PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, April 19, 2022

TIME: 2:30 p.m. - 3:46 p.m.

DOCKET NO: M-100, Sub 163

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

Investigation Regarding the Ability of North Carolina's Electricity, Natural Gas, and Water/Wastewater Systems to Operate Reliably During Extreme Cold Weather

VOLUME 2

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P R O C E E D I N G S

CHAIR MITCHELL: Let's come to order and go on the record, please, ma'am. We've got PSNC on the stand. So would you-all please introduce yourselves for the record.

MS. JACKSON: Hi, good afternoon. I'm Rose Jackson, Director of Gas Supply on behalf of PSNC.

MR. SWINDLER: I am Scott Swindler. I'm Director of Gas Operations for DENC.

MR. RAYNOR: Hey, good afternoon. My name is Bill Raynor, I'm the Manager of Engineering Projects and I'm responsible for our LNG plant in Cary, North Carolina.

MS. JACKSON: Good afternoon, Chair Mitchell and Commissioners. During February of 2021, Texas experienced an unprecedented winter weather event. North Carolina had previously experienced Polar Vortex events in January of 2014, February of 2015, and January of 2018. As a result of these extreme winter weather conditions in North Carolina, Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina or PSNC had implemented many of the recommendations of the

FERC and NERC report related to the Texas event.

I appreciate an opportunity to present a summary of PSNC's responses in Docket Number M-100, Sub 163, and I'm happy to answer any questions with my colleagues Mr. Bill Raynor and Mr. Scott Swindler. Please feel free to ask questions throughout the presentation.

The deregulated environment of Texas incentivizes energy providers to reduce generation and operating costs in order to compete. The regulated environment of North Carolina focuses on reliability which allows utilities to acquire firm capacity to ensure deliverability and emphasizes preventative maintenance.

I would also like to identify some distinctions, obvious as they are, about natural gas utilities versus electric utilities.

First, gas utilities do not generate the product we sell with the exception of liquified natural gas or LNG, which removes a lot of the winter prep gas utilities are required to do when compared to electric utilities.

Second, virtually all of the delivery infrastructure of gas utilities are underground, safe from the freezing rain, wind and ice that can accompany a cold weather event. Although winter preparation is just as important to gas utilities as electric utilities, our presentation will be different from what you've heard from our electric colleagues.

And with that, our presentation is up. We did something similar to what our electric colleagues did, we broke down the presentation based on a segment of questions. The first question in the general category was related to changes that PSNC had implemented due to lessons learned from the February 2021 Texas weather event. And as you can see here the plant that we have, the Cary LNG plant is the only plant where we generate the product that we sell.

We did in an assessment of our spare parts inventory focusing on temperature sensitive equipment and emergency response equipment. We also evaluated the heat trace equipment and added to our winter preparation -- our winter preparedness inventory, we added valve positioners. And we're also -- we have a consideration of weather factors that were identified as part of that Texas weather event for planned plant improvements.

The next section is weather and load forecasting. And there's two different types of --

CHAIR MITCHELL: Ms. Jackson, I'm going to stop you because I want to follow up with you on the LNG facility.

MS. JACKSON: Okay.

CHAIR MITCHELL: So, will you go back one slide, please, ma'am? Can you talk about electric service at that facility?

MS. JACKSON: I will defer to my colleague Mr. Raynor.

CHAIR MITCHELL: Okay.

MR. RAYNOR: I understand we're on a distribution service at that facility, a general service-type service. We do have backup power there; that's an important feature of the plant.

CHAIR MITCHELL: Okay. So tell me about that backup generation?

MR. RAYNOR: Yes, it is a diesel powered backup generator that supports our critical functions of vaporization and holding.

CHAIR MITCHELL: Can you to the extent that you're able to answer this question, what happens to that facility if it loses power?

MR. RAYNOR: Well, we would automatically switch to our backup power system, and if we were vaporizing it would probably require a restart of our vaporization process, so it would be suspended for, you know, momentarily until we got our backup power reestablished and checked out all of our equipment and put everything back online.

CHAIR MITCHELL: Okay. And the holding tank, I mean, what happens to the material in the holding tank?

MR. RAYNOR: That's a great question. Our boil-off compressors are what maintains the pressure coming off the tank and there's a, I'm going to just call it, sponginess that you have some lag time as far as the pressure that you can build in our tank in between. Once -- those boil-off compressors don't have to run continuously. We manage the pressure in a tank within a range so for a brief power interruption there wouldn't be any concern.

CHAIR MITCHELL: And can you quantify briefly for me if you can?

MR. RAYNOR: As far as the --

CHAIR MITCHELL: Power --

MR. RAYNOR: Be without power about maybe six hours or so, something like that.

CHAIR MITCHELL: Okay. And I assume that the backup generator there is subject to testing protocols?

MR. RAYNOR: Yes. We run it weekly. We have quarterly inspections and annual inspections as well.

CHAIR MITCHELL: Okay. Thank you.

MR. RAYNOR: That's a key part of our operation, yes.

CHAIR MITCHELL: Thank you for that.

COMMISSIONER McKISSICK: Let me ask a quick follow up to the Chair's questions. When you're going to that backup generation system, I mean, how many hours is it prepared to function, operate until electricity is restored?

MR. RAYNOR: We have an 8,000 gallon diesel tank.

COMMISSIONER McKISSICK: Okay.

MR. RAYNOR: And it sort of depends on the load, I guess, that's on the unit at the time. I would estimate maybe three or four days maybe before we had to refuel --

COMMISSIONER McKISSICK: Okay.

MR. RAYNOR: -- before we had to refuel.

COMMISSIONER McKISSICK: Excellent. That gives me some idea, you know, because I mean by that power -- time, you would expect reasonably anticipated it would be restored. I just didn't know if it was a matter of hours as opposed to a matter of days. And when it is functioning you have full capabilities to do everything you would normally do as if electricity was being provided?

MR. RAYNOR: That's a really good subtle point there. We can -- holding mode which would run our boil-off compressors right, which run pretty much year-round.

COMMISSIONER McKISSICK: Sure.

MR. RAYNOR: Vaporization which is when would we be vaporizing to put gas back on the system. We can run both of those functions with our backup power system. We don't have enough power generation to liquefy.

COMMISSIONER McKISSICK: I see. Okay. Well, that certainly clarifies it. Thank you.

