BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NAVIGATOR HEARTLAND GREENWAY, LLC FOR A PERMIT UNDER THE SOUTH DAKOTA ENERGY CONSERVATION AND TRANSMISSION FACILITIES ACT TO CONSTRUCT THE HEARTLAND GREENWAY PIPELINE IN SOUTH DAKOTA	**HP22-002** **RICHARD KUPREWICZ SURREBUTTAL TESTIMONY IN SUPPORT OF LANDOWNER INTERVENORS**

INTRODUCTION

1. Please state your name, position, and business address.

Answer: My name is Richard B. Kuprewicz. I am the President of Accufacts Inc. ("Accufacts") which is headquartered at 8151 164th Ave. NE, Redmond, Washington 98052.

2. Have you previously submitted testimony in this proceeding?

Answer: Yes.

3. To whose testimony are you responding in surrebuttal?

Answer: I am responding to the rebuttal testimony of the following individuals:

- Mark Hereth, dated June 23, 2023, including his Rebuttal Testimony and its Exhibit A, "Management of Ground Movement Hazards for Pipelines - Final Report," CRES Project No. CRES-2012-M03-02, February 29, 2017; and Exhibit B, "Guidelines for Management of Landslide Hazards for Pipelines, prepared for INGAA Foundation and a Group of Sponsors, prepared by Geosyntec Consultants, Inc., Golder Associates, Inc. and Center for Reliable Energy Systems (CRES), Version 1 August 17, 2020.

- Stephen Lee, dated June 26, 2023, including his Rebuttal Testimony and its Exhibit A, PHMSA email to Mark Maple (ICC Safety division ICC) indicating, "If a pipeline transports CO_2 as a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state, the pipeline is regulated pursuant to part 195, even if a segment of the pipeline **temporarily** [emphasis added] experiences operating conditions in which the fluid in not maintained in a supercritical state;" and Exhibit B, DNV Design Verification Report, dated June 6, 2023.

SUMMARY OF TESTIMONY

4. Please summarize your testimony.

Answer: Based on my background and experience, I will briefly focus my Surrebuttal Testimony concerning the carbon dioxide pipeline proposed by Navigator Heartland Greenway, LLC ("NHG"), into three key areas related to siting of carbon dioxide pipelines:

1. The need for the South Dakota Public Utilities Commission ("SDPUC") to require NHG to provide approximate temperature profiles (temperature versus milepost) for its proposed pipelines so as to identify areas of the pipeline that will transport carbon dioxide in a liquid phase and not in a supercritical phase, as outlined further below;
2. The need for the SDPUC to require NHG to conduct and disclose computer modeling and a methodology to predict the dispersion of carbon dioxide from a rupture of the proposed pipeline, that is capable of taking into account all of the

following factors: the actual initial phase of the carbon dioxide along the pipeline; pipeline diameter, operating pressure, purity of the CO_2 stream, pipe segment length, distance between mainline valves, valve closure times, product release rate, representative climatological data, and characteristic topography, so as to assist the Commission in its assessment of the unavoidable risks that would be created by the proposed pipeline.

3. The fact that numerous industry practices, such as those included in Exhibit A and B to the testimony of Mark Hereth, referenced above, are not incorporated into federal pipeline safety regulations for many good safety reasons, as they are gravely inadequate and even incomplete in many important areas as discussed further below.

5. Why should the Commission require that approximate temperature profiles be provided for the proposed pipelines in South Dakota?

Answer: In making informed siting decisions related to the risks of siting a carbon dioxide pipeline, the approximate temperature profile should be provided by the Applicant so that the most likely phase of carbon dioxide along the pipeline can be ascertained. Where the temperature of the carbon dioxide is below approximately 88 degrees Fahrenheit (the critical temperature of carbon dioxide), the carbon dioxide will be in a liquid phase at pipeline pressures, and not in a supercritical phase. Given the weather extremes exhibited in South Dakota, the depth of the frost line in South Dakota, and the fact that the pipeline will not be insulated or heated, it is certain that most of the proposed pipeline will operate at temperatures well below the critical temperature, in which locations the pipeline will not be transporting supercritical carbon dioxide. Based on public responses supplied by

Navigator in Illinois, I expect that the vast majority of the pipeline mileage (on an order greater than 95%) will be permanently operated with carbon dioxide in a liquid phase and not in a supercritical phase, though the Commission should require NHG to confirm this. Pipeline operating temperature affects carbon dioxide density and related pipeline release dynamics. Carbon dioxide density substantially impacts the mass of carbon dioxide that can be released and the geographic scope of the area that could be affected by a pipeline rupture. Given the expected operating conditions of the pipeline I would expect the liquid phase to be on the order of 20 to 40 percent denser than carbon dioxide at its supercritical state at its injection temperature. The lower the operating temperature, the greater the mass of carbon dioxide in the pipeline and the greater the amount of carbon dioxide that would be released upon rupture. Therefore, the NHG pipelines proposed operating temperature range, its average operating temperatures by month, and its temperature profile are important safety information needed to determine the accuracy of NHG's worst case discharge calculations. Normally, such information is supplied in at least two basic boundary cases: 1) the temperature profile of the pipeline during the coldest time of the year, and 2) the temperature profile of the pipeline during the warmest time of the year. Absent such temperature information, the Commission will not be able to independently verify the reasonableness of NHG's plume dispersion modeling.

6. How do you respond to Mr. Hereth's statement that the carbon dioxide in NHG's pipeline will be transported in a supercritical state, such that the regulatory concerns identified in your paper do not apply to its project?

Answer: It is a virtual certainty that the vast majority of the carbon dioxide in NHG's pipeline will be in a liquid state, because the carbon dioxide will cool below 88 degrees

Fahrenheit (the approximate supercritical temperature) as it is transported through the much cooler earth in the uninsulated underground pipeline. It is likely that NHG has conducted engineering studies related to pipeline operating temperatures, which studies would settle this issue. To resolve this dispute, the Commission should simply require NHG to disclose these important studies or to develop and release such important information for this proceeding. In the unlikely event that NHG has not conducted temperature profile studies, then Mr. Hereth's testimony has no basis in fact.

7. How do you respond to the statements by Mr. Lee that the carbon dioxide in NHG's proposed pipeline will not be maintained in a supercritical state during transport, but that this fact is irrelevant because PHMSA has asserted that it has jurisdiction over the entire pipeline?

Answer: First, I note that Mr. Lee's statement is in conflict with Mr. Hereth's statement. Second, Exhibit A to Mr. Lee's testimony, the email from Tewabe Asebe, an unidentified PHMSA employee, to Mark Maple of the Illinois Commerce Commission, is not as clearcut as implied by Mr. Lee. The PHMSA employee states: "If a pipeline transports CO_2 as a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state, the pipeline is regulated pursuant to part 195, even if a segment of the pipeline temporarily experiences operating conditions in which the fluid is not maintained in a supercritical state. If, however, a pipeline has operational controls in place (e.g., pressure limiting devices) that prevent CO_2 from entering a supercritical state, the pipeline would not be regulated under Part 195." This statement fails to address a situation where a segment of a carbon dioxide pipeline operates below the critical temperature at all times, such that the operating conditions are not "temporary." Moreover, the email fails to recognize that low temperature is more likely to result in operation in a liquid state than low pressure, because NHG's pipeline operators would be able to increase operating pressure via use of pumps, whereas its operators have provided no evidence as to how carbon dioxide will be maintained above its critical temperature, a requirement to assure supercritical state.

NHG will have little control over carbon dioxide temperature, because its pipeline will be neither insulated nor externally heated and the temperature will be substantially impacted by heat loss to the ground, that in turn is subject to seasonal variations in ground temperature, the rate of throughput, and distance from pump stations, which pumping would provide the only heat added to the carbon dioxide. PHMSA's assertion of jurisdiction is not as clear as suggested by Mr. Lee.

The question of PHMSA's jurisdiction over NHG's proposed pipeline and other proposed carbon dioxide pipelines when they are transporting carbon dioxide in a liquid phase is a legal matter that has not yet been determined by the courts. In the event of a leak or rupture of a carbon dioxide pipeline operating in a liquid state, to avoid liability, a pipeline operator could argue that the pipeline at the time of rupture was not within federal pipeline safety jurisdiction. I recommended that PHMSA amend its regulations to eliminate this ambiguity. Until PHMSA does so via a rulemaking, PHMSA's jurisdiction over transportation of liquid carbon dioxide is ambiguous.

Mr. Lee does not discuss the underlying point here that pipeline operating temperature at the time of a rupture can substantially impact the amount of carbon dioxide released, and this in turn impacts the danger zone of the proposed pipelines. NHG should release temperature studies so that the Commission, intervenors, and first responders are able to assess the accuracy of NHG's dispersion modeling, as well as PHMSA's asserted claims of jurisdiction.

8. What is your response to the statements of Mr. Hereth and Mr. Lee statements related to running ductile fractures and his reliance on his Exhibit B, the DNV Design Verification Report?

Answer: First, I note that the entirety of the federal regulation on prevention of running ductile fractures is contained in 49 C.F.R. §111, which states in full: "carbon dioxide pipeline system must be designed to mitigate the effects of fracture propagation." Thus, this federal regulation contains no detailed safety standards for prevention of running ductile fractures. Instead, the judgment about how to prevent running ductile fractures is left entirely to pipeline operator judgment. Mr. Hereth asserts that this utterly vague federal safety standard has the benefit of allowing "new methods to be used as they are developed and published," which statement assumes that the pipeline industry will in fact develop and implement new methods to prevent such fractures. In my experience, such vague standards are more likely to result in passivity and a failure to adopt improved technology due to cost considerations or operator inertia. Moreover, since PHMSA regulations establish safety standards related to pipeline operating pressure, 49 C.F.R. § 195.406, there is no reason why PHMSA could not establish pressure-based safety standards for methods to prevent running ductile fractures, for example to determine the need for greater steel strength or the design and use of crack arrestors, based on the pressures that can be predicted to result from the explosive decompression of carbon dioxide pipelines. Also, where crack arrestors are used, PHMSA could specify their maximum spacing along a pipeline.

Second, the DNV Design Verification Report does not specifically describe any actions to be taken by NHG or specific requirements for the design of NHG's pipeline with regard to prevention of running ductile fractures. Instead, the DNV report claims to be a comprehensive review of NHG's "design philosophy" and it generally confirms that NHG's design references the appropriate industry standards. Mr. Lee claims that the DNV document includes "steps to mitigate ductile fracture propagation, including sections or areas of pipeline of more conservative design factors including locations of bores, horizontal directional drills, valves and crack arrestors as warranted to further design and implement redundant fracture control mitigation systems." The DNV document does not describe or discuss any of these engineering issues. It does not expressly confirm that NHG has in fact identified "sections or areas of pipeline of more conservative design factors" needed to prevent running ductile fractures; does not describe if and where NHG will install crack arrestors to prevent running ductile fractures; and does not otherwise state how NHG will mitigate this risk. It merely lists a large number of industry standards and states in general terms that the NHG design paperwork complies with them.

Moreover, running ductile fractures may also be caused by variations in the proportion of contaminants including noncompressible gases, but as discussed in the report attached to my direct testimony, PHMSA currently has no safety standards related to carbon dioxide stream quality and contaminant controls.

9. What is your response to Mr. Hereth's and Mr. Lees discussion of carbon dioxide pipeline release dynamics and modeling?

