COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Application of Duke Energy Kentucky, Inc., for a Certificate of Public Convenience and Necessity Authorizing the Construction of a Gas Pipeline from Erlanger, Kentucky to Hebron, Kentucky	)))))	Case No. 2019-00388

PETITION OF DUKE ENERGY KENTUCKY, INC. FOR CONFIDENTIAL TREATMENT OF INFORMATION CONTAINED IN ITS RESPONSES TO STAFF'S SECOND SET OF DATA REQUESTS

Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company), pursuant to 807 KAR 5:001, Section 13, respectfully requests the Commission to classify and protect certain information provided by Duke Energy Kentucky in its Responses to Commission Staff's (Staff) Second Request for Information issued on January 30, 2020. Specifically, the Company requests confidential treatment for the responses to Staff's Information Request Nos. 1, 3, and 4 (Confidential Information). The information that Duke Energy Kentucky seeks confidential treatment on generally includes the name of a specific customer and its load information.

In support of this Petition, Duke Energy Kentucky states:

1. The Kentucky Open Records Act exempts from disclosure certain critical infrastructure information per KRS 61.878(1)(m). To qualify for this exemption and, therefore, maintain the confidentiality of the information, a party must establish that disclosure of the record would expose a vulnerability in providing the location of public

utility critical systems. Public disclosure of the information identified herein would, in fact, prompt such a result for the reasons set forth below.

2. The Confidential Information submitted and for which the Company is seeking confidential protection is customer specific account and load information. This information details how the customer operates and uses natural gas that would give that customer's competitors a distinct advantage. Moreover, the disclosure of specific load information could have a chilling effect on the Company's ability to negotiate pricing in the future for similar services if this information were publicly available to the customer's own competitors.

3. The Confidential Information is distributed within Duke Energy Kentucky, only to those who must have access for business reasons and is generally recognized as confidential and proprietary in the energy industry.

4. The Confidential Information for which Duke Energy Kentucky is seeking confidential treatment is not known outside of Duke Energy Corporation.

5. Duke Energy Kentucky does not object to limited disclosure of the Confidential Information described herein, pursuant to an acceptable protective agreement, with the Attorney General or other intervenors with a legitimate interest in reviewing the same for the purpose of participating in this case.

6. This information was, and remains, integral to Duke Energy Kentucky's effective execution of business decisions and safety of its systems. And such information is generally regarded as confidential or proprietary. Indeed, as the Kentucky Supreme Court has found, "information concerning the inner workings of a corporation is 'generally

accepted as confidential or proprietary.'" *Hoy v. Kentucky Industrial Revitalization Authority*, 904 S.W.2d 766, 768 (Ky. 1995).

7. In accordance with the provisions of 807 KAR 5:001, Section 13(3), the Company is filing one copy of the Confidential Information separately under seal, and one copy without the confidential information included.

8. Duke Energy Kentucky respectfully requests that the Confidential Information be withheld from public disclosure for a period of ten years. This will assure that the Confidential Information – if disclosed after that time – will no longer be commercially sensitive so as to likely impair the interests of the Company or its customers if publicly disclosed.

9. To the extent the Confidential information becomes generally available to the public, whether through filings required by other agencies or otherwise, Duke Energy Kentucky will notify the Commission and have its confidential status removed, pursuant to 807 KAR 5:001 Section 13(10)(a).

WHEREFORE, Duke Energy Kentucky, Inc., respectfully requests that the Commission classify and protect as confidential the specific information described herein.

Respectfully submitted,

Rocco O. D'Ascenzo (92796)
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Cincinnati, Ohio 45201-0960
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CERTIFICATE OF SERVICE

This is to certify that the foregoing electronic filing is a true and accurate copy of the document being filed in paper medium; that the electronic filing was transmitted to the Commission on February 14, 2020; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and that a copy of the filing in paper medium is being delivered via 2nd day delivery to the Commission on the 14th day of February, 2020 and a copy of the filing is also being electronically mailed to the following:

Hon. Justin McNeil
Hon. Larry Cook
The Office of the Attorney General
Utility Intervention and Rate Division
700 Capital Avenue, Ste. 118
Frankfort, Kentucky 40601

Rocco O. D'Ascenzo

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Phillip Agee, Director of Gas Sales and Delivery Services, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information, and belief.

Phillip Agee Affiant

Subscribed and sworn to before me by Phillip Agee on this 13th day of February 2020.

