BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Niagara Mohawk Power Corporation d/b/a National Grid

Cases 17-E-0238 & 17-G-0239

August 2017

Pre-Filed Exhibits of Staff
Gas Safety Panel

William Wade
Utility Supervisor

Michael Pasinella
Utility Engineer 2 (Safety)

Jeremiah Belda
Assistant Engineer (Mechanical)

William Koch
Assistant Engineer (Mechanical)

Office of Electric, Gas, & Water

State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Case 17-G-0239

Index of Gas Safety Panel (GSP) Exhibits

Exhibit GSP-1

Relied Upon Responses to Information Requests

Table of Contents

Date of Request: March 17, 2017 Request No. DPS-PF 228
Due Date: April 28, 2017 NMPC Req. No. NM Gas-PF228

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Response to Staff's Pre-Filing Information Requests
Gas Utilities

Request for Information

SUBJECT: **Gas Safety**

Leak Prone Pipe (LPP) Replacement (if applicable)

Request:

228. For each operating service territory, provide the total mileage of LPP replaced, per material type, as of December 31 for each of the previous five calendar years.

Response:

The total miles of LPP retired, per material type, as of December 31st for each of the previous five calendar years is provided below.

Material	2012	2013	2014	2015	2016
Cast Iron	27	33.6	39.6	37.7	44.2
Unprotected Bare Steel	1	6.8	2.4	1.2	1.4
Unprotected Coated Steel	0	0	0	0	0

Name of Respondent: Saadat Khan

Date of Reply: April 28, 2017

Date of Request: March 17, 2017 Request No. DPS-PF 227
Due Date: April 28, 2017 NMPC Req. No. NM Gas-PF227

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Response to Staff's Pre-Filing Information Requests
Gas Utilities

Request for Information

SUBJECT: **Gas Safety**
Leak Prone Pipe (LPP) Replacement (if applicable)

Request:

227. For each operating service territory, provide the total mileage of LPP remaining, per material type, as of December 31 for each of the previous five calendar years.

Response:

The table below sets forth the total miles of leak-prone main remaining as of December 31st for each of the previous five calendar years.

Material	2012	2013	2014	2015	2016
Cast Iron	585	548	523	489	453
Unprotected Bare Steel	58	57	59	58	55
Unprotected Coated Steel	180	179	172	169	163

Name of Respondent: Date of Reply:
Saadat Khan April 28, 2017

Date of Request: March 17, 2017 Request No. DPS-PF 183
Due Date: April 28, 2017 NMPC Req. No. NM Gas-PF183

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Response to Staff's Pre-Filing Information Requests
Gas Utilities

Request for Information

SUBJECT: **Gas Safety**
Leak Management

Request:
183. Provide the total number of Type 1, 2A, 2, and 3 leaks on the system which were backlogged on December 31 for each of the previous five calendar years.

Response:

The table below sets forth the total number of Type 1, 2A, 2, and 3 leaks on the Company's system that were backlogged on December 31st for each of the previous five calendar years.

	2012	**2013**	**2014**	**2015**	**2016**
Type 1	0	0	0	1	0
Type 2A	2	0	1	3	3
Type 2	2	0	4	13	18
Sub-total	4	0	5	17	21
Type 3	1,675	1,650	1,547	919	940
Total	1,679	1,650	1,552	936	961

Name of Respondent: Date of Reply:
Saadat Khan April 28, 2017

Date of Request: March 17, 2017
Due Date: April 28, 2017

Request No. DPS-PF 226
NMPC Req. No. NM Gas-PF226

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

Response to Staff's Pre-Filing Information Requests
Gas Utilities

Request for Information

SUBJECT: **Gas Safety**

Damage Prevention

Request:

226. How has the Company performed when compared with that of its specific damage prevention calendar year-end targets for the previous five calendar years?