Answer: Carbon dioxide exhibits several unusual properties that distinguish its movement on release from the movement of products released by conventional hydrocarbon transmission pipelines (e.g., petroleum or natural gas transmission pipelines). A review of phase diagrams for carbon dioxide shows that upon rupture a carbon dioxide pipeline will decompress from the operating pressure at the time of the rupture to atmospheric pressure, and the carbon dioxide will increase in volume forming a gas by a factor of approximately 400 to 500 times the pipeline initial volume upon warming to ambient temperature. Such decompression is explosive and is the result of the carbon dioxide converting from a dense (liquid or supercritical) phase to a low-density gas phase. The force of this explosion may be impacted by the phase of the carbon dioxide (i.e., liquid or supercritical), its temperature and pressure, and the presence of contaminants.

Moreover, the rate of carbon dioxide release from a pipeline rupture can vary considerably over time, even above the initial rate of release, due to the possible formation of dry ice within the pipeline upstream and downstream of the pipeline failure site. As a result, the dynamics of carbon dioxide pipeline ruptures are remarkedly different than conventional hydrocarbon transmission pipeline ruptures that decline with time. These dynamics make carbon dioxide pipeline ruptures much more dangerous and their dynamics and impacts more difficult to predict than conventional hydrocarbon transmission pipelines ruptures.

Since release volumes and dynamics depend in part on the phase of the carbon dioxide at the time of rupture, the Commission should require that NHG identify the areas of the pipeline that will be in supercritical and which segments will be in liquid phase for the boundary cases identified above, supported by appropriate temperature profiles.

The other major point that commands much respect from carbon dioxide pipeline releases is that, once warmed by the atmosphere, carbon dioxide releases are colorless, odorless, and heavier than air and may travel considerable distances depending on weather and topography. For example, the Denbury Gulf Coast Pipeline, LLC, carbon dioxide pipeline rupture near Satartia, Mississippi, forced rescue and medical evacuation of the residents of Satartia, some located over one mile from the rupture site. This pipeline had a nominal diameter of 24-inches and the distance between the nearest upstream and downstream valves was 9.55 miles. Pipeline and Hazardous Materials Safety Administration ("PHMSA") Failure Investigation Report - Denbury Gulf Coast Pipelines, LLC, May 26, 2022, page 4 (Exhibit A).[1] In its Consent Agreement with Denbury, PHMSA ordered that Denbury reassess whether a rupture of the pipeline "could affect" all high consequence areas within two miles of the pipeline. PHMSA Consent Agreement, March 23, 2023, page 5, para. 19 (Exhibit B). Although the proposed pipeline would at six and eight inches in diameter contain less carbon dioxide per foot than the Denbury pipeline, it is possible that the distance of pipeline vented could be up to two times longer, assuming that NHG proposes to locate valves in accordance with 49 C.F.R. § 195.260(c), which allows valve spacing up to 15 miles apart where a pipeline could affect a high consequence area, and up to 20 miles apart in other areas. Even ruptures of relatively smaller diameter carbon dioxide pipelines could kill or harm persons and animals a considerable distance from the rupture site. To understand the risks that would be created by the proposed pipeline, the Commission should determine this danger zone based on a clear and defensible and conservative methodology.

While dispersion modeling can predict the possible danger zone resulting from a rupture of any carbon dioxide pipeline, not all dispersion modeling takes account of topography

[1] Because of the file size that may interfere with transfer through some servers, my Exhibit A may be downloaded from PHMSA's website at: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-05/Failure%20Investigation%20Report%20-%20Denbury%20Gulf%20Coast%20Pipeline.pdf.

and gravity, the range of weather conditions, and vegetation types. Reliance on simplistic dispersion models can be useless and even negligent. For example, Denbury relied on the PHAST model to predict the "could affect" areas near its pipeline. The PHAST model is owned by DNV, a consultant for NHG. The PHMSA Consent Agreement states that "the earlier PHAST dispersion analysis was wrong and that the town of Satartia was a "could-affect" HCA and should have been included in Denbury's Public Awareness and Damage Prevention Program." Exhibit B at page 5, para. 18. That is, the PHAST model substantially underpredicted the potential dispersion of the carbon dioxide following a rupture of the Denbury pipeline, with the result that Denbury did not include the Town of Satartia or its local first responders in the company's emergency response planning or public education programs. With regards to this rupture, Mr. Lee's testimony states: "sufficient emergency response training and awareness per 49 CFR 195.403 may not have been adequately considered and addressed in the operator's integrity management plan and procedures." Mr. Lee fails to recognize that the reason for Denbury's complete failure to provide "emergency response training and awareness" to local residents and first responders was due entirely to the failure of DNV's PHAST model to predict that the residents of the Town of Satartia were at risk. Denbury's PHAST model runs found that Satartia was outside of the predicted area of hazardous carbon dioxide levels. Due to its reliance on the PHAST model, Denbury excluded Satartia area residents and emergency responders from its public education and training programs, such that neither the residents nor the first responders anticipated and were prepared for a rupture of the pipeline. The Satartia rupture demonstrated that use of the PHAST model to predict the full extent of the danger zone following a pipeline rupture is likely to underestimate the danger zone, such that its use is unreasonable and would constitute negligence.

Simple models, such as the PHAST model, fail to accurately account for weather conditions, turbulence, and more importantly the effects of topography and gravity on heavier than air carbon dioxide gas. In particular, gravity never shuts off and can easily overcome the effect of wind speed and direction, particularly during times of very low wind speed, which was the case at the time of the Satartia rupture.

It is critically important that the Commission, the public, and first responders have access to the best available dispersion modeling that takes into account all of the factors discussed herein, including but not limited to carbon dioxide phase, topography, and weather.

Current PHMSA federal minimum pipeline safety regulations do not adequately identify nor codify the actions that operators must take to address the unique properties and risks created by carbon dioxide pipelines designated for carbon sequestration services. This is a major deficiency in current federal pipeline safe safety regulations that needs to be addressed by PHMSA. Although PHMSA has announced a rulemaking to improve its carbon dioxide pipeline safety regulations, this effort will take at least another two years. While NHG seeks to build its pipeline so as to exploit the federal 45Q tax credit as soon as possible, such artificial federal incentive does not justify Commission approval of construction before PHMSA completes its rulemaking and among other improvements fully investigates carbon dioxide pipeline rupture dispersion modeling and acts to integrate robust modeling requirements into federal law.

Mr. Lee criticizes me because I did not provide volumes or concentrations of carbon dioxide following a rupture of NHG's proposed pipelines, essentially faulting me for not running my own dispersion models. Yet, Mr. Lee, who presumable has access to NHG's dispersion modeling fails to provide such data himself. He also states that I ignore 49 C.F.R. § 195.452, which relates to pipeline integrity management in high consequence areas, but he fails to discuss this regulation, the definitions related to it in 49 C.F.R. § 195.450, or Appendix C to the regulations, which provides guidance on implementation of integrity management programs. What Mr. Lee fails to recognize is that these regulations are intended to identify high consequence areas and specify design and operation safety standards for these areas, but they were originally written to address hydrocarbon pipeline spills, not carbon dioxide pipeline spills, which behave radically differently from each other. When PHMSA extended its high consequence area regulations to supercritical carbon dioxide pipelines it did not modify these regulations to account for the differences in these products. Therefore, these regulations are deficient in multiple ways, including by failing to recognized that carbon dioxide does not flow into water or overland like petroleum products. Moreover, as Mr. Lee recognizes, plume modeling is not defined nor required by this outdated regulation such that there are no standards for carbon dioxide plume modeling in the federal pipeline safety regulation. Thus, NHG's plume modeling is not subject to any specific federal plume modeling standards, whatsoever. Further, Mr. Lee does not describe or discuss the efficacy of NHG's plume modeling methodology, its assumptions, or its outputs. Therefore, he provides no assurance whatsoever about the quality or reasonableness of NHG's plume modeling effort.

With regard to NHG's compliance with 49 C.F.R. § 195.210(a), related to pipeline location, due to 49 U.S.C. § 60104(e), which statute was enacted after the regulation and which prohibits PHMSA from issuing safety standards related to pipeline location, Mr. Lee fails to recognize that 49 C.F.R. § 195.210(a) is unenforceable and in my experience PHMSA has therefore never attempted to enforce this rather meaningless regulation.

Mr. Lee also claims that NHG is using modeling "to identify buffer zones where applicable that exceed the Part 195 requirements." Mr. Lee fails to cite any reference for such carbon dioxide buffer zone requirements, because none exist. The word "buffer" is used exclusively in Part 195 in 49 C.F.R. § 195.12, which exclusively regulates "low-stress pipelines in rural areas," which category does not include supercritical or liquid carbon dioxide transmission pipelines. PHMSA regulations do not otherwise define any "zone" for carbon dioxide pipelines related to buffers, hazards to health, or high consequence areas. PHMSA regulations contain no plume modeling or "buffer zone" requirements for carbon dioxide pipelines. Thus, while it is certainly possible to use plume modeling to try to identify buffer zones, federal pipeline safety regulations contain no standards for such effort. Pipeline operators are free to use or not use any dispersion model in any way they wish and to choose a buffer zone (or not), with the result that federal law does not provide any assurance that NHG's dispersion modeling or buffer zone determination meets any quality or safety requirements other than those of the company's own invention.

Mr. Lee also references the "Potential Impact Radius" ("PIR") definition in the natural gas pipeline regulations in 49 C.F.R. § 192.903, which is defined by a formula to try and determine the hazard zone in the event of a pipeline rupture. This formula contains two variables: the pipeline diameter and its maximum allowable operating pressure, plus a natural gas-specific adjustment factor, which is based in theory on the heat of combustion. The formula is a simple way of estimating the area near a natural gas pipeline rupture in which a "potential failure of a [natural gas] pipeline could have significant impact on people or property." This formula was not designed for use in estimating the area in which people or property could be impacted by a carbon dioxide pipeline rupture. Since this formula is based on the theorical heat of combustion, and carbon dioxide does not combust, there is no engineering justification for its use in estimating the potential impact zone for natural gas pipelines. Unlike the blast and thermal radiation generating buoyancy from a natural gas pipeline rupture ignition, carbon dioxide does not combust and rarely if ever radiates from a rupture site in a circle. Thus, I disagree with Mr. Lee that the use of the PIR formula has any utility in estimating the hazard zone in the event of a carbon dioxide pipeline rupture.

Mr. Lee also states that "DNV . . . has facilitated hazard identification and risk analysis, including studying the potential vapor cloud air dispersion for controlled and accidental releases of carbon dioxide from the pipeline," which suggests that NHG may have relied on DNV's PHAST model, in addition to the inappropriate use of the PIR formula, to establish the non-existent Part 195 "buffer zones" that it claims to have used in selecting a pipeline route.

Finally, Mr. Lee states that NHG is developing a NAV-911 system, researching possible odorants, and considering the installation of a fiber optic sensing system, but he does not otherwise describe these in-process and/or possible efforts. Absent greater assurance that NHG will successfully implement such efforts and the uncertainty that such research approaches will be ineffective in the field, the Commission should not rely on such statements.