SHANNON L. WALL
Notary Public, North Carolina
Mecklenburg County
My Commission Expires
June 28, 2022

Shanon Wall
NOTARY PUBLIC

My Commission Expires: 6/28/2022

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Martin P. Petchul, General Manager, Gas Asset Management and Engineering, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Martin P. Petchul Affiant

Subscribed and sworn to before me by Martin P. Petchul on this 11th day of February 2020.

SHANNON L. WALL
Notary Public, North Carolina
Mecklenburg County
My Commission Expires
June 28, 2022

Shannon L. Wall
NOTARY PUBLIC

My Commission Expires: 6/28/2022

VERIFICATION

**STATE OF NORTH CAROLINA) **
) SS:
COUNTY OF MECKLENBURG)

The undersigned, Amy D. Presson, General Manager, Gas Major Projects, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Amy D Presson

Amy D. Presson Affiant

Subscribed and sworn to before me by Amy D. Presson on this 6th day of February, 2020.

NOTARY PUBLIC

My Commission Expires:

Raina Lagienne
NOTARY PUBLIC
Union County, NC
My Commission Expires November 04, 2023

KyPSC Case No. 2029-00388
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REQUEST:

Refer to Duke Kentucky's response to Commission Staff's First Request for Information (Staff's First Request), Item 1.

a. Duke Kentucky states that it forecasted the addition of 922 residential and commercial customers for 2019. Provide the actual number of new residential and commercial customers that Duke Kentucky added in 2019.

b. Duke Kentucky states that with the addition of the new Amazon Air Hub in northern Kentucky, Duke Kentucky expects to see continued steady customer growth.

   (1) Provide the amount of customer and load growth that Duke Kentucky is expecting from the new Amazon Air Hub.

   (2) Provide all documentation demonstrating that Duke Kentucky is projecting steady customer growth in general for 2020 and 2021.

RESPONSE:

<u>**CONFIDENTIAL PROPRIETARY TRADE SECRET**</u>

a. Duke Energy Kentucky added 888 residential and commercial customers in 2019.

b. (1) The Amazon Air Hub will have a total connected load of [redacted] MCF per hour with a total maximum daily usage of [redacted] MCF per day.

(2) Duke Energy Kentucky projects steady customer growth for several reasons. First, Boone County is currently the fastest growing county in the 15 county Cincinnati Metropolitan Statistical Area. Second, the $1.5 billion Amazon Air Hub is one of the largest economic development wins in Northern Kentucky history and is expected to create 2,000 new jobs. Projects of this magnitude tend to spur ancillary commercial and business growth along with new residential development. Additionally, The Tri-County Economic Development organization is actively engaged in marketing the Northern Kentucky region to potential new businesses which will have natural gas needs while also working with existing companies on expansion opportunities who will have growing requirements for natural gas. There are sites in the vicinity of the Amazon sites that are prime for commercial and industrial development such as the Walton Industrial Park, the Richwood exchange area and the Litton Lane area. Finally, the Kentucky Transportation Cabinet is moving forward with several road improvement projects that will provide access to additional land for development throughout Boone County which will help accommodate future growth that is expected in the area.

PERSON RESPONSIBLE: Phillip Agee

Duke Energy Kentucky
Case No. 2019-00388
Staff Second Set Data Requests
Date Received: January 30, 2020

STAFF-DR-02-002

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 2(e), and provide the federal regulations that Duke Kentucky is referencing in this response.

RESPONSE:

Please see STAFF-DR-02-002 Attachment for the two new sections to the Code of Federal Regulations 49 Part 192 regarding traceable, verifiable, and complete records, specifically §192.607 and §192.624.

PERSON RESPONSIBLE: Martin P. Petchul

be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102, section 7 (incorporated by reference, *see* § 192.7).

* * * * *

■ 14. Section 192.205 is added to read as follows:

§ 192.205 Records: Pipeline components.

(a) For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials.

(b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting the manufacturing standard and pressure rating for valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

■ 15. In § 192.227, paragraph (c) is added to read as follows:

§ 192.227 Qualification of welders.

* * * * *

(c) For steel transmission pipe installed after July 1, 2021, records demonstrating each individual welder qualification at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

■ 16. In § 192.285, paragraph (e) is added to read as follows:

§ 192.285 Plastic pipe: Qualifying persons to make joints.

* * * * *

(e) For transmission pipe installed after July 1, 2021, records demonstrating each person's plastic pipe joining qualifications at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.

