STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-9, SUB 698

In the Matter of Application of Piedmont Natural Gas Company, Inc., for Approval of Appendix F to Its North Carolina Service Regulations	)	PUBLIC STAFF FINAL REPORT

NOW COMES THE PUBLIC STAFF – North Carolina Utilities Commission (Public Staff), by and through its Executive Director, Christopher J. Ayers, and, respectfully submits its final report as provided for in the Commission's *Order Requiring Collaborative Meetings, Reports and Additional Information* (Order) issued in this docket on May 4, 2017.

1. Pursuant to the Order, the Public Staff convened and facilitated meetings of the parties to this docket for the purpose of discussing the issues surrounding Alternative Gas standards and testing requirements, with the ultimate goal of developing such Alternative Gas standards and testing requirements for Piedmont Natural Gas Company, Inc. (Piedmont), to incorporate into its Service Regulations as Appendix F. The meetings were held on June 2, 2017, July 14, 2017, and August 25, 2017. On June 27, 2017, a subgroup of the parties met to discuss technical issues.

2. On October 26, 2017, Piedmont filed a revised version of Appendix F, which had been reviewed by the parties to the collaborative process. The filing stated that, to the best of Piedmont's knowledge, there are no further objections to

the revised Alternative Gas standards reflected in the revised version of Appendix F.

3. The Order required the Public Staff's report to include the information requested in the Commission questions attached to the Order as Attachment A. The information provided by Piedmont, Public Service Company of North Carolina, Inc. (PSNC), the Public Staff, Duke Energy Carolinas, LLC (DEC), the Coalition for Renewable Natural Gas (RNG Coalition), Enerdyne Power Systems, Inc. (Enerdyne), the North Carolina Pork Council (NCPC), the North Carolina Sustainable Energy Association (NCSEA), and Duke University are as shown below.

COMMISSION QUESTIONS

1. Recognizing that interstate pipeline gas is subject to the pipeline gas quality standards that are approved by the Federal Energy Regulatory Commission (FERC), provide the details of all standards, testing equipment and tests that Piedmont, PSNC, Frontier and Toccoa use to ensure that natural gas delivered to their systems from interstate pipelines meet their gas quality standards.

PIEDMONT'S RESPONSE: Piedmont does not individually test gas quality characteristics of gas received from its upstream capacity suppliers. Instead, it relies on those suppliers to abide by the applicable gas quality specifications of those upstream pipelines (approved by FERC) and periodically monitors gas quality information available from equipment owned and operated by its upstream capacity suppliers.

PSNC'S RESPONSE: PSNC monitors the chromatograph information on Transco's website. PSNC also monitors the information from its own chromatograph located at its Cary Energy Center (LNG facility).

2. Provide the details of all standards, testing equipment and tests that Transco, or other interstate pipelines, use to ensure that natural gas delivered to their systems from gas producers meet their gas quality standards.

PIEDMONT'S RESPONSE: Please see gas quality standards of Transco and Columbia Gas Transmission located at (i) www.1Line.williams.com/Transco/index.html and (ii) www.columbiapipeinfo.com/infopost/#. For Transco, select "Tariff" and the gas quality standards are located in Section 3 of the General Terms and Conditions of Transco's tariff. For Columbia, select "Columbia Gas Transmission" under the "Pipeline" tab and then select "Tariff." Columbia's gas quality standards are contained in Section 25 of the General Terms and Conditions.

PSNC'S RESPONSE: PSNC is aware of the Quality standards set forth in Section 3 of Part IV - General Terms and Conditions of Transco's FERC Gas Tariff. PSNC has no reason to believe that gas delivered to or from Transco does not meet the requirements set forth in its Tariff. As stated above, PSNC monitors the chromatograph information on Transco's website.

DUKE UNIVERSITY'S RESPONSE: To provide information regarding the differences between natural gas accepted from the Transco pipeline ("geologically derived natural gas") and the Alternative Gas contemplated by Piedmont's proposed Appendix F, Duke University has engaged an independent laboratory to test geologically derived natural gas for the compounds identified in Piedmont's proposed Appendix F, and to confirm the quantity/concentration of those specified compounds. When testing is complete, the University will provide the results to the Public Staff and all parties to this docket. The University notes that there are a limited number of laboratories capable of analyzing the full suite of compounds listed in proposed Appendix F and that for some tests, on-site sampling by a dedicated laboratory technician is required to ensure sample integrity and successful testing. Moreover, the University considers the testing costs, at approximately $21,000 per sample for the full suite of compounds, as not insignificant and therefore relevant to this docket because they have the potential to materially affect biogas development by substantially increasing testing complexity and costs. In particular, the lack of capable laboratories together with the high cost of testing, particularly in instances in which multiple tests may be required or in which quantities injected are small in comparison to the flow in the pipeline, could present an overly burdensome barrier to Alternative Gas development.

3. In Piedmont's proposed Appendix F, under the heading "Alternative Gas Quality Standards," there is a list of numerous specific standards, such as delivery temperature and sulfur content, with which Alternative Gas would

be required to comply. For each such standard, state the corresponding standard that Piedmont presently requires of natural gas delivered to its system.

<u>**PIEDMONT'S RESPONSE**</u>: Piedmont does not currently have specific standards for heat content, gas quality or allowable constituents in its tariff. Rather, Piedmont relies on and refers to such requirements in the tariffs of its upstream interstate transmission providers. In North Carolina this is primarily Transco or, to a much smaller extent, Columbia Gas.

4. In Piedmont's proposed Appendix F, under the heading "Testing Requirements," there are numerous specific tests with which Alternative Gas would be required to comply. For each such test, state the corresponding testing requirement, or the absence of such a testing requirement, that Piedmont presently requires of natural gas delivered to its system.

<u>**PIEDMONT'S RESPONSE**</u>: As indicated in prior responses, Piedmont does not specify specific gas quality characteristics in the gas stream received from upstream pipelines and does not independently test (or require testing) for conformance with those pipeline standards. Instead, Piedmont relies on the FERC approved gas quality provisions of the upstream pipeline tariffs and the testing conducted by those pipelines of gas delivered into the interstate system. This approach is both practical (inasmuch as there is no reasonable way in which suppliers could further process natural gas ultimately delivered to Piedmont to

meet any higher standard than the interstate pipeline standard) and historically reasonable given the extremely stable and known composition and heat content of natural gas delivered by interstate natural gas pipelines.

DUKE UNIVERSITY'S RESPONSE: As indicated in the University's response to Question #2, an independent laboratory is in the process of performing analyses of geologically derived natural gas delivered by Transco via PSNC to the University's on-campus steam plant as well as the biogas produced by the anaerobic digester installed at the Loyd Ray Farms (Yadkin County) waste-to-energy system. Both tests will analyze the gas streams for the presence and concentration of the compounds listed in Piedmont's proposed Appendix F. The testing will require sixteen separate sampling and testing protocols. The University will provide a detailed description of the protocols applied when it submits the results.

5. In Docket Nos. E-7, Subs 1086 and 1087, the Commission issued an Order approving registration statements for DEC to use directed biogas, including poultry and swine biogas produced in Missouri and Oklahoma. At page 2, the Order states: "The biogas produced by both directed biogas suppliers will be cleaned to pipeline quality, metered, injected into the interstate pipeline system, and nominated for use by DEC at Buck and Dan River." Provide the details, including the type of biomethane being delivered, the pressure at which the biogas is delivered into the interstate system, the applicable quality and testing standards required, and the source of the standards (state Commission, FERC, etc.) for the Missouri and

Oklahoma interconnection points that will receive this directed biogas onto the interstate pipeline.

<u>DEC'S RESPONSE</u>: DEC's Buck and Dan River facilities are receiving directed swine waste-derived biogas from Roeslein Alternative Energy, LLC ("Roeslein"), located near Princeton, Missouri, and High Plains Bioenergy, LLC ("High Plains"), located in Guymon, Oklahoma.

The specifications for the biogas being delivered to Buck and Dan River by Roeslein are as shown on the attached Gas Quality Specifications for TransCanada under the column header "ANR" (Attachment A). See also the specifications listed at "Part 6.13 Quality" on the attached ANR Pipeline Company, FERC Gas Tariff, Third Revised Volume No. 1, filed at the FERC in Docket No. RP10-1380-000 (Attachment B).

For High Plains, the specifications are shown on the attached DCP Gas Quality Standards (Attachment C).

"The gas shall be merchantable, at all times complying with the following requirements. The gas shall be commercially free of crude oil, water in the liquid phase, brine, air, dust, gums, gum-forming constituents, bacteria, and other objectionable liquids and solids, and not contain more than:

(a) ¼ grain of H_2S per 100 cubic feet

(b) Two mole percent of carbon dioxide

(c) Two mole percent of nitrogen

(d) Ten parts per million by volume of oxygen, and not have been subjected to any treatment or process that permits or causes the admission of oxygen, that dilutes the gas, or otherwise causes it to fail to meet these qualify specifications.

(e) Fifteen mole percent of combined carbon dioxide, nitrogen, and oxygen

(f) Seven point two pounds of water vapor per MMcf"

The gas shall:

(g) Not exceed 120 degrees Fahrenheit in temperature at the delivery point

(h) Have a total heating value of at least 950 Btus per cubic foot

(i) Otherwise meet the specifications required by the transporting pipelines at the Redelivery Points

The type of biomethane being delivered from Roeslein is biogas derived from swine waste. The type of biomethane being delivered from High Plains is a combination of biogas derived from swine waste and other biomass.

The pressure at which the biogas is delivered into the interstate system is dependent upon specific pipeline conditions at the injection points at each individual site. For example, a project that interconnects at a distribution level may be able to utilize a lower pressure, while a project that interconnects at a transmission level will need a higher pressure to ensure that the gas is properly injected into the pipeline.

The source for the standards for the Missouri and Oklahoma interconnection points that will receive the directed biogas onto the interstate pipeline is the FERC tariff filing.

6. Piedmont states that in some situations Alternative Gas may be as much as 100% of the gas flow in certain segments of Piedmont's system under certain operating conditions.

(a) If the quality of gas to downstream customers – particularly the heat content – materially changes as a result, does a decision by Piedmont to accept Alternative Gas at a given point on its system constitute a "change under the control of the utility" within the meaning of Commission Rule R6-18(1)?

(b) Commission Rule R6-34(c) requires the utility to determine the allowable range of monthly average heating values within which its customers' appliances may be expected to function properly without repeated readjustment of the burners. If the heat content delivered to customers can vary from the 980 Btu/SCF minimum with 100% Alternative Gas to 1,030 Btu/SCF or more with 100% interstate pipeline gas, would that constitute a range within which customers' appliances would require repeated adjustments?

PIEDMONT'S RESPONSE:

(a) If Piedmont's proposed Alternative Gas standards, as revised by filing made in this docket on October 26, 2017, are approved then Piedmont does not believe that a material change in the character of gas service will occur within the meaning of Rule R6-18.

(b) Based on Piedmont's operating experience, it does not believe that gas with a minimum heat content of 980 Btu/SCF would require repeated adjustments of its customers' appliances.

DUKE UNIVERSITY'S RESPONSE: As submitted in an August 23, 2017, memorandum to the Public Staff, Duke University communicated that its end-use equipment and the gas delivery systems to such equipment can accept pipeline gas with a heat content of 960 British thermal units per cubic foot (Btu/scf) with no impact to safety and reliability of the campus steam generating plants.

Such information is relevant to this docket because the University operates natural-gas-burning equipment that is similar in design and nature to equipment used by other customers across North Carolina, including Piedmont's customers, who consume in excess of 1.7 billion cubic feet annually. The fact that Duke University is not an end-use customer of Piedmont but of PSNC should not affect the applicability of this information. Reasonably modern combustion control devices used to produce heat and/or power generation equipment can be retuned at minimal cost to accept pipeline gas at 960 Btu/scf and, in some cases, a heat content lower than 960 Btu/scf.

