada notified PHMSA of a non-conformance issue involving coating damage which Transcanada was in the process of investigating. There were several locations in which the contractor did not follow Transcanada's coating specifications. Specifically, weld blankets were not being utilized to protect the existing coating on the pipe to prevent weld splatter from damaging the coating. Transcanada's specification TES-WELD-PL- US Welding of Pipelines and Tie-ins, Section 8.11 states that "existing coatings on piping shall be protected to minimize damage that may result from the welding operations" which was not being followed by the contractor. After investigating 23 suspected locations, Transcanada confirmed the coating damage and repaired the coating per the specifications.

During the inspection, PHMSA observed several girth welds had coating damage due to weld splatter. There were a total of 98 identified locations excavated in which Transcanada made coating repairs. Transcanada needs to assure that specification 8.11 is followed to be in compliance with 195.202.

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $200,000 per violation per day the violation persists up to a maximum of $2,000,000 for a related series of violations. For violations occurring prior to January 4, 2012, the maximum penalty may not exceed $100,000 per violation per day, with a maximum penalty not to exceed $1,000,000 for a related series of violations. We have reviewed the circumstances and supporting documents involved in this case, and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to correct the item(s) identified in this letter. Failure to do so will result in Transcanada being subject to additional enforcement action.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 4-2013-5017W**. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Sincerely,

R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.	OMB NO: 2137-0047 EXPIRATION DATE: 01/31/2014

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	06/08/2011
	No.	20110171 - 16159 ------------------------- (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline.*

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	**Original:**	**Supplemental:**	**Final:**
		Yes	**Yes**

Last Revision Date:	11/02/2011
1. Operator's OPS-issued Operator Identification Number (OPID):	32334
2. Name of Operator	TC OIL PIPELINE OPERATIONS INC
3. Address of Operator:	
3a. Street Address	717 TEXAS AVE
3b. City	HOUSTON
3c. State	Texas
3d. Zip Code	77002
4. Local time *(24-hr clock)* and date of the Accident:	05/07/2011 06:20
5. Location of Accident:	
Latitude:	45.95307
Longitude:	-97.9057
6. National Response Center Report Number (if applicable):	975573
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	05/07/2011 09:55
8. Commodity released: *(select only one, based on predominant volume released)*	Crude Oil
- Specify Commodity Subtype:	
- If "Other" Subtype, Describe:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend: %:	
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend (e.g. B2, B20, B100): B	
9. Estimated volume of commodity released unintentionally (Barrels):	400.00
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):	
11. Estimated volume of commodity recovered (Barrels):	400.00
12. Were there fatalities?	No
- If Yes, specify the number in each category:	
12a. Operator employees	
12b. Contractor employees working for the Operator	
12c. Non-Operator emergency responders	
12d. Workers working on the right-of-way, but NOT associated with this Operator	
12e. General public	
12f. Total fatalities (sum of above)	
13. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	

13d. Workers working on the right-of-way, but NOT associated with this Operator	
13e. General public	
13f. Total injuries (sum of above)	
14. Was the pipeline/facility shut down due to the Accident?	
- If No, Explain:	
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown:	
14b. Local time pipeline/facility restarted:	
- Still shut down? (* Supplemental Report Required)	
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	0
18. Time sequence *(use local time, 24-hour clock)*:	
18a. Local time Operator identified Accident:	05/07/2011 09:00
18b. Local time Operator resources arrived on site:	05/07/2011 09:00

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of Accident onshore?	Yes
If Yes, Complete Questions (2-12)	
If No, Complete Questions (13-15)	
- If Onshore:	
2. State:	North Dakota
3. Zip Code:	58017
4. City	Brampton
5. County or Parish	Sargent
6. Operator-designated location:	Milepost/Valve Station
Specify:	MP ND 216.7
7. Pipeline/Facility name:	Ludden Pump Station
8. Segment name/ID:	Glacial Lakes
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Accident:	Originated on Operator-controlled property, but then flowed or migrated off the property
11. Area of Accident (as found):	Aboveground
Specify:	Typical aboveground facility piping or appurtenance
- If Other, Describe:	
Depth-of-Cover (in):	
12. Did Accident occur in a crossing?	No
- If Yes, specify below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
- Name of body of water, if commonly known:	
- Approx. water depth (ft) at the point of the Accident:	
- Select:	
- If Offshore:	
13. Approximate water depth (ft) at the point of the Accident:	
14. Origin of Accident:	
- In State waters - Specify:	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- On the Outer Continental Shelf (OCS) - Specify:	
- Area:	
- Block #:	
15. Area of Accident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility:	Interstate
2. Part of system involved in Accident:	Onshore Pump/Meter Station Equipment and Piping
- If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:	