10. What responses do you have to Mr. Lee's rebuttal testimony related to contaminants?

Answer: Mr. Lee states that the carbon dioxide will be produced by "high purity sources" and that the carbon dioxide will meet "quality specifications" contained in shipper agreements. He also states the NHG will have "measures in place to ensure specifications are met." He does not describe these measures, the equipment used to accomplish these measures, or how they will be enforced. He also fails to state that these "quality specifications" are not required by or regulated by federal pipeline safety standards, and instead are entirely private standards contained in private contracts that are subject to change without notice to PHMSA or any other regulator. Thus, Mr. Lee fails to provide any meaningful discussion of NHG's carbon dioxide quality specifications, the equipment used to control and monitor contaminants, or the contractual enforcement mechanisms available to enforce its private specifications. Mr. Lee also fails to recognize that water and hydrogen sulfide (H_2S) are not the only possible contaminants that could impact pipeline operations and safety. For example, pipeline operations may be impacted by the accidental inclusion of noncompressible gases, such as oxygen and nitrogen. Further, Mr. Lee does not discuss the potential for the NHG pipeline to be used to transport carbon dioxide product streams from additional types of industrial facilities, such as coal and natural gas power plants, chemical plants, cement plants, and other industrial facilities that produce less pure product streams.

11. What are your concerns about the industry references included by Mr. Hereth's Exhibit A and B?

Answer: Many pipeline safety industry practices are wisely not incorporated by reference into federal minimum pipeline safety regulations, either in whole or by part, for various good reasons, lack of proper public feedback in a regulatory pipeline safety process being one. Industry practice revisions are not necessarily improvements in safety. For example, Mr. Hereth's Exhibit A and B referenced above provide much discussion without addressing the specific threat associated with abnormal loading breakaway landside forces that usually result in pipeline rupture. The CRES report issued February 28, 2017 and the later Geosyntec Consultants, Inc. report of August 17, 2020 may be well meaning, but they missed an important concept: that no pipeline can be designed to handle the extreme abnormal loading forces associated with breakaway landslides, especially in steep terrain. Continued pipeline ruptures such as the February 2020 Satartia, MS rupture is a clear recent example of a pipeline's inability to deal with such abnormal loading forces, but also is instructive about the deficiencies in PHMSA's safety standards due in part to their vague requirements, excessive deferral to industry standards, and failure to require use of improved technology. The Satartia pipeline rupture was caused by liquification of soil in the pipeline's right-of-way in very steep terrain during heavy rainfall which is nothing new to that region. Possible breakaway landslide areas in a right-of-way are just not that hard to identify along a pipeline. Yet, according to the PHMSA Consent Agreement, Denbury implemented vague and outdated geohazard identification safety standards so as to fail to identify the geohazard that caused its rupture. Exhibit B pages 3-4, para. 14; page 5, para. 20. To correct Denbury's lax implementation, PHMSA ordered Denbury to "update" its geohazard program. Exhibit A at page 6, para. 30. Likely, this update requires Denbury to perform photogrammetry surveys via drone, which Denbury undertook in reaction to its rupture. PHMSA, Notice of Probably Violation, May 5, 2022, at page 12 (Exhibit C). Photogrammetry is a common, affordable, and long-available technology that uses standard photographs to generate three-dimensional images that can be used to track land threats such as possible breakaway landslides affecting a pipeline's ROW, and their possible movements over time. This technology identified 10 additional geohazard areas along the Denbury pipeline route. Even though this technology has been available for years, the pipeline industry continues to depend on simple visual inspection of pipeline routes by airplane pilots.

12. Does this conclude your testimony?

Answer: Yes.

<u>/s/ Richard B. Kuprewicz</u>

Richard B. Kuprewicz

Exhibit No. 1

Curriculum Vitae.

Richard B. Kuprewicz

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Profile:

As president of Accufacts Inc., I specialize in gas and liquid pipeline investigation, auditing, risk management, siting, construction, design, operation, maintenance, training, SCADA, leak detection, management review, emergency response, and regulatory development and compliance. I have consulted for various local, state and federal agencies, NGOs, the public, and pipeline industry members on pipeline regulation, operation and design, with particular emphasis on operation in unusually sensitive areas of high population density or environmental sensitivity.

Employment:

Accufacts Inc. **1999 – Present**

Pipeline regulatory advisor, incident investigator, and expert witness on all matters related to gas and liquid pipeline siting, design, operation, maintenance, risk analysis, and management.

Position: President
Duties:
> Full business responsibility
> Technical Expert

Alaska Anvil Inc. **1993 – 1999**

Engineering, procurement, and construction (EPC) oversight for various clients on oil production facilities, refining, and transportation pipeline design/operations in Alaska.

Position: Process Team Leader
Duties:
> Led process engineers group
> Review process designs
> Perform hazard analysis
> HAZOP Team leader
> Assure regulatory compliance in pipeline and process safety management

ARCO Transportation Alaska, Inc. **1991 - 1993**

Oversight of Trans Alaska Pipeline System (TAPS) and other Alaska pipeline assets for Arco after the Exxon Valdez event.

Position: Senior Technical Advisor
Duties:
> Access to all Alaska operations with partial Arco ownership
> Review, analysis of major Alaska pipeline projects

ARCO Transportation Co. **1989 – 1991**

Responsible for strategic planning, design, government interface, and construction of new gas pipeline projects, as well as gas pipeline acquisition/conversions.

Position: Manager Gas Pipeline Projects
Duties:
> Project management
> Oil pipeline conversion to gas transmission
> New distribution pipeline installation
> Full turnkey responsibility for new gas transmission pipeline, including FERC filing

Four Corners Pipeline Co. **1985 – 1989**

Managed operations of crude oil and product pipelines/terminals/berths/tank farms operating in western U.S., including regulatory compliance, emergency and spill response, and telecommunications and SCADA organizations supporting operations.

Position: Vice President and Manager of Operations
Duties: > Full operational responsibility
> Major ship berth operations
> New acquisitions
> Several thousand miles of common carrier and private pipelines

Arco Product CQC Kiln **1985**

Operations manager of new plant acquisition, including major cogeneration power generation, with full profit center responsibility.

Position: Plant Manager
Duties: > Team building of new facility that had been failing
> Plant design modifications and troubleshooting
> Setting expense and capital budgets, including key gas supply negotiations
> Modification of steam plant, power generation, and environmental controls

Arco Products Co. **1981 - 1985**

Operated Refined Product Blending, Storage and Handling Tank Farms, as well as Utility and Waste Water Treatment Operations for the third largest refinery on the west coast.

Position: Operations Manager of Process Services
Duties: > Modernize refinery utilities and storage/blending operations
> Develop hydrocarbon product blends, including RFGs
> Modification of steam plants, power generation, and environmental controls
> Coordinate new major cogeneration installation, 400 MW plus

Arco Products Co. **1977 - 1981**

Coordinated short and long-range operational and capital planning, and major expansion for two west coast refineries.

Position: Manager of Refinery Planning and Evaluation
Duties: > Establish monthly refinery volumetric plans
> Develop 5-year refinery long range plans
> Perform economic analysis for refinery enhancements
> Issue authorization for capital/expense major expenditures

Arco Products Co. **1973 - 1977**

Operating Supervisor and Process Engineer for various major refinery complexes.

Position: Operations Supervisor/Process Engineer
Duties: > FCC Complex Supervisor
> Hydrocracker Complex Supervisor
> Process engineer throughout major integrated refinery improving process yield and energy efficiency

Qualifications:

Served for over fifteen years as a member representing the public on the federal Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC), a technical committee established by Congress to advise PHMSA on pipeline safety regulations.

Committee members are appointed by the Secretary of Transportation.

Served seven years, including position as its chairman, on the Washington State Citizens Committee on Pipeline Safety (CCOPS).

Positions are appointed by the governor of the state to advise federal, state, and local governments on regulatory matters related to pipeline safety, routing, construction, operation and maintenance.

Served on Executive subcommittee advising Congress and PHMSA on a report that culminated in new federal rules concerning Distribution Integrity Management Program (DIMP) gas distribution pipeline safety regulations.

As a representative of the public, advised the Office of Pipeline Safety on proposed new liquid and gas transmission pipeline integrity management rulemaking following the pipeline tragedies in Bellingham, Washington (1999) and Carlsbad, New Mexico (2000).

Member of Control Room Management committee assisting PHMSA on development of pipeline safety Control Room Management (CRM) regulations.

Certified and experienced HAZOP Team Leader associated with process safety management and application.

Education:

MBA (1976)	Pepperdine University, Los Angeles, CA
BS Chemical Engineering (1973)	University of California, Davis, CA
BS Chemistry (1973)	University of California, Davis, CA

Publications in the Public Domain:

1. “An Assessment of First Responder Readiness for Pipeline Emergencies in the State of Washington,” prepared for the Office of the State Fire Marshall, by Hanson Engineers Inc., Elway Research Inc., and Accufacts Inc., and dated June 26, 2001.

2. “Preventing Pipeline Failures,” prepared for the State of Washington Joint Legislative Audit and Review Committee (“JLARC”), by Richard B. Kuprewicz, President of Accufacts Inc., dated December 30, 2002.

3. “Pipelines - National Security and the Public’s Right-to-Know,” prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated May 14, 2003.

4. “Preventing Pipeline Releases,” prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated July 22, 2003.

5. “Pipeline Integrity and Direct Assessment, A Layman’s Perspective,” prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated November 18, 2004.

6. “Public Safety and FERC’s LNG Spin, What Citizens Aren’t Being Told,” jointly authored by Richard B. Kuprewicz, President of Accufacts Inc., Clifford A. Goudey, Outreach Coordinator MIT Sea Grant College Program, and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated May 14, 2005.

7. “A Simple Perspective on Excess Flow Valve Effectiveness in Gas Distribution System Service Lines,” prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated July 18, 2005.

8. “Observations on the Application of Smart Pigging on Transmission Pipelines,” prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated September 5, 2005.

9. “The Proposed Corrib Onshore System - An Independent Analysis,” prepared for the Centre for Public Inquiry by Richard B. Kuprewicz, dated October 24, 2005.

10. “Observations on Sakhalin II Transmission Pipelines,” prepared for The Wild Salmon Center by Richard B. Kuprewicz, dated February 24, 2006.

11. “Increasing MAOP on U.S. Gas Transmission Pipelines,” prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2006. This paper was also published in the June 26 and July 1, 2006 issues of the Oil & Gas Journal and in the December 2006 issue of the UK Global Pipeline Monthly magazines.

12. “An Independent Analysis of the Proposed Brunswick Pipeline Routes in Saint John, New Brunswick,” prepared for the Friends of Rockwood Park, by Richard B. Kuprewicz, dated September 16, 2006.

13. “Commentary on the Risk Analysis for the Proposed Emera Brunswick Pipeline Through Saint John, NB,” by Richard B. Kuprewicz, dated October 18, 2006.

14. “General Observations On the Myth of a Best International Pipeline Standard,” prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2007.

15. “Observations on Practical Leak Detection for Transmission Pipelines – An Experienced Perspective,” prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated August 30, 2007.

16. “Recommended Leak Detection Methods for the Keystone Pipeline in the Vicinity of the Fordville Aquifer,” prepared for TransCanada Keystone L.P. by Richard B. Kuprewicz, President of Accufacts Inc., dated September 26, 2007.

17. “Increasing MOP on the Proposed Keystone XL 36-Inch Liquid Transmission Pipeline,” prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated February 6, 2009.

18. “Observations on Unified Command Drift River Fact Sheet No 1: Water Usage Options for the current Mt. Redoubt Volcano threat to the Drift River Oil Terminal,” prepared for Cook Inletkeeper by Richard B. Kuprewicz, dated April 3, 2009.

19. “Observations on the Keystone XL Oil Pipeline DEIS,” prepared for Plains Justice by Richard B. Kuprewicz, dated April 10, 2010.

20. “PADD III & PADD II Refinery Options for Canadian Bitumen Oil and the Keystone XL Pipeline,” prepared for the Natural Resources Defense Council (NRDC), by Richard B. Kuprewicz, dated June 29, 2010.