MS. JACKSON: But during this type of weather event, if I could follow up on that comment,

we would typically be vaporizing and not liquefying.
MR. RAYNOR: True.
MS. JACKSON: Because we would be withdrawing from a tank in order to supply customers rather than injecting gas to prepare for that scenario.
COMMISSIONER McKISSICK: Got it. And I think in your response you also talked about adding spare positioner boards for essential control equipment. What do those boards consist of?
MR. RAYNOR: I probably should have characterized it better, a valve positioner. One of the things that we observed with the Texas event was that the mechanical failures were largely attributable to frozen equipment.
COMMISSIONER McKISSICK: Yes.
MR. RAYNOR: So, we just took the few that we were going to look at our plant equipment and what we had in inventory and see if we saw a gap or if we didn't have something that we thought we needed from a past experience, and we identified a valve that has a certain type of positioner on it and moves the valve, that we didn't have any spares in our inventory. So, we made the decision to get

that and provide another layer of reliability to our operation. But these are valves that -- this particular valve positioner controls the flow of LNG from our tank, our pump skid, up to the vaporizers which push the gas out into the system. So, others are in critical pieces of --

COMMISSIONER McKISSICK: Pieces of components. I see. That helps a lot as well. Thank you.

MR. RAYNOR: You're welcome.

MS. JACKSON: The next section of questions was related to weather and load forecasting. The Company performs two types of forecasting. The first one is our long-term forecasting, and you're probably most familiar with that, because in preparation for our annual prudence filing we work with our resource planning group that evaluates the weather all the way up into this last winter system. They use a statistical modeling program that estimates our design day demand, which is going to be the amount of our demand on the coldest scenario. So, we go back and look at the 70 years of weather history that we have, we use the heating degree days from the coldest day that has occurred on the system and we apply those heating degree days to the current mix of customers that we have on the system.

That long-term forecast evaluates what our firm customer need is. We do not forecast for interruptible load because we're not required to serve that load. And so the result of the long-term forecast, we take that and we compare it to our asset stack to evaluate what our reserve margin is going to be and if we need to go out and find additional assets to meet that demand.

So, typically when we make our filing on an annual basis, we're looking out five years but the actual model itself goes out further than that. We evaluate 10-years because as you're well aware of in the past we could say three to five years is the timeline for new pipeline capacity now that's seven plus, and the timeline associated with any new projects is very uncertain.

So, we use that, that long-term forecasting to handle what type of assets we may need in the future and also to evaluate our system planning for our distribution system.

Where did we see the growth on our system?

What geographic areas we're going to see that growth in? So, our gas supply team that I manage along with the engineering and operations team works together to identify where our future needs are going to be.

Now, with regard to the short-term forecasting, the Company does not forecast weather. As you have heard from our electric colleagues, we do not handle our own weather forecast. We don't have a meteorologist assigned to us. We rely on third-party services. Primarily, DTN is our weather provider and what happens is we get forecasts in from DTN twice a day. Our gas control group takes that and forecasts heating degree days, well takes the heating degree days forecasted by DTN. They match up actual historical usage based on the weather parameters that have been identified by DTN and the heating degree days, and then they send that forecast to my gas supply group and we evaluate what type of assets will be needed to supply customers, firm customers, on that day.

With that, you may have seen some questions about like the weekends. We buy supply over the weekend but then we evaluate on a daily basis do we use storage or do we buy daily gas, so that enables us to do so. Any questions on weather or load forecasting?

(Pause).

Okay. The next section of questions was related to load shedding or curtailment planning. The first section related to customer outages or curtailment. We typically don't call it load shedding. That's more of an electrical term, electric term. But with regards to customer outages, firm customers are only interrupted due to outages such as third-party damage. So, if we have a third party that hits a line customers may lose service in that regard.

If PSNC encountered some type of pressure or a gas deliverability issue from Transco, that would probably be considered our catastrophic event and that would be the time when we would be faced with having to curtail customers or asking customers to voluntarily cooperate with us to meet that reduced volumes of gas that we are seeing coming into our gas. But, to date, we have not seen that type of catastrophic event. Typically, it's related to third-party damage.

In the event that that type of interruption were to occur, we would rely on the Company to relight first and then we would call on our Dominion Energy affiliates and also other utility resources that we have through the Southern Gas Association to restore service.

The most typical types of curtailments that you will hear about on our system is related to interruptible customers. These customers pay a lower rate in exchange for their obligation to interrupt if needed in order to ensure that we can meet the firm customer's needs.

So, the procedures that we have are laid out in Rider A of the Company's tariff. In the event that we are required to curtail a customer, we enter that curtailment into our electronic bulletin board which generates an email that goes to the emergency contacts that the customer has provided to us and then if the individual account manager for that customer curtailed will follow up with that customer via a phone call to ensure that they have received a message. If the customer is a transportation customer, their pooler is also notified via email through the electronic bulletin board.

One of the big changes in our system after the Polar Vortex events of 2014 and '15, we realized as a Company that we needed more tools in our toolbox to be able to balance supply versus demand other than curtailment.

Prior to our rate case in 2016, curtailment was really the only tool we had to ensure that interruptible customers would go off natural gas in order to protect firm customers and ensure their priority of service on our system. But with the approval of our rate case in Docket Number G-5, Sub 565, we were able to implement operational orders which enables the Company to require poolers to balance receipts and deliveries within a specified tolerance. So, in the event that a pooler is able to bring gas to the system then we redeliver that gas to their customers. It also allowed customers to participate in that aggregation into a pool, so if you have one customer that's long and one customer that's short they can net those differences and provide that valuable balancing service within the pooler's pool.

Just to follow up on some of the questions earlier, the power generation companies on our system are actually considered not only customers but poolers. So, in the event they are able to get gas to our system, we make every opportunity to redeliver that gas to their plants.

There is penalties imposed for noncompliance prior to operational orders being in place. There was no type of incentive to ensure compliance in the event that we were to encounter this type of cold weather event. The procedures are identified in Article 5 of our Transportation Pooling Agreement within our tariff. And in the event that there is an operational order, we post that on our electronic bulletin board and it's followed up with an email that goes out to all the poolers affected.

Also, a number of our interruptible customers have converted to firm transportation, our firm sales, since the Polar Vortex events of 2014 and 2018. A number of those customers identified issues with obtaining their alternate fuel during such weather events. So, we have seen a dramatic change there on our system as well. Any questions?

CHAIR MITCHELL: I just want to follow up on the power gen comment that you made. So, are you aware of whether any of the power generators that the Company serves are on interruptible contracts, interruptible service of any kind?

MS. JACKSON: There is an interruptible service provision. But, once again, because they are acting as their own poolers if they are able to deliver the supply, then, we'll make every opportunity to redeliver that supply to the power plant. There may be an instance where - I can't imagine - it would be something highly unusual on the system like a pressure issue or some type of third-party damage that may impact it. But, once again, it's a transportation agreement so if they can deliver the supply we're going to do our best to get it to the plant.

CHAIR MITCHELL: So why are they -- why does interruptibility come into this at all? I mean, why is that term important to the -- or included in this arrangement you have with the power generators?