3. Item involved in Accident:	Relief Line
- If Pipe, specify:	
3a. Nominal diameter of pipe (in):	
3b. Wall thickness (in):	
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	
3d. Pipe specification:	
3e. Pipe Seam , specify:	
- If Other, Describe:	
3f. Pipe manufacturer:	
3g. Year of manufacture:	
3h. Pipeline coating type at point of Accident, specify:	
- If Other, Describe:	
- If Weld, including heat-affected zone, specify:	
- If Other, Describe:	
- If Valve, specify:	
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	2009
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Leak
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	Connection Failure
- If Other, Describe:	
- If Rupture - Select Orientation:	
- If Other, Describe:	
Approx. size: in. (widest opening) by	
in. (length circumferentially or axially)	
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	No
1a. If Yes, specify all that apply:	
- Fish/aquatic	
- Birds	
- Terrestrial	
2. Soil contamination:	Yes
3. Long term impact assessment performed or planned:	No
4. Anticipated remediation:	Yes
4a. If Yes, specify all that apply:	
- Surface water	Yes
- Groundwater	
- Soil	Yes
- Vegetation	
- Wildlife	
5. Water contamination:	Yes
5a. If Yes, specify all that apply:	
- Ocean/Seawater	
- Surface	Yes
- Groundwater	Yes
- Drinking water: *(Select one or both)*	
- Private Well	
- Public Water Intake	
5b. Estimated amount released in or reaching water (Barrels):	5.00
5c. Name of body of water, if commonly known:	Unknown, swamp area in close proximity to the pump station
6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program?	No
7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	No
7a. If Yes, specify HCA type(s): *(Select all that apply)*	

- Commercially Navigable Waterway:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- High Population Area:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Other Populated Area	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Drinking Water	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Ecological	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
8. Estimated Property Damage:	
8a. Estimated cost of public and non-Operator private property damage	$ 1,000
8b. Estimated cost of commodity lost	$ 40,000
8c. Estimated cost of Operator's property damage & repairs	$ 25,000
8d. Estimated cost of Operator's emergency response	$ 250,000
8e. Estimated cost of Operator's environmental remediation	$ 750,000
8f. Estimated other costs	$ 250,000
Describe:	Repair costs to the faclity and other facilities
8g. Total estimated property damage (sum of above)	$ 1,316,000

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	1,097.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	1,440.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	No
- If Yes - (*Complete 5a. – 5e. below)*	
5a. Type of upstream valve used to initially isolate release source:	
5b. Type of downstream valve used to initially isolate release source:	
5c. Length of segment isolated between valves (ft):	
5d. Is the pipeline configured to accommodate internal inspection tools?	
- If No, Which physical features limit tool accommodation? (*select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	

- If Yes, Which operational factors complicate execution? (*select all that apply*)	
- Excessive debris or scale, wax, or other wall buildup	
- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other -	
- If Other, Describe:	
5f. Function of pipeline system:	
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?	Yes
If Yes -	
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	Yes
- If Yes:	
7a. Was it operating at the time of the Accident?	Yes
7b. Was it fully functional at the time of the Accident?	Yes
7c. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
7d. Did CPM leak detection system information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
8. How was the Accident initially identified for the Operator?	Controller
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including contractors", "Air Patrol", or "Guard Patrol by Operator or its contractor" is selected in Question 8, specify the following:	Operator employee
9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?	No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: (provide an explanation for why the Operator did not investigate)
- If No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	due to the cause of the release resulted from a broken fitting on the thermal relief valve, the controlled did not contrubute to the release.
- If Yes, specify investigation result(s): *(select all that apply)*	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
Provide an explanation for why not:	
- Investigation identified no control room issues	
- Investigation identified no controller issues	
- Investigation identified incorrect controller action or controller error	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above:	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
1a. Specify how many were tested:	
1b. Specify how many failed:	
2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Specify how many were tested:	
2b. Specify how many failed:	

PART G – APPARENT CAUSE

Select only one box from PART G in shaded column on left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing or root causes of the Accident in the narrative (PART H).

