October 3, 2019

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. G002/M-19-498

Dear Mr. Wolf:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

> In the Matter of Northern States Power Company, doing business as Xcel Energy's (Xcel or the Company) Petition for Approval of Changes in Contract Demand Entitlements.

The Petition was filed on August 2, 2019 by:

> Lisa Peterson
> Manager, Regulatory Analysis
> Xcel Energy
> 414 Nicollet Mall
> Minneapolis, Minnesota 55401

The Department will provide its final recommendations to the Minnesota Public Utilities Commission (Commission) after the Company files its Update or Supplement on November 1, 2019. The Department is available to respond to any questions the Commission may have on this matter.

Sincerely,

/s/ SACHIN SHAH
Rates Analyst

SS/ar
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. G002/M-19-498

I. SUMMARY OF XCEL'S REQUEST

Northern States Power Company, doing business as Xcel Energy (NSP, Xcel or the Company) filed a demand entitlement petition (Petition) on August 2, 2019, with the Minnesota Public Utilities Commission (Commission). The Company requested Commission approval to place the Purchased Gas Adjustment (PGA) changes into effect on November 1, 2019. The Company stated that, in the event that the Commission does not act by November 1, 2019, the Company, pursuant to Minnesota Statute § 216B.16, Subd. 7, Minnesota Rule 7825.2920, and Xcel's PGA tariffs, will provisionally place the PGA changes into effect on November 1, 2019, subject to later Commission approval.

In its Petition, Xcel requested approval from the Commission to implement its proposed interstate pipeline transportation, storage entitlement, and other demand-related contracts for 2019-2020 effective November 1, 2019. The Company requested that the adjustments be made through the PGA to reflect changes in its firm pipeline demand entitlement levels[1] as follows:

- increase its Minnesota jurisdictional design-day (DD) capacity by 7,955 dekatherms per day (Dth/day), about 1.08% (7,955 Dth/735,741 Dth);
- change the capacity resources used to meet the design-day requirements and increase the amount of capacity resources (total entitlements) for Minnesota by 11,475 Dth/day or 1.47% (11,475 Dth/779,864 Dth);
- increase the reserve margin from 6.00% to 6.41% for Minnesota;
- slightly increase the jurisdictional allocation to Minnesota (rather than North Dakota) to 87.57% from 87.51% to reflect usage patterns; and
- change its recovery of Supply Reservation fees.

The Company has supply entitlements with five companies, Northern Natural Gas (NNG or Northern), Viking Gas Transmission Company (VGT), ANR Pipeline (ANR), Great

[1] The entitlement levels discussed in Xcel's filing are for the total Minnesota Company which encompasses the combined entitlements for Xcel's Minnesota and North Dakota jurisdictions. Minnesota's portion of the entitlements is the total combined entitlements times the Minnesota allocation factor discussed below. The Department has included Department Attachment 1, which shows the effect of the demand entitlement changes in the Minnesota jurisdiction.

Lakes Gas Transmission Company (GLT), and Williston Basin (WBI). Xcel requested changes in demand volumes for ANR and NNG for the Minnesota Company. The full detail by contract is located in Attachment 1, Schedule 2 and Attachment 2, Schedule 1 of the Petition.

As indicated in Attachments 1 and 2 of the Petition, Xcel proposed a number of changes in its demand entitlements that, in total, would increase costs from all source systems by approximately $15,628,761. This amount is for Minnesota and North Dakota customers. As discussed further below, the capacity increases are related to reliability needs across the Xcel system. The cost increases are due to not only the capacity increases on NNG, but also the increased cost of contracts already owned and negotiated by Xcel for NNG, VGT, ANR, and WBI and decreased costs for GLT.

The Company proposed increased entitlements from NNG. Changes were proposed to be made to NNG Pipeline capacity and entitlements. The net change is an increase of 11,475 Dth/day on a Minnesota jurisdictional basis. Xcel noted that there is an increase in the reserve margin, from 6.00% to 6.41%, due to the increase in entitlements relative to the increased design-day consumption. Xcel also stated that the "reserve margin is appropriate given the need to balance the uncertainty of: (a) experiencing DD conditions; (b) actual consumer demand during DD conditions; and (c) the need to protect against the potential loss of a source of firm natural gas supply."

Xcel also continued to treat storage-capacity demand charges as commodity costs instead of demand costs beginning with the Company's July 2014 PGA as ordered in Xcel's grouped 2007-2013 Contract Demand Entitlement Filings.[2] Xcel provided a summary of hedging transactions in place for the upcoming heating season in response to reporting requirements established in the Commission's May 27, 2008 and April 22, 2016 *Orders* in Docket No. G002/M-08-46 and Docket No. G002/M-16-88, respectively.

In Section II below, the Department's analysis of the Company's request includes the following areas:

- design-day requirements;
- proposed overall demand entitlement levels;
- reserve margins;
- jurisdictional allocation;
- supplier reservation fees; and
- the PGA cost recovery proposals.

[2] Docket Nos. G002/M-07-1395, G002/M-08-1315, G002/M-09-1287, G002/M-10-1163, G002/M-11-1076, G002/M-12-862, and G002/M-13-663, Order dated June 9, 2014.

II. DEPARTMENT'S ANLAYSIS OF XCEL'S REQUEST

A. XCEL'S PROPOSED DESIGN-DAY LEVELS

1. Xcel's Customer Base

Xcel expects an increase of 4,304 customers between the 2018-2019 and 2019-2020 heating seasons in the Minnesota jurisdiction (from 461,078 to 465,382). The Company projected that this increase in customer base would increase the design-day requirements for Minnesota by 7,955 Dth.

2. Xcel's Forecast

Consistent with its approach since its 2004-2005 demand-entitlement filing, the Company used two forecast methodologies in its estimate of its design-day requirement for the 2019-2020 heating season: the Actual Peak Use-per-Customer Design Day (UPC DD) and the Average Monthly Design Day (Avg. Monthly DD). The Department assesses the foundations of the methodologies below.

a. Actual Peak Use-per-Customer Design Day (UPC DD)

The UPC DD method employs a use-per-customer number of 1.57393 Dth/day to estimate the design-day demand forecast, based on the actual use per customer on Thursday, January 29, 2004, which was a day for which only firm customers were on the system (See Attachment 1, Schedule 3, page 2 of 2. Xcel multiplied the 1.57393 Dth/day value by estimates of total firm customers in all of Xcel's service areas and added the contracted billing demand for Small and Large Demand Billed Customers to arrive at the total expected design-day demand for the Xcel system. Thus, unlike the Avg. Monthly DD method, the way customers are distributed among service areas does not affect the aggregate forecasts produced by the UPC DD method because the total number of customers and the resulting total volume is unchanged no matter where the customers are located.

Xcel's analysis using the UPC DD and the Avg. Monthly DD resulted in an equivalent total expected design-day demand for the Xcel system.[3] If either cold temperatures or differences in results compared with the Avg. Monthly DD method indicate that the 1.57393 Dth/day peak-day use-per-customer volume is out of date, the Company stated that it will adjust the volume accordingly.

b. Average Monthly Design Day

The Avg. Monthly DD method is a statistical method that uses linear regression analysis to estimate design-day demand. Xcel performs a separate regression on each demand area for both residential

[3] See the Petition's Attachment 1, Schedule 3 page 1 of 2 and Attachment 1 Schedule 1 pages 1 through 5.

and commercial customers.[4] These separate demand areas have their own specific usage characteristics based on the input data; as such, the coefficients used to estimate use per customer vary from service area to service area. Consequently, the shifting of customers among demand areas can affect the aggregate forecasts produced by the Avg. Monthly DD method. The Company's service areas were unchanged from the 2016-2017 heating season to the 2017-2018 heating season; therefore, any changes in the aggregate forecast numbers using the Avg. Monthly DD method are related to typical growth dynamics and data turnover (Xcel used the 62 most recent months of data in its analysis),[5] and to the usage characteristics of customers in a given demand area.

The Company summarized its output statistics for each of its demand areas in Attachment 1, Schedule 1, of its Petition. Of the R-squared values for its various statistical models, 81% are greater than 0.80, which suggests that a high level of the predictive quality of the model is included in the input data for the specified variables. The models that have R-squared values less than 0.80 are generally associated with models that have a smaller number of customers. This result is not surprising, or even of concern, because a smaller number of customers will inherently increase data variability because changes in consumption by a single customer, or group of customers will have a much greater impact on total consumption than an estimation group that has a larger number of customers.

The statistics presented by the Company in its Petition suggest that the Avg. Monthly DD method produces acceptable forecasts. In Docket No. G002/M-13-663 the Department noted that, while acceptable, the Avg. Monthly DD method might not represent the best option available for forecasting natural gas needs. The Department noted that there were potential issues related to the model because it assumes natural gas consumption is constant at all temperatures; the Avg. Monthly DD estimates the average demand area consumption based on a given temperature, instead of for a peak day where consumption is likely to be above average. After conversations with the Company it was concluded that using a regression model based on daily consumption data would be very difficult due the fact that it would require a forecast of daily interruptible load in order to isolate firm load. Further Xcel's duel method approach counteracts some of the issues inherent in the Avg. Monthly DD method as the Avg. Monthly DD method generally results in higher forecasted requirements than those produced using the UPC DD method.

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[4] Xcel has 15 separate demand areas. The demand areas that the Company conducts separate analyses on are as follows: Metro, Brainerd, Mainline, Mainline—Welcome, Willmar, Paynesville, VGT-Chisago, Watkins, Tomah, Red Wing, Grand Forks MN, Fargo MN, Grand Forks ND, Fargo ND, and WBI ND.

[5] In its Attachment 1, page 3 of 10, Xcel stated the following:

> The Avg. Monthly DD calculation is based on linear regression using 62 data points, from January 2014-February 2019, as shown on Attachment 1, Schedule 1, Pages 2-5. … Traditionally, these regressions use 60 data points in complete years. However, in order to incorporate the extreme cold events of January 2019, we have included the additional months through February 2019.

Xcel noted that some of the Company's SM COMM Models had autocorrelation present in the regression analysis. The presence of autocorrelation in a regression analysis implies that the errors are not independent of each other. This would violate one of the basic assumptions in typical regression analysis which is that one normally assumes that the errors are all independent of one another. Hence, the presence of autocorrelation would affect the validity of the statistical tests that are typically applicable to regression analysis such as, for example, the coefficient of determination ("R-squared") test statistic, and the t-statistic. When forecasting with an ordinary least squares (OLS) regression model, absence of autocorrelation between the errors is very important. As recommended in the Company's previous demand entitlement filing, Xcel did check and correct its regression models for autocorrelation and the Department appreciates Xcel doing so.

Xcel also noted that in three regression models, Fargo MN Residential, WBI Residential and Grand Forks MN Small Commercial, the analysis resulted in negative intercept coefficients which would indicate negative usage at zero Heating Degree Days (HDDs). The Company stated the following:[6]

> Strictly speaking, this would indicate negative gas use at 0 HDD, which is not realistically possible. To correct for this, we adjusted the heating degree day values to 0 for each summer month for the affected areas. This supports our base use of gas during the summer months, which is not temperature dependent, and is more reflective of reality. We then performed the regression analysis on the three areas, which resulted in positive intercept coefficients, though not statistically significant from zero.

The Department agrees with Xcel that negative usage at zero HDDs is impossible and appreciates Xcel's correction.

Thus, overall the Department concludes that Xcel's forecast methodology is acceptable and the Department agrees with Xcel that the Company should continue to use the two methods to develop its design-day estimate, updating the UPC DD method when appropriate.

[6] See Petition's Attachment 1, pages 3-4 of 10.

3. *Xcel's Forecasts*

Xcel projected that its Minnesota and North Dakota design-day requirements will increase by 8,540 Dth/day to 849,248 Dth/day in the 2019-2020 heating season, or a 1.0% increase. The Company's forecast of its Minnesota design-day requirements is 743,696 Dth/day, an increase of 7,955 Dth/day, or an increase of 1.1%. In addition, the forecasted North Dakota usage for 2019-2020 is 105,553 Dth/day, an increase of 585 Dth/day, or a 0.6% increase from the 2018-2019 heating season.

Xcel's customer forecast shows the number of Minnesota customers increasing by 4,304, from 461,078 in the 2018-2019 forecast to 465,382 in the 2019-2020 forecast, an increase of approximately 0.9%. The North Dakota customer count is forecasted to increase by approximately 0.2% to 57,771 in 2019-2020, up from 57,661 in 2018-2019.

The Department notes that the bigger rate of increase in forecasted Minnesota gas consumption indicates that the proportion of design-day responsibility on the Xcel system shifted to Minnesota from North Dakota, after some years of the reverse trend. According to the *Petition*, the consumption allocator for Minnesota for the 2018-2019 heating season is 87.57%, up from 87.51% during the 2018-2019 heating season.

The Department concludes from the Company's descriptions of its forecasting techniques that Xcel's forecasting of design-day levels were performed appropriately.

B. *DEMAND ENTITLEMENT LEVELS*

Xcel's Petition proposed changes in the resources used to meet its design-day customer requirements. Overall, the Company's system firm supply entitlements, which include entitlements for Minnesota and North Dakota, rose, from 891,171 Dth/day to 903,665 Dth/day, or 1.4%.

1. *Northern Natural Gas*

The majority of Xcel's firm pipeline transportation contracts are with NNG. Most of these contracts were put in place in 2007 and ran through October 2017. As described in 2016-2017 filing, Xcel already renewed the long-term contacts for another 10-year term through October 2027 due to a required one-year advance notice for extension. As part of the extension, the renewal included a $0.01/Dth rate increase beginning November 1, 2017.

As described in the 2017-2018 filing, the Company added three new entitlements for the 2017-2018 heating season that serve peak demand. According to the Company, 918 Dth/day of incremental capacity at St. Cloud, Minnesota, 3,333 Dth/day in the Lake Elmo, Minnesota area, and 8,486 Dth/day in the Twin Cities were added, effective November 1, 2017.[7] As described in last year's filing, Xcel stated the following:[8]

> In addition, as NSP continues to look at long-term customer and design day forecasts we have contracted for additional entitlements on Northern's system to meet growing demand to be effective November 1, 2019. These expansions are part of NSP's discount agreement with Northern and will provide NSP with capacity to meet design day requirements. The costs will be reflected in next year's Contract Demand Entitlement filing.

In the instant Petition, Xcel stated the following:[9]

> As discussed in the 2018-2019 Contract Demand Entitlement filing, NSP has contracted for incremental capacity on Northern's system as part of its Northern Lights 2019 project and existing contract rights, to be effective November 1, 2019 to meet growing demand. This expansion, for an additional 10,482 Dth/day on a year-round basis, is part of NSP's existing discount agreement with Northern, and provides NSP with capacity to meet design day requirements. Specifically, the incremental capacity provides for growth in the St. Cloud, MN area, as well as the Twin Cities. The incremental capacity is priced at the existing substantial discount, and is in effect for the remainder of the contract term.

In addition, Xcel stated the following:[10]

> The schedule shows an increase of demand related total costs of approximately $15,628,761 ($13,686,106 for Minnesota), including contract demand and supplier entitlement changes. This increase is due primarily to the dramatic proposed increase in Northern Natural Gas's tariff rates projected to be in effect January 1, 2020, which represents 90% of the total demand related increase.
>
> … As mentioned above, in response to Northern's filed Form 501 G, the comments from shippers in the docket, and its own analysis, [Federal Energy Regulatory Commission] FERC initiated a Section 5 (complaint) rate proceeding against Northern on January 16, 2019 (RP19-59), stating that Northern may be over-recovering its cost of service. The order required Northern to file a Cost and Revenue Study by April 1, 2019.

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[7] Docket G002/M-17-586 - Petition Attachment 1, page 4.
[8] Docket No. G002/M-18-528 Petition Attachment 1, page 5 of 8.
[9] See Petition's Attachment 1, page 5 of 10.
[10] Id. and pages 8-9 of 10.

> On July 1, Northern filed a Section 4 rate case (RP19-1353) proposing a 91% rate increase to the Market Area, including NSP's service territory, effective August 1, 2019. We anticipate that FERC will suspend the rates for the maximum five-month term to be effective January 1, 2020 subject to refund. NSP filed a protest of Northern's proposed rates on July 15, and will be an active participant in the case to ensure just and reasonable rates moving forward. While NSP has significant discounts on much of its service from Northern, the proposed rate increase is a significant impact on our demand costs, and is the majority of the increase shown **on Attachment 1, Schedule 2 Pages 1 and 2**. NSP will update the CD Filing with any rate change as a result of the rate case proceeding.

As mentioned above Northern has filed a rate case at FERC and has proposed dramatic increases in their rates. Xcel's protest that the Company filed on July 15, 2019 at FERC is included as Department Attachment 2. In its protest, Xcel stated the following:[11]

> … Currently, Northern's Market Area rates are already the highest of all neighboring pipelines (See Table 1 below).

Table 1

Pipeline	Zone	MonthlyRate[54]	Northern rate higher by %
Northern	Field Market Winter	$28.88100	
Viking	Zone 1-2 Category 1	$5.73940	403%
Great Lakes	West-East	$8.18600	253%
ANR Pipeline	ML-7 (Market)	$5.72900	404%
WBI Energy	System	$9.84165	193%
Northern Border	Morgan to Vent	$6.27297	360%
	-	**Average:**	**323% higher**

54. Northern's current Market Area winter rate is $15.153.

[11] See Northern States Power Company, a Minnesota Corporation (NSPM) and Northern States Power Company, a Wisconsin corporation (NSPW) (collectively referred to herein as the "NSP Companies), and Southwestern Public Service Company (SPS), *Motion to Intervene and Protest of The Northern States Power Companies and Southwestern Public Service Company*, filed on July 15, 2019 in FERC Docket No. RP-19-1353-000 at page 13 and included as Department Attachment 2.

On July 31, 2019, FERC issued its *Order Accepting and Suspending Tariff Records, Subject to Refund, Rejecting Tariff Revisions, and Establishing Hearing Procedures and Technical Conference* (FERC NNG Order) in FERC Docket No. RP19-1353-000. Ordering point (A) of the FERC Order stated the following:[12]

> The tariff records in Appendix A are accepted and suspended to be effective January 1, 2020, subject to refund and the outcome of the hearing and technical conference established in the body of this order.

In the instant Petition, Xcel stated the following:[13]

> Xcel Energy respectfully requests Commission approval of our 2019-2020 Heating Season Supply Plan effective November 1, 2019, and approval to implement the retail rate impact of this filing in our PGA effective with November 1, 2019 usage.

However, Xcel should not implement the retail rate impacts in its PGA "effective with the November 1, 2019 usage" of FERC approved tariffs that are currently "suspended to be effective January 1, 2020, subject to refund." Any changes to NNG rates will not be effective until January 1, 2020; therefore, Xcel's PGA should also not reflect those changes until January 1, 2020. Given that the above Northern changes impact the instant Petition, the Department recommends that Xcel in its November 2019 Supplemental Filing and/or Update provide not only the costs to Xcel of the Northern changes described above both at FERC rates in effect beginning November 1, 2019 but also at the expected rates beginning January 1, 2020 for all the capacity that Xcel has contracted with NNG.

2. Viking Gas Transmission

The Company also made two adjustments to demand entitlements needed to serve peak demand on its VGT pipeline. Xcel stated that it renewed three Viking firm capacity entitlements of 10,000 Dth/day, 72,213 Dth/day and 15,000 Dth/day respectively that expire on October 31, 2019 at the same terms for an additional five-year term. Over the past several years, Xcel has purchased short-term capacity on Viking. The Company stated that "favorable spot market price differential between Emerson and Chicago City Gates, have resulted in higher than normal demand on Viking." Xcel for the 2019-2020 heating season stated that "NSP will look to acquire 10,794 Dth/day of delivered supply from a producer/marketer of Viking capacity for December through February, to meet seasonal peaking needs."

It is important to note that delivered supply is not reported in the demand section of the PGA, but instead in the commodity portion due to the fact that Xcel would not own the pipeline capacity and the

[12] See FERC NNG Order at page 13 and included as Department Attachment 3.
[13] See Petition at page 8.

third party's pipeline cost will be imbedded in the commodity cost to form a delivered price. Therefore, Xcel will provide an update or supplement to its Petition in November 2019 that shows the final pipeline and supply entitlements for the 2019-2020 heating season.

Xcel stated the following:[14]

> On June 28, 2019 Viking filed with the FERC a general Section 4 rate case (RP19-1340) to change rates effective August 1, 2019 in accordance with its previous rate case settlement. Viking proposed an average seven percent rate increase to the rates for NSP. On July 10, NSP filed a protest requesting the proposed rates be suspended for the maximum five-months, implemented thereafter subject to refund, and set for hearing.[15] We anticipate new rates to be effective January 1, 2020 subject to refund pending the resolution of the case. NSP will be an active participant in the case as Viking's largest customer. The impact of the proposed rate increase is included in Attachment 1, Schedule 2 Pages 1 and 2. NSP will update the CD Filing with any rate change as a result of the rate case proceeding.

On July 31, 2019, FERC issued its *Order Accepting and Suspending Tariff Record, Subject to Refund, Accepting Tariff Record, Establishing Hearing Procedures and Terminating FERC Form No. 501-G Proceeding* (FERC VGT Order) in FERC Docket No. RP19-1340-000. Ordering point (A) of the FERC VGT Order stated the following:[16]

> The tariff record reflecting rate increases (Part 5.0, Statement of Rates, 34.0.0) is accepted and suspended, to be effective upon motion on January 1, 2020, subject to refund and the outcome of the hearing established herein, as discussed in the body of this order.

As with NNG's proposed rate increase, Xcel should not implement the retail rate impacts in its PGA "effective with the November 1, 2019 usage" of FERC approved tariffs that are currently "suspended, to be effective upon motion on January 1, 2020, subject to refund." Given that the above Viking changes impact the instant Petition, the Department recommends that Xcel in its November 2019 Supplemental Filing and/or Update provide not only the costs to Xcel of the Viking changes described above both at FERC rates in effect beginning November 1, 2019 but also at the expected rates beginning January 1, 2020 for all the capacity that Xcel has contracted with VGT.

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[14] Petition at Attachment 1, page 8 of 10.
[15] See the July 10, 2019 *Motion to Intervene and Protest of Northern States Power Company – Minnesota and Northern States Power Company – Wisconsin* filed in FERC Docket RP19-1340, and included as Department Attachment 4.
[16] See FERC VGT Order at page 7 and included as Department Attachment 5.

3. Great Lakes Gas Transmission

Xcel had one change to its Great Lakes firm capacity entitlements resulting in no change to contract quantity. Xcel stated that it "consolidated three GLT firm transportation agreements into the renewal of two contracts effective April 1, 2020 at the same terms as the original agreements." However in Attachment 2, Schedule 1, page 2 of 3 of the Petition, the Company shows the contract length to be for 2 years with an expiration date of March 31, 2021. Thus, the contracts would have been effective April 1, 2019. The Department requests that Xcel clarify the effective and expiration dates of the GLT agreements. The Company stated that the GLT capacity supports withdrawal and summer injection of ANR storage quantities in addition to supporting its Northern capacity.[17] In addition, there were changes to the contract prices as a result of a settlement of Great Lakes' rate case at FERC[18] that resulted in reduced rates from the previously effective FERC rates.

4. ANR Pipeline

There was also a small addition to capacity on the ANR Pipeline pursuant to the ANR Pipeline tariff. In addition, Xcel stated that one firm transportation agreement with ANR Pipeline was renewed for five years at the maximum tariff rate. The Company stated the following:[19]

> Additionally, we renewed one firm transportation agreement, which provides 66,500 Dth/day of transportation capacity upstream of our Viking entitlements, for five years at the maximum tariff rate. This is a slight rate increase from our previous contract rate. However, this region is fully contracted and we were unable to continue the previous rate. This contract provides access to Chicago market gas supplies; providing regional diversity of supply and gas supplies for our backhaul services on Viking. This contract remains necessary to meet the supply requirements on a design day.

5. ANR Storage Co (ANRS)

The Company stated that it had extended a service agreement with ANRS for one more year, effective April 1, 2020. The agreement allows for storage of gas supplies in Michigan. In addition, the Company stated the following:[20]

> This agreement allows for the storage of gas supplies in Michigan, and provides cost effective method to meet our obligation to supply gas at the

[17] Petition Attachment 1, Schedule 5 and Attachment 1 pages 6-7 of 10.
[18] Id.
[19] See Petition Attachment 1, pages 6-7 of 10.
[20] Id.

> Carlton interconnect with Northern. In addition, the capacity provides regional supply diversity, and increased reliability of gas supplies during extreme cold events.

6. WBI Pipeline.

There were changes to the contract prices as a result of a settlement of WBI's rate case at FERC[21] that resulted in increased rates from the previously effective FERC rates.

7. Conclusion

The Department has analyzed the above changes in design-day entitlement resources and each change, except for the implementation date of the proposed NNG and VGT rates that are subject to refund, appears reasonable at this time to serve firm customers on a peak day. The Department will provide its final conclusions and recommendations once Xcel has filed a supplement or update to its Petition in November 2019 that shows the final pipeline and supply entitlements for the 2019-2020 heating season.

C. PROPOSED RESERVE MARGIN

Xcel's proposed design-day reserve margin in Minnesota is 6.41% for 2019-2020, which is a slight increase from the 6.00% figure in 2018-2019. As the Company stated, the reserve margin serves to protect against the loss of a firm gas-supply source and the risk of actual consumer demand exceeding the design day. Xcel stated that its proposed reserve margin of 47,643 Dth/day, as shown in further detail in Department Attachment 1, is appropriate to meet its design-day needs. Xcel has previously stated the following:[22]

> To our knowledge, reserve levels are not set or specified by any state or federal agency for utility gas service. However, the Commission has generally found between 5 and 7 percent to be reasonable. We plan for no system outages related to upstream resources when considering our gas reserve margin. Any outage could result in the loss of heat for our customers during some of the coldest parts of the year and would necessitate extraordinary and time-consuming measures to resume service. We deem such an event unacceptable and design our system and entitlements accordingly.

[21] Id.
[22] See Xcel's 8-1-2017 Petition at Attachment 1, page 7 of 8.

> This use of reserve margin differs from the electric industry. For the electric transmission system managed by the Midwest Independent System Operator (MISO), for example, the reserve margin is two to three times higher than our gas reserve margin and based on an assumed loss of load one day in every ten years.

Xcel's proposed reserve margin is within the 5-7 percent range that serves as a rule of thumb in deciding whether a given margin is reasonable. The Department, therefore, concludes that the 2019-2020 reserve margin is not unreasonable.

In general, the Department notes that it has previously provided a detailed discussion and update on the reserve margin discussion in its *August 1, 2019 Supplemental Comments* in Docket No. G002/M-18-528.

D. JURISDICTIONAL ALLOCATIONS

The 2019-2020 heating season jurisdictional allocation factor, which is used to allocate new peak capacity to Minnesota and North Dakota, remained within 0.50 percentage points of the projection for the prior heating season. The allocation factor is calculated by dividing the design-day forecasted demand for Minnesota (743,696 Dth/day) by the same demand for the Company's system (849,248 Dth/day). The Avg. Monthly DD results are used to update the allocation factor, which increased from 87.51% to 87.57%.[23]

Small annual changes in the allocation factor are almost inevitable. A locational change of a handful of customers in one state or the other can change the total numbers upon which the allocation factor is based and therefore change the allocation between the states. Again, such changes are typically not significant. The Department concludes that Xcel's proposed jurisdictional allocation change is reasonable.

E. SUPPLIER RESERVATION FEES

Xcel stated that its Supplier Reservation fees have changed. The resulting net change is an increase of $111,882 annually based on the proposed addition of 5,394 Dth/day year-over-year. Each of the supplier contracts is listed in the Trade Secret version of the Company's Petition. The Department will not comment on each individual contract, but has reviewed the filings and can confirm that Xcel's proposal appears reasonable.[24]

[23] Petition Attachment 1, pages 6 and 7.
[24] Petition Attachment 1, Schedule 2, page 1.

F. XCEL'S PGA COST RECOVERY PROPOSAL

Xcel proposed to reflect the costs associated with the demand entitlements identified in the Petition in the PGA effective November 1, 2019. The demand entitlements in Xcel Attachment 2, Schedule 2, Page 1 of 4, represent the demand entitlements for which the Company's firm customers will pay. Attachment 2 Schedule 2 of the Petition compares the July 2019 PGA costs to the currently proposed November 2019 PGA costs for several customer classes. The resulting per-Dth cost changes related strictly to changes in demand costs have the following annual rate effects.

- Annual demand costs increase by $0.1725/Dth, or approximately $15.00 more annually, for the average Residential customer consuming 87 Dth annually;
- Annual demand costs increase by $0.1852/Dth, or approximately $52.60 more annually, for the average Small Commercial customer consuming 284 Dth annually;
- Annual demand costs increase of $0.1665/Dth, or approximately $243.53 more annually, for the average Large Commercial customer consuming 1,463 Dth annually; and
- No Change in annual demand costs for the average Small Interruptible, Medium Interruptible, and Large Interruptible customers. These customer classes are not allocated demand costs under the current cost allocation plan.

The bill impacts described above relate solely to changes in demand cost and are based on the demand data provided by the Company. Based on its review, the Department concludes that the Company's PGA cost recovery proposal is not reasonable at this time as described in further detail above regarding the implementation dates. Thus, the Department recommends that Xcel in its November 2019 Supplemental Filing and/or Update provide not only the costs to Xcel of the Northern and Viking changes described above both at FERC rates in effect beginning November 1, 2019 but also at the rates in effect beginning January 1, 2020 for all the capacity that Xcel has contracted with NNG and VGT and to update its comparison to the October PGA rather than the July PGA.

III. CONCLUSIONS AND RECOMMENDATIONS

The Department will file its final recommendations after the Company's November 2019 supplement or update to its demand entitlement proposal.

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Department Attachment 1
Docket No. G002/M-19-498
Demand Entitlement Analysis*

	Number of Firm Customers			Design-Day Requirement			Total Entitlement Plus Peak Shaving			Reserve Margin	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Heating Season	Number of Customers	Change from Previous Year	% Change From Previous Year	Design Day (Dth)	Change from Previous Year	% Change From Previous Year	Total Design-Day Capacity (Dth)	Change from Previous Year	% Change From Previous Year	Reserve Margin	% of Reserve [(7)-(4)]/(4)
2019-2020**	465,382	4,304	0.93%	743,696	7,955	1.08%	791,339	11,475	1.47%	47,643	6.41%
2018-2019**	461,078	3,309	0.72%	735,741	5,594	0.77%	779,864	3,566	0.46%	44,123	6.00%
2017-2018**	457,769	3,373	0.74%	730,147	4,922	0.68%	776,298	10,764	1.41%	46,151	6.32%
2016-2017**	454,396	3,766	0.84%	725,225	7,747	1.08%	765,534	3,382	0.44%	40,309	5.56%
2015-2016**	450,630	4,221	0.95%	717,478	1,533	0.21%	762,152	798	0.10%	44,674	6.23%
2014-2015**	446,409	4,836	1.10%	715,945	9,010	1.27%	761,354	12,029	1.61%	45,409	6.34%
2013-2014**	441,573	2,363	0.54%	706,935	4,776	0.68%	749,325	4,078	0.55%	42,390	6.00%
2012-2013**	439,210	155	0.04%	702,159	(135)	-0.02%	745,247	153	0.02%	43,088	6.14%
2011-2012**	439,055	2,461	0.56%	702,294	2,683	0.38%	745,094	1,313	0.18%	42,800	6.09%
2010-2011**	436,594	2,896	0.67%	699,611	5,124	0.74%	743,781	(4,486)	-0.60%	44,170	6.31%
2009-2010**	433,698	4,846	1.13%	694,487	9,482	1.38%	748,267	15,976	2.18%	53,780	7.74%
2008-2009**	428,852	(2,651)	-0.61%	685,005	1,288	0.19%	732,291	10,785	1.49%	47,286	6.90%
2007-2008**	431,503	7,088	1.67%	683,717	5,984	0.88%	721,506	25,249	3.63%	37,789	5.53%
2006-2007	424,415	2,845	0.67%	677,733	6,887	1.03%	696,257	4,568	0.66%	18,524	2.73%
2005-2006	421,570	10,584	2.58%	670,846	21,191	3.26%	691,689	16,569	2.45%	20,843	3.11%
2004-2005	410,986	9,353	2.33%	649,655	46,187	7.65%	675,120	31,805	4.94%	25,465	3.92%
2003-2004	401,633	5,826	1.47%	603,468	(4,388)	-0.72%	643,315	1,040	0.16%	39,847	6.60%
2002-2003	395,807			607,856			642,275			34,419	5.66%
Average:			0.96%			1.21%			1.24%		5.76%

	Firm Peak-Day Sendout			Per Customer Metrics			
	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Heating Season	Firm Peak-Day Sendout (Dth)	Change from Previous Year	% Change From Previous Year	Excess per Customer [(7) - (4)]/(1)	Design Day per Customer (4)/(1)	Entitlement per Customer (7)/(1)	Peak-Day Send per Customer (12)/(1)
2019-2020**	NA			0.1024	1.5980	1.7004	NA
2018-2019**	735,822	(9,309)	-1.25%	0.0957	1.5957	1.6914	1.5959
2017-2018**	745,131	11,420	1.56%	0.1008	1.5950	1.6958	1.6277
2016-2017**	733,711	14,382	2.00%	0.0887	1.5960	1.6847	1.6147
2015-2016**	719,329	31,828	4.63%	0.0991	1.5922	1.6913	1.5963
2014-2015**	687,501	(2,489)	-0.36%	0.1017	1.6038	1.7055	1.5401
2013-2014**	689,990	243	0.04%	0.0960	1.6009	1.6969	1.5626
2012-2013**	689,747	30,484	4.62%	0.0981	1.5987	1.6968	1.5704
2011-2012**	659,263	(16,404)	-2.43%	0.0975	1.5996	1.6970	1.5015
2010-2011	675,667	84,736	14.34%	0.1012	1.6024	1.7036	1.5476
2009-2010	590,931	(10,494)	-1.74%	0.1240	1.6013	1.7253	1.3625
2008-2009	601,425	15,551	2.65%	0.1103	1.5973	1.7076	1.4024
2007-2008	585,874	16,911	2.97%	0.0876	1.5845	1.6721	1.3578
2006-2007	568,963	31,303	5.82%	0.0436	1.5969	1.6405	1.3406
2005-2006	537,660	286	0.05%	0.0494	1.5913	1.6407	1.2754
2004-2005	537,374	(23,876)	-4.25%	0.0620	1.5807	1.6427	1.3075
2003-2004	561,250	26,865	5.03%	0.0992	1.5025	1.6017	1.3974
2002-2003	534,385			0.0870	1.5357	1.6227	1.3501
Average			2.10%	0.0913	1.5874	1.6787	1.4677

*Some numbers may differ from Xcel Attachments due to rounding
**-Reflects the UPC DD method.

Prepared by the Minnesota Department of Commerce, Division of Energy Resources

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Natural Gas Company	**)**	**Docket No. RP19-1353-000**

MOTION TO INTERVENE AND PROTEST OF THE NORTHERN STATES POWER COMPANIES AND SOUTHWESTERN PUBLIC SERVICE COMPANY

Northern States Power Company, a Minnesota Corporation (NSPM) and Northern States Power Company, a Wisconsin corporation (NSPW) (collectively referred to herein as the "NSP Companies), and Southwestern Public Service Company (SPS) respectfully move for leave to intervene and protest[1] Northern Natural Gas Company's (Northern) filing, pursuant to section 4 of the Natural Gas Act (NGA),[2] to revise Northern's FERC Gas Tariff, Sixth Revised Volume No. 1 (Tariff).[3] Northern's Rate Case Filing includes: (i) dramatic rate increases and changes to the rate schedules and General Terms and Conditions in Northern's Tariff, to be effective August, 1, 2019 (Northern's proposed "Base Case");[4] and (ii) *pro forma* tariff sheets proposing changes to Northern's rate design and cost allocation methodology, modifications to certain charges, and other significant tariff revisions, which Northern requests that the Commission set for hearing (Northern's "Prospective Case").[5]

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1 The NSP Companies and SPS move to intervene and protest this filing pursuant to Rules 214 and 211, respectively, of the Federal Energy Regulatory Commission's (FERC or Commission) Rules of Practice and Procedure, 18 C.F.R. §§ 385.214 and 385.211 (2019).