21. “The State of Natural Gas Pipelines in Fort Worth,” prepared for the Fort Worth League of Neighborhoods by Richard B. Kuprewicz, President of Accufacts Inc., and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated October, 2010.

22. “Accufacts’ Independent Observations on the Chevron No. 2 Crude Oil Pipeline,” prepared for the City of Salt Lake, Utah, by Richard B. Kuprewicz, dated January 30, 2011.

23. “Accufacts’ Independent Analysis of New Proposed School Sites and Risks Associated with a Nearby HVL Pipeline,” prepared for the Sylvania, Ohio School District, by Richard B. Kuprewicz, dated February 9, 2011.

24. “Accufacts’ Report Concerning Issues Related to the 36-inch Natural Gas Pipeline and the Application of Appleview, LLC Premises: 7009 and 7010 River Road, North Bergen, NJ,” prepared for the Galaxy Towers Condominium Association Inc., by Richard B. Kuprewicz, dated February 28, 2011.

25. “Prepared Testimony of Richard B. Kuprewicz Evaluating PG&E’s Pipeline Safety Enhancement Plan,” submitted on behalf of The Utility Reform Network (TURN), by Richard B. Kuprewicz, Accufacts Inc., dated January 31, 2012.

26. “Evaluation of the Valve Automation Component of PG&E’s Safety Enhancement Plan,” extracted from full testimony submitted on behalf of The Utility Reform Network (TURN), by Richard B.Kuprewicz, Accufacts Inc., dated January 31, 2012, Extracted Report issued February 20, 2012.

27. “Accufacts’ Perspective on Enbridge Filing to NEB for Modifications on Line 9 Reversal Phase I Project,” prepared for Equiterre Canada, by Richard B. Kuprewicz, Accufacts Inc., dated April 23, 2012.

28. “Accufacts’ Evaluation of Tennessee Gas Pipeline 300 Line Expansion Projects in PA & NJ,” prepared for the Delaware RiverKeeper Network, by Richard B. Kuprewicz, Accufacts Inc., dated June 27, 2012.

29. “Impact of an ONEOK NGL Pipeline Release in At-Risk Landslide and/or Sinkhole Karst Areas of Crook County, Wyoming,” prepared for landowners, by Richard B. Kuprewicz, Accufacts Inc., and submitted to Crook County Commissioners, dated July 16, 2012.

30. “Impact of Processing Dilbit on the Proposed NPDES Permit for the BP Cherry Point Washington Refinery,” prepared for the Puget Soundkeeper Alliance, by Richard B. Kuprewicz, Accufacts Inc., dated July 31, 2012.

31. “Analysis of SWG’s Proposed Accelerated EVPP and P70VSP Replacement Plans, Public Utilities Commission of Nevada Docket Nos. 12-02019 and 12-04005,” prepared for the State of Nevada Bureau of Consumer Protection, by Richard B. Kuprewicz, Accufacts Inc., dated August 17, 2012.

32. “Accufacts Inc. Most Probable Cause Findings of Three Oil Spills in Nigeria,” prepared for Bohler Advocaten, by Richard B. Kuprewicz, Accufacts Inc., dated September 3, 2012.

33. “Observations on Proposed 12-inch NGL ONEOK Pipeline Route in Crook County Sensitive or Unstable Land Areas,” prepared by Richard B. Kuprewicz, Accufacts Inc., dated September 13, 2012.

34. “Findings from Analysis of CEII Confidential Data Supplied to Accufacts Concerning the Millennium Pipeline Company L.L.C. Minisink Compressor Project Application to FERC, Docket No. CP11-515-000,” prepared by Richard B. Kuprewicz, Accufacts Inc., for Minisink Residents for Environmental Preservation and Safety (MREPS), dated November 25, 2012.

35. “Supplemental Observations from Analysis of CEII Confidential Data Supplied to Accufacts Concerning Tennessee Gas Pipeline’s Northeast Upgrade Project,” prepared by Richard B. Kuprewicz, Accufacts Inc., for Delaware RiverKeeper Network, dated December 19, 2012.

36. “Report on Pipeline Safety for Enbridge’s Line 9B Application to NEB,” prepared by Richard B. Kuprewicz, Accufacts Inc., for Equiterre, dated August 5, 2013.

37. “Accufacts’ Evaluation of Oil Spill Joint Investigation Visit Field Reporting Process for the Niger Delta Region of Nigeria,” prepared by Richard B. Kuprewicz for Amnesty International, September 30, 2013.

38. “Accufacts’ Expert Report on ExxonMobil Pipeline Company Silvertip Pipeline Rupture of July 1, 2011 into the Yellowstone River at the Laurel Crossing,” prepared by Richard B. Kuprewicz, November 25, 2013.

39. “Accufacts Inc. Evaluation of Transco’s 42-inch Skillman Loop submissions to FERC concerning the Princeton Ridge, NJ segment,” prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated June 26, 2014, and submitted to FERC Docket No. CP13-551.

40. Accufacts report “DTI Myersville Compressor Station and Dominion Cove Point Project Interlinks,” prepared by Richard B. Kuprewicz for Earthjustice, dated August 13, 2014, and submitted to FERC Docket No. CP13-113-000.

41. “Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco’s Leidy Southeast Expansion Project,” prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated September 3, 2014, and submitted to FERC Docket No. CP13-551.

42. Accufacts’ “Evaluation of Actual Velocity Critical Issues Related to Transco’s Leidy Expansion Project,” prepared by Richard B. Kuprewicz for Delaware Riverkeeper Network, dated September 8, 2014, and submitted to FERC Docket No. CP13-551.

43. “Accufacts’ Report to Portland Water District on the Portland – Montreal Pipeline,” with Appendix, prepared by Richard B. Kuprewicz for the Portland, ME Water District, dated July 28, 1014.

44. “Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco’s Leidy Southeast Expansion Project,” prepared by Richard B. Kuprewicz and submitted to FERC Docket No. CP13-551.

45. Review of Algonquin Gas Transmission LLC’s Algonquin Incremental Market (“AIM Project”), Impacting the Town of Cortlandt, NY, FERC Docket No. CP14-96-0000, Increasing System Capacity from 2.6 Billion Cubic Feet (Bcf/d) to 2.93 Bcf/d,” prepared by Richard B. Kuprewicz, and dated Nov. 3, 2014.

46. Accufacts’ Key Observations dated January 6, 2015 on Spectra’s Recent Responses to FERC Staff’s Data Request on the Algonquin Gas Transmission Proposal (aka “AIM Project”), FERC Docket No. CP 14-96-000) related to Accufacts’ Nov. 3, 2014 Report and prepared by Richard B. Kuprewicz.

47. Accufacts’ Report on Mariner East Project Affecting West Goshen Township, dated March 6, 2015, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.

48. Accufacts’ Report on Atmos Energy Corporation (“Atmos”) filing on the Proposed System Integrity Projects (“SIP”) to the Mississippi Public Service Commission (“MPSC”) under Docket No. 15-UN-049 (“Docket”), prepared by Richard B. Kuprewicz, dated June 12, 2015.

49. Accufacts’ Report to the Shwx’owhamel First Nations and the Peters Band (”First Nations”) on the Trans Mountain Expansion Project (“TMEP”) filing to the Canadian NEB, prepared by Richard B. Kuprewicz, dated April 24, 2015.

50. Accufacts Report Concerning Review of Siting of Transco New Compressor and Metering Station, and Possible New Jersey Intrastate Transmission Pipeline Within the Township of Chesterfield, NJ (“Township”), to the Township of Chesterfield, NJ, dated February 18, 2016.

51. Accufacts Report, “Accufacts Expert Analysis of Humberplex Developments Inc. v. TransCanada Pipelines Limited and Enbridge Gas Distribution Inc.; Application under Section 112 of the National Energy Board Act, R.S.C. 1985, c. N-7,” dated April 26, 2016, filed with the Canadian Nation Energy Board (NEB).

52. Accufacts Report, “ A Review, Analysis and Comments on Engineering Critical Assessments as proposed in

PHMSA's Proposed Rule on Safety of Gas Transmission and Gathering Pipelines," prepared for Pipeline Safety Trust by Richard B. Kuprewicz, dated May 16, 2016.

53. Accufacts' Report on Atmos Energy Corporation ("Atmos") filing to the Mississippi Public Utilities Staff, "Accufacts Review of Atmos Spending Proposal 2017 – 2021 (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 15, 2016.

54. Accufacts Report, "Accufacts Review of the U.S. Army Corps of Engineers (USACE) Environmental Assessment (EA) for the Dakota Access Pipeline ("DAPL")," prepared for Earthjustice by Richard B. Kuprewicz, dated October 28, 2016.

55. Accufacts' Report on Mariner East 2 Expansion Project Affecting West Goshen Township, dated January 6, 2017, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.

56. Accufacts Review of Puget Sound Energy's Energize Eastside Transmission project along Olympic Pipe Line's two petroleum pipelines crossing the City of Newcastle, for the City of Newcastle, WA, June 20, 2017.

57. Accufacts Review of the Draft Environmental Impact Statement for the Line 3 Pipeline Project Prepared for the Minnesota Department of Commerce, July 9, 2017, filed on behalf of Friends of the Headwaters, to Minnesota State Department of Commerce for Docket Nos. CN-14-916 & PPL-15-137.

58. Testimony of Richard B. Kuprewicz, president of Accufacts Inc., in the matter West Goshen Township and Concerned Citizens of West Goshen Township v. Sunoco Pipelines, L.P. before the Pennsylvania Public Utilities Commission, Docket No. C-2017-2589346, on July 18, 2017, on Behalf of West Goshen Township and Concerned Citizens of West Goshen Township.

59. Direct Testimony of Richard B. Kuprewicz, president of Accufacts Inc., on Behalf of Friends of the Headwaters regarding Enbridge Energy, Limited Partnership proposal to replace and reroute an existing Line 3 to the Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission (MPUC PL-9/CN-14-916 and MPUC PL-9/PPL-15-137), September 11, 2017 and October 23, 2017.

60. Direct Testimony of Richard B. Kuprewicz On Behalf of The District of Columbia Government, before the Public Service Commission of the District of Columbia, in the matter of the merger of AltaGas Ltd. and WGL Holdings, Inc., Formal Case No. 1142, September 29, 2017.

61. Report to Mississippi Public Utilities Staff ("MPUS"), "Accufacts Review on Atmos Energy Corporation's Proposed Capital Budget for Fiscal Year 2018 related to System Integrity Program Spending (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated December 4, 2017.

62. Report to Hugh A. Donaghue, Esquire, Concord Township Solicitor, "Accufacts Comments on Adelphia Project Application to FERC (Docket No. CP18-46-000) as it might impact Concord Township," dated May 30, 2018.

63. Report to Mississippi Public Utilities Staff ("MPUS"), "Accufacts Review on Atmos Energy Corporation's Proposed Capital Budget for Fiscal Year 2019 related to System Integrity Program Spending (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 20, 2018.

64. Report to West Goshen Township Manager, PA, "Accufacts report on the repurposing of an existing 12-inch Sunoco pipeline segment to interconnect with the Mariner East 2 and Mariner East 2X crossing West Goshen Township," dated November 8, 2018.

65. Report to West Whiteland Township Manager, PA, "Accufacts Observations on Possible Pennsylvania State Pipeline Safety Regulations," prepared by Richard B. Kuprewicz, dated March 22, 2019.

