Case No. PUR-2018-00065
Sponsor: RESPONDENT
Exhibit No 22

Witness: GREGORY M. LANDER
Bailiff: JABARI T. ROBINSON

Summary of Testimony of Gregory M. Lander

My name is Gregory M. Lander. I am head of Skipping Stone, Inc.'s Energy Logistics practice. The purpose of my testimony today is to describe two areas of missing or inadequate analysis in the Company's 2018 IRP that relate to the IRP's consideration of costs of the Atlantic Coast Pipeline and raise significant concerns about whether the Company has, in fact, identified a reasonable least-cost generation scenario. First, I will testify that the Company did not study or present an analysis of the cause, frequency, duration or magnitude of natural gas price spikes. Analyzing four scenarios for forward-looking basis projections between different pricing locations, I calculated the **avoidable**, **net cost** to Company ratepayers of new pipeline capacity like the Atlantic Coast Pipeline to be as high as $3 billion over the next 20 years. The second area of missing or incomplete analysis that my testimony will address is that the Company has not performed a comparative analysis of all-in fuel cost, as it should be required to do as part of the least-cost planning exercise of the 2018 IRP. The load factor of a short-term peak caused by extreme winter weather is so low that meeting such demands with gas-fired only units, which require costly long-term pipeline capacity, is not prudent.

The Company's 2018 IRP embeds the costs of the Atlantic Coast Pipeline into each of the generation scenarios it presents. In essence, the IRP asks the Commission to accept that the Atlantic Coast Pipeline is built and that ratepayers should pay for it without ever explaining to the Commission what those costs are and why they are justified in a least-cost planning exercise. Absent comparative analysis of viable alternative fueling logistics and their respective associated all-in costs that would be the product of these analyses, it is unlikely in the extreme that the Company's IRP has achieved the objective of identifying a reasonable, least-cost generation scenario.

even in extreme diesel price situations. In the chart below I show the frequency of price spikes in Zone 6 Non-NY since August 2004 through June 30th, 2018.

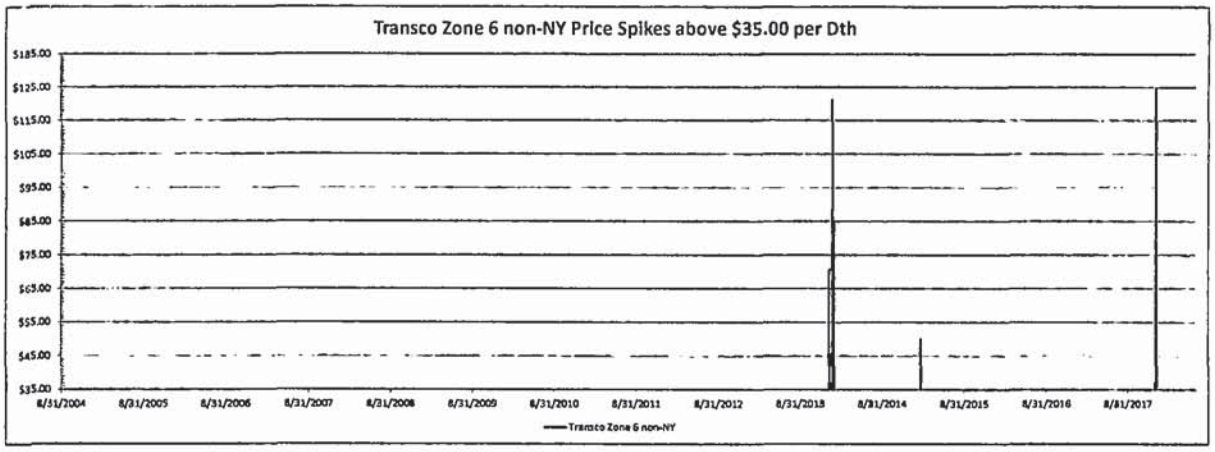

Chart 1

As can be seen in the chart above, there have been 5 separate price spikes over the 13 years and 10 months covered by the chart. The 13 years and 10 months is how long Zone 5 prices have been published by Natural Gas Intelligence (NGI).