Also, it is the shared opinion of the University's professional utilities staff and consulting engineers that the engineering design community does not consider a heat content of 1030 Btu/scf to be the "typical" condition for pipeline natural gas in North Carolina. Rather, a heat content of 1015 Btu/scf has been the nominal value employed in design calculations for specifying equipment, based both on historical averages for delivered North Carolina gas and to allow a factor of safety for fluctuating heat content. In fact, no North Carolina LDC guarantees a minimum heat content to its customers, nor does the interstate Transco pipeline, the Cardinal pipeline, or any other upstream pipeline. It is of further note that an operating condition of 100% Alternative Gas at 960 Btu/scf is only 55 Btu/scf less, or 5.42% less than the nominal value of 1015 Btu/scf.

The University's in-house and consulting experts have determined that a boundary limit of 960 Btu/scf would result in minimal to no change in existing equipment and its operation. Should lower heat content gas be blended down with geologically derived natural gas at any proportion, this heat content differential would be even less, again requiring minimal to no change to equipment and operations.

7. In their comments, the RNG Coalition and Enerdyne discuss nitrogen rejection equipment. Provide in detail the benefits and costs of such nitrogen rejection equipment and/or any other method to bring the minimum Btu/SCF to 980 or higher.

<u>RNG COALITION'S RESPONSE</u>: Nitrogen rejection units (NRU) are one solution to increasing BTU content and lower nitrogen concentration in product gas. However NRUs are not common to alternative gas projects because they add to project complexity, cost *($3-10 million in CAPEX, and as much as 30% more power consumption)*, and methane loss *(as much as 15% or more of a project's methane is lost), (lost methane equals lost revenue)*.

NRUs come in many forms: multiple types of pressure swing absorption (PSA), cryogenic, membrane-based, etc. The problem with all of these is expense. All development projects are in a fight against economic infeasibility. Consequently, most projects are constructed without NRUs.

NRUs have great application in the oil and gas industry where flows are literally 10-500 times the largest RNG plants. Instead, RNG facilities are mostly using PSA.

Developers use NRUs when they have no choice, or as expensive insurance against nitrogen in the feed gas. The pros and cons of individual technologies are vast. However, they do work.

An alternative to the expense and complexity of an NRU is to spike the product gas with propane to meet the BTU and/or Wobbe spec.

Note that nitrogen is primarily a landfill problem. Wastewater Treatment Plants and on-farm digesters often have little or no nitrogen.

ENERDYNE'S RESPONSE: Enerdyne did not provide a response to this question.

8. Natural gas pipes are of different sizes, including 2-inch, 4-inch, 8-inch pipes. Explain the benefits and costs of injecting the biogas into different size pipes, how the gas quality will be affected depending on what size pipe it is injected into, and the likelihood of the biogas causing damage due to the size of the pipe.

PIEDMONT'S RESPONSE: Piedmont's purpose in filing its proposed Alternative Gas standards for Commission approval was to address the unknown qualities and characteristics of such gas so as to ensure the continued safety and reliability of service through Piedmont's facilities. Piedmont made its proposals in order to facilitate the possible expanded use of Alternative Gas within the State of North Carolina. The potential risk of receiving Alternative Gas into any particular distribution/transmission line rises as the percentage of Alternative Gas in that pipeline rises. The primary impact of injecting Alternative Gas into different size distribution/transmission lines is the resulting relative percentage of gas in those pipelines consisting of Alternative Gas. Inasmuch as flow through such differing sized pipes is a product of pipeline volume, pressure, and demand the size of the pipeline alone is not determinative of the risk. That being said, and all other things (pressure and flow) being equal, larger lines with higher volumes should be less risky than smaller lines simply because of the increased opportunity to blend the Alternative Gas supplies with pipeline sourced natural gas – thereby reducing the relative percentage of Alternative Gas flowing through the line.

PSNC'S RESPONSE: Pipe size is not the only variable to consider. Larger pipe has a greater capacity; at the same pressure; smaller pipe has a smaller capacity (SCFH). Conversely, to the extent, a smaller pipe could accept the quantity of the injected Alternative Gas, the velocity is greater on the smaller pipe. Greater velocity contributes to the blending of the Alternative Gas with the natural gas which "balances" the heating value and disperses trace contaminants. Therefore, if there were unwanted contaminants in the Alternative Gas that could damage the pipe, the blending to dilute these is aided more by flow and velocity than just pipe size. However, flows and velocities on PSNC's system vary and all flows and velocities are certainly affected by the downstream load—i.e., flow and velocity in most points on PSNC's system is higher in the winter than in the summer. When choosing an injection point, flows and velocities can be more significant factors than pipe size.

DUKE UNIVERSITY'S RESPONSE: The primary concerns raised by Piedmont in its proposed Appendix F appear to revolve around heat content and constituents of Alternative Gas, which might affect pipeline integrity and the integrity of the gas delivered to its customers. These factors are ultimately mitigated by blending and dilution of Alternative Gas with geologically derived natural gas. To that end, pipe size, volumetric flow, and pressure are all important to consider in ensuring that Piedmont's concerns are mitigated. The University is of the opinion that it would be a relatively straightforward exercise for Piedmont to determine and identify for Alternative Gas developers the points along its pipeline that would be acceptable for injection (i.e., points at which pipe diameter, volumetric flow, and pressure are ideal), and which portions of its system would be problematic for Alternative Gas injection. Such an approach could significantly simplify the process by which developers and gas utilities will identify interconnection points that minimize financial and technical risks. Such a collaborative approach would benefit ratepayers and Alternative Gas buyers interested in purchasing Alternative Gas and encourage economic development in the Alternative Gas sector, to the benefit of the entire state of North Carolina, and also hasten compliance with the swine-waste set aside in the Renewable Energy and Energy Efficiency Portfolio Standard (REPS).

9. After developing Alternative Gas standards and testing requirements, if the Alternative Gas causes damage to the pipes, such as corrosion of steel piping and components and accelerated degradation of plastic piping and components, or to the gas-burning equipment, explain in detail what course of action should be taken next.

PIEDMONT'S RESPONSE: Allowing Alternative Gas to flow onto the systems of North Carolina local distribution companies is not a risk-free proposition. The different parties to this proceeding have provided varying analyses of the risks of such action with Piedmont and PSNC taking a conservative approach and a number of the intervenors arguing that the risk is minimal to non-existent. If all risk is to be avoided, then the Commission should decline to allow Alternative Gas to be injected into the systems of North Carolina LDCs. Piedmont does not believe, based upon the information it is currently aware of, that the total exclusion of Alternative Gas is necessary but it does believe that prudent and cautious provisions regarding how and under what conditions such gas should be received should be adopted – at least until more experience with this new product is gained. If Alternative Gas is ultimately allowed onto the systems of North Carolina LDCs and damage to customer equipment or distribution/transmission facilities occurs, then that damage will be required to be repaired and the impacted facilities repaired or replaced. Delivery of the offending Alternative Gas should also be curtailed in those circumstances until additional mitigation measures are put into place to ensure no further damage to or degradation of equipment occurs as a result of the injection of Alternative Gas into LDC systems. Ultimately, changes to the provisions governing gas quality characteristics of Alternative Gas may need to be made.

PSNC'S RESPONSE: If the Alternative Gas meets the prescribed standards and testing requirements there should be no damage to the pipes. However, if damage was to occur, PSNC would take immediate action to stop receipt of the Alternative Gas that was causing the damage. PSNC would repair its facilities to ensure compliance with all applicable regulations and operations policies, and conduct an investigation to determine why the damage occurred and who should be held responsible.

10. Piedmont states that Alternative Gas is comprised of varying constituents in addition to methane that are different from those contained in natural gas. It adds, "These include potentially corrosive chemical compounds as well as potentially dangerous biologic constituents which may pose a threat to ... the health of humans coming into contact with them". What specific biological constituent or constituents does Piedmont expect might be found? Provide in detail what actions will be taken if dangerous biologic constituents are found to be present in Alternative Gas injected into Piedmont's system. Also, provide the details of how customers will be notified if dangerous biologic constituents are found which may pose a threat to the health of humans coming into contact with them.

PIEDMONT'S RESPONSE: Piedmont is unsure what biologicals may be found in Alternative Gas since it has no prior experience with receiving and testing Alternative Gas. Appendix F, as proposed by Piedmont in its October 26, 2017 filing in this docket, requires testing for the following biologicals:

- APB – acid producing bacteria
- SRB – sulfate reducing bacteria
- IOB – iron oxidizing bacteria

Proposed Appendix F also identifies permissible volume and size bacteria allowed during sample testing.

If a dangerous biological constituent or biological constituents are found, Piedmont can interrupt or suspend the source of these constituents pursuant to the proposed Appendix F.

Customers may be notified in a variety of ways depending on the circumstances present regarding the potential constituent(s). Piedmont may communicate with customers via telephone, dispatching personnel, in cooperation with the local media, or any combination of these methods.

DUKE UNIVERSITY'S RESPONSE: As indicated in the University's response to Question #2, Duke University's testing of swine-waste-derived biogas from the anaerobic digester installed at the Loyd Ray Farms in Yadkin County will provide an example to confirm the presence and concentration of any biological constituents of concern. The University will submit the full results to the Public Staff and all parties to this docket as soon as the analyses are complete.

11. Commission Rule R6-18 deals with the procedure to be followed whenever there is a material change in the character of the gas service. The difference between gas with a heat content of 1,030 Btu/SCF and gas providing 980 Btu/SCF is about 4.9%. (The difference between 1,030 Btu/SCF gas and the 960 Btu/SCF heat content recommended by the NCPC is 6.8%. and the 950 Btu/SCF heat content level advocated by the RNG Coalition as the ideal minimum heating value is almost 7.8% lower than Piedmont's typical interstate heat content). Given that level of change, should the Commission consider it a material change? If not, why not?

PIEDMONT'S RESPONSE: Rule R6-18 requires that any material change in the character of gas service under the control of the utility be submitted to the Commission for approval. As noted above, Piedmont does not believe that a change from current actual pipeline heating values to a lower heat content level of 980 Btu/SCF is necessarily a material change within the meaning of Rule R6-18 but does believe that any standard lower than 980 Btu/SCF would be material and problematic for Piedmont's continuing operations. In either event, however, the proposed changes are before the Commission in this proceeding.

PSNC'S RESPONSE: PSNC does not have an opinion on whether gas with a heat content of 950 or 960 Btu/SCF necessarily represents a material change in the character of gas service.

12. When the parties finalize their proposed Alternative Gas standards and submit them to the Commission, include with your submission information regarding any Alternative Gas standards that conflict with the Commission's current rules, and what the parties suggest be done so that the Commission rules do not conflict with the Alternative Gas standards.

<u>PIEDMONT'S RESPONSE</u>: Piedmont believes that its proposed Alternative Gas standards, as revised on October 26, 2017, are consistent with the Commission's current rules.

<u>PSNC'S RESPONSE:</u> PSNC has no information that Piedmont's Alternative Gas standards conflict with the Commission's current rules.

<u>PIEDMONT</u>

13. Piedmont's cover letters in Dockets Nos. G-9, Subs 699 and 701 (Subs 699 and 701) state, "No other customer will be impacted by the Agreement...." However, the Application and Comments and Reply Comments in this docket make clear that Alternative Gas may be materially different from natural gas, particularly with regard to heat content. In a response to a data request from the NCPC, Piedmont states, "with respect to the two pending applications for approval of Alternative Gas production on its system, the Alternative Gas may be up to 100% of the gas flow in certain segments of Piedmont's system under certain operating conditions."

(a) Does Piedmont accept responsibility if any customer is adversely impacted by its decision to accept Alternative Gas into its system?

(b) With regard to the Alternative Gas producers involved in Subs 699 and 701, what pressures will they have to reach to inject gas into Piedmont's system?

(c) Piedmont's Reply Comments [page 24 of 34] revealed that, with regard to the project in G-9, Sub 699, C2e intends to truck organic swine waste to a location for anaerobic digestion. Is that location on the 10-inch or 8-inch lines? If not, why not?