MS. JACKSON: It's just to protect the system in the event we were to have that type of catastrophic situation or that unusual operating circumstance where we couldn't redeliver all of their volumes. When we have a firm obligation such as we have to firm and commercial customers, we plan for that and we take that into consideration. But the power plants as discussed earlier have the ability to use alternate fuel where our firm residential and commercial customers do not.

CHAIR MITCHELL: Are these -- are the pooling arrangements reduced to writing? Are there written agreements among the poolers and PSNC?

MS. JACKSON: Yes, ma'am. There are actually contracts that are in our tariff that states all the requirements that they're obligated to perform.

CHAIR MITCHELL: Okay. Thank you.

MS. JACKSON: Uh-huh (yes). Okay. The next section is related to plant performance and that's in regards to Questions 12 through 13. We identified the peak day for each of the last three winters which is not an indication of the total, the top three days the system has encountered, so I wanted to clarify that. During the last three winters we curtailed one to two interruptible customers. The last three winters really have not been colder than normal. They've been more normal weather. During 2014, 2015 and 2018, we saw more curtailments during that time period. But, once again, once the operational orders were in play that allows us to issue operational orders to ensure that supply and demand are in balance and it protects the system.

And then as I stated in my opening remarks with regards to the FERC and NERC report recommendations, the Key Recommendation 6 lists the recommendations related to natural gas infrastructure. And many of those measures have already been implemented by our Company as a result of the actual winter, extreme winter conditions we went through in that 2014-2015 timeframe.

So, that concludes our prepared remarks, but we're available for any questions you might have.

CHAIR MITCHELL: Let me check in with Commissioners. Questions for PSNC? Commissioner McKissick?

COMMISSIONER McKISSICK: You explained how your modeling is done in terms of considering what type of peak demand you're concerned about, but how does that -- and I guess what I'd like to know, I know that you indicated the coldest day was in 10 years is what you're looking for, but how does that compare to what happened out in Texas in terms of that type of event that occurred?

MS. JACKSON: We actually go back 70 years of historical data and we pulled -- which I think our peak day was in 1970 -- our peak gas day.

COMMISSIONER McKISSICK: Peak gas day.

MS. JACKSON: We pulled the heating degree days on that actual weather event.

COMMISSIONER McKISSICK: Right.

MS. JACKSON: But then we take that, those heating degree days, and we apply it to the estimated demand for our current mix of customers. So, let's say that we have it by rate category and our forecast model takes into effect and applies the heating degree days on that actual coldest day ever and determines what that design day need is going to be for our customers, for the customers.

COMMISSIONER McKISSICK: Coldest day ever.

MS. JACKSON: Yes, sir.

COMMISSIONER McKISSICK: And if they use a similar type of planning paradigm out in Texas, what would it have predicted? You know, I mean, I'm just trying to see if the weather out there was so extreme that it deviated from say whatever that coldest day had been in an equivalent timeframe coldest day ever for them?

MS. JACKSON: Commissioner McKissick, I really think that the bigger issue in Texas was related to their regulatory structure, the fact that they are deregulated.

COMMISSIONER McKISSICK: Yes.

MS. JACKSON: Those companies do not have the same oversight that we do as regulated utilities. And they're also incented to reduce cost any way they can in order to compete in that marketplace. We, as regulated utilities, have to come before you all once a year to show you that we are prepared for our design day. So, I'm not certain that any of those utilities in Texas are required to do any of that. I'm just not as familiar with the requirements that they have, but I do know in a deregulated environment it's vastly different from what we have here in North Carolina.

COMMISSIONER McKISSICK: Sure. And I agree with your assessment about that. It was just more of a matter of curiosity more than anything else. Thank you.

MS. JACKSON: You're welcome.

CHAIR MITCHELL: Okay. I have a few questions for you-all. Anybody can answer them so I'll just direct them to the group. Talk some about the Company's curtailment procedures. Just walk us through in the event that the Company got there and had to begin curtailing customers, how would that take place?

MS. JACKSON: We -- typically, it's related to interruptible customers. And we have --

our gas control group plans as far as their winter prep they train for curtailments on the system. So, in the event we have -- we receive a forecast that determines that we may need to curtail interruptible customers, we identify those customers and as stated before we send out an email to the customers affected. We send out an email to their pooler if they're on transportation and their individual account manager follows up with a phone call to ensure that that email has been received.

Also, during those time periods we are probably going to have an operational order on our system as well and Transco was going to have an operational flow order on its system, also. So the penalties associated with Transco's OFO, our operational order, it's going to -- those incentives, those penalties are in place to ensure compliance. So, it would be some type of catastrophic event on Transco before we would begin curtailing firm customers.

CHAIR MITCHELL: Understood. And so then let's assume a catastrophic event occurs so then what would the process be?

MS. JACKSON: It would be based on the

Commission Rules that we have in place, but it's also going to be based on location. Let's say that we had some type of catastrophic failure off of a point on Transco that would only affect the west, like the Asheville region, then we would begin curtailing -- we would begin contacting customers, asking for a voluntary curtailment and then we would follow up by looking at that local area trying to determine which customers we would have to curtail. If it's only some type of event that would impact the west, we're certainly not going to curtail customers in the east unless we absolutely have to. If it could impact system-wide, then we would evaluate that at that time.

CHAIR MITCHELL: And you touched on this just a minute ago, but how is the Company training for this? Are system operators trained to handle this type of situation should it occur?

MS. JACKSON: Yes, ma'am. Our gas control group actually manages gas control for both South Carolina and North Carolina. In North Carolina, because we have most of our industrial load as transporting we don't have as many curtailments because they've contracted with a pooler to bring in their gas. In South Carolina, we actually have a lot of customers on interruptible sales so that group curtails annually for South Carolina. So, they are very proficient at the process they go through. But, as stated before, we have a winter prep meeting that involves engineering, gas supply, and gas control every year and then subsequent to that meeting the gas controllers are trained on the requirements they're going to have for the upcoming winter season which includes curtailments.

CHAIR MITCHELL: Okay. Going back just a minute, you were describing the process for curtailment in the event of a catastrophic event or failure on the system and you described how the Company would try to limit the impact of curtailments based on location. So, as you're going through, let's say you've gotten to that point and you're in a specific location on the system, who gets curtailed first? I mean talk about, sort of, order of priority of customers.

MR. SWINDLER: I can give you an example. So, we had a pipeline issue out in the western part of the State and we were going to lose pipeline all the way out to Bryson City. And we needed to set big loads, so we worked with the key accounts folks and they called all those customers and they told them what the situation was. All of them went off and it gave us enough time to keep from depleting that whole system to where we got down to no pressure. Because on a gas system what you've got to do as soon as you go to no pressure you have to start the process of shutting it in and then go through the process of getting all the air out of it and then go through another process of where all your customers are shut in and then you've got to get the air out of their system. So, you take measures to try to keep from getting to that point.