Response:

The Company has outperformed its damage prevention targets for the previous five calendar years, with the limited exception of the total damages and mismarks metrics in calendar year 2015, as shown below:

Metric	Target	2015 Performance
Total damages per 1000 one-call tickets	≤2.5	2.87
Damages due to mismarks	≤0.48	0.71

Name of Respondent:
John Fiume

Date of Reply:
April 28, 2017

Date of Request: June 14, 2017 Request No. DPS-330 MP-5
Due Date: June 26, 2017 NMPC Req. No. NM-809

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Michael Pasinella

TO: National Grid, Gas Safety Panel

SUBJECT: **INTEGRITY MANAGEMENT**

Request:

In these interrogatories, all requests for data, workpapers or supporting calculations should be construed as requesting any Word, Excel, or other computer spreadsheet models in original electronic format with all formulae intact.

1. Does NMPC utilize in-line inspections for the direct assessment of any pipelines that it maintains? If yes, identify the total miles of main that NMPC maintains, the number of miles that can be in-line inspected, and the first date on which each pipeline mile, or segment, could be inspected with an in-line tool.

2. Has NMPC identified any structural anomalies within the pipelines that it maintains during the previous three years (2014, 2015, and 2016) while utilizing in-line inspections? If yes, how many have been identified?

3. Would the anomalies identified in response to DPS-330(2) have been identified using direct assessment methods other than in-line inspections? If so, identify those methods, and explain how would they identify these anomalies.

4. How does in-line inspection differ from other direct assessment methods?

5. Specify NMPC's preferred method of direct assessment, and explain in detail why it is the Company's preferred method.

Response:

1. Yes. The Company uses in-line inspections ("ILI") as follows:

   Total DOT reportable pipeline = 271.96 miles
   Total ILI enabled pipeline = 110.4 miles

Pipeline Number	Length	Year of ILI	Anomalies Discovered
Pipeline E36	9.45 miles	2012	4
Pipeline 56/64	36 miles	2014	527
Pipeline E18	23.94 miles	2017	2*
Pipeline 16	40.99 miles	Scheduled 2017	ILI has not yet been run

   *ILI vendor provided immediate action anomalies on preliminary report anticipating more anomalies will be reported in Vendor's final report.

2. Yes. The Company has identified anomalies through ILI as follows:

ILI Run Report Year	Number of Anomalies Reported
2014	527
2015	0 – no ILI runs*
2016	0 – no ILI runs*

   *In some years there are no ILI-enabled pipelines scheduled for required inspections.

3. As an alternative to ILI, Niagara Mohawk uses external corrosion direct assessment ("ECDA"). The ECDA method detects pipe coating defects or anomalies. ILI is capable of detecting an anomaly regardless of the condition of the pipe coating and can detect pipe wall loss, manufacturing defects, and changes in geometry. It is not possible to conclude with certainty that a given inspection method would have missed the anomalies that were actually detected; however, ECDA is likely to miss anomalies that did not include evidence of external coating defects. Of the 527 anomalies detected via ILI in 2014, 12 involved internal defects.

4. ILI assesses the entire pipeline length from the launcher to the receiver including High Consequence Areas ("HCAs") and non-HCAs (as defined in 16 NYCRR Part 255.903(e)), assessing for both internal and external pipe wall defects and changes in geometry from inside the pipe. ECDA assesses the pipeline segments classified as HCAs. ECDA can identify external defects in the pipe that correspond with coating defects.

5. Both ILI and ECDA are effective methods to detect pipeline anomalies. ILI can increase the effectiveness of surveys; therefore, the Company is strategically working toward making more of its higher risk pipelines ILI enabled through its Integrity Management Program ("IMP").

Name of Respondent:
Kevin Conklin

Date of Reply:
June 26, 2017

Date of Request: June 14, 2017 Request No. DPS-328 MP-3
Due Date: June 26, 2017 NMPC Req. No. NM-807

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Michael Pasinella

TO: National Grid, Gas Safety Panel

SUBJECT: **GAS ACCOUNTS WITHOUT A CUSTOMER OF RECORD, OR SOFT-OFFS**

Request:

In these interrogatories, all requests for data, workpapers or supporting calculations should be construed as requesting any Word, Excel, or other computer spreadsheet models in original electronic format with all formulae intact.

1. For each of the previous five calendar years (2012, 2013, 2014, 2015, and 2016), provide the total number of accounts in which gas was supplied without having a customer of record.

2. For each of the accounts identified in response to DPS-328(1), provide the time elapsed between identifying premises without a customer of record to the time the gas meters were locked (if any). If meters at these premises were not locked, explain why not.