Apparent Cause:	G6 - Equipment Failure

G1 - Corrosion Failure - only one **sub-cause** can be picked from shaded left-hand column

External Corrosion:	
Internal Corrosion:	
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	
- If Other, Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	
- If Yes :	
4a. Was failed item considered to be under cathodic protection at the time of the Accident?	
If Yes - Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	
- Other:	
7. Type of corrosion *(select all that apply)*: -	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other:	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*: -	
- Field examination	
- Determined by metallurgical analysis	

- Other:	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	
- Elbow	
- Other:	
- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	

G2 - Natural Force Damage - only one **sub-cause** can be picked from shaded left-handed column	
Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If High Winds:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event?	
6a. If Yes, specify: *(select all that apply)*	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	
G3 - Excavation Damage - only one **sub-cause** can be picked from shaded left-hand column	
Excavation Damage – Sub-Cause:	
- If Excavation Damage by Operator (First Party):	
- If Excavation Damage by Operator's Contractor (Second Party):	
- If Excavation Damage by Third Party:	
- If Previous Damage due to Excavation Activity:	
Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Accident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	

4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
5a. If Yes, for each examination, conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from: *(select all that apply)* -	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred: *(select all that apply)* -	
- Public	
- If "Public", Specify:	
- Private	
- If "Private", Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator:	
10. Type of excavation equipment:	
11. Type of work performed:	
12. Was the One-Call Center notified?	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption (hours)	
17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well):*	
Root Cause:	
- If One-Call Notification Practices Not Sufficient, specify:	
- If Locating Practices Not Sufficient, specify:	
- If Excavation Practices Not Sufficient, specify:	
- If Other/None of the Above, explain:	
G4 - Other Outside Force Damage - *only one **sub-cause** can be selected from the shaded left-hand column*	
Other Outside Force Damage – Sub-Cause:	

- If Nearby Industrial, Man-made, or Other Fire/Explosion as Primary Cause of Incident:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation:	
- If Electrical Arcing from Other Equipment or Facility:	
- If Previous Mechanical Damage NOT Related to Excavation:	
Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
3. Has one or more internal inspection tool collected data at the point of the Accident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
6. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	

Describe:	
- If Intentional Damage:	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	
G5 - Material Failure of Pipe or Weld - only one **sub-cause** can be selected from the shaded left-hand column	
Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."	
Material Failure of Pipe or Weld – Sub-Cause:	
1. The sub-cause selected below is based on the following: *(select all that apply)*	
- Field Examination	
- Determined by Metallurgical Analysis	
- Other Analysis	
- If "Other Analysis", Describe:	
- Sub-cause is Tentative or Suspected; Still Under Investigation (Supplemental Report required)	
- If Construction, Installation, or Fabrication-related:	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Original Manufacturing-related (NOT girth weld or other welds formed in the field):	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related:	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	
3. Specify:	
- Other - Describe:	
Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional factors: (*select all that apply*):	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other:	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the Accident?	
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	

- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
7. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident -	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site -	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?	
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: -	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
G6 – Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – Sub-Cause:	Threaded Connection/Coupling Failure
- If Malfunction of Control/Relief Equipment:	
1. Specify: *(select all that apply)* -	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- ESD System Failure	
- Other	
- If Other – Describe:	
- If Pump or Pump-related Equipment:	
2. Specify:	
- If Other – Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	Threaded Fitting
- If Other – Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other – Describe:	
- If Defective or Loose Tubing or Fitting:	
- If Failure of Equipment Body (except Pump), Tank Plate, or other Material:	
- If Other Equipment Failure:	
5. Describe:	

Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure: *(select all that apply)*	
- Excessive vibration	Yes
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported commodity	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	

G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column	
Incorrect Operation – Sub-Cause:	
Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage	
Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow	
1. Specify:	
- If Other, Describe:	
Valve Left or Placed in Wrong Position, but NOT Resulting in a Tank, Vessel, or Sump/Separator Overflow or Facility Overpressure	
Pipeline or Equipment Overpressured	
Equipment Not Installed Properly	
Wrong Equipment Specified or Installed	
Other Incorrect Operation	
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Accident related to *(select all that apply)*: -	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Accident?	
5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	

G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column	
Other Accident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	

2. Specify:	

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

A release occurred at the Ludden Pump Station on the ¾" pipe nipple under the thermal relief valve located on the facility discharge piping. A root cause analysis has been conducted and the failed fitting investigation performed. The fatique failure of the 3/4" pipe nipple occurred as a result of excessive vibratio. Results have been provided to PHMSA.

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

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Preparer's E-mail Address	dan_cerkoney@transcanada.com
Preparer's Facsimile Number	701-483-1431
Authorized Signature's Name	Daniel C Cerkoney
Authorized Signature Title	Compliance Engineer
Authorized Signature Telephone Number	701-290-1176
Authorized Signature Email	dan_cerkoney@transcanada.com
Date	11/02/2011

URS

November 18, 2011

Mr. Kris Roberts
North Dakota Department of Health
918 E. Divide Avenue, 4th Floor
Bismarck, North Dakota 58501-1947

Subject: Release Progress Report – Ludden Pump Station
TransCanada – Keystone Pipeline, LP
Brampton, North Dakota

Dear Mr. Roberts:

This report transmits the results of the October 2011 sampling of the land farmed area and surface water in the wetlands at the TransCanada Keystone Pipeline, LP Ludden Pump Station site near Brampton, North Dakota. This report is submitted in reference to your October 26, 2011 correspondence and the finalization of cleanup actions by TransCanada at this site.