So, we talk about a curtailment process, if you ever got to the point where you had to do residential customers or commercial customers, the real small ones, you would probably be in a point of system preservation and you would be sacrificing pieces of the system where you would actually be valving off parts of the system and shutting those off to keep the main supply lines gassed up so you wouldn't have to re-purge the whole system out. So, it would be a systematic process of you may have to shut some system off to do that.

CHAIR MITCHELL: Okay. And Ms. Jackson, you've mentioned the winter planning meeting. I assume that's an annual meeting --

MS. JACKSON: Yes, ma'am.

CHAIR MITCHELL: -- that occurs. Any other regular training or simulations that occur related to winter weather preparedness or system failure preparedness?

MS. JACKSON: Mr. Raynor or Mr. Swindler can talk to their -- the requirements for gas operations. But certainly in terms of gas supply and gas control, we have a monthly meeting where we evaluate what the upcoming month, we look at what the short-term forecast is projecting for that month and we work with our resource planning group that does a monthly forecast. They are the same group that does our design day forecast. But gas control also does a forecast and we compare the two and then we evaluate how to set up for the upcoming month and that occurs on a monthly basis. It also includes a number of folks from our risk group but also from our accounting group as well.

MR. RAYNOR: I'll just offer up at the LNG plant in Cary prior to winter we get our gears up to temperature, get our pumps and our piping cooled down, do a -- have a test run of vaporization prior to December 1; that's our practice.

CHAIR MITCHELL: And that's an annual -- those are annual?

MR. RAYNOR: Yes, ma'am.

MS. JACKSON: We also have customer meetings with our large account group. And in preparation for the winter season that customer group sends out notifications to all of our industrial or interruptible customers to just remind them that the winter heating season is upon us to make sure that they test their alternate fuel equipment and remind them of the curtailment provisions in our tariff.

CHAIR MITCHELL: Is that a post Polar Vortex practice?

MS. JACKSON: No, ma'am, we've always done that. I think that our customers are now more in-tuned as to what type of ramifications a Polar Vortex event could have because of the price of natural gas that was charged as part of those penalties.

MR. SWINDLER: And there's one more

process I'd like to add, it deals with the engineering side of it. So, there's also a meeting every year, it's a system enhancement meeting where they pull all the weather data, how the system performed, and then they also take the models and they apply the design day models to it, and we look on the system and proactively find places that may be weak and get them corrected before they become a problem. And the typical pressure is a 30 pound, so even at 30 pounds there's typically, you know, if it overshot it some there's some reserve there, too, so that's the process.

CHAIR MITCHELL: Okay. A question about the operational orders. In the data that the Company provided in response to Question 12, it appears that the tolerance limits for the operational orders increased by 5 percent every year between 2019 and 2021. Can you just help us understand that?

MS. JACKSON: Yes, ma'am. Originally, when the operational orders were put into place, we only had one static percentage that we could apply. But then Transco began to implement what we call bracketed operational flow orders where not only did they have us protecting on the short side, they said not only you have to have a tolerance on a short side but also on the long side so, in effect, the shippers on their system are balancing Transco's system. Because we have to stay in our lane, if you will, we might have a 5 percent tolerance on the short side and a 10 percent tolerance on the long side. So depending on what our assets look like we have to implement operational orders on our system to ensure compliance with Transco's operational flow orders, and that's generally what drives our operational orders.

CHAIR MITCHELL: Okay. And then -- okay. A question about the coordination with your electric power providers. Do you-all -- I mean, based on what you have told us today about the service provided to the facility in Cary, you're taking service at the distribution level. Does the Company have any compressor stations that are electric as opposed to gas powered?

MR. SWINDLER: No.

MS. JACKSON: No, they are all gas.

CHAIR MITCHELL: Any other critical infrastructure that would be electric versus gas powered?

MR. RAYNOR: Not that I'm aware of.

MR. SWINDLER: The flow control stations and all they all have generator backup, those type of things. The compressor stations generally are gas driven and they have for the accessories and all they have generator backup on them.

CHAIR MITCHELL: Okay. Can any of you talk to the coordination in which you engage with your -- with the electric company for service that it provides to PSNC or that the electric companies provide to PSNC?

MR. SWINDLER: I remember in -- you know, it was 10-years or so ago we were asked about facilities, critical facilities, that might would be impacted by a brownout and we provided some information then with the account numbers and everything. So --

MR. RAYNOR: I can't say personally whether we're still under that protected service or not. It's something I need to follow up on.

CHAIR MITCHELL: And would that be within your purview of responsibilities?

MR. RAYNOR: Yes, I'll follow up.

CHAIR MITCHELL: Okay. Let me pause and see if there are questions from other Commissioners. Commissioner Clodfelter?

COMMISSIONER CLODFELTER: I have a question about coordination with the electric utilities as well, but it doesn't involve coordination with respect to the service you provide to each other, it relates to the service that you both provide to customers. And I'll -- because I can think concretely about it and it's real in my head I'll use myself as an example, but scale it up. So the question is really about what if you scale this up.

So, if you were to have either a physical event that caused an interruption in my gas supply or you had to curtail me, I'm not interruptible, I'm a residential customer, but if I were an interruptible customer, sales customer, or you had a physical event for me as a residential customer, I'm going to convert to my emergency electric backup supply which is going to change the load Duke experiences.

So, let's say the case that you had out there where you were about to have a major problem going out from Asheville to Bryson City, are there protocols and mechanisms in place for you to say to Duke Progress, hey guys, get ready, you may experience a rather substantial change in your load because we're about to have either a curtailment or a physical interruption to our service.

It can also work vice versa. I've had situations where I've been able to increase my use of gas service when I've had problems with electric service, because they've used backup generation to convert from one type of water heating to another type, so the load changes. The customers have fuel choice, not just between, sort of, oil and gas is what we've been talking about with electric customers, but customers can choose between electric and gas. And so do you guys talk to each other about how your load -- your decisions might affect the demand or the load on the other?

MS. JACKSON: Typically, you're going to see more impact to gas utilities in the event that there is an electric outage because --

COMMISSIONER CLODFELTER: Sure.

MS. JACKSON: -- if you have -- let's say that your home has HVAC that's electric and a gas pack, I mean, a gas -- I mean, a heat pump --

COMMISSIONER CLODFELTER: Right.

MS. JACKSON: -- and the power goes out but you have gas logs in your home --

COMMISSIONER CLODFELTER: Right.

MS. JACKSON: -- they're going to crank those gas logs up.

COMMISSIONER CLODFELTER: Well, it's a -- I agree, it's absolutely right. It's a two-way thing.

MS. JACKSON: Right.

COMMISSIONER CLODFELTER: And my question really is focused on what mechanisms do you have in place for each to talk to each other about those kind of events that's going to shift the customer utilization of the two different fuels?