■ 17. Section 192.493 is added to read as follows:

§ 192.493 In-line inspection of pipelines.

When conducting in-line inspections of pipelines required by this part, an operator must comply with API STD 1163, ANSI/ASNT ILI–PQ, and NACE SP0102, (incorporated by reference, *see* § 192.7). Assessments may be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102, provided they comply with those sections of NACE SP0102 that are applicable.

■ 18. Section 192.506 is added to read as follows:

§ 192.506 Transmission lines: Spike hydrostatic pressure test.

(a) *Spike test requirements.* Whenever a segment of steel transmission pipeline that is operated at a hoop stress level of 30 percent or more of SMYS is spike tested under this part, the spike hydrostatic pressure test must be conducted in accordance with this section.

(1) The test must use water as the test medium.

(2) The baseline test pressure must be as specified in the applicable paragraphs of § 192.619(a)(2) or § 192.620(a)(2), whichever applies.

(3) The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least 8 hours as specified in § 192.505.

(4) After the test pressure stabilizes at the baseline pressure and within the first 2 hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or 100% SMYS. This spike hydrostatic pressure test must be held for at least 15 minutes after the spike test pressure stabilizes.

(b) *Other technology or other technical evaluation process.* Operators may use other technology or another process supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent. Operators must notify PHMSA 90 days in advance of the assessment or reassessment requirements of this subchapter. The notification must be made in accordance with § 192.18 and must include the following information:

(1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;

(2) Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;

(3) Data requirements, including original design, maintenance and operating history, anomaly or flaw characterization;

(4) Assessment techniques and acceptance criteria;

(5) Remediation methods for assessment findings;

(6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;

(7) Procedures for remaining crack growth analysis and pipeline segment life analysis for the time interval for additional assessments, as required; and

(8) Evidence of a review of all procedures and assessments by a qualified technical subject matter expert.

■ 19. In § 192.517, paragraph (a) introductory text is revised to read as follows:

§ 192.517 Records: Tests.

(a) An operator must make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505, 192.506, and 192.507. The record must contain at least the following information:

* * * * *

■ 20. Section 192.607 is added to read as follows:

§ 192.607 Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.

(a) *Applicability.* Wherever required by this part, operators of onshore steel transmission pipelines must document and verify material properties and attributes in accordance with this section.

(b) *Documentation of material properties and attributes.* Records established under this section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (*e.g.*, yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this section needed to meet the requirements of the ECA method at § 192.624(c)(3) or the fracture mechanics requirements at § 192.712 must be maintained for the life of the pipeline.

(c) *Verification of material properties and attributes.* If an operator does not have traceable, verifiable, and complete records required by paragraph (b) of this section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities: Anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following:

(1) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.

(2) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.

(3) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.

(4) If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.

(5) Verification of material properties and attributes for non-line pipe components must comply with paragraph (f) of this section.

(d) *Special requirements for nondestructive Methods.* Procedures developed in accordance with paragraph (c) of this section for verification of material properties and attributes using nondestructive methods must:

(1) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage;

(2) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and

(3) Use test equipment that has been properly calibrated for comparable test materials prior to usage.

(e) *Sampling multiple segments of pipe.* To verify material properties and attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements:

(1) The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: Nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. If the dates between the manufacture or construction of the pipeline segments exceeds 2 years, those segments cannot be considered as the same vintage for the purpose of defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous.

(2) For each population defined according to paragraph (e)(1) of this section, the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavation activities pursuant to § 192.614, until completion of the lesser of the following:

(i) One excavation per mile rounded up to the nearest whole number; or

(ii) 150 excavations if the population is more than 150 miles.

(3) Prior tests conducted for a single excavation according to the requirements of paragraph (c) of this section may be counted as one sample under the sampling requirements of this paragraph (e).

(4) If the test results identify line pipe with properties that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past, the operator must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an expanded sampling approach in accordance with § 192.18.

(5) An operator may use an alternative statistical sampling approach that differs from the requirements specified in paragraph (e)(2) of this section. The alternative sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an alternative sampling approach in accordance with § 192.18.

(f) *Components.* For mainline pipeline components other than line pipe, an operator must develop and implement procedures in accordance with paragraph (c) of this section for establishing and documenting the ANSI rating or pressure rating (in accordance with ASME/ANSI B16.5 (incorporated by reference, *see* § 192.7)).