66. Accufacts Public Comments on the Proposed Joint Settlement, BI&E v. Sunoco Pipeline L.P. ("SPLP"), Docket No. C-2018-3006534 ("Proposed Settlement"), submitted on August 15, 2019 to the Pennsylvania Public Utility Commission on the behalf of West Goshen Township as an intervener.

67. Report to West Whiteland Township Manager, Ms. Mimi Gleason, "Accufacts Perspective on Two Questions from West Whiteland's Board of Supervisors on Proposed Changes to ME 2 and ME 2X Construction/Operational Activities within West Whiteland," dated September 5, 2019."

68. Report to West Goshen Township Manager, Mr. Casey LaLonde, "Accufacts Report on the episode on the evening of 8-5-19 at the Mariner East Boot Road Pump Station ("Event"), Boot Road, West Goshen Township, PA," dated September 16, 2019.

69. Provided direct testimony before the Arizona Corporation Commission, In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on Fair Value of the Properties of Southwest Gas Corporation Devoted to its Arizona Operations (Docket No. G-01551A-19-0055), testified on behalf of Utilities Division Arizona Corporation Commission, February 19, 2020.

70. Report to West Goshen Township Manager, Mr. Casey LaLonde, "Accufacts Report on the Mariner East 2X Pipeline Affecting West Goshen Township," dated July 23, 2020.

71. Assisted the Commonwealth of Massachusetts, Office of the Attorney General in developing pipeline safety processes to be incorporated into the settlement agreement related to Columbia Gas' sale of Assets to Eversource following the Merrimack Valley, Massachusetts overpressure event of September 13, 2018.

72. Report to Natural Resources Defense Council, Inc., "Accufacts' Observations on the Use of Keystone XL Pipeline Pipe Exhibiting External Coating Deterioration Issues from Long Term Storage Exposure to the Elements," October 1, 2020.

73. Report to Pennsylvania Public Utilities Commission ("PAPUC"), "Accufacts Comments on Proposed Pennsylvania Intrastate Liquid Pipeline Safety Regulations," dated October 29, 2021, prepared for West Whiteland Township Board of Supervisors, West Whiteland Township, PA. Filed to PAPUC public web docket November 5, 2021 by West Whiteland Township under Reference Docket Number L-2019-3010267. Addresses suggested improvements in proposed pipeline safety rules for PA intrastate liquid transmission pipelines.

74. Submitted written testimony of Richard B. Kuprewicz on Behalf of Bay Mills Indian Community to ALJ Dennis Mack, dated December 14, 2021, in the matter of the Application of Enbridge Energy, Limited Partnership for Authority to Replace and Relocate the Segment of Line 5 Crossing the Straits of Mackinac into a Tunnel Beneath the Straits of Mackinac, before the State of Michigan Public Service Commission, U-20763.

75. Public presentation to New York State Indian Point Nuclear Facility Decommissioning Oversight Board on Holtec removal activities in proximity to Enbridge three Natural Gas Transmission Pipelines, March 17, 2022.

76. Report to Pipeline Safety Trust and Bold Alliance, "Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S.," March 23, 2022.

77. Accufacts Inc., Public Presentation For the National Academies of Science Engineering Medicine and The Transportation Research Board, "To Committee on Criteria for Installing Automatic and Remote-Controlled Shutoff Valves on Existing Gas and Hazardous Liquid Transmission Pipelines," 4/27/22.

78. Accufacts Inc, "6/13/22 Webinar to Illinois Emergency Responders, Healthcare Providers, & Local Officials on Responses to CO_2 Transmission Pipeline Releases," 6/13/22.

79. Accufacts Report for Pipeline Safety Trust, "Safety of Hydrogen Transportation by Gas Pipelines," 11/28/22.

Exhibit No. 2

Accufacts Inc.
"Clear Knowledge in the Over Information Age"

Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S.

prepared for the

Pipeline Safety TRUST Credible. Independent. In the public interest.
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by
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March 23, 2022

This report is developed from information clearly in the public domain. The views expressed in this document represent the opinion of the author.

I. Introduction

Accufacts Inc. ("Accufacts") was asked to review and comment on various aspects related to carbon dioxide transmission pipeline safety and federal pipeline safety regulations within the U.S. In recent years there has been considerable discussion about how to address carbon dioxide emissions and global warming through carbon capture, utilization, and sequestration (aka "CCUS" or "CCS"). CCS efforts are intended to help mitigate climate change by capturing carbon dioxide emissions both before and after they are released to the atmosphere and permanently storing such material deep in underground geological structures.

The federal Pipeline Safety Act ("PSA") directs the U.S. Department of Transportation ("DOT") to issue detailed safety standards with regard to the design, construction, operation, and maintenance of CO_2 pipelines.[1, 2] In turn, the DOT has delegated its authority to the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). The PSA's broad mandate is supplemented by detailed federal regulations.[3] The PSA expressly prohibits state and local regulation that interferes with or supplements federal safety standards for interstate pipelines.[4] States meeting certain conditions may supplement federal pipeline safety regulation on their intrastate pipelines as long as such state regulations are not in conflict with federal pipeline safety regulations.

The U.S. has the most mileage of CO_2 transmission pipelines in the world, consisting of approximately 5,150 miles, out of a total 229,287 miles of hazardous liquid transmission pipelines within the U.S.[5] The vast majority, if not all, of these CO_2 existing pipelines are driven by enhanced oil recovery ("EOR") efforts that increase oil production utilizing CO_2 in a supercritical state. Most of this supercritical state CO_2 comes from high pressure higher purity natural underground source domes. It is an excellent solvent for EOR efforts, but the CO_2 must be injected into oil fields as a supercritical fluid.

CCS efforts are driven by an entirely different purpose such that CO_2 used for CCS could be shipped as a gas or a non-supercritical liquid. However, current federal safety regulations regulate only pipelines that transport supercritical CO_2 containing over 90% carbon dioxide molecules, and not pipelines that ship CO_2 in these other lower concentrations or forms, leaving a large regulatory gap. Moreover, even the regulations for supercritical CO_2 pipelines are incomplete or inadequate and place the public at

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[1] 49 U.S.C. § 60101 *et seq*.
[2] 49 U.S.C. § 60102(a) and (i).
[3] 49 C.F.R. Part 195.
[4] 49 U.S.C. § 60104(c) ("A State authority may not adopt or continue in force safety standards for interstate pipeline facilities or interstate pipeline transportation.")
[5] PHMSA reporting database, "Hazardous Liquid Pipeline Miles and Tanks," as of January 31, 2022 for CO_2 commodity at: https://portal.phmsa.dot.gov/analytics/saw.dll?Portalpages&PortalPath=%2Fshared%2FPDM%20Public%20Website%2F_portal%2FPublic%20Reports&Page=Infrastructure.

great risk, especially from the tens of thousands of miles of CO_2 pipelines that may be driven by CCS efforts.[6]

A flurry of multibillion dollar CO_2 pipeline proposals have recently been announced, likely driven by enhanced tax credit incentives provided by Internal Revenue Code § 45Q.[7, 8, 9] Congress provided these enhancements in the Bipartisan Budget Act of 2018, and expanded by the Infrastructure Investment and Jobs Act of 2021 ("Acts of 2018 and 2021").[10] As intended, these laws accelerated CCS and CO_2 pipeline development efforts, because they make such credits more available and valuable to certain generators of CO_2 emissions and require projects to start construction by January 1, 2026.[11] Since most carbon dioxide emitters are likely considerable distances from suitable deep, permanent underground storage sites, it is understandable that CO_2 transmission pipelines may be needed between emitters and these storage sites. If CO_2 pipeline mileage increases as projected, the CO_2 pipeline network could soon rival the existing oil and natural gas pipeline networks in size and complexity. PHMSA would be faced with the greatest and fastest pipeline expansion in the history of the U.S. pipeline industry, and many of these pipelines could threaten the safety of countless individuals and communities.

This report is intended to increase regulator and public awareness of the regulatory challenges posed by this proposed massive expansion in CO_2 pipeline mileage and the unique safety risks of transporting CO_2, especially in its supercritical state. It focuses on a higher-level review of the more technical pipeline safety matters, based on decades of pipeline safety experience including pipeline failure investigations, process engineering and process safety management practice, as well as years of experience in processing and handling many tons of liquid CO_2. This report also makes specific recommendations for improvements in federal pipeline safety regulations needed to fill regulatory gaps and ensure public safety. The proposed CO_2 pipeline boom presents

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[6] For one perspective see what I would call a planning study from Princeton University, "Net-Zero America - Potential Pathways, Infrastructure, and Impacts," Final Report, October 29, 2021, pp. 212 – 219 of 348, indicating a possible need of over 60,000 new miles of CO_2 pipelines by 2050.

[7] Des Moines Register, "What we know about two carbon capture pipelines proposed in Iowa," https://www.desmoinesregister.com/story/money/business/2021/11/28/what-is-carbon-capture-pipeline-proposals-iowa-ag-ethanol-emissions/8717904002/, Nov. 28, 2021.

[8] Agweek, "World's largest carbon capture pipeline aims to connect 31 ethanol plants, cut across Upper Midwest," https://www.agweek.com/business/worlds-largest-carbon-capture-pipeline-aims-to-connect-31-ethanol-plants-cut-across-upper-midwest 12/6/2021.

[9] S&P Global Platts, "Oil producer Denbury plans CO_2 storage hub in southern Alabama." https://www.spglobal.com/platts/en/market-insights/latest-news/energy-transition/020822-oil-producer-denbury-plans-co2-storage-hub-in-southern-alabama, 2/8/2022.

[10] 26 U.S.C. § 45Q.

[11] I.R.C. § 45Q.

PHMSA with an unprecedented challenge; hopefully, this report will help PHMSA rise to this challenge.

II. A brief history of U.S. federal CO_2 pipeline safety regulation

PHMSA and its predecessor agencies, such as the Office of Pipeline Safety, have historically relied on more prescriptive minimum safety approaches. In the past several decades federal minimum pipeline safety regulations have, by the industry's lobbying, shifted to more "performance-based" approaches that rely heavily on certain industry standards or recommended practices, some of which are incorporated by reference into federal pipeline safety regulation.[12] This industry driven shift can result in changes in pipeline safety regulations without proper public input. A prime example may be in the development of CO_2 transmission pipeline safety regulations that historically have been a very small percentage of overall transmission pipeline mileage in the U.S. This country may be facing a significant increase in CO_2 transmission pipeline mileage without appropriate pipeline safety regulatory development or enactment, leaving the country and the public ill prepared for a tsunami of CO_2 pipeline construction.

Congress, in Section 211 of the Pipeline Safety Reauthorization Act of 1988, required that the DOT regulate carbon dioxide transported by pipeline facilities. Part of this concern was driven by a 1986 natural carbon dioxide release event in Lake Nyos, Cameroon spanning many miles with over 1,700 fatalities, underscoring the dangers and possible consequences of CO_2 releases.[13] On July 12, 1991, federal regulators issued a minimalist final rule that mainly added the words "and carbon dioxide" to existing federal minimum pipeline safety regulations developed for hazardous liquid petroleum pipelines (49CFR§195). It opted to not issue standards specifically applicable to supercritical CO_2 pipelines due to the small number of already existing and anticipated CO_2 pipelines. Even though the situation is about to change dramatically, PHMSA has not proposed to review and overhaul its CO_2 pipeline standards, such that these limited regulations are still in effect today.[14] As a result, many of PHMSA's regulations no longer are adequate to protect public safety.

For example, under federal regulations "carbon dioxide" is defined as follows:

> "Carbon Dioxide means a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state."[15]

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[12] 49CFR§195.3 What documents are incorporated by reference partly or wholly in this part?