2 15 U.S.C. § 717c.

3 Northern Natural Gas Company's NGA Section 4 Rate Case, Docket No. RP19-1353-000 (filed Jul. 1, 2019) (Rate Case Filing).

4 Rate Case Filing transmittal letter (Transmittal Letter) at 1. Northern's proposed Base Case tariff sheets are contained in Appendix A to the Rate Case Filing.

5 Transmittal Letter at 1-2. Northern's *pro forma* Prospective Case tariff sheets are contained in Appendix B to the Rate Case Filing.

Northern's Rate Case Filing does not provide the Commission or interested parties with adequate information to determine whether the changes proposed in either case are just and reasonable. In addition to Northern's Base Case proposal to increase its rates by up to 90 percent for certain customers, the NSP Companies and SPS have identified substantial issues with individual components of Northern's proposal requiring, at the very least, further analysis and explanation, and making discovery and a hearing necessary. The NSP Companies and SPS support Northern's request to the Commission to set the Prospective Case Tariff revisions for hearing and urge the Commission to also set all of the issues (including the Base Case tariff sheets) in Northern's Base Case proposal for full evidentiary hearing procedures. The NSP Companies and SPS respectfully request that the Commission: (i) suspend the Base Case rates for the maximum period permitted by the NGA as anticipated by Northern;[6] (ii) make the rates subject to refund after the suspension period; and (iii) establish an evidentiary hearing to fully explore all issues raised by and related to both the Base and Prospective Cases including, but not limited to, the issues raised in this protest.[7]

I. EXECUTIVE SUMMARY

The Commission should set all issues raised by Northern's Base and Prospective Case proposals for hearing, including how the rate and Tariff changes proposed in both cases relate to and affect Northern's existing capacity segmentation and scheduling priority practices. Although

[6] Although Northern requested an August 1, 2019 effective date for the Base Case rates, Northern "anticipates . . . that the rates . . . will be subject to a five-month suspension period and placed into effect January 1, 2020." Transmittal Letter at 1.

[7] Northern notes that it does not oppose consolidation of the Commission's ongoing investigation of Northern's rates pursuant to section 5 of the NGA with this proceeding. Transmittal Letter at 2. The NSP Companies and SPS do not oppose consolidation.

Northern's filing in compliance with Order No. 849[8] indicated that a rate reduction is warranted and resulted in the Commission setting Northern's rates for investigation under section 5 of the NGA,[9] Northern has proposed to increase its rates to be *two to four times higher* than neighboring pipelines for certain customers. The dramatic rate increase is not adequately supported by the Rate Case Filing, and moreover, would seem to price Northern's services out of the market. Through their preliminary review of the Rate Case Filing, the NSP Companies and SPS have identified multiple contested issues of material fact related to the derivation of proposed rates, including, but not limited to, Northern's:

- Proposed cost of service for market-based rate (MBR) storage services;[10]
- Inclusion of fees paid to financial hedge counterparties to terminate the hedges early;[11]
- Continued amortization of certain testing costs;[12]
- Test period adjustments to billing determinants and throughput volumes,[13]
- Proposed rolled-in rate treatment of the West Leg 2014 expansion project and inclusion of "retained revenues" in the benefits calculation for the Northern Lights package of expansion projects;[14]
- Other rate components, such as cost of service, depreciation and negative salvage rates, intercompany charges, and discount adjustments for affiliate agreements;[15] and
- Calculation of excess accumulated deferred income tax (ADIT), proposed estimated remaining facility life, use of the Reverse South Georgia amortization method, and amortization timing.[16]

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8 *Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Federal Income Tax Rate*, Final Rule, 164 FERC ¶ 61,031 at P 31 (2018); *order den'g reh'g*, 167 FERC ¶ 61,051 (2019) (Order No. 849).

9 *Northern Natural Gas Company*, 166 FERC ¶ 61,033 (2019) at Ordering Paragraphs (A)-(D) (Hearing Order); 15 U.S.C. § 717d.

10 *See, infra*, Section IV.A (2) at pp. 15-16.

11 *See, infra*, Section IV.A (3) at pp. 16-17.

12 *See, infra*, Section IV.A (4) at pp. 17-18.

13 *See, infra*, Section IV.A (5)(a-b) at pp. 18-21.

14 *See, infra*, Section IV.A (6-7) at pp. 21-23.

15 *See, infra*, Section IV.A (8)(a-d) at pp. 23-27.

16 *See, infra*, Section IV.B at pp. 27-29.

In addition to the rate-specific issues, the NSP Companies and SPS have identified contested issues of material fact raised by Northern's proposed Tariff revisions in the Base and Prospective Cases that must be set for hearing. In the Base Case, Northern's proposed (i) changes to its open season posting procedures, (ii) elimination of the Carlton Resolution commodity surcharge, and (iii) replacement of its annual semi-annual fuel tracker FERC filing with periodic website postings and an annual informational filing, all require exploration through discovery and a full evidentiary hearing.[17] In Northern's Prospective Case, which it has asked the Commission to set for hearing, Northern proposes an average rate increase of up to 220 percent for certain customers and major operational changes that raise issues of cost causation responsibility and/or significant potential restrictions on customers' existing rights, as discussed in detail below.

The Tariff revisions included in the Base and Prospective Cases are inextricably linked to and directly implicate Northern's current capacity segmentation and scheduling priority practices, which should be set for hearing. As the NSP Companies and SPS explain, Northern's practices are not fully compliant with Order Nos. 636[18] and 637,[19] and the Commission's directives to Northern in the compliance proceedings following those orders. The NSP Companies and SPS have provided the Prepared Answering Testimony of Michael Boughner and supporting Attachments 1-

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17 *See* Section IV.C, *infra*, for the NSP Companies' and SPS's discussion of several preliminary contested issues of material fact raised by the proposed Base Case Tariff revisions.

18 *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, FERC Stats. and Regs., Regs. Preambles 1991-1996 ¶ 30,939 (1992), *order on reh'g*, Order No. 636-A, FERC Stats. and Regs., Regs. Preambles 1991-1996 ¶ 30,950 (1992), *order on reh'g*, Order No. 636-B, 61 FERC ¶ 61,272 (1992), *reh'g denied*, 62 FERC ¶61,007 (1993); *aff'd in part, rev'd in part*, *United Distrib. Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *cert. denied,* 117 S.Ct. 1723 (1997)*; order on remand*, Order No. 636-C, 78 FERC ¶61,186 (1997).

19 *See Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. and Regs., Regs. Preambles July 1996-December 2000 ¶ 31,091, clarified, Order No. 637-A, 91 FERC ¶ 61,169, *reh'g denied*, Order No. 637-B, 92 FERC ¶ 61,062 (2000).

4 to that testimony, as an Appendix to this Protest to explain how Northern currently implements scheduling priority, provide examples of the scheduling issues caused by Northern's practices, and answer certain assertions made in the Prepared Direct Testimony of Mr. Kent Miller.[20]

II. COMMUNICATIONS

The NSP Companies and SPS request that all communications in this proceeding be served on each of the following representatives:[21]

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Director, Gas Resource Planning
Xcel Energy Services Inc.
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[20] Rate Case Filing, Exhibit No. NNG-00008, Prepared Direct Testimony of Kent Miller (Miller Testimony).

[21] The NSP Companies and SPS request waiver of 18 C.F.R. § 385.203(b)(3) (2019) to allow more than two individuals representing the companies to be included on the official service list. Xcel Energy Services Inc. is the centralized service company for Xcel Energy Inc. holding company system and, *inter alia*, represents the NSP Companies and SPS in matters before the Commission.

III. BACKGROUND AND MOTION TO INTERVENE

A. The NSP Companies' and SPS's Interest in This Proceeding.

1. The NSP Companies

The NSP Companies are wholly-owned utility operating company subsidiaries of Xcel Energy Inc. and are public utilities engaged in the business of distributing natural gas and electricity to retail consumers for residential, commercial, and industrial use. NSPM is a combination gas and electric utility with its principal office in the City of Minneapolis, Minnesota. NSPM is authorized to do business in the States of Minnesota, North Dakota, and South Dakota. NSPW is a corporation created and organized under the laws of the State of Wisconsin, with its principal office in the City of Eau Claire, Wisconsin. NSPW is authorized to do business in the States of Wisconsin and Michigan. The NSP Companies provide retail gas service to approximately 650,000 customers and retail electric service to approximately 1.7 million customers. The NSP Companies also own and/or operate substantial natural gas-fired generation.

The NSP Companies have contracted for firm transportation and storage services on Northern to serve both their retail gas local distribution company loads and for fuel deliveries to gas fired electric generation plants serving retail electric customers of the NSP Companies.[22] In 2018, the NSP Companies incurred approximately $75.5 million in transportation, storage, and balancing reservation charges from Northern.

2. SPS

SPS is a wholly-owned utility operating company subsidiary of Xcel Energy Inc., and is a public utility incorporated in New Mexico. SPS is engaged in the generation, transmission, distribution, and sale of electric energy. SPS serves approximately 389,000 retail and wholesale

[22] The NSP Companies serve no wholesale electric requirements customers, but make wholesale sales into the regional electric markets administered by the Midcontinent Independent System Operator, Inc. (MISO) from generation owned or controlled by the NSP Companies.

electric customers in the Panhandle and south plains of Texas, and eastern and southeastern New Mexico. SPS owns and/or operates substantial natural gas-fired generation. SPS provides cost-based retail and wholesale electric services subject to regulation by the Commission, the Public Utilities Commission of Texas, and the New Mexico Public Regulation Commission. Approximately 19 percent of SPS's total loads are wholesale electric loads governed by electric sales rate schedules regulated by the Commission. SPS has contracted for firm transportation and storage service on Northern, taking deliveries from the pipeline to power SPS's gas-fired electric generating plants. In 2018, SPS incurred approximately $14.4 million in transportation, storage, and balancing service charges from Northern.

B. Operational and Procedural Background

1. Northern's Pipeline System

Northern currently charges customers separate zonal "Field Area" and "Market Area" reservation rates,[23] with its pipeline facilities divided by a virtual point on the pipeline referred to as Northern's Field/Market Demarcation line (Demarc).[24] The Market Area is the upper-Midwest geographic area north of Demarc, and the Field Area is south of Demarc.[25] Northern describes the services provided in the two areas as follows:

> Northern delivers gas to local distribution companies ("LDCs"), end users, marketers, and other interstate pipeline companies via town border stations and interconnects located throughout the entire Market Area. . . The Field Area serves two diverse markets – it primarily serves as a supply source for Market Area deliveries and secondarily serves competitive markets within the Field Area, including off-system markets served through interconnection points with other interstate and intrastate pipelines.[26]

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[23] Miller Testimony at p. 109, lines 6-7.

[24] *Id.* at p. 2, lines 9-18, p. 118, lines 2-3. Demarc is currently located at Clifton, Kansas. *Id.* at p. 117, lines 18-19.

[25] *Id.* at p. 2, lines 9-18.

[26] *Id.* at p. 2, lines 9-18.

2. Northern's FERC Form 501-G Filing

In response to the federal corporate income tax reduction resulting from the Tax Cut and Jobs Act (TCJA),[27] the Commission required interstate natural gas pipelines with cost-based rates to submit an abbreviated cost and revenue study designed to demonstrate the effects of the reduced corporate tax rate on the pipelines' cost of service (FERC Form No. 501-G).[28] Northern submitted its Form No 501-G in compliance with Order No. 849 on October 11, 2018.[29]

Northern's Form No. 501-G demonstrated that the TCJA reduced Northern's income tax expenses by approximately $47.4 million per year,[30] resulting in a significant reduction in Northern's overall cost of service. Northern's annual cost of service included on the Form No. 501-G, based on 2017 actuals and adjusted for the reduced income tax allowance, was $564,981,559.[31] Despite the significant reduction in Northern's yearly federal income tax expenses shown on the Form No. 501-G, concurrent with the form, Northern filed a statement arguing that it should not be required to reduce its rates to return those tax savings to customers.[32]

3. NGA Section 5 Investigation

On January 16, 2019, the Commission responded to Northern's Form No. 501-G filing by (i) instituting an investigation of Northern's current rates, (ii) setting the proceeding for hearing, and (iii) directing Northern to file a cost and revenue study within 75 days of the order.[33] The

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[27] Tax Cut and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2054 (2017).

[28] Order No. 849 at P 31.

[29] Northern Natural Gas Company's FERC Form No. 501-G (Form No. 501-G) and Statement Demonstrating Why No Rate Adjustment is Warranted (Form No. 501-G Statement), Docket No. RP19-59-000 (filed Oct. 11, 2018).

[30] Form No. 501-G, at 1, line 32 (total income tax allowance), column E minus column C.

[31] *Id.* at 1, line 33, column E.

[32] Form No. 501-G Statement at 3.

[33] *Northern Natural Gas Company*, 166 FERC ¶ 61,033 (2019) at Ordering Paragraphs (A)-(D) (Hearing Order).

Order found that Northern may be "substantially over-recovering its cost of service."[34] The parties to the proceeding participated in a pre-hearing conference on February 12, 2019, and a settlement conference on May 16, 2019. In compliance with the Commission's Hearing Order, Northern filed its cost and revenue study on April 1, 2019.[35] Pursuant to the procedural schedule set by the Presiding Administrative Law Judge,[36] Commission Trial Staff and intervenors filed prepared direct testimony and exhibits on June 25, 2019. On June 27, 2019, during a customer conference call, Northern informed customers of its intention to file a section 4 rate case on July 1, 2019.

4. Northern's NGA Section 4 Rate Case Filing

On July 1, 2019, Northern filed a general NGA section 4 rate case proposing dramatic increases to its transportation and storage rates, to be effective August 1, 2019. The Rate Case Filing proposes an annual cost of service of more than $1 billion[37] using a base period of twelve months that ended March 31, 2019 (Base Period), adjusted for the test period ending December 31, 2019 (Test Period).[38] Compared to the $565 million indicated in Northern's October 2018 Form 501-G filing, Northern proposes an increase to its cost of service of 77 percent. The filing reflects a proposed overall rate of return of 10.26 percent,[39] and a proposed return on equity (ROE) of 14.2 percent.[40] Northern's derivation of the rates relies, among other things, on Northern's proposed:

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[34] *Id.* at P 1.

[35] Northern Natural Gas Company's Cost and Revenue Studies, Docket No. RP19-59-000 (filed Apr. 1, 2019) (Cost and Revenue Study).

[36] *See*, *Order Establishing Procedural Schedule and Rules of Procedure for Hearing*, Docket No. RP19-59-000 (issued February 19, 2019).

[37] Transmittal Letter at 3; *see also*, Rate Case Filing, Exhibit No. NNG-00061, Statement A, line 16 (showing $1.005 billion Test Period cost of service).

[38] Transmittal Letter at 2.

[39] *Id.* at 7; Exhibit No. NNG-00061, Statement A; Exhibit No. NNG-00078, Schedule F-1.

[40] Transmittal Letter at 7; Exhibit No. NNG-00053, Prepared Direct Testimony of Dr. Bente Villadsen (Villadsen Testimony) at pp. 45-46; Exhibit No. NNG-00078, Schedule F-1.

income tax allowance and amortization of excess ADIT,[41] discount adjustment for discounted agreements with one of Northern's affiliates;[42] a change to Northern's cost allocation methodology involving Northern's treatment of fixed costs for liquefied natural gas (LNG);[43] and roll-in treatment of certain expansion facilities.[44]

In addition to the substantial rate increase proposed in the Base Case, Northern proposes significant changes to its Tariff terms and conditions with an effective date of August 1, 2019. Among other things, Northern proposes:

- Changes to the Carlton Resolution Surcharge and reimbursement procedures;
- Elimination of the requirement for Northern to make semi-annual filings with the Commission regarding the pipeline's tracking of fuel and unaccounted-for gas loss; and
- Modification of open season posting procedures to require posting of only the winning bid rather than all bids.[45]

In the Prospective Case, where Northern indicates that a rate increase of up to 108 percent for Market Area transportation service, and an average rate increase of 220 percent for Field Area transportation service would occur, Northern proposes major changes to its Tariff,[46] including, but not limited to:

- Replacing the current zonal rates for Northern's Market and Field Areas with system-wide reservation rates for transportation service;
- Moving the location of Demarc between the Field and Market Areas from Clifton, Kansas to the suction side of the Beatrice, Nebraska compressor station;
- Eliminating the base variable redetermination in the TF rate Schedule;

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[41] Transmittal Letter at 8; Exhibit No. NNG-00005, Prepared Direct Testimony of Jay Nigh (Nigh Testimony) at pp. 7-9 Exhibit No. NNG-00038, Prepared Direct Testimony of Joseph Lillo (Lillo Testimony) at pp. 15-18.

[42] Transmittal Letter at 8; Miller Testimony at pp. 48-57; Exhibit No. NNG-00001, Prepared Direct Testimony of Bambi Heckerman (Heckerman Testimony) at p. 26.

[43] Transmittal Letter at 9; Miller Testimony at pp. 57-59; Heckerman Testimony at p. 29.

[44] Transmittal Letter at 9-11; Miller Testimony at pp. 70-87; Nigh Testimony at pp. 25-28.

[45] Transmittal Letter at 11-12.

[46] *Id.* at 12.

- Modifying the penalty structure in the Firm Deferred Delivery (FDD) rate schedule to give Northern the power to unilaterally restrict a shipper's service;
- Increasing the Daily Delivery Variance Charges ("DDVCs");
- Adding a new fuel charge for storage service;
- Changing the Field Area monthly index price; and
- Changing the rate design for Northern's Field Area commodity rates.[47]

All of Northern's proposed changes raise significant issues of cost causation and responsibility and/or involve potential restrictions on Northern's customers' existing rights under the Tariff. Northern asks that the Commission set the Prospective Case for hearing.[48]

C. Motion to Intervene

As firm shippers on Northern's pipeline system, the NSP Companies and SPS are interested parties,[49] and will be directly affected by the outcome of this proceeding. Northern's proposed rate increase would significantly raise the NSP Companies' service rates; the other changes proposed in the Rate Case Filing would significantly impact the NSP Companies' and SPS's service on Northern's pipeline system; and the companies' interests on this proceeding cannot be adequately represented by other parties. As such, the participation of the NSP Companies and SPS as intervenors will serve the public interest. Therefore, the NSP Companies and SPS respectfully move the Commission for leave to intervene in this proceeding with full participant rights.

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47 Transmittal Letter at 5.

48 Transmittal Letter at 1-2; Rate Case Filing, Appendix B.

49 NGA section 15(a), 15 U.S.C. § 717(n)(a).

IV. PROTEST

Northern's Rate Case Filing has not demonstrated that the proposed Base Case rate changes and the Tariff revisions proposed in the Prospective and Base Case tariff sheets are just and reasonable. The full impacts of the proposed changes are not discernible from the contents of Northern's filing, which raises multiple disputed issues of material fact. The NSP Companies and SPS respectfully request that the Commission suspend Northern's proposed rates for the maximum suspension period, and set Northern's Base and Prospective Cases for a full evidentiary hearing.

The NSP Companies and SPS representatives and counsel have spent an inordinate amount of time trying to identify and decipher the changes proposed in Northern's Base and Prospective Cases. While the Protest below addresses a number of issues the NSP Companies and SPS have been able to identify in Northern's Rate Case Filing, it is based upon a preliminary review – the NSP Companies and SPS cannot be certain that they have identified all of the problematic issues and changes proposed in the filing in the limited time available. At this time, the NSP Companies and SPS protest at least the following elements of the Rate Case Filing and explicitly reserve the right to raise additional issues upon further examination of the Rate Case Filing and take a position on any and all issues that may arise during the development of this proceeding.

A. Northern Has Not Shown That its Proposed Base Case Rates for Transportation and Storage Services are Just and Reasonable.

As the proponent of a significant increase to its transportation and storage rates, Northern bears the burden of demonstrating that its proposed changes are just and reasonable.[50] As discussed in more detail in Section IV.A.8.a, *infra*, Northern's Base Case filing proposes a massive increase to the pipeline's cost of service in a very short period of time. Northern's October 2018 Form No. 501-G indicated the need for a rate decrease and included a cost of

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[50] *See* 18 C.F.R. § 154.301(c).

service of approximately $565 million.[51] Similarly, Northern's Cost and Revenue Study filing on April 1, 2019 used a cost of service of approximately $756 million.[52] Several months later, Northern is claiming a $1 billion cost of service and a substantial rate increase. Northern's spending and the other cost of service components described in the Rate Case Filing require discovery and investigation at hearing.

1. Northern Has Not Adequately Supported Rates That are Two to Four Times Higher Than Neighboring Pipelines.

The Rate Case Filing does not adequately support rates that are ***two to four times higher than neighboring pipelines*** and fails to meet Northern's burden to demonstrate that the proposed rates are just and reasonable. Currently, Northern's Market Area rates are already the highest of all neighboring pipelines (*see* Table 1 below). Northern claims that it has had to provide discounts, develop expansion projects, and enter into special agreements with shippers to avoid bypass in the Market Area.[53] If the increased rates proposed in the Base Case were implemented, Northern's Market Area rates would be two to four times higher than its neighbors. Rate disparities with neighboring pipelines would be greater still under the Prospective Case.

Table 1

Pipeline	Zone	Monthly Rate[54]	Northern rate higher by %
Northern	Filed Market Winter	$28.88100	
Viking	Zone 1-2 Category 1	$5.73940	403%
Great Lakes	West-East	$8.18600	253%
ANR Pipeline	ML-7 (Market)	$5.72900	404%
WBI Energy	System	$9.84165	193%
Northern Border	Morgan to Vent	$6.27297	360%
		Average:	**323% higher**

[51] Form No. 501-G at 1, line 33, column E.

[52] Cost and Revenue Study, Statement A, Total Adjusted Base Period Amount, line 16, col. (c). Testimony filed by FERC Staff and customers in the NGA section 5 proceeding in response to Northern's Cost and Revenue Study also supported the need for a rate decrease.

[53] Miller Testimony at pp. 15-32.

[54] Northern's current Market Area winter rate is $15.153.

Likewise, Northern's Field Area rates were already high compared to its neighbors in Northern's supply areas of the Permian and Mid-Continent (*see* Table 2 below). If the increased rates proposed in the Base Case were implemented, Northern's Field Area rates would be on average 58 percent higher than its neighboring Field Area pipelines. Northern already provides deep discounts to its Field Area rates, as shown by the proposed discount adjustment of a 77 percent reduction to billing determinants in the Base Case of the Rate Case Filing.[55] If Northern's proposed Base Case rate changes became effective, it would likely require Northern to engage in further discounting, which could then prompt an even higher discount adjustment in its next rate case. Discount adjustments of this size call into question whether Northern has derived its Field Area rates properly.

Table 2

Pipeline	Zone	Monthly Rate	Northern rate higher by %
Northern	Filed Base Case Field Winter	$13.3880[56]	
El Paso Natural Gas	FT-1 Texas Rate	$8.8950	51%
Transwestern	FTS-1 East of Thoreau	$10.6400	26%
ANR Pipeline	ML-5 (Field)	$5.72900	134%
Natural Gas Pipeline of America	FTS - Peak Period - Midcontinent	$8.5800	56%
		Average:	**58% higher**

Further, if Northern implements the proposed change to rate design included in the Prospective Case, Northern's Field Area rates would become on average 273 percent higher than its neighbors (*see* Table 3 below). The NSP Companies and SPS struggle to understand the logic in such a significant rate increase given Northern's claims regarding significant competition

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55 *See* Rate Case Filing, Exhibit No. NNG-00130, Schedule J-1 at p. 1.

56 Northern's current Field Area winter rate is $9.853.

requiring substantial discounting of 77 percent in the Field Area[57] Such an increase in rates would cause rate shock to shippers. These issues must be examined closely in hearing.

Table 3

Pipeline	**Zone**	**Monthly Rate**	**Northern rate higher by %**
Northern	Filed *Pro forma* Field Winter	$31.5550[58]	
El Paso Natural Gas	FT-1 Texas Rate	$8.8950	255%
Transwestern	FTS-1 East of Thoreau	$10.6400	197%
ANR Pipeline	ML-5 (Field)	$5.72900	451%
Natural Gas Pipeline of America	FTS - Peak Period - Midcontinent	$8.5800	268%
		Average:	**273% higher**

As discussed in more detail below, Northern's Rate Case Filing raises many issues of contested material fact, and on its face, does not support the proposed increase to rates. But beyond the need for further scrutiny and investigation of the rate components, the NSP Companies and SPS are baffled by Northern's business strategy evidenced in the filing, which would seem to price the pipeline's services out of the market. Northern describes significant competition from other pipelines and claims that the pipeline has had to take measures to avoid losing shippers to bypass options. However, based on the Rate Case Filing, Northern seems to be inviting its shippers to seek other options, and encouraging other pipelines to seek to build in Northern's service areas.

2. Northern Has Not Adequately Supported its Proposed Cost of Service for Market-based Rate Storage Services.

Northern's failure to adequately support its proposed cost of service of approximately $9.5 million for its MBR storage service[59] should be explored through discovery and set for hearing. Northern provides two types of storage services – regular cost based storage services

[57] Miller Testimony, p. 48, lines 11-12; *see also* Exhibit No. NNG-00130, Schedule J-1, at p. 1.

[58] Northern's current Field Area winter rate is $9.853.

[59] *See* Exhibit No. NNG-00126 (Schedule I-a(3)) at line 11, column (b).

and MBR storage.[60] In its order authorizing Northern to provide MBR storage services, the Commission directed Northern to "separately account for all costs and revenues associated with facilities to provide the market-based services," to enable review "to ensure that existing customers will not subsidize the costs of the expansion."[61] Northern has failed to adequately support the reported accounting entries for the MBR facilities.[62] Northern's proposed allocation of costs to MBR storage services is inadequate, and these issues should be set for hearing.

3. Northern Fails to Adequately Support its Inclusion of Cash Settlements to Financial Hedge Counterparties for Early Termination of the Hedges in Rates.

Northern's inclusion of more than $39 million in fees associated with Northern's early termination of financial hedge agreements in its derivation of rates[63] requires further scrutiny and should be set for hearing. In its Deferred Loss on Fuel Derivatives regulatory asset, Northern includes payments totaling $39,362,400 that it explains were cash settlements to financial hedge counterparties to allow Northern to terminate certain hedges in 2018 before their contracted 2022 expiration date.[64] Northern filed an agreement, with a fixed cash fuel provision and other contract provisions (Cash Agreement), as a non-conforming agreement in Docket No. RP05-181,[65] and committed to the Commission that no other shippers would be impacted by the Cash

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[60] In November 2006, in Docket No. RP06-437, Northern received authorization to provide MBR service to the initial shippers of a proposed expansion of Northern's Redfield storage facility. *See Northern Natural Company*, Order Authorizing Market-Based Rates, 117 FERC ¶ 61,191 (2006) (MBR Order).

[61] MBR Order at P 21

[62] Exhibit No. NNG-00126 (Schedule I-a(3)), at line 2, column (b).

[63] *See* Exhibit No. NNG-00064, Schedule B-2, column (e); Lillo Testimony at pp. 18-20.

[64] Lillo Testimony at p. 18, lines 17 – p. 19, line 12; *see also*, Exhibit No. NNG-00040, at line 12, column (b).

[65] Northern Natural Gas Company, Changes to FERC Gas Tariff Fifth Revised Volume No. 1, Docket No. RP05-181-000, at 6 (filed February 11, 2005) (Cash Agreement Filing).

Agreement.[66] The Cash Agreement became effective in 2007, with a primary contract term through 2019, and the option for three one-year extensions (through 2022).[67]

Despite the uncertainty of the Cash Agreement extending beyond 2019, Northern made the risky business decision to enter into financial hedge agreements with terms through 2022, three years longer than the Cash Agreement's term. Northern maintains that the $39 million in termination fees are recoverable from all customers, and created an account to amortize the balance over three years.[68] However, Northern's business decision to enter into Price Swaps through 2022, when the Cash Agreement was reasonably expected to terminate in 2019, was risky and unwise. Such costs are Northern's responsibility, and should not be included in the cost of service for ratemaking purposes. Northern's claim that the cost of the termination payments is offset by the benefit of higher rates paid to Northern by the Cash Agreement shipper starting November 1, 2018[69] is not supported and requires further analysis and should be set for hearing.

4. The Rate Case Filing Raises a Disputed Issue of Material Fact Regarding an Expiring Provision of the 2005 Settlement.

Northern's proposal to continue amortizing costs associated with smart pigging and hydrostatic testing[70] raises contested issues of material fact as to the meaning of an expiring provision of the 2005 Settlement,[71] and should be set for hearing. Pursuant to the 2005

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66 Cash Agreement Filing at 6.

67 Mr. Miller and Mr. Lillo both mischaracterize the term of the Cash Agreement as being from "2007 to 2022." Miller Testimony at p. 68, lines 4-5; Lillo Testimony at p. 18, lines 14-15. In fact, the Cash Agreement was set to terminate in 2019, with three one year options to extend. *See* Cash Agreement Filing, Firm Throughput Service Agreement, TF Rate Schedule, Contract No. 111463, which shows the term of the agreement as November 1, 2007 through October 31, 2019.

68 Lillo Testimony at p. 20, ;lines 1-13.

69 *Id.* at p. 20, lines 11-13.

70 *Id.* at p. 24, line 6 – p. 25, line 9; Nigh Testimony p. 16, lines 13-19; Exhibit No. NNG-00064, Schedule B-2.

71 Northern Natural Gas Co. 111 FERC ¶ 61,444 (2005) (2005 Settlement).

Settlement, Northern was previously allowed to reflect its smart pigging and hydrostatic testing (or "testing") costs up to an annual cap of $7.5 million as a regulatory asset.[72] Northern incurred $10.3 million for testing costs in the Base Period above the annual $7.5 million cap, and claims that it will incur $9.2 million more in the Test Period.[73]

The NSP Companies and SPS oppose Northern's proposal to continue amortization of the testing costs. Northern apparently reads Article I.G of the 2005 Settlement as giving Northern authorization to continue amortize the testing costs it has incurred each year. However, the settlement provision could also be read to say that amortization authority was a one-time right not a recurring right. Northern's proposal raises a contested issue of material fact as to the meaning of the settlement provision and should be set for hearing.

5. Some of Northern's Proposed Test Period Adjustments Have Not Been Adequately Supported and Should be Set for Hearing.

Northern's Rate Case Filing proposes a number of Test Period adjustments to its Base Period billing determinants and throughput volumes that Northern has not supported as (i) sufficiently known and measurable within the adjustment period ending December 31, 2019, and (ii) appropriate for inclusion in the derivation of Northern's rates. At this time, the NSP Companies and SPS protest at least the following proposed Test Period adjustments, and respectfully request that the Commission set them for hearing:

a. Northern Has Not Adequately Supported its Proposed Test Period Adjustments to Billing Determinants.

Northern proposes significant reductions to its billing determinants for the Market and Field Areas that are not adequately supported by the Rate Case Filing. For example, Northern

72 *See* 2005 Settlement at Article I, Section G.

73 Rate Case Filing, Exhibit No. NNG-00031, Prepared Direct Testimony of Thomas Correll (Correll Testimony), at p. 30, lines 2-4; *see also*, Exhibit No. NNG-00029 at line (7).

proposes to reduce billing determinants in the Market Area by 691,223 Dth, based on expired contracts without fully explaining the basis for the adjustment.[74] Northern's witness, Mr. Miller claims that the "vast majority" of the reduction relates to the expiration of firm agreements with two customers.[75] However, Mr. Miller does not provide any explanation for the remainder of the proposed reduction (beyond the "vast majority"), or provide any specifics as to the MDQ amounts associated with the expired contracts. Northern also fails to support its proposal to reduce Market Area billing determinants by approximately 1.5 million Dth, explaining only that the reduction is associated with expired short-term agreements.[76]

For the Field Area, Northern fails to support significant adjustments to Permian supply receipts of approximately 1.4 million Dth, simply stating that Northern has not received extension notifications from customers.[77] Given the extensive growth of natural gas production in the Permian Basin and continuing constraints for delivery out of the region,[78] Northern's proposed adjustment requires further explanation and support, and should be set for hearing.

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[74] Miller Testimony at p. 35, lines 13-14.

[75] *Id.* at p. 35, lines 14-22.

[76] *Id.* at p. 36, lines 4-5.

[77] *Id.* at p. 38, lines 6-12.

[78] *See*, *e.g.*, Miller Testimony at p. 27, lines 16-17 ("capacity constrained Permian region"); p. 28, lines 8-9 ("due to the large increase in production primarily in the Permian region"); at p. 28, line 21 – p. 29, line 1 ("In 2016, Field to Demarc transportation volumes averaged 394,000 Dth/day. This transportation volume rose to 525,000 Dth/day in 2017 and 937,000 Dth/day in 2018. Transportation volumes to Demarc for the first part of 2019 are similar to the volumes experienced in 2018"); p. 30, lines 6-10 ("**Northern works with customers to deliver those excess supplies to local intrastate and interstate pipelines for further delivery out of capacity-constrained areas**. During roughly the last 18 months, the intra-field delivery segment has been unusually active in the Permian region with **the dramatic increase of Permian production**") (emphasis added); p. 115, lines 21-22 ("Capacity is not expected to be available for delivery point realignment downstream of Demarc").

For storage services, Northern proposes to remove interruptible deferred delivery (IDD) storage service billing determinants of 34.8 million Dth.[79] Northern defends the proposed adjustment by a cursory statement that "there is no fundamental reason for customers to contract for this interruptible storage service as it is the lowest priority service available."[80] However, Northern's claim is not supported by the Base Period actuals, and requires further scrutiny.

b. Northern Has Not Adequately Supported its Proposed Test Period Adjustments to Base Period Throughput Volumes.

Northern has not adequately supported the Test Period adjustments included in the proposed decrease of over 310 million Dth to Northern's total Base Period firm and interruptible throughput.[81] Overall, Northern proposes a 58,799,826 Dth decrease to Northern's Base Period Market Area volumes.[82] Northern proposes to makes weather adjustments to its Market Area throughput – a 3.78 Bcf reduction to winter volumes and a 23.8 Bcf reduction to summer volumes[83] – based only on claims that the Base Period volumes were affected by abnormal weather conditions.[84] However, Northern has failed to present convincing evidence that its Base Period volumes should automatically be reduced to match volumes averaged over 2016-2018/2019 time period.

Similarly, Northern fails to adequately explain its proposed Test Period adjustment to reduce Market Area Base Period commodity volumes by approximately 46.4 Bcf,[85] claiming

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[79] Miller Testimony at p. 40, lines 1-4.

[80] *Id.* at p. 40, lines 2-4.

[81] *Id.* at p. 40, lines 10-14; *see also*, Exhibit No. NNG-00086, Schedule G-3.

[82] *Id.* at p. 40, lines 14-15; *see also*, Exhibit No. NNG-00086, Schedule G-3.

[83] *Id.* at p. 42, lines 5-11.

[84] *Id.* at p. 42, line 7.

[85] *Id.* at p. 42, lines 17-18.

only that the proposed decrease is "primarily the result of expired short-term contracts."[86] If there are other contract changes that support the proposed decrease, Northern failed to include them in the Rate Case Filing.