3. For each of the accounts identified in response to DPS-328(1), provide the number of accounts that had meter readings since the last known customer of record, and the number of accounts that have not had a meter reading since the last known customer of record.

4. Specify the number of accounts identified in response to DPS-328(1) that are equipped with automatic meter reading systems.

5. How many of the accounts identified in response to DPS-328(1) are registering gas consumption despite being associated with unoccupied premises?

6. Specify the total consumption and associated dollar amounts booked for each account identified in response to DPS-328(1).

7. Explain the accounting treatment and/or booking method for cost recovery and associated usage with gas consumed by meters in “soft-off” status (e.g. recorded under “lost and unaccounted for” gas consumption, uncollectible, or some other category).

8. How many inside meters without a customer of record have not been accessible:
   a. for less than one month;
   b. for more than one month but less than or equal to three months;
   c. for more than three months but less than or equal to six months;
   d. for more than six months but less than or equal to one year; and
   e. for more than one year?

9. For meters that are located inside a premise wo which the Company could not gain access, provide the number of attempts the Company made to gain access.

10. Explain what action(s) the Company has taken to date to improve access to inside meters.

11. For the meters that have shown gas usage and have been inaccessible for more than one year, how did the Company determine the amount of gas used as opposed to amount that the Company assigned to leaks or theft of service estimates?

Response:

1. The total number of accounts that did not have a customer of record for some period of time during calendar years 2012, 2013, 2014, 2015, and 2016 is provided in table below.

Year	Number of Accounts
2012	41,835
2013	40,447
2014	42,495
2015	34,330
2016	28,741

2. See Attachment 1 for list of Niagara Mohawk’s inactive accounts for calendar years 2012 through 2016, the date the account was identified as inactive, and the number of days until the account was locked. In November 2014, the Company enhanced its procedures for addressing inactive accounts. Accounts identified after this date were remediated according to the Company’s Inactive Accounts procedure.
   The accounts inactive for 0-60 days are in various stages of the Company’s inactive account process, which involves field visits and back office work to gain access to the premises to

lock the meter. In cases where the accounts have remained inactive for 60 days or more because the Company has not been able to gain access to the premises, the accounts have been referred to the legal process to secure court-ordered access (replevin).

3. All 187,848 meters had at least one meter reading since the last known customer of record.

4. 187,597 accounts identified in response to Question 1 are equipped with automatic meter reading systems.

5. 75,008 accounts identified in response to Question 1 registered some amount of gas consumption during the period 2012 to 2016.

6. Total consumption on these accounts was 15,631,161 therms at an estimated cost of $6,171,006.76 (assuming June gas pricing as listed below) over the five-year period 2012 to 2016.

Rate Class	Usage	Per Therm Monthly Cost Of Gas Rate Effective 6/1/17	Cost
	9,352*	0.395193	$3,695.84
SC1	13,143,630	0.395193	$5,194,270.57
SC1T	340,089	0.395193	$134,400.79
SC2	2,078,363	0.392253	$815,244.12
SC2T	57,260	0.392253	$22,460.41
SC3	791	0.379013	$299.80
SC6	1,676	0.379013	$635.23
Total	15,631,161		$6,171,006.76

*Service class not available.

7. The gas consumption on meters in an inactive status is recorded as Lost and Unaccounted For (“LAUF”) gas.

8.a.-e. The tables below show the number of inside meters without a customer of record that have not been accessible over the requested periods of time.

Pre-2015

Period	Number of accounts
< 30 Days	30,355
1-3 months	17,852
3-6 months	9,223
6-12 Months	5,910
> 1 year	5,353

2015

Period	Number of accounts
< 30 Days	10,341
1-3 months	5,121
3-6 months	2,333
6-12 Months	1,437
> 1 year	784

2016

Period	Number of accounts
< 30 Days	11,206
1-3 months	4,184
3-6 months	1,855
6-12 Months	689
> 1 year	1

All years

Period	Number of accounts
< 30 Days	51,902
1-3 months	27,157
3-6 months	13,411
6-12 Months	8,036
> 1 year	6,138

9. From January 1, 2012 to December 31, 2016, the Company has made 124,024 attempts to gain access to meters that are located inside premises the Company could not access.