Sampling and Analysis Results

Soil Sampling

The land farmed area was resampled on October 20, 2011. The sample locations are shown on Figure 1 and the results are summarized on Table 1. Analytical results continued to show total extractable hydrocarbon (TEH) concentrations in soils below North Dakota Department of Health (NDDH) clean-up levels at all sampling locations.

Water Sampling

The majority of the wetlands previously sampled were found to have no standing water on October 20, 2011, with the exception of the background sample location ¼ mile north of the pump station. The sample location is shown on Figure 2 and the results are summarized on Table 2.

Observed Site Conditions

The crops in the farmed area had been destroyed prior to the October 20, 2011 site visit and the field had been tilled. See attached aerial photograph from October 5, 2011 (Figure 3) showing site and land farm restoration condition.

Recommendation

Based on current conditions at the TransCanada Ludden Pump Station site and your correspondence dated October 26, 2011, we request that no further investigation or remediation be required and that the site be considered for closure.

URS Corporation
Fifth Street Towers
100 South Fifth Street, Suite 1500
Minneapolis, MN 55402
612.370.0700 Tel
612.370.1378 Fax

URS

If you have any questions, please contact Robert Baumgartner of TransCanada Keystone Pipeline at (832) 320-5538 or myself at (612) 373-6849.

Sincerely,

Bruce R. Galer

Bruce R. Galer, PG
Senior Geologist

cc: Robert Baumgartner, TransCanada Keystone Pipeline

Table 1
Summary of Laboratory Analysis-Wetland Water Samples
Ludden Pump Station, Brampton, ND-October 20, 2011

Location	Units	WTLD-025	WTLD-26-N	WTLD-026-S	WTLD-026-Trench	WTLD-027	1/2 Mi-WILD	1/4 MI-N-WTLD	PS-ADJ-WTLD	Human Health Limit Class III Water
Sample Date		10/20/11	10/20/11	10/20/11	10/20/11	10/20/11	10/20/11	10/20/11	10/20/11	
Type		NA	NA	NA	NA	NA	NA	Background-Grab	NA	
Analyte										
TEH(C09-C40)	mg/L	NA	NA	NA	NA	NA	NA	0.11	NA	---
TEM (C09-C40)	mg/L	NA	NA	NA	NA	NA	NA	0.11	NA	---
Benzene	µg/L	NA	NA	NA	NA	NA	NA	<1	NA	71
Ethylbenzene	µg/L	NA	NA	NA	NA	NA	NA	<1	NA	2,900
Toluene	µg/L	NA	NA	NA	NA	NA	NA	<1	NA	200,000
Xylene (Total)	µg/L	NA	NA	NA	NA	NA	NA	<3	NA	10,000*

NOTES: mg/L=Milligrams per liter
µg/L= Micrograms per liter
<x = Not detected to reporting limits of x
TEM=total extractable range hydrocarbons without silica gel preparation
TEH=total extractable range hydrocarbons with silica gel preparation
* None listed for Class III water, value represents Class II water, wetlands unlisted are considered Class III waters
--- = No applicable standard
NA = No surface water present at sample location

Location	Units	WTLD-25	WTLD-26-N	WTLD-26-S	WTLD-26-Trench	WTLD-27	1/2 Mi-WILD	1/4 MI-N-WTLD	PS-ADJ-WTLD	Aquatic Life Value Acute ***	Aquatic Life Value Chronic ***
Sample Date		10/20/11	10/20/11	10/20/11	10/20/11	10/20/11	10/20/11	10/20/11	10/20/11		
Type		NA	NA	NA	NA	NA	NA	Background-Grab	NA		
Analyte											
Aluminum, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<200	NA	---	---
Antimony, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<10	NA	---	640**
Arsenic, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<10	NA	340	150
Barium, dissolved	µg/L	NA	NA	NA	NA	NA	NA	56.5	NA	---	---
Beryllium, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<5.0	NA	---	---
Boron, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<150	NA	---	---
Cadminum, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<1	NA	2.1	0.27
Chromium, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<10	NA	1,800	86
Copper, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<10	NA	14.0	9.3
Lead, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<3	NA	82	3.2
Nickel, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<20	NA	470	52
Selenium, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<15	NA	20	5.0
Silver, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<10	NA	3.8	---
Thallium, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<15	NA	---	0.47**
Zinc, dissolved	µg/L	NA	NA	NA	NA	NA	NA	<20	NA	120	120
Ammonia Nitrogen	mg/L	NA	NA	NA	NA	NA	NA	0.13	NA	---	---