Northern proposes an overall 249,495,703 Dth decrease to Northern's Base Period Field Area volumes,[87] an astonishing 31 percent reduction. Like Northern's Market Area, the Field Area is also fully subscribed, and Northern's neighbors in the region expect this trend to continue.[88] Permian basin oil and gas production is booming, causing all Permian pipelines to be full. While there are pipeline expansions planned, the development of new pipeline capacity is not keeping up with the booming oil and gas development and all Permian pipelines are expected to be full for the foreseeable future. Northern proposes significant Test Period reductions to Field Area throughput that have not been adequately supported. For example, Northern has proposed Test Period adjustments to reduce Field Area throughput by 207.6 Bcf,[89] and to reduce other Field Area deliveries by 41.9 Bcf.[90] Mr. Miller's testimony does not adequately support these proposed Test Period adjustments, and they should be set for hearing.

6. Northern's Proposed Rolled-in Rate Treatment of the West Leg 2014 Expansion Project Requires Further Scrutiny.

It is unclear whether Northern's Rate Case Filing demonstrates that its proposal to roll the costs of the West Leg 2014 expansion project into system-wide rates[91] is just, reasonable, and

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86 Miller Testimony at p. 43, lines 1-2.

87 *Id.* at p. 40, lines 14-18; *see also*, Exhibit No. NNG-00086, Schedule G-3.

88 *See* Kinder Morgan 2019 Customer Meeting West Region Gas Pipelines presentation at https://pipeline2.kindermorgan.com/Documents/EPNG/WRGP_Customer_Meeting_April_29_2019-20190429162248.pdf, pages 14-15.

89 Miller Testimony at p. 43, lines 12-13.

90 *Id.* at p. 44, lines 7-10.

91 Transmittal Letter at 11.

consistent with the Commission's Certificate Policy Statement.[92] In Docket No. CP13-528, the Commission denied predetermined roll-in treatment of the West Leg 2014 expansion project because the project costs exceeded revenues.[93] Northern argues that circumstances have changed such that rolled-in treatment is now warranted. However, Northern's witness, Mr. Miller, provides only a few cursory statements to support roll-in of the project,[94] and bases the revenue calculation on Northern's proposed rates,[95] which are significantly higher than existing rates. Northern's assertion that the project's revenues now exceed the costs cannot be verified until final rates are established as a result of this proceeding.[96] This issue should be set for hearing.

7. Northern's Proposal to Include "Retained Revenue" in its Benefits Calculation Requires Further Scrutiny.

The NSP Companies and SPS oppose Northern's proposal to include an estimate of revenues retained as a result of securing long-term commitments from certain customers as a result of the Northern Lights expansion projects when calculating whether revenues exceed costs such that the projects should receive roll-in treatment. Northern coins the term "retained revenues" to describe these potential avoided losses of revenues.[97] According to Mr. Miller, Northern's calculation of net benefits associated with the Northern Lights package of expansion projects includes "the revenue retained by averting bypass.

In rejecting the inclusion of retained revenue in the Northern Lights expansion certificate proceeding, the Commission noted, "[t]he value of these retained contractual entitlements is not

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[92] *Pricing Policy For New and Existing Facilities Constructed by Interstate Natural Gas Pipeline*, 71 FERC ¶ 61,241 (1995), *reh'g denied*, 75 FERC ¶61,105 (1996) (Certificate Policy Statement).

[93] Transmittal Letter at 11; *Northern Natural Gas Company*, 146 FERC ¶ 61,194 (2014).

[94] Miller Testimony at p. 87, lines 2-8.

[95] *Id.* at p. 87, line 8.

[96] Exhibit No. NNG-0009 at note 1.

[97] Miller Testimony at p. 85, line 11; *see also* Exhibit No. NNG-00018, Workpapers, pp. 1-9.

revenue that will be generated as a result of the construction of the facilities," and concluded that it would not be consistent with the Certificate Policy Statement to include such revenue.[98] To the extent Northern proposes to include retained revenue in its estimated benefits for the Northern Lights expansion projects, Northern has failed to support deviating from the Commission's policy statement. The inclusion of estimated revenues that are not the direct result of the project in question would be contrary to the Commission's long-established roll-in policy (as noted in the certificate order) and should be rejected here. Overall, Northern's proposed rolled-in rate treatment for the Northern Lights expansion projects is not adequately explained, requires further scrutiny, and should be set for hearing.

8. Components of Northern's Proposed Rates Require Investigation Through a Full Evidentiary Hearing.

Northern's proposed rate increases for transportation and storage services raise contested issues of material fact that cannot be resolved without discovery and a hearing. In addition to the specific issues discussed above, Northern's proposed rate components that require further scrutiny include, but are not limited to the proposed: (i) cost of service, (ii) ROE; (iii) depreciation and negative salvage rates, (iii) corporate overhead allocations, and (iv) a discount adjustment for multiple discounted rate agreements with Northern's affiliates.

a. All Cost of Service Issues Must be Fully Investigated in an Evidentiary Hearing.

Northern has not adequately explained the proposed increase in its annual cost of service. The Rate Case Filing uses a cost of service of approximately one billion dollars – a 77 percent increase over the $565 million shown on Northern's Form No. 501-G filing,[99] and a 32 percent increase over the $756 million cost of service Northern filed in its cost and revenue study on

[98] *Northern Natural Gas Company*, 127 FERC ¶ 61,133 at P 21 (2009).

[99] Rate Case transmittal letter at 4.

April 1, 2019.[100] Northern's proposed cost of service is based, *inter alia*, on Northern's operations and maintenance expenses, a 59.37 percent equity / 40.63 percent debt capital structure,[101] a proposed ROE of 14.2 percent,[102] and a transmission plant depreciation rate of 2.79 percent.[103] Overall, Northern has proposed significant changes to its cost of service that have not been shown to be just and reasonable by the information provided in the Rate Case Filing. The Commission should investigate and set for hearing in this proceeding why Northern's proposed cost of service in this filing is so much greater than it was a scant three months ago.

b. Northern's Proposed Changes to Depreciation Rates and Negative Salvage Should be Set for Hearing.

Northern's proposed depreciation and negative salvage rates represent a significant component of the proposed rate increase and should be set for hearing. Northern proposes to increase its depreciation rates for (i) onshore transmission plant from 1.5[104] to 2.79 percent;[105] underground storage plant from 1.25[106] to 3.11 percent;[107] and (iii) LNG storage plant from 1.25 percent[108] to 2.95 percent.[109] Coupled with Northern's proposal to establish a new additional annual accrual rate for negative salvage of 0.096 percent for onshore transmission plant[110] and

[100] Cost and Revenue Study, Statement A, Total Adjusted Base Period Amount, line 16, col. (c).

[101] Lillo Testimony at 3, lines 4-5; *see also* Exhibit No. NNG-00038, Schedule F-2.

[102] Lillo Testimony at p. 4, lines 4-5; *see also*, Villadsen Testimony at p. 45, line 5 – p. 46, line 5

[103] Rate Case Filing, Exhibit No. NNG-00042, Prepared Direct Testimony of Dr. Jonathan Lesser (Lesser Testimony) at p. 6, Table 1; Exhibit NNG-00108, Statement H-2, column (g).

[104] Lillo Testimony at p. 5, line 17.

[105] Transmittal Letter at 6; Lesser Testimony at p. 6, Table 1.

[106] Lillo Testimony at p. 5, line 17.

[107] Lesser Testimony at p. 6, Table 1.

[108] Lillo Testimony at p. 5, line 18.

[109] Lesser Testimony at p. 6, Table 1.

[110] *Id.* at p. 62, lines 6-8; *see also* Exhibit No. NNG-00052.

0.92 percent for LNG storage plant[111] (a separate annual accrual of approximately $29.4 million),[112] the proposed change in depreciation expense and negative salvage has significant effects on Northern's customers' rates. The combination of the higher depreciation rates and the new negative salvage rates yield a total rate of 3.75 percent for transmission plant and 2.95 percent for LNG plant, dramatic increases over Northern's existing depreciation rates.[113]

Based on the information provided by Northern, it is not clear whether Northern has demonstrated reasonable support for the significant changes in depreciation. Northern's proposed changes to depreciation expense and negative salvage have significant impacts on the overall rates, and must be evaluated in detail by the parties through discovery and the Commission at hearing.

c. Northern's Proposed Corporate Intercompany Charges Require Further Scrutiny.

Northern provides almost no support for its proposed assignment of corporate costs from parent company Berkshire Hathaway Energy Company (BHE) to Northern. Northern witness, Mr. Nigh, provides only a glancing explanation of the services Northern obtains from BHE,[114] and cursorily notes that the corporate costs that are not directly assigned from BHE to Northern are allocated using "various formulas . . . consistent with those reflected on page 358 of Northern's 2018 FERC Form 2.[115]

Although Mr. Nigh discusses the BHE-assigned costs in the context of Statement H-1, Part 1, Operations and Maintenance Expense,[116] the NSP Companies and SPS could not locate

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[111] Lesser Testimony at p. 62, lines 1-3; *see also* Exhibit No. NNG-00052.

[112] *Id.* at p. 62, lines 1-8.

[113] *Id.*, Summary of Testimony at p. iii.

[114] Nigh Testimony; *see also*, Exhibit No. NNG-00106, Schedule H-1(2)(j) (Intercompany and Interdepartmental Transactions).

[115] Nigh Testimony at p. 13, line 20 – p. 14, line 1.

[116] Exhibit No. NNG-00091.

any line items in Statement H-1 that show the total allocation of corporate costs from BHE to Northern. Further, Northern provides no explanation or support for the proposed Test Period adjustment of approximately $10.4 million for "Intercompany and Interdepartmental Transactions" shown on Schedule H-1 (2)(j), line 23, column (n).[117]

To meet its burden of demonstrating that its proposed rates are just and reasonable, Northern is required to support its proposal with substantial evidence.[118] A gas pipeline filing a rate case must "be prepared to go forward at hearing and sustain, solely on the material submitted with its filing, the burden of proving that the proposed changes are just and reasonable."[119] The filing and supporting workpapers must be of such composition, scope, and format as to comprise the company's complete case-in-chief.[120] Northern's proposed corporate cost allocation is completely unsupported. Northern's customers must be given the opportunity to further develop the record regarding the proposed corporate overhead allocation through discovery and hearing.

d. Northern's Proposed Discount Adjustments for its Affiliate's Discounted Rate Agreements Should be Set For Hearing.

Northern's proposal to adjust its billing determinants to account for its discounted contracts with an affiliate requires more scrutiny through discovery and a hearing. Northern calculated its revenues and billing determinants set forth in Statement G of the Rate Case Filing

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[117] Exhibit No. NNG-00106, Schedule H-1 (2)(j).

[118] *Permian Basin Area Rate Cases*, 390 U.S. 747, 791-92 (1968); *Pub. Serv. Commission of the State of N.Y. v. FERC*, 813 F. 2d 448, 465 (D.C. Cir. 1987).

[119] 18 C.F.R. § 154.301(c) (2019).

[120] *Id.*

using a discount adjustment for multiple[121] discounted rate contracts with Northern's affiliates, MidAmerican Energy Company and MidAmerican Energy Services, LLC (collectively referred to herein as "MidAmerican").[122] The pipeline has a heavy burden to show that discount adjustments are just and reasonable when they involve discounts to affiliates.[123] Although Northern attempts to justify the discounts granted to MidAmerican on the grounds that other, non-affiliated shippers have received the same or similar discounts,[124] the fact that a pipeline has given non-affiliates similar discounts is not sufficient to justify a discount to an affiliate.[125] In other words, "[t]he Commission does not routinely grant pipelines a discount adjustment, but grants such an adjustment only to the extent that the discount was required to meet competition."[126] It is unclear from the record whether Northern's proposed discount adjustment for affiliate agreements is consistent with Commission policy, and this issue should be set for discovery and a hearing.

B. Early Amortization of Northern's Excess Accumulated Deferred Income Tax is Contrary to Commission Policy.

The NSP Companies and SPS oppose early amortization of Northern's $407 million Test Period balance of excess ADIT[127] before placing into effect rates reflective of such amortization,

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[121] Northern's support for its discounted affiliate agreements is inconsistent. Mr. Miller lists seven discounted affiliate agreements by contract number in his testimony (Miller Testimony at p. 56, line 4), but Exhibit No. NNG-00015 lists only six, omitting Contract No. 133518.

[122] Miller Testimony at pp. 50-56; *see also* Exhibit No. NNG-00015.

[123] *Tennessee Gas Pipeline Co.*, 135 FERC ¶ 61,208 at P 190 (2011); *Trunkline Gas Co.*, 90 FERC ¶ 61,017 at 61,087 and 61,096 (2000).

[124] Miller Testimony at p. 57,lines 1-5.

[125] *Panhandle Eastern Pipe Line Co.*, 74 FERC ¶ 61,109 at 61,402 (1996); *Tennessee Gas Pipeline,* 135 FERC ¶ 61,208 at P 190.

[126] *Id.* at P 24.

[127] Rate Case Filing, Exhibit No. NNG-00038, Lillo Testimony at p. 16, lines 2-3.

and ask that all other aspects of Northern's proposed treatment of excess ADIT be set for hearing. Such early amortization would be contrary to Commission policy and precedent.[128]

Northern's witness, Mr. Joseph Lillo, states that under the new 21 percent federal corporate income tax rate resulting from the TCJA, Northern calculated excess ADIT of almost $298 million as of December 31, 2017.[129] Northern's total excess ADIT regulatory liability, including an income tax gross-up of $109,447,737, is approximately $407 million.[130] In its filing, Northern proposes to amortize the $407 million over the estimated remaining life of the affected facilities, an average of 44 years, based on the Reverse South Georgia methodology, beginning January 1, 2018.[131]

The NSP Companies and SPS disagree with Northern's proposal to begin amortizing excess ADIT on January 1, 2018. Northern's proposal to begin amortizing its excess ADIT prior to reflecting the amortization in rates, is contrary to accounting regulations[132] and Commission

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[128] *See, e.g.*, *Accounting for Income Taxes*, Letter Ruling, Docket No. AI93-5-000 (issued April 23, 1993), *order denying reh'g*, *In re: Columbia Gas Transmission Corp. and Columbia Gulf* Transmission *Co.*, 64 FERC 61,352 (1993); *see also*, P*ublic Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes*, Notice of Proposed Rulemaking, 165 FERC ¶ 61,117 at P 39 (2018) (NOPR) (In the context of transmission formula rates, the Commission has stated that "public utilities should not amortize an excess ADIT regulatory liability for accounting purposes until it is included in ratemaking." (citing 18 C.F.R. part 101, Account 182.3 (Other Regulatory Assets), which states: "The amounts recorded in this account are generally to be charged, concurrently with the recovery of the amounts in rates…"). NOPR at note 65.

[129] Lillo Testimony at p. 15, lines 15-16.

[130] *Id.* at p. 16, lines 1-3.

[131] *Id.* at p. 17, line 3 – p. 18, line 3.

[132] Accounting Standards Codification (ASC) 980 – Regulated Operations:

> If a gain or other reduction of net allowable costs is to be amortized over future periods for rate-making purposes, the regulated enterprise shall not recognize that gain or other reduction of net allowable costs in income of the current period. Instead, it shall record it as a liability for future reductions of charges to customers that are expected to result.

policy and precedent.[133] Allowing Northern to begin amortization of its large balance of excess ADIT prior to placing into effect rates that reflect such amortization would harm the pipeline's customers. First, customers would have a higher rate base in any future rate case due to the earlier amortization. Second, customers would never be able to recover the excess ADIT amortization that occurred before the effective date of new rates set through this NGA section 4 proceeding. Any early amortization of Northern's excess ADIT would contravene the Commission's accounting rules and long-standing Commission policy.

In addition to the timing of Northern's proposed amortization, the NSP Companies and SPS submit that the Northern's calculation of excess ADIT, the appropriateness of Northern's proposed estimated remaining facility life and use of the Reverse South Georgia method all require further analysis and explanation, and should be examined at hearing.

C. Northern's Proposed Base Case Tariff Revisions Have Not Been Shown to be Just and Reasonable and Should be Set for Full Evidentiary Hearing.

Northern has suggested a number of changes to its Tariff in the Base Case that raise contested issues of material fact, would impact Northern's customers' existing rights and services, and make it necessary for the Base Case to be set for full evidentiary hearing.

[133] *See, e.g.*, *Accounting for Income Taxes*, Letter Ruling, Docket No. AI93-5-000 (issued April 23, 1993), *order denying reh'g*, *In re: Columbia Gas Transmission Corp. and Columbia Gulf Transmission Co.*, 64 FERC 61,352 (1993); *see also*, P*ublic Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes*, Notice of Proposed Rulemaking, 165 FERC ¶ 61,117 at P 39 (2018) (NOPR) (In the context of transmission formula rates, the Commission has stated that "public utilities should not amortize an excess ADIT regulatory liability for accounting purposes until it is included in ratemaking." (citing 18 C.F.R. part 101, Account 182.3 (Other Regulatory Assets), which states: "The amounts recorded in this account are generally to be charged, concurrently with the recovery of the amounts in rates…"). NOPR at note 65.

1. Northern's Proposed Change to its Open Season Posting Procedures Would Decrease Transparency and Eliminate Valuable Market Information.

The NSP Companies and SPS oppose Northern's proposal to change its open season posting procedures to post only winning bid information.[134] Northern has not demonstrated that the current procedures are insufficient or cause any harm – rather, Northern claims only that posting the losing bid information is irrelevant. Contrary to Northern's claim, the NSP Companies and SPS find losing bid information relevant and valuable. That information provides transparency into the bidding process, and allows customers to verify that Northern is conducting bid evaluations in compliance with the Tariff. Posting the losing bid information also provides market data regarding the level of interest in capacity at a given point. Northern's proposed change to its open season posting procedures should be explored at hearing.

2. Northern's Proposed Elimination of the Carlton Commodity Surcharge Would Cause Undue Harm to Carlton Sourcers.

The NSP Companies and SPS oppose Northern's proposed changes to Carlton Resolution penalty assessment and reimbursement procedures.[135] As a result of the settlement agreement provisions described in Mr. Miller's testimony, Northern may call upon the NSP Companies to deliver up to approximately 33,500 Dth per day into Northern's pipeline at the Great Lakes Gas Transmission interconnect.[136] Currently, other shippers share in the costs associated with the requirement for the Carlton volumes through the assessment of a Carlton Commodity Surcharge, for which the shippers who actually source the volumes at Carlton are reimbursed.[137] As "Carlton Sourcers," the NSP Companies would be directly and negatively impacted by the

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[134] Miller Testimony at p. 89, line 8 – p. 90, line 5.

[135] *Id.* at p. 90.

[136] *Id.* at p. 90, lines 15-22.

[137] *Id.* at p. 90, line 22 – 92, line 5.

proposed elimination of the Carlton Commodity Surcharge, which is currently $0.0175 per Dth per day, and related elimination of reimbursement to Carlton Sourcers.[138]

Northern's claim that Carlton Sourcers are receiving an "unjust and unreasonable windfall" through the assessment and reimbursement of the Carlton Commodity Surcharge is incorrect,[139] and Mr. Miller's argument comparing the cost of gas supplies at the relevant system receipts misses the point.[140] The NSP Companies hold firm storage and transportation capacity on other pipelines so that they may perform as required when Northern posts a Carlton resolution to deliver supply to Carlton. The NSP Companies pay reservation charges on a monthly basis to other pipelines to be ready to provide this service when Northern (in its sole discretion) requires Carlton Sourcers to supply gas at Carlton. Carlton Commodity Surcharge reimbursements do not fully cover the reservation charges or make the NSP Companies fully whole. Mr. Miller's gas supply price comparison argument[141] ignores the fact that the NSP Companies hold firm capacity to perform under Northern's requirement.

3. Northern Should Not be Allowed to Change its Fuel Charge Without Prior Commission Review and Approval.

The NSP Companies and SPS oppose NNG's proposal to eliminate its semi-annual fuel tracker FERC filing, to be replaced with periodic postings on Northern's website, and a once-a–year, after-the-fact, informational filing with the Commission.[142] The purpose of the periodic fuel tracker filings is to provide the Commission and Northern's customers with the opportunity to review and comment on (or protest) Northern's proposed changes to fuel charges. Northern's

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[138] Miller Testimony at p. 90, lines 9-13.

[139] *Id.* at p. 91, lines 15-19.

[140] *Id.* at p. 91, line 20 – p. 94, line 7.

[141] *Id.* at p. 91, line 21 – p. 94, line 7.

[142] *Id.* at p. 101, line 20 – p. 102, line 18.

proposal would replace a periodic filing requirement that has worked well, with an annual filing that provides the Commission and Northern's customers only with an after-the-fact review of Northern's actions over the previous year. In effect, Northern is asking for the ability to change its fuel charge (a significant cost to customers) without prior Commission review, which the Commission should not allow.

In Northern's last fuel filing, it reported total annual fuel consumed in 2018 of 22,930,357 Dths.[143] Assuming a spot gas price of $2.50 to $3.00 (roughly equivalent to recent gas prices), that fuel consumption amount adds up to an annual dollar expenditure by Northern's customers of $57 to $69 million over one year to acquire the gas to pay Northern's fuel charges. Charges of that magnitude have too much effect on Northern's customers to allow Northern to merely periodically post them on a website without any prior review by the Commission or Northern's shippers.

There are far less draconian ways to address any inconveniences to Northern caused by the periodic fuel requirement. For example, Northern could simply change its Tariff to allow it to file for out-of-cycle adjustments if fuel balances build to unacceptable levels. Alternatively, Northern could change its Tariff to allow it to revise projected throughput, upon good cause shown, to adjust for expected changes, such as weather normalization or known changes in system operations. Such a change would allow Northern to establish an accurate fuel charge upfront without risking the build-up of fuel balances from an improper fuel charge. Either method would serve Northern's needs while still allowing the Commission and customers to review proposed fuel rates prior to such rates going into effect.

Overall, Northern's proposed Base Case Tariff revisions raise multiple significant contested issues of material fact, and should be set for hearing.

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[143] Northern Natural Gas Company's Periodic Rate Adjustments for Fuel, Docket No. RP19-634-000 (filed Feb. 1, 2019).

D. Northern's "Prospective Case" Tariff Sheets Should be Set for Hearing.

The NSP Companies and SPS agree with Northern's request that the Commission set the *pro forma* tariff sheets included in Northern's Prospective Case for hearing. Northern proposes sweeping changes in its *pro forma* Prospective Case tariff sheets, and all of the issues raised in the Prospective Case should be suspended and set for hearing. Based on a preliminary review, the NSP Companies and SPS have identified the following, non-exhaustive list of issues proposed in Northern's Prospective Case that raise immediate concerns and require further investigation through discovery and hearing.

On a prospective base, Northern proposes to eliminate its current zonal system of cost allocation between its Market and Field areas, and implement system-wide rates.[144] The proposed implementation of system-wide rates creates the potential for cross-subsidization issues between Northern's customers, and would have significant rate impacts on customers. With the proposed rate design change, Northern claims that customers will enjoy increased flexibility in accessing all supply points on a secondary basis and the advantages afforded by segmentation.[145] Yet Northern has acknowledged that constraints on its system may prevent customers from benefiting from the rate design change,[146] and, as discussed below in Section IV.E, Northern's current capacity segmentation and point-based scheduling priority practices make it unlikely that customers would experience the benefits that Northern describes.

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[144] Transmittal Letter at 9; Exhibit No. NNG-00025, Prepared Direct Testimony of Dr. George Briden (Briden Testimony) at p.3, lines 9-12.

[145] Miller Testimony at p. 116, lines 11-17; Briden Testimony at p. 11, lines 15-21, at p. 12, lines 14-15, and at p. 17, lines 11-12.

[146] Miller Testimony at p. 116, lines 21-22.

Northern also proposes to move the location of Demarc between the Field and Market Areas.[147] This proposal would affect the existing contract rights of shippers with receipt points in the area. For example, shippers holding rights to the REX receipt point would be exposed to new and additional charges without receiving additional benefits.

Similarly, Northern's proposal to modify the Daily Delivery Variance Charges (DDVCs) and related changes to SMS[148] would significantly increase penalties imposed on shippers without adequate demonstration of the need for change. Northern's proposal also appears to add a new fuel charge to storage service without any demonstration that the quantities in question are actually owed by shipper rather than being the responsibility of the pipeline. Northern also proposes to change the Field Area monthly index price without demonstrating that a change is required and without presenting how customers will be affected by such a change.[149]

All of these proposed changes raise significant issues of cost causation and responsibility or restrict shipper's existing tariff rights, and should be set for hearing.

E. Northern's Base and Prospective Cases Highlight and Implicate Significant Issues with Northern's Capacity Segmentation and Scheduling Practices That Should be Set for Hearing.

The proposed Tariff revisions included in Northern's Base and Prospective Cases relate to and affect Northern's current capacity segmentation and scheduling priority practices, and raise issues with regards to those practices that must be explored at hearing. As discussed below, Northern assigns priority to shippers' nominations based on the priority of service associated with the requested receipt and delivery points rather than providing "within-the-path" scheduling, which assigns priority based on whether the requested points lie along the shipper's

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147 Heckerman Testimony at p. 58.

148 *Id.* at p. 55.

149 Miller Testimony at pp. 129-131.

primary contract path. The NSP Companies and SPS provide the Prepared Answering Testimony of Michael Boughner as an Appendix to this Protest to provide specific examples of Northern's current scheduling practices, which are based on how Northern implemented scheduling priorities and capacity segmentation on its system, and to describe how those practices harm shippers. Mr. Boughner also answers certain assertions made by Northern witness, Mr. Kent Miller, in his prepared direct testimony.

Mr. Boughner explains that although Northern allows shippers the flexibility to request transactions involving receipt and delivery points that are not included in the shipper's contract (The Commission refers to these as secondary points, while Northern refers to them as alternate points), Northern has not fully implemented the Commission's rules regarding scheduling priority procedures that were designed to provide shippers with the ability to use those flexible receipt and delivery points in a competitive and efficient manner.[150] Instead of providing within-the-path scheduling, which is described below, Northern assigns scheduling priority to transactions based on the receipt and delivery points requested by a shipper for a particular transaction (referred to herein as a "point-based" approach). In addition to being contrary to Commission policy and precedent, Northern's point-based scheduling practices have real-world adverse operational and financial effects on Northern's customers. Northern's capacity segmentation and current scheduling practices and the issues raised here by the NSP Companies and SPS are inextricably linked to proposed Tariff revisions included in Northern's Base and Prospective Cases and should be set for hearing pursuant to NGA section 4 as issues of contested material fact raised by Northern's Rate Case Filing.

[150] *See* Protest, Appendix, Prepared Answering Testimony of Michael Boughner (Boughner Testimony).

1. Background and History

In Order No. 636,[151] along with mandating the separation of pipeline transportation and sales services, the Commission implemented a number of regulations that were designed to enhance natural gas pipeline competition and efficiency. For example, the Commission required pipelines to provide customers with flexible receipt and delivery point rights.[152] Flexible point rights provide firm shippers with the ability to change their receipt or delivery point on a pipeline system so that they can receive and deliver gas to any point included in the firm capacity rights for which they pay.[153] As Mr. Boughner explains, Northern does provide customers with the ability to change receipt and delivery points.

Through the course of pipelines' Order No. 636 compliance filing proceedings, the Commission also developed a requirement for pipelines to allow the segmentation of capacity.[154] Segmentation refers to customers' ability to subdivide their firm capacity into segments, with each segment equal to the contract demand of the original contract, and use those segments for different capacity transactions.[155] In Order No. 637, the Commission adopted a regulation requiring pipelines to permit a shipper to segment its contracted-for firm capacity "into separate parts for its own use or for the purpose of releasing that capacity to replacement shippers to the extent such segmentation is operationally feasible."[156] In discussing the operational feasibility of segmentation, the Commission noted that permitting segmentation on a reticulated pipeline might create operational difficulties, but rejected reticulation as an automatic excuse for a

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[151] *See supra*, n. 18.

[152] Order No. 636 at p. 30,429.

[153] *Id.* at pp. 30,420-21.

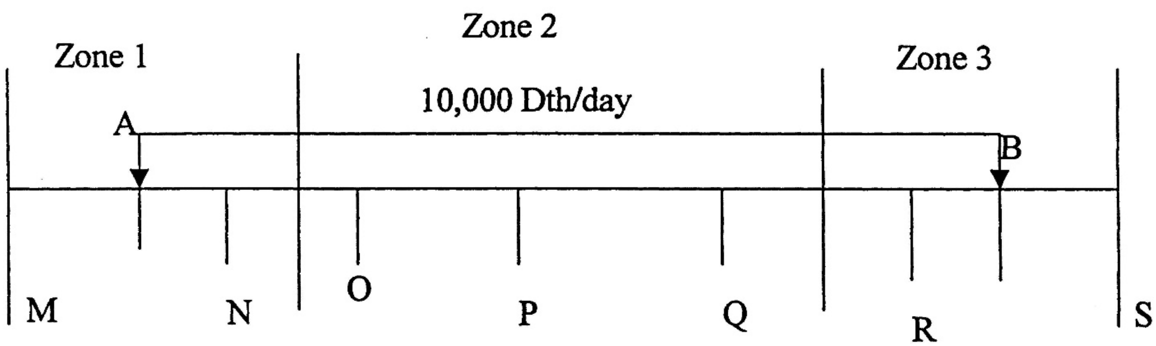
[154] Order No. 637-A at 31,589.

[155] Order No. 637 at p. 31,301.

[156] *Id.* at 31,303-304.

pipeline to refuse to provide segmentation.[157] The Commission provided examples to clarify how it intended for capacity segmentation to work.

Diagram 1[158]



Referring to Diagram 1 above, which was included in Order No. 637-A, the Commission provided the following example to explain shippers' rights to use their segmented capacity:

> a shipper has a contract for 10,000 Dth per day from receipt point at A to delivery point B. The shipper has the flexibility to segment capacity throughout zones 1-3 (point M through point S), so long as the combined nominations of it and replacement shippers do not exceed the mainline contract demand of 10,000 Dth. The shipper has the right to segment outside of its path because it is paying the full rates for zones 1-3 and, therefore, has the right to use all points within the zones for which it pays. Thus, the shipper could nominate and ship 10,000 Dth from point M to point P, while at the same time nominate and ship another 10,000 Dth from point P to point S. But the shipper could not nominate 10,000 Dth from point M to point Q and nominate 10,000 Dth from point P to point S, because that would result in 20,000 Dth nominated in segment P-Q.

Northern proposed to implement segmentation in the Field Area in two phases, but did not implement physical segmentation in the Market Area.[159] In practice today, 14 years after Northern's implementation filings, Permian area shippers on Northern's system have access to one segmentation point in the Texas Panhandle. However, shippers have no other access to

[157] Order No. 637-A at p. 31,591.

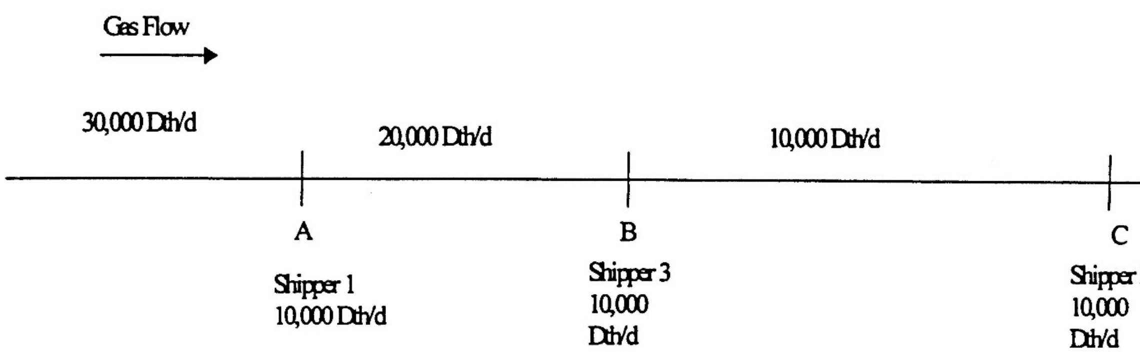
[158] Reproduced from Order No. 637-A at 31,592.

[159] *Northern Natural Gas Company*, Third Order on Compliance with Order No. 637 and Order on Rehearing and Clarification, 108 FERC ¶ 61,124 (2004)

segmentation points between southwest Texas and the Kansas/Nebraska border. In the Market Area, shippers have one segmentation point, but none in the load centers of the upper Midwest.

In Order No. 637 and its progeny, the Commission also directed pipelines to revise their scheduling priority procedures to provide shippers with greater ability to use their flexible receipt and delivery points to "enhance competition and improve efficiency across the pipeline grid."[160] In Order No. 637-A, the Commission adopted a policy, designed to improve competition, that required pipelines to implement a contract path-based model (often referred to as "within-the-path) giving higher priority rights to shippers when they use secondary points located along the contract path between their primary points as compared to other shippers using secondary points.[161] The Commission provided gas flow diagram examples to illustrate its policy.

Diagram 2[162]



Referring to Diagram 2 above, reproduced from Order No. 637-A, the Commission explained its within-the-path scheduling priority approach as follows:

> two shippers paying the same rate for capacity in a zone seek to use a secondary delivery point which is upstream of one shipper and

[160] Order No. 637 at 31,296.

[161] Order No. 637-A at 31,598 ("each pipeline must use the within-the-path allocation method in its compliance filing, unless it can demonstrate that such an approach is operationally infeasible or leads to anticompetitive outcomes on its system.")

[162] Reproduced from Order No. 637-A at 31,597.

> downstream of the other. In the example below, shippers 1 and 2 pay the same rate for 10,000 Dth/d of capacity in the zone, with primary points at A and C respectively, and both shippers seek to deliver gas to point B. The pipeline is sized such that 30,000 Dth/d can be delivered to point A, 20,000 Dth/d to point B, and 10,000 Dth/d to point C.
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> * * *
>
> Under the within-the-path allocation approach, shipper 2 would have a higher priority than shipper 1 to use mainline capacity to reach secondary points within its capacity path. By using within-the-path priority, shipper 2 has a firm right to mainline capacity to delivery point B and, therefore, becomes a more effective competitor to the shipper holding primary point capacity at point B. Shippers needing capacity to point B now have a choice of buying mainline capacity from shipper 2 or shipper 3. Under this policy, shipper 2 would have primary mainline rights to ship to or beyond point B, but would have secondary rights to make deliveries at point B.[163]

In other words, a shipper seeking to use a secondary delivery point within its scheduling path has priority over other shippers.

During Northern's Order No. 637-A compliance proceeding, the Commission directly ordered Northern to implement within-the-path scheduling. In a Letter Order issued in response to Northern's status report regarding its phased implementation plan, the Commission stated:

> In Order No. 637-A, the Commission held that each pipeline must afford a higher priority over mainline capacity to a shipper seeking to use secondary points within its capacity path than a shipper seeking to use mainline capacity outside its path, unless the pipeline can demonstrate that such an approach is operationally infeasible or leads to anti-competitive outcomes on its system. Northern's currently effective tariff does not reflect such scheduling priorities. Accordingly, we direct Northern to incorporate these scheduling priorities when it implements Phase 2 of its segmentation plan, consistent with Northern's prior statements that it would do so.[164]

Northern then made filings purporting to implement within-the path scheduling, which were accepted by the Commission.[165] However, as Northern has applied its scheduling practices

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[163] Order No. 637 at 31,596-597.

[164] *Northern Natural Gas Company*, Letter Order, 112 FERC ¶ 61,316 at P 10 (2005).

[165] *See* Northern's filings in Docket No. RP00-404-0017.

to shipper transaction requests, as explained by Mr. Boughner, Northern has not fully implemented the Commission's directive to provide within-the-path scheduling.