10. Under the current inactive account procedure (implemented in April 2015), the Companies will make at least two visits to access accounts within 60 days of the account being identified as inactive. After two unsuccessful visits, the account is referred to Field Operation to cut in the service in the street or the legal replevin process to secure access.

    The Companies have implemented various improvements to the process for gaining access to inactive accounts, including:

    - Developed new end-to-end procedures for locking inactive accounts
    - Deploying additional CMS/back office resources
    - Enhanced customer communications on inactive accounts

- CMS field personnel are collecting access controller information (*e.g.*, rent/for sale sign contact information)
- The back office now contacts other tenants in the building, previous tenants, uses additional Google mapping and tax records as well as contacting the municipalities on foreclosed properties to attempt access the premises
- Established a legal process for securing access to vacant premises.

11. The Company does not distinguish between gas usage on inactive accounts and other forms of lost and unaccounted for gas for purposes of their LAUF calculations. See the response to Question 7.

<u>Name of Respondent</u>:	<u>Date of Reply</u>:
Matt Schleier	June 26, 2017
Kellie I. Smith	

Date of Request: July 15, 2017 Request No. DPS-328 MP-3 AMENDED
Due Date: July 25, 2017 NMPC Req. No. NM-807

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Michael Pasinella

TO: National Grid, Gas Safety Panel

SUBJECT: **GAS ACCOUNTS WITHOUT A CUSTOMER OF RECORD, OR SOFT-OFFS**

Request:

In these interrogatories, all requests for data, workpapers or supporting calculations should be construed as requesting any Word, Excel, or other computer spreadsheet models in original electronic format with all formulae intact.

1. For each of the previous five calendar years (2012, 2013, 2014, 2015, and 2016), provide the total number of accounts in which gas was supplied without having a customer of record.

2. For each of the accounts identified in response to DPS-328(1), provide the time elapsed between identifying premises without a customer of record to the time the gas meters were locked (if any). If meters at these premises were not locked, explain why not.

3. For each of the accounts identified in response to DPS-328(1), provide the number of accounts that had meter readings since the last known customer of record, and the number of accounts that have not had a meter reading since the last known customer of record.

4. Specify the number of accounts identified in response to DPS-328(1) that are equipped with automatic meter reading systems.

5. How many of the accounts identified in response to DPS-328(1) are registering gas consumption despite being associated with unoccupied premises?

6. Specify the total consumption and associated dollar amounts booked for each account identified in response to DPS-328(1).

7. Explain the accounting treatment and/or booking method for cost recovery and associated usage with gas consumed by meters in "soft-off" status (e.g. recorded under "lost and unaccounted for" gas consumption, uncollectible, or some other category).

8. How many inside meters without a customer of record have not been accessible:
   a. for less than one month;
   b. for more than one month but less than or equal to three months;
   c. for more than three months but less than or equal to six months;
   d. for more than six months but less than or equal to one year; and
   e. for more than one year?

9. For meters that are located inside a premise wo which the Company could not gain access, provide the number of attempts the Company made to gain access.

10. Explain what action(s) the Company has taken to date to improve access to inside meters.

11. For the meters that have shown gas usage and have been inaccessible for more than one year, how did the Company determine the amount of gas used as opposed to amount that the Company assigned to leaks or theft of service estimates?

Response:

The Company's response to DPS-328 that was submitted on June 26, 2017 contained various data errors. The data that was provided (i) included accounts from outside the relevant period and (ii) reflected incorrect inactive periods or resolution dates for multiple accounts. To address these issues, the Company performed a manual scrub of the relevant inactive account data and is amending its response accordingly.

1. The corrected total number of accounts to which gas was supplied without having a customer of record for some period of time during calendar years 2012, 2013, 2014, 2015, and 2016 is provided in table below.

Year	Number of Accounts
2012	31,738
2013	31,886
2014	32,829
2015	15,646
2016	11,359

2. Attachment 1 provides a corrected list of Niagara Mohawk's inactive accounts for calendar years 2012 through 2016, the date the account was identified as inactive, and the number of days until the account was locked.