Q. What does that tell you?

A. It tells me the price spikes in Zone 5 and Zone 6 are infrequent.

Q. What about their duration and magnitude?

A. With respect to duration, one price spike continued for 7 days, one for 4 days, two were for 2 days and one was for 1 day. In total there were only 16 days in the 13 years and 10 months in which Zone 5 and Zone 6 experienced a price spike above $35.00 per Dth. With respect to magnitude, averaging the daily price for each of the 5 price spike periods, the highest average magnitude over the consecutive days was $86.59 which was for the 2-day price spike this past winter. Over the 16 days total duration, the average cost per Dth was $68.26. The durations in some cases persisted over weekends and my calculations take account of that. In the 13 years and 10 months there were 5,052 days.

This means that less than 0.33% of the time prices in Zone 6 Non-NY spiked. If one only looked at the period between the first spike (January 6, 2014) and June 30, 2018, that extent of time was 1,636 days. Over this shorter period, prices spiked only 1% of the time.

Q. Can adding more capacity and/or gas to either or both of Zones 6 or 5 address these spikes?

A. No, adding capacity or gas to either of these zones will not address spikes caused by New York City constraints—that is constraints between Station 210 and the boroughs of New York City.

Q. Is there any infrastructure or other changes that can address the constraints between Station 210 and the boroughs of New York City?

A. Yes, and just such a project is slated for completion and in-service for the winter of 2019/2020 (the winter after the coming one). Transco's Northeast Supply Enhancement project, a.k.a NESE, will increase capacity into New York City by 400,000 Dthd.

Q. Will the NESE help alleviate the New York City driven price spikes in Zone 5 and Zone 6?

A. Yes.

Q. Please explain why.

A. There are two pipelines that deliver into the boroughs of New York City and to the pricing location known as Zone 6 NY. They are Texas Eastern Transmission (TETCO) and Transco. TETCO can deliver 1.9 Bcfd (1,904,468 Dthd). Transco can deliver the 2.27 Bcfd discussed above. The total of these two is just over 4.1 Bcfd (4,177,487 Dthd). The 400,000 Dthd of additional capacity created by the NESE project increases total NY

City pipeline delivery capacity to 4,577,487 Dthd, an increase of 9.6%. This is also an increase of Transco's New York City delivery capacity of 17.6%. This latter number is the more significant for Transco Zone 5 and Zone 6 non-NY pricing because 17.6% more Transco demand can be served from Station 210, which is the origin point for the NESE capacity. In other words, the increased capacity created by NESE will mean fewer days in which gas deliveries into New York City are constrained.

Q. Is it your conclusion then that the NESE project will have an impact on the frequency, duration and magnitude of potential future price spikes?

A. Yes. The NESE project will certainly reduce duration and with that the average magnitude (which is directly related to duration) of price spikes, and it certainly won't increase, and will likely decrease, their frequency.

Q. So, if we ignore the effect of the NESE project and prices continue to only spike one percent of the time, as you've shown has been the pattern since 2014, are there ways the Company can avoid the impacts of those spikes on ratepayers?

A. Yes, when it comes to an electric generator avoiding those spikes, the generator can generate electricity with back-up dual fuel (i.e., diesel), or it can buy pipeline capacity connecting their generators to a supply area receipt location. The choice between these two options, should, in my opinion, be made on the basis of least-cost.

Q. Did you do any comparative analysis between these two options as they would affect the Company?

A. Yes. I provide that analysis below when I discuss Company load factors and appropriate planning based upon load duration analysis and associated load factors.

not serve the plants that need the gas, i.e. it does not have a connection to the CT plant or plants that will be used to meet this peak winter early morning demand. It's that simple.

Q. Please explain what you mean and why that is important?

A. It is important because if the Company wants to fuel power plants at that precise time of the day, i.e. the 5:00 AM to 8:00 AM period on winter mornings during an extreme weather event, it has to have fuel. If the CT plant intended to meet this demand gap is only gas fired, the Company has to have firm pipeline capacity to run that CT plant, and if the Company has to have firm winter capacity, utility ratepayers will be asked to pay for it 365 days a year[5]. If the plant can be fired by natural gas or light fuel oil, like diesel generally, then the Company does not have to have firm natural gas pipeline capacity and it saves that fixed cost expense and, importantly, utility ratepayers do not have to pay that fixed cost expense.