(d) On page 24 of its Reply Comments, Piedmont discussed the OptimaKV project, which is covered by the Agreement in Sub 701. Piedmont stated that the project "will consist of 5 covered lagoon digesters where Alternative Gas will be collected, piped to a central location for clean-up using pressure swing adsorption technology and then injected into Piedmont's transmission system.

Has Piedmont made OptimaKV aware of potential changes in federal pipeline safety regulations concerning rural gathering pipelines?

(e) Commission Rule R6-18(1) requires that the utility shall make material changes only with the approval of the Commission, and after adequate notice to the customers. The Agreements for which Piedmont seeks approval in Subs. 699 and 701 were filed as confidential. How does Piedmont intend to give adequate notice to its customers when the location points of the Alternative Gas producers are not revealed?

(f) Will Piedmont allow the producers in Subs 699 and 701 to choose where their gas is injected into its system? If so, is it reasonable to consider this change as under Piedmont's control, within the meaning of Commission Rule R6-18(1)? If Piedmont's answer is "No," explain.

PIEDMONT'S RESPONSE:

(a) If Piedmont's proposed Alternative Gas standards, as revised on October 26, 2017, are approved, without modification, then Piedmont will accept responsibility for adverse customer impacts resulting from Alternative Gas received by Piedmont that is in compliance with those standards.

(b) Sub 699 interconnects with a 6 inch pipeline that has a current Maximum Allowable Operating Pressure of 718 psig.

(c) Sub 699 interconnects with a 6 inch pipeline.

(d) No.

(e) As discussed above, Piedmont believes that its proposed Alternative Gas standards, as revised on October 26, 2017, will mitigate the risks of receiving Alternative Gas on its system and has filed those standards for Commission approval. It does not currently believe that such standards, in their current form, represent a material change in the character of gas service under Rule R6-18 and has not specifically and independently advised its customers of the pendency of this proceeding. Piedmont has no objection to advising potentially impacted customers of the pendency of this proceeding if the Commission believes that such notice is necessary or appropriate.

(f) The location and volumes of Alternative Gas to be received by Piedmont with respect to any particular Alternative Gas project will be determined by Piedmont and the potential Alternative Gas supplier through negotiations. Piedmont's determination of where to allow an Alternative Gas supplier to access its system (and what volumes of Alternative Gas are allowed to flow into its system at that point) could establish the predicate for a determination that Piedmont facilitated a "material change" in the character of service for one or more downstream customers; however, Piedmont believes that its proposed standards, as revised on October 26, 2017, would not result in a "material change" in the character of service for such customers and plans, in any event, to present such projects to the Commission and Public Staff for review and approval prior to implementation.

14. Please explain whether Piedmont uses heat content as a factor in billing its customers. If so, provide the details of how heat content factors into a customer's bill.

PIEDMONT'S RESPONSE: Heat content is a factor used in calculating bills for natural gas service rendered to Piedmont's customers. Measurement of a customer's natural gas usage is performed on a volumetric basis, meaning that a reading of the customer's natural gas meter is used to identify the cubic feet of natural gas that flowed thru the customer's meter over a specific period of time. Piedmont's billing rates, as approved by the NCUC, are set on a $ per therm basis. Therefore, the heat content factor (aka heat factor) provides the necessary conversion to align the measured usage at the customer's meter with the approved billing rate for any period of time.

For any given billing period, the heat factor applied to customer usage can vary by region. For billing purposes in light of varying heat factors across our system, Piedmont has subdivided its system into several Common Gas Areas ("CGAs"). The CGAs capture the differing heating values of gas delivered to customers located in various parts of Piedmont's system. Piedmont has segregated its NC service territory into 11 CGAs presently, based on Piedmont's analysis of gas flows across its system.

15. Commenters representing Alternative Gas producers seek to inject Alternative Gas that has the lowest heat content allowable into Piedmont's distribution system. In the NCPC's Comments, it was reported that Piedmont responded in a data request that the average heating value of gas in Piedmont's pipeline is 1031 Btu/SCF. Footnote 11 on page 12 of Piedmont's Reply Comments states:

> **Transco's gas quality standards provide for a minimum heat value of 980 BTUs/SCF for gas delivered into its system – which is the same minimum heat content proposed by Piedmont in Appendix F. The actual gas Piedmont has received from Transco, however, has consistently had a heat content of very close to 1030 BTUs/SCF.**

Given Piedmont's statement that, under some operating conditions, some segments of its system may receive 100% Alternative Gas, how will Piedmont bill customers on those segments downstream of Alternative Gas injection points to ensure that they will not be adversely impacted by Alternative Gas agreements?

<u>PIEDMONT'S RESPONSE</u>: Piedmont periodically evaluates the demarcation of its CGAs, including when new receipt points are added. Piedmont will continue to monitor and evaluate its CGAs with the addition of receipt points for Alternative Gas supplies, and modify its CGAs as necessary to ensure that no customers are adversely impacted by these interconnections.

16. There is a 10-inch line and an 8-inch line in Duplin County. At what pressures do those lines operate? What is the direction of flow on those lines; does the direction change periodically? What is Piedmont's estimate of the volume of gas that those lines carry?

PIEDMONT'S RESPONSE: The10-inch line and an 8-inch line in Duplin County both have a Maximum Allowable Operating Pressure of 962 psig.

Flow on the10-inch line and an 8-inch line in Duplin County is typically from north to south. With varying system demand, gas can flow from the south to the north on those lines. Flow ranges from a maximum of 15,000 mcf per day in winter design conditions to a minimum summer condition of 2,500 mcf per day.

Sub 699 will interconnect to a 6 inch pipeline that flows East- West and interconnects with the 10 inch pipeline. The 6 inch pipeline flow ranges from maximum of 4,000 mcf per day in winter design conditions to a minimum summer condition of 2,500 mcf per day.

17. Piedmont used the landfill gas standards adopted by its sister LDC, Duke Energy Ohio, as one source of information in establishing standards. Describe in detail Duke Energy Ohio's facilities that receive landfill gas. Include the size and composition of the pipeline into which landfill gas is injected, the pressure, and whether or not the facilities are limited to transport of landfill gas. If the landfill gas is blended with interstate pipeline gas, describe the average heat content of the blended gas.

PIEDMONT'S RESPONSE: Duke Energy Ohio receives landfill gas into a 12-inch steel main with a Maximum Allowable Operating Pressure of 35 Psig supplying a large distribution system. Specific Gravity is limited to 0.596 above which Gas Control will valve off the interconnect station. Contract allows injection of up to 400 mcfh. When injection rates drop, the line is back fed from the natural gas system.

18. When Piedmont has established a satisfactory course of business with a natural gas supplier or marketer, such that Piedmont feels confident about the quality of natural gas being delivered by the supplier or marketer, does Piedmont continue to require regular gas quality testing by that supplier or marketer? If not, explain the details of how Piedmont determines to cease requiring such regular gas quality testing.

PIEDMONT'S RESPONSE: Please see responses to questions 1 and 4 above.

19. Piedmont stated that Duke may be "receiving" directed biogas from production facilities in Missouri and Oklahoma for the benefit of one or more of its electric distribution utilities. Describe in detail the interconnection with facilities in those states, including the heat content, pipeline the gas is injected into and the pressure at which the biogas is delivered into the pipeline.

PIEDMONT'S RESPONSE: Piedmont does not have knowledge of this information.

PUBLIC STAFF

20. With regard to Commission Rule R6-18(1) [Change in Character of Service], does the Public Staff believe that the acceptance of Alternative Gas into Piedmont's system at points chosen by an Alternative Gas supplier constitutes a change that is under Piedmont's control?

PUBLIC STAFF'S RESPONSE: Commission Rule R6-18 provides the procedure to be followed whenever there is "a material change in the character of the gas service". The Public Staff is unaware of any instance in which the Commission has applied or interpreted this Rule.

Alternative Gas is defined in proposed Appendix F to Piedmont's North Carolina Service Regulations as "gas capable of combustion in customer appliances or facilities which is similar in heat content and chemical characteristics to natural gas produced from traditional underground well sources and which is intended to act as a substitute or replacement for Natural Gas (as that term is defined in Piedmont's North Carolina Service Regulations)." Assuming Piedmont's proposed Alternative Gas quality standards are approved by the Commission, the Public Staff does not believe that acceptance of the Alternative Gas into Piedmont's system would constitute a material change in the character of the gas service within the meaning of Commission Rule R6-18.

In regards to system injection "points chosen by an Alternative Gas supplier," Piedmont has indicated to the Public Staff that the injection points on its system are mutually agreed upon by Piedmont and the Alternative Gas supplier, rather than the points being "chosen" by the Alternative Gas supplier.

21. If the Commission approves Appendix F, will Piedmont be required to seek Commission approval for agreements with additional Alternative Gas suppliers? If so, will Piedmont be obligated to provide adequate notice of such Agreements to its customers?

PUBLIC STAFF'S RESPONSE: The Public Staff believes that Piedmont should file such agreements with the Commission for informational purposes. Assuming Piedmont's proposed Alternative Gas standards are approved by the Commission and the Alternative Gas proffered for delivery into Piedmont's system meets those specifications, the Public Staff does not believe that customer notice should be triggered. If the Alternative Gas does not meet the specifications, Piedmont has indicated it may interrupt or suspend its receipt and acceptance of Alternative Gas and should provide notice to its affected or potentially affected customers.

22. Does the Public Staff have an opinion on the need to adjust bills to reflect the lower heat content in Alternative Gas? Ease of administration is a well-accepted principle of ratemaking. The use of system-average heat content in billing was explicitly approved for PSNC in its last general rate case in Docket No. G-5, Sub 565. Is a variance of almost 5% acceptable for customers who are presently receiving gas that has a heat content close to the system average?

PUBLIC STAFF'S RESPONSE: PSNC uses a system-wide heat factor for all customer bills that is derived by computing a weighted average of all of its take-off stations along interstate pipelines. Piedmont has 11 "common gas areas" that have different heat factors according to the heat content of the gas in those regions. Piedmont may want to implement "sub areas" if the injection of Alternative Gas begins to significantly change the heat content of a particular common gas area. The Public Staff believes that the common gas areas (and possible sub areas) employed by Piedmont maintain reasonable accuracy for customer billing purposes.

Using data obtained from Piedmont's monthly Gas Utility Reports provided to the Public Staff, the Public Staff has calculated that the simple average heat content of natural gas for the twelve month period of September 2016-August 2017 was 1034 Btu/SCF. Piedmont's proposed minimum heating value of 980 Btu/SCF is 5.22% lower than the historic 1034 Btu/SCF; however, this variance assumes that a customer would be receiving 100% Alternative Gas, which is very unlikely unless a customer is adjacent to the Alternative Gas injection point and is located on a section of the distribution system that has relatively low volume flow. The Public Staff does not anticipate that Alternative Gas will become a major source of gas supply, and, therefore, customers are not likely to experience significant variations in heat content.

PSNC

23. On page 5 of PSNC's Comments, a statement is made that "Gas quality and interchangeability requirements should accommodate differing local needs and, for that reason, such requirements should be considered on a case-by-case basis." What is meant by "local needs?"

PSNC'S RESPONSE: "Local needs" refers to the characteristics of the Alternative Gas, and the quantities of that gas, being produced and proposed to be injected into PSNC's system, and the nature and characteristics of PSNC's system (pressure, pipe size, flows and velocities, etc.) at the proposed injection point.

24. When the parties finalize their proposed Alternative Gas standards and submit them to the Commission, explain which Alternative Gas standards proposed are directed to the local needs of Piedmont and may not necessarily be applicable to another LDC system.

PSNC'S RESPONSE: An LDC could potentially be more flexible with its gas quality standards where very small quantities of Alternative Gas were being injected into its system at a point where the flows and velocities are consistently very high, therefore blending the very small quantity of Alternative Gas with the much greater quantity of natural gas.

NCPC (see also Question 34)

25. On page 8 of the NCPC's Comments, it requests that the Commission convene a stakeholder conference "with the express purpose of developing

a standard governing the obligation of a local distribution company in North Carolina to receive, transport and deliver biogas." What is the basis of the NCPC's assertion that a natural gas local distribution company has an obligation to receive biogas?