NOTES: mg/L=Milligrams per liter
µg/L= Micrograms per liter
<x = Not detected to reporting limits of x
** Class III Steam Human Health Standard, no aquatic standard listed
*** Some values may be adjusted based on hardness and pH.
NA = No surface water present at sample location

Table 2
Summary of Laboratory Analysis-Land Farming
Ludden Pump Station, Brampton, ND

May 15, 2011

Location	Units	LF-A	LF-B	LF-C	LF-D	LF-BKG-A	LF-BKG-B	Clean-up Level
Sample Date		5/15/11	5/15/11	5/15/11	5/15/11	5/15/11	5/15/11	
Sample Type		Composite	Composite	Composite	Composite	Composite	Composite	
Chemical of Concern								
% Moisture	%	29.3	28	21.6	18.9	20.7	20.7	
TEH(C09-C40)	mg/kg	228	3.1	4.9	143	3.0	3.5	100
TEM(C09-C40)	mg/kg	214	13	10.7	198	13.7	9.2	100
pH	Std. Units	7.2	5.4	7.1	7.1	5.6	5.9	
Nitrate as N	mg/kg	<5.7	9.4	5.1	<4.9	8.1	7.2	
Total Phosphorus	mg/kg	348	388	349	332	428	337	
Total Organic Carbon	mg/kg	3530	5630	6980	10300	4070	4140	

August 2, 2011

Location	Units	LF-A	LF-B	LF-C	LF-D	LF-E*	LF-BKG-A	LF-BKG-B	Clean-up Level
Sample Date		8/2/11	8/2/11	8/2/11	8/2/11	8/2/11	8/2/11	8/2/11	
Sample Type		Composite	Composite	Composite	Composite	Composite	Composite	Composite	
Chemical of Concern									
% Moisture	%	6.4	12.4	21.1	11.8	23.4	36.2	10.1	
TEH(C09-C40)	mg/kg	4.6	4.2	4.1	5.6	7.7	6.8	4.3	100
TEM(C09-C40)	mg/kg	8.8	9.1	5.3	15.2	11.2	10.3	8.9	100
pH	Std. Units	5.3	5.2	5.5	5.0	7.5	7.7	8.2	
Nitrate as N	mg/kg	<4.3	4.6	<5.1	5.9	<5.2	<6.3	<4.5	
Total Phosphorus	mg/kg	274	287	329	340	273	404	307	
Total Organic Carbon	mg/kg	3810	7300	6670	4810	2810	8670	2870	

October 20, 2011

Location	Units	LF-A	LF-B	LF-C	LF-D	LF-BKG-A	LF-BKG-B	Clean-up Level
Sample Date		10/20/11	10/20/11	10/20/11	10/20/11	10/20/11	10/20/11	
Sample Type		Composite	Composite	Composite	Composite	Composite	Composite	
Chemical of Concern								
% Moisture	%	14.4	7	12.6	9.5	17.5	8.7	
TEH(C09-C40)	mg/kg	8.6	4.1	8.4	74.2	6.2	5.6	100
TEM(C09-C40)	mg/kg	14.2	6.5	10.8	87.4	6.8	9.7	100
pH	Std. Units	7	5	6.3	6.0	8.3	7.9	
Nitrate as N	mg/kg	18.6	10.2	31.2	12.4	6.7	4.3	
Total Phosphorus	mg/kg	347	344	363	327	406	348	
Total Organic Carbon	mg/kg	12100	8030	7040	5640	7100	6690	

NOTES:

TEM=total extractable range hydrocarbons without silica gel preparation

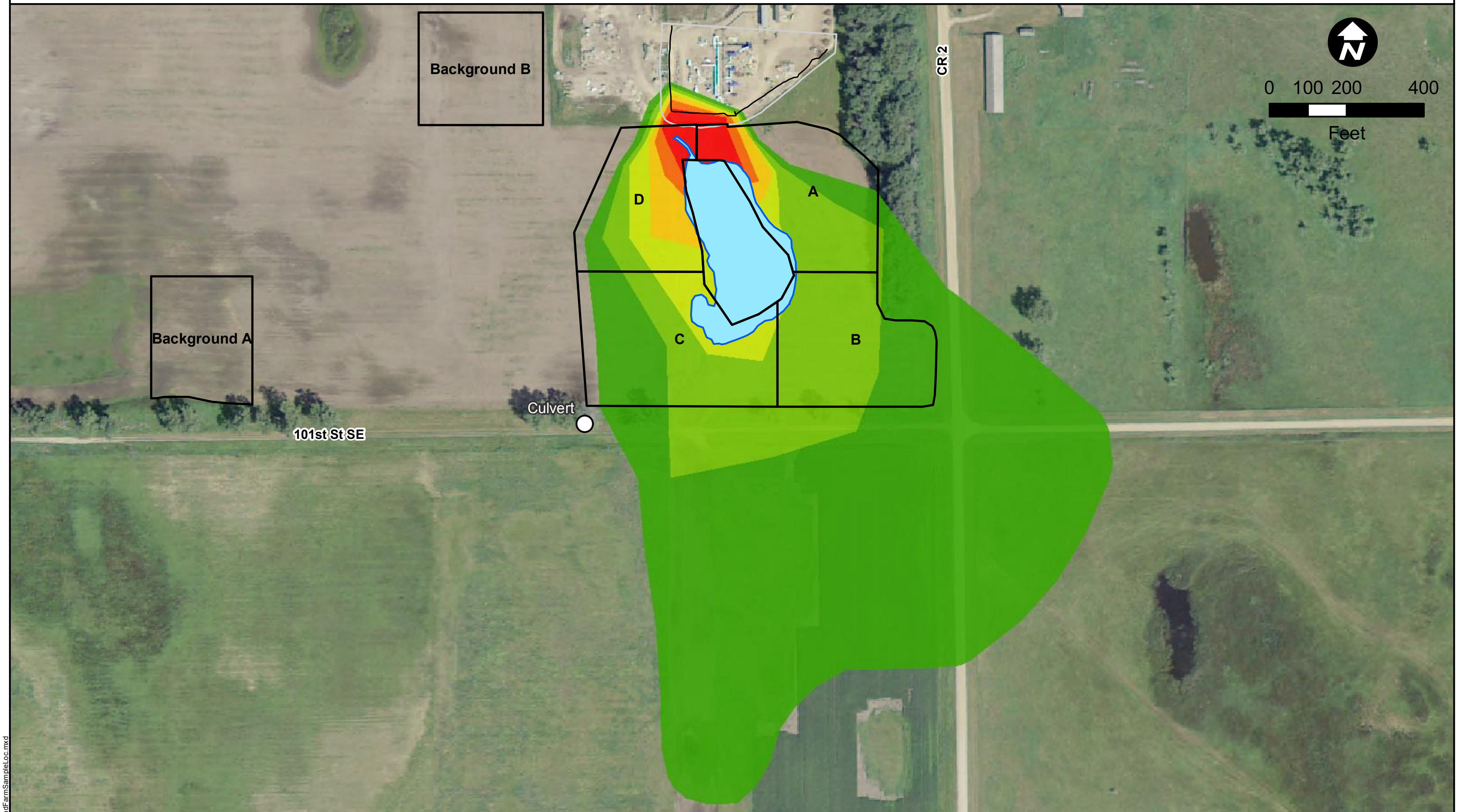
TEH=total extractable range hydrocarbons with silica gel preparation

* In August 2 sampling, the portion of the field that was scraped to remove surficial oil was separated from sample areas LF-A and LF-B and sampled as sample LF-E.

TransCanada Ludden Pump Station

Figure 1. Land Farm Sample Locations - October 20, 2011

URS
Fifth Street Towers
100 South Fifth Street, Suite 1500
Minneapolis, MN 55402
612.370.0700 Tel
612.370.1378 Fax

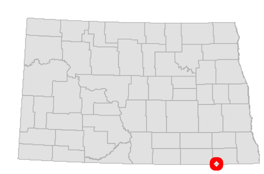


Fence	Misted Areas				
Toe of Slope		Continuous = 91-100% coverage		Sporadic-High = 6-10% coverage	
Pond		Broken = 51-90% coverage		Sporadic-Low = 1-5% coverage	
		Patchy = 11-50% coverage		Trace = <1% coverage	

Data:
SCAT areas collected by GPS in May 2011.