[13] Federal Register / Vol. 56, No. 113 / Wednesday, June 12, 1991/Rules and Regulations, Research and Special Programs Administration (RSPA), DOT, Docket No. PS-112, Amendment 195-45, RIN 2137-AB72, 49CFR Part 195, "Transportation of Carbon Dioxide by Pipeline," final rule.

[14] *Ibid*, p. 26924.

[15] 49CFR§195.2 Definitions.

The above definition is clearly not appropriate to deal with CCS CO_2 pipelines, nor is that its intent as demonstrated further in this report.

Existing U.S. CO_2 transmission pipelines are primarily located in sparsely developed or more rural locations and, as mentioned previously, involve approximately 5,150 miles moving CO_2 mostly from natural underground sources/domes to EOR projects. The current definition of "carbon dioxide" does not include pipelines that transport supercritical carbon dioxide streams in which CO_2 makes up less than 90 percent of the stream. It also excludes pipelines that transport CO_2 as a non-supercritical liquid or gas. In 1991, there were only a very limited number of pipelines transporting CO_2 in these other forms that apparently didn't justify the need for federal regulation, which is not the case now.

In 2011, Congress, in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Section 15, mandated that the Secretary of Transportation "prescribe minimum safety standards for the transportation of carbon dioxide by pipeline in a gaseous state." As a result, PHMSA issued a report in early 2015 entitled "Background for Regulating the Transportation of Carbon Dioxide in a Gaseous State."[16] Unfortunately, PHMSA never issued new regulations for transportation of CO_2 as a gas.

Thus, PHMSA currently has no regulations applicable to pipelines transporting CO_2 as a gas, liquid, or in a supercritical state at concentrations of CO_2 less than 90 percent. This regulatory gap means that current federal pipeline safety regulations are clearly inadequate because CO_2 pipeline companies could develop CO_2 gas and liquid pipelines that fall outside of this narrow federal rule. The definition of "carbon dioxide" should be modified so that all CO_2 transmission pipelines are regulated by federal law and held to appropriate minimum safety standards. Otherwise, CO_2 pipelines could be designed, constructed, operated, and maintained with no federal or state oversight.

III. CO_2 transmission pipelines can take on three basic forms

CO_2 transmission pipelines can be designed to transport carbon dioxide either as a supercritical state fluid, a liquid (aka in a subcritical or chilled state), or as a gas. Within the industry the term "dense phase" is often used to label CO_2 pipelines operating in either a supercritical state fluid or in a liquid phase as explained below. It is odd that the proposed new CO_2 transmission pipeline applications recently reviewed have not clearly stated in what phase they are designed to operate, their temperature ranges, nor their quality requirements.[17] The key characteristics of supercritical, liquid, and gaseous CO_2 transmission pipelines are summarized below.

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[16] PHMSA report dated February 2015, posted to the 2016 docket under PHMSA-2016-0049-001 at www.regulations.gov.

[17] For example, see Summit Carbon Solutions, "Application to the South Dakota Public Utilities Commission for a Permit for the SCS Carbon Transport LLC (SCS) Pipeline Under the Energy Conversion and Transmission Facility Act – Document Number: SCS-0700-ENV-05-PE-009-A," dated February 7, 2022.

i. **Supercritical state CO_2 transmission pipelines**

Pure CO_2 has a critical temperature of about 88 ºF (33 ºC) and a critical pressure of approximately 1070 psia, or pounds force per square inch absolute (73 atm). At temperatures and pressures above these critical values, CO_2 is not technically a liquid and instead is in a supercritical state as a dense phase "fluid" or vapor with properties between that of a liquid and a gas. This supercritical fluid will not condense to liquid within the pipeline, as long as the temperature remains above the critical temperature, no matter how high the pressure is increased above the critical pressure. If the temperature along a supercritical state pipeline drops below the critical temperature, part of the fluid will condense to liquid with a higher density than the fluid. If the pressure along a supercritical state pipeline drops below 1070 psia, part of the CO_2 will convert to a gas/liquid mixture depending on the temperature.

The primary reason that the existing 5,000 or so miles of CO_2 pipelines transport CO_2 in a supercritical state is because CO_2 in this state is an excellent solvent having no liquid surface tension. It readily dissolves oil trapped in porous rock. In contrast, CO_2 destined for sequestration could be transported as a gas or liquid, because sequestration does not, as a practical matter, need the CO_2 to be in a supercritical state, and federal law does not require transportation in a supercritical state. In fact, a clever pipeline operator could employ loopholes to avoid federal pipeline safety oversight by PHMSA. Clearly the sources and needs of CO_2 for EOR are not the same as those for the CCS objective, which is to remove CO_2 from the atmosphere.

CO_2 supercritical fluid transmission pipeline operating pressures usually range from 1,200 to 2,200 pounds force per square inch gauge, or psig. The higher pressure is set based on the maximum operating pressure ("MOP") usually related to a pipe specification limit.[18] There are a minor number of CO_2 supercritical state pipelines that have been designed to operate at much higher MOPs (*e.g.*, 3200 psig). Moving CO_2 as a dense phase supercritical state fluid permits the use of pumps along a pipeline instead of compressors that would be needed to move the material if it were a gas. For pipelines, the use of pumps to move higher density fluids requires smaller, less complex, equipment that is more efficient in moving mass along a pipeline than compressors (*i.e.*, pumps are cheaper to build, install, maintain, and operate than compressors). In addition, the higher MOPs of supercritical state CO_2 pipelines permit them to utilize smaller diameter pipe, albeit much stronger pipe, to move the same tonnage of CO_2 as compared to shipment as a gas. In contrast, gas pipelines require larger diameter pipe to move the same tonnage, because they must usually operate at pressures lower than the supercritical pressure (1070 psig), otherwise some of the CO_2 could convert to a liquid

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[18] MOP stands for maximum operating pressure for liquid pipelines and is defined in federal minimum pipeline safety regulations that provide conditions for "normal" operation of pipelines. Pipelines are permitted to exceed MOP within certain limits, under certain situations.

(depending on the temperature along the pipeline) and such liquid slugs would severely damage/destroy the compressors used in gas pipelines.

While there are many cost/efficiency advantages to moving CO_2 in a supercritical state, there is one well known threat associated with supercritical state operation. A CO_2 pipeline operating in a supercritical state can be more prone to pipe running ductile fractures than hazardous liquids or natural gas pipelines. Running ductile fractures are unusual and particularly dangerous fractures that can "unzip" a CO_2 transmission pipeline for extended distances exposing great lengths of the buried pipeline. These extreme rupture forces throw tons of pipe, pipe shrapnel, and ground covering, generating large craters along the failed pipeline. It is well known that CO_2 pipelines operating in dense phase, either supercritical or as a liquid, are particularly susceptible to such running ductile fractures. Although current federal regulations recognize this risk, they do not contain any detailed requirements that specifically identify how to address fracture propagation threats. Though there are various approaches well known in the industry (*i.e.*, pipe steel fracture toughness parameters, usually for new pipe, and/or mechanical arrestors such as valves, thicker/tougher pipe transitions) such approaches should be specifically mentioned in safety regulation.[19] To address this risk, PHMSA should revise federal regulations, especially for supercritical CO_2 pipelines, to specifically mitigate the effects of these fracture propagation forces. The current regulations do not adequately address these CO_2 fracture risks.

ii. Liquid CO_2 transmission pipelines

Subcooled or subcritical state means to transport CO_2 as a liquid that usually requires chilling and/or cooling of the stream slightly below ambient temperatures to assure the pipeline is operated in one phase, that of a liquid. For new pipelines this also may require the use of pipeline insulation, though not always, to reduce temperature increase of the CO_2 along the pipeline, assuring it stays as a liquid. It is important that cooling stay well above the pipe carbon steel brittle transition temperature of approximately - 20 ºF to avoid the threat of catastrophic pipeline rupture. Despite these obstacles, transporting CO_2 as a liquid, basically at its highest density, which is typically about double the density of CO_2 fluid in its supercritical state, allows the pipeline transportation of more tonnage of carbon dioxide with even smaller diameter pipe than a supercritical state operation, as well as lower MOPs. Because the liquid phase operation also has a lower viscosity, a liquid CO_2 pipeline system for a given length can utilize a fewer number of pump stations that can have major advantages over supercritical state or gas pipeline approaches needed to move similar tonnage of CO_2. For CCS objectives, liquid phase CO_2 transmission pipelines additional efficiency over their supercritical state or gas counterparts may justify the additional cooling infrastructure along such

[19] 49 CFR§195.111 Fracture propagation. The regulation states in full: "A carbon dioxide pipeline system must be designed to mitigate the effects of fracture propagation." Thus, pipeline safety law contains no detailed standards to prevent running ductile fractures leaving much room for misinterpretation.

pipelines. It is worth emphasizing that PHMSA chose to not issue regulations for CO_2 pipelines designed to operate as a liquid, so such pipelines are currently unregulated.

iii. CO_2 gas transmission pipelines

New pipelines designed to move CO_2 as a gas in a transmission pipeline is not likely, given that the system must be operated at lower pressures. For a CO_2 gas pipeline, the MAOP must not exceed approximately 1,000 psig at normal operating temperatures, so that the CO_2 is maintained as a gas and does not convert to a liquid as this could be disastrous for the pipeline's compressors.[20] For an equivalent daily CO_2 tonnage pipeline capacity, the requirement to keep design pressure lower drives such new gas pipeline approaches to much higher pipe diameters than their liquid or supercritical state pipeline alternatives. However, specific situations may exist where existing liquid or larger diameter natural gas pipelines could be "repurposed" into primarily CO_2 gas service.[21] Such change in service, will most likely be highly limited in its pipeline mileage and, in my opinion, should exceed the requirements identified in ADB-2014-04, addressing repurposing of natural gas pipelines or liquid pipelines. For example, an Advisory Bulletin, or ADB, does not carry the force of promulgated pipeline safety regulation but is issued to more quickly alert pipeline operators of PHMSA concerns on certain issues. ADB-2014-04 does not address, nor was it intended to address, the specific additional challenges associated with unique fracture propagation risks associated with CO_2 transmission pipelines as previous discussed. While there are unique situations where nonoperating or underutilized pipelines exist, there are several factors that can make repurposing of such pipelines to CO_2 gas service economically attractive, given the billions of dollars in tax credit incentives associated with CCS under the Acts of 2018 and 2021, and the associated start construction deadline. The critical deadlines to meet tax credit triggers could make timing of such conversions more favorable than routing and construction of new CO_2 pipelines for CCS. Such pipeline conversions would be at much greater risk of failure from CO_2 service than conventional hydrocarbon or new construction CO_2 pipelines, given the unique and increased potential for CO_2 pipeline ruptures from various risks associated with CO_2 operation. Only time will tell, given the economic temptations and timing thresholds, whether such repurposing of an existing transmission pipeline to CO_2 service will prove practical for CCS utilization.

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[20] MAOP stands for maximum allowable operating pressure, which is the standard for gas pipelines and is defined in federal minimum pipeline safety regulations that provide conditions for "normal" operation of pipelines. Pipelines are permitted to exceed MAOP within certain limits, under certain situations.

[21] See DOT PHMSA, Advisory Bulletin, ADB-2014—04, "Pipeline Safety: Guidance for Pipeline Flow Reversals, Product Changes and Conversion to Service," Docket No. PHMSA–2014–0040, Sept 12, 2014.