(1) Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.

(2) Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are:

(i) Larger than 2 inches in nominal outside diameter,

(ii) Material grades of 42,000 psi (Grade X–42) or greater, or

(iii) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

(3) Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination.

(g) *Uprating.* The material properties determined from the destructive or nondestructive tests required by this section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assumed yield strength of 24,000 psi in accordance with § 192.107(b)(2).

■ 21. In § 192.619, the introductory text of paragraphs (a) introductory text and (a)(2) and (4) are revised and paragraphs (e) and (f) are added to read as follows:

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure (MAOP) determined under paragraph (c), (d), or (e) of this section, or the lowest of the following:

* * * * *

(2) The pressure obtained by dividing the pressure to which the pipeline segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 psi (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the Table 1 to paragraph (a)(2)(ii):

TABLE 1 TO PARAGRAPH (a)(2)(ii)

Class location	Factors,[1] segment—			
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under § 192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

[1] For offshore pipeline segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

* * * * *

(4) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with § 192.607, if applicable, and the history of the pipeline segment, including known corrosion and actual operating pressure.

* * * * *

(e) Notwithstanding the requirements in paragraphs (a) through (d) of this section, operators of onshore steel transmission pipelines that meet the criteria specified in § 192.624(a) must establish and document the maximum allowable operating pressure in accordance with § 192.624.

(f) Operators of onshore steel transmission pipelines must make and retain records necessary to establish and document the MAOP of each pipeline segment in accordance with paragraphs (a) through (e) of this section as follows:

(1) Operators of pipelines in operation as of [July 1, 2020 must retain any existing records establishing MAOP for the life of the pipeline;

(2) Operators of pipelines in operation as of July 1, 2020 that do not have records establishing MAOP and are required to reconfirm MAOP in accordance with § 192.624, must retain the records reconfirming MAOP for the life of the pipeline; and

(3) Operators of pipelines placed in operation after July 1, 2020 must make and retain records establishing MAOP for the life of the pipeline.

■ 22. Section 192.624 is added to read as follows:

§ 192.624 Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.

(a) *Applicability.* Operators of onshore steel transmission pipeline segments must reconfirm the maximum allowable operating pressure (MAOP) of all pipeline segments in accordance with the requirements of this section if either of the following conditions are met:

(1) Records necessary to establish the MAOP in accordance with § 192.619(a), including records required by § 192.517(a), are not traceable, verifiable, and complete and the pipeline is located in one of the following locations:

(i) A high consequence area as defined in § 192.903; or

(ii) A Class 3 or Class 4 location.

(2) The pipeline segment's MAOP was established in accordance with § 192.619(c), the pipeline segment's MAOP is greater than or equal to 30 percent of the specified minimum yield strength, and the pipeline segment is located in one of the following areas:

(i) A high consequence area as defined in § 192.903;

(ii) A Class 3 or Class 4 location; or

(iii) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of instrumented inline inspection tools.

(b) *Procedures and completion dates.* Operators of a pipeline subject to this section must develop and document procedures for completing all actions required by this section by July 1, 2021. These procedures must include a process for reconfirming MAOP for any pipelines that meet a condition of § 192.624(a), and for performing a spike test or material verification in accordance with §§ 192.506 and 192.607, if applicable. All actions required by this section must be completed according to the following schedule:

(1) Operators must complete all actions required by this section on at least 50% of the pipeline mileage by July 3, 2028.

(2) Operators must complete all actions required by this section on 100% of the pipeline mileage by July 2, 2035 or as soon as practicable, but not to exceed 4 years after the pipeline segment first meets a condition of § 192.624(a) (*e.g.*, due to a location becoming a high consequence area), whichever is later.

(3) If operational and environmental constraints limit an operator from meeting the deadlines in § 192.624, the operator may petition for an extension of the completion deadlines by up to 1 year, upon submittal of a notification in accordance with § 192.18. The notification must include an up-to-date plan for completing all actions in accordance with this section, the reason for the requested extension, current status, proposed completion date, outstanding remediation activities, and

any needed temporary measures needed to mitigate the impact on safety.

(c) *Maximum allowable operating pressure determination.* Operators of a pipeline segment meeting a condition in paragraph (a) of this section must reconfirm its MAOP using one of the following methods:

(1) *Method 1: Pressure test.* Perform a pressure test and verify material properties records in accordance with § 192.607 and the following requirements:

(i) *Pressure test.* Perform a pressure test in accordance with subpart J of this part. The MAOP must be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in § 192.619(a)(2)(ii).