<u>**NCPC'S RESPONSE**</u>: Currently there are no natural gas production plants in North Carolina. *See, North Carolina Oil and Gas Study Under Session Law 2011-276 at* 93-94 (April 30, 2012). Thus, the transmission of gas from an in-state point of production to an in-state end user or to a consumer out-of-state has not been part of North Carolina's natural gas landscape. This state of affairs is due to historical circumstances and the absent of geological reserves. There is no aversion to innovation or advancing technology in the state. Indeed, to a limited extent renewable natural gas from landfills is collected and used in North Carolina, normally on-site, and with the advent of "fracking," the commercial-scale production and transmission of natural gas in North Carolina was beginning to emerge until a decline in prices made that type of venture unattractive. Given these circumstances, the transmission or transportation of natural gas from the point of production in North Carolina to an end-user in or out-of-state is not a commercial play and at present no North Carolina law explicitly requires a local distribution company ("LDC") to provide transportation or redelivery services. *See, State ex rel Utilities Commission v. CUCA,* 328 N.C. 37, 399 S.E.2d 98, 103 (N.C. 1991). *But see,* N.C. Gen. Stat. § 62-36.01 (authorizing the Commission to order a franchised natural gas local distribution company to negotiate and enter into service agreements (including "backhaul" agreements) when, among other

considerations, such agreements will provide increased competition in North Carolina's natural gas industry).

Although not explicitly required to provide transportation or redelivery services, Piedmont Natural Gas Company, Inc. ("Piedmont") offers those services in its assigned territory as a means to provide its customers the ability to buy gas on the "spot" market. In such instances, Piedmont transports or redelivers gas originally owned by a third-party to a customer/buyer in Piedmont's service area for a fee. *See,* Piedmont Natural Gas Company, Inc., *North Carolina Service Regulations* at 4 (defining "services" as including transportation and redelivery services); 2016 *N.C. Utilities Commission Report* pg. 73 ("Piedmont and its subsidiaries are also engaged in the acquisition, marketing, transportation, and storage of natural gas"); Piedmont Natural Gas Company, Inc., *North Carolina Rate Schedules* 113 & 114.

Pursuant to the utility franchise, Piedmont has a state-granted monopoly covering the services it provides in its franchised area. N.C. Gen. Stat. § 62-110. No entity qualifying as a natural gas utility can provide services similar to the services Piedmont provides in its service territory. *See Commission Rules and Regulations,* Rule R 6-60 ("[n]o natural gas utility shall construct or operate natural gas facilities in territory occupied by and receiving similar service from another natural gas utility except upon written . . . approval by the Commission"), Rule R 6-61 ("[n]o natural gas utility under the jurisdiction of the Commission shall construct or operate a natural gas pipeline facility outside of its designated territory . . . or to be connected to an interstate pipeline . . . without having first applied in writing to, and obtained the written approval of the Commission"). In return for receiving this exclusive, monopoly franchise, Piedmont is obligated to render adequate, efficient and reasonable service. *See, State ex rel Utilities Commission v. Morgan,* 277 N.C. 255, 177 S.E.2d 405 (1970) *aff'd on reh* 278 N.C. 235, 179 S.E.2d 419 (1971) ("having been granted a monopoly in its franchise area, the utility is under a duty to render reasonably adequate service."). *See also,* N.C. Gen. Stat. §62-131(b) ("Every public utility shall furnish adequate, efficient and reasonable service.") and *State ex rel Utilities Commission v. Buck Island,* 592 S.E.2d 244, 251, 162 N.C. App. 568 (2004) (all public utilities have an obligation to provide adequate, efficient and reasonable services). Piedmont is also required to provide its services in a manner that does not grant any unreasonable preference or subjects any person to any unreasonable prejudice or disadvantage. N.C. Gen. Stat. § 62-140. "There must be no unreasonable discrimination between those receiving the same kind and degree of service." *Utilities Comm. v. Mead Corp.,* 238 N.C. 451, 462, 78 S.E.2d 290, 298 (1953).

Taken together then, having decided to provide transportation and redelivery services as part of the portfolio of services it undertakes in its franchise territory and having been given an exclusive monopoly to provide those services, Piedmont has a duty to allow access to those services openly, fairly and without imposing any unreasonable restrictions or requirements, and to provide those services to <u>any</u> eligible person seeking the services. The Court of Appeals underscored this duty in 2004 when it confirmed that "[a] public utility must serve alike all who are similarly circumstanced with reference to its system, and favor cannot be extended to one which is not offered to another, nor can a privilege given one be refused another." *Buck Island,* 592 S.E.2d at 250 *quoting Utilities Commission v. Water Company,* 248 N.C. 27, 30, 102 S.E.2d 377, 379 (1958).

In most instances what is being contemplated by in-state producers of renewable natural gas ("RNG") is no different than Piedmont's existing transportation arrangement. That is, Piedmont will be redelivering or transporting RNG acquired by one of its customers, *e.g.,* Duke Energy Progress, from a supplier other than Piedmont. Like gas on the spot market, the customer will acquire the RNG from a third-party supplier. Piedmont will then provide the transportation necessary to bring the RNG to the location of use within its service area.

In other instances, however, there may be a non-qualitative distinction where Piedmont is asked to provide transportation services between a producer of RNG and a buyer outside of Piedmont's service area. Like the services Piedmont provides in connection with the transportation of geologically-derived natural gas that originates outside of its service territory, Piedmont will move the RNG through its pipeline network from supplier to purchaser. The ultimate consumer would not be Piedmont's customer but the RNG producer's customer and a customer of some other LDC. The services contemplated still amount to transporting gas. Since Piedmont provides transportation services to producers and consumers of geologic natural gas, Piedmont also is required to provide the same kind and degree of service to RNG producers and consumers subject to similar standards and criteria.

26. On page 7 of the NCPC's Reply Comments, it states, "In reality, the blended gas stream is likely to be dominated by fossil-derived natural gas with a higher Btu." What is the basis for that assumption?

<u>NCPC'S RESPONSE</u>: The biogas produced from renewable sources in North Carolina, such as swine waste, will be processed at a facility very similar to, if not the same as a facility used to process gas from conventional geologic plays, such as the shale gases in other states. Impurities will be removed and the biogas upgraded to an RNG suitable for injection into Piedmont's pipeline. The processing facility can be located in areas that provide optimal access to existing and future pipelines.

It is unlikely that Piedmont's pipeline will be devoid of natural gas at the point of injection. Rather, in most all cases it is likely that at the point of injection Piedmont's pipeline will contain gas that is derived predominately from geologic sources. It also likely that Piedmont's main line will be substantially larger in size and contain substantially higher volumes of gas than the line leading from the RNG processing facility to Piedmont's line. If these factors are desired they can be engineered into the project. Thus, in all cases the RNG flow rate at the point of interconnection will be substantially less than the rate of flow in main line receiving the RNG. This scenario will result in a blended gas stream dominated by geologic natural gas. And again, if this scenario is desired, it could be engineered into the project.

It should not be lost, however, that the natural gas flowing in the main line – regardless of source, either geologic or otherwise – was required to meet the prevailing standards, specifications, and requirements when injected. As such, engineered "dilution" of RNG makes little sense. Once injected the gas becomes blended and uniform, comparable to the blended gas from the various sources upstream of the point where Piedmont receives the gas entering its service territory.

27. In a data response to the NCPC, Piedmont explicitly stated, "with respect to the two pending applications for approval of Alternative Gas production on its system, the Alternative Gas may be up to 100% of the gas flow in certain segments of Piedmont's system under certain operating conditions." Would the NCPC be willing to accept a requirement that Alternative Gas production would be curtailed if the concentration at any point down-steam caused the heating value to fall below a level determined by the Commission?

<u>NCPC'S RESPONSE</u>: The heating value of the gas in Piedmont's distribution system on average is 1031 Btu/SCF. Given that the gas stream at the point of interconnection is likely to be dominated by geologic natural gas, the addition of RNG is unlikely to affect the heating value of the blended stream in a material way. Even in an unlikely scenario where equal amounts of RNG with a heating value of 960 Btu/SCF were added to a stream of geologic natural gas with an average heating value of 1031 Btu/SCF, the resulting blended gas stream would have a heating value of 995.5 Btu/SCF or 15 points higher than what Piedmont is recommending in its proposed gas quality standard.

Nevertheless, Piedmont has expressed a hypothetical concern about two situations where, under certain circumstances and given certain "operating conditions," the gas stream after a point of interconnection might be dominated by RNG. If such circumstances and conditions were to occur, Piedmont suggests that the heating value of the blended gas stream might fall below the level desired by the customer. While curtailment might be one approach to address this problem (assuming it exists) there are other approaches that in any set of circumstances may be more appropriate. Adopting a "one-size-fits-all" response like automatic curtailment limits options and from an economic and technological standpoint makes little sense.

For example, if a design study showed a real potential for the heating value of the blended gas stream to fall below an acceptable level, one answer might be to adjust the point of injection. Alternatively, it might be feasible to blend in components (like hydrocarbons) to enhance the heating value. Nitrogen reduction might also be an option as would adjusting flow rate at the point of interconnection. In short, there are multiple options. An approach like curtailment is not necessarily the best choice in all instances and could elevate the concerns of one customer over other customers resulting in discrimination towards others served on the same main line. *See,* N.C. Gen. Stat. § 62-140. "There must be no unreasonable discrimination between those receiving the same kind and degree of service." *Utilities Comm. v. Mead Corp.,* 238 N.C. 451, 462, 78 S.E.2d 290, 298 (1953)).

From an overall project standpoint, the potential for third-party curtailment makes financing very difficult. Investors want a predictable rate of return which is dependent on relatively constant production levels. Contracts also have supply requirements and expose project developers to liability if missed. The potential for third-party curtailment would disrupt production, disrupt distribution and impact the project developer's ability to meet contract demands. These potentials make financing a project more difficult, if not impossible.

In short, third-party curtailment is a drastic measure. There are multiple options any one of which may be better suited for the situation at hand. Moreover, at the moment the "problem" is hypothetical. Consequently, until the NCPC knows more about the situation Piedmont is referencing, the conditions that need to be present for the risk to arise, and all of the options available, NCPC could not agree to production curtailment as the sole solution for this hypothetical concern.

ENERDYNE

28. On Page 4 of Enerdyne's Reply Comments, Enerdyne contends that, "the Commission should ensure that the charges passed through to a RNG producer are based on actual cost, and that the actual cost of interconnection is not marked up to create a 'profit center' for the pipeline owner." North Carolina law allows utilities to earn a fair return on the investment they make to provide utility service. If LDCs are prohibited from earning a return on capital invested for interrconnecting [sic] Alternative Gas

providers, why should LDCs commit their capital to construct such interrconnections [sic]?

__ENERDYNE'S RESPONSE__: Enerdyne acknowledges that Chapter 62 entitles a utility to earn a fair return on reasonable and prudent investment made by the utility in order to provide utility service, and Enerdyne was not suggesting that an LDC should not earn a return on capital invested for interconnecting Alternative Gas/RNG providers. Enerdyne has no problem with an LDC earning its Commission-approved return on such investment.

Enerdyne's concern is that the interconnection fee proposed by Piedmont is dramatically higher than the interconnection fees charged by other LDCs for interconnecting with RNG suppliers, which gives rise to the concern that the proposed fees were not calculated on an appropriate basis. Enerdyne or its affiliates have paid from as little as approximately $235,000 for a 2" tap, to slightly over $1M for a 3" tap. Piedmont's proposed interconnection charge from $1.4M to $2M, is far higher than interconnection fees charged elsewhere. Enerdyne would expect to be charged a reasonable fee to establish an interconnection point, based on approved utility accounting and ratemaking practices as approved by the Commission.