IV. CO_2 transmission pipelines pose different risks than traditional hydrocarbon transmission pipelines

Carbon dioxide gas is odorless, colorless, doesn't burn, is heavier than air, and is an asphyxiant and intoxicant, making CO_2 pipeline releases harder to observe and avoid especially as a released plume spreads and migrates well off the pipeline right-of-way. CO_2 properties differ from those for materials moved in hazardous hydrocarbon liquid or natural gas transmission pipelines. CO_2 pipeline releases significantly increase the possible "affected" or "potential impact" area identified in federal regulations addressing hydrocarbon transmission pipelines upon pipeline rupture release, and CO_2 pipeline ruptures have a greater potential to endanger the public. Current federal pipeline safety regulations do not incorporate these important CO_2 differences to assure safety to the public. Federal pipeline safety regulatory changes are warranted if CO_2 pipeline mileage is to be increased dramatically in the U.S., especially under CCS. CO_2 transmission pipelines have many unique failure dynamics such that a rupture may impact significantly greater geographic areas than hydrocarbon pipelines. In particular, a combination of CO_2 phase/temperature changes may result in explosive pipe release forces as the CO_2 converts to gas. Moreover, CO_2's lack of odor and invisibility means that it may not be possible for citizens and first responders to determine if they are in a hazard area before they are harmed, unless they have access to a CO_2 detection meter. It is important that anyone using such CO_2 detection meters assure that such equipment has been properly calibrated/maintained and users properly trained in their use and limitations. Once a CO_2 pipeline release has been warmed by the surrounding environment, it travels unseen influenced by gravity, terrain, and the wind, preferentially settling in low spots, displacing air and providing no warning to persons and animals caught in the invisible release plume. Hydrocarbon pipeline releases that haven't ignited, can usually be detected by unusual smell or sight, which makes CO_2 pipeline releases different and harder to detect by emergency responders or the public.

During a CO_2 pipeline rupture release, multiple phase changes can result not only in the significant lowering of temperature near the pipe failure site, but also the likelihood of solid CO_2 formation (i.e., dry ice). Dry ice particles within the fluid can contribute to fogging in the air and ground around the pipeline release, as well as the formation of dry ice within the pipeline upstream/downstream of the pipe failure site that can impact the rate of release out of a pipe failure. Such dry ice blockage can result in temporary restriction/blockage within the pipe, affecting release rate, especially for smaller diameter transmission pipelines experiencing rupture fracture.

In CO_2 pipelines experiencing smaller, slower rate releases, often called leaks, such as through minor holes or cracks, the resulting lower rate CO_2 rich clouds may disperse/dissipate after a short time. In much larger rate releases, such as pipeline rupture fractures caused from various anomalies or pipeline threats, the resulting release of cold gas and dry ice solid mixtures can be quite dangerous (see video of

DNV rupture failure test of an CO_2 8-inch diameter pipeline).[22] The CO_2 released from a pipeline will be heavier than air, and the high-rate release from a pipe rupture will form cold dense gas fog clouds comprised of dry ice particles and visible water vapor as the humidity in the air condenses from the extreme cooling. Such high-rate releases can produce areas of low visibility from "fog," both from dry ice particles and water condensation. The CO_2 pipeline rupture fog becomes transparent when eventually warmed by the surrounding environment. Upon warming, the CO_2 plume can flow considerable distances from the pipeline unobserved, traveling over terrain, displacing oxygen while settling or filling in low spots. Oxygen displacement can starve gasoline or diesel powered equipment, such as first responder and private vehicles, causing such equipment to malfunction or even shut off, and cause pilot lights on furnaces, stoves, and natural gas fireplaces to go out. Oxygen displacement by CO_2 gas can cause asphyxiation of humans and animals, that can lead to death. Further, CO_2 gas can cause disorientation, confusion, and unconsciousness, which can be dangerous for persons caught in the plume, especially those who are driving, using power equipment, or exposed to cold weather. Cooling of a CO_2 release can also impact the rate of release and exacerbate pipe fracture propagation during rupture. Clearly, dispersion modeling for analyzing potential impact areas for CO_2 pipeline failures and their related released gas plumes, must consider the propensity of heavier than air CO_2 gas to displace oxygen and to follow the terrain as terrain factors can play a critical role in evaluating a potential area and receptors that could be affected by a CO_2 pipeline release. It is vitally important to not underestimate the potential distance that a CO_2 pipeline rupture plume can reach and affect, especially in nonlevel terrain. Additional safety margins should be employed in populated areas when using dispersion modeling results for CO_2 pipeline releases.

Before the U.S. is blanketed with a major increase in CO_2 transmission pipeline mileage driven by CCS efforts, substantial changes need to be implemented in federal pipeline safety regulations specifically addressing the unique dangers of CO_2 in transmission pipelines in any phase. CO_2 is not flammable. It doesn't burn or explode/detonate from ignition, so heat radiation is not an issue of concern as in conventional hydrocarbon pipelines. CO_2 can, however, generate similar overpressure "blast" forces upon pipeline rupture (from the high-rate releases associated with pipeline fracture failure, see previous referenced 8-inch CO_2 pipeline rupture test). CO_2 pipeline rupture and resulting rapid "blast like" expansion forces dissipate quickly with distance from the pipeline but can easily extend well beyond the pipeline right of way. The areas potentially impacted by ruptures of oil and gas transmission pipelines are well defined in current federal regulations, which estimate how far liquid hydrocarbon will spread and the blast or burn radius resulting from a natural gas pipeline rupture. The danger zone for human life for hazardous hydrocarbon liquid and natural gas pipeline releases is generally measured in feet, albeit many thousands of feet for larger diameter higher pressure pipelines.

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[22] Video of 2013 DNV Spadeadam Research and Testing test experiment of dense phase CO_2 8-inch buried pipeline rupture,
https://www.dnv.com/oilgas/laboratories-test-sites/dense-phase-spadeadam-video.html.

In contrast, a CO_2 pipeline's impact area may be measured in miles, not feet. This is likely because:

- CO_2 pipeline ruptures can release many tons of CO_2,
- the compressed CO_2 will expand into gas phase upon pipeline rupture and fill a much larger volume that it did inside the pipe, and
- the CO_2 may not disperse quickly because it is heavier than air, meaning that it will tend to flow toward and settle in low lying areas including ravines, valleys, and basements.

Current federal pipeline safety regulations do not provide any methodology for assessing the hazard zone for CO_2 pipelines or require that pipeline operators adequately address this risk.

V. Impact of impurities on CO_2 pipelines

The amounts and types of impurities in a CO_2 stream can have an impact on pipeline design and approaches. Current CO_2 pipeline regulations, which only address CO_2 pipelines greater than 90% CO_2 concentration compressed to a supercritical state, make no mention as to the level of non-CO_2 impurities such as H_2S, which can be lethal even in very low parts per million concentrations. Also, impurities can affect the range of safe operating pressures. Most of the natural sources of CO_2 for existing pipelines contain CO_2 well above 90%, but this may not be the case for all CO_2 streams captured from industrial facilities. Federal regulation should be modified to adequately regulate CO_2 pipelines used for CCS, and subsequent transportation by transmission pipeline, especially because CCS pipelines may operate differently from those used for EOR. Such federal regulatory improvements should focus on public safety for all forms/phases of CO_2 transmission pipelines. There are some very pure sources of CO_2 emitters, such as ethanol plants and some hydrogen reformers, that emit very high concentrations of CO_2 to the atmosphere that require very little, if any, impurity treatment to prepare for pipeline transportation for CCS.[23] Unlike most of the currently existing CO_2 pipelines whose sources are underground natural gas domes or reservoirs, CSS pipelines may be supplied from various sources where the concentration of CO_2 is quite low and needing concentration, processing, and treatment for contaminant removal before it may be safely transported by pipeline.

There appears to be no transmission pipeline in the U.S. that transports pure CO_2, although there are pipelines that move very high concentrations of CO_2, well above 90%, containing only small levels, of impurities, especially those from natural sources of CO_2. Such CO_2 rich sources can still contain impurities, such as hydrogen sulfide, methane, carbon monoxide, oxygen, nitrogen oxide, sulphur oxide, hydrogen, or

[23] My experience is that purity from such CO_2 specialized emitters can exceed 99.9 % with trace impurities.

water.[24] The types and amounts of impurities in a CO_2 rich pipeline is largely driven by the source of CO_2, and proper operation of associated upstream treatment equipment to assure the material meets pipeline quality specifications, which is not always assured. At relatively low levels of impurities, such as at trace or levels in the lower parts per million, the specific effects of the impurities on the overall stream critical thermodynamic properties (such as enthalpy, entropy, density, and viscosity), are not significantly impacted. However, higher impurity concentrations, such as impurities measured in percentage concentrations should not be ignored as they can impact the critical pressure, but more importantly the critical temperature, such that even a percent or two change in impurity levels can result in unexpected phase change from dense phase fluid to other phases. Such phase changes may impact the system hydraulics, and to some extent the rupture release dynamics should the pipeline fail.

Two impurities that might be possible in CO_2 pipelines merit mention given their unique dangers to pipelines and the public: water and H_2S. CO_2 pipelines are usually made from carbon steel and require special maximum water quality specifications typically measured in the part per million, or its equivalent, that prevents the possibility of free water forming anywhere in the pipeline system. The presence of free water in a CO_2 stream permits the formation of carbonic acid in the pipeline, an acid that has a ferocious appetite for carbon steel. Given the rapidity and unpredictability at which carbonic acid can attack pipelines, prudent CO_2 pipeline operators have voluntarily established maximum water quality limitations for their input streams. Given the risks associated with carbonic acid attack, PHMSA should not leave this critical factor to company discretion, but instead should adopt federal regulations that specify a maximum water quality limitation for CO_2 pipelines.

Hydrogen sulfide, or H_2S, is mentioned here because of a curious item identified in an article related to a supercritical state CO_2 pipeline rupture failure in Mississippi in early 2020.[25] The observations noted in the article by responders of a "green cloud" from the pipeline release, is a possible indication of high levels of H_2S. Further investigation indicates that the source of the CO_2 (Jackson Dome) has levels of H_2S at 5 percent, or 50,000 ppm. In contrast, the Centers for Disease Control and Prevention states that a level of 300 parts per million is "immediately dangerous to life or health."[26] While the H_2S level that transitions into "sour" gas is not defined in federal

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[24] For example, see Suoton P. Peletire, Nejat Rahmanian, Iqbal M. Mujtaba, "Effects of Impurities on CO_2 Pipeline Performance, Chemical Engineering Transactions," Vol. 57, 2017.

[25] Dan Zegart Huffpost article, "The Gassing of Satartia," August 26, 2021 at https://www.huffpost.com/entry/gassing-satartia-mississippi-co2-pipeline_n_60ddea9fe4b0ddef8b0ddc8f,

[26] https://www.cdc.gov/niosh/idlh/7783064.html. It is my understanding that while a few states have attempted to impose H_2S limits on intrastate pipelines, there is no such federal pipeline safety regulation limiting H_2S on transmission pipelines, even though there are OSHA H_2S limits on workplace workers, much lower than 300 ppm.

pipeline safety regulations, serious questions need to be raised about this specific CO_2 pipeline operation.

For CCS generated CO_2, from fuel combustion emission, an expected source for CCS, H_2S is not a likely contaminant of the stream with trace levels of H_2S in the less than 1 ppm to be expected. Treatment for the removal of water and water quality enforcement control limitations, however, are critical for CCS pipelines transporting CO_2 from combustion sources. Yet, current federal pipeline safety regulations also do not require that this risk be addressed.