MS. JACKSON: I don't think there's formal communication, but we typically know because we serve, excuse me, the power plants in our area, so we typically know if there's some type of outage because they will send over what their requirements are on a daily basis and we're prepared for those changes in demand and they are typically short term in nature.

COMMISSIONER CLODFELTER: Okay.

MS. JACKSON: So you may see increases when one utility has an outage that goes to the other. But I don't think they're going to be long term in nature and I don't think there will be tremendous volumes that would be impacted.

COMMISSIONER CLODFELTER: And would you typically have a way of knowing if you're about to experience an interruption due to say damage to a pipeline? Will they typically know that?

MS. JACKSON: Typically, everybody knows it because it's broadcasted on the news. (Laughing) I mean, I hate to say that, but with today's social media and the instantaneous news feed that we all have, you typically find out about it through social media to be honest.

COMMISSIONER CLODFELTER: Okay.

MR. SWINDLER: And if you're an impacted customer you're probably going to get a door tag. We would have created orders that are standing by and the local operations would have already -- would have started phone calls to you and everything to talk about what the process is going to be.

COMMISSIONER CLODFELTER: Okay. Thank you

for that. I appreciate it.
CHAIR MITCHELL: Commissioner Brown-Bland?
COMMISSIONER BROWN-BLAND: Good afternoon.
MS. JACKSON: Good afternoon.
COMMISSIONER BROWN-BLAND: I apologize that I -- it was definitely my loss not to be here and hear from Ms. Jackson, as she regularly appears in our annual review of cost proceedings and I'm sure the rest of you who have not served on that panel had an opportunity to see just how knowledgeable she is. But I did have just one question I wanted to ask you. Do your LNG storage facilities require electricity to convert LNG to usable gas?
MR. RAYNOR: Yes. We do have backup power there but it doesn't carry every process at the plant to convert pipeline gas into liquid. We do have to have commercial power to drive that equipment.
COMMISSIONER BROWN-BLAND: And in terms of cold weather preparation, does that bring anything else into play for you?
MR. RAYNOR: Well, typically, we are liquefying it in the non-winter part of the season

so it doesn't affect us in that regard. I mean, our backup power generation, our diesel backup generator provides the power that we need for our vaporization and our start holding mode if we're not making or sending out gas, so it covers those two processes but not the liquefaction process.

MS. JACKSON: So it won't interrupt us in the event we need to withdraw LNG from the tank but it could impact us in the summertime when we're trying to inject.

COMMISSIONER BROWN-BLAND: Thank you.

MR. SWINDLER: I always found it interesting, too, the LNG plant, the liquefaction process is about four million a day in and the plant can put out about a hundred million a day out on the vaporization side for cold weather support.

MS. JACKSON: Or 4,000 dekatherms injected, a 100,000 dekatherms withdrawn.

MR. SWINDLER: Yeah, I'm a cubic feet. (Laughing)

MS. JACKSON: Engineering versus gas supply. (Laughing)

CHAIR MITCHELL: Any additional questions from Commissioners? Public Staff?

MR. NADER: Absolutely. Jordan Nader with the Energy Division - Public Staff.

Can you all hear me alright?

MS. JACKSON: Yes, sir.

MR. NADER: So, we sent you data responses, let's see here, data requests on March 29th, and my question is related to Question 8.

Going back earlier you referenced pressure issues on the system. And in a situation, going to what Commissioner Clodfelter was referencing of the interoperability between these two utility systems, if there was an unexpected trip with the electric system, let's say, cold weather/ice storm knocks out a distribution circuit, the brunt of this question is are there emergency backup generators connected to your system that are behind meters that you don't necessarily have visibility of that could increase flow and cause pressure issues?

MR. SWINDLER: Our system is designed and when, you know, we know that when the meter and everything was put in it would be designed to support that as a firm load.

MR. NADER: And so if a customer, let's say, a commercial customer goes in at one point, 10 years down the line the building gets sold, a new customer comes in, they're worried about backup generation and they don't communicate to you that they've installed a natural gas-fired generator, what -- I mean, would there -- is there enough headroom in the system that it doesn't present any concerns?

MS. JACKSON: Typically, the accounts -- the medium account groups would be in contact with that customer.

MR. NADER: Okay.

MS. JACKSON: And they work closely with them as they make those type of changes.

MR. NADER: Okay.

MS. JACKSON: So, I'm not sure --

MR. SWINDLER: And it's an -- it's kind of an interesting process that happened. So, when you have a winter, say, electrical outage, well just imagine you have your furnace at home and you have an electrical outage, you're not pulling gas, so typically you've already shed off some, you know, so the generators and all wouldn't make up that difference on what you let out. So, there's kind of a little bit of a balance there that some is going to naturally shed and then others is going to come on. I mean, it is possible that somebody adds a load that we don't know about and causes some problems. It may would cause more issues on their meter set and our facility is supplying them because we didn't know about it, so it may be a localized issue that it would cause.

MR. NADER: Okay. Very good. Thank you.

MR. LITTLE: That's all from the Public Staff.

CHAIR MITCHELL: Checking in one last time. Thank you very much guys. You are -- you may all step down.

MS. JACKSON: Thank you.

MR. SWINDLER: Thank you.

MR. RAYNOR: Thank you.

CHAIR MITCHELL: Thank you for your participation today. We appreciate your participation today.

Next up, we've got Piedmont.

Good afternoon, gentlemen, would you please introduce yourselves for the record?

MR. LONG: Good afternoon, Chair Mitchell. My name is Adam Long. I'm the Vice President of

Pipeline Operations representing Piedmont Natural Gas.

MR. MOSER: Good afternoon. I'm Neil Moser, Director of Engineering & Asset Planning.

MR. PATTON: Good afternoon. I'm Jeff Patton, Manager of Pipeline Services.

MR. JEFFRIES: And, Chair Mitchell, in addition to our primary presenters, we also have Mr. Bruce Barkley who's Vice President of Rates and Gas Supply for Piedmont, and Ms. Sarah Stabley who's the Managing Director of Gas Supply Optimization and Pipeline Services.

CHAIR MITCHELL: All right. Well, good afternoon, everyone. You-all may begin.

MR. LONG: Chair Mitchell, what you'll see up on the screen is a footprint for Piedmont Natural Gas in North Carolina and a few statistics. Piedmont is very happy today to talk with the Commission on our responses to your questions. We would ask that at any time during this presentation if you have a question please do stop us and we'll be happy to address your questions.

Piedmont has a rather large footprint in North Carolina, just under 800,000 customers, over

17,000 miles of distribution line of pipe and more than 2,500 miles of transmission pipe.

To answer all of the Commission's questions we put all of our reliability topics into six sections as shown up on the screen. We'll start with the Texas event and go into load forecasting, curtailment, restoration services, coordination with our electric generators, and then system planning and its criticality for reliability.