3. All 123,458 meters had a least one meter reading since the last known customer of record.

4. Of the total 123,458 identified accounts, 123,243 accounts are equipped with automatic meter reading systems.

5. Of the 123,458 identified accounts, 61,800 accounts registered some amount of gas consumption during the period 2012 to 2016.

6. Total consumption on the 123,458 identified accounts was 9,703,262 therms, at an estimated cost of $3,834,661 (assuming June 2017 gas pricing as listed below) over the five-year period 2012 to 2016:

Rate Class	Sum Of Usage	Per Therm Monthly Cost Of Gas Rate Effective 6/1/17	Dollar Amount
SC1	9,703,262	0.395193	$3,834,661

7. No amendment to the June 26, 2017response is required.

8. The tables below provide the corrected numbers of inside meters without a customer of record that have not been accessible over the requested periods of time.

Pre 2015

Days	Number of accounts
< 30 Days	22,794
1-3 months	14,703
3-6 months	7,429
6-12 Months	4,654
> 1 year	3,889

2015

Days	Number of accounts
< 30 Days	4,830
1-3 months	2,265
3-6 months	920
6-12 Months	603
> 1 year	311

2016

Days	Number of accounts
< 30 Days	4,638
1-3 months	1,487
3-6 months	675
6-12 Months	244
> 1 year	0

All

Days	Number of accounts
< 30 Days	32,262
1-3 months	18,455
3-6 months	9,024
6-12 Months	5,501
> 1 year	4,200

9. From January 1, 2012 to December 31, 2016, the Company made 69,443 attempts to gain access to meters that are located inside premises the Company could not access.

10. No amendment to the June 26, 2017 response is required.

11. No amendment to the June 26, 2017 response is required.

Name of Respondent:
Matt Schleier
Daniel D'Eletto

Date of Reply:
July 25, 2017

Date of Request: July 12, 2017 Request No. DPS-565 MP-10
Due Date: July 24, 2017 NMPC Req. No. NM-1151

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Michael Pasinella

TO: National Grid, Gas Safety Panel

SUBJECT: **GAS ACCOUNTS WITHOUT A CUSTOMER OF RECORD, OR SOFT-OFFS**

Request:

In these interrogatories, all requests for data, workpapers or supporting calculations should be construed as requesting any Word, Excel, or other computer spreadsheet models in original electronic format with all formulae intact.

1. How long does the Company estimate it will take to get all currently known accounts with no customer of record locked, including those where the service will have to be cut in the street due to lack of access to an internal meter?

2. How long would it take to get all accounts with no customer of record to be less than 30 days old?

3. How long would it take to get all accounts with no customer of record to be less than 60 days old?

4. Data presented in the Company's response to DPS-328(1) shows the Company locking out 3,514 accounts on 12/31/2016. The maximum for any other day between 1/1/2012 and 6/13/2017 was 388. Explain how it is possible that 3,514 inactive accounts were cured on the same date.

5. Explain how more than 300 inactive accounts were locked off on each of the following dates:

a. 6/1/2012,
b. 8/1/2012,
c. 10/1/2012,
d. 11/1/2012,
e. 7/1/2013,
f. 8/1/2013,
g. 11/1/2013,
h. 7/1/2014,
i. 8/1/2014,
j. 9/2/2014,
k. 9/3/2014,
l. 10/1/2014,
m. 11/3/2014,
n. 12/1/2014.

6. In response to DPS-328(1), the Company indicated that 15,631,161 therms were metered through the 187,848 accounts that had no customer of record at some point during the time period 2012 through 2016. Verify that neither the Company nor any customers were billed for the cost of those 15,631,161 therms.

7. Provide the therms metered through the 187,848 accounts that neither the Company nor any customers were billed for the following billing periods (GAC reconciliation periods):

a. January 1, 2012 to August 31, 2012;
b. September 1, 2012 to August 31, 2013;
c. September 1, 2013 to August 31, 2014;
d. September 1, 2014 to August 31, 2015;
e. September 1, 2015 to August 31, 2016; and
f. September 1, 2016 to December 31, 2016.

Response:

1. In accordance with the Company's inactive accounts procedure, Niagara Mohawk secures all services with no customer of record or refers the accounts to a legal replevin process within 60 days of the account becoming inactive. Because the replevin process requires a court order and law enforcement intervention to secure access to the customer's premises, it can take up to a year in some cases.