2. Examples of Recent Scheduling Issues in the Field Area Demonstrate Northern's Point-based Scheduling Practices.

Mr. Boughner's testimony provides three examples of recent transactions in which Northern has "cut" (not scheduled) SPS's service as a result of assigning secondary priority to SPS's firm service, top priority contract path when SPS has requested receipt or delivery to a secondary point along that contract path. Mr. Boughner first explains that Northern assigns transaction scheduling priority based on the receipt and delivery points requested by a shipper for a particular transaction rather than using a within-the-path scheduling model.[166] When a shipper requests a secondary point, even if that secondary point is along the shipper's firm service contract path, Northern treats the entire path, from the receipt to the delivery point, as secondary and assigns it a lower priority. Northern's practice result in shipper's request to use a secondary point causing that shipper's entire contract path to lose its primary firm service priority, and thus, to be a risk for being not scheduled or "cut" in situations in which the pipeline has more requests than capacity. Under the Commission's rules, primary firm service may only be cut during pipeline *force majeure* or maintenance events.

Mr. Boughner provides three examples of recent situations in which SPS's service was cut because of a capacity constraint, despite SPS only using primary and secondary points included on its firm service contract path.[167] Mr. Boughner then provides a fourth example describing the circuitous method SPS has had to use at times to move natural gas between points on Northern's system, including having to enter into an interruptible transportation agreement

[166] Boughner Testimony at p. 8.
[167] *Id.* at pp. 9-18.

and pay for interruptible service to move from point to point in addition to SPS's firm service for transportation along the same contract path.[168]

3. Northern's Segmentation and Scheduling Practices are Directly Related to the Changes Proposed in Northern's Base Case.

Northern's current segmentation and scheduling priority practices are directly related to changes proposed in Northern's Base Case, and should be set for hearing pursuant to NGA section 4 with the other issues raised by the Rate Case Filing.

Northern's failure to schedule transactions using contract path priority is reflected in Northern's proposed test period adjustments to reduce throughput. For the Field Area, Northern reduced Test Period quantities associated with deliveries to Demarc by 207.6 Bcf.[169] Further, Northern reduced test period quantities by 41.9 Bcf associated with other field area deliveries.[170] However, Northern's explanation and support for the proposed throughput reductions is inconsistent with the reality of its current Field Area capacity segmentation and scheduling priority practices.

Northern's proposed reduction to Field Area throughput includes short-term, month-to-month contracts that shippers use to access lower cost gas supplies in response to changing market conditions. Spot prices have been volatile in the Permian Basin with some gas prices approaching zero or even dropping into negative territory. The volatility has put a premium on flexible transportation capacity to move between the changing low-cost supply points. It is not clear from the information provided by Northern, but much of the throughput quantities removed from the test period appear to be related to the month-to-month business resulting from this price

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[168] Boughner Testimony at pp. 18-21

[169] Miller Testimony at p. 43, line 13.

[170] *Id.* at p. 44, line 8.

volatility. This month-to-month business is, in large part, derived from Northern's point-based scheduling practices.

Northern's restricted scheduling practices have created an incremental demand for Northern capacity by forcing shippers to buy firm capacity to obtain primary path priorities. A hearing is needed to obtain further information about the receipt points, delivery points, and related services for this month-to-month business. However, there is a direct relationship between the throughput quantities Northern has removed and its current scheduling practices. If Northern is required by the Commission to fully implement a within-the-path scheduling process, it may affect future Permian area revenues. Accordingly, the two issues, Permian throughput and Northern's scheduling practices should be examined together in hearing.

Northern's proposal to modify the Account Balance Transfer provision in Rate Schedule FDD, Section F (Tariff Sheet No. 136) is also related to Northern's scheduling priority practices. Northern proposes to limit shippers' current ability to transfer account balances between storage receipt and delivery points without being charged additional injection or withdrawal fees only to situations in which Northern is not allocating requested transactions due to a capacity constraint.[171] As described in Mr. Boughner's testimony, SPS has primary firm receipt and delivery points on its TFX contract on both sides of the Brownfield compressor station constraint, and holds account balances at Storage Points on its FDD contract on both sides of the same Brownfield compressor constraint. Northern's proposed change to the Account Balance Transfer provision would further restrict SPS's ability to flexibly use the transportation capacity for which it has contracted. Based on SPS's experience with the Brownfield compressor station

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[171] Northern characterizes this change as simply a clarification. Transmittal Letter at 11; Heckerman Testimony at p. 44, lines 19-20, p. 46 lines 20-22; Miller Testimony at p. 87, line 15, p. 88, lines 8-9, and p. 88 line 16 – p. 89, line 5. However, a review of the current Tariff language show that is not the case.

constraint over the last few years and reasonable expectation that the point will continue to be constrained, the Account Balance Transfer modification Northern proposes would result in SPS effectively losing some of its flexibility to transfer account balances between those FDD Storage Points that are separated by the Brownfield constraint.

Northern's proposal directly implicates its current scheduling practices. Northern would have no need for he proposed modification to the Account Balance Transfer provision if Northern used within-the-path scheduling. If Northern properly implemented within-the-path scheduling rules, then SPS would be able to properly use its contracted capacity and Account Balance Transfers would be less substantial. Restricting shippers' ability to use their contracted capacity is contrary to Commission policy. The proposed change for Account Balance Transfers and the related appropriate scheduling practices for capacity allocation should be set for hearing.

4. Northern's Segmentation and Scheduling Practices are Directly Related to Changes Proposed in the Prospective Case.

Northern's current segmentation and related scheduling priority practices are directly related to Northern's proposals under the Prospective Case and must be considered at hearing along with the other *pro forma* Tariff provisions. For example, Northern's Prospective Case includes proposed modification of its Field Area segmentation rules, making Northern's current inter-related segmentation and scheduling priority practices inextricably tied to proposals Northern includes in the Rate Case Filing. As noted by Mr. Miller, "Northern proposes changes appropriate to . . . implement system-wide rates, which includes the modification of Field Area Segmentation."[172]

[172] Miller Testimony at p. 108, line 15-16.

Northern's segmentation and scheduling priority practices are also directly implicated by Northern's proposal to eliminate its zones and transition to a system-wide reservation rate. As the Commission noted in Order No. 637-A:

> The goal in permitting shippers to segment capacity is to enable firm shippers to use the capacity for which they have contracted as flexibly as possible without infringing on the legitimate rights of other shippers. In the case of a reticulated pipeline charging a postage stamp rate, firm shippers are paying for the use of the entire pipeline in their rates. The pipeline, therefore, has the obligation to optimize the system so that firm shippers can make the most effective use of the capacity for which they pay. On reticulated pipelines with postage stamp rate structures, where shippers have no specifically defined paths, the pipeline should permit firm shippers to use all points on the system and to use or release segments of capacity between any two points, while continuing to use other segments of capacity.[173]

Mr. Miller claims that the proposal to implement a system-wide rate will provide Market Area shippers with firm service to have greater access to capacity in the Field Area.[174] However, given Northern's current capacity segmentation status and point-based scheduling priority practices, it is far from certain that Northern's proposed transition would have that result. The uncertainty of that result is compounded by the current constraints delivering gas out of the Permian basin and the expectation that new pipeline capacity will not keep up with the booming oil and gas development for the foreseeable future.

Northern's proposal to transition to a system-wide reservation rate requires review of Northern's current scheduling and segmentation practices to determine whether the continuation of Northern's practices under a system-wide rate would actually permit shippers to use all points on the system. The NSP Companies and SPS are concerned that without within-the-path scheduling, Northern's proposal to implement a system-wide reservation rate would not promote

[173] Order No. 637-A at 31, 591.

[174] Miller Testimony at p. 111, line 8 – p. 112, line 8.

shippers' ability to use receipt and delivery points in the Field Area, due to Northern assigning secondary priority to requested transactions and then cutting them due to constraints. This would deprive shippers of the very benefit that Northern offers as a justification for transitioning to system-wide reservation rates.

As Mr. Boughner points out in his testimony, Northern's current point based scheduling practices artificially limit shippers' access to secondary points and reduce shippers' ability to use their firm rights at secondary points.[175] Without a change to Northern's current point-based scheduling practices, shippers will be greatly restricted in the use of secondary points and will not be able to realize the promise of system-wide flexibility promised by Northern. Further, Mr. Miller states in his testimony that with the advent of system-wide reservation rates, shippers will have just two segmentation points (the current one in the Field Area and Demarc in the Market Area).[176] A proposal to offer only two segmentation points for a lengthy pipeline system of 14,794 miles, traversing nine states raises serious questions about Northern's compliance with the Commission's Order 637-A requirements and is another reason why these issues should be considered at hearing along with a review of the proposed system-wide reservation rate design.

Northern's proposal to relocate its current scheduling point "Demarc" is also directly related to Northern's current capacity segmentation and scheduling priority practices. Demarc originally referred to the demarcation point between the Field and Market rate zones. While Demarc's current location is related to the Clifton Compressor station location, Demarc is actually a virtual contract point for administrative purposes. Northern proposes to move this contract point (theoretically) north to be north or downstream of the REX Pipeline interconnect and the Trailblazer interconnect, which are two important supply points into Northern. Similar to

[175] Boughner Testimony at pp. 8-9, 13, 16, 20-21.
[176] Miller Testimony at p. 116, lines 11-17.

the above discussion, the proposed relocation of the Demarc point raises inter-related questions of Northern's full compliance with the Commission's Order No. 637-A scheduling and segmentation procedures. The relocation of Demarc may not be necessary under a within-the-path scheduling model as such a model is designed to handle questions of priority at receipt and delivery points. In any event, the proposed relocation of Demarc and questions of the appropriate scheduling model for allocating capacity at that point should be addressed jointly in hearing.

As discussed above, Northern appears to be proposing a number of tariff changes to address perceived issues that could be better handled with less disruption to Northern's existing practices and shippers' business by adopting a within-the-path scheduling practices.

Finally, Northern proposes a number of revisions in the Prospective Case to Tariff sheets that are related to Northern's point-based, rather than within-the-path scheduling practices. A non-exhaustive list of Tariff sheets to which Northern has proposed revisions that directly involve Northern's capacity segmentation and scheduling practices includes:

- Tariff Sheet 101, Rate Schedule TF, Firm Throughput Service and Tariff Sheet 116, Rate Schedule TFX, Firm Throughput Service.

Northern's proposed revisions to these rate schedules highlight the scheduling priority issues raised by Northern's proposal to eliminate its zones and implement a system-wide rate. The relevant provisions of the revised sheets, which contain identical revisions state:

> Shipper shall have the option to request firm throughput service (i) for the Market Area, (ii) for the Field Area, or (iii) a Combined Service. A Shipper with Combined Service may not realign the primary firm receipt or delivery points to points that would not traverse Demarc and retain its primary rights to transport from the Field Area to the Market Area for the quantities realigned.[177]

- Tariff Sheet 153, Rate Schedule MPS, Pooling Service

[177] Rate Case Filing, *Pro Forma* Marked Tariff at pp. 15, 24.

The proposed revisions involve the locations of pooling points and create a "South Pool" which includes, *inter alia*, Demarc (POI #37654) and the Demarc Segmentation Point.[178]

- Tariff Sheet 203, General Terms and Conditions, Definitions

This Tariff Sheet revises the definitions of Demarc,[179] Market Area,[180] and Segmentation.[181] As discussed above, the proposal to move Demarc is directly related to Northern's failure to provide within-the-path scheduling. Likewise the other revised Tariff definitions and the following revised Tariff Sheets all directly relate to Northern's capacity segmentation and scheduling priority practices.

- Tariff Sheet 286, General Terms and Condition, Capacity Release (involving segmentable releases)[182]
- Tariff Sheet 305, General Terms and Conditions, 56. Segmentation of Capacity, A. Market Area, and Tariff Sheet 305A, General Terms and Conditions, 56. Segmentation of Capacity, A. Field Area[183]

Northern's current segmentation and related scheduling priority practices are directly related to Northern's proposals under the Prospective Case and must be considered at hearing along with the other *pro forma* Tariff provisions.

5. In the Alternative, the Commission Should Exercise its Discretion to Set Northern's Scheduling Practices for Hearing Pursuant to NGA Section 5 Because They are Clearly Contrary to Commission Policy.

In the alternative, if the Commission does not find that Northern's proposed Tariff changes included in the Base and Prospective Cases directly relate to Northern's inter-related capacity segmentation and point-based scheduling practices, the Commission should exercise its

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[178] Rate Case Filing, *Pro Forma* Marked Tariff at p. 43.

[179] *Id.* at p. 53.

[180] *Id.* at p. 54.

[181] *Id.* at p. 61.

[182] *Id.* at p. 80.

[183] *Id.* at pp. 94, 95.

considerable discretion to set consideration of those issues for hearing in this proceeding. When "the Commission is made aware of [an existing] tariff provision that is clearly contrary to Commission policy" in an NGA section 4 proceeding, the Commission may take action under section 5 of the NGA and set the existing provision or practice for hearing along with other issues raised in a pipeline's NGA section 4 filing even if the existing tariff provision is not directly related to the subject filing and no complaint has been filed.[184] Here, Northern's implementation of its existing Tariff provisions clearly contravenes Commission policy and precedent, and do not comply with the Commission's directive to Northern to provide within-the-path scheduling to its customers.[185]

Further, considering the segmentation and scheduling priority issues within the context of Northern's Rate Case Filing would further the goal of administrative efficiency. In 2013, WBI proposed to separately state fuel rates for two lateral projects in a general NGA section 4 rate case filing (but proposed no other changes to its existing fuel mechanism), and the Commission set those proposed modifications for hearing.[186] The Commission ruled that issues related to WBI's existing fuel mechanism or fuel rates raised by protestors could be "considered at hearing pursuant to section 5 of the NGA."[187] In denying WBI's request for rehearing, the Commission ruled that it was reasonable to allow parties to pursue whether WBI's existing fuel mechanism and rates conform with Commission policy at hearing because the parties would already be considering

[184] *Tuscarora Gas Transmission Co*., 120 FERC ¶61,022 P 13 (2007) (when the Commission has been made aware that a tariff provision clearly conflicts with Commission policy, the Commission may act pursuant to section 5 even though it is not directly related to the subject filing and no complaint has been filed.); *see also Nat. Gas Supply Assoc., et al*., 137 FERC ¶ 61,051 at P 27 (order on rehearing); *Southern Nat. Gas Co*., 135 FERC ¶ 61,056 at PP 13, 16-17 (2011).

[185] *Northern Natural Gas Company*, Letter Order, 112 FERC ¶ 61,316 at P 10 (2005).

[186] *WBI Energy Transmission, Inc*., 145 FERC ¶ 61,176 at PP 11-13, *order on reh'g*, 147 FERC ¶ 61,002 (2014).

[187] 145 FERC ¶ 61,176 at P 11.

WBI's proposal to provide two separately-stated fuel rates at hearing.[188] The Commission noted that "it would not be administratively efficient to require the initiation of a completely separate proceeding, including the possibility of yet another hearing," to consider parties' objections to WBI's existing fuel mechanism when WBI's proposed changes in the rate case filing implicated the existing mechanism and fuel rates, and were already set for hearing.[189] Just as in the WBI case, the goals of administrative efficiency support setting the segmentation and scheduling priority issue for hearing with the other issues raised in Northern's Rate Case Filing.

Northern's current use of point-based scheduling rather than within-the-path scheduling as required by Order No. 637-A is contrary to Commission precedent and policy, adversely affects customers' ability to schedule receipts and deliveries on Northern's system; causes customers to pay twice for use of the same firm capacity, and is unjust and unreasonable. Northern's Rate Case Filing directly implicates Northern's current inter-related capacity segmentation and scheduling practices, and the interplay between Northern's existing practices and Northern's proposed Tariff changes should be fully investigated through discovery and considered at hearing.

V. REQUEST FOR MAXIMUM SUSPENSION

The NSP Companies and SPS respectfully request that the Commission suspend Northern's proposed Base Case rates for the maximum five-month period permitted under section 4 of the NGA, as anticipated by Northern,[190] and make Northern's imposition of the proposed rates after the suspension period subject to refund. The Commission applies the maximum suspension period

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188 147 FERC ¶ 61,002 at PP 6-8.

189 *Id.* at P 6.

190 Transmittal Letter at 1; *see also*, Lillo Testimony at p. 24, line 21 (discussing the effective date of the case, "which is assumed to be January 1, 2020").

where "preliminary study leads the Commission to believe that the filing may be unjust, unreasonable, or that it may be inconsistent with other statutory standards."[191] As discussed above, Northern has not demonstrated that its proposed rates are just and reasonable, or that maximum suspension would lead to "harsh and inequitable results."[192] Consistent with Commission policy and the issues raised by the NSP Companies and SPS, the Commission should suspend Northern's proposed rates for the maximum period and make them subject to refund.

VI. REQUEST FOR FULL EVIDENTIARY HEARING

The NSP Companies and SPS support Northern's request that the Commission set the *pro forma* Prospective Case for hearing.[193] The NSP Companies and SPS also respectfully request that the Commission also order a full evidentiary hearing on the rates the Base Case tariff revisions Northern proposed in the Rate Case Filing, and Northern's implementation of within-the-path under the Base Case and Prospective Cases to determine whether Northern's proposed rates and tariff changes are just and reasonable and not unduly discriminatory. The Commission is obliged to conduct a hearing where genuine issues of material fact exist and cannot be resolved on the written record alone.[194] As discussed above, the NSP Companies' and SPS's preliminary analysis of the Rate Case Filing, conducted without the benefit of discovery, has identified numerous disputed issues of material fact that require further investigation.[195] Discovery and a

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[191] *El Paso Natural Gas Co.*, 112 FERC ¶ 61,150, P 92 (2005), *reh'g denied*, 116 FERC ¶ 61,016 (2006), *review denied sub nom. Freeport-McMoRan Corp. v. FERC*, 669 F.3d 302 (D.C. Cir. 2012).

[192] *CenterPoint Energy – Miss. River Transmission, LLC*, 140 FERC ¶ 61,253, P 78 (2012) (citing *Valley Gas Transmission, Inc.*, 12 FERC ¶ 61,197 (1980)).

[193] Transmittal Letter at 1-2.

[194] *See*, *e.g.*, *Cajun Elec. Power Coop., Inc. v. FERC*, 28 F.3d 173, 177 (D.C. Cir. 1994); *Moreau v. FERC*, 982 F.2d 556, 568 (D.C. Cir. 1993); *Vt. Dep't of Pub. Serv. v. FERC*, 817 F.2d 127, 140 (D.C. Cir. 1987).

[195] *See*, *supra,* section IV.

full evidentiary hearing are essential to ensure that the necessary facts are developed to determine whether Northern's proposed rates, terms and conditions of service are just and reasonable and not unduly discriminatory.

VII. CONCLUSION

The NSP Companies and SPS respectfully submit that overall, the Rate Case Filing fails to adequately support the proposed rates and Tariff revisions, and demonstrates that they may be unjust and unreasonable. For the foregoing reasons, and for good cause shown, the NSP Companies and SPS respectfully ask that the Commission (i) grant this motion to intervene; (ii) suspend Northern's proposed rates for the maximum period; (iii) set the Base and Prospective Cases proposed in the Rate Case Filing for full evidentiary hearing; (iv) order a review in the same hearing of Northern's capacity segmentation practices and failure to provide within-the-path scheduling; and (v) take other action consistent with the protest set forth above.

Date: July 15, 2019

Respectfully submitted,

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APPENDIX

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Northern Natural Gas Company	)	**Docket No. RP19-1353-000**
	)	

Prepared Answering Testimony

of

Michael Boughner

On Behalf of

Northern States Power Company, a Minnesota corporation,

Northern States Power Company, a Wisconsin corporation, and

Southwestern Public Service Company

July 15, 2019

TABLE CONTENTS AND LIST OF FIGURES AND ATTACHMENTS

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ATTACHMENTS

I. INTRODUCTION

Q. State your name and business address.

A. My name is Michael Boughner. My business address is 1800 Larimer Street, Suite 1000, Denver, Colorado 80202.

A. Qualifications

Q. By whom are you employed and what is your position?

A. I am employed by Xcel Energy Services Inc. (XES), the "centralized service company" subsidiary of Xcel Energy Inc. (Xcel Energy). Xcel Energy is a holding company with, among other things, four utility operating company subsidiaries: Northern States Power Company, a Minnesota corporation (NSPM), Northern States Power Company, a Wisconsin corporation (NSPW) (jointly referred to herein as NSP or the NSP Companies), Southwestern Public Service Company (SPS), and Public Service Company of Colorado (PSCo). The NSP Companies provide natural gas and electric utility service to parts of North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. SPS provides electric utility service to parts of Texas and New Mexico. PSCo provides retail natural gas and retail and wholesale electric utility service in Colorado. My title is Director, Gas Supply and Market Operations.

Q. Briefly outline your responsibilities as Director, Gas Supply and Market Operations.

A. I am responsible for managing and directing the natural gas supply procurement activities for Xcel Energy's regulated Operating Companies, including NSP and SPS. This includes overseeing the development of operational and strategic natural gas purchasing practices and day-to-day purchasing parameters. I also direct the scheduling functions for the

Operating Companies' natural gas supply.

Q. Describe your business and educational background.

A. I graduated from Virginia Polytechnic Institute and State University in 1997 with a Bachelor of Science degree in Mechanical Engineering. I graduated with an MBA from the University of Denver in 2017.

Q. Describe your professional experience.

A. In 2000, I started with Cinergy Corporation, where I managed several projects including implementation of weather and demand forecast processes and preparations for the launch of the Midwest Independent System Operator (MISO) Day 2 Market. In 2004, I joined XES as a Manager of Market Operations and was responsible for market design and policy development in both the MISO and Southwest Power Pool (SPP) regions. In 2007, I transferred to the position of Manager of Commercial Operations Projects & Compliance. In November 2010, I accepted the position of Manager of Generation Control and Dispatch. In this role, my main responsibilities were to ensure the reliable and economic dispatch of the Operating Companies' generation assets. In May 2014, I accepted my current position as Director, Gas Supply.

Q. Have you testified or filed testimony before any regulatory authorities?

A. Yes. I filed testimony before the Public Utility Commission of Texas in Docket No. 46025, an SPS Fuel Reconciliation proceeding, on the topics of natural gas forecasts, natural gas purchases, and the effect of the SPP Integrated Marketplace on natural gas expenses. I filed testimony before the New Mexico Public Regulation Commission in Case No. 14-00348-UT on natural gas prices and SPS's natural gas procurement policies, the Wisconsin Public Service Commission in Case No. 05-EI-139 on the topic of independent system operator market charge types, and the Colorado Public Utilities Commission in Case No. 16A-0053G regarding the application for a Cost of Service Gas Program through investment in gas reserves.

B. Purpose of Testimony and List of Attachments

Q. On whose behalf are you presenting this testimony?

A. I am sponsoring this testimony on behalf of NSP and SPS, who are both natural gas transportation and storage customers of Northern Natural Gas Company (Northern).

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to answer certain assertions made in Northern's Exhibit No. NNG-00009, Prepared Direct Testimony of Kent Miller (Miller Testimony), and to demonstrate that, in practice, Northern does not use within-the-path scheduling as required by Order No. 637, and that failure causes real harm to the NSP Companies and SPS, and likely harms all of Northern's shippers.

Q. Please identify the attachments to this testimony that you are supporting.

A. In addition to my prepared testimony, I am supporting the following figures and attachments. The Figures provide examples of scheduling events where SPS did not receive requested natural gas transportation service due to Northern's failure to use within-the-path scheduling, and the Attachments provide other support for my testimony.

Figures	**Description**
Figure 1	May 2 Secondary Receipt to Primary Delivery
Figure 2	May 4 Primary Receipt to Secondary Delivery

Figure 3	May 10 Secondary Receipt to Primary Delivery
Figure 4	May 10 Interruptible to Primary Delivery

Attachments	**Description**
Attachment 1	Demarc to Waha Price Comparison
Attachment 2	Map of Northern Natural Texas System
Attachment 3	Open Season Posting
Attachment 4	Index of Shippers Excerpt

Q. Were these attachments prepared by you or under your supervision or direction?

A. Yes.

C. Background

Q. How does scheduling work for interstate pipelines?

A. The Federal Energy Regulatory Commission (FERC or Commission) established transportation scheduling rules in Order 636 and updated them in Order No. 637. The Protest of Northern's Rate Case Filing submitted by the NSP Companies and SPS (Protest), which my testimony supplements, provides a short history of the Commission's transportation scheduling rules, and Northern's compliance filings in response to those rules. *See* Protest at Section IV.E.

In general, shippers submit an electronic request for service, or nomination, from a stated receipt point to stated delivery point and suppliers submit a corresponding request. The pipeline first matches the two requests and then evaluates all other requests for the same capacity. If there is adequate space, the pipeline "schedules" the capacity. If there are more nominations than space available, capacity is scheduled in order of priority as discussed later in my testimony. This scheduling process can occur five times over two days in five nomination cycles. However, if a firm shipper wants to be assured of capacity, it should submit its request in the first cycle the day before the natural gas is needed. For simplicity here, I will not make distinctions between the five cycles as that is not important to my discussion.

Q. How are priorities of service established for competing scheduling requests?

A. The Commission established priority rules which are included in pipeline tariffs. The Commission mandated flexible receipt and delivery points and established primary and secondary (Northern uses the term "alternate") service rights to allow shippers to use points on their contract paths, but not listed in their contracts, at a higher service priority and created primary and secondary rights. In general, primary firm (primary) service goes first, followed by secondary firm (secondary), then interruptible service. Primary service refers to the receipt and delivery points listed on the applicable service contract and the pipeline capacity (or path) connecting those points. Secondary service applies to receipt and/or delivery points that are requested by the shipper, but which are not listed on the contract. Pursuant to the Commission's rules, primary shippers are permitted to use secondary points on a primary path basis when the secondary point is located along its original contract path. If a secondary point is outside the original contract path, the service would be provided on a secondary path basis.

Q. How are transportation requests scheduled using the priorities of service?

A. As noted above, pipelines evaluate all requests for the same capacity to determine whether different transaction requests have different priorities. When a pipeline has more requests than capacity, it must "cut" or not schedule some of those requests. In such cases, the pipeline will cut interruptible service first. If requests are still greater than capacity, then it will cut secondary service. Under the Commission's rules, primary firm service may only be cut during pipeline force majeure or maintenance events.

Q. What determines which secondary requests will be cut and which served?

A. Under this type of process, there will inevitably be occasions where some but not all secondary requests must be cut. In Order No. 637-A, the Commission required interstate pipelines to use a contract path-based model that allows shippers to retain their primary rights along their contract path between their primary points when they use secondary points.[1] *See* page 38 of the Protest, which shows a diagram illustrating this concept, excerpted from Order 637-A at page 31,597. The Commission states that the downstream shipper (Shipper 2) has primary path rights to all upstream points; shown in the diagram as Point "B," shipper 3.[2] The Commission selected a path-based model to encourage competition, allocative efficiency, and to provide flexibility to shippers.[3] The Commission referred to this path-based model as "within-the-path scheduling," and I use that term below.

Q. How does the Commission encourage flexible service for shippers?

A. The Commission created the primary and secondary rights discussed above. Flexible receipt and delivery points allow shippers to use points not listed in their contracts at a

1 Order No. 637-A, 91 FERC ¶ 61,169 at pp. 31,596-98, *reh'g denied*, Order No. 637-B, 92 FERC ¶ 61,062 (2000).

2 *Id.* at pp. 31,597-98.

3 *Id.* at p. 31,598.

higher service priority. Further, the Commission adopted within-the-path scheduling to give primary shippers more flexibility to use their contracted capacity.

Q. Why is flexible service important to the NSP Companies and SPS?

A. Flexible receipt and delivery points are very important to the NSP Companies, SPS, and to other shippers. Flexible receipt points allow us to take advantage of lower cost natural gas supplies when they become available at secondary points, thus saving our customers money. Flexible receipt points allow us to access alternate sources of supply if our original sources fail due to plant outages or pipeline maintenance. Flexible delivery points allow us to shift our purchased supplies to different locations in response to changes in the weather, such as one region being colder than forecasted. Flexible delivery points also allow us to move natural gas fuel to an alternate generation plant when one plant unexpectedly goes off-line or conducts a scheduled outage.

Q. Have pipelines implemented the Commission's within-the-path scheduling model?

A. Generally, yes, pipelines use within-the-path scheduling. I am responsible for scheduling daily on nine different interstate pipelines on which the XES operating companies hold firm transportation capacity. Of these nine interstate pipelines, eight provide within-the-path scheduling, and Northern is the only pipeline that does not provide within-the-path scheduling. In any event, we rarely experience secondary cuts along our primary contract path on any of our other eight firm pipelines.

Q. How is Northern different?

A. As explained below, Northern uses a point-based scheduling procedure rather than a within-the-path model.

Q. Explain point-based scheduling.

A. Northern allows shippers access to secondary receipt and delivery points. However, when a secondary point is requested, it causes the entire path from the receipt to the delivery point to be treated as secondary. This treatment greatly increases the risks of a primary shipper being cut during the scheduling process when it uses a secondary point, because Northern's scheduling procedure does not use a separate path priority. Under such a practice, the use of a secondary point will cause the entire contract path to lose its primary priority.

Q. Why is within-the-path scheduling important to shippers like the NSP Companies and SPS?

A. As mentioned earlier, point flexibility gives the NSP Companies and SPS the option, among other things, to seek out lower cost natural gas supplies, to find an alternative source of supply if the original source fails, to shift loads to other areas when an unexpected change in demand occurs, and to react to shifts in generation plant operations. While some of these actions are economic in nature, others support human welfare needs. The Commission's within-the-path model provides the NSP Companies and SPS, and other shippers, the ability to fully use their existing firm service contract rights for which they pay a reservation charge. In some cases, this will result in significant cost savings for shippers' customers; in other cases it will improve the reliability of the service. Northern's point-based procedure creates barriers to the efficient use of the NSP Companies' and SPS's firm capacity, causes greater costs to our customers, creates inefficiency in the marketplace, and reduces the reliability of the energy grid.

II. TESTIMONY

Q. Do you have examples of these scheduling problems?

A. Yes, I recently documented some of the frequent occurrences caused by Northern's failure to use within-the-path scheduling. I present four recent real-life occurrences here involving the days of May 2, May 4, and May 10 of 2019.

Q. Are these the only instances where you have witnessed Northern's failure to use within-the-path scheduling?

A. No, I have provided only four examples here for the sake of brevity. In reality, Northern's use of a point-based scheduling model has adversely affected the NSP Companies, SPS, and other shippers practically every day during calendar year 2019, many days in 2018, and earlier. To ensure the reliability of service, the NSP Companies and SPS have actually altered how and where they buy and schedule natural gas supplies on Northern's system, to their operational and financial detriment.

Q. Describe the first example.

A. On May 2, 2019, a portion of SPS's requested transportation service involving a secondary receipt point was cut. SPS requested service from a secondary receipt point (EP Waha) rather than its contracted primary receipt point (NNG Oasis) to its primary delivery point, because natural gas transportation costs on an upstream pipeline were lower that day at the secondary receipt point. The EP Waha secondary receipt point that SPS requested is located upstream of SPS's primary firm service contract path. Northern assigned secondary priority to the requested transaction, from the secondary receipt point to the primary delivery point (SPS Lubbock) and the path in between the two points. There is currently a pipeline constraint (at the Brownfield compressor station) along this contract path. By a constraint, I mean that service requests often exceed Northern's capacity through the compressor station, which often results in Northern cutting secondary and interruptible capacity requests if the receipt to delivery path goes through the constraint. On May 2, 2019, despite SPS holding primary firm rights on the contract path that travels through the Brownfield compressor station, Northern cut the SPS request for lack of available capacity, since it had been assigned a secondary priority.

Q. Would you explain this transaction?

A. Yes, please refer to the Figure 1 below, which replicates the figure used by the Commission on page 31,592 of Order No. 637-A to illustrate how pipelines were instructed to implement within-the-path scheduling, and adds labels to illustrate SPS's real-life example. My figure is a little unwieldly since it includes a number of imaginary scheduling points from the Commission's diagram that are not applicable to this case. However, I thought it best to stick closely to the Commission's original example to allow for a comparison between the Commission's within-the-path scheduling model and Northern's point-based scheduling practices.

Figure 1
(May 2)

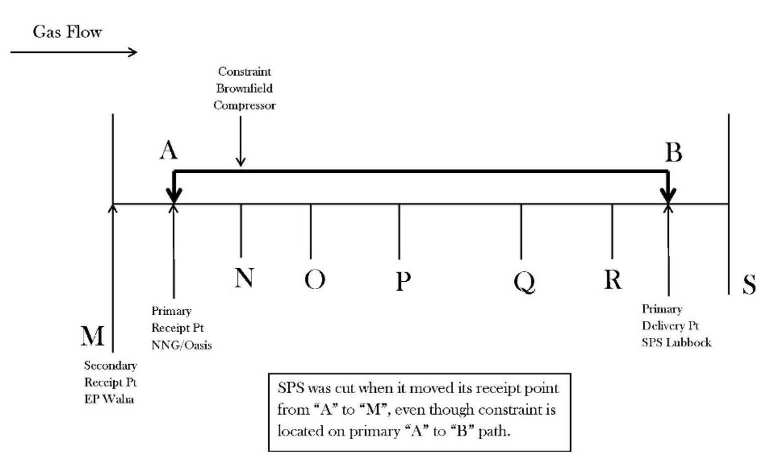


Figure 1 shows SPS's primary receipt point "A" at NNG Oasis and its primary delivery point "B" at SPS Lubbock. It also shows the relative location of the constraint at the Brownfield compressor station. You will notice that the Brownfield compressor is located along the primary contract path between the primary receipt point "A" and the primary delivery point "B." Finally, Figure 1 shows the secondary receipt point EP Waha at "M." Northern cut SPS' requested transaction from "M" to "B," because it assigned the entire transaction including the path between those two points a secondary firm priority. Northern's scheduling practices assign service priority based on the receipt and delivery points at which a shipper requests service.

Q. How would the same transaction be treated under a within-the-path model?

A. Referring again to Figure 1, within-the-path scheduling requires that the path between receipt point "A" and delivery point "B" (the SPS Lubbock delivery point) be assigned a primary contract path. Further, within-the-path scheduling means that a firm shipper is allowed to use any points outside its primary contract path on a secondary basis. Therefore, receipt point "M" (SPS's requested EP Waha) should receive secondary priority. Delivery point "B" continues to be treated as primary, since there is no requested change at that point. As described on pages 31,592-593 of Order No. 637-A, the SPS contract path would be primary where it flows through the Brownfield compressor constraint. Therefore, SPS's requested transaction would have been scheduled, not cut, unless Northern had been experiencing a *force majeure* or maintenance event.

In Order No. 637-A, the Commission stated: "[t]he shipper has the flexibility to segment capacity throughout zones 1-3 (point M through point S) . . . [t]hus, the shipper could nominate and ship 10,000 Dth from point M to point P, while at the same time nominat[ing] and ship[ping] another 10,000 Dth from point P to point S."[4] In that example, the Commission was discussing a segmentation example, allowing the shipper to break its contract into separate, temporary contracts for flexibility purposes. However, the flexibility principle described applies equally to the real-life example I described. The shipper has the right to use multiple points along its contract path without undue restriction from the pipeline. In particular, the Commission emphasized that the shipper may, on a day-to-day basis, use a secondary receipt point "M" that is upstream of its primary receipt point "A" without downgrading its primary rights along "A" to "B."[5]

Q. How are Northern's practices different from the other pipelines on which the XES operating companies take service?

A. Despite Northern's commitments to the Commission to implement within-the-path scheduling,[6] in practice, Northern schedules transactions using a point-based procedure, rather than a path-based model. When SPS requested the use of a secondary receipt point on May 2, 2019, it caused the entire transaction from "M" to "B" to be assigned secondary priority, which prompted the service cut at the Brownfield compressor station constraint. This is contrary to my understanding of the Commission's Order 637-A requirements, because it denies SPS and other shippers the flexibility to seek out other receipt and delivery points. In this case, SPS was attempting to purchase lower cost natural gas supplies at the secondary point, which would have saved its own customers money and would have promoted the Commission's allocative efficiency goals. On May

[4] Order No. 637-A, pp. 31,592-593.