29. Describe in detail the Alternative Gas facilities of the six entities described on Enerdyne Revised Exhibit 1, including:

(a) The type of biomethane being delivered, the size and material (iron, plastic) of the pipeline into which Alternative Gas is

injected, the pressure, whether the pipeline contains interstate gas, and whether or not the pipeline facilities are limited to the transport of Alternative Gas.

(b) Whether all of these entities local distribution companies whose systems receive natural gas from interstate pipelines.

(c) The applicable quality and testing standards required, and the source of the standards (state Commission, FERC, etc.) for each of the interconnections of these six entities with the LDC.

<u>ENERDYNE'S RESPONSE</u>: Enerdyne's Revised Exhibit 1 summarized the specifications utilized by six pipeline companies which accept Alternative Gas/RNG, as compared to the specifications proposed by Piedmont. The six biomethane "landfill gas – RNG" facilities listed in Revised Exhibit 1 are a good cross section of the renewable natural gas industry. Three of the pipelines identified there are interconnected with current or former Enerdyne projects, and three represent projects owned by other RNG project developers. Three of the RNG recipients identified there are LDCs, and the other three are transmission companies providing either interstate or intrastate delivery.

Enerdyne continues to gather the specific information requested relating to those projects, and will supplement this response as additional information is obtained. Subject to that caveat, Enerdyne's preliminary responses to this question is as follows:

1. TransCanada Pipeline (formerly Columbia Gas transmission companies - two of which were known as Columbia Gas Transmission and Columbia Gulf Transmission), has agreed to take landfill gas from an Enerdyne project in Boyd County, Kentucky, starting in 2018. The original estimated charge for connecting with those two lines was approximately $473,000. Since the acquisition by TransCanada the tap fee has increased to $534,000. Enerdyne's 2.1 mile line that will reach the interconnection point/tap will be a 4" steel line, and the tap will be 3". These coat and wrap steel lines will be tested to over 1500 PSI, the TransCanada line pressures vary between 950 PSI and 1050 PSI. TransCanada's minimum BTU specification is 967 and its pipeline is not limited to the transport of Alternative Gas.

There are actually three side by side Columbia/TransCanada transmission lines connecting the Gulf with northeastern states. These lines contain interstate geologic natural gas and are not exclusively connected to RNG suppliers. These are billion cubic feet per day (BCF) pipelines (one of which may, in fact, fuel Piedmont).

Before the Columbia LDCs and transmission companies split in July 2015, Enerdyne worked with Columbia Gas of Ohio and Columbia Gas of Kentucky. Columbia Gas of Ohio is an LDC that connected a 16 mile upgrade line to the ARIA owned LFG facility at the SWACO Landfill Authority just south of Columbus. That facility moves about 3500 DTs per day. The applicable test standards for both are listed with FERC.

2. Montauk Energy has a LFG project located at the Rumpke Landfill, and that project interconnects with Duke Energy's Gas facility near Cincinnati, Ohio on the north side of the I-275 beltway in Colrain. This Montauk facility has been located there since the late 1980's. Montauk's delivery pipe connects directly into Duke's LDC local delivery system line and the RNG is used in the immediate vicinity. Montauk has an 8,700 foot 12" steel coat and wrapped pipeline that operates at 25-30 PSI and connects to Duke's 8" steel line at the interconnection point. The Duke Energy pipeline facilities are not limited to the transport of Alternative Gas. This is one of seven high BTU plants operated around the country by Montauk and the Duke Energy specifications are the second most rigorous specifications that Montauk deals with – at five of its projects the minimum BTU specification is below 967. The specifications in Duke Energy's LDC tariff for receipt of LFG at that landfill are considerably more relaxed and are not consistent with the specifications proposed by Piedmont.

3. There are several RNG projects connected to the Atmos Energy/Atmos Gas Pipeline, and Atmos' standards are posted on its website. Atmos is an LDC, and its pipeline facilities are not limited to the transport of Alternative Gas. One project interconnecting with Atmos is the McCommus Bluff Landfill owned by the City of Dallas. Energy Power Partners recently acquired this project from Clean Energy with processing capacity of 15 million cubic feet per day. Steel lines from that project interconnect with the pipeline at less than 300 PSI. Atmos' 950 BTU specification and its testing protocol are set forth in its tariff.

The Morrow Renewable Energy's project at Republic's Greenwood Farms Landfill in Tyler, Texas, is connected to Gulf South Pipeline, an intrastate pipeline, and its pipeline facilities are not limited to the transport of Alternative Gas. That project was constructed in 2009, designed to treat 3.6 MM SCFD of raw landfill gas. The line is carbon steel coated 4" pipe, which runs to a 2" tap on Atmos' 12" or 14" steel line.

4. The Houston Gas Pipeline is an intrastate transmission pipeline, owned by Energy Transfer, that transports geologic natural gas from the gathering fields in Southern and SE Texas to a massive terminal in Houston. One of the RNG projects feeding into this intrastate line is the Fort Bend LFG project.

The Houston Pipeline (HPL) operates at over 900 PSI, but fluctuates to as low as 750 PSI. The HPL line is a 12" steel line and the line from the Ft. Bend LFG project is 4" steel running 2.2 miles to the point of interconnection with HPL, which is a 2" tap. The cost to complete the tap and associated measuring and testing equipment was $278,000. HPL has a 950 BTU minimum specification, which is common. The HPL pipeline facilities are not limited to the transport of Alternative Gas.

The Fort Bend LFG project was purchased from Enerdyne and Morrow Renewable Energy four weeks ago by a subsidiary of Detroit Edison (DTE Energy), a large Midwestern electric and gas utility. DTE Energy owns an LDC that serves 1.2 million customers in Michigan, as well as several High BTU projects in its LDC service area. DTE Energy both accepts landfill gas from other RNG projects and injects LFG from its own projects into the Michgas system. Enerdyne and Morrow owned this facility for over five years.

5. The Southern Star Pipeline is a transmission line that supplies natural gas to many LDCs in Kansas and Nebraska. An Enerdyne affiliate, Renewable Power Producers, LLC (Enerdyne), has a project in Lawrence, Kansas located at the Hamm Landfill, which project is currently in startup mode, and all lines are complete. Southern Star's transmission line connects many gas producers to many LDC users. Southern Star's transmission line operates between 550-625 PSI, and Enerdyne's 7.2 mile 6" steel pipeline runs to a 2" tap on the Southern Star line that has been hydrostatically tested to 1000 PSI. Southern Star's pipeline facilities are not limited to the transport of Alternative Gas.

The receiving pipeline's principal utility concerns are 950 BTU quality, low moisture, and low hydrogen sulfide. Enerdyne has tested for other constituents that have been determined not to be a concern. Enerdyne submitted something akin to a one-line electrical drawing to Southern Star's engineers illustrating its plant components and technology for their technical review, which allows the pipeline's engineering team gets to understand the components and what tasks they perform.

6. Atlanta Gas Light (AGL), an LDC now owned by Southern Companies and known as Southern Gas, has connected several LFG projects to its system over the past decade. After getting over its initial concerns about handling LFG, Southern Gas has developed its own high BTU projects both in its service territory

and in Eastern Tennessee. Air Liquide is a large French manufacturer of gas and gas manufacturing equipment which operates around the world. Air Liquide and DuPont have a division called Modal, located in Wilmington, Delaware that has built and sold LFG equipment to over 20 High BTU plants. Air Liquide has also bought the Jacobe plant near the Atlanta airport and has been operating that project for the last four years. 950 BTU is the AGL/SouthernGas minimum gas quality specification. The LFG injected to the AGL line is actually physically consumed in the Atlanta area but is technically sold to users in California though the gas nomination process.

AGL has a ring pipeline that encircles the City of Atlanta, and AGL operates for Air Liquide its 3" ½ mile long steel pipeline that connects to AGL's 20" pipeline, which operates at 300 PSI. The AGL pipeline facilities are not limited to the transport of Alternative Gas. Other than the RNG projects that feed into the AGL ring around Atlanta, all of AGL's system is supplied from interstate gas transmission connections.

NCSEA

30. NCSEA stated that it "supports pipeline standards that would enhance the ability of electric public utilities to comply with the REPS set-aside obligations while not impacting rates for natural gas customers." If the acceptance of Alternative Gas into Piedmont's system results in certain natural gas customers receiving 5% or more less heat content in their gas,

would NCSEA agree that some adjustment would have to be made to avoid "impacting rates?"

<u>**NCSEA'S RESPONSE**</u>: Yes, NCSEA agrees that an adjustment may be necessary to avoid impacting rates if Alternative Gas results in certain natural gas customers receiving gas with a heating value of less than the standard heating value set forth in the utility's tariff. However, if natural gas customers receive gas with the heating value that is set forth in the utility's tariff, then NCSEA does not believe that an adjustment is necessary.

31. NCSEA objects to what it describes as "duplicative requirements by necessitating both pre-injection testing and in-pipeline monitoring" in Appendix F. Does in-line monitoring include the installation and measurement of gas quality with a chromatograph? If so, how would pre-injection testing measure such gas quantities as heat content on a continual basis?

<u>**NCSEA'S RESPONSE**</u>: If a chromatograph is installed to provide in-pipeline monitoring and measurement of gas quality, then it is NCSEA's position that it is unnecessary to require pre-injection testing for the same gas qualities.

<u>RNG COALITION</u>

32. On page 2 of its Comments, the RNG Coalition asserts that:

[R]NG Coalition members own, operate, build, install, transport, or otherwise service and support the 56 RNG projects in North America. Forty-eight (48) of those projects inject RNG into common carrier, natural gas pipelines.

(a) How does the RNG Coalition define a "common carrier natural gas pipeline?"

(b) Describe in detail the facilities into which the 48 projects inject RNG into common carrier, natural gas pipelines. Include the size and composition of the pipeline into which Alternative Gas is injected, the pressure, and whether or not the facilities are limited to the transport of Alternative Gas.

(c) If the Alternative Gas is blended with interstate pipeline gas, describe the average heat content of the blended gas.

<u>RNG COALITION'S RESPONSE</u>:

(a) The RNG Coalition's reference to "common carrier natural gas pipeline" means a pipeline that transports natural gas and is connected with the broader network of natural gas pipelines. Common carrier is inclusive of Local Delivery Carriers (LDC), interstate and intrastate transmission and gathering lines. A "common carrier natural gas pipeline" is distinguished from a "dedicated pipeline" which only transport gas from one point to another (i.e. a landfill gas facility to an electricity generating turbine), and does not also transport natural gas from other source points.

(b) Biomethane leaves the RNG facility having met the pipeline company's gas quality tariff. The biomethane is transported via a dedicated pipeline to an interconnection facility. Rigid steel is the traditional material that makes up many distribution pipelines. Flexible plastic and corrugated stainless steel tubing are often used in newer pipelines. Natural gas in transmission pipelines may be compressed up to 1,500 psi. in pipelines that typically have diameters of 16 inches to 48 inches. Distribution pipelines, on a national basis, are typically 1 inch to 24 inches in diameter and may have pressures as low as 0.25 psi to 100 psi.

The RNG producer delivers the biomethane to the Interconnection Facility at a Point of Receipt. The Interconnection Facility typically includes a shut off valve, gas chromatograph, buffer tank, compressor, gas cooler, flowmeter, odorization, sampling port, disconnect valve, and finally a meter. Biomethane flows through these components before reaching the natural gas pipeline.

Interconnection Facilities are not limited to the transport of Alternative Gas. In fact, none of the 48 projects cited deliver to transport systems that are limited to the transport of Alternative Gas.

US EPA's Renewable Fuel Standard even requires that qualified-RNG meets the common carrier natural gas system standards.

(c) The average heat content of blended Alternative Gas and Interstate Pipeline Gas depends on the heat content of both gas components and the volume ratio of both and is therefore not universally answerable.

33. **On page 6 of its Comments, the RNG Coalition states:**

As a purely practical matter, RNG is already delivered through Piedmont's system in North Carolina, either by virtue of the directed biogas scenarios approved by the Commission in other dockets, and/or by virtue of the fact that pipelines connecting to Piedmont have transported RNG for years (and some for decades).