2. Curing accounts by day 30 would require an additional 900 accounts to be cut and capped and an additional 2,490 accounts to be placed in the replevin process each year. The incremental cost to cure accounts with no customer of record within 30 days would be $5.75 million per year, including the estimated cost to reconnect accounts that were cut and capped.

3. Currently, all accounts over 60 days old with no customer of record have been referred to the replevin process. As discussed above, the timing of the replevin process is dependent on court procedures and scheduling that is not within the Company's control.

4. The Company has submitted an amended response to DPS-328 to update the number of inactive accounts. Please see Attachment 1 to DPS-328 (AMENDED). The 3,514 accounts provided in the original response inadvertently included data for 2017. The correct number of cured inactive accounts on December 31, 2016 is 771 accounts.

5. Please see the Company's response to DPS-328 (AMENDED) for updated data. Please note that the data represents the number of inactive accounts that were cured on that date, either by transitioning to a new customer or locked, and that the Company usually experiences higher volumes of connect and disconnect requests on the first of the month.

6. Please see the Company's response to DPS-328 (AMENDED) for updated data. As indicated therein, the number of accounts with no customer of record for at least some period of time between 2012 and 2016 totaled 123,458. The usage recorded on such accounts was not billed.

7. The unbilled usage for the 123,458 accounts with no customer of record experienced was as follows:

Date Range	Usage
January 1, 2012 to August 31, 2012;	604,156
September 1, 2012 to August 31, 2013;	2,238,027
September 1, 2013 to August 31, 2014;	3,469,306
September 1, 2014 to August 31, 2015;	2,536,890
September 1, 2015 to August 31, 2016; and	723,901
September 1, 2016 to December 31, 2016.	130,982

<u>Name of Respondent</u>:
Matt Schleier
Daniel D'Eletto

<u>Date of Reply</u>:
July 24, 2017

Date of Request: June 14, 2017 Request No. DPS-333 MP-7
Due Date: June 26, 2017 NMPC Req. No. NM-812

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Michael Pasinella

TO: National Grid, Gas Safety Panel

SUBJECT: **RESIDENTIAL METHANE DETECTION**

Request:

In these interrogatories, all requests for data, workpapers or supporting calculations should be construed as requesting any Word, Excel, or other computer spreadsheet models in original electronic format with all formulae intact.

1. On Pages 18 and 19 of the Panel's Pre-Filed Direct Testimony, NMPC proposes to distribute 3,000 residential methane detectors at a cost of $150,000 in fiscal years 2019, 2020, and 2021.

    a. How was the target of 3,000 detectors determined?
    b. What criteria will be used to determine the targeted deployment locations for these methane detectors?
    c. How were the costs associated with the methane detectors forecasted?

2. Does NMPC currently participate in any research programs and/or committees that have focused on the development of residential methane detectors? If so, identify and describe each program and/or committee. If not, explain why not.

3. What is the Company's current understanding of when the methane detectors identified in response to DPS-333(2) would be adopted and commercialized?

4. Are the methane detectors that NMPC plans to install the same as the methane detectors identified in response to DPS-333(2)? If not, how do they differ, and why is NMPC selecting a different detector?

5. Explain in detail why NMPC considers it reasonable to implement a residential methane detection program before the new methane detectors are developed fully.

<u>Response</u>:

1.
   a. The Company's target of 3,000 residential methane detector ("RMD") units per year for fiscal years 2019, 2020, and 2021 was based on the scale of the recently-established RMD pilot program for KEDNY, which will deploy a total of 10,000 RMDs over a three-year period across KEDNY's larger customer base.

   b. As stated in the Direct Testimony of the Gas Safety Panel at page 22 and the Direct Testimony of the Gas Infrastructure and Operations Panel at page 84, the Company intends to work collaboratively with Staff over the next year to implement this program, including targeting distribution of RMDs.

   c. The RMD Program forecast is based on the approximate market price of commercially-available RMD units of $50.00 per unit.