(ii) *Material properties records.* Determine if the following material properties records are documented in traceable, verifiable, and complete records: Diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength).

(iii) *Material properties verification.* If any of the records required by paragraph (c)(1)(ii) of this section are not documented in traceable, verifiable, and complete records, the operator must obtain the missing records in accordance with § 192.607. An operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with § 192.607.

(2) *Method 2: Pressure Reduction.* Reduce pressure, as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by the greater of 1.25 or the applicable class location factor in § 192.619(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (*i.e.*, the location-specific operating pressure at each location).

(i) Where the pipeline segment has had a class location change in accordance with § 192.611, and records documenting diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:

(A) For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4.

(B) For pipeline segments where a class location changed from Class 1 to Class 3, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by 2.00.

(ii) Future uprating of the pipeline segment in accordance with subpart K is allowed if the MAOP is established using Method 2.

(iii) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, the operator must notify PHMSA in accordance with § 192.18 no later than 7 calendar days after establishing the reduced MAOP. The notification must include the following details:

(A) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in § 192.624(c)(2);

(B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with § 192.712;

(C) Justification that establishing MAOP by another method allowed by this section is impractical;

(D) Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material properties records, material properties verified in accordance § 192.607, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and

(E) Planned duration for operating at the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts.

(3) *Method 3: Engineering Critical Assessment (ECA).* Conduct an ECA in accordance with § 192.632.

(4) *Method 4: Pipe Replacement.* Replace the pipeline segment in accordance with this part.

(5) *Method 5: Pressure Reduction for Pipeline Segments with Small Potential Impact Radius.* Pipelines with a potential impact radius (PIR) less than or equal to 150 feet may establish the MAOP as follows:

(i) Reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during 5 years preceding October 1, 2019, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period. The reduced MAOP must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire pipeline segment or the operating pressure gradient (*i.e.*, the location specific operating pressure at each location);

(ii) Conduct patrols in accordance with § 192.705 paragraphs (a) and (c) and conduct instrumented leakage surveys in accordance with § 192.706 at intervals not to exceed those in the following table 1 to § 192.624(c)(5)(ii):

TABLE 1 TO § 192.624(c)(5)(ii)

Class locations	Patrols	Leakage surveys
(A) Class 1 and Class 2	3½ months, but at least four times each calendar year	3½ months, but at least four times each calendar year.
(B) Class 3 and Class 4	3 months, but at least six times each calendar year	3 months, but at least six times each calendar year.

(iii) Under Method 5, future uprating of the pipeline segment in accordance with subpart K is allowed.

(6) *Method 6: Alternative Technology.* Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with § 192.18. The notification must include descriptions of the following details:

(i) The technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated;

(ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered;

(iii) Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;

(iv) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength;

(v) If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.712;

(vi) Operational monitoring procedures;

(vii) Methodology and criteria used to justify and establish the MAOP; and

(vii) Documentation of the operator's process and procedures used to implement the use of the alternative technology, including any records generated through its use.

(d) *Records.* An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

■ 23. Section 192.632 is added to read as follows:

§ 192.632 Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines.

When an operator conducts an MAOP reconfirmation in accordance with § 192.624(c)(3) "Method 3" using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA must comply with the requirements of this section. The ECA must assess: Threats; loadings and operational circumstances relevant to those threats, including along the pipeline right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance. The ECA must quantify the interacting effects of threats on any defect in the pipeline.

(a) *ECA Analysis.* (1) The material properties required to perform an ECA analysis in accordance with this paragraph are as follows: Diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and Charpy v-notch toughness values based upon the lowest operational temperatures, if applicable. If any material properties required to perform an ECA for any pipeline segment in accordance with this paragraph are not documented in traceable, verifiable and complete records, an operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with § 192.607. The ECA must integrate, analyze, and account for the material properties, the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including close interval surveys, coating surveys, interference surveys required by subpart I of this part, cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by §§ 192.617, 192.710, and subpart O of this part.

(2) The ECA must analyze and determine the predicted failure pressure for the defect being assessed using procedures that implement the appropriate failure criteria and justification as follows:

(i) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure of each defect in accordance with § 192.712.