(a) Does the RNG Coalition believe that "directed biogas" physically moves through Piedmont's system? If so, explain in detail which out-of-state project the directed biogas comes from, how it reaches Piedmont's system and what percentage of the gas in any part of Piedmont's system that it traverses does it make up.

(b) With regard to the pipelines connecting to Piedmont that have transported RNG for years or decades, describe in detail which

Alternative Gas projects are the source of such gas, how the gas moves to North Carolina, and what percentage of the flow on such pipelines is Alternative Gas.

RNG COALITION'S RESPONSE:

(a) Yes. At least one RNG Coalition member daily schedules and nominates "directed biogas" through Piedmont's system to a customer in North Carolina. The gas in question is injected into Dominion Transmission, Inc. (DTI) at the DTI spec.

(b) Methane is methane. Once the biomethane molecules are injected into the common carrier pipeline system, the bio-methane molecules are indistinguishable from geologic methane molecules.

Injecting natural gas (whether geologic or alternative) into the common carrier pipeline is much like making a deposit at a bank and withdrawing it from an ATM. While you are not removing the same bills (molecules) that you deposited with the bank, the deposited money is accounted to you and debited from you at withdrawal. We don't have a way to tracking which molecules or what percentage of flow are in North Carolina pipeline. However, we know that RNG has been injected for years into nearby systems. For example, in Georgia, the Dekalb County and Live Oak facilities put RNG into the Atlanta Gas and Light system. In Louisiana, the River Birch and Jefferson Davis Paris put RNG into the Atmos and Gulf South systems. In New York, Fresh Kills has injected RNG into the National Grid system for more than 30 years. In Tennessee, North Shelby injects RNG into the Memphis Light Gas and Water system.

RNG COALITION AND NCPC

34. The RNG Coalition contends that "The Appendix F requirement for Nitrogen at 'not more than 2% by volumetric basis is arbitrary and exclusionary since ACP accepts Nitrogen at up to 4%." The NCPC makes the same argument, pointing to both the nitrogen and the total inerts standards in the Atlantic Coast Pipeline's and Piedmont's gas quality standards. The NCPC states that "Piedmont explains the more stringent requirements in its Alternative Gas Quality Standards as being based on 'differences between pipeline provided natural gas and Alternative Gas.'" The NCPC then asserts, "That explanation lacks merit and suggests bias."

However, the RNG Coalition concedes that "Because biomethane does not have all of the higher-chain hydrocarbons, it does not reach the BTU levels of geologic natural gas." And the NCPC states that "Natural gas contains other 'wet alcohols' such as propane, butane and ethane that by the mere presence increase the heat value. Biogas does not contain these constituents and to consistently reach the 980 Heating Value a producer would need to produce a biogas consisting of 98% methane or would have to blend in propane or some other higher hydrocarbons.

By arguing for the rejection of the 4% nitrogen standard, do both the RNG Coalition and the NCPC accept the injection of other hydrocarbons into Alternative Gas as the preferred method of increasing heat value to the 980 Btu/SCF heat value minimum or to the system average of approximately 1,030 Btu/SCF, if those levels are ordered by the Commission?

RNG COALITION'S RESPONSE: Injection of other hydrocarbons into Alternative Gas is technically feasible, but often cost prohibitive to a project's economics. It is not the preferred method of increasing heating value to 980 Btu/SCF. More preferable would be an allowance for achieving the heating value through blending of alternative gas and pipeline gas in the pipe. For instance, if the average heating value of the pipeline gas is 1000 Btu/SCF at the point of injection, and the volume in the pipe is at a 1:1 ratio with the Alternative Gas injected, we can know that Alternative Gas injection at 960 Btu/SCF will achieve the desired 980 Btu/SCF.

If the Commission decides to set a minimum heating value for Alternative Gas at 980 Btu/SCF, and reject the above recommendation, then the RNG Coalition encourages the Commission to look for ways to financially support projects' procurement of hydrocarbon injection.

NCPC'S RESPONSE: The limit for nitrogen in Piedmont's proposed Alternative Gas Quality Standard is 2.0% by volumetric basis. The limit for nitrogen in the proposed standard for the Atlantic Coast Pipeline is 4.0%. Transco has no limit for nitrogen and no other tariff identified sets the limit on nitrogen as low as Piedmont's proposal. Thus, the NCPC believes Piedmont's proposal for nitrogen is too restrictive and unjustified. The RNG standard for nitrogen should be 4% by volumetric basis. This position is not only supported by the disparity between Piedmont's proposed standard and the standards adopted and in use by other pipeline companies, but also is underscored by Piedmont's failure to advance a credible basis for any disparity in the proposed RNG standard for nitrogen. *See,* Docket G-9, Sub 698, Comments by North Carolina Pork Council at 8 to 10. Consequently, in answer to the question, the NCPC's objection to the proposed 2% nitrogen standard is based on what's being done elsewhere and the lack of any rational basis for the proposed standard. NCPC's comment is not an endorsement of any method for enhancing heating value if such enhancement becomes necessary. Simply, the 2% limitation for nitrogen in Piedmont's proposed standard is inconsistent with <u>all</u> tariffs on geologic natural gas where uniformly, the nitrogen standard is set at 4% or higher and Piedmont has not justified its proposed diversion from the norm.

To be sure, as the Commission's question suggests, the removal of nitrogen from a gas stream is one way of enhancing the heating value. There are other ways of achieving the same result, however. Thus, if enhancing the heating value of a RNG gas stream is determined to be necessary, the project developer should be given the opportunity to identify the most appropriate response.

There is a common misconception stated throughout Piedmont's petition and the comments filed in Docket G-9, Sub 698 that RNG injected into the intra-state system will be materially different than what's in the pipeline already at the point of injection. While the source of the RNG *(e.g.,* animal waste or landfills) will have some bearing on what is found in the gas stream and at what levels, all of the biogas collected from any source will be subjected to intensive processing before being injected into the transmission or distribution lines. *See,* Docket G-9, Sub 698, *Comments of the Coalition for Renewable Natural Gas.* There are unlikely to be any impurities, let alone any impurities that present a real health or safety risk. Indeed a profile of the gas stream will be developed as part of any agreement to place RNG in the pipeline and the gas stream will be monitored at the point of interconnection. Any deviations from the acceptable profile will be detected and the gas flow disconnected if deemed necessary. A concern with biologics or other impurities is, to some extent, overstated and not realistic.

This concludes the Public Staff's final report in response to the Commission's Order.

Respectfully submitted, this the 31st day of October, 2017.

PUBLIC STAFF
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Electronically submitted
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CERTIFICATE OF SERVICE

I do hereby certify that I have this day served a copy of the foregoing upon each of the parties of record in this proceeding or their attorneys of record by emailing them an electronic copy or by causing a paper copy of the same to be hand-delivered or deposited in the United States Mail, postage prepaid, properly addressed to each.

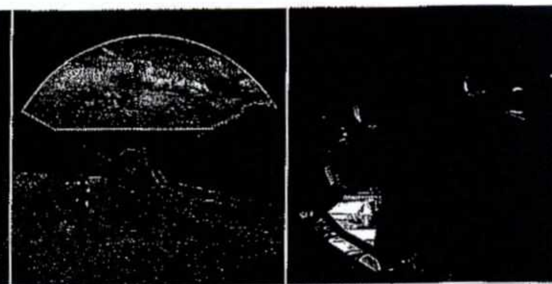
This the 31st day of October, 2017.

Electronically submitted
/s/ Elizabeth D. Culpepper
Elizabeth D. Culpepper

ATTACHMENT A

Gas Quality Specifications

TransCanada and other pipelines



TransCanada Pipelines

Specs	Canadian Mainline	NGTL/ATCO Pipelines	Foothills (BC) Zone 8	Foothills (Sask.) Zone 9	GTN	North Baja	ANR
Hydrogen Sulphide	Max 23 mg/m³	Max 23 mg/m³	Max 23 mg/m³	Max 23 mg/m³	Max 0.25 grains/Ccf³	Max 0.25 grains/Ccf³	Max 1 grains/Ccf³ SE & SW area 1/4 grains/ Ccf³ Mainline area
Total Sulphur	Max 115 mg/m³	Max 115 mg/m³	Max 230 mg/m³	Max 230 mg/m³	Max 10 grains/Ccf³	Max 0.75 grains/Ccf³ Total, 0.3 grains/Ccf³ mercaptan	Max 20 grains/Ccf³
Carbon Dioxide	Max 2% by volume	Max 2% by volume	Max 2% by volume	Max 2% by volume	Max 2% by volume	Max 2% by volume	Max 2% by volume
Oxygen	Max 0.4% by volume	Max 0.4% by volume	Max 0.4% by volume	Max 0.4% by volume	Max 0.4% by volume	Max 0.2% by volume	Max 1% by volume
Nitrogen	See TCPL Mainline Tariff	Not specified	Not specified	Not specified	Not specified	Max 3% incl. CO_2, N_2, He, O_2,	Max 3% by volume
Temperature	Max. 50°C	Max. 49°C	Max. 43.3°C	Max. 49°C	Max. 110°F	Max. 105°F or Min. 50°F	Min 40°F Max 120°F
Heating Value	Min. 36 MJ/m³ Max, 41.34 MJ/m³	Min. 36 MJ/m³	Min. 36 MJ/m³	Min. 36 MJ/m³	Min. 995 BTU/ft³	Min. 990 BTU/ft³ or Max. 1150 BTU/ft³	Min. 967BTU/ft³ Max. 1200 BTU/ft³
Water	Max. 65 mg/m³	Max. 65 mg/m3 or Max. dp -10°C at > 8275 kPa	Max. 65 mg/m³ or Max. dp -10°C at > 8275 kPa	Max. 65 mg/m3 or Max. dp -10°C at > 8275 kPa	Max. 4 lbs/MMcf	Max. 7 ibs/MMcf	Max. 7 lbs/MMcf
Hydrocarbon Dewpoint	Max. -10°C at 5500kPa absolute	Max. -10°C at operating pressure	Max. -10°C at operating pressure	Max. -10°C at operating pressure	Max. 15°F up to 800 psig	Max. 20°F up to 600 psig	Max. 15°F
Interchangeability	See TCPL Mainline Tariff	Not Specified	Not Specified	Not Specified	Not Specified	Wobbe Number: Min: 1279 Max: 1385	Not Specified

Canadian Pipelines

Specs	Alliance Canada	Union	Enbridge (Tecumseh Pipeline)	TransGas	West Coast	TQM
Hydrogen Sulphide	Max. 23 mg/m³	Max. 7 mg/m3	Max. 7 mg/m3	Max. 6 mg/m³	Max. 6 mg/m³	Max. 23 mg/m³
Total Sulphur	Max. 115 mg/m³	Max. 460 mg/m3	Max. 460 mg/m3, 5 mg/m3 mercaptan	Max. 23 mg/m³ total, 6 mg/m³ mercaptan	Max. 23 mg/m³	Max. 115 mg/m³
Carbon Dioxide	Max. 2% by volume	Max. 2% by volume	Max. 2% by volume	Max. 2% by volume	Max. 2% by volume	Max. 2% by volume
Oxygen	Max. 0.4% by volume	Max. 0.4% by volume	Max. 0.4% by volume	Max. 0.4% by volume	Max. 0.4% by volume	Max. 0.4% by volume
Nitrogen	Max. 4% by volume incl. N2, CO2, O2	Not specified	Not specified	Max. 15 ml/m³ each (nitric oxide & total oxides of nitrogen)	Not specified	Not specified
Temperature	Max. 50°C, Min. 5°C	Max 43°C	Not specified	Max. 50°C	Max. 54°C	Max. 50°C
Heating Value	Min. 36 MJ/m³, Max. 60 MJ/m³	Min. 36 MJ/m3 Max. 40.2 MJ/m3	Min. 36 MJ/m3 Max. 40.2 MJ/m3	Min. 35 MJ/m³	Min. 36 MJ/m³	Min. 36 MJ/m³
Water	Max. 65 mg/m³	Max. 65 mg/m3	Max. 80 mg/m3	Max. 65mg/m³ at 101.325 kPa and 15°C	Max. 65 mg/m³	Max. 65 mg/m³
Hydrocarbon Dewpoint	-5°C at normal opt. conditions	Max. -8°C at operating pressure	Max. -10°C at 5500 kPa	Max. -10°C at opt. Pressure	Max. -9°C at del. pres.	Not specified
Interchangeability	Not Specified	Refer to Union Tariff	Refer to Enbridge Tariff	Not Specified	Not Specified	Not Specified

The Gas Quality Specifications tables are intended to be used for planning purposes only and although TransCanada endeavours to maintain the information in such a way that is accurate and current, it may not provide accurate results. Use of this information is at user's sole risk and TransCanada shall not be liable for user's, or any party's, use of or reliance on any results obtained from it.