Q. What are the conclusions of your testimony?

A. First, the Company did not study or present any analysis of the cause, frequency, duration or magnitude of natural gas price spikes and did not assess what infrastructure developments are already underway and under development that could reduce, if not eliminate, the frequency, duration, and magnitude of such price spikes. In my opinion, such an analysis is necessary for the Company to identify a reasonable least-cost planning scenario in its 2018 IRP.

Second, analyzing four scenarios for forward looking basis projections, two related to what those projections would have looked like in 2014 and two related to what

[5] In the natural gas pipeline business it is widely recognized that aside from Florida and southernmost California pipelines' system demands peak in the November through March (i.e., winter) period. As a result, in order to reserve winter pipeline capacity, especially on fully subscribed pipelines, shippers have to agree to reserve and pay for 365 day per year service.

1 projections look like today, for the basis between different pricing locations, I calculated
2 the ***net cost*** to Company ratepayers, (a net cost that is avoidable), of new pipeline
3 capacity connecting Dominion South Point to Transco Zone 5 where the Company's
4 generation facilities are located, i.e. the same path as the proposed Atlantic Coast
5 Pipeline, to be as high as $3 billion over the next 20 years. I corroborated my analysis
6 using natural gas price data provided by the Company which showed a net cost to
7 Company ratepayers of the Atlantic Coast Pipeline to be $2.5 billion over the next twenty
8 years. Based on these analyses, Company ratepayers will experience no net value from
9 paying for the path connecting Dominion South Point to Transco Zone 5 as the Atlantic
10 Coast Pipeline would.
11 Third, the Company presented no evidence that it examined either generation or
12 associated fuel logistics load factors in its assessment of what is the least-cost generation
13 scenario in its 2018 IRP. In my opinion, an examination of generation and associated fuel
14 logistics load factors should be a required element of the Company's 2018 IRP.
15 Fourth, the Company did not present a cost justification for retirement of at least two of
16 its units proposed to be retired totaling 1,597 MW (winter rating) of peaking capacity.
17 The Company also fails to explicitly articulate, as part of its 2018 Plan, a plan for having
18 dual fuel capability at all under-construction and planned future Natural Gas CC and CT
19 units. Each of these options could eliminate the need to add any costly firm, pipeline
20 capacity. In my opinion, a consideration of cost justification for retirement and
21 consideration of the costs of dual fuel capability should be required elements of the 2018
22 IRP.

Fifth, the Company failed to assess the availability of vaporized LNG as a reasonable source of supply which could be delivered through existing lines on peak demand hours and days; thereby avoiding the fixed costs of additional pipeline capacity. In my opinion, the consideration of vaporized LNG delivered through existing lines on peak demand hours and days should be a required element of the 2018 IRP.

Sixth, had the Company analyzed its load serving requirements and projected load serving requirements with demand duration curves as part of their least-cost planning, it would see that the load factor of its projected demands is so low that meeting such demands with gas-fired only units is not prudent from a fixed-cost incurrence perspective. Multiple other alternatives are available to the Company, including not retiring certain heavy oil units, installing dual fueled CTs, power purchases from PJM, demand response, and battery storage that would provide a cost advantage over investment in new pipeline capacity to serve new gas-fired generation. In my opinion, consideration of these other alternatives to meet demand during peak hours and days should be a required element of the 2018 IRP.

Seventh, given the apparent failure of Company to identify the above enumerated costly risks to ratepayers and the_lack in this or last year's IRPs of any discussion of cost justification, or discussion of risk mitigation associated with these costly risks, the Company's has failed to fulfill its obligation to undertake both least-cost planning as well as to anticipate and plan for mitigating both known and knowable financial risks to ratepayers; as well as for planning for mitigating both known and knowable potential and likely financial risks to ratepayers.