(ii) The ECA must analyze any metal loss defects not associated with a dent, including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe, to determine the predicted failure pressure. ASME/ANSI B31G (incorporated by reference, *see* § 192.7) or R–STRENG (incorporated by reference, *see* § 192.7) must be used for corrosion defects. Both procedures and their analysis apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations' procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth).

(iii) When determining the predicted failure pressure for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used and documented.

(iv) If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must assume 30,000 p.s.i. or determine the material properties using § 192.607.

(3) The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.

(4) The MAOP must be established at the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in § 192.619(a)(2)(ii).

(b) *Assessment to determine defects remaining in the pipe.* An operator must utilize previous pressure tests or develop and implement an assessment program to determine the size of defects remaining in the pipe to be analyzed in accordance with paragraph (a) of this section.

(1) An operator may use a previous pressure test that complied with subpart J to determine the defects remaining in the pipe if records for a pressure test meeting the requirements of subpart J of this part exist for the pipeline segment. The operator must calculate the largest defect that could have survived the pressure test. The operator must predict how much the defects have grown since the date of the pressure test in

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 2(g).

a. Duke Kentucky provides four key factors that dictate the need for the proposed project in lieu of reasonable alternatives, with the first key factor being recoupling high-pressure loss along UL02. Explain how the proposed project will recoup high-pressure loss along UL02.

b. Duke Kentucky lists the second key factor as minimizing piping/routing. Expand on how the proposed project will minimize piping/routing.

c. Duke Kentucky lists the third key factor as proximity to the nearest interstate suppliers. Further explain this third key factor.

d. Duke Kentucky lists the fourth key factor as projected future large volume customers along the proposed pipeline route. Provide the projected future large volume customers that Duke is referring to in this statement and their projected annual volumes.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET

a. Pressure loss thru a pipeline is a function of flow rate, by providing an alternate gas path thru UL60, the flow through pipeline UL02 will be reduced, therefore reducing the pressure loss. This was confirmed with the modeling described in response to CONFIDENTIAL STAFF-DR-01-002(a).

b. The proposed UL60 project is approximately seven miles in length. To achieve similar pressure improvements at the extents of the system, AM03 would need to be looped approximately 15 miles from the Taylor Mill South Regulator Station on pipeline AM07 in Taylor Mill, KY to the Walton Delivery Station on pipeline UL57 in Walton, KY.

c. Presently Duke Energy Kentucky's only interconnection to an interstate pipeline system is from KO Transmission; the next closest interstate pipeline is Texas Gas Transmission operating in Dearborn, Switzerland, and Ohio Counties in Indiana and Carroll County, Kentucky. Currently, there are no plans to interconnect to this supplier but having a large diameter pipeline on the western portion of the Duke Energy Kentucky system provides future optionality.

d. Specifically, this statement was referring to [redacted] and associated commercial growth. See response to STAFF-DR-02-001 and STAFF-DR-02-004.

PERSON RESPONSIBLE: Martin P. Petchul

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 3(a), and provide the expected load of the new customer in 2021, as well as for the future years. Provide all documentation regarding the same.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET

The estimated annual usage (MCF/year) of the new customer is noted below and is memorialized in the Natural Gas Minimum Usage Agreement filed confidentially with the Kentucky Public Service Commission on January 27, 2020.

2021 – [redacted] MCF
2022 – [redacted] MCF
2023 – [redacted] MCF
2024 – [redacted] MCF
2025 – [redacted] MCF
2026 – [redacted] MCF
2027 – [redacted] MCF
2028 – [redacted] MCF
2029 – [redacted] MCF
2030 – [redacted] MCF

PERSON RESPONSIBLE: Phillip Agee

STAFF-DR-02-005

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 3(c) and (d). Confirm that the new customer that is requesting service by January 1, 2021, will pay 100 percent of the costs of the proposed project that are directly associated with providing service to the new customer. If not, explain why not in detail.

RESPONSE:

The new customer will pay 100 percent of the costs associated with the provision of natural gas service to the new facility which is currently under construction. The Confidential Natural Gas Minimum Usage Agreement filed with the Kentucky Public Service Commission on January 27, 2020 details the estimated cost of this project and the new customer's usage requirements needed to ensure recovery of all applicable costs.

PERSON RESPONSIBLE: Phillip Agee

Duke Energy Kentucky
Case No. 2019-00388
Staff Second Set Data Requests
Date Received: January 30, 2020

STAFF-DR-02-006

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 5(a).

a. Provide an explanation of what "Other Direct Costs" entails, which is part of the Phase 1 Estimate, and a breakdown of the same.

b. Provide an explanation of what "Overhead and Allocations" entails, which is part of the Phase 1 estimate, and a breakdown of the same.

c. Provide a breakdown of what is included in the Phase 1 "Project Contingency."