[5] *Id.*

[6] Northern Natural Gas Company's Report on Phase 1 of Field Area Segmentation, transmittal letter at 2, Docket No. RP00-404-017 (filed July 1, 2005).

2, 2019, purchasing gas at point "M" (EP Waha) instead of "A" (NNG Oasis), would have saved SPS customers approximately $0.13 per Dth.[7] That level of cost difference amounts to a 73 percent increase in SPS' cost to transport gas that day.

Q. Describe the second example.

A. On May 4, 2019, a portion of SPS's requested firm transportation service involving a secondary delivery point was cut. In this case, SPS requested service at a secondary delivery point (SPS Lubbock) instead of its contracted primary delivery point (Moore County), since it was attempting to re-direct natural gas to a generation plant experiencing higher-than-expected natural gas burns over the day. In this example, the secondary delivery point is located within the primary contract path. Northern assigned the requested transaction from the primary receipt point (Tippet Plant) to the secondary delivery point (SPS Lubbock), and the path in between the two points, a secondary priority. Once again, there was a constraint at the Brownfield compressor station. Due to the capacity constraint and the secondary priority assigned to SPS's nomination, Northern cut the SPS request. Northern cut SPS's service even though the secondary delivery point SPS requested was located along SPS's firm contract path.

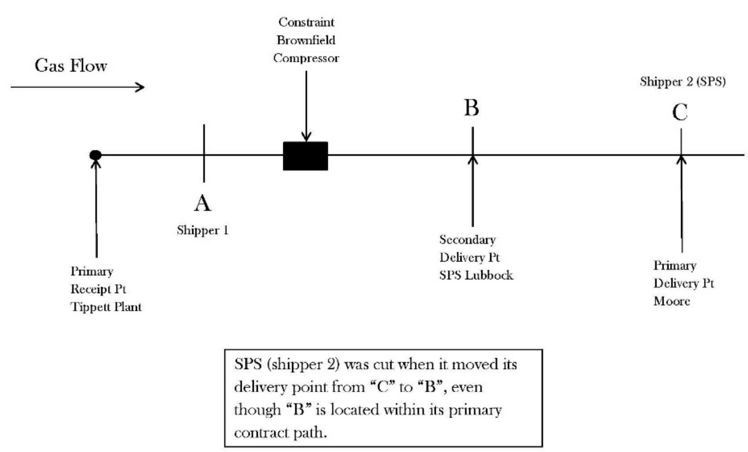
Q. Would you explain this transaction?

A. Yes, please refer to Figure 2 below, which replicates the figure used by the Commission on page 31,597 of Order No. 637-A to illustrate how pipelines were instructed to implement within-the-path scheduling, and adds labels to illustrate SPS's real-life example. Figure 2 shows SPS's primary receipt point at the Tippet Plant and its primary

[7] The $0.13 Dth per day cost savings would have been the result of the avoided transportation cost on the Oasis Intrastate Pipeline.

delivery point "C" at Moore County. It also shows the relative location of the constraint at the Brownfield compressor station. You will notice that again the Brownfield compressor is located along the primary contract path between the primary receipt point at Tippet and the primary delivery point "C." Finally, Figure 2 shows the secondary delivery point, SPS Lubbock, at "B." Northern cut SPS's requested transaction from Tippet to "B," because it assigned the entire transaction including the path between those two points a secondary priority due to its point-based scheduling practices.

Figure 2
(May 4)



Q. How would the transaction be treated under a within-the-path model?

A. Referring again to Figure 2, within-the-path scheduling would assign a primary contract path to the path between the Tippet receipt point and delivery point "B." Further, the shipper is allowed to use any points inside its primary contract path on a higher priority, secondary basis. Therefore, the Tippet receipt point should receive primary priority.

Further, the path between Tippet and delivery point "B" (the SPS Lubbock delivery point) should be treated as primary firm. Delivery point "B" would be treated as secondary. Under the Order No. 637 rules as described starting on page 31,597 of Order No. 637-A, the transaction SPS requested should have been assigned a primary priority and would not have been cut during scheduling. In reference to Figure 2, the Commission stated that shipper 2 at point "C" (SPS in our case) has a higher priority right to capacity at "B" and along the primary contract path. Order No. 637-A at p. 31,598. In noting its policy change to adopt the within-the-path approach to improve competition, the Commission noted, again in reference to Figure 2, that: *"[u]nder the within-the-path allocation approach, shipper 2 would have a higher priority than shipper 1 to use mainline capacity to reach secondary points within its capacity path."* Order No. 637-A at p. 31,597 (emphasis added).

Q. How are Northern's practices different?

A. Figure 2 illustrates that Northern does not follow the Order 637-A requirements. Northern's point-based scheduling practices do not assign a separate priority for the contract path. When SPS requested the use of a secondary delivery point on May 4, 2019, Northern treated the whole transaction, from Tippet to "B," to be treated as secondary, which prompted the cut at Brownfield. This is contrary to the Commission's Order 637 requirements, because it denies SPS and other shippers the flexibility to seek out other receipt and delivery points. SPS was attempting to re-direct natural gas to a generation plant that was experiencing increased natural gas burns. In this case, the cut caused SPS to lose access to a lower cost gas supply, with the replacement option costing its customers an additional $1.38 per Dth.[8] This increase in cost was notable compared to the 18 cent applicable maximum tariff rate for the scheduled transaction.

Q. Describe the third example.

A. On May 10, 2019, SPS replicated the secondary receipt move attempted on May 2nd. The transaction was cut again. Like the first example, SPS requested service from a secondary receipt point (EP Waha) rather than its contracted primary receipt point (NNG Oasis). Based on its point-based scheduling rules, Northern assigned secondary priority to the requested transaction from the secondary receipt point to the primary delivery point (SPS Lubbock) and the path in between the two points. Once again, there was a constraint at the Brownfield compressor station. Due to the capacity constraint and Northern's assignment of secondary priority to the requested transaction, Northern cut the SPS request. The cut occurred even though the constraint was located along SPS's primary contract path.

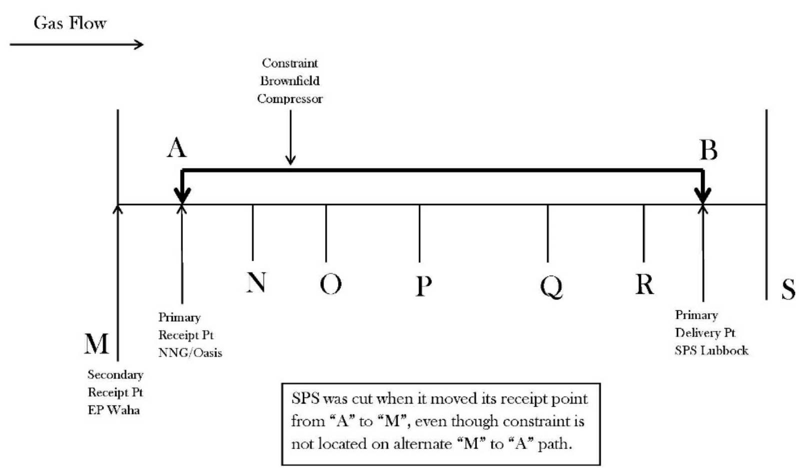
Q. Would you explain this transaction?

A. Yes, please refer to Figure 3 below, which replicates the diagram used by the Commission on page 31,592 of Order No. 637-A, and adds labels to reflect SPS's receipt and delivery points and illustrate SPS's real-life example. Figure 3 shows SPS's primary receipt point "A" at NNG Oasis and its primary firm delivery point "B" at SPS Lubbock. It also shows the relative location of the constraint at the Brownfield compressor station. Again notice that the Brownfield compressor is located along the primary contract path between the primary receipt point "A" and the primary delivery point "B." Finally,

[8] The $1.38 per Dth replacement cost is the difference between SPS's applicable storage weighted average cost of gas and the gas spot price that day at the receipt point.

Figure 3 shows SPS's secondary receipt point EP Waha at "M." Northern cut SPS's requested transaction from "M" to "B," because it assigned the entire transaction including the path between "A" and "B" a secondary priority based on the points requested rather than the contract path.

Figure 3
(May 10)



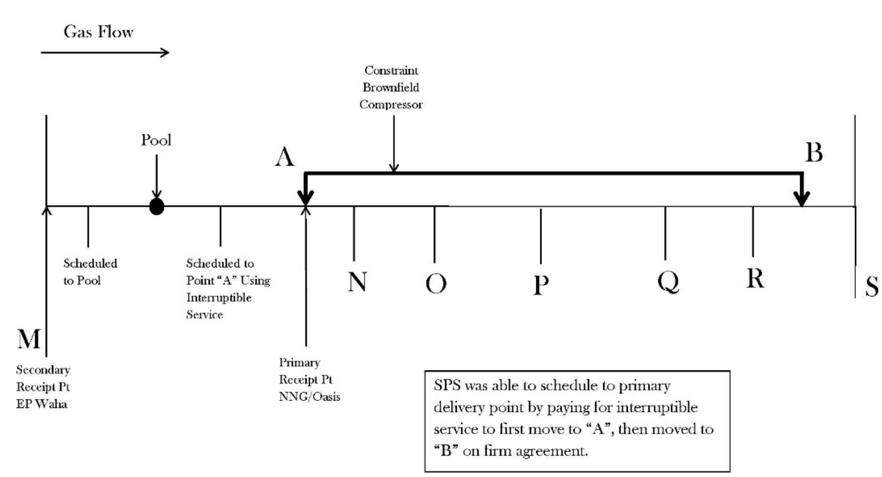
Q. What did you do after your scheduling request was cut?

A. SPS took a different approach in the next scheduling cycle. We submitted a transportation request using the primary receipt and delivery points "A" and "B," along with a separate request described later. The "A" to "B" transaction was scheduled by Northern even though the Brownfield constraint still existed. In this case, Northern assigned the "A" to "B" transaction a primary priority (the highest priority), which allowed it to be scheduled through the constraint. In other words, the transaction was scheduled because it used two primary points, yet the transaction was cut when SPS requested a secondary receipt point following the same primary path. Likewise, as shown in Figure 2 previously, Northern cut the transaction when SPS requested a secondary delivery point on the same primary firm service path.

Q. Did you submit other transportation requests at the same time?

A. Yes, SPS did submit another transportation request along with the request to move from "A" to "B." Please refer to Figure 4 below. SPS submitted a request to move from "M" to a pooling account. At the same time, SPS submitted a request to use an interruptible transportation agreement to move from the pooling account to "A." These transactions were scheduled by Northern and not cut. I believe the interruptible transaction (lowest scheduling priority) succeeded because the Brownfield constraint is downstream of "A," so no cuts were required on the path from "M" to "A." By this circuitous route, SPS was able to obtain the original desired scheduling request shown in Figure 3, where SPS attempted to schedule from "M" (EP Waha) to "B" (SPS Lubbock). Of course, in the Figure 3 case, the transaction was cut even though SPS used firm capacity. In the Figure 4 case, SPS was able to complete the transaction using interruptible capacity.

Figure 4
(May 10)



Q. Why doesn't SPS use this interruptible option every day?

A. The applicable maximum tariff rate is 18 cents per dekatherm (Dth) every day for the firm reservation capacity serving these points. On May 10, 2019 SPS paid an additional 8 cents per Dth for the interruptible capacity, which increased SPS's customers' transportation costs by over one-third. Depending on natural gas prices in the area, using interruptible capacity to accomplish this transaction would be uneconomic on most days. But, more importantly, why should SPS be required to pay twice for firm capacity that the Commission policy states that SPS already has the right to use?

Q. What do you conclude from this outcome?

A. I draw two conclusions from Figures 3 and 4. First, SPS's secondary receipt point request on May 10 was not cut because of a lack of firm capacity held by SPS between "M" and "B," because the interruptible transaction on Figure 4 was scheduled. The cut was due to the Brownfield compressor station constraint located on SPS's primary contract path in contradiction of the Commission's Order 637-A requirements. Second, Northern's point-based scheduling practices resulted in SPS paying twice for service to which SPS holds firm contract rights, and resulted in a significant increase of the applicable costs. Further, this outcome illustrates a primary contrast between the Commission's within-the-path scheduling model and Northern's point-based practices. Northern's point-based scheduling practices only result in SPS's requested transactions succeeding during times when there is capacity constraint if the requested transaction involves a primary receipt point and a primary delivery point. When SPS requests the use of a secondary point, Northern assigns a lower priority to the transaction and the service request is ultimately cut despite the fact that SPS holds primary firm path rights through the constraint. If

Northern followed the within-the-path model, the SPS transaction described in my real-life examples would have been scheduled through the Brownfield constraint in both circumstances; when the requested transactions used primary points and when it used a secondary point. This is the outcome that I believe the Commission intended when it adopted within-the-path scheduling and is how other pipelines implemented within-the-path scheduling.

Q. Based on your experience, how do you think Northern would respond to your examples?

A. Based on my previous conversations with Northern, they have responded that they have followed their scheduling procedures and made the appropriate scheduling cuts. However, I am not claiming here that Northern is not following its scheduling procedures. My point in this testimony is that Northern's point-based scheduling rules are contrary to Commission policy, and cause real harm to Northern's shippers.

Q. What has Northern said to you when asked about these types of scheduling issues?

A. In our previous conversations and meetings, Northern has stated that SPS is getting cut because SPS is using secondary points. If we want to ensure that we are not cut, then we should use primary points only. Northern's practice of discouraging the use of secondary points by its shippers is, in my understanding, contrary to the Commission's goals of flexible receipt and delivery points as established in Order 636, and the within-the-path scheduling requirement adopted in Order 637-A. Another suggestion we often hear from Northern is that we should purchase natural gas from supply points that do not involve pipeline constraints. For example, Northern has suggested buying natural gas from the Demarc supply point and moving it down to our service points. However, this particular alternative would involve natural gas supply that is much more expensive. In this case, the Demarc price over 2019 has averaged $1.94 Dth/Day higher than the Waha supply point, which is quite significant (*see* Attachment 1 for a demonstration of the average spot price). Hypothetically, if we purchased 20,000 Dth/day at Demarc rather than Waha over a year at that price difference, our customers would experience an incremental cost increase of $14 million. Once again, such a suggestion is contrary to the Commission's goals of promoting flexibility to support an efficient, competitive marketplace.

Q. Has Northern offered to sell you additional capacity?

A. Northern claims (and all evidence supports its contention) that the Field Area is fully subscribed[9] and Northern's neighbors in the region believe this will likely be so for some time to come.[10] Accordingly, traditional firm capacity is not available. However, Northern has suggested that SPS purchase a rather unusual contract offering that appears to be unique to the Northern system. Northern refers to these contracts as contiguous paths. In the examples presented here, the Brownfield compressor station is the constraint point (*see* Attachment 2, Northern Natural Texas Map). To achieve a higher scheduling priority through Brownfield, we would purchase two contiguous path contracts, the first contract starting at our original receipt point and ending at the Brownfield station and the second contract starting at the Brownfield station and ending at our original delivery

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[9] *See*, *e.g.*, Miller Testimony at p. 27, lines 16-17 ("capacity constrained Permian region"), p. 30, lines 6-10 ("During roughly the last 18 months, the intra-field delivery segment has been unusually active in the Permian region with **the dramatic increase of Permian production**") (emphasis added).

[10] *See* Kinder Morgan 2019 Customer Meeting West Region Gas Pipelines presentation at https://pipeline2.kindermorgan.com/Documents/EPNG/WRGP_Customer_Meeting_April_29_2019-20190429162248.pdf, pages 14-15.

point. By placing these two contracts back-to-back, we would overcome Northern's scheduling practices and successfully schedule through the Brownfield constraint. In other words, even though SPS already holds firm capacity through Brownfield, we would need to purchase two contiguous contracts (effectively paying Northern's tariff rate twice) to be scheduled through Brownfield. In practice, I do not believe shippers actually pay the tariff rate twice. Rather, I believe Northern multiplies the requested quantity by the number of "paths," places the multiple receipt and delivery points on a single contract, and charges the rate once instead of multiple times. In this way, they achieve the same economic value as charging multiple rates. In Figure 4 above, I discussed back-to-back transactions using interruptible transportation and SPS's firm transportation agreement, but this was a single day event and provided an economic option that day for delivering natural gas to our power plants. When Northern presented an option using back-to-back firm contracts, we declined to purchase such capacity, because we believe it would be inappropriate and raises questions about compliance with the Commission's policies.

Q. Is Northern's contiguous path contract option limited to Brownfield locations?

A. No, Northern commonly pursues such multiple sales of capacity. *See* the attached Open Season Posting from Northern's website dated March 15, 2019 (Attachment 3). In this posting, Northern states at the bottom of page 3 that "a customer may choose to increase the value of its bid by adding a contiguous path(s)." "For purposes of contiguous path bids, customers may use the following pooling points in their bids: Brownfield…, Permian Pooling…, Beaver Pooling…, or Mullinville." In other words, a shipper may improve the net present value of its bid by agreeing to pay Northern separately for service to Brownfield and to Permian and to Beaver and to Mullinville (up to 4 times) when one contract for the entire path would be the norm. While it may seem strange to agree to pay multiple times for a single service, a number of shippers have agreed to contiguous deals. Attachment 4 lists nine shippers that (as of July 1, 2019) hold contiguous "paths" into and out of Brownfield. As noted above, I believe the contract quantity is doubled rather than doubling the contract rate (this may be seen by comparing the receipt/delivery quantity to the contract quantity "MDQ"). These contiguous contracts are supported by Northern's scheduling practices; if Northern fully implemented the Commission's within-the-path scheduling requirements, there would be no need to create such contracts.

Q. Does NSP experience similar scheduling issues in Northern's market area?

A. The examples I selected involved receipt and delivery points in Texas in Northern's Field Area. I include a Field Area Map as Attachment 2 to illustrate where this portion of Northern's system is located in west Texas. However Northern's Market Area in the upper Midwest commonly faces similar issues due to Northern using a point-based scheduling system rather than within-the-path scheduling. These issues are most prominent in the Market Area during winter peak delivery months. In order to provide recent, timely examples, for purposes of this testimony, I concentrated on Northern's Feld Area, where scheduling issues tend to be year-round.

Q. Is Northern's pipeline system too complicated to perform within-the-path scheduling?

A. Not in my opinion. Northern does have portions of its Market Area in the upper Midwest where natural gas can physically be delivered by flowing from two opposite directions. However, this is not an insurmountable issue. Other complicated pipeline systems used by the XES operating companies have found ways to provide within-in-path scheduling on their systems. For example, the Viking Gas Transmission (Viking) system has the capability of physically flowing in both directions on the majority of its system. However, Viking offers within-the-path scheduling both ways on its system. Colorado Interstate Gas's (CIG) system includes reticulated portions containing looped pipeline segments and reversible flows. Yet, CIG offers within-the-path scheduling. Great Lakes Gas Transmission's (Great Lakes) system also contains reversible flows across its system from end-to-end. Nevertheless, Great Lakes provides within-the-path scheduling on its system.

Q. Are these problems just due to Northern's system being fully subscribed?

A. No, the problem is not that Northern is fully subscribed. The CIG system referenced above has portions of its system that are fully subscribed, and yet they offer within-the-path scheduling. The problem is that Northern has elected to prioritize and schedule or cut transactions based on the receipt and delivery points requested by the shipper rather than consideration of the shipper's contract path. This practice denies shippers the flexibility to use secondary points to seek lower cost natural gas supply and to respond to unexpected changes in supply and load due to changes in weather and plant operations. Whether a pipeline system is fully subscribed or not, pipelines should properly allocate capacity to the shippers holding firm capacity on the pipeline system. In fact, a fully-subscribed system escalates the need for within-the-path scheduling to ensure shippers who have subscribed for firm capacity are afforded the flexibility granted them by FERC policy.

Q. Will the adoption of a system-wide reservation rate design provide greater scheduling flexibility?

A. I do not believe so. In his Prepared Direct Testimony, Mr. Miller claims on page 123 that shippers will have access to the entire Northern system on an alternate basis once system-wide reservation rate zone is implemented. However, based on my experience with

Northern's system, that is unlikely if Northern continues its current point-based scheduling practices and does not implement within-the-path scheduling. Northern's current scheduling procedures will cause secondary capacity to be cut at many potential locations on Northern's system if a Field to Market scheduling transaction is requested. Further, Northern's system is essentially fully subscribed in the Field and Market Area, and especially in the Permian Area according to Mr. Miller,[11] and it is unlikely that capacity could be aligned to give a shipper an end-to-end contract in any event due to lack of capacity. In Mr. Miller's testimony, he discusses how the gas-fired electric generation market in the Field Area, which SPS is part of, has seen tremendous growth in recent years.[12] Further, Mr. Miller acknowledges on page 115 of his testimony that "[c]apacity is not expected to be available for delivery point realignment downstream of Demarc." Despite Northern's assertions that a postage stamp rate design will provide added shipper flexibility, the fully subscribed system and Northern's point-based scheduling practices will prevent any such benefit to shippers now.

Q. Does that conclude your prepared answering testimony?

A. Yes.

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[11] Miller Testimony at p. 27, lines 16-17 ("capacity constrained Permian region"), p. 28, lines 8-9 ("due to the large increase in production primarily in the Permian region"), p. 30, lines 6-10 (discussing efforts to deliver out of the capacity constrained Permian region).

[12] Miller Testimony at p. 31, lines 4-8:

> Deliveries for electric generation have remained strong in the Field Area. Northern has not seen a decline in the electric generation market in Northern's Field Area. For comparison purposes, Northern's delivery to electric generators in the Field Area were approximately 20 percent of the volumes delivered to Demarc in 2018. In total, the electric generation market was 38 percent of total Field Area deliveries in 2018.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Natural Gas Company) **Docket No. RP19-1353-000**

Affidavit of Michael Boughner

Michael Boughner, being first duly sworn according to law, on oath deposes and says that he is the witness who prepared the answering testimony in the above-captioned proceeding that accompanies this affidavit; that the statements contained therein are true and correct to the best of his knowledge and belief; and that he is authorized to make the same representation to the Federal Energy Regulatory Commission.

Michael Boughner

Subscribed and sworn to before me this 12 day of July, 2019.

Cassandra Kutches
Notary Public

CASSANDRA KUTCHES
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20164039269
MY COMMISSION EXPIRES OCTOBER 13, 2020

ATTACHMENT 1

DEMARC TO WAHA PRICE COMPARISON

	NNG Demarc	WAHA	Diffference
1/1/2019	$ 3.085	$ 2.165	$ 0.920
1/2/2019	$ 3.085	$ 2.165	$ 0.920
1/3/2019	$ 2.580	$ 2.430	$ 0.150
1/4/2019	$ 2.390	$ 2.385	$ 0.005
1/5/2019	$ 2.430	$ 1.725	$ 0.705
1/6/2019	$ 2.430	$ 1.725	$ 0.705
1/7/2019	$ 2.430	$ 1.725	$ 0.705
1/8/2019	$ 2.440	$ 2.060	$ 0.380
1/9/2019	$ 2.680	$ 2.150	$ 0.530
1/10/2019	$ 2.635	$ 2.055	$ 0.580
1/11/2019	$ 2.635	$ 1.990	$ 0.645
1/12/2019	$ 2.630	$ 1.815	$ 0.815
1/13/2019	$ 2.630	$ 1.815	$ 0.815
1/14/2019	$ 2.630	$ 1.815	$ 0.815
1/15/2019	$ 3.195	$ 2.215	$ 0.980
1/16/2019	$ 3.385	$ 2.310	$ 1.075
1/17/2019	$ 3.465	$ 2.285	$ 1.180
1/18/2019	$ 3.350	$ 1.670	$ 1.680
1/19/2019	$ 3.275	$ 1.450	$ 1.825
1/20/2019	$ 3.275	$ 1.450	$ 1.825
1/21/2019	$ 3.275	$ 1.450	$ 1.825
1/22/2019	$ 3.275	$ 1.450	$ 1.825
1/23/2019	$ 2.970	$ 1.970	$ 1.000
1/24/2019	$ 3.155	$ 2.140	$ 1.015
1/25/2019	$ 3.170	$ 2.675	$ 0.495
1/26/2019	$ 3.160	$ 2.300	$ 0.860
1/27/2019	$ 3.160	$ 2.300	$ 0.860
1/28/2019	$ 3.160	$ 2.300	$ 0.860
1/29/2019	$ 3.790	$ 2.550	$ 1.240
1/30/2019	$ 3.780	$ 2.325	$ 1.455
1/31/2019	$ 4.225	$ 2.365	$ 1.860
2/1/2019	$ 2.655	$ 2.080	$ 0.575
2/2/2019	$ 2.460	$ 1.480	$ 0.980
2/3/2019	$ 2.460	$ 1.480	$ 0.980
2/4/2019	$ 2.460	$ 1.480	$ 0.980
2/5/2019	$ 2.600	$ 0.070	$ 2.530
2/6/2019	$ 2.610	$ 0.165	$ 2.445
2/7/2019	$ 2.755	$ 0.485	$ 2.270
2/8/2019	$ 3.430	$ 1.065	$ 2.365
2/9/2019	$ 2.700	$ 1.125	$ 1.575
2/10/2019	$ 2.700	$ 1.125	$ 1.575
2/11/2019	$ 2.700	$ 1.125	$ 1.575
2/12/2019	$ 2.725	$ 1.320	$ 1.405
2/13/2019	$ 2.595	$ 2.015	$ 0.580
2/14/2019	$ 2.645	$ 1.935	$ 0.710
2/15/2019	$ 2.675	$ 2.030	$ 0.645

	NNG Demarc	WAHA	Diffference
2/16/2019	$ 2.680	$ 1.900	$ 0.780
2/17/2019	$ 2.680	$ 1.900	$ 0.780
2/18/2019	$ 2.680	$ 1.900	$ 0.780
2/19/2019	$ 2.680	$ 1.900	$ 0.780
2/20/2019	$ 2.735	$ 2.065	$ 0.670
2/21/2019	$ 2.660	$ 1.740	$ 0.920
2/22/2019	$ 2.705	$ 1.620	$ 1.085
2/23/2019	$ 2.790	$ 1.240	$ 1.550
2/24/2019	$ 2.790	$ 1.240	$ 1.550
2/25/2019	$ 2.790	$ 1.240	$ 1.550
2/26/2019	$ 3.165	$ 1.165	$ 2.000
2/27/2019	$ 3.325	$ 1.130	$ 2.195
2/28/2019	$ 3.195	$ 0.975	$ 2.220
3/1/2019	$ 3.145	$ 1.035	$ 2.110
3/2/2019	$ 8.475	$ 2.055	$ 6.420
3/3/2019	$ 8.475	$ 2.055	$ 6.420
3/4/2019	$ 8.475	$ 2.055	$ 6.420
3/5/2019	$ 4.475	$ 3.100	$ 1.375
3/6/2019	$ 3.080	$ 1.665	$ 1.415
3/7/2019	$ 2.965	$ 1.130	$ 1.835
3/8/2019	$ 2.750	$ 1.165	$ 1.585
3/9/2019	$ 2.755	$ 0.730	$ 2.025
3/10/2019	$ 2.755	$ 0.730	$ 2.025
3/11/2019	$ 2.755	$ 0.730	$ 2.025
3/12/2019	$ 2.475	$ 0.915	$ 1.560
3/13/2019	$ 2.535	$ 1.260	$ 1.275
3/14/2019	$ 2.600	$ 1.670	$ 0.930
3/15/2019	$ 2.705	$ 2.360	$ 0.345
3/16/2019	$ 2.630	$ 1.485	$ 1.145
3/17/2019	$ 2.630	$ 1.485	$ 1.145
3/18/2019	$ 2.630	$ 1.485	$ 1.145
3/19/2019	$ 2.635	$ 0.275	$ 2.360
3/20/2019	$ 2.640	$ 0.140	$ 2.500
3/21/2019	$ 2.585	$ 0.210	$ 2.375
3/22/2019	$ 2.570	$ (0.030)	$ 2.600
3/23/2019	$ 2.455	$ 0.255	$ 2.200
3/24/2019	$ 2.455	$ 0.255	$ 2.200
3/25/2019	$ 2.455	$ 0.255	$ 2.200
3/26/2019	$ 2.490	$ (0.620)	$ 3.110
3/27/2019	$ 2.350	$ (0.025)	$ 2.375
3/28/2019	$ 2.300	$ (0.790)	$ 3.090
3/29/2019	$ 2.390	$ (1.950)	$ 4.340
3/30/2019	$ 2.390	$ (1.950)	$ 4.340
3/31/2019	$ 2.390	$ (1.950)	$ 4.340
4/1/2019	$ 2.565	$ (0.550)	$ 3.115
4/2/2019	$ 2.605	$ (0.140)	$ 2.745

	NNG Demarc	WAHA	Diffference
4/3/2019	$ 2.545	$ (3.755)	$ 6.300
4/4/2019	$ 2.520	$ (5.790)	$ 8.310
4/5/2019	$ 2.455	$ (0.545)	$ 3.000
4/6/2019	$ 2.310	$ (0.755)	$ 3.065
4/7/2019	$ 2.310	$ (0.755)	$ 3.065
4/8/2019	$ 2.310	$ (0.755)	$ 3.065
4/9/2019	$ 2.530	$ 0.340	$ 2.190
4/10/2019	$ 2.575	$ (0.245)	$ 2.820
4/11/2019	$ 2.590	$ 0.250	$ 2.340
4/12/2019	$ 2.545	$ 0.425	$ 2.120
4/13/2019	$ 2.475	$ 0.355	$ 2.120
4/14/2019	$ 2.475	$ 0.355	$ 2.120
4/15/2019	$ 2.475	$ 0.355	$ 2.120
4/16/2019	$ 2.310	$ 0.025	$ 2.285
4/17/2019	$ 2.385	$ 0.375	$ 2.010
4/18/2019	$ 2.320	$ 0.470	$ 1.850
4/19/2019	$ 2.095	$ 0.230	$ 1.865
4/20/2019	$ 2.095	$ 0.230	$ 1.865
4/21/2019	$ 2.095	$ 0.230	$ 1.865
4/22/2019	$ 2.095	$ 0.230	$ 1.865
4/23/2019	$ 2.100	$ 0.320	$ 1.780
4/24/2019	$ 2.095	$ 0.475	$ 1.620
4/25/2019	$ 2.135	$ 0.855	$ 1.280
4/26/2019	$ 2.125	$ 0.775	$ 1.350
4/27/2019	$ 2.240	$ 0.320	$ 1.920
4/28/2019	$ 2.240	$ 0.320	$ 1.920
4/29/2019	$ 2.240	$ 0.320	$ 1.920
4/30/2019	$ 2.345	$ 0.060	$ 2.285
5/1/2019	$ 2.360	$ 0.155	$ 2.205
5/2/2019	$ 2.425	$ 0.315	$ 2.110
5/3/2019	$ 2.340	$ 0.410	$ 1.930
5/4/2019	$ 2.180	$ 0.215	$ 1.965
5/5/2019	$ 2.180	$ 0.215	$ 1.965
5/6/2019	$ 2.180	$ 0.215	$ 1.965
5/7/2019	$ 2.285	$ 0.110	$ 2.175
5/8/2019	$ 2.315	$ 0.130	$ 2.185
5/9/2019	$ 2.310	$ 0.250	$ 2.060
5/10/2019	$ 2.250	$ 0.315	$ 1.935
5/11/2019	$ 2.255	$ 0.280	$ 1.975
5/12/2019	$ 2.255	$ 0.280	$ 1.975
5/13/2019	$ 2.255	$ 0.280	$ 1.975
5/14/2019	$ 2.300	$ 0.460	$ 1.840
5/15/2019	$ 2.265	$ 0.765	$ 1.500
5/16/2019	$ 2.135	$ 0.860	$ 1.275
5/17/2019	$ 2.205	$ 0.220	$ 1.985
5/18/2019	$ 2.275	$ (0.110)	$ 2.385
5/19/2019	$ 2.275	$ (0.110)	$ 2.385
5/20/2019	$ 2.275	$ (0.110)	$ 2.385

*Source *Platts Gas Daily Report*

	NNG Demarc	WAHA	Diffference
5/21/2019	$ 2.385	$ (0.330)	$ 2.715
5/22/2019	$ 2.235	$ (0.570)	$ 2.805
5/23/2019	$ 2.090	$ 0.010	$ 2.080
5/24/2019	$ 2.105	$ 0.110	$ 1.995
5/25/2019	$ 2.155	$ (2.315)	$ 4.470
5/26/2019	$ 2.155	$ (2.315)	$ 4.470
5/27/2019	$ 2.155	$ (2.315)	$ 4.470
5/28/2019	$ 2.155	$ (2.315)	$ 4.470
5/29/2019	$ 2.210	$ (1.670)	$ 3.880
5/30/2019	$ 2.345	$ (0.790)	$ 3.135
5/31/2019	$ 2.255	$ 0.015	$ 2.240
6/1/2019	$ 2.035	$ (0.435)	$ 2.470
6/2/2019	$ 2.035	$ (0.435)	$ 2.470
6/3/2019	$ 2.035	$ (0.435)	$ 2.470
6/4/2019	$ 2.060	$ (0.110)	$ 2.170
6/5/2019	$ 2.045	$ 0.335	$ 1.710
6/6/2019	$ 2.110	$ 0.860	$ 1.250
6/7/2019	$ 2.080	$ 0.970	$ 1.110
6/8/2019	$ 1.930	$ 1.005	$ 0.925
6/9/2019	$ 1.930	$ 1.005	$ 0.925
6/10/2019	$ 1.930	$ 1.005	$ 0.925
6/11/2019	$ 2.005	$ 1.275	$ 0.730
6/12/2019	$ 2.080	$ 0.725	$ 1.355
6/13/2019	$ 2.065	$ 0.450	$ 1.615
6/14/2019	$ 1.730	$ (0.035)	$ 1.765
6/15/2019	$ 1.610	$ (0.240)	$ 1.850
6/16/2019	$ 1.610	$ (0.240)	$ 1.850
6/17/2019	$ 1.610	$ (0.240)	$ 1.850
6/18/2019	$ 2.115	$ (0.025)	$ 2.140
6/19/2019	$ 2.080	$ (0.050)	$ 2.130
6/20/2019	$ 2.100	$ 0.190	$ 1.910
6/21/2019	$ 1.920	$ 0.325	$ 1.595
6/22/2019	$ 1.530	$ 0.025	$ 1.505
6/23/2019	$ 1.530	$ 0.025	$ 1.505
6/24/2019	$ 1.530	$ 0.025	$ 1.505
6/25/2019	$ 1.900	$ 0.300	$ 1.600
6/26/2019	$ 1.970	$ 0.495	$ 1.475
6/27/2019	$ 1.980	$ 0.225	$ 1.755
6/28/2019	$ 1.995	$ -	$ 1.995
6/29/2019	$ 1.995	$ -	$ 1.995
6/30/2019	$ 1.995	$ -	$ 1.995
7/1/2019	$ 2.020	$ (0.150)	$ 2.170
7/2/2019	$ 1.995	$ 0.005	$ 1.990
7/3/2019	$ 2.000	$ (0.025)	$ 2.025
	Average Differential:		**$ 1.94**