Cold weather is really the primary threat to Piedmont's system. As PSNC stated, our assets are underground and not subject to the same issues that an electric provider would have with wind and ice. Our critical equipment is maintained and tested annually and designed to be reliable to a temperature below 0° Fahrenheit.

After the 2021 Texas event, Piedmont Natural Gas took it upon themselves to work with other utilities in North Carolina and interstate providers to do a self assessment of how our equipment would work at extreme low temperatures. In that self assessment, Piedmont worked with Williams - Transco as well as PSNC to evaluate all of our LNG facilities, our pressure station facilities and pipeline facilities to see if there were lessons learned by Williams in their Gulf Coast operations or by the other utilities to see if there was something we could learn and benefit from for cold weather operations. After that assessment, Piedmont decided that there was no changes warranted to our system, that we had already incorporated those best practices and other design features in previous cold weather events.

Piedmont maintains redundancy of our critical equipment in our operations. All of our critical electric needs for our system are backed up either by a generator or a UPS system with a battery supply.

We have an Emergency Operating Plan that does not require electricity, internet or telecommunications for our system to work. And we have simulator training for our control room and they are trained on how to deal with emergencies as well as day-to-day operations.

COMMISSIONER CLODFELTER: Question for you, sir. What applications do you use battery backup? When do you choose to use battery backup?

MR. LONG: So, we would have battery

backup at a facility that monitored only pipeline stations so we could see pressure or temperature or flow, and that battery backup is good for more than 24-hours. It's monitored live by our control room so we can see when the power is off, the status of the battery backup system, and an alert before it starts to fail so we can respond.

COMMISSIONER CLODFELTER: But you have a 24-hour capability --

MR. LONG: Yes.

COMMISSIONER CLODFELTER: -- discharge for 24 hours?

MR. LONG: For more than 24 hours.

COMMISSIONER CLODFELTER: Thank you.

MR. LONG: When we talk about load forecasting, as Piedmont submitted in our question to the Commission, we used the GasDay Program to produce daily and hourly natural gas demand forecasts. This system is used by more than 40 companies in 32 states. And the forecasted weather is entered into the GasDay hourly system from 7 a.m. to 5 p.m. each day. Piedmont gets what we believe is very high quality weather data that goes into our GasDay to make it very accurate. And even though weather forecasting is not perfect, I like to refer to meteorologists as weather guessers most of the time, but we have tools to meet our peak day demand such as our three on-system LNG storage facilities in North Carolina as well as peaking supply resources and interstate storage.

For curtailment, Piedmont has actually never curtailed any firm customers. Generally, seasonable winters have resulted in limited recent curtailments of only interruptible customers. When we curtail interruptible customers or firm customers we do it in conjunction with Commission Rules R6-19.2. Interruptible customers are always, of course, interrupted first and in order of lowest margin. Firm customers, even though we've never done it before, would be interrupted in order of lowest margin first. Residential customers are always the last to be interrupted and to date has never happened on Piedmont's system.

The Company communicates directly with our interruptible customers every year. We validate those contacts annually to ensure that we have the latest information and contact names.

In the very unlikely event that we ever

had firm curtailment, Piedmont puts together a communication plan as part of our Incident Command System that would include an overall emergency response, and then we disseminate that message over television, radio and social media.

When it comes to restoring natural gas customers it is a little bit different than our electric part of the Company. Restoring natural gas to customers is fairly time consuming. The Company has very good internal resources from our other operating areas. We operate in five states, and the technicians in those states are eligible to come work in North Carolina in the event that we need extra manpower because they are familiar with our system, our procedures and our equipment.

In addition, we're members of SGA, Southern Gas Association, and AGA, the American Gas Association, and subscribe to their mutual assistant agreements that are validated every year.

A widespread restoration has never actually occurred to Piedmont to date, but to restore customers we have in the presentation the steps you'd have to take to restore a residential customer. It's very time consuming and very labor consuming, which is why we have resources outside of the State to help us if it was ever needed and the mutual assistance with neighboring utilities.

COMMISSIONER DUFFLEY: I have a quick question. If that were ever to happen, you say time consuming and extensive, what does time consuming mean? Can you -- days, weeks?

MR. MOSER: So, as an example, we had third-party damage some period of time ago in Farmville, east of here. We had a third-party damage that resulted in the outage of that community. I think the number was somewhere around 1,400 customers impacted. As described here, the first step, of course, to make the situation safe, but to valve off and contain the leak; go to every subsequent downstream customer and valve those off so that the system can be purged, repressurize and then we're to go back and relight all those customers.

In that event, I think from the time of damage until we had full restoration service restored, it was somewhere in the 36 to 48-hour range. So, as you look, for as much as you would increase that number particularly depending upon geography, those times definitely are measured in days if not longer.

COMMISSIONER DUFFLEY: Thank you.

MR. LONG: For electric generation, Piedmont does serve five interruptible electric generators and then 10 firm service electrical generators in North Carolina.

We have frequent communication with our generators in addition to normal daily communication and then extra communication during critical times of severe weather.

CHAIR MITCHELL: Mr. Long, I'm going to ask you a question about just following up there. I just heard you say that the Company serves five power gen customers on interruptible service.

MR. LONG: Uh-huh (yes).

CHAIR MITCHELL: And that may be inconsistent with what we heard earlier today, it may not be. I just am hoping you can help me understand what the Company means when it says "interruptible service".

MR. LONG: So, we serve multiple power providers such as Duke Energy Carolinas, Duke Energy Progress and then independent power providers -

Southern Company. These companies have different contracts. Most of them have firm service contracts. Some of those companies have interruptible service contracts for units on their property. They are interruptible service contracts.

I believe Mr. McAllister was talking about interruptible service, and for all of the firm contracts that Duke Energy has, when they redeliver gas to our system, we redeliver that on a firm basis, and we have never not redelivered that firm gas. But there are units on that system that are interruptible that if we get a time of interruption and they were scheduled that they would not run.

CHAIR MITCHELL: Okay. I may need you to go through that one more time. So, it sounds like the Company, Piedmont, has the right to interrupt service for certain of these customers.

MR. LONG: Based on their contract.

CHAIR MITCHELL: Based on the contract.

MR. LONG: Uh-huh (yes).

CHAIR MITCHELL: But that redelivery is always for --

MR. LONG: So they -- to make it simple there's two types of contracts. There's firm contracts. Piedmont has always delivered on our firm contracts. There are interruptible contracts and they are standard interruptible contracts. But if we called it curtailment, that we would curtail those contracts to those units. And there are five plants that have that type of contract.

CHAIR MITCHELL: Okay. Five power generating facilities. Okay. Thank you.

MR. JEFFRIES: And Chair Mitchell, to the extent it's helpful, Piedmont's response to Public Staff Data Request 9(a) has the details of those plants.

MR. LONG: So, if we had to interrupt firm customers, although it has never happened, it is done on a lowest margin basis in accordance with Commission Rule R6-19.2.