Projection:
NAD83 UTM Zone 14N

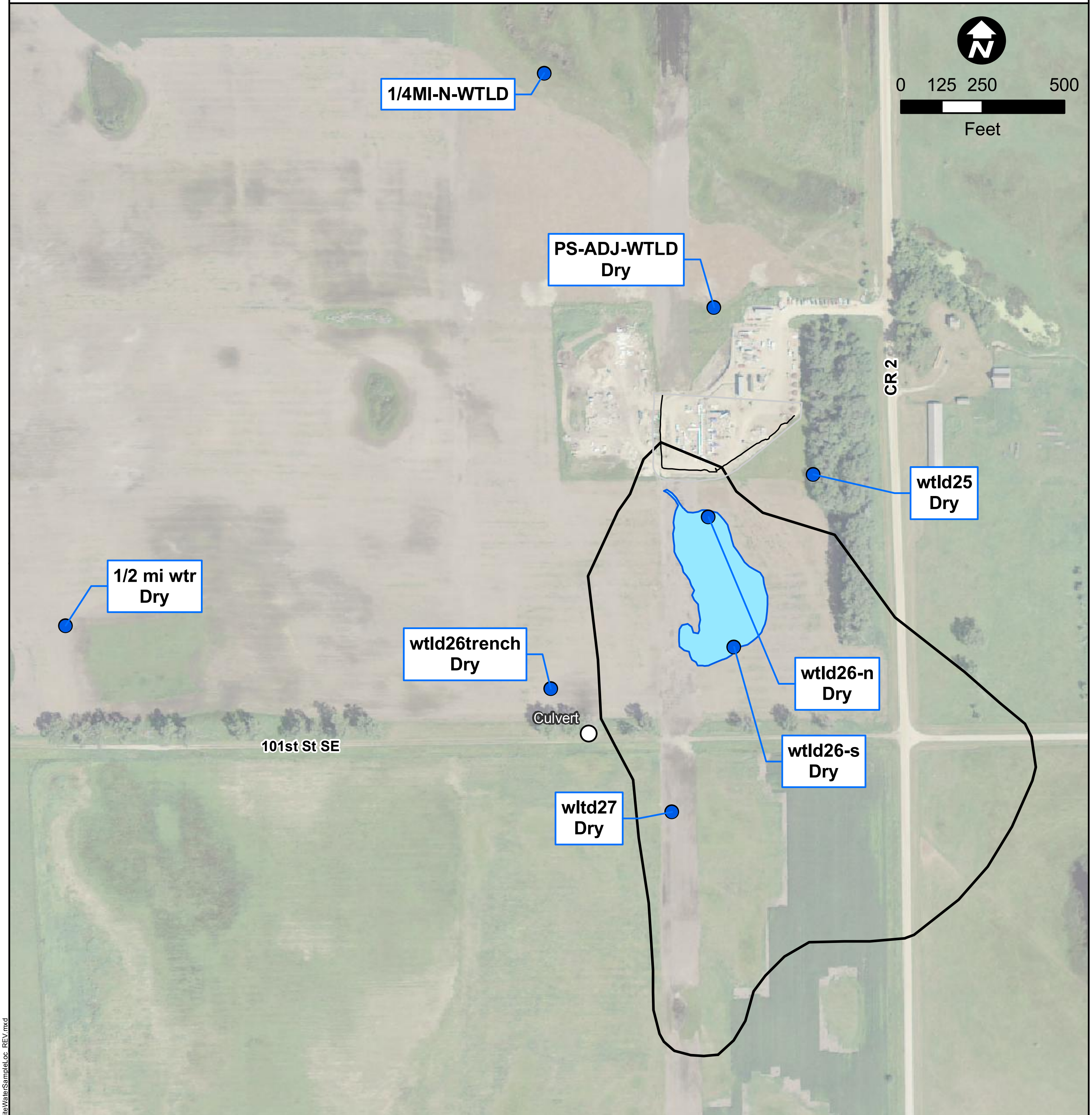
029656



TransCanada Ludden Pump Station

Figure 2. Off-Site Water Sampling Locations - October 20, 2011

URS
Fifth Street Towers
100 South Fifth Street, Suite 1500
Minneapolis, MN 55402
612.370.0700 Tel
612.370.1378 Fax

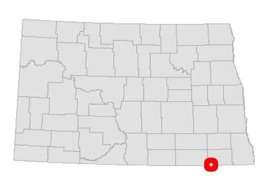


Fence
Misted Spray Area
Toe of Slope
Pond
Off-Site Water Sample

Data:
SCAT areas collected by GPS in May 2011.

Projection:
NAD83 UTM Zone 14N

029657



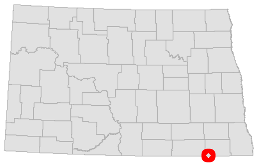
Q:\31810958\06_GIS\Data\08312011\Fig2_offSiteWaterSampleLoc_REV.mxd

TransCanada Ludden Pump Station

Figure 3. Site Restoration as of October 5, 2011

URS
Fifth Street Towers
100 South Fifth Street, Suite 1500
Minneapolis, MN 55402
612.370.0700 Tel
612.370.1378 Fax

029658



Environmental Incident Report

This report has been submitted.