2. Yes. Niagara Mohawk participates in RMD research in collaboration with the Gas Technology Institute ("GTI") and NYSEARCH. Over the past year, the Company has participated in a pilot of over 300 commercially-available RMD units as part of a GTI study. The Company also is involved with a NYSEARCH design and pilot study for a new RMD device. Additionally, Niagara Mohawk and Con Edison have been leading efforts to enhance existing Underwriters Laboratories ("UL") Standard for Safety (Forth Edition), UL -1484.

3. As mentioned above, some units in the GTI study are already commercially available. For example, Universal, First Alert, and Kidde devices are available for purchase and follow the current UL standard set at a detection of 25 lower explosive limit or "LEL." Both the Company and the industry are working to lower the UL standard from 25 LEL to 10 LEL. The NYSEARCH unit will be set at 10 LEL, and a working model has been developed. Once ready, Niagara Mohawk, along with a number of utilities, will participate in field testing of these units. At this point, the Company does not know when the NYSEARCH unit will be commercially available.

4. The Company's proposal is to distribute RMD units to customers, but not to install the units. As stated above, the Company's forecast is based on RMDs that are currently commercially-available. In the event that research over the next year results in a clearly superior RMD unit, the Company will reconsider the best use of the budget for this program in consultation with Staff, including possibly distributing a smaller number of more effective units, depending on unit costs and availability closer to the Rate Year.

5. The Company believes it is appropriate to implement a modest RMD initiative in Upstate New York using commercially-available units to promote the development and deployment of RMDs. While RMD technology is continuing to develop and improve, available devices will enhance customer safety.

<u>Name of Respondent</u>:	<u>Date of Reply:</u>
Michael Gallinaro	June 26, 2017

Date of Request: June 14, 2017 Request No. DPS-329 MP-4
Due Date: June 26, 2017 NMPC Req. No. NM-808

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Michael Pasinella

TO: National Grid, Gas Safety Panel

SUBJECT: **INDEPENDENT ASSESSMENT**

Request:

In these interrogatories, all requests for data, workpapers or supporting calculations should be construed as requesting any Word, Excel, or other computer spreadsheet models in original electronic format with all formulae intact.

1. The Panel states on pages 9 and 10 of its Pre-Filed Direct Testimony that "the Company proactively engaged an industry expert specializing in compliance to provide an independent assessment ("IA") of all processes." Provide the report that summarizes the IA.

2. Indicate how the IA was paid for and the total cost. Include in your response how the costs were allocated to ratepayers and shareholders.

3. If ratepayer funding was used to pay for the IA, indicate what portion of the total was allocated to NMPC.

4. For each recommendation described in the report, indicate whether or not NMPC will accept and implement the recommendation, and when. If NMPC does not intend to implement any such recommendation, explain why not.

5. Does the IA or any of its recommendations deal with the training, assessment, and evaluation related to operator qualifications (OQ) for utility employees or contractor employees? If so, describe the recommendations and how they will improve the security of the OQ testing process, including both cyber and physical security aspects of that process.

6. Describe how the Northeast Gas Association (NGA) ensures that OQ requirements are met for NMPC's employees and contractor workforce.

7. Describe the changes to the OQ program that NGA is considering, why the changes are necessary from NMPC's perspective, and whether the changes will increase costs to ratepayers.

8. If costs related to OQ will increase, provide the dollar amount of the increase that is expected in the rate year.

9. How will IA recommendations be weighted and prioritized for implementation?

10. Page 10 of the Panel's Pre-Filed Direct Testimony refers to API RP1173, which deals with pipeline safety management standards. Explain how NMPC coordinates API RP 1173 with contractor management?

11. Will adherence to API RP 1173 improve the ability for contractors to report problems in the field? If so, explain how.

12. Does NMPC view the pipeline safety regulations as minimum requirements for the safe operation of a natural gas system, or the maximum requirements that a local distribution company should adhere to?

13. Explain how NMPC's procedures are reviewed to ensure that they comply with all applicable gas safety regulations. In your response, explain whether any of these procedures exceed the requirements specified in applicable regulations (e.g., a leakage survey that is repeated semi-annually instead of annually as required by the regulations).

14. The Panel describes on page 15 of its Pre-Filed Direct Testimony proposed enhancements to the QA/QC program. Describe the current efforts to allow field employees to report problems to local supervision, and how that information gets socialized across NMPC and up to senior management to produce any needed changes in operating practices or procedures.