ATTACHMENT 2

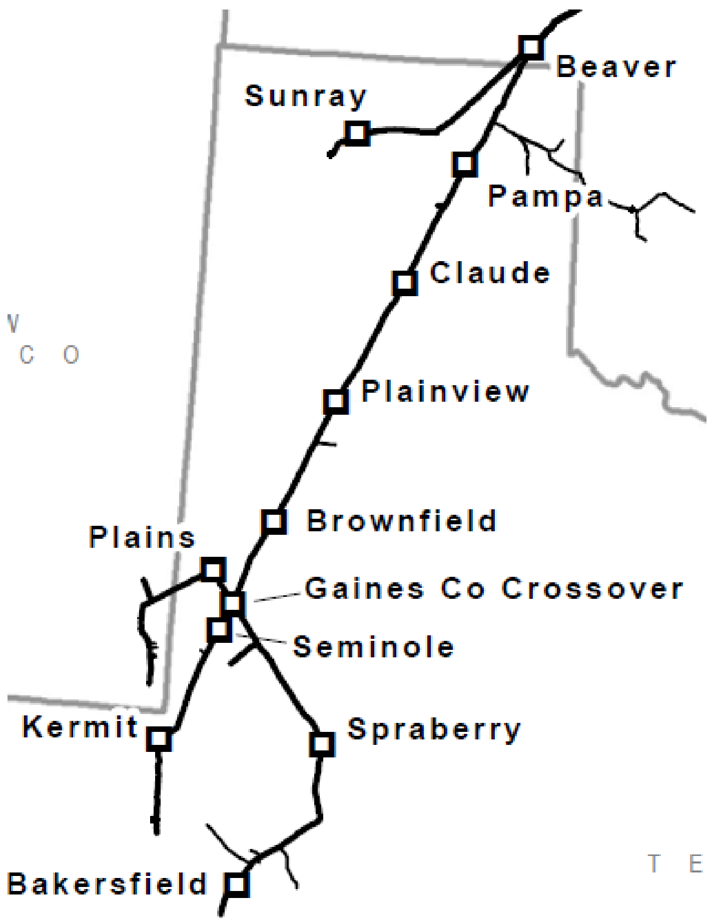
MAP OF NORTHERN NATURAL GAS TEXAS SYSTEM

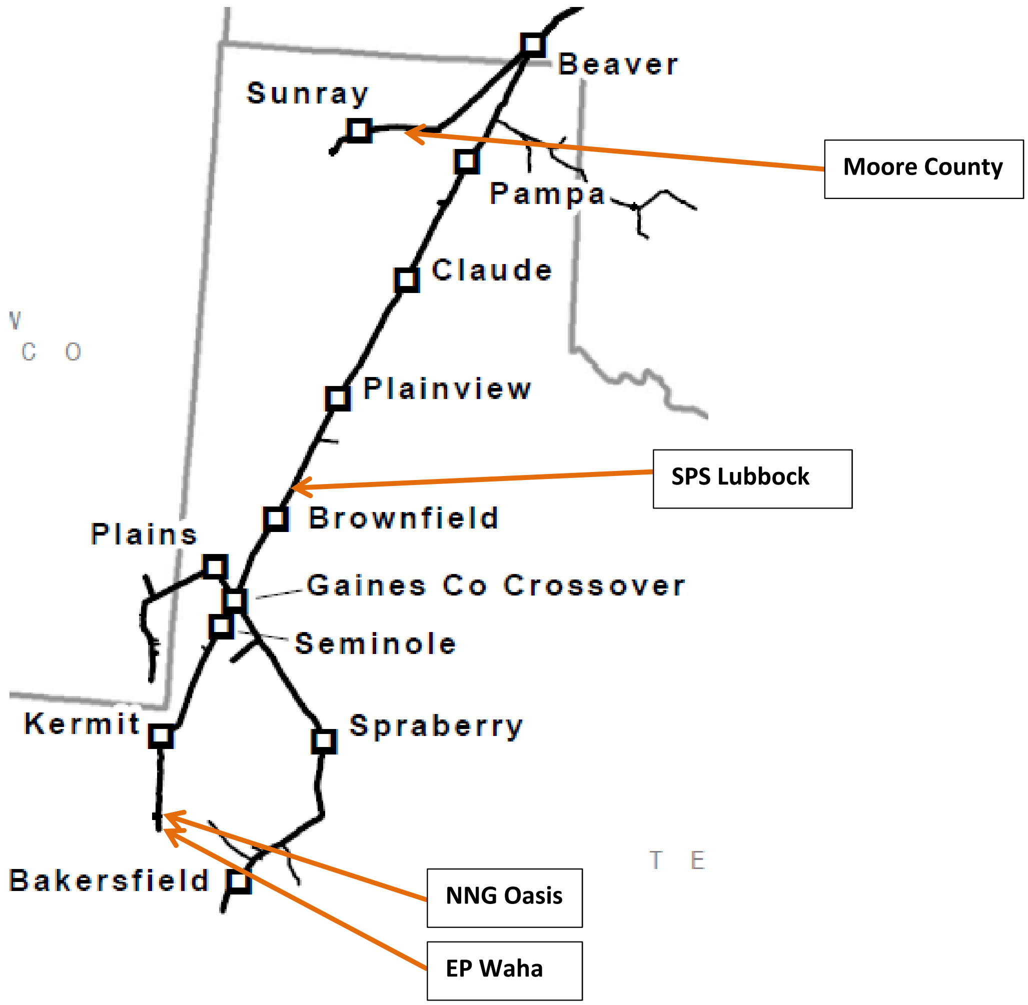
Docket No. RP19-1353

Prepared Answering Testimony of Michael Boughner

Attachment 2

Map of Northern Natural Gas Texas System




Beaver
Sunray
Moore County
Pampa
Claude
Plainview
SPS Lubbock
Brownfield
Plains
Gaines Co Crossover
Seminole
Kermit
Spraberry
Bakersfield
NNG Oasis
EP Waha

ATTACHMENT 3

OPEN SEASON POSTING

Northern Natural Gas
A BERKSHIRE HATHAWAY ENERGY COMPANY

TSP Name: Northern Natural Gas Company	**Post Date/Time:** 03/15/2019 08:52 AM
TSP: 784158214	**Notice Effective Date/Time:** 03/15/2019 08:52 AM
Notice ID: **045501**	**Notice End Date/Time:** 03/19/2019 02:00 PM
Notice Type: TSP Capacity Offering	**For Gas Day(s):** 03/14/2019 - 03/19/2019
Subject: FIELD TO DEMARC SUMMER 2019 AND FIELD AREA DELIVERIES OPEN SEASON (UPDATED 3/15/19)	**Notice Status:** Supersede
	Prior Notice: 045474
Critical: N	**Required Response Indicator Description:** 5-No response required

Notice Text:

REVISED 3/15/19:

On December 21, 2018, Northern Natural Gas Company (Northern) posted an open season for Field to Demarc capacity for service commencing on April 1, 2019. This update provides the awarding parameters that will be used to evaluate bids as well as the available capacity Northern is willing to sell as a result of maintenance outages during the 2019 summer. As Northern determines specific outage dates, additional capacity may be available in a future open season or in the daily market.

Northern is hereby soliciting binding bids for firm throughput service commencing on the first day of April, May, or June 2019, from any Field Area receipt point to NNG Field/Mkt Demarcation-16B (POI 37654) (Demarc) or any other delivery point in the Field Area. Northern will also accept bids for service with a start date of November 1, 2019 for any delivery point located in MIDs 1 through 7. Specific delivery points of note in the Field Area include, but are not limited to: El Paso/NNG Plains 26 Del (POI 2618), Atmos Spraberry (POI 2174), Enterprise Spraberry (POI 229), and Oneok Westex Seagraves (POI 1504). Capacity for delivery to Demarc is limited to 100,000 Dth/day from April 1 through May 31, 2019 and 50,000 Dth/day beginning June 1, 2019.

Interested customers may request firm throughput service by submitting a signed binding bid form. Customers requesting service are responsible for ensuring arrangements have been made for any capacity necessary on any upstream or downstream pipeline for their volumes to be confirmed during the nomination and scheduling process. Parties requesting service to downstream pipelines with gas quality standards different from Northern’s tariff, may be subject to curtailment by the downstream pipelines. Northern will cooperate with parties to attempt to resolve any gas quality issues.

Open Season Timing

The open season commenced on December 21, 2018 and ends at 2:00 p.m. CCT on March 19, 2019. To be considered in the open season, a binding Bid Form must be signed by customer and received by Northern by the close of the open season, 2:00 p.m. CCT on March 19, 2019. If you have any questions, please contact your Account Manager or Steve Thomas (402) 398-7468.

Open Season Procedures

1) Submit your binding Bid Form to Northern either via facsimile to **(402) 398-7413** or e-mail to NNGOpenSea@nngco.com. The Bid Form must include the requested rate, receipt point(s), delivery point(s), volume, in-service date and term. Please state in your bid the minimum amount of capacity you are willing to accept.

   Term:
   The bid quantity must be uniform daily MDQ for any month included in the term and only consecutive months will be allowed. Due to the varying levels of available capacity by month and

by receipt location, customers should state on the bid form if a partial term or alternate receipt location is acceptable.

Receipt Points:
All receipt points within the Field Area will be considered. Depending on the delivery point(s) selected in the open season, availability of a particular receipt point may be limited. Northern anticipates sufficient group capacity is available through the Beaver compressor station such that all capacity awarded for delivery to Demarc may be served from receipt points located in the Beaver C & Beaver System South Group (#177 Receipt Points), however the specific receipt point requested may be limited due to other group capacity availability. Further, under certain operational assumptions, Northern may have limited capacity available to serve receipt points located in the Roger Mills Hemphill Allocation Group (#14 Receipt Points); however, certain other group capacities may be reduced and such requests may not be awarded. Northern has determined that for April 2019 only, there is 23,350 Dth/day of capacity available for receipts located within Brownfield South Allocation Group (#998 Receipt Points), which would include up to 10,000 Dth/day from receipt points located within the Mitchell to Gaines Allocation Group (#825 Receipt Points). Interested customers may submit bids that include receipt points located in these groups. Northern reserves the right to allocate receipt point capacity among the requests in order to optimize the amount of service that can be provided.

Delivery Points:
Delivery points located within the Field Area, which includes Demarc, with associated primary receipt points located in the Field Area will be considered. Northern will also accept bids for up to 48,154 Dth/day of available delivery capacity at the El Paso/NNG Plains 26 Del (POI 2618) with a start date of June 1, 2019.

Rates:

Customers can bid the maximum tariff rate, a rate for transportation service between the maximum and minimum tariff rate (Discounted Rate), or a rate above the maximum tariff rate (Negotiated Rate). For bid evaluation purposes, Negotiated Rates that are higher than the maximum rate will be evaluated as a maximum tariff rate bid; provided, however, a customer may choose to increase the value of its bid by adding a contiguous path(s) as detailed below.

Northern will be filing a Section 4 rate case in mid-2019. This filing will reflect a significant increase to the maximum rates due to the non-revenue generating capital requirement to modernize the pipeline system. Increased rates are projected to become effective January 1, 2020.

Discounted or Negotiated Rates may be two-part fixed-rates (with a maximum commodity rate), one-part fixed-rates, or index-based formula rates as outlined below.

Index-based formula rates:
Index-based formula rates with primary delivery to Demarc will be accepted using the formula template below where customer provides three variables: index location(s) to be used in variable (Y) (within the stipulations for the location of the receipt point bid as provided below), and provides a bid for the fixed rate variables (A) and (C) below:

The daily charge for the Contract MDQ shall be the MDQ multiplied by the arithmetic value obtained from the formula [(X minus ((Y plus A) divided by B)) times C] where (X) = the Midpoint price from "Gas Daily" Northern, demarc; (Y) = the Midpoint price from "Gas Daily" index location; (A) = premium or discount to applicable index; (B) = 1.0 less the applicable fuel percentage for deliveries to Demarc from the fuel Section of the primary receipt point; and (C) = percentage of formula to Northern. However, in no event will [X minus ((Y plus A) divided by B) times C] be less than zero for any individual component of the index location(s) used in Y. The monthly charge will be the sum of all daily charges from the formula above.

Customers may submit alternative formula rate bids; however, Northern reserves the right to reject any index-based bid that deviates from the above template.

Northern reserves the right to award only a portion of the available capacity using index-based formula rates. Customers providing a fixed-rate bid may provide an alternative rate structure for all or a portion of the term bid for Northern to consider in lieu of the fixed rate.

Northern will evaluate formula-based rate bids that use *Platts Gas Daily* Indices by using the *Platts Gas Daily* index price assumptions in the table below and 0.0344 for the applicable fuel percentage for primary Permian receipts (Sections 1 and 2 Fuel) and 0.0258 for the applicable fuel percentage for primary Mid-continent receipts (Section 2 Fuel).

	X	Y	Y	Y	Y	Y	Y
	Northern, demarc	El Paso, Permian	El Paso, West Texas	Waha	Panhandle, Tx.-Okla.	Southern Star	NGPL, Midcontinent
April 2019	$2.56	$0.82	$0.58	$0.60	$2.34	$2.39	$2.26
May 2019	$2.39	$0.98	$0.74	$0.76	$2.23	$2.28	$2.17
June 2019	$2.44	$1.21	$0.99	$1.01	$2.29	$2.34	$2.19
July 2019	$2.60	$1.69	$1.43	$1.45	$2.44	$2.49	$2.35
August 2019	$2.60	$1.75	$1.46	$1.48	$2.47	$2.52	$2.38
September 2019	$2.51	$1.45	$1.13	$1.15	$2.44	$2.49	$2.36
October 2019	$2.53	$1.82	$1.57	$1.59	$2.36	$2.41	$2.26

***Updated 3/15/19**

Contiguous Paths:

A customer may choose to increase the value of its bid by adding a contiguous path(s). The sum of the value of the contiguous paths will be used to calculate the NPV of the bid.

A contiguous path is two or more contract paths where the receipt point of one path is the same location as the delivery point of another path. For purposes of contiguous path bids, customers may use the following pooling points in their bids: Brownfield Pooling Point (POI #79387 in MID 6), Permian Pooling Point (POI #54009 in MID 4), Beaver Pooling Point (POI #54576 in MID 11) or

Mullinville Pooling Point (POI #54575 in MID 13).

For example, for a contiguous path bid to Demarc with receipt points located south of the Brownfield compressor station to be considered, the bid would contain a path that begins with a physical receipt point located in MIDs 1 through 6 and could contain a delivery point of the Brownfield Pooling Point (POI #79387), and the associated contiguous path must be the receipt point of the Brownfield Pooling Point (POI #79387) and the ultimate delivery point of Demarc. A customer's bid may include more than one contiguous path. Northern reserves the right to reject all or portions of a contiguous path bid that requires displacement of capacity on the contract in order to accommodate the combination of receipt and delivery points in the bid.

Discounted or Negotiated Rate bids that contain a contiguous path will be subject to the additional charges, as detailed below, when alternate points are used, which will impact the rate paid by customer resulting in the entire bid being a Negotiated Rate. Northern may allocate the value of Discounted Rate bids among the contiguous paths such that no path will be above the maximum rates for bid evaluation purposes, but will be subject to additional rates if alternate receipt or delivery points are used.

For fixed rate bids, Northern will accept bids with a $0.00 commodity rate for primary delivery quantities to the Brownfield, Permian, Beaver or Mullinville Pooling Points. Alternate delivery quantities to any primary delivery point (e.g., Demarc) in excess of the delivery point MDQ will be subject to additional charges, as described later in this notice.

For index-based formula rate bids, Northern will accept bids with a zero rate for the portion of the bid with primary delivery quantities to the Brownfield, Permian, Beaver, or Mullinville Pooling Points and an index-based formula rate on that portion of the bid with primary delivery point located at Demarc. Alternate delivery quantities to any primary delivery point (e.g., Demarc) in excess of the delivery point MDQ will be subject to additional charges, as described later in this notice.

The following is the acceptable formula template for index-based formula rate contiguous bids with primary delivery to Demarc:

The daily charge for the portion of the Contract MDQ located at Demarc shall be that point MDQ multiplied by the arithmetic value obtained from the formula [(X minus ((Y plus A) divided by B)) times C] where (X) = the Midpoint price from "Gas Daily" Northern, demarc; (Y) = the Midpoint price from "Gas Daily" index location; (A) = premium or discount to applicable index; (B) = 1.0 less the applicable fuel percentage for deliveries to Demarc from the fuel section of the primary receipt point(s); and (C) = percentage of formula to Northern. However, in no event will [X minus ((Y plus A) divided by B) times C] be less than zero for any individual component of the index location(s) used in Y. The total daily charge for the portion of the Contract MDQ located "at the contiguous point" will be $0.00. The monthly charge will be the sum of all daily charges from the formula above.

2) Northern's Bid Evaluation:

The capacity will be awarded to the highest bid(s) based on a determination of the best bid, or combination of bids that result in the highest net present value (NPV) of reservation revenue, on a per unit of capacity basis, using revenues from the start of the service through October 31, 2019. Northern will also include in the NPV the revenues for November 1, 2019 through March 31, 2022 for delivery points located in MIDs 1 through 7. Northern has the right to aggregate bids, or portions of bids, that generate the highest NPV to Northern. **Northern reserves the right to reject any bid, or portion thereof, that contains a Discounted or Negotiated Rate beyond October 31, 2019.** The NPV per unit will be determined by discounting the cash flow (using the FERC interest rate) generated from the transportation reservation rate multiplied by the volume for each month, by bid, and then dividing the NPV by the maximum daily quantity bid. ***Northern will award maximum rate bids prior to awarding any equivalent valued (NPV/unit value) fixed rate bids at the maximum rate (discounted bid).** The assumed reservation component used in the bid evaluation process for fixed one-part rate bids will be the one-part rate less $0.06/Dth/day for receipt points south of the Brownfield compressor station and $0.03/Dth/day for receipt points north of the Plainview compression station, however, the deduction will only be applied once to a one-part contiguous bid. Northern will evaluate formula-based rates bids as described in this notice and no commodity rate deduction will be used for NPV purpose. Northern will adjust annual, or greater, fixed-rate bids to seasonal rates using the same ratio between Northern's Summer (April through October) and Winter (November through March) maximum tariff rates and the same monthly rate for that season. For evaluation purposes, the NPV calculation of contiguous paths will be performed for each individual path and then added together for bid comparison. Any bid with contiguous paths must contain contiguous paths for the entire term of the bid.

3) Northern will consider contingencies in the bids.

4) Northern has the right to accept bids or portions of bids that maximize the resulting contracted volumes.

5) All winning bids, except maximum rate bids, will be subject to the following terms:

a) If any primary points are realigned, the reservation rate for the entire MDQ shall be increased by $0.30/Dth/day for the remaining term of the agreement.

b) Reservation charge credits: Customers waive their right to reservation charge credits under Section 22 of the General Terms and Conditions of Northern's tariff. However, customers' charges shall be reduced, in Northern's sole discretion, for any quantity that is unable to be delivered up to the MDQ. In the event of an outage on Northern's pipeline system that impacts the customer's ability to flow the primary receipt and delivery points in the agreement, Northern and customer will work together on a commercially reasonable basis to realign to a different point. If no such point is available, then customer will not pay more for services than if reservation charge credits would have applied pursuant to Northern's tariff.

6) Awarded bids at Discounted or Negotiated Rates from receipt points located south of the Brownfield compressor station will be subject to the following additional terms:

a) Northern will accept and evaluate formula-based rate bids that use the Platts Gas Daily Spreads between (i) either "El Paso, Permian," "El Paso, West Texas," "Waha" or some defined combination thereof, and (ii) "Northern, demarc," less Northern's published fuel from MIDs 1-7 to Demarc as the variable component. Northern will consider formula-based rate bids that contain other fixed rate components (e.g., percentage factor that applies to the formula spread and a fixed rate addition or subtraction from the published index price).

b) Bidder can use all receipt points located in MIDs 1 through 7 (including the aggregate MID 1-7 pooling point, Brownfield and Permian pooling points) on an alternate basis at the rate bid. In the event of an outage on Northern's pipeline system that impacts the Bidder's ability to schedule any primary receipt and delivery points, Bidder may use either (1) any Field Area receipt point located in MIDs 8 through 16A for delivery to Demarc or (2) any receipt point located in MIDs 1 through 7 for delivery to any Field Area delivery point during the outage at the rate bid.

c) Bidders without contiguous bids shall pay an additional $0.20/Dth/day for delivered quantities received at alternate receipt points located in MIDs 8 through 16A and an additional $0.40/Dth/day for quantities delivered to alternate delivery points located in MIDs 1 through

16A.

d) Bidders awarded contiguous paths shall pay the following:

i) Fixed-price rate Bidders shall pay an additional $0.20/Dth/day for delivered quantities from alternate receipt points located in MIDs 8 through 16A, and an additional $0.40/Dth/day for quantities delivered to alternate delivery points located in MIDs 1 through 16A, and an additional charge equal to the higher of Northern's maximum tariff rate or the "Gas Daily" spread between Midpoints for Demarc and El Paso, West Texas for any non-primary delivered quantities at Demarc or Demarc Deferred Delivery.

ii) Index-based formula rate Bidders with contiguous bids shall pay an additional $0.20/Dth/day for delivered quantities received at alternate receipt points located in MIDs 8 through 16A, and an additional $0.40/Dth/day for quantities delivered to alternate delivery points located in MIDs 1 through 16A, and an additional charge equal to the higher of Northern's maximum tariff rate or the "Gas Daily" spread between Midpoints for Demarc and El Paso, West Texas for any non-primary delivered quantities at Demarc or Demarc Deferred Delivery.

7) Awarded bids at Discounted or Negotiated Rates from receipts points located north of the Plainview compressor station will be subject to the following additional terms:

a) Northern will accept bids and evaluate formula-based rate bids that use the Platts Gas Daily Spread between (i) "El Paso, Permian," "El Paso, West Texas," "Waha," "Panhandle, Tx.-Okla.," "Southern Star," "NGPL, Midcontinent" or some defined combination thereof, and (ii) "Northern, demarc," less Northern's published fuel from MIDs 8 through 16A to Demarc as the variable component. Northern will consider formula-based rate bids that contain other fixed rate components (e.g., percentage factor that applies to the index spread and a fixed rate addition or subtraction from the published index price).

b) Bidder can use all available receipt points located in MIDs 8 through16A (including the aggregate MID 8-12 Pooling Point, MID 13-16A Pooling Point, and the Beaver Pooling Point) on an alternate basis without additional charges. In the event of an outage on Northern's pipeline system that impacts the Bidder's ability to schedule any primary receipt and delivery points, Bidder may use any primary receipt point for delivery to any Field Area delivery point during the outage at the rate bid.

c) Bidder shall pay the higher of an additional $0.40/Dth/day or the formula value calculated by using the Midpoint price of "Gas Daily" Panhandle, Tx.-Okla. less the Midpoint price of "Gas Daily" El Paso, West Texas for delivered quantities received at receipt points in MIDs 1 to 7 and an additional $0.20/Dth/day for quantities delivered to delivery points in MIDs 1 through 16A.

d) Bidders awarded contiguous paths shall pay the following:

i) Fixed-price rate Bidders shall pay an additional $0.40/Dth/day for delivered quantities from alternate receipt points located in MIDs 1 through 7, and an additional $0.20/Dth/day for quantities delivered to alternate delivery points located in MIDs 1 through 16A, and an additional charge equal to the higher of Northern's maximum tariff rate or the "Gas Daily" spread between Midpoints for Demarc and El Paso, West Texas for any non-primary delivered quantities at Demarc or Demarc Deferred Delivery.

ii) Index-based formula rate Bidders with contiguous bids shall pay an additional $0.40/Dth/day for delivered quantities received at alternate receipt points located in MIDs 1 through 7, and an additional $0.20/Dth/day for quantities delivered to alternate delivery points located in MIDs 1 through 16A, and an additional charge equal to the higher of Northern's maximum tariff rate or the "Gas Daily" spread between Midpoints for Demarc and El Paso, West Texas for any non-primary delivered quantities at Demarc or Demarc Deferred Delivery.

8) Northern and customer may agree to extension rights for all or a portion of the contract MDQ.

9) Bidder(s) must meet the creditworthiness provisions of Northern's tariff. Upon request by Northern, Bidder shall provide appropriate credit assurance within ten (10) business days of Northern's request. If a non-creditworthy Bidder fails to provide the appropriate security, Northern

may award the capacity to the next best bid(s) or proceed to remarket the capacity, and Bidder will be liable for any difference in value of the bids, in addition to any other remedies available by law.

10) Transportation service agreements are to be executed by customer within 30 calendar days of tender by Northern or prior to service commencing.

11) Northern will evaluate and award capacity for incremental bids based on the terms of this open season. Any remaining capacity will be released as generally available capacity. However, in accordance with Northern's tariff, Northern will process any requests for realignment (without incremental rates) in the order they were received within seven (7) work days of the close of the open season or by 5 p.m. on March 25, 2019.

12) Northern and customer may agree to amend the service agreement, as allowed by Northern's Tariff, at any time after award of the capacity.

Non-Critical notices are located on Northern's website at the following address - http://www.northernnaturalgas.com/InfoPostings/Notices/Pages/NonCritical.aspx

ATTACHMENT 4

INDEX OF SHIPPERS EXCERPT

Shipper Name	Rate Schedule	Contract No.	Contract Effective Date	Contract Primary Term Expiration Date	Neg Rate (Y/N)	MDQ	Point Type R=Rec D=Del	Point Name [yi]	Zone Name [yl]	Point MDQ	Footnote ID[yo]
CENTENNIAL RESOURCE PRODUC	TFX_F_1_12	133532	11/1/2018	10/31/2019	N	27,600					k6/k7
							R	OASIS/NNG WAHA	Field	13,800	
							R	BROWNFIELD POOLING POINT	Field	13,800	
							D	NNG FIELD/MKT DEMARCATION -16B	Field	13,800	
							D	BROWNFIELD POOLING POINT	Field	13,800	
CENTENNIAL RESOURCE PRODUC	TFX_F_1_12	133532	11/1/2019	3/31/2020	N	27,600					k6/k7
							R	OASIS/NNG WAHA	Field	13,800	
							R	BROWNFIELD POOLING POINT	Field	13,800	
							D	NNG FIELD/MKT DEMARCATION -16B	Field	13,800	
							D	BROWNFIELD POOLING POINT	Field	13,800	
CENTENNIAL RESOURCE PRODUC	TFX_F_11_3	133532	11/1/2019	3/31/2020	N	60,600					k6/k7
							R	OASIS/NNG WAHA	Field	30,300	
							R	BROWNFIELD POOLING POINT	Field	30,300	
							D	NNG FIELD/MKT DEMARCATION -16B	Field	30,300	
							D	BROWNFIELD POOLING POINT	Field	30,300	
CONEXUS ENERGY LLC	TFX_F_7_10	132622	7/1/2019	7/2/2019	N	40,000					k6/k7
							R	BROWNFIELD POOLING POINT	Field	40,000	
CONEXUS ENERGY LLC	TFX_F_7_10	132622	7/3/2019	10/31/2019	N	41,428					k6/k7
							R	BROWNFIELD POOLING POINT	Field	41,428	
							D	BROWNFIELD POOLING POINT	Field	41,428	
CONEXUS ENERGY LLC	TFX_F_7_7	135850	7/1/2019	7/2/2019	N	41,428					k6/k7
							R	DCP LINAM RANCH PLANT OUTLET	Field	15,000	
							R	OASIS/NNG WAHA	Field	25,000	
							R	BROWNFIELD POOLING POINT	Field	1,428	
							D	BROWNFIELD POOLING POINT	Field	41,428	
ECO-ENERGY NATURAL GAS LLC	TFX_F_6_10	135336	6/1/2019	10/31/2019	N	29,364					k6/k7
							R	OASIS/NNG WAHA	Field	14,682	
							R	BROWNFIELD POOLING POINT	Field	14,682	
							D	EL PASO/NNG PLAINS 26 DEL	Field	14,682	
							D	BROWNFIELD POOLING POINT	Field	14,682	
ECO-ENERGY NATURAL GAS LLC	TFX_F_1_12	135337	6/1/2019	10/31/2020	N	11,924					k6/k7
							R	OASIS/NNG WAHA	Field	5,962	
							R	BROWNFIELD POOLING POINT	Field	5,962	
							D	EL PASO/NNG PLAINS 26 DEL	Field	5,962	
							D	BROWNFIELD POOLING POINT	Field	5,962	
ECO-ENERGY NATURAL GAS LLC	TFX_F_1_12	135339	11/1/2019	10/31/2020	Y	29,364					k6/k7
							R	ONEOK WESTEX SEAGRAVES	Field	14,682	
							R	BROWNFIELD POOLING POINT	Field	14,682	
							D	EL PASO/NNG PLAINS 26 DEL	Field	14,682	
							D	BROWNFIELD POOLING POINT	Field	14,682	
ETC MARKETING LTD.	TFX_F_1_12	134563	2/22/2019	10/31/2019	Y	17,200					k6/k7
							R	OASIS/NNG WAHA	Field	8,600	
							R	BROWNFIELD POOLING POINT	Field	8,600	
							D	EL PASO/NNG PLAINS 26 DEL	Field	8,600	
							D	BROWNFIELD POOLING POINT	Field	8,600	
HARTREE PARTNERS LP	TFX_F_7_10	132382	7/3/2019	8/31/2019	N	103,568					k6/k7

Shipper Name	Rate Schedule	Contract No.	Contract Effective Date	Contract Primary Term Expiration Date	Neg Rate (Y/N)	MDQ	Point Type R=Rec D=Del	Point Name [yi]	Zone Name [yl]	Point MDQ	Footnote ID[yo]
							R	BROWNFIELD POOLING POINT	Field	103,568	
							D	BROWNFIELD POOLING POINT	Field	103,568	
HARTREE PARTNERS LP	TFX_F_7_10	132382	9/1/2019	10/31/2019	N	103,568					k6/k7
							R	BROWNFIELD POOLING POINT	Field	103,568	
							D	BROWNFIELD POOLING POINT	Field	103,568	
HARTREE PARTNERS LP	TFX_F_7_7	132382	7/1/2019	7/2/2019	N	137,983					k6/k7
							R	BUSHTON POOLING POINT	Field	37,983	
							R	BROWNFIELD POOLING POINT	Field	100,000	
							D	BUSHTON POOLING POINT	Field	37,983	
HARTREE PARTNERS LP	TFX_F_7_10	132906	7/3/2019	10/31/2019	N	26,620					k6/k7
							R	BROWNFIELD POOLING POINT	Field	26,620	
							D	BROWNFIELD POOLING POINT	Field	26,620	
HARTREE PARTNERS LP	TFX_F_7_7	132906	7/1/2019	7/2/2019	N	35,464					k6/k7
							R	BUSHTON POOLING POINT	Field	9,764	
							R	BROWNFIELD POOLING POINT	Field	25,700	
							D	BUSHTON POOLING POINT	Field	9,764	
HARTREE PARTNERS LP	TFX_F_7_7	135849	7/1/2019	7/2/2019	N	103,568					k6/k7
							R	EL PASO/NNG PLAINS 30(REC)	Field	70,000	
							R	OASIS/NNG WAHA	Field	30,000	
							R	BROWNFIELD POOLING POINT	Field	3,568	
							D	BROWNFIELD POOLING POINT	Field	103,568	
HARTREE PARTNERS LP	TFX_F_7_7	135851	7/1/2019	7/2/2019	N	26,620					k6/k7
							R	OASIS/NNG WAHA	Field	25,700	
							R	BROWNFIELD POOLING POINT	Field	920	
							D	BROWNFIELD POOLING POINT	Field	26,620	
MACQUARIE ENERGY LLC	TFX_F_7_10	132308	7/1/2019	10/31/2019	N	35,320					k6/k7
							R	BROWNFIELD POOLING POINT	Field	35,320	
							D	BROWNFIELD POOLING POINT	Field	35,320	
OCCIDENTAL ENERGY MARKETIN	TFX_F_7_10	129809	7/1/2019	10/31/2019	N	4,144					k6/k7
							R	BROWNFIELD POOLING POINT	Field	4,144	
							D	BROWNFIELD POOLING POINT	Field	4,144	
TARGA GAS MARKETING LLC	TFX_F_1_12	134630	11/1/2019	3/31/2022	Y	100,000					k6/k7
							R	OASIS/NNG WAHA	Field	50,000	
							R	BROWNFIELD POOLING POINT	Field	50,000	
							D	NNG FIELD/MKT DEMARCATION -16B	Field	50,000	
							D	BROWNFIELD POOLING POINT	Field	50,000	
TENASKA MARKETING VENTURES	TFX_F_7_10	132668	7/1/2019	10/31/2019	N	41,428					k6/k7
							R	BROWNFIELD POOLING POINT	Field	41,428	
							D	BROWNFIELD POOLING POINT	Field	41,428	

6 Rate Schedule field has 3 parts: (1) Rate Schedule; (2)Area M=Market F=Field or G=Gulf Coast and (3) month range to which Detail record applies. Ex. 1_12 is January-December. 10_10 is October only. 11_3 is November-
7 Summing Max Daily Qty for Detail records may produce an incorrect total quantity for a contract due to different points and months of service

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon the parties designated on the official service list compiled by the Secretary for the above-captioned dockets in accordance with the requirements of Rule 2010 of the Federal Energy Regulatory Commission's Rules of Practice and Procedure, 18 C.F.R. 385.2010 (2019).

Dated at Washington, D.C. on the 15th day of July, 2019.

/s/ Maeve Tibbetts
Maeve Tibbetts
Pierce Atwood LLP
1875 K Street NW
Suite 700
Washington, D.C. 20006

Document Content(s)

168 FERC ¶ 61,069
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur and Richard Glick.

Northern Natural Gas Company	Docket Nos. RP19-1353-000 RP19-59-000

ORDER ACCEPTING AND SUSPENDING TARIFF RECORDS, SUBJECT TO REFUND, REJECTING TARIFF REVISIONS, AND ESTABLISHING HEARING PROCEDURES AND TECHNICAL CONFERENCE

(Issued July 31, 2019)

1. On July 1, 2019, in Docket No. RP19-1353-000, Northern Natural Gas Company (Northern) filed revised tariff records[1] pursuant to section 4 of the Natural Gas Act (NGA). Northern proposes significant rate increases, modifications to certain rate schedules, and various other changes to the General Terms and Conditions (GT&C) of its tariff, effective August 1, 2019. As discussed below, the Commission accepts and suspends certain tariff records to be effective January 1, 2020, subject to refund, the outcome of a hearing and technical conference established herein and rejects one tariff proposal. In addition, the Commission makes determinations related to procedural issues in Northern's motion to terminate the NGA section 5 proceeding established by the Commission in Docket No. RP19-59-000.[2]

Background

2. Northern states that it operates a 14,794-mile interstate natural gas pipeline system, extending from West Texas to the Upper Peninsula of Michigan. Northern states that it provides firm and interruptible transportation and storage service under a variety of rate schedules and has two rate zones. The Field Area stretches from Texas

[1] *See* Appendix A.

[2] *Northern Natural Gas Co.*, 166 FERC ¶ 61,033 (2019) (Investigation Order).

to the Demarcation Zone in Northern Kansas and the Market Zone stretches from the Demarcation Zone to the Upper Peninsula of Michigan.

3. Northern's current rates were established in a settlement of its Docket No. RP03-398-000 general section 4 rate case.[3] On January 16, 2019, the Commission issued an Investigation Order that instituted a formal inquiry of Northern's rates pursuant to NGA section 5 and set the matter for hearing before an Administrative Law Judge (ALJ).[4]

Proposal

4. Northern is proposing two sets of tariff records, constituting its Base Case and its *pro forma* Prospective Case, which are designed on different rate design principles but use the same overall cost of service. Northern proposes the Base Case to become effective August 1, 2019 and the Prospective Case to become effective prospectively upon Commission review and approval.