Piedmont participates in Duke Energy's review of the 2021 Texas event. Went through that with Duke Energy and again found no changes for the Piedmont system were warranted.

When we look at system planning there's two critical aspects that deal with reliability. One is the interstate capacity and the other is Piedmont's actual infrastructure system.

For interstate capacity, we have a design day of an average of 8.69° Fahrenheit and that's based on actual weather day January 21st of 1985, the coldest day in our service territory in the last 40 years. The demand is determined using a regression analysis to project our firm customer usage on that day. We annually review in the gas cost prudence review and the NCUC has ordered the review and consideration of five potential modifications for Piedmont's process, which we are looking at.

For Piedmont's infrastructure, we do a detailed model of future considerations while looking at project growth and the design day weather. Our planning horizon is a minimum of five years looking at system growth and how our system will react. Our planning model is reviewed and updated routinely throughout the year. It's not a static model, it's dynamic, and we look at it. And our infrastructure is designed and constructed -- new infrastructure is designed and constructed to the model forecast and insufficiency for our firm customers.

That concludes our prepared remarks.

We're open to any questions from Commissioners.

CHAIR MITCHELL: Let me check in with Commissioners. Questions for Piedmont? Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: Good afternoon. Just a few questions. And I think that you probably heard at least a portion of these with PSNC, but could you discuss your natural gas curtailment procedures and the protocol to curtail the various classes of customers?

MR. LONG: So, for our IT customers, we would curtail an impacted system in order of margin for the customers on that system. And we do that on not an annual basis, on a regular basis based on weather conditions. For firm customers, we've never had to curtail before. But in the event that we would have to curtail on a particular gas system and just like Commission Rule R6-19.2 requires, we would curtail in order of the lowest margin for those firm customers.

COMMISSIONER BROWN-BLAND: And your highest priority is?

MR. LONG: Highest priority, the last customer to ever be curtailed is residential customers.

COMMISSIONER BROWN-BLAND: And if curtailment is necessary, do you treat your electric generators the same as any other transportation customer or is there some other preferential treatment?

MR. LONG: No. In accordance with the Commission Rules, they would be treated as a firm customer and then be curtailed based on their margin.

COMMISSIONER BROWN-BLAND: All right. In response to the Commission's Question 1, the Company stated that it conducted a review of its low temperature operating requirements for critical equipment in order to validate its operability in extreme cold weather. Could you walk us through the steps involved and what you did for that review?

MR. LONG: Of course. So, first, we reached out to other utilities in North Carolina and then our interstate natural gas provider Williams - Transco, and then we looked at critical facilities for all three companies, did site visits, and looked at manufacturer recommendation temperature ranges for that equipment. We looked at our inventory of parts, our training, and then our annual maintenance practices for all of that equipment. Then after site visits and talking with the manufacturers for Piedmont specifically, we determined that we'd already incorporated all of those maintenance activities. That equipment was set up to work at a temperature below 0° Fahrenheit. And there were no maintenance or operating practices that we saw at a peer utility or an interstate utility that would have benefited us, so we maintained our current annual maintenance and operations there.

COMMISSIONER BROWN-BLAND: Without -- you didn't see the need for any tweaking or any changes at all, just kept it the same?

MR. LONG: It's the same operating plan. The most we did is one of our -- one of the utilities we have in Southern Ohio and Northern Kentucky realized temperatures down to negative 14° Fahrenheit. We have similar equipment, similar maintenance practices. We asked what do you do different from what we do and we did not glean anything important that we would need to do that they're currently doing. And they are reliably operating at those temperatures.

COMMISSIONER BROWN-BLAND: So, we're able to benefit here in North Carolina from the knowledge that you have in the other even colder weather states?

MR. LONG: Yes, ma'am.

COMMISSIONER BROWN-BLAND: And then in your response -- your response to Question 3, you stated that the GasDay model is provided by Marquette and that the GasDay model is licensed by 40 other LDCs in 32 states. Do you know how many other LDCs are in the southern region?

MR. PATTON: I'm aware that, I believe, from memory, I think Frontier might use Marquette GasDay, based on their filings, but I can't speak offhand which ones are in the southern region.

COMMISSIONER BROWN-BLAND: And do you have any info or feedback as to whether the error rates for their last three winter peaks in the -- for the three days before the winter peaks in that region? Do you have any idea what that might be?

MR. PATTON: I do not.

COMMISSIONER BROWN-BLAND: All right. And then finally, with regard to the FERC/NERC recommendation that the electric utilities at least annually perform simulations of emergency load, does Piedmont conduct simulation training of a load shedding event for control room operators?

MR. LONG: So, in our normal control operations we balance load daily. And it is part of our training profile to do training on what an emergency situation would be as well as daily operations.

COMMISSIONER BROWN-BLAND: And you stated the gas grid operation and balancing is part of the normal control room operation and is conducted during operator qualification training at least every three years. Is that the industry approach? Is that optimal for the industry or are you exceeding industry or --

MR. LONG: So, I can't speak to what the industry does. I will say that the approach we use is used by other utilities, but whether it exceeds industry basis I don't know that our industry has baselines, that type of function.

COMMISSIONER BROWN-BLAND: Is there -- do you know the Company's reasoning for why three years is sufficient or why three years versus any other period of time?

MR. LONG: I can go back and check to see if we documented why we chose three years.

COMMISSIONER BROWN-BLAND: Okay. Thank you.

CHAIR MITCHELL: Any additional questions for the Company?

(Pause).

Public Staff?

MR. NADER: Good afternoon. Jordan Nader, Public Staff. I'll pose to you the same question I posed before on Question 8 from our data request, concerns about unknown electric backup generators that are tied into your system. Your response I appreciate. Is there anything within your customer data files that you -- like this or in surveys with key accounts or anything like that to know that these generators exist or do you assume you have enough headroom if a firm customer turns on their emergency generator because the electric grid went down?

MR. MOSER: I think you'll find our answer very similar to that offered by PSNC. We size for connected load at time of customer and for the largest customers there is the major accounts liaison and it occurs for those customers. With that said, I think Mr. Swindler hit on a point, the size of meter set is likely going to be a limiting factor. So, if the customer adds load without contacting us, that meter set could limit their deliverability, it could isolate that and keep it -- keeping interruptions, a section of that load confined to that customer.

MR. NADER: So it would be a physical limitation of the pipe running to the property?

MR. MOSER: Correct.

MR. NADER: Okay. Very good. No further questions.

CHAIR MITCHELL: With that, I believe we are -- there are no additional questions for Piedmont, so you-all may step down. Thank you very much.

Next up, we will hear from Frontier Natural Gas.

MR. JEFFRIES: Chair Mitchell, presenting today for Frontier Natural Gas are Mr. Fred Steele who's the President and General Manager of Frontier, and along with Taylor Younger who's the Regulatory Compliance Engineer for the Company.