VI. Areas needing additional federal pipeline safety focus for CO_2 pipelines

Based on my experiences, the following are my preliminary observations on specific areas where CO_2 pipeline safety regulation improvement efforts should focus.

1. **PHMSA should update the definition of carbon dioxide in current regulation.**
   The current "carbon dioxide" definition incorporated into pipeline safety regulation is driven by EOR and does not or may not apply to all CO_2 pipelines that may be developed for CCS projects. Federal regulations need to be modified to assure that federal standards apply to all CO_2 transmission pipelines that transport CO_2 for CCS projects, including all supercritical, gas, and liquid CO_2 transmission pipelines.

2. **PHMSA needs to identify in regulation the potential impact areas for CO_2 pipeline ruptures.**
   The unique, and potentially very large impact areas for CO_2 pipeline ruptures need to be developed, defined, and promulgated into pipeline regulations. As mentioned previously, these areas are most likely to be measured in miles, not feet.

3. **Specific CO_2 pipeline federal regulations should not be based solely on industry Recommended Practices.**
   Changes in the CO_2 pipeline safety regulation are needed and should be prescribed to avoid misinterpretation or misuse. Recent efforts by many in the industry to rely on more performance-based standards, even those incorporated by reference, have proven ineffective and disastrous. Such industry efforts also remove an important party to pipeline safety regulatory development, the public. Ironically, it is the public that has the most to lose from inadequate pipeline safety regulation if such referenced citations are not clear, relevant, effective, and cannot be enforced in assuring pipeline safety.

4. **PHMSA should specifically identify how to incorporate fracture propagation protection on CO_2 transmission pipelines.**
   Given the differential propensity for CO_2 pipelines to propagate fractures along the pipeline upon rupture, regulations should specifically list pipeline design methods to arrest CO_2 fracture propagation.

5. **PHMSA should mandate the use of odorant injection into CO_2 transmission pipelines.**
   Given the inability to detect or observe a CO_2 pipeline release, it is time to require the use of odorant injection in such pipelines, especially those pipelines that are not in unpopulated areas, to assist the public in identifying dangerous releases.

6. **PHMSA should require CO_2 pipeline operators to update their required procedural manuals related to coordination with local emergency response agencies for CO_2 pipeline ruptures.**
   The major differences and uniqueness of CO_2 pipeline releases compared to hydrocarbon pipelines require that pipeline operators improve the sections of their federally mandated operation, maintenance, and emergencies procedural manuals for emergency response to CO_2 pipeline ruptures.[27] In particular, operators must be required to periodically and fully inform, train, and equip key local officials and emergency responders with regard to special response actions unique to CO_2 pipeline releases. Moreover, upon a rupture, pipeline operators must inform state and local emergency personnel so that they can quickly and adequately protect impacted citizens and themselves.

7. **PHMSA should establish regulations setting specific maximum contaminant impurities for CO_2 pipelines.**
   Given the various sources and the unique risk associated with the introduction of water into a CO_2 pipeline, PHMSA should prescribe the maximum concentration of water allowed in them. This requirement goes well beyond a quality specification given the ability of water to rapidly cause CO_2 pipeline failures in unpredictable ways. Given the wide range of impurity sources for CO_2 streams for CCS, PHMSA should review a full range of limits for all common impurities and consider establishing maximum levels for all impurities that pose a safety risk in federal pipeline safety regulations.

8. **PHMSA should strengthen federal regulations for conversion of existing pipelines to CO_2 pipeline service.**
   It is not clear whether the public interest is best served by CO_2 shipment in existing transmission pipelines converted to CO_2 service. Further, the general conditions of PHMSA's advisory bulletin are not adequate for conversion to CO_2 pipelines. PHMSA should fully investigate the risks of such conversions and issue regulations appropriate to the serious risks that could result from repurposing a pipeline for CO_2 service.

VII. Conclusions

Current federal minimum pipeline safety regulations focus on higher concentration CO_2 pipelines transporting CO_2 in a supercritical state for use in oil production. Such

[27] 49CFR§195.402 and 49CFR§192.605 Procedural manual for operations, maintenance, and emergencies.

regulations are incomplete or in conflict with the intent of CCS, to reduce CO_2 content in the atmosphere to address global warming. Federal pipeline safety regulation concerning CO_2 pipelines need specific changes to address the likely expansion of CO_2 transmission pipeline mileage expected by CCS efforts enhanced by the Acts of 2018 and 2021.

Certain manufacturing processes, such as ethanol and some hydrogen reforming refinery units, produce CO_2 emission that are very pure CO_2, with only trace amounts of contaminants, that are higher priority choices for CCS and associated pipelines, most likely new liquid transmission pipelines, especially under the immense tax credits associated with the Acts of 2018 and 2021. Current federal pipeline safety regulations, however, are not adequate to deal with the additional pipeline risks associated with the expected significant increase in associated CO_2 transmission pipelines under CCS.

The country is ill prepared for the increase of CO_2 pipeline mileage being driven by federal CCS policy. Federal pipeline safety regulations need to be quickly changed to rise to this new challenge, and to assure that the public has confidence in the federal pipeline safety regulations.[28]

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[28] Disclosure: The author prepared this report for the Pipeline Safety Trust but retained full editorial control. The author received compensation from the Pipeline Safety Trust and the Bold Alliance for the preparation of this report.

South Dakota Public Utilities Commission Information Guide to Siting Pipelines

This guide is intended to offer a simple overview of the Public Utilities Commission's process in making a decision to approve or deny the construction of pipeline facilities specific to South Dakota Codified Laws Chapter 49-41B (www.sdlegislature.gov/Statutes/Codified_Laws) and South Dakota Administrative Rules Chapter 20:10:22 (www.sdlegislature.gov/Rules/RulesList). This guide is informational and does not address all situations, variations and exceptions in the pipeline siting process and proceedings of the PUC.

PUC Authority

The South Dakota Legislature gave the PUC authority to issue permits for certain pipelines. South Dakota pipelines within the commission's siting jurisdiction include those designed to transport coal, gas, liquid hydrocarbons, liquid hydrocarbon products, or carbon dioxide, for example. In considering applications, the commission's primary duty is to ensure the location, construction and operation of the pipeline will produce minimal adverse effects on the environment and the citizens. The commission determines these factors based on definitions, standards and references specified in South Dakota Codified Laws and Administrative Rules. In pipeline siting cases, the commission has one year from the date of application to make a decision.

> The commission strives to issue a reasoned decision and conditions, where appropriate, that uphold the law and discourage a potentially expensive and lengthy appeal process.

In rendering its decision, the commission may grant the permit, deny the permit, or grant the permit with terms, conditions or modifications of the construction, operation or maintenance as the commission finds appropriate and legally within its jurisdiction. The commission does not have authority to change the route or location of a project. The decision of the commission can be appealed to the circuit court and, ultimately, to the South Dakota Supreme Court.

The PUC is not involved in the easement acquisition process that occurs between applicants and landowners. Likewise, the PUC does not have a role in the eminent domain process, which is handled in the circuit court system. Landowners with concerns about these issues should seek advice from their personal attorney.

Applicant Responsibility

The applicant that seeks the PUC's approval must show its proposed project:

- will comply with all applicable laws and rules;
- will not pose a threat of serious injury to the environment nor to the social or economic condition of inhabitants or expected inhabitants in the siting area;
- will not substantially impair the health, safety or welfare of the inhabitants; and
- will not unduly interfere with the orderly development of the region with due consideration having been given to the views of the governing bodies of affected local units of government.

PUC Staff Role

PUC staff members assigned to work on a pipeline siting case will typically include one attorney and multiple analysts. Staff attorneys have educational and practical experience in administrative law, trial procedure and business management principles. Staff analysts have expertise in engineering, research and economics. Some of the work the staff does involves reviewing data and evidence submitted by the applicant and intervenors, requesting and analyzing opinions from experts, and questioning the parties. The staff considers this information relative to state laws and rules and presents recommendations to the Public Utilities Commissioners.

Public Involvement

South Dakotans have a variety of ways to stay informed and involved. Read more on back.

South Dakota Public Utilities Commission
500 E. Capitol Ave., Pierre, SD 57501
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09/2022

Review the electronic docket. A docket is the continually updated collection of documents filed with the commission for a particular case. Dockets are accessible under the Commission Actions tab on the PUC website, www.puc.sd.gov. Dockets are labeled to correspond with their type and filing date. For example, the Navigator Heartland Greenway Carbon Dioxide Pipeline docket is HP22-002; HP for hydrocarbon and carbon dioxide pipeline, 22 for the year 2022 and 002 to indicate it was the second hydrocarbon and carbon dioxide pipeline docket filed with the commission in 2022.

Attend a public input meeting. The PUC will hold a public input meeting or meetings on a pipeline siting case, with 30 days notice, as physically close as practical to the proposed route. At the meeting, the applicant describes its project and the public may ask questions and offer comment. Commissioners and staff attend this public meeting.

Submit comments. Members of the public are encouraged to submit written comments about an active siting case to the PUC. These ***informal*** public comments are reviewed and considered by the PUC commissioners and staff. Comments should include the docket number or siting project name, commenter's full name, mailing address, e-mail address and phone number. These comments should be emailed to puc@state.sd.us or mailed or hand-delivered to PUC, 500 E. Capitol Ave., Pierre, SD 57501. Comments are posted in the "Comments" section of the docket within a reasonable time after having been received. The commenter's name, city and state will be posted along with their comment. Comments received from businesses, organizations or other commercial entities (on letterhead, for example) will include the full contact information for such.

Please follow these guidelines when submitting written comments to the PUC:

- For comments sent by email, the maximum file size is 10 MB. If you have questions, please contact South Dakota PUC staff at 605-773-3201 (Monday – Friday, 8 a.m. – 5 p.m. Central Time).
- For comments sent by U.S. mail or hand delivered, no more than twenty (20) 8.5" x 11" pages, including attachments and support materials, should be submitted with a comment. Sheets with printing on both sides are counted as two pages.
- A reference document, article or other attachment not written by the person commenting should clearly identify the source of the content. The inclusion of any copyrighted material without accompanying proof of the commenter's explicit right to redistribute that material will result in the material being rejected.
- In instances where individual comments are deemed to be a duplicate or near duplicate copies of a mass message campaign, the PUC will post only a representative sample and list the name, city and state of the commenter.
- Comments containing threatening language or profanity will be rejected.
- Multimedia submissions such as audio and video files will not be accepted as written comments.
- Electronic links will not be accepted.

Become an intervenor. Individuals who wish to be formal parties in a siting case may apply to the commission for intervenor status. Intervention deadline is clearly indicated within the docket. Intervention is appropriate for people who intend to actively participate in the case through legal motions, discovery (requests for facts or documents), the written preparation and presentation of actual evidence, and in-person participation in a formal hearing. Intervenors are legally obligated to respond to discovery from other parties and to submit to cross-examination at a formal hearing. Individuals seeking only to follow the progress of a siting case or to offer comments for the PUC's consideration need not become intervenors.

Communicate on record. Verbal communication between a commissioner and a person with an interest in a matter before the commission that does not occur in a public forum or as part of the official record should be avoided. Those who communicate in writing with a commissioner about an open or imminent docket matter should understand that their comments will become part of the official record and subject to review by all parties and the public. Likewise, comments made at a PUC public proceeding or submitted to the commission relative to a docket matter become part of the record, open to review by all parties and the public. Because commissioners have a decision-making role in docket matters, any discussion with a commissioner about an open or imminent docket must take place in an open forum, such as a public meeting, with notice given to all parties.