RESPONSE:

a. Other Direct Costs includes items such as permits, legal support for permitting, public informational meeting costs, communication support costs, and other miscellaneous expenses (such as office supplies and meeting resources, etc.) that are needed during the project that do not fit into another defined bucket.

Permits	$	10,000
Legal Support	$	10,000
Public Information Meeting	$	10,000
Communication Support	$	25,000
Miscellaneous	$	10,000
Other Direct Costs	**$**	**65,000**

b. Overhead and Allocations represents labor loaders for fringe benefits, payroll taxes, and incentives, as well as, allocated costs of corporate overhead not directly charged to a specific project. The amount allocated to each project is estimated based on typical expenditures and is variable, depending upon the number of projects actively underway within Duke Energy Kentucky at any given time.

c. Project Contingency is an estimated amount added to the base cost of a project to probabilistically account for cost uncertainties and to improve the predictability of project cost projections. It accounts for various risks and events that might be encountered during project development and execution. These funds are only used as needed throughout the project.

PERSON RESPONSIBLE: Amy Presson

Duke Energy Kentucky
Case No. 2019-00388
Staff Second Set Data Requests
Date Received: January 30, 2020

STAFF-DR-02-007

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 5(b).

a. Provide an explanation of what "Other Direct Costs" entails, which is part of the Phase 2 Estimate, and a breakdown of the same.

b. Provide an explanation of what "Overhead and Allocations" entails, which is part of the Phase 2 estimate, and a breakdown of the same.

c. Provide a breakdown of what is included in the Phase 2 "Project Contingency."

RESPONSE:

a. Other Direct Costs includes items such as permits, legal support for permitting, public informational meeting costs, communication support costs, and other miscellaneous expenses (such as office supplies and meeting resources, etc.) that are needed during the project that do not fit into another defined bucket.

Permits	$	10,000
Legal Support	$	5,000
Public Information Meeting	$	10,000
Communication Support	$	15,000
Miscellaneous	$	10,000
Other Direct Costs	**$**	**50,000**

b. Overhead and Allocations represents labor loaders for fringe benefits, payroll taxes, and incentives, as well as, allocated costs of corporate overhead not directly charged to a specific project. The amount allocated to each project is estimated based on typical expenditures and is variable, depending upon the number of projects actively underway within Duke Energy Kentucky at any given time.

c. Contingency is an estimated amount added to the base cost of a project to probabilistically account for cost uncertainties and to improve the predictability of project cost projections. It accounts for various risks and events that might be encountered during project development and execution. These funds are only used as needed throughout the project.

PERSON RESPONSIBLE: Amy Presson

Duke Energy Kentucky
Case No. 2019-00388
Staff Second Set Data Requests
Date Received: January 30, 2020

STAFF-DR-02-008

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 6, and provide the state and federal regulations that Duke Kentucky is referencing to in the response.

RESPONSE:

Please see response to STAFF-DR-02-002.

PERSON RESPONSIBLE: Martin P. Petchul

STAFF-DR-02-009

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item. 7.

a. Explain whether the proposed project will allow for any savings or reductions in Duke Kentucky's current costs.

b. Explain whether the new customer requesting service by January 1, 2021, will be contributing to the annual ongoing cost of operation of the proposed project, including the required periodic inspections and testing.

c. Confirm that the estimated annual cost of operation of approximately $101,500, excluding ongoing maintenance of $10,000, is entirely incremental to Duke Kentucky's current inspection expenses. If this cannot be confirmed, explain.

RESPONSE:

a. The proposed project will not allow for savings or reduction in Duke Energy Kentucky current costs.

b. The new customer will be contributing to the project's ongoing operations and maintenance (O&M) costs. O&M costs have been accounted for in Duke Energy Kentucky's feasibility model which was used to determine the new customer's minimum usage requirements as detailed in the Natural Gas Minimum Usage Agreement filed with the Kentucky Public Service Commission on January 27, 2020.

c. The ongoing cost of maintenance is entirely incremental to Duke Energy Kentucky's current inspection expenses. The $10,000 is the cost of annual inspections required by federal mandates. The $101,500 represents inspection and maintenance costs done every seven years per federal mandate and distributed evenly over seven years.