5. The Base Case supports a general rate increase to Northern's rates and proposes certain changes to rate schedules and Northern's GT&C. The rates reflect an overall cost of service of $1,005 million, as compared to the approximately $480 million cost of service established in the 2005 Settlement. Northern states that its proposed rates are based on a cost of service for a 12-month base period ending March 31, 2019, adjusted for known and measurable changes that would become effective within the nine months ending December 31, 2019. Northern mainly attributes its increased cost of service to capital costs associated with modernization and maintenance. Northern states that it has incurred approximately $328 million of capital costs during the base period and anticipates incurring an additional $504 million during the test period from April 1, 2019 through December 31, 2019. This equates to approximately $830 million of capital costs during the combined base and test period. Northern states that the increase in its cost of service is partially offset by the lower federal corporate income tax rate, including amortization of excess deferred income taxes. Northern proposes to update its depreciation rates from those included in the 2005 Settlement and, for the first time, proposes negative salvage rates for onshore transmission and liquefied natural gas (LNG) storage plant. Northern also proposes a 14.2 percent return on equity (ROE) applied to an expected capital structure of 59.4 percent equity and 40.6 percent debt. Northern states that it has provided discounted rates to a number of shippers and that its proposed rates reflect an iterative revenue crediting discount adjustment. Northern states that it proposes to roll in six facility expansions related to its Northern Lights Expansion Project and the West Leg 2014 project.

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[3] *Northern Natural Gas Co.*, 111 FERC ¶ 61,444 (2005) (2005 Settlement).

[4] Investigation Order, 166 FERC ¶ 61,033.

6. Northern states that the proposed cost allocation and rate design in its Base Case is based on the same modified straight fixed-variable rate design principles used to establish the rates contained in the 2005 Settlement whereby an agreed-upon amount of fixed costs is assigned to usage charges.

7. Northern, as part of its Base Case, also proposes several changes to its GT&C, as follows.

- Reduction of the Carlton Resolution Surcharge to $0.00 per Dth, and changes to the penalty for failure to source Carlton supply;
- Changes to firm transmission rates to permit an average rate to be charged where a customer contracts for service in different seasons with different seasonal rates, without exceeding Northern's maximum tariff rates;
- Revisions to Rate Schedule FDD to (1) remove the list of storage points from the tariff, because those points are posted on the website, and (2) clarify that account balance transfers will not be allowed during capacity allocations;
- Modification of open season posting procedures to require posting of only the winning bid rather than all bids;
- Changes to allow Northern to permit customers to use the imbalance to-storage imbalance resolution method to resolve imbalances for prior period adjustments;
- Changes regarding operational balancing agreements;
- Removal of the required levels for System Balancing Agreements and adding alternative agreements;
- Revisions to Northern's Periodic Rate Adjustment for tracking and recovery of fuel and unaccounted for gas loss;
- Removal of obsolete gas processing provisions;
- Update to the net reservation charge credit percent for the No-Profit method;
- Various housekeeping changes to facilitate the above changes, eliminate obsolete provisions, and correct grammar.

8. Northern states that "[t]he 2005 Settlement provided that in 'Northern's next general section 4 rate case proceeding, Northern will propose a cost allocation methodology different from the current Market Area/Field Area cost allocation methodology.'"[5] Consistent with that provision, Northern proposes, as part of its *pro forma* Prospective Case, to change the fixed cost allocation associated with its Market Area and Field Area reservation charges, from the current zone methodology to a system-wide methodology. In addition, Northern proposes (i) consolidating Rate Schedule TF from four services into two services: TF12 (firm transportation for annual service with winter and summer rates) and TF5 (firm transportation for the five winter months from November through March); (ii) eliminating small customer

[5] Northern's, July 1, 2019 Filing in Docket No. RP19-1353-000 at 9.

Rate Schedule GS-T, and permitting Small Customers to convert to other rate schedules; (iii) changes to rate design for Field Area usage rates; and (iv) adoption of a Straight Fixed-Variable (SFV) rate design. In addition, Northern proposes implementation of a contract restructuring opportunity and supporting software changes.

9. Northern, as part of its Prospective Case, also proposes several revisions to its GT&C, as follows.

- Revision of the imbalance resolution provisions to resolve imbalances in the Market Area or Field Area and revise the Field Area monthly index price calculations;
- Changes to Rate Schedule FDD to ensure that storage is not over-filled or depleted;
- Provision of more pooling opportunities for shippers by adding more interconnect pools and regional pools, and elimination of the "MID 17" pool;
- Modification and simplification of the Daily Delivery Variance Charges and related changes to the System Management Service rate schedule;
- Changes to the Periodic Rate Adjustment mechanism related to cycle gas and retained storage gas at the Redfield and Lyons storage facilities as well as coverage for all transmission related compressors' electric power costs;
- Relocation of the Demarcation point (Demarc point); and
- Various housekeeping changes.

10. Northern states that on January 28, 2019, as renewed on June 10, 2019, Northern filed a motion to terminate the NGA section 5 proceeding established by the Commission in Docket No. RP19-59-000. Northern states that the Commission has not ruled on Northern's motion to terminate. Northern states that to the extent the NGA section 5 proceeding is not terminated prior to the Commission setting this NGA section 4 rate filing for hearing, Northern would not oppose the consolidation of the investigation of the NGA section 4 rate filing with the pending NGA section 5 proceeding in Docket No. RP19-59-000.

Notice and Comments

11. Public notice of Northern's filing was issued on July 8, 2019. Interventions and protests were due as provided in section 154.210 of the Commission's regulations.[6] Pursuant to Rule 214,[7] all timely filed unopposed motions to intervene and any unopposed motions to intervene filed out-of-time before the issuance date of this order

[6] 18 C.F.R. § 154.210 (2018).

[7] 18 C.F.R. § 385.214 (2018).

are granted. Granting late intervention at this stage of the proceeding will not disrupt this proceeding or place additional burdens on existing parties. The entities that submitted protests and comments in response to Northern's filing are listed in Appendix B. On July 19, 2019, Northern filed a motion to answer protests.

12. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213 (a)(2) (2018), prohibits answers to protests or answers unless otherwise permitted by the decisional authority. We accept Northern's answer because it has provided information that assisted us in our decision-making process.

13. All of the protesters raise general rate case issues and assert that Northern has not shown its proposed rates to be just and reasonable. The protesters request that the Commission establish a hearing to consider the lawfulness of Northern's proposed Base and Prospective Case rates and services, and suspend the Base Case tariff records for the maximum statutory period, subject to refund.

14. Several parties protest aspects of Northern's proposed revisions to the GT&C. NSP Companies argue that Northern's current scheduling, segmentation and capacity release policies adversely affect the Base Case's billing determinants.[8] They argue that the cumulative effects of Northern's proposals with regard to the Base Case's Account Balance Transfer and open season capacity award posting, and the Prospective Case's changes to the Demarc point, pooling, operational zones, capacity release and segmented capacity will further adversely affect the results of Northern's scheduling of customers' secondary and segmented nominations. NSP Companies contend that Northern's currently effective scheduling, segmentation and capacity release provisions assign priority to shippers' nominations based on the priority of service associated with the requested receipt and delivery points. NSP Companies argue the process may be contrary to the "within-the-path" mandates of Order No. 637-A.[9] NSP Companies oppose Northern's proposal to change its open season posting procedures to post only winning bid information.[10] NSP Companies state they find losing bid information relevant and

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[8] NSP Companies Protest at 34-48.

[9] *Id.* (citing *Regulation of Short-Term Natural Gas Transportation Services, and Regulation of Interstate Natural Gas Transportation Services,* Order No. 637, FERC Stats. and Regs., ¶ 31,091 (cross-referenced at 90 FERC ¶ 61,109), *clarified*, Order No. 637-A, 91 FERC ¶ 61,169, *reh'g denied,* Order No. 637-B, 92 FERC ¶ 61,062 (2000))..

[10] NSP Companies Protest at 30.

valuable and that Northern has not demonstrated its current procedures are insufficient or cause harm.

15. NSP Companies[11] protest the elimination of the Carlton Commodity Surcharge. NMDG[12] requests summary rejection of the proposal. NSP Companies and NMDG explain that Northern may call upon them to deliver up to approximately 33,500 Dth per day into Northern's pipeline at the Great Lakes Gas Transmission interconnect. NSP Companies and NMDG contend that other shippers share in the costs associated with the requirement for the Carlton volumes through the assessment of a Carlton Commodity Surcharge, for which the shippers who actually source the volumes at Carlton are reimbursed. They argue that Northern's proposal would continue to impose an obligation for some shippers to source gas at a particular point, with no compensation for that obligation, despite the shippers being exposed to above market pricing for sourcing gas at a point to benefit Northern's system. NMDG also argues that elimination of the Carlton Commodity Surcharge is a rate design issue and therefore must be part of the Prospective, not Base Case as required by the 2005 Settlement.[13]

16. NMDG, whose members are generally small customers, also requests summary rejection of Northern's Prospective Case proposal to eliminate the small customer classification.[14] Golden Spread, with regard to the Prospective Case, is concerned about the proposed firm entitlement open season, and whether shippers will be required to acquire undesired capacity.[15]

17. NMDG also requests that the Commission summarily reject the following proposals in Northern's Prospective Case: (i) adoption of a system-wide reservation charge in place of separate Field Area and Market Area reservation charges, (ii) elimination of Annual TF12 Base and Variable redetermination and other changes in TF service, and (iii) modifications to Northern's System Management Service and its Daily Delivery Variance Charges.[16] Tenaska requests summary rejection of Northern's proposal to replace its Periodic Rate Adjustment filings pursuant to NGA

[11] *Id.* at 30-31.

[12] NMDG Protest at 10-11.

[13] *Id.* at 11.

[14] *Id.* at 16-21.

[15] Golden Spread Protest at 3.

[16] NMDG Protest at 13-16.

section 4 with postings of changes in its fuel and lost and unaccounted gas retention percentages on its website.

18. NSP Companies, NMDG, Black Hills, PGC, MUD and Golden Spread request that the Commission suspend the Base Case proposed GT&C changes for the full five months and set both the Base and Prospective Case GT&C changes for hearing. Black Hills further requests that the Commission not establish a technical conference to discuss these tariff matters, as it speculates such procedures will impede the settlement process.

19. In its answer, Northern opposes NMDG and Tenaska's motions for summary disposition. Northern claims that there are material facts in dispute regarding those issues, and therefore, summary disposition is not appropriate.[17] Northern also argues that its capacity segmentation and scheduling priority practices are fully consistent with the Commission's requirements and that the Commission has approved them.[18] Northern states that if the Commission does not dismiss NSP's protest, Northern does not oppose NSP's request to address its arguments in the NGA section 4 rate case. However, Northern states that because NSP is challenging an existing practice that Northern has not proposed to change, NSP has the burden of proof under NGA section 5 to demonstrate its current practices are not just and reasonable. Northern renews its request that the Commission terminate the NGA section 5 proceeding in Docket No. RP19-59-000, or alternatively consolidate it with the instant filing.[19] Finally, Northern states that it would not oppose establishing settlement judge and hearing judge procedures to examine all the issues raised in Northern's filing.[20]

Discussion

20. The Commission accepts and suspends, subject to refund, the proposed tariff records listed in Appendix A to be effective January 1, 2020, subject to the outcome of the hearing procedures and a technical conference established below. The Commission rejects one tariff revision as discussed below.

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[17] Northern Answer at 10-12.

[18] *Id.* at 12-13.

[19] *Id.* at 5-9.

[20] *Id.* at 4-5.

Hearing and Technical Conference Procedures

21. Northern's filing raises many issues that warrant further investigation. The Commission finds that there are material issues of fact in dispute concerning, among other things, cost of service, functionalization, cost allocation and rate design. Accordingly, the Commission will establish a hearing before an ALJ to explore the issues arising from the filing, including, but not limited to, those summarized above and set forth in the protests with regard to both the Base and Prospective Cases.

22. Northern must adhere to section 154.303(c)(2) of the Commission's regulations, which provides that at the end of the test period, the pipeline must remove from its rates costs associated with any facility that is not in service or for which certificate authority is required but has not been granted.[21] In addition, the Commission will specifically address several additional issues and their relationship to the hearing to be established herein.

23. The Commission directs staff to convene a technical conference to address certain non-rate tariff issues related to the proposed services and terms and conditions. The issues to be addressed at the technical conference include, but are not limited to, Northern's proposals concerning current capacity segmentation and scheduling practices and open season posting procedures.

Revisions to Periodic Rate Adjustment

24. Northern's currently effective fuel and unaccounted for gas retention percentages are established through a periodic rate adjustment (PRA) mechanism as provided in Section 53A of Northern's GT&C. Pursuant to GT&C Section 53A.5, Northern makes annual NGA section 4 filings to update its Field Area fuel and Unaccounted-For (UAF) percentages and seasonal NGA section 4 filings to update its Market Area fuel and UAF percentages.[22]

25. Northern proposes to revise GT&C Section 53A.5 to eliminate the periodic NGA section 4 filing requirements under Section 53A and requests authority to change fuel and UAF percentages on an as-needed basis to prevent significant over or under recoveries. Northern proposes to post any such changes on its website at least one month before changes become effective. Northern proposes to eliminate the requirement to receive FERC approval for each PRA change and, instead, file an annual report with FERC on or before April 1 each year detailing the fuel used and UAF percentages collected as

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[21] 18 C.F.R. § 154.303(c)(2) (2018).

[22] Northern, Ex. NNG-8 at 101:18-22.

compared to the actual incurrences.[23] Northern also proposes various other changes to GT&C Section 53A, for example to conform terminology to its proposed rate zone and other changes.

26. NMDG,[24] NSP Companies[25] and Tenaska[26] argue that Northern's proposal to no longer file a NGA section 4 filing in which it would bear the burden of supporting its rate changes is inconsistent with the NGA. Tenaska[27] requests the Commission summarily reject Northern's changes to its PRA reporting requirements, while NMDG[28] requests the changes either be summarily rejected or addressed in an evidentiary hearing. The Commission's regulations regarding periodic adjustments require pipelines to file to explain their rate adjustments to allow customers and the Commission the opportunity to review and comment or protest any adjustments that have been charged.[29] Northern's proposal to eliminate the annual and seasonal rate change filings and to instead file an annual report supporting, after the fact, its rate changes may compromise a shipper's rights under the NGA to meaningfully protest the adjustments made thereunder. It may also narrow the Commission's ability to address and remedy such objections if necessary.[30] For these reasons, the proposed revision to GT&C Section 53A.5 is rejected. This finding is without prejudice to the remaining components of Northern's PRA proposal, which are suspended and set for hearing below. Northern is required to file revised tariff records as necessary to ensure that the remaining components of Northern's PRA proposal are consistent with the currently effective periodic NGA section 4 filing requirements.

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[23] *Id.* at 102:1-12.

[24] NMDG Protest at 12-13.

[25] NSP Companies Protest at 31-32.

[26] Tenaska Protest at 5-8.

[27] *Id.* at 5-6.

[28] NMDG Protest at 12-13.

[29] 18 C.F.R. § 154.403 (2018).

[30] *See TransColorado Gas Transmission Co.*, 87 FERC ¶ 61,027, at 61,100-01 (1999). *See also Rockies Express Pipeline LLC*, 163 FERC ¶ 61,011, at P 9 (2018); and *Portland Natural Gas Transmission System*, 166 FERC ¶ 61,134, at P 36 (2019).

Other GT&C Hearing Issues

27. As noted above, Northern proposes several revisions to its terms and conditions of service. With the exception of Northern's proposal to eliminate its NGA section 4 filing obligation for changes to its PRA, the Commission accepts and suspends all of these proposed revisions. The Commission determines that several of Northern's proposed GT&C revisions are related to its rate design proposals and should be addressed at the hearing established above. First, Northern's proposed changes to its PRA that are not rejected above are rate related and are accordingly set for hearing. Second, Northern proposes a revision to its billing procedures that would permit averaged firm transportation rates to be charged where customers contract for months of service over different seasonal rates without exceeding Northern's maximum tariff rates. Parties should address whether such averaging compromises the objectives of seasonally differentiated rate design.[31] Third, Northern's Prospective Case proposes to convert the Small Customer tariff provisions to the standard provisions applicable to all other shippers. The Commission has found that proposals affecting small customers' use of a small customer transportation service raise issues involving the appropriate cost allocations among the pipeline's different customer classes, and accordingly such proposals must be considered in a general NGA section 4 rate case.[32] Fourth, Northern proposes to reduce the Carlton Commodity Surcharge to zero. Northern supports its proposal on the basis that the Carlton Sourcers have received a windfall to the detriment of other shippers on Northern's system.[33] This is a material issue of fact best resolved through a hearing. Fifth, all proposed revisions to the GT&C related to zones, sectors, and Demarc are related to Northern's proposed changes to its rate design, and should be addressed in the hearing. Finally, Northern proposes to update the *force majeure* net reservation charge credit percent for the No-Profit method. Because this reservation charge credit is derived from elements of the cost of service,[34] its calculation is best addressed in the hearing proceedings.

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[31] *Policy Statement Providing Guidance with Respect to the Designing of Rates*, 47 FERC ¶ 61,295, at 62,054 (1989).

[32] *Enable Mississippi River Transmission, LLC*, 165 FERC ¶ 61,285, at P 150 (2018); *ANR Pipeline Co.*, 146 FERC ¶ 61,087, at P 29 (2014).

[33] Northern, Ex. NNG-8 at 91:6-19.

[34] Northern, Ex. NNG-4.

Suspension

28. Based upon review of the filing, the Commission finds that the proposed tariff records set forth in Appendix A have not been shown to be just and reasonable, and may be unjust, unreasonable, and unduly discriminatory or otherwise unlawful. Accordingly, the Commission shall accept and suspend the effectiveness of the tariff records in Appendix A for five months, to be effective January 1, 2020, subject to refund, hearing and technical conference, as set forth in this order.

29. The Commission's policy regarding suspensions is that tariff filings generally should be suspended for the maximum period permitted by statute where preliminary study leads the Commission to believe that the filing may be unjust, unreasonable, or inconsistent with other statutory standards.[35] It is recognized, however, that shorter suspensions may be warranted in circumstances where suspension for the maximum period may lead to harsh and inequitable results.[36] Such circumstances do not exist for the tariff records set forth in Appendix A. The Commission will exercise its discretion to suspend them for the maximum period, to be effective January 1, 2020, subject to refund and the outcome of the hearing and technical conference procedures ordered herein.

30. In its Transmittal Letter to the instant filing, Northern states, "Northern files this motion to place the Base Case tariff sheets into effect *at the expiration of any suspension period set by the Commission*, provided the Base Case tariff sheets are approved as filed and without condition." (Emphasis added.) The Commission's regulations at 18 C.F.R. § 154.7(a)(9) (2018) provide two options regarding the filing of a motion to place suspended rates into effect pursuant to NGA section 4(e). In the case of a minimal suspension, the pipeline may include in its filing a motion to: (1) place the proposed rates into effect at the end of the suspension period; or (2) reserve the right to file a later motion. Northern includes with its filing a motion to place the proposed tariff provisions into effect at the end of any suspension period. Pursuant to 18 C.F.R. § 154.7(a)(9), such a motion only applies to minimal suspensions and cannot apply to five-month suspensions. Thus, the motion included in Northern's filing is ineffective for purposes of moving the proposed tariff records into effect at the end of the suspension period. If and when Northern decides to move the suspended tariff record into effect, it must do so consistent with 18 C.F.R. § 154.206(a) (2018) of the Commission's regulations.[37]

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[35] *See Great Lakes Gas Transmission Co*., 12 FERC ¶ 61,293 (1980) (five-month suspension).

[36] *See Valley Gas Transmission, Inc*., 12 FERC ¶ 61,197 (1980) (one-day suspension).

[37] *American Midstream (AlaTenn), LLC*, 149 FERC ¶ 61,123, at P 30 (2014).

Motion to Terminate NGA Section 5 Investigation

31. Northern states that on January 28, 2019, as renewed on June 10, 2019, Northern filed a motion to terminate the NGA section 5 proceeding in Docket No. RP19-59-000. In those motions, Northern admits that the Commission has broad discretion to decide whether to issue an order opening an investigation under section 5 of the NGA. However, Northern contends that the calculations upon which the Commission based its conclusion to open the investigation were inaccurate. Specifically, Appendix A to the Commission's Investigation Order adjusted revenues by $115,386,243 for the changes in all revenue accounts during the first two quarters of 2018. Northern contends that the Commission failed to recognize that more than half of this revenue increase, $60,774,052, was related to operational gas sales. Pursuant to the FERC Form No. 501-G, Northern contends that these gas sales revenues should have been excluded. The Commission, Northern continues, erroneously deducted from total operating revenue only the $28,436,340 in operational gas sales from calendar year 2017, instead of the $89,210,392 in operational gas sales through the second quarter of 2018 ($28,436,340 plus $60,774,052). Northern calculates the ROE would have been 14.3 percent, not 17.3 percent, if operational gas sales had been properly removed.[38] Northern requests that the Commission terminate the NGA section 5 investigation because the corrected section 5 analysis provides no support for a finding that Northern's existing rates are unjust or unreasonable under the Commission's historical application of NGA section 5.

32. Northern states that the Commission has not ruled on Northern's motion to terminate. Northern states that to the extent the NGA section 5 proceeding is not terminated prior to the Commission setting this NGA section 4 rate filing for hearing, Northern would not oppose the consolidation of the investigation of the NGA section 4 rate filing with the pending NGA section 5 proceeding in Docket No. RP19-59-000. CenterPoint,[39] Indicated Shippers,[40] NNSA,[41] and NSP Companies[42] state they do not

[38] Northern also contends that FERC Form No. 501-G was incomplete in reflecting all costs associated with gas sales. If those costs were to have been included, Northern calculates the indicative ROE of 13.7 percent.

[39] CenterPoint Protest at 7-8.

[40] Indicated Shippers Protest at 2.

[41] NNSA Protest at 6.

[42] NSP Companies Protest at 2.

oppose consolidating the two cases. The MPSC, however, states consolidation is not appropriate as the test periods of the two proceedings are different.[43]

33. The Commission denies Northern's motion to terminate the proceeding in Docket No. RP19-59-000. The Commission agrees with Northern that Appendix A of the Investigation Order did not deduct the correct amount of operational gas sales which, if performed, would have led to an indicative ROE of 14.3 percent. Notwithstanding that error, other factors, such as the changes on Northern's system discussed in the Investigation Order, fully supported the Commission's decision to initiate the investigation. Northern's filing of an NGA section 4 rate case does not invalidate the need to explore the issues identified in Investigation Order. Moreover, the rate resulting from the resolution of the NGA section 5 proceeding may go into effect before the rates resulting from the NGA section 4 proceeding and set the refund floor for the NGA section 4 proceeding. Further, because the test periods of the two proceedings partially overlap,[44] the record in the Docket No. RP19-59-000 proceeding may be applicable to the general rate case proceeding. For these reasons, the Commission denies Northern's motion to terminate and leaves it to the discretion of the Chief Administrative Law Judge whether to consolidate the Docket No. RP19-59-000 proceeding with Northern's NGA section 4 proceeding.[45]

<u>The Commission orders</u>:

(A) The tariff records in Appendix A are accepted and suspended to be effective January 1, 2020, subject to refund and the outcome of the hearing and technical conference established in the body of this order.

(B) Proposed GT&C Section 53A.5 is rejected, as discussed in the body of this order. Northern is required to file within 30 days of the date of this order compliance tariff records as necessary to ensure that the remaining components of Northern's PRA

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[43] MPSC Protest at 6.

[44] Northern's Docket No. RP19-59-000 test period is twelve months ending December 2018, with a six-month adjustment period ending June 2019 (Northern's Docket No. RP19-59-000 Transmittal Letter dated April 1, 2019, at 1), whereas FERC Trial Staff's test period for Northern is twelve months actuals ending March 2019 (Ex. S-1 at 2:17-22). In Docket No. RP19-1353-000, Northern's 12-month base period ends March 31, 2019, and adjusted for known and measurable changes ending December 31, 2019.

[45] 18 C.F.R. § 375.304(b) (2018).

proposal are consistent with the currently effective periodic NGA section 4 filing requirements.

(C) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and the NGA, particularly sections 4, 5, 8, 9, and 15 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the NGA (18 C.F.R. Chapter I), a public hearing shall be held concerning the justness and reasonableness of Northern's proposed tariff records, as discussed in the body of this order.

(D) A Presiding Administrative Law Judge, to be designated by the Chief Administrative Law Judge for that purpose pursuant to 18 C.F.R. § 375.304, must convene a prehearing conference in this proceeding to be held within 20 days after issuance of this order, in a hearing or conference room of the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426. The prehearing conference is for the purpose of clarification of the positions of the participants and establishment by the presiding judge of any procedural dates necessary for the hearing. The presiding administrative law judge is authorized to conduct further proceedings in accordance with this order and the rules of practice and procedure.

(E) The Commission's staff is directed to convene a technical conference to explore the certain issues raised by Northern's filing and report to the Commission within 120 days of the issuance of this order.

(F) Northern's motion to terminate the investigation proceeding in Docket No. RP19-59-000 is denied.

By the Commission. Commissioner McNamee is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

Appendix A

Northern Natural Gas Company
FERC NGA Gas Tariff
Gas Tariffs

Tariff records accepted and suspended, effective January 1, 2020, subject to refund, condition, hearing, and technical conference:

Sheet No. 50, Currently Effective Rates TF, 15.0.0
Sheet No. 51, Currently Effective Rates TFX and LFT, 18.0.0
Sheet No. 52, Currently Effective Rates TI, 16.0.0
Sheet No. 53, Currently Effective Rates GS-T and CS-1, 16.0.0
Sheet No. 54, Effective Rates TF TFX LFT GS-T TI and FDD, 24.0.1
Sheet No. 54A, Fuel Unaccounted-For Exemptions, 8.0.0
Sheet No. 54B, Fuel Unaccounted-For Exemptions, 4.0.0
Sheet No. 55, Effective Rates FDD PDD IDD and SMS, 2.0.0
Sheet No. 59, MIDS, 3.0.0
Sheet No. 59A, MIDS, 3.0.0
Sheet No. 60, MIDS, 12.0.0
Sheet No. 60A, MIDS, 12.0.0
Sheet No. 61, Reserved for Future Use, 11.0.0
Sheet No. 62, Reserved for Future Use, 23.0.0
Sheet No. 109, Rate Schedule TF, 1.0.0
Sheet No. 124, Rate Schedule TFX, 2.0.0
Sheet No. 132, Rate Schedule TI, 2.0.0
Sheet No. 135D, Rate Schedule FDD, 8.0.0
Sheet No. 135E, Rate Schedule FDD, 4.0.0
Sheet No. 136, Rate Schedule FDD, 2.0.0
Sheet No. 140, Rate Schedule FDD, 3.0.0
Sheet No. 142C, Rate Schedule PDD, 7.0.0
Sheet No. 144, Rate Schedule IDD, 8.0.0
Sheet No. 154, Rate Schedule MPS, 4.0.0
Sheet No. 155, Rate Schedule MPS, 4.0.0
Sheet No. 201B, G T and C Table of Contents, 4.0.0
Sheet No. 205, G T and C Definition of Terms, 7.0.0
Sheet No. 205A, G T and C Definition of Terms, 4.0.0
Sheet No. 206, G T and C Definition of Terms, 4.0.0
Sheet No. 206A, G T and C Definition of Terms, 1.0.0

Sheet No. 207, G T and C Definition of Terms, 1.0.0
Sheet No. 236, G T and C Reservation Charge Credits, 1.0.0
Sheet No. 252, G T and C Requests For Service, 2.0.0
Sheet No. 263A, G T and C Allocation of Capacity, 3.0.0
Sheet No. 263B, G T and C Allocation of Capacity, 2.0.0
Sheet No. 263C, G T and C Allocation of Capacity, 2.0.0
Sheet No. 263D, G T and C Allocation of Capacity, 2.0.0
Sheet No. 264, G T and C Billing Throughput Quantity, 3.0.0
Sheet No. 267, G T and C Balancing, 3.0.0
Sheet No. 269A, G T and C Balancing, 2.0.0
Sheet No. 281, G T and C Quality, 1.0.0
Sheet No. 282, G T and C Processing, 1.0.0
Sheet No. 283, G T and C Processing, 1.0.0
Sheet No. 292A, G T and C No-Notice Obligation, 2.0.0
Sheet No. 300, G T and C Periodic Rate Adjustment, 2.0.0
Sheet No. 300A, G T and C Periodic Rate Adjustment, 2.0.0
Sheet No. 301, G T and C Periodic Rate Adjustment, 1.0.0
Sheet No. 301A, G T and C Periodic Rate Adjustment, 1.0.0
Sheet No. 301B, G T and C Periodic Rate Adjustment, 1.0.0
Sheet No. 301C, G T and C Periodic Rate Adjustment, 1.0.0

Appendix B
List of Commenters and Protestors, and Abbreviations

Atmos Energy Corporation (Atmos Energy)
Black Hills Service Company, LLC (Black Hills)
BP Canada Energy Marketing Corp. and XTO Energy Inc. (Indicated Shippers)
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas (CenterPoint)
Encore Energy Services, Inc. (Encore)
Golden Spread Electric Cooperative, Inc. (Golden Spread)
Metropolitan Utilities District of Omaha (MUD)
Michigan Public Service Commission (MPSC)
Minnesota Public Utilities Commission (MPUC) and the Minnesota Department of Commerce, Division of Energy Resources (MDC)
Northern Municipal Distributors Group[46] and the Midwest Region Gas Task Force Association (jointly, NMDG)[47]
Northern Natural Shipper Alliance (NNSA)
Northern States Power Companies[48] and Southwestern Public Service Company (jointly, NSP Companies)
Process Gas Consumers Group and Industrial Energy Consumers of America (jointly, PGC)
Tenaska Marketing Ventures (Tenaska)
Upper Midwest Shipper Group[49]

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[46] Alton, Cascade, Cedar Falls, Circle Pine, Coon Rapids, Emmetsburg, Everly, Gilmore, Graettinger, Guthrie Center, Harlan, Hartley, Hawarden, Lake Park, Manilla, Manning, Orange City, Osage, Preston, Remsen, Rock Rapids, Rolfe, Sabula, Sac City, Sanborn, Sioux Center, Tipton, Waukee, West Bend, Whittemore, and Woodbine.

[47] Austin Utilities, Circle Pines, Community Utility Company, Dooley’s Natural Gas, Great Plains Natural Gas Company, Greater Minnesota Gas, Hibbing, Hutchinson, New Ulm, Northwest Natural Gas Company, Owatonna, Round Lake, Sheehan’s Gas Company, Inc., Two Harbors, Virginia, and Westbrook, Minnesota; Midwest Natural Gas, Inc., and St. Croix Valley Natural Gas, Wisconsin; Watertown, South Dakota; and the Cities of Fremont, Lyons, and Stromsburg, and the Village of Pender, Nebraska.

[48] Northern States Power Company, a Minnesota Corporation and Northern States Power Company, a Wisconsin Corporation.

[49] Interstate Power & Light Company; Wisconsin Power & Light Company; Madison Gas and Electric Company; Minnesota Energy Resources Corporation; Wisconsin Electric Power Company; Wisconsin Gas LLC; and Upper Michigan Energy Resources Corporation.

Valero Renewable Fuels Company, LLC (Valero Renewable)

Document Content(s)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Viking Gas Transmission Company) Docket No. RP19-1340-000

MOTION TO INTERVENE AND PROTEST OF NORTHERN STATES POWER COMPANY – MINNESOTA AND NORTHERN STATES POWER COMPANY – WISCONSIN

Northern States Power Company, a Minnesota corporation (NSPM), and Northern States Power Company, a Wisconsin corporation (NSPW) (referred to jointly herein as the NSP Companies), respectfully move for leave to intervene and protest[1] Viking Gas Transmission Company's (Viking) filing, pursuant to section 4 of the Natural Gas Act (NGA),[2] to revise Viking's FERC Gas Tariff, First Revised Volume No. 1, to be effective August, 1, 2019.[3]

Viking's Rate Case Filing does not provide the Commission or interested parties with enough information to determine whether Viking's proposed rate changes are just and reasonable as filed. The NSP Companies have identified substantial issues with individual components of Viking's proposal requiring, at the very least, further analysis and explanation, and making discovery and a full evidentiary hearing necessary. The NSP Companies respectfully request that the Commission suspend the Rate Case Filing for the maximum five-month period permitted by the NGA, make the rates subject to refund after the suspension period, and establish an

1 The NSP Companies move to intervene and protest this filing pursuant to Rules 214 and 211, respectively, of the Federal Energy Regulatory Commission's (FERC or Commission) Rules of Practice and Procedure, 18 C.F.R. §§ 385.214 and 385.211 (2019).

2 15 U.S.C. § 717c.

3 Viking Gas Transmission Company's NGA Section 4 Rate Case, Docket No. RP19-1340-000 (filed Jun. 28, 2019) (Rate Case Filing).

evidentiary hearing to fully explore all issues raised by the Rate Case Filing, including, but not limited to, the issues raised in this protest.

Due to the size and complexity of the Rate Case Filing, the issues raised in this Protest should not be considered an exhaustive list of rate components that the NSP Companies may ultimately oppose. The NSP Companies explicitly reserve the right to take a position on any and all issues that may arise during the development of this proceeding.

I. COMMUNICATIONS

The NSP Companies request that all communications in this proceeding be served on each of the following representatives:[4]

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[4] The NSP Companies request waiver of the restriction in 18 C.F.R. § 385.203(b)(3) (2019) to allow more than two individuals representing the NSP Companies to be included on the official service list for this proceeding. Xcel Energy Services Inc. is the centralized service company for the Xcel Energy Inc. holding company system and, *inter alia*, represents the NSP Companies in proceedings before the Commission.

II. BACKGROUND AND MOTION TO INTERVENE

A. Background

1. The NSP Companies

The NSP Companies are wholly-owned utility operating company subsidiaries of Xcel Energy Inc. and are public utilities engaged in the business of distributing natural gas and electricity to retail consumers for residential, commercial, and industrial use. NSPM is a combination gas and electric utility with its principal office in the City of Minneapolis, Minnesota. NSPM is authorized to do business in the States of Minnesota, North Dakota, and South Dakota. NSPW is a corporation created and organized under the laws of the State of Wisconsin, with its principal office in the City of Eau Claire, Wisconsin. NSPW is authorized to do business in the States of Wisconsin and Michigan. The NSP Companies provide retail gas service to approximately 650,000 customers and retail electric service to approximately 1.7 million customers. The NSP Companies also own and/or supply substantial natural gas-fired generation.

The NSP Companies are firm transportation service customers of Viking. Viking service is used, primarily, to serve retail gas local distribution company loads and, when necessary, for fuel deliveries to gas fired electric generation plants.

2. Viking's FERC Form No. 501-G Filing

In response to the federal corporate income tax reduction resulting from the Tax Cut and Jobs Act (TCJA),[5] the Commission required interstate natural gas pipelines with cost-based rates to submit an abbreviated cost and revenue study designed to demonstrate the effect of the

[5] Tax Cut and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2054 (2017).

reduced corporate tax rates on the pipelines' cost of service (FERC Form No. 501-G).[6] Viking submitted its Form No 501-G in compliance with Order No. 849 on December 6, 2018.[7]

Viking's Form No. 501-G demonstrated that the TCJA income tax rate reduction has reduced Viking's income tax expenses by approximately $1.9 million per year[8] resulting in a significant reduction in Viking's overall cost of service. The annual cost of service included on Viking's Form No. 501-G, based on 2017 actuals and adjusted for the reduced income tax allowance, was $29.6 million.[9]

3. Viking's Rate Case Filing

On June 28, 2019, Viking filed a general NGA section 4 rate case proposing an average seven percent increase to the NSP Companies' transportation rates,[10] with a proposed effective date of August 1, 2019.[11] Pursuant to the settlement of Viking's last NGA section 4 rate case filing, Viking was required to submit new rates to take effect no later than January 1, 2020.[12] The Rate Case Filing proposes an annual cost of service of $37,497,329[13] using a test year ending February 28, 2019,[14] as compared to the $29.6 million indicated in Viking's Form 501-G – an

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[6] *Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Federal Income Tax Rate*, Final Rule, 164 FERC ¶ 61,031 at P 31 (2018); *order den'g reh'g*, 167 FERC ¶ 61,051 (2019) (Order No. 849).