CHAIR MITCHELL: Good afternoon, Mr. Steele and Ms. Younger. You all may proceed.

MR. STEELE: Thank you, Chair Mitchell. Chair Mitchell, Commissioners, we would like to thank -- Frontier would like to thank you for the opportunity to participate in today's technical conference to answer your questions relating to Frontier's operational reliability during extreme cold weather.

Frontier was not affected by the February 2021 Texas weather event. To assist in your understanding of the Frontier Natural Gas system, we'd like to offer the following further support to the previously submitted data request responses.

Frontier has never experienced a system outage due to extreme weather conditions. Frontier conducts a cold weather preparation system review annually. Frontier utilizes Marquette Energy Analytics to assist us in a development of our design day or load temperature operating requirements and determining its natural gas system supply planning.

Frontier secures enough natural gas supply annually to meet the forecasted design day natural gas load for its customers. The design day methodology and calculations for the customer load is described annually in Frontier witness testimony of the Company's annual review of gas costs.

In the event of an emergency curtailment, Frontier would communicate with its interruptible customers via telephone, text message and emails. Frontier also utilizes local news, radio, social media outlets, and contacts the -- contact the local emergency agency if curtailment of firm customers were to become necessary.

With that, I mean, that really concludes our prepared remarks. We are willing to offer a presentation after this conference in that we did not come with one prepared. So, with that, we're willing to answer questions.

CHAIR MITCHELL: Thank you very much. Let me check in with Commissioners. Questions for Frontier? Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: Actually, I don't have much for you but I do have a couple. So, has Frontier communicated with its customers that use electric generators and rely on natural gas, have you communicated with them about the appropriate switching capabilities and operating requirements in case you did have to curtail?

MR. STEELE: We do have communication with those interruptible customers that we know that have alternative means of energy. So, yes, we have communicated with them and we try to do that annually.

COMMISSIONER BROWN-BLAND: And when you communicate or do you have specific policies and procedures that are in place for them, those with the electric generators?

MS. YOUNGER: For the electric generators we don't. We do keep track on our feasibility model. So, when our sales people go out and sign people up, we do keep track if they have an electric generator at that, you know, at that time. But we do not have that data readily available in a database that we can just pull and know exactly where those generators are in the field. We haven't signed any big customers up with that. I know sometimes they'll come through and they're mostly small commercial or residential, so.

COMMISSIONER BROWN-BLAND: Do you have any, you know, general applicable, generally applicable policies that you share with them or that you would have them to -- procedures to go through with respect to being prepared to curtail?

MS. YOUNGER: So the curtailment policies, we do share those with our transportation customers, but that's a little separate from the generator customers. So, we do not have anything available for the generator customers at this time.

COMMISSIONER BROWN-BLAND: All right. So, no you don't have like a standard. It's more of a case-by-case or whatever is needed.

MS. YOUNGER: Right.

COMMISSIONER BROWN-BLAND: Okay. And it does get pretty cold in your territory, doesn't it?

MS. YOUNGER: It does.

COMMISSIONER BROWN-BLAND: So, you're comfortable with operating at generally colder temperatures than the other two LDCs that we heard from?

MS. YOUNGER: We prepare our heaters. We have kind of a winter preparedness, preparedness, that we go through. So, we make sure our heaters are ready. We supply them with like, um, different procedures, so, annually.

COMMISSIONER BROWN-BLAND: And your customers, as I recall you serve some farm customers and it's critical to them that they not be without heat?

MR. STEELE: That's correct.

COMMISSIONER BROWN-BLAND: So you oversee or somehow advise them regarding their backup or understand that they do have adequate backup.

MS. YOUNGER: They understand that if we ever did have to curtail them, they do understand that they are not interruptible so we're never going to go and curtail them. I mean, but they might -- you know, we might have an outage through Transco, but they are -- they do know that they are not a transportation customer. So, if there is an outage, there is an outage whether they have alternative fuel or not, you know, we told them, so.

MR. STEELE: Some of the poultry farmers do have backup some do not.

COMMISSIONER BROWN-BLAND: All right. Thank you.

COMMISSIONER CLODFELTER: Talk a little bit about what kind of arrangements you have for operation of your own infrastructure in the event of loss of electrical power. Do you have battery backup? Do you have generators? What do you use to back up your electricity supply for your own infrastructure?

MS. YOUNGER: We do not have electric supply to any of our infrastructure.

MR. STEELE: That's right.

COMMISSIONER CLODFELTER: Nothing?

MR. STEELE: Nothing.

MS. YOUNGER: But --

COMMISSIONER CLODFELTER: What about for your -- I mean, Piedmont says they use batteries to back up their monitoring and sensors. Do you do the same?

MS. YOUNGER: We have battery powered, you know, telemetry.

COMMISSIONER CLODFELTER: Okay. Same as what Piedmont was telling us. Got it. Thank you.

COMMISSIONER HUGHES: We haven't talked too much about customers that when they lose their electricity the impact it has on gas. Are your gas customers as independent of the electrical system as you are, I mean, the farms? Do you see a big drop when there are just even normal electric outages in

your area? It's more of curiosity, it's not --
MR. STEELE: I guess I'm not quite sure. Restate your question again.
COMMISSIONER HUGHES: Oh, just when you -- when electricity goes out, you-all --
MR. STEELE: Right.
COMMISSIONER HUGHES: For example, for farms, do they have any problem with their equipment needing electricity and do they stop using gas when they lose electricity?
MR. STEELE: We've not really experienced anything. I can't say that we've ever had that experience happen to any of our customers at Frontier at this point. So, that's the best answer I can give, because that's not happened.
COMMISSIONER HUGHES: Okay. Well, I know my colleague has invested in a generator so he's okay, and I'm not so I was just trying to learn --
MR. STEELE: You know, some of the poultry farmers, as they said, they do have some of -- some of them have some backup but not all of them.
COMMISSIONER HUGHES: And on the residential side most of them don't probably, I mean, even though they have gas at their house --

MR. STEELE: That's right.

COMMISSIONER HUGHES: -- they don't have heat?

MR. STEELE: Right.

COMMISSIONER HUGHES: So it's --

MR. STEELE: Right.

CHAIR MITCHELL: One last call for questions. Public Staff?

MR. NADER: No questions.

CHAIR MITCHELL: You-all may step down. Thank you so much for being here with us today.

MR. STEELE: Thank you.

CHAIR MITCHELL: With that, we've come to the end of our technical conference for the natural gas and the electric utilities. Appreciate everybody's preparation and participation today, and we will be adjourned. Thank you very much.

(The proceedings were adjourned)

C E R T I F I C A T E

I, KIM T. MITCHELL, DO HEREBY CERTIFY that the Proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

Kim T. Mitchell

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