North Dakota Department of Health
Environmental Health Section
1.701.328.5210 or 1.701.328.5166

North Dakota Department of Emergency Services
1.701.328.8100
1.800.472.2121 State Radio 24-Hour Hotline

If this is an emergency, or for additional assistance, please call the Health or Emergency Services Department at the numbers shown above

This form is NOT for RCRA-exempt oilfield related incidents
(for RCRA-exempt oilfield incidents click here)
(if you are not sure which form to use click here)

Fill out information as completely as possible
Error messages appear to the right of the field
Use the Tab key or mouse to move between fields
Pressing the Enter key while in the form will submit the report
Required fields are shown in Red

Location Information:

County	Sargent
Township	129
Range	58
Section	26
Quarter	
QQSection	
QQQSection	

Location Description (911 address or location from nearest town)

10075 119th Ave SE
Brampton, ND 58017

Distance to Nearest Residence or Occupied Building 1.3 Units Miles

Incident Information:

Date 5/7/2011
(mm/dd/yyyy) If unknown, enter date of discovery
Time

029659

0605

hhmm 24-hour time, no colon

Type Other (fill in box)

Pipeline Pump Station Equipment

Estimated Duration 30 Units minutes

Estimated Volume 500 Units barrels

Substance released or of concern (include trade and/or chemical name if applicable)

Crude Oil

Agriculture Related? No

Is this substance on EPA's Extremely Hazardous Substance list? No

To find out if this substance is on the EHS list, Click Here

Describe Cause

Small diameter piping failure.

Action Taken and Recommended/Planned Future Action
(how spill was contained, soil excavated, emergency approval
to burn contaminant, evacuation of nearby personnel, etc.)

Pipeline system shutdown and pump station isolated.
Company and contractor spill response crews mobilized to the facility.
Oil contained and controlled onsite by earthen berm. Offsite oil mist delineated. Absorbent boom and
earthen dam were used to collect sheen and control flow from ponded water on adjacent property to the

Where will recovered wastes be disposed?

Recovered crude oil/water mix transported to LePier Oil, Fosston, MN for recycling.
Excavated oil impacted gravel/soil will be transported to Veolia LF, Buffalo MN

Impact Information:

Fatalities 0

Injuries 0

Medium affected 04 - water and soil

Immediate Risk Evaluation (explosive atmosphere, immediate health hazards, etc.)

NA - work conditions were monitored throughout response/cleanup activities.

Potential Environmental Impacts

029660

(describe impacts to, or likelihood of impacts, to surface water, ground water, soils, etc.)

Soils - oil saturated soils were excavated as described above. Residual oil impacts will be treated using insitu landfarming techniques.
Surface water - oil sheen was collected utilizing absorbent boom. Potential dissolved impacts are being monitored.

Responsible Party Information:

Responsible Party	TransCanada
Address (Line 1)	13710 FNB Parkway
Address (Line 2)	Suite 300
City	Omaha
State/Province	NE - Nebraska
Zip	68154
Contact First Name	Robert
Contact Last Name	Baumgartner
Contact Telephone	832-320-5538
Contact Email	robert_baumgartner@trai

Property Owner if not the Responsible Party

Has or will the incident be reported to property owner? Unknown

Reporting Information:

First Name	Robert
Last Name	Baumgartner
Date Reported (mm/dd/yyyy)	5/7/2011
Time Reported	1015

hhmm 24-hour time, no colon

Other agencies that have or will be notified

- [ ] NDDES
- [ ] State Fire Marshal
- [ ] State Highway Patrol
- [x] Local Fire Department
- [x] Local Law Enforcement
- [x] Local Emergency Manager

Other

To see if this incident is required to be reported to the National Response Center (NRC) Click Here

029661

Has or will the incident be reported to the NRC ?? 1-800-424-8802 Yes

Additional E-Mail Recipients to send report to

robert_baumgartner@transcanada

Official Use Only:

State Agency Person Who Received Call First Name

Last Name

Department of Emergency Services Incident Number

Send this email to Department of Mineral Resources No

Pressing the submit button will send an E-Mail version of this completed Environmental Incident Report to NDDH Environmental Health Section and ND Dept. of Emergency Services personnel

Submit

029662

CERTIFICATE OF SERVICE

I hereby certify that on this 1st day of October 2015, Dakota Rural Action filed the foregoing on the Public Utilities Commission of the State of South Dakota e-filing website. Also on this day, a true and accurate copy of the foregoing was transmitted via email to the following:

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