Website: http://www.transcanada.com/customerexpress/index.html
E-mail: customer_express@transcanada.com
The Pipeline: 403.920.PIPE (7473)
January 2016

TransCanada
In business to deliver

6.12 MEASUREMENT AND MEASUREMENT EQUIPMENT

6.12.1 Measurement Equipment.

(a) The volume of Gas delivered at the Receipt Point(s) and at the Delivery Point(s) shall be measured by:

(1) An orifice meter, designed, installed, maintained and operated as recommended in the latest issue of American National Standard ANSI/API 2530 (American Gas Association Gas Measurement Report No. 3), entitled "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids", as such publication may be revised from time to time (hereinafter referred to as "AGA Report No. 3"); or

(2) A turbine meter, designed, installed, maintained and operated as recommended in the latest issue of American Gas Association Transmission Measurement Committee Report No. 7, entitled "Measurement of Fuel Gas by Turbine Meters", as such publication may be revised from time to time (hereinafter referred to as "AGA Report No. 7"); or

(3) A positive displacement meter, installed and operated in accordance with generally accepted industry practices.

(b) Auxiliary measuring equipment shall be installed, maintained and operated in accordance with generally accepted industry practices.

6.12.2 Measurement Computations and Factors.

(a) The volume of Gas delivered at each Receipt Point and Delivery Point shall be calculated by means of an electronic flow computer located at, or by the processing of meter charts recorded at, each Receipt Point or each Delivery Point, in either case in the following manner:

(1) When the measuring equipment is an orifice meter, the flow of Gas through the meter shall be computed in the manner recommended in AGA Report No. 3, properly using all factors set forth therein.

(2) When the measuring equipment is a turbine meter, the volume of Gas delivered through the meter shall be computed in the manner recommended in AGA Report No. 7, properly using all factors set forth therein.

(3) When the measuring equipment is a positive displacement meter, the volume of Gas delivered through the meter shall be computed by properly applying, to the volume delivered at flowing Gas pressures and temperatures, correction factors for (i) absolute static pressure, (ii) flowing Gas temperature, and (iii) compressibility ratio.

(b) The volume of Gas delivered shall be computed using the standards and factors determined as follows:

(1) The unit of volume for the purpose of measurement shall be one thousand cubic feet of Gas at a temperature of sixty (60) degrees Fahrenheit and a pressure of 14.73 pounds per square inch absolute. For the purpose of pricing hereunder, the Dekatherm equivalent of such unit of volume shall be determined by multiplying each such unit of volume by the total heating value per cubic foot of the Gas delivered hereunder (adjusted to a common temperature and pressure base) and by dividing the result by one thousand (1000).

(2) The average absolute atmospheric (barometric) pressure at each Receipt Point and each Delivery Point shall be assumed to be equal to the value, in pounds per square inch, shown in the table below corresponding to the location of the Receipt Point or Delivery Point, irrespective of the actual location or elevation above sea level of the Receipt Point or Delivery Point or of variations in actual atmospheric pressure from time to time:

Michigan; Wisconsin; Indiana; Kentucky; Tennessee; Illinois; Iowa; Missouri; Ohio	14.4

Onshore Louisiana; Offshore Louisiana; Offshore Texas	14.7
Oklahoma; Kansas; Texas Panhandle	13.5
Wyoming	12.1

(3) The flowing temperature of the Gas shall be determined by means of an instrument of standard manufacture accepted in the industry for this purpose.

(4) The supercompressibility factor used in computing the volume of Gas delivered through an orifice meter shall be determined in a manner which yields results consistent with the results produced by the procedures presented in American Gas Association Transmission Measurement Committee Report No. 8, entitled "Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases."

(5) The specific gravity of the Gas used in computing the volume of Gas delivered through a meter shall be determined by one of the following methods:

(i) At intervals of not more than six (6) Months, by means of an instrument of standard manufacture accepted in the industry for this purpose using a sample of Gas from the Gas stream at the Receipt Point or Delivery Point.

(ii) By means of an instrument of standard manufacture accepted in the industry for this purpose installed at a point to measure the specific gravity of the Gas stream from which Gas is being delivered at the Receipt Point or Delivery Point.

(6) The compressibility ratio factor "s" used in computing the volume of Gas delivered through a turbine meter or a positive displacement meter shall be determined by the equation s = (Fpv)2, in which "Fpv" is the supercompressibility factor determined as described in Section 6.12.2(b)(4).

(7) In determining the flowing temperature factor, supercompressibility factor, and compressibility ratio factor "s" for use in computing the volume of Gas delivered through a meter, the flowing Gas temperature for only the period(s) of time that Gas was flowing through the meter shall be used.

6.12.3 Measurement Testing and Accuracy.

All flow, measuring, testing and related equipment shall be of standard manufacture and type approved by Transporter. If applicable, Transporter or Shipper may install check measuring equipment and telemetering equipment, provided that such equipment shall be so installed as not to interfere with the operations of the operator. Transporter, or Shipper, in the presence of the other party, shall have access to measuring equipment at all reasonable times, but the reading, calibrating, and adjusting thereof and the changing of charts, if any, shall be done by the operator of the facilities. Transporter or Shipper shall have the right to be present at the time of the installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating or adjusting done by the operator of the measuring equipment. The records from such measuring equipment shall remain the property of the operator, but upon request, the other party may request records, including charts, if any, together with calculations therefrom for inspection, subject to return within thirty (30) Days after receipt thereof. Reasonable care shall be exercised in the installation, maintenance and operation of the measuring equipment so as to avoid any inaccuracy in the determination of the volume of Gas received and delivered.

The accuracy of all measuring equipment shall be verified by operator at reasonable intervals, and if requested, in the presence of representatives of the other party, but neither Transporter nor Shipper shall be required to verify the accuracy of such equipment more frequently than once in any thirty (30) Day period. If the operator agrees to verification and test of measuring equipment and fails to perform such verification and testing, then the other party shall have the right to cease or temporarily discontinue service under this Agreement relative to such measuring equipment. If either party at any time desires a special test of any measuring equipment, it will promptly notify the other party and the parties shall then cooperate to secure a prompt verification of the accuracy of such equipment. Transportation and related expenses involved in the testing of meters shall be borne by the party incurring such expenses, provided, however, that Shipper shall not be responsible for such Transportation and related expenses if the special testing reveals that the meter(s) is (are) not operating within the required tolerance level of two percent (2%).

The operator, for purposes of this section, shall be the owner of the equipment referenced herein, or the agent of such owner, or such other person as the parties may agree in writing.

If, upon any test, any measuring equipment is found to be in error, such errors shall be taken into account in a practical manner in computing the deliveries. If the resultant aggregate error in the computed receipts or deliveries is not more than two percent (2%), then previous receipts or deliveries shall be considered accurate. All equipment shall, in any case, be adjusted at the time of test to record correctly. If, however, the resultant aggregate error in computing receipts or deliveries exceeds two percent (2%), at a recording corresponding to the average hourly rate, of Gas flow rate for the period since the last preceding test, the previous recordings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon, but in case the period is not known definitely or agreed upon, such correction shall be for a period extending over one-half of the time elapsed since the date of the last test.

6.12.4 Measurement Corrections.

In the event any measuring equipment is out of service, or is found registering inaccurately and the error is not determinable by test, previous recordings of receipts or deliveries through such equipment shall be determined as follows; provided, however, that the correction period shall be within six (6) Months of the production Month, with a three (3) Month rebuttal period and provided, further, that such standard shall not apply in the case of deliberate omission or misrepresentation or mutual mistake of fact. Mutual agreement between parties, legal decisions, and regulatory guidance may be necessary to determine if the event qualifies for an extension of the above time periods. Parties' other statutory or contractual rights shall not otherwise be diminished by this standard:

(a) by using the registration of any check meter or meters if installed and accurately registering, or in the absence of (a);

(b) by correcting the error if the percentage of error is ascertainable by calibration, special test or mathematical calculation, or in the absence of both (a) and (b) then;

(c) by estimating the quantity of receipt or delivery based on receipts or deliveries during preceding periods under similar conditions when the meter was registering accurately.

6.12.5 New Methods of Measurement.

If at any time during the term hereof, a new method or technique is developed with respect to Gas measurement or the determination of the factors used in such Gas measurement, such new method or technique may be substituted upon mutual agreement thereto by both parties.

6.12.6 Preservation of Measurement Records.

The parties agree to preserve for a period of at least three (3) years or such longer period as may be required by public authority, all test data, charts, if any, and other similar records.

6.12.7 Other Equipment.

Shipper or Transporter may install, maintain, and operate odorizing (at a Delivery Point only), regulating, telemetering, heating and fogging equipment at its own expense as it shall desire at each Receipt Point or Delivery Point, and the operator of such equipment at its own expense shall provide the other party a suitable site therefor and allow the other party free access to and use of the site; provided that such equipment shall be so installed, maintained and operated as not to interfere with the operation or maintenance of the operating party's measuring equipment at each Receipt Point or Delivery Point. All such equipment as Shipper or Transporter shall desire to install shall be constructed, installed and operated to conform to the other party's requirements. Shipper or Transporter may remove any of its equipment installed on such site at any time.

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Effective: September 30, 2010

Docket No. RP10-1380-000
Accepted: November 5, 2010

6.13 QUALITY

Gas delivered to, and received by, Transporter, shall meet the following specifications:

1. Heat Content. Heat content shall mean the gross heating value per cubic foot of Gas delivered at each Receipt Point and Delivery Point. The Gas at each Receipt Point shall have a heat content not greater than 1200 BTUs per cubic foot nor less than 967 BTUs per cubic foot when determined on a dry basis. Transporter shall have the right to waive such BTU content limits if, in Transporter's sole opinion, Transporter is able to accept Gas with a BTU content outside such limits without affecting Transporter's operations. The total heating value per cubic foot of Gas shall be determined at each Receipt Point and each Delivery Point by one of the following methods:

   (a) by means of an instrument of standard manufacture installed to measure the heating value of the Gas being delivered at the Receipt Point or the Delivery Point;

   (b) at intervals of not more than six (6) Months by means of an instrument of standard manufacture and a sample of Gas from the Gas stream from which Gas is being delivered at the Receipt Point or the Delivery Point; or

   (c) other methods mutually agreed upon by both parties.

   For the purpose of calculating receipts and deliveries, the heat content of the Gas so determined at each such point shall be deemed to remain constant at such point until the next determination. The unit of quantity for the purpose of determining total heating value shall be one (1) cubic foot of anhydrous Gas at a temperature of sixty (60) degrees Fahrenheit and an absolute pressure of 14.73 psia.

2. Freedom from Objectionable Matter. The Gas received and delivered hereunder:

   (a) shall be commercially free from objectionable odors, dust, water and any other solid or liquid matter which might interfere with its merchantability or cause injury to or interference with proper operation of the equipment through which it flows and any substance that might become separated from the gas in Transporter's facilities.