[7] Viking Gas Transmission Company's Filing in Compliance with Order No. 849 – FERC Form No. 501-G, Docket No. RP19-386 (filed Dec. 6, 2018) (Form No. 501-G).

[8] Form No. 501-G, at 1, line 32 (total income tax allowance), column E minus column C.

[9] *Id.* at 1, line 33, column E.

[10] *See* Rate Case Filing, Marked Tariff Sections, Statement of Rates at pp. 1-3.

[11] Rate Case Filing transmittal letter at 2.

[12] Petition of Viking Gas Transmission Company For Approval of Settlement, Docket No. RP14-1185-000, Article III (filed Aug. 15, 20145) (2014 Settlement); *see also*, *Viking Gas Transmission Co.*, 149 FERC ¶ 61,0003 (2014) (order approving settlement).

[13] Rate Case Filing transmittal letter at 3, 4.

[14] *Id*. at 2.

increase of 26 percent. The filing reflects a proposed overall rate of return of 9.22 percent,[15] and a proposed return on common equity of 15.24 percent.[16] Viking proposes to retain its pre-existing zonal and "Term Differentiated Rate" structures, and beyond the significant rate increase, the Rate Case Filing includes only ministerial Tariff changes.

B. Motion to Intervene

As firm shippers on Viking, the NSP Companies are interested parties within the meaning of NGA section 15(a), and will be directly affected by the outcome of this proceeding. Viking's Rate Case Filing proposal would increase the NSP Company's rates for service, resulting in increased gas rates for the NSP Companies' retail natural gas customers. The NSP Companies' interests on this proceeding cannot be adequately represented by other parties. As such, the participation of the NSP Companies as intervenors will serve the public interest. Therefore, the NSP Companies respectfully move the Commission for leave to intervene in this proceeding with full participant rights.

III. PROTEST

Viking has not demonstrated that the proposed rate increase in its Rate Case Filing is just and reasonable. The Rate Case Filing raises issues of material fact, and the full impacts of the proposed changes are not discernible from the contents of Viking's filing. The NSP Companies respectfully request that the Commission suspend Viking's proposed rates for the maximum five-month suspension period, and set the Rate Case Filing for a full evidentiary hearing.

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15 Rate Case Filing, Exhibit No. VGT-0003, Prepared Direct Testimony of Julie D. Weatherly (Weatherly Testimony) at p. 7, lines 17-18.

16 Rate Case Filing, Exhibit No. VGT-0001, Prepared Direct Testimony of Ronald M. Mucci (Mucci Testimony), at p. 7, lines 10-14.

This protest is based upon a preliminary review, and the NSP Companies explicitly reserve the right to raise additional issues upon further examination of the Rate Case Filing, and as additional information becomes available. At this time, the NSP Companies protest at least the following elements of the Rate Case Filing.

A. Viking Has Not Shown That its Proposed Rate Increase for Transportation Service are Just and Reasonable.

Viking's proposed rate increase, including an average seven percent increase to its maximum recourse rate for Firm Transportation Service agreements longer than five years,[17] raises contested issues of material fact that cannot be resolved without discovery and a hearing. These issues include, but are not limited to the proposed: (i) cost of service, (ii) depreciation and negative salvage rates, (iii) corporate overhead allocations, and (iv) accounting treatment, as shown on Viking's filed Statement G, of imbalance management costs, load management cost reconciliation, and calculation methodology for gas balance shown on Schedule I-5.

1. Viking's Proposed Cost of Service May be Excessive, Unjust, and Unreasonable.

The Rate Case Filing uses a cost of service of $37,497,329 – a 15.4 percent increase over the stipulated $32,487,290 cost of service established by the 2014 settlement.[18] Viking's proposed cost of service is based, *inter alia*, on Viking's operations and maintenance (O&M) expenses, a 60.51 percent debt / 39.49 percent equity capital structure,[19] a proposed return on

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[17] Rate Case Filing, Marked Tariff Sections, Statement of Rates at pp. 1-3.

[18] Rate Case transmittal letter at 4.

[19] Mucci Testimony at p. 9, lines 10-11. Viking based its capital structure on the capital structure of Viking's debt-issuing parent company, ONEOK. Weatherly Testimony at p. 7, line 19 – p. 8, line 2.

equity (ROE) of 15.24 percent,[20] and a transmission plant depreciation rate of 2.39 percent.[21] Viking's overall proposed cost of service appears excessive, and individual cost components require further evaluation and discovery.

Finally, the cost of service proposed in the Rate Case Filing is wholly inconsistent with the reduction to Viking's cost of service indicated by Viking's FERC Form No. 501-G filing. In December 2018, Viking's Form No. 501-G calculations, based on 2017 actuals adjusted for the TCJA income tax rate reduction, resulted in an annual cost of service of $29.6 million.[22] The Rate Case Filing fails to support and explain the significant delta between the cost of service shown on the Form No. 501-G abbreviated cost and revenue study Viking filed approximately seven months ago and the test period numbers in the Rate Case Filing. Viking's Form No. 501-G indicated that a rate reduction is warranted; now Viking is filing to increase rates by an average of seven percent for customers like the NSP Companies, with service subscriptions longer than five years.

Overall, Viking has proposed significant changes to its cost of service that have not been shown to be just and reasonable by the information provided in the Rate Case Filing and should be set for hearing.

2. Viking's Proposed Changes to Depreciation Rates and Negative Salvage Should be Set for Hearing.

Viking's proposed depreciation and negative salvage rates represent a significant component of the proposed rate increase and should be set for hearing. Viking proposes an

[20] Mucci Testimony at p. 7, lines 5-13; Rate Case Filing, Exhibit No. VGT-0009, Prepared Direct Testimony of Dr. M. Ray Perryman (Perryman Testimony) at p. 6, lines 2-13 and Figure 1.

[21] Rate Case Filing, Exhibit VGT-0002, Prepared Direct Testimony of Laura M. Wolf at p. 11, lines 3-4 (Wolf Testimony); Exhibit VGT-0021 (Statement H) at p. 26, Statement H-2, column (g).

[22] Form No. 501-G, at 1, line 33. column (e).

increase to its depreciation rate for transmission plant from 2.0 percent[23] to 2.39 percent.[24] Coupled with Viking's proposal to establish an additional annual accrual rate for negative salvage of 1.10 percent (a separate annual accrual of approximately $2.4 million),[25] the proposed change in depreciation expense and negative salvage has significant effects on Viking's customers' rates. The combination of the higher deprecation rate and the new salvage rate yields a total rate of 3.49 percent, which is an increase of 75 percent over the currently effective rate of 2.0 percent.

Based on the information provided by Viking, it is not clear whether Viking has demonstrated reasonable support for the significant changes in depreciation. Viking's proposed changes to depreciation expense and negative salvage have significant impact on the overall rates, and must be evaluated in detail by the parties through discovery and the Commission at hearing.

3. Viking's Proposed Corporate Intercompany Charges Require Further Scrutiny.

Viking has proposed direct assignment and direct and indirect allocation of approximately $7 million in corporate charges from parent company ONEOK, Inc. (ONEOK) to Viking.[26] These costs are roughly 19 percent of the total $37.5 million claimed cost of service and require further scrutiny and should be set for hearing. The Rate Case Filing provides minimal explanation of the corporate charges, and describes only the basic three-step allocation methodology used to divide charges among the companies ONEOK manages. Viking witness,

[23] 2014 Settlement, Appendix B to Stipulation and Agreement.

[24] Rate Case Filing, Exhibit No. VGT-0012 at p. 84; Exhibit No. VGT-0021 (Statement H) at p. 26, Statement H-2 at line 7, column (g).

[25] Rate Case Filing, Exhibit No. VGT-0011, Prepared Direct Testimony of Larry E. Kennedy at p. 7, lines 10-12, p. 34, lines 18-20.

[26] Rate Case Filing, Exhibit VGT-0021 (Statement H) at p. 24, Schedule H-1 (2)(j) at line 20, column (e).

Ms. Weatherly, provides only a general explanation of how ONEOK allocates charges among the companies.[27] Further, the test period adjustment of $308,000 shown on Schedule H-1 (2)(j), line 30, column (e) comes with little explanation or support. Viking's customers should be given the opportunity to further develop the record regarding the proposed corporate overhead allocation through discovery and hearing.

4. Certain of Viking's Proposed Accounting Treatments Require Further Scrutiny and Should be Set for Hearing.

Viking's Rate Case Filing proposes accounting treatments of certain cost of service components that require further scrutiny and should be set for hearing, including, but not limited to Viking's: (i) cash-outs for imbalances and fuel (Schedules G-6 (2)[28] and G-6 (3)),[29] (ii) accounting for line pack gas management through the Load Management Cost Reconciliation Adjustment (LMCRA) (Schedule G-6 (4)),[30] and (iii) calculation of gas balance for the test period (Schedule I-5).[31]

Schedule G-6(2) shows imbalance cash-outs for the test period in excess of $500,000,[32] and Schedule G-6(4) reflects LMCRA surcharges of almost $250,000 for the same period.[33] The testimony Viking filed to support the schedules included in Statements G and I provides little detail or explanation for the proposed accounting treatment of the Statement G rate components or Viking's calculation methodology to determine the appropriate lost and unaccounted for gas

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[27] Weatherly Testimony at pp. 14, line 1 – 15, line 16; *see also* Exhibit No. VGT-0021 (Statement H) at pp. 23-24, Schedule H-1 (2)(j).

[28] Rate Case Filing, Exhibit No. VGT-0020 (Statement G) at pp. 116-125, Schedule G-6 (2).

[29] *Id.* at pp. 126-132, Schedule G-6 (3).

[30] *Id.* at pp. 133-141, Schedule G-6 (4).

[31] Rate Case Filing, Exhibit No. VGT-0022 (Statement I) at p. 11, Schedule I-5.

[32] Rate Case Filing, Exhibit VGT-0020 (Statement G) at p. 125, Schedule G-6 (2) at line 308, column (h).

[33] *Id.* at p. 125, line 308, column (h).

volumes.[34] Some of the proposed accounting treatments and calculation methodologies contained in Statements G and I require further explanation and should be set for hearing.

B. Some of Viking's Proposed Test Period Adjustments Have Not Been Adequately Supported and Should be Set for Hearing.

Viking's Rate Case Filing proposes a number of test period adjustments that Viking has not supported as sufficiently known and measurable within the adjustment period ending November 30, 2019 and appropriate for inclusion in the development of Viking's rates. A non-exhaustive list of Viking's proposed test period adjustments that should be explored through discovery and at hearing include: (i) the $1.6 million purchase of a spare compressor engine; (ii) $1.8 million adjustment to operations & maintenance expenses; (iii) $500,000 labor cost adjustment; and (iv) the removal of five contracts from the subscriptions listed on Statement G.

Viking included a test period adjustment of $1,601,208 in its Material and Supplies account for the purchase of a spare compressor engine.[35] The cost associated with buying a spare compressor engine appears to be a one-time, non-recurring item that should be reviewed prior to inclusion in the development Viking's rates. The explanation Viking provides for the purchase (having a spare compressor engine in Viking's inventory will minimize service disruption if one of Viking's compressors fails) does not provide adequate support, without further information, to allow the inclusion of this purchase in rates.

Viking's proposed O&M cost adjustments are not adequately supported and explained. Although Viking's witness, Mr. Dunbar, claims that the adjustments are necessitated by "cost

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[34] Rate Case Filing, Exhibit No. VGT-0005, Prepared Direct Testimony of Alan T. Droll (Droll Testimony) at p. 13, line 8 – p. 14, line 4.

[35] Wolf Testimony at p. 10, lines 10-11; Rate Case Filing, Exhibit No. VGT-0008, Prepared Direct Testimony of Wesley R. Dunbar (Dunbar Testimony) at p. 8, lines 16-22; Exhibit No. VGT-0018 (Statement E) at p. 3, Schedule E-2 at line 15, columns (b) and (g).

increases that are not cyclical, or one-time," Mr. Dunbar does not adequately support his claim that the costs "represent the new normal O&M cost expectations for Viking."[36]

Viking proposes eight adjustments to base period O&M costs, totaling $1.8 million.[37] However, Viking provides only cursory statements to support most of the proposed adjustments. For example, in support of Viking's proposed labor cost adjustment of $524,281,[38] Mr. Dunbar makes summary assertions in a few sentences that Viking's labor costs have increased due to low unemployment and increased demand and competition for skilled labor.[39] However, Viking provides no empirical support for such assertions.

Viking also failed to adequately support and explain the circumstances behind its proposed removal of the reservation and commodity volumes associated with five contracts from the calculation of Viking's billing determinants.[40] Viking's witness, Mr. Droll, notes only that the contracts in question are expired Rate Schedule FT-A contracts for more than one month and associated release contracts.[41] Mr. Droll goes on to note that the proposed adjustment "reduced annual reservation and commodity billing determinants by 347,000 Dth and 8,110,049 Dth, respectively."[42] Viking provides no explanation as to the circumstances behind the expiration of the contracts or support for this significant proposed test period adjustment. The proposed

[36] Dunbar Testimony at p. 3, lines 2-4.

[37] Weatherly Testimony at p. 10, lines 6-8; Exhibit No. VGT-0021 (Statement H) at pp. 5-13, Schedule H-1(2).

[38] Weatherly Testimony at p. 12, lines 12-21.

[39] Dunbar Testimony at p.3, line 13 – p. 4, line 3.

[40] Exhibit No. VGT-0020 (Statement G) at p. 111, Schedule G-3 at lines 4-9, column (g).

[41] Droll Testimony at p. 9. Lines 4-7.

[42] *Id.* at p. 9, lines 8-10.

removal of the contracts' reservation billing determinants and commodity volumes requires further scrutiny and should be set for hearing.

C. Early Amortization of Viking's Excess Accumulated Deferred Income Tax is Contrary to Commission Policy.

Any amortization of Viking's $14,079,440 test period balance of excess accumulated deferred income tax (ADIT)[43] before placing into effect reduced rates reflective of such amortization is contrary to Commission policy and precedent. Viking's tax witness, Mr. Blake, states that:

> Viking has amortized the regulatory liability associated with the TCJA resulting in a credit to income tax allowance of $172,526 for the ten months ended December 31, 2018; $48,409 for the two months ended February 28, 2019 and $217,842 for the nine months ending November 30, 2019. The resulting credit is $220,935 for the base period and $283,504 for the twelve months ending November 30, 2019. As required under [the Average Rate Assumption Method (ARAM)], the amortization of the regulatory liability began in January 2018 at the asset level for each asset where the book depreciation exceeded tax depreciation.[44]

Viking's assertion that it is required to begin amortizing excess ADIT on January 1, 2018 is questionable. Viking's proposal to begin amortizing its excess ADIT prior to reflecting the

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[43] Rate Case Filing, Exhibit No. VGT-0004, Prepared Direct Testimony of Timothy S. Blake (Blake Testimony) at p. 7, lines 7-9.

[44] *Id.* at p. 10, lines 3-10.

amortization in rates, is contrary to accounting regulations[45] and Commission policy and precedent.[46]

Allowing Viking to begin amortization of its large balance of excess ADIT prior to placing into effect new rates that reflect such amortization would harm the pipeline's customers. First, customers would have a higher rate base in any future rate case due to the earlier amortization. Second, customers would never be able to recover the excess ADIT amortization that occurred before the effective date of new rates set through this NGA section 4 proceeding. Any early amortization of Viking's excess ADIT would contravene the Commission's accounting rules and long-standing Commission policy.

IV. REQUEST FOR MAXIMUM SUSPENSION

The NSP Companies respectfully request that the Commission suspend Viking's proposed rates for the maximum five-month period permitted under section 4 of the NGA and make Viking's imposition of the proposed rates after the suspension period subject to refund. The Commission applies the maximum suspension period where "preliminary study leads the

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[45] Accounting Standards Codification (ASC) 980 – Regulated Operations:

> If a gain or other reduction of net allowable costs is to be amortized over future periods for rate-making purposes, the regulated enterprise shall not recognize that gain or other reduction of net allowable costs in income of the current period. Instead, it shall record it as a liability for future reductions of charges to customers that are expected to result.

[46] *See, e.g.*, *Accounting for Income Taxes*, Letter Ruling, Docket No. AI93-5-000 (issued April 23, 1993), *order denying reh'g, In re: Columbia Gas Transmission Corp. and Columbia Gulf* Transmission *Co.*, 64 FERC 61,352 (1993); *see also*, P*ublic Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes*, Notice of Proposed Rulemaking, 165 FERC ¶ 61,117 at P 39 (2018) (NOPR) (In the context of transmission formula rates, the Commission has stated that "public utilities should not amortize an excess ADIT regulatory liability for accounting purposes until it is included in ratemaking." (citing 18 C.F.R. part 101, Account 182.3 (Other Regulatory Assets), which states: "The amounts recorded in this account are generally to be charged, concurrently with the recovery of the amounts in rates…"). NOPR at note 65.

Commission to believe that the filing may be unjust, unreasonable, or that it may be inconsistent with other statutory standards."[47] As discussed above, Viking has not demonstrated that its proposed rates are just and reasonable. Nor has it shown that maximum suspension would lead to "harsh and inequitable results."[48] Consistent with Commission policy, and based on the issues raised by the NSP Companies, the Commission should suspend Viking's proposed rates for the maximum five-month period, subject to refund.

V. REQUEST FOR FULL EVIDENTIARY HEARING

The NSP Companies respectfully request that the Commission order a full evidentiary hearing on the Rate Case Filing to determine whether Viking's proposed rates are just and reasonable and not unduly discriminatory. The Commission is obliged to conduct a hearing where genuine issues of material fact exist and cannot be resolved on the written record alone.[49] As discussed above, the NSP Company's preliminary analysis of the Rate Case Filing, conducted without the benefit of discovery, has identified numerous disputed issues of material fact that require further investigation.[50] Discovery and a full evidentiary hearing are necessary to ensure that the necessary facts are developed to determine whether Viking's proposed rates, terms and conditions of service are just and reasonable and not unduly discriminatory. Accordingly, the

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[47] *El Paso Natural Gas Co.*, 112 FERC ¶ 61,150, P 92 (2005), *reh'g denied*, 116 FERC ¶ 61,016 (2006), *review denied sub nom. Freeport-McMoRan Corp. v. FERC*, 669 F.3d 302 (D.C. Cir. 2012).

[48] *CenterPoint Energy – Miss. River Transmission, LLC*, 140 FERC ¶ 61,253, P 78 (2012) (citing *Valley Gas Transmission, Inc.*, 12 FERC ¶ 61,197 (1980)).

[49] *See, e.g.*, *Cajun Elec. Power Coop., Inc. v. FERC*, 28 F.3d 173, 177 (D.C. Cir. 1994); *Moreau v. FERC*, 982 F.2d 556, 568 (D.C. Cir. 1993); *Vt. Dep't of Pub. Serv. v. FERC*, 817 F.2d 127, 140 (D.C. Cir. 1987).

[50] *See, supra.* section III.

Commission should establish an evidentiary hearing to evaluate the justness and reasonableness of Viking's proposed rates.

VI. CONCLUSION

The NSP Companies respectfully submit that overall, the Rate Case Filing fails to adequately support the proposed rates, and they may be unjust and unreasonable. For the foregoing reasons, and for good cause shown, the NSP Companies respectfully ask that the Commission (i) grant this motion to intervene; (ii) suspend Viking's proposed rates for the maximum period; (iii) set the Rate Case Filing for full evidentiary hearing; and (iv) take other action consistent with the protest set forth above.

Dated: July 10, 2019

Respectfully submitted,

/s/ Valerie L. Green

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Attorneys for Northern States Power Company, a Minnesota corporation and Northern States Power Company, a Wisconsin corporation

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon the parties designated on the official service list compiled by the Secretary for the above-captioned dockets in accordance with the requirements of Rule 2010 of the Federal Energy Regulatory Commission's Rules of Practice and Procedure, 18 C.F.R. 385.2010 (2019).

Dated at Washington, D.C. on the 10th day of July 2019.

/s/ Jenekia Shade

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Document Content(s)

168 FERC ¶ 61,070
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur and Richard Glick.

Viking Gas Transmission Company — Docket Nos. RP19-386-000, RP19-1340-000

ORDER ACCEPTING AND SUSPENDING TARIFF RECORD SUBJECT TO REFUND, ACCEPTING TARIFF RECORD, ESTABLISHING HEARING PROCEDURES, AND TERMINATING FERC FORM NO. 501-G PROCEEDING

(Issued July 31, 2019)

1. On June 28, 2019, Viking Gas Transmission Company (Viking) filed, in Docket No. RP19-1340-000, a Natural Gas Act (NGA) section 4 rate case (2019 Rate Case) to fulfill its obligations under the pre-packaged settlement resolving its prior rate proceeding (2014 Settlement).[1] To implement its proposed rate and tariff changes, Viking filed tariff records to be effective August 1, 2019.[2] As discussed below, the Commission accepts and suspends for five months the rate increases reflected in Viking's 2019 Rate Case, subject to refund and the outcome of a hearing, and accepts a tariff record implementing a minor administrative update. The Commission also terminates Viking's FERC Form No. 501-G proceeding in Docket No. RP19-386-000.

I. **Background**

2. Viking states that it provides transportation services from an interconnection with TransCanada Pipeline Company at the Canadian border near Emerson, Manitoba, to an end-point in central Wisconsin, where it interconnects with ANR Pipeline Company. Viking states that it is currently a bidirectional system that was originally designed to

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[1] *See Viking Gas Transmission Co.*, 149 FERC ¶ 61,003 (2014) (Settlement Order).

[2] Viking Gas Transmission Company, FERC NGA Gas Tariff, Viking - FERC Gas Tariff, Tariff, Volume No. 1, 7.0.0 and Part 5.0, Statement of Rates, 34.0.0.

bring western Canadian supplies to upper Midwest markets in North Dakota, Minnesota, Wisconsin, and indirectly, Michigan.[3]

3. On October 1, 2014, the Commission approved a pre-packaged settlement agreement in Docket No. RP14-1185-000, i.e., the 2014 Settlement, which resolved all issues in Viking's prior NGA section 4 rate case and established its currently effective rates.[4] Viking states that the instant filing fulfills a requirement set forth in Article III of the 2014 Settlement requiring Viking to submit new rates to take effect, assuming a five-month suspension period in the instance of a proposed rate increase, no later than January 1, 2020.[5]

4. Order No. 849 required interstate natural gas pipeline companies to file a FERC Form No. 501-G containing an abbreviated cost and revenue study primarily using data in the pipelines' 2017 FERC Form Nos. 2 and 2-A.[6] On December 6, 2018, Viking filed its FERC Form No. 501-G in Docket No. RP19-386-000 and elected Option 3 (statement explaining why no rate adjustment is needed) because the 2014 Settlement required Viking to file a general NGA section 4 rate case with rates to become effective no later than January 1, 2020. Viking's FERC Form No. 501-G indicated that it is a separate income taxpaying entity. Therefore, its FERC Form No. 501-G included a reduced tax allowance reflecting the reduced federal corporate income tax rate mandated by the Tax Cuts and Jobs Act of 2017 (TCJA).[7] Viking's FERC Form No. 501-G showed a Total Estimated Return on Equity (ROE) of 36.0 percent after adjusting for the income tax

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[3] Ex. VGT-0006 at 2-3.

[4] Viking states that its Commission-approved rates, including its currently effective rates, have, since at least as far back as 2002, been established on a "black box" basis, i.e., there is no stipulated cost of service, rate base, or billing determinants identified. Viking notes that the prior rate components submitted here were presented and attested to in Viking's last general NGA section 4 rate case in Docket No. RP14-1214-000, which was subsequently withdrawn, but served as the basis for the approval of Viking's pre-packaged settlement in Docket No. RP14-1185-000. Transmittal at 4.

[5] *Id.* at 1 & n.3 (citing Settlement Order, 149 FERC ¶ 61,003).

[6] *Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Federal Income Tax Rate,* Order No. 849, 83 Fed. Reg. 36,672 (July 30, 2018), 164 FERC ¶ 61,031 (2018), *reh'g denied*, Order No. 849-A, 167 FERC ¶ 61,051 (2019).

[7] An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018, Pub. L. No. 115-97, 131 Stat. 2054 (2017).

reduction.[8] Viking's FERC Form No. 501-G showed an indicated cost-of-service reduction of 4.2 percent. Viking's FERC Form No. 501-G filing was protested, with protestors citing concerns about Viking's ROE and excess accumulated deferred income taxes (ADIT).

II. <u>Proposal</u>

5. In the instant NGA section 4 filing, Viking proposes a general rate increase applicable to its jurisdictional transportation services in order to avoid a revenue deficiency in light of Viking's current and projected cost of operations. Viking states that the proposed rate increase reflects increases in its cost of service and overall billing determinants, for the twelve months ending February 28, 2019, adjusted for known and measurable changes that will become effective prior to November 30, 2019, the end of the test period.[9]

6. Viking proposes rates designed upon a total annual cost of service of $37,497,329 and a total rate base of $71,955,739, which includes new plant that Viking expects to be added and in service by the end of the test period.[10] Viking states that the cost of service reflects an ROE of 15.24 percent[11] and a capital structure of 60.51 percent debt and 39.49 percent equity (which includes 0.12 percent of preferred stock).[12] Viking states that its overall rate of return of 9.22 percent is based upon the capital structure of Viking's debt-issuing parent company, ONEOK, Inc. (ONEOK).[13] Furthermore, Viking proposes changes to its annual depreciation and negative salvage rates originally approved by the Commission in the settlement of Viking's general NGA section 4 proceeding in Docket No. RP02-132-002, and retained in the Commission-approved pre-packaged 2014 Settlement in Docket No. RP14-1185-000.[14] Here, Viking proposes a

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[8] Total Estimated ROE is the ROE as calculated in Viking's FERC Form No. 501-G on page 3, line 26.

[9] Transmittal at 2.

[10] Ex. VGT-0001 at 6.

[11] Viking states that it developed the 15.24 percent ROE from a proxy group of seven companies using the discounted cash flow methodology. *See* Ex. VGT-0009 at 6.

[12] Ex. VGT-0019 at 1.

[13] Ex. VGT-0003 at 7.

[14] Transmittal at 4.

depreciation rate for transmission plant of 2.39 percent[15] and an additional annual accrual rate for negative salvage of 1.10 percent.[16]

7. Viking's filing also reflects the continued use of its current zonal rate design and existing Term Differentiated Rate (TDR) structure. Viking's TDR structure divides Viking's contract portfolio for each zone into three categories with differing rates based on contract length: Category 1 (one day to less than three years); Category 2 (three years to less than five years); and Category 3 (five or more years).[17] During the test period, Viking projects an increase in annual reservation billing determinants of 154,585 dekatherms (Dth), for a total of 6,960,521 Dth (total includes interruptible transportation reservation billing determinants and a small discount adjustment), and a decrease in annual commodity billing determinants of 6,170,663 Dth, for a total of 119,491,090 Dth.[18]

8. Finally, Viking proposes a minor administrative update to the title page of its tariff to reflect the name and contact information of the person to whom communications regarding the tariff should be addressed. Aside from the rate increases and this administrative tariff change, Viking proposes no other tariff revisions in this filing.[19]

III. <u>Notice of Filing, Interventions, and Protests</u>

9. Public notice of Viking's filings in Docket Nos. RP19-386-000 and RP19-1340-000 was issued on December 6, 2018, and June 28, 2019, respectively. Interventions and protests were due as provided in section 154.210 of the Commission's regulations.[20] Pursuant to Rule 214,[21] all timely filed motions to intervene and any unopposed motion to intervene out-of-time filed before the issuance date of this order are granted. Granting late intervention at this stage of the proceeding will not disrupt the proceeding or place additional burdens on existing parties.

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[15] Ex. VGT-0002 at 11.

[16] Ex. VGT-0011 at 7.

[17] Ex. VGT-0005 at 5.

[18] *Id*. at 11 and Ex. VGT-0020 at 1.

[19] Transmittal at 4-5.

[20] 18 C.F.R. § 154.210 (2018).

[21] 18 C.F.R. § 385.214 (2018).

10. On December 18, 2018, Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation (collectively, NSP Companies); WEC Energy Group, Inc., on behalf of its subsidiaries Minnesota Energy Resources Corporation and Wisconsin Gas LLC; CenterPoint Energy Resources Corporation (CenterPoint); and the Michigan Public Service Commission submitted protests or made adverse comments to Viking's FERC Form No. 501-G filing in Docket No. RP19-386-000. On July 10, 2019, Viking Shipper Alliance (Shipper Alliance), CenterPoint, and NSP Companies filed protests in response to Viking's filing in Docket No. RP19-1340-000.

11. All protesting parties contend that Viking's cost of service appears excessive and request additional review of its various components. Specifically, Shipper Alliance argues for further examination of large test period additions included in Viking's various cost-of-service accounts such as Account No. 367 (Mains), Account No. 368 (Compressor Station Equipment), Account No. 392 (Transportation Equipment), and Account No. 861 (Maintenance Supervision and Engineering). Shipper Alliance also protests Viking's proposed depreciation rate and ROE, arguing that Viking lacks reasonable support and justification for these proposals.

12. NSP Companies assert that Viking's proposed cost of service is inconsistent with the cost-of-service reductions indicated in Viking's FERC Form No. 501-G filing. NSP Companies specifically take issue with Viking's accounting treatments of certain cost-of-service components, including those found in Schedule G-6 and Schedule I-5. NSP Companies also protest Viking's proposed removal of the reservation and usage volumes associated with five contracts from the calculation of Viking's billing determinants, and argue that Viking provided no explanation as to the circumstances behind the expiration of these contracts.

13. Shipper Alliance and NSP Companies take issue with Viking's test period addition of $1.6 million for a spare compressor, and the corporate overhead charges directly assigned and allocated to Viking from its parent, ONEOK. Shipper Alliance and NSP Companies also note that Viking began amortization of Viking's TCJA regulatory liability without reducing rates to reflect that amortization. Shipper Alliance asserts that by doing this, Viking is amortizing the regulatory liability to itself, increasing its net income in conflict with the instructions to Account No. 254 set forth in 18 C.F.R. Part 201.[22] NSP Companies assert that allowing Viking to begin amortizing its large

[22] Shipper Alliance Protest at 4 & n.4 (citing 18 C.F.R. pt. 201 (Account No. 254C) (2019) requiring that, "[i]f it is later determined that the amounts recorded in this account will not be returned to customers through rates or refunds, such amounts shall be credited to Account [No.] 421, Miscellaneous Nonoperating [I]ncome, or Account [No.] 434, Extraordinary Income, as appropriate, in the year such determination is made.").

balance of excess ADIT prior to establishing new rates that reflect such amortization would harm the pipeline's customers by causing customers to face a higher rate base in any future rate case due to the earlier amortization. NSP Companies further argue that customers would never be able to recover the excess ADIT amortization that occurred before the effective date of new rates set through this NGA section 4 proceeding.

14. Generally, the protesting parties request that the Commission set all rate-related matters in the instant proceeding for evidentiary hearing to examine the justness and reasonableness of Viking's proposed rates and accept and suspend the rate filing for the maximum five-month period permitted by the NGA.

IV. Discussion

15. Viking's 2019 Rate Case filing raises many issues that warrant further investigation. The Commission finds that there are material issues of fact in dispute concerning, among other things, cost of service, rate of return, depreciation and negative salvage rates, cost allocation, and rate design. Accordingly, the Commission will establish a hearing before an Administrative Law Judge to explore the issues arising from the filing, including, but not limited to, those summarized above and set forth in the protests.

16. Accordingly, the Commission accepts and suspends for five months, subject to refund, Viking's tariff record reflecting rate increases for its services, so that the proposed changes may be reviewed at hearing. The Commission, however, accepts Viking's tariff record reflecting administrative changes to the title page of its tariff record because changes to the name and contact information of the person to whom communications regarding the tariff should be addressed are merely ministerial and not substantive.

A. Hearing Process

17. Viking must adhere to section 154.303(c)(2) of the Commission's regulations, which provides at the end of the test period, the pipeline must remove from its rates costs associated with any facility that is not in service or for which certificate authority is required but has not been granted.[23]

B. Suspension

18. Based upon review of the filing, the Commission finds that Viking's proposed rate increases have not been shown to be just and reasonable, and may be unjust, unreasonable, and unduly discriminatory or otherwise unlawful. Accordingly, the Commission shall accept for filing and suspend Viking's proposed Statement of Rates

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[23] 18 C.F.R. § 154.303(c)(2) (2018).

tariff record for five months, to be effective January 1, 2020, subject to refund and the outcome of the hearing ordered herein.

19. The Commission's policy regarding suspension is that tariff filings generally should be suspended for the maximum period permitted by statute where a preliminary study leads the Commission to believe that the filing may be unjust, unreasonable, or inconsistent with other statutory standards.[24] It is recognized, however, that shorter suspensions may be warranted in circumstances where suspension for the maximum period may lead to harsh and inequitable results.[25] Such circumstances do not exist here, except for the tariff record containing only ministerial changes. Therefore, the Commission will suspend for the maximum period of five months the proposed tariff record that implements the rate increases listed herein, to be effective January 1, 2020, subject to refund and the outcome of the hearing ordered herein.

C. FERC Form No. 501-G

20. Order No. 849 required all interstate natural gas companies with cost-based stated rates to file the FERC Form No. 501-G.[26] Because Viking has now filed a rate case under NGA section 4, the justness and reasonableness of its rates can be investigated in that proceeding. Therefore, the Commission terminates Viking's FERC Form No. 501-G proceeding in Docket No. RP19-386-000.

The Commission orders:

(A) The tariff record reflecting rate increases (Part 5.0, Statement of Rates, 34.0.0) is accepted and suspended, to be effective upon motion on January 1, 2020, subject to refund and the outcome of the hearing established herein, as discussed in the body of this order.

(B) The title page tariff record (Tariff, Volume No. 1, 7.0.0) is accepted, effective August 1, 2019, as discussed in the body of this order.

(C) Upon its motion to place suspended rates into effect, Viking must remove from those rates the cost of facilities not placed in service before the end of the test period.

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[24] *See Great Lakes Gas Transmission Co.*, 12 FERC ¶ 61,293 (1980) (five-month suspension).

[25] *See Valley Gas Transmission, Inc.*, 12 FERC ¶ 61,197 (1980) (one-day suspension).

[26] Order No. 849, 164 FERC ¶ 61,031 at P 30.

(D) The captioned FERC Form No. 501-G proceeding in Docket No. RP19-386-000 is terminated, as discussed in the body of this order.

(E) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and the NGA, particularly sections 4, 5, 8, 9, and 15 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the NGA (18 C.F.R. Chapter I), a public hearing shall be held concerning the justness and reasonableness of Viking's proposed tariff records, as discussed in the body of this order.

(F) A Presiding Administrative Law Judge, to be designated by the Chief Administrative Law Judge for that purpose pursuant to 18 C.F.R. § 375.304 (2018), must convene a prehearing conference in this proceeding to be held within twenty (20) days after issuance of this order, in a hearing or conference room of the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426. The prehearing conference shall be held for the purpose of clarifying the positions of the participants and establishing any procedural dates necessary for the hearing. The Presiding Administrative Law Judge is authorized to conduct further proceedings in accordance with this order and the Commission's Rules of Practice and Procedure.

By the Commission. Commissioner McNamee is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

Document Content(s)

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Comments

Docket No. G002/M-19-498

Dated this **3rd** day of **October 2019**

/s/Sharon Ferguson

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