PERSON RESPONSIBLE: Amy Presson – a., c.
Phillip Agee – b.

Duke Energy Kentucky
Case No. 2019-00388
Staff Second Set Data Requests
Date Received: January 30, 2020

STAFF-DR-02-010

REQUEST:

Provide the referenced federal regulation that requires an in-line inspection to be performed every seven years.

RESPONSE:

Please see STAFF-DR-02-010 Attachment.

Each threat identified in a pipe segment must be assessed every seven years. See §192.937 in STAFF-DR-02-010 Attachment. The typical potential threats to pipeline segments are internal corrosion, external corrosion, stress corrosion cracking, fabrication defects, construction defects, third-party damage, and outside force damage. See §192.917 in STAFF-DR-02-010 Attachment.

Assessment options for these potential threats are internal inspection tools, pressure testing, or direct assessment. See §192.919 and §192.921 in STAFF-DR-02-010 Attachment. The assessment option chosen depends on the identified threat to be examined.

Internal inspection tools can address all of these potential threats and is the industry standard for assessment. These tools can be deployed without interrupting service to customers.

Pressure testing is another method but requires that segments of pipe to be taken out of service, filled with water, tested, de-watered, dried, purged, re-pressurized to the appropriate pressure before service can be restored to customers. This method is best for isolated segments and pipeline segments that can be taken out of service without affecting customers. For integrated systems, this is typically a not a viable option.

Direct assessment can address external, internal, and stress corrosion cracking only. Since each pipe segment has some element of a third-party damage threat, direct assessments are not acceptable for full assessment. Also, for vintage pipe segments, direct assessment is not a viable option for assessing fabrication or construction defects.

PERSON RESPONSIBLE: Martin P. Petchul

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of February 5, 2020

Title 49 → Subtitle B → Chapter I → Subchapter D → Part 192 → Subpart O → §192.917

Title 49: Transportation
PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS
Subpart O—Gas Transmission Pipeline Integrity Management

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§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

Link to an amendment published at 84 FR 52253, Oct. 1, 2019.

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Static or resident threats, such as fabrication or construction defects;

(3) Time independent threats such as third party damage and outside force damage; and

(4) Human error.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe.

(e) *Actions to address particular threats.* If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.

An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. An evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment.

(3) *Manufacturing and construction defects.* If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(5) *Corrosion.* If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18231, Apr. 6, 2004]

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of February 5, 2020

Title 49 → Subtitle B → Chapter I → Subchapter D → Part 192 → Subpart O → §192.919

Title 49: Transportation
PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS
Subpart O—Gas Transmission Pipeline Integrity Management

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§192.919 What must be in the baseline assessment plan?

An operator must include each of the following elements in its written baseline assessment plan:

(a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (*See* §192.917.);

(b) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment. (*See* §192.917.) More than one method may be required to address all the threats to the covered pipeline segment;

(c) A schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule;

(d) If applicable, a direct assessment plan that meets the requirements of §§192.923, and depending on the threat to be addressed, of §192.925, §192.927, or §192.929; and

(e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of February 5, 2020

Title 49 → Subtitle B → Chapter I → Subchapter D → Part 192 → Subpart O → §192.921

Title 49: Transportation
PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS
Subpart O—Gas Transmission Pipeline Integrity Management

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§192.921 How is the baseline assessment to be conducted?

Link to an amendment published at 84 FR 52253, Oct. 1, 2019.

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (*See* §192.917).

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

(c) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §192.917(e) to address particular threats that it has identified.

(d) *Time period.* An operator must prioritize all the covered segments for assessment in accordance with §192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

(e) *Prior assessment.* An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in §192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of §192.937 and §192.939.

(f) *Newly identified areas.* When an operator identifies a new high consequence area (*see* §192.905), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.

(g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.

(h) *Plastic transmission pipeline*. If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of §192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18232, Apr. 6, 2004]

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of February 5, 2020

Title 49 → Subtitle B → Chapter I → Subchapter D → Part 192 → Subpart O → §192.937

Title 49: Transportation
PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS
Subpart O—Gas Transmission Pipeline Integrity Management

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§192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

Link to an amendment published at 84 FR 52254, Oct. 1, 2019.

(a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* §192.917), or by confirmatory direct assessment under the conditions specified in §192.931.

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(5) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with §192.931.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18234, Apr. 6, 2004]