   (b) shall not contain more than sixteen (16) parts per million (one (1) grain per one hundred (100) cubic feet of Gas) of hydrogen sulfide in the Southeast Area Facilities and Southwest Area Facilities and shall not contain more than four (4) parts per million (one quarter grain per one hundred (100) cubic feet of Gas) of hydrogen sulfide in the Mainline Area Facilities, as determined by the method prescribed in the Gas Processors Association Standard 2377, entitled "Test for

Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes";

(c) shall not contain more than twenty (20) grains of total sulfur (including the sulfur in any hydrogen sulfide and mercaptans) per one hundred (100) cubic feet of Gas;

(d) shall not at any time have an oxygen content in excess of one percent (1%) by volume and the parties hereto shall make every reasonable effort to keep the Gas free of oxygen;

(e) shall be free of water and hydrocarbons in liquid form and shall in no event contain water vapor in excess of seven (7) pounds per million cubic feet of Gas;

(f) shall not contain more than two percent (2%) by volume of carbon dioxide;

(g) shall be delivered at a temperature not in excess of one hundred twenty (120) degrees Fahrenheit or less than forty (40) degrees Fahrenheit; and

(h) shall not contain more than three percent (3%) by volume of nitrogen.

(i) shall not contain any toxic, hazardous materials or substances, or any deleterious material potentially harmful to persons or to the environment, including but not limited to, polychlorinated biphenyls and substances requiring investigation, remediation or removal under any law, regulation, rule or order in effect from time to time.

3. Hydrocarbon Dewpoint. Transporter may not refuse to accept delivery of Gas with a Hydrocarbon Dewpoint equal to or less than 15 degrees Fahrenheit ("F"), provided that such Gas satisfies all other applicable provisions of Transporter's FERC Gas Tariff. This Standard shall be referred to as Transporter's Hydrocarbon Dewpoint Safe Harbor. Transporter may, from time to time, as operationally necessary, establish and post on its Internet site a limit on Hydrocarbon Dewpoint (no lower than the Hydrocarbon Dewpoint Safe Harbor) for receipts on specified HDP Segments to cure or prevent hydrocarbon liquid fallout. Transporter may post on its Internet site such limits when operational and engineering considerations on Transporter's System upstream of designated Monitoring Points demonstrate the need for such limits in order to prevent anticipated hydrocarbon liquid fallout, to correct problems from actual hydrocarbon liquid fallout, or to assure that gas would be accepted for delivery into interconnects, including with interstate or intrastate pipelines, end users, and local distribution companies.

(a) Procedures for Postings. Transporter shall establish Monitoring Points on its system for the purpose of posting Hydrocarbon Dewpoint limits pursuant to

Section 6.13 paragraph 3. For purposes of this section, "HDP Segment(s)" shall be that portion of Transporter's System between Monitoring Points or, for the furthermost upstream Monitoring Points of Transporter's System, the applicable HDP Segment shall be the remaining portion of Transporter's upstream system.

(i) HDP Problem(s) - Actual Hydrocarbon Liquid Fallout - If Transporter experiences hydrocarbon liquid fallout on Transporter's system, Transporter may post on its Internet site Hydrocarbon Dewpoint limits (no lower than 15 degrees F) at the point where the liquid fallout occurs and then to the receipt points upstream of that location within the HDP Segment where the fallout is occurring. If that will not correct the Hydrocarbon Dewpoint problem, Transporter shall apply Hydrocarbon Dewpoint limits for each HDP Segment immediately upstream of the HDP Segment where the liquid fallout occurs up to the nearest Monitoring Point that satisfies the Hydrocarbon Dewpoint limit. Any such Hydrocarbon Dewpoint limit shall be applied uniformly to all receipt points in such HDP Segments. Transporter's analysis and posting of HDP limits shall not skip over any HDP Segment between the HDP Problem and the furthermost upstream HDP Segment to which an HDP limit is posted.

(ii) HDP Problem(s) - Anticipated Hydrocarbon Liquid Fallout - When Transporter anticipates hydrocarbon liquid fallout under foreseeable operating conditions on Transporter's System, Transporter may post on its Internet site, pursuant to the procedures established in this section below, Hydrocarbon Dewpoint limits (no lower than 15 degrees F) for the HDP Segment(s) of Transporter's System required to prevent the anticipated liquid fallout. Transporter may make a posting when Transporter's analysis of system operating factors indicates a need for a limitation. Such factors may include, but are not limited to, anticipated processing plant operation, pressure reduction, flow patterns, flowing gas temperatures, and Hydrocarbon Dewpoint temperatures. Hydrocarbon Dewpoint limitations posted pursuant to this section shall be applied to all HDP Segment(s) where potential for liquid fallout is anticipated absent such Hydrocarbon Dewpoint limitation and to all HDP Segments required to prevent the anticipated liquid fallout under foreseeable operating conditions, provided such posting shall not skip over any HDP Segment between the HDP Problem and the furthermost upstream HDP Segment to which an HDP limit is posted. Transporter shall post on its Internet site an explanation of the basis for the HDP limit. Upon Shipper's request, Transporter shall provide, within three Business Days, a written detailed explanation of the nature and level of the anticipated hydrocarbon liquid fallout problem, the reasons for its choices of the posted HDP limit and the affected HDP Segments.

(iii) Transporter shall post HDP limits in a given HDP Segment only to the extent necessary to prevent liquid fallout from occurring in order to manage and operate Transporter's system in a safe and reliable manner. Such posted Hydrocarbon Dewpoint limits shall remain in effect no longer than necessary.

(iv) To the extent that it is operationally feasible, Transporter will not apply the Hydrocarbon Dewpoint limits of this section to meters that are not upstream of a processing plant with available capacity and that flow 500 Dth or less per day.

(v) Transporter will provide as much notice of such limitation as reasonably practicable and will attempt to provide such notice at least ten (10) days prior to the effective date of the limitation.

(vi) Posted Hydrocarbon Dewpoint limitations shall not exceed the limits needed to correct the specifically identified or anticipated HDP Problem on specific HDP Segments of Transporter's system.

(vii) Where the Transporter can not fully correct an HDP Problem by posting a Hydrocarbon Dewpoint limit in the most downstream HDP Segment experiencing or anticipating to experience a HDP Problem, it may post a Hydrocarbon Dewpoint limit in subsequent upstream HDP Segment(s) but the Hydrocarbon Dewpoint limit in the subsequent HDP Segment(s) may be no stricter than the limit in the first HDP Segment. Where the Hydrocarbon Dewpoint of an upstream Monitoring Point complies with the posted Hydrocarbon Dewpoint limit, Transporter shall not apply any Hydrocarbon Dewpoint limit to that point or any other upstream receipt point in the sequential HDP Segment.

(viii) When Transporter posts a Hydrocarbon Dewpoint limit on the Sandwich - Georgetown - Defiance HDP Segment (the SGD HDP Segment) then the gas receipts into the SGD HDP Segment either from interconnects or from any adjacent HDP Segment feeding gas directly into the SGD HDP Segment must meet the posted HDP limit for the SGD HDP Segment.

(ix) Transporter will not require processing of gas at receipt points upstream of the tailgate of a straddle plant that meets the posted Hydrocarbon Dewpoint limit without processing.

(x) To the extent operationally practicable, Transporter may allow gas that does not meet a posted Hydrocarbon Dewpoint limitation at receipt points to continue to flow provided that Transporter approves a "pairing" proposal as set forth in Section 6.13 paragraph 3(c).

(xi) Transporter shall allow gas that does not meet a posted Hydrocarbon Dewpoint limitation at receipt points to continue to flow provided that the Shipper or a third party provides to Transporter proof of processing at a plant within the HDP Segment where the gas at the tailgate of that plant satisfies the Hydrocarbon Dewpoint limitation for the applicable HDP Segment.

(b) Monitoring Points. Transporter shall utilize the following Monitoring Points to establish HDP Segments on Transporter's System for purposes of posting Hydrocarbon Dewpoint limits per this Section 6.13 paragraph 3.

1. Eunice Headstation East
2. Eunice Headstation West

3. Greensburg Headstation East
4. Greensburg Headstation West

5. Defiance Station East
6. Defiance Station South
7. Defiance Station North

8. Sandwich Station North
9. Sandwich Station South
10. Sandwich Station East

11. Georgetown Station

(c) Pairing. To the extent operationally feasible, and subject to the conditions below, Transporter may allow a shipper whose Gas does not meet a posted Hydrocarbon Dewpoint limit to pair its Gas with a shipper whose Gas satisfies the posted specification.

(i) A shipper wishing to pair must provide ANR with a written proposal for the pairing of its volumes (including but not limited to E-Mail or facsimile).

(ii) Upon receipt of a pairing proposal, Transporter will determine whether the proposal can physically occur on Transporter's system without causing undue risk to Transporter's operations.

(iii) If Transporter determines that shipper's proposal is physically possible, then Transporter will evaluate whether the commingled stream that would result from the proposal satisfies the Hydrocarbon Dewpoint limitation.

(iv) To the extent that Transporter determines that the pairing proposal does not meet one or more of the above listed conditions, Transporter will provide shipper a written denial specifying the basis for the determination.

(v) Transporter shall permit all shippers interested in pairing to post relevant data, including contact information, on its Internet site.

(d) Transporter shall post on its Internet site each Receipt Point Hydrocarbon Dewpoint value Transporter calculates, within 24 hours after making the calculations, and the method by which the Hydrocarbon Dewpoint value was calculated.

(e) Transporter shall post on its Internet site each blended Hydrocarbon Dewpoint and blended BTU values Transporter calculates for a line segment of its system within 24 hours of such calculation.

(f) HDP Measurement - Transporter shall perform the Hydrocarbon Dewpoint (cricondentherm) calculations for Section 6.13 paragraph 3 using the Peng-Robinson equation of state and C6+ assumptions consistent with industry practices. Upon a shipper's request, Transporter shall conduct a C9+ analysis; provided that in no event shall Transporter be required to conduct such C9+ analysis at any one receipt point more frequently than once every twelve months, except if a new source of supply has been added at that point.

4. Failure to Meet Specifications. Should any Gas tendered for delivery hereunder fail at any time to conform to any of the specifications of this Section 6.13 ("Non-Conforming Gas"), the affected Party shall notify the party tendering such Gas of any such failure and the affected party may at its option suspend all or a portion of the receipt of any such Non-Conforming Gas, and shall be relieved of obligations hereunder for the duration of such time as the Non-Conforming Gas does not meet such specifications. Nothing in this Section 6.13 shall prevent Transporter from waiving any quality specifications where the acceptance of Non-Conforming Gas will not in the reasonable judgment of Transporter adversely impair its operation. The exclusive remedy of the Affected Party shall be liquidated damages not to exceed the greater of (a) ten dollars ($10.00), or (b) two times the Spot Price Index (as defined in Section 6.16 of these General Terms and Conditions, for each Dekatherm of such Non-Conforming Gas.

5. Commingling. It is recognized that Gas delivered by Shipper will be commingled with other Gas transported hereunder by Transporter. Accordingly, the Gas of Shipper shall be subject to such changes in heat content as may result from such commingling and Transporter shall, notwithstanding any other provision herein, be under no obligation to redeliver for Shipper's account, Gas of a heat content identical to that caused to be delivered by Shipper to Transporter.

F. QUALITY OF GAS

F.1 **<u>Quality Specifications.</u>** The gas shall be merchantable, at all times complying with the following quality requirements. The gas shall be commercially free of crude oil, water in the liquid phase, brine, air, dust, gums, gum-forming constituents, bacteria, and other objectionable liquids and solids, and not contain more than:

(a) ¼ grain of H_2S per 100 cubic feet.
(b) Two mole percent of carbon dioxide.
(c) Ten mole percent of nitrogen.
(d) Ten parts per million by volume of oxygen, and not have been subjected to any treatment or process that permits or causes the admission of oxygen, that dilutes the gas, or otherwise causes it to fail to meet these quality specifications.
(e) Fifteen mole percent of combined carbon dioxide, nitrogen, and oxygen.
(f)Seven point two (7.2) pounds of water vapor per MMcf.

The gas shall:
(g) Not exceed 120° F. in temperature at the Delivery Point.

(h) Have a total heating value of at least 950 Btus per cubic foot.
(i) Otherwise meet the specifications required by the transporting pipelines at the Redelivery Points.