15. Describe the process used to communicate changes in practices or procedures from senior management to employees working in the field, including the contractor work force.

16. Describe the process used to communicate issues identified by employees in the field to Department of Public Service (DPS) Staff, including both field Staff and senior DPS management.

Response:

1. Please see Attachment 1 for a copy of the report that summarizes the IA (the "Report") . Please note that Attachment 1 contains confidential information. Because of the nature of the confidential information and how it is included throughout the documents comprising Attachment 1, redaction is impractical. Therefore, Attachment 1 is being provided only in confidential form (a redacted version will not be separately provided). As discussed at the recent procedural conference, the Company anticipates that a protective order

governing the handling of confidential material will be issued by the Administrative Law Judges shortly. Please protect the information from public disclosure.

2. The total cost of the IA from inception through April 2017 was $669,793. The costs were charged to work order XG210016645 as part of the Gas Business Enablement ("GBE") Program and allocated across all of National Grid's local gas distribution companies in New York State.

3. The total cost of the IA in the Historic Test Year (calendar year 2016) was $532,019, of which $61,319 was allocated to Niagara Mohawk. The IA costs were normalized from the Historic Test Year and not included in the Rate Year forecast. See Exhibit ___ (RRP-11), Workpaper to Exhibit ___ (RRP-3), Schedule 1, Workpaper 2.

4. The Report provides recommendations intended to enhance the Company's existing Process Safety Management System ("PSMS"), in accordance with API RP 1173. Niagara Mohawk is currently developing a plan and timeline for implementing enhancements to the PSMS, based upon the recommendations in the Report. In addition, the GBE Program will address a majority of the recommendations, as discussed in the testimony of the Gas Infrastructure and Operations Panel.

5. Part Two of the Report ("Addressing Regulatory Compliance Concerns") addresses the competency and management of contractors (Finding 37), training delivery (Findings 53, 54 and 56), and coordination with the NGA (Finding 55). The findings and accompanying recommendations are as follows:

Finding	**Recommendation**
(37) Improve Competency and Management of Contractors -- Regulators have identified issues with contractor evaluations, security of tests, individual documentation, management of qualification duties, maintenance of competencies, updating qualifications as procedures change, reevaluation timeframes, and task specific abnormal operating conditions (AOC's).	(58) Communicate hazard assessment requirements and conduct contractor orientations. Integrate prequalification safety reviews, pre-job reviews of site specific requirements, contractor safety plans, oversight inspections during jobs, and post job evaluations. Use standard metrics to evaluate how well performance supports a path to zero quality or safety incidents. (59) Define and control all stages of managing contractors and establish safety plans that define roles and expectations. (60) Establish a policy that details the steps of the contractor management process and implement a sustainable system.

(53) Evaluate the Blend of Training Delivery -- State audit findings of failure to follow procedures, and our observations that not all employees review procedures indicate the need to evaluate how training on procedures is conducted. (54) Define the Blend of Training – Learning and Development (“L&D”) training does not include specific procedures. Although procedure training is part of on the job training, it can be more consistent. (56) Key Factors in Training Improvement -- Consider: Workforce demographic and how it will change, the best course materials for various audiences, new options for training delivery, intervals for refresher training, short and long term training effectiveness, and training for Supervisors.	(90) Reevaluate and adjust the 70-20-10 (classroom-hands-on-on the job) training blend. (91) Hands on training should be on the equipment that employees and contractors will be using. (92) Conduct procedure specific training at L&D Centers. (93) Provide on the job training on specific equipment used. (94) Tie understanding of individual tasks to the entire job. (96) Continue to develop training that addresses specific federal, state and local requirements as well as requirements to operate and maintain gas operations equipment safely and efficiently.
(55) Ensure There Are No Gaps Between the NGA Task Execution and Company Procedures -- It is important that training include specific requirements in Company procedures, work methods and specifications.	(95) Ensure training content addresses Company specific procedure requirements. Enhance the NGA training to include examples of completed documentation.

With regard to improving the security of the operator qualifications (“OQ”) testing process, Niagara Mohawk had begun to address this issue before the Report was completed. Moreover, the Report focuses primarily on the effectiveness of the Company’s training (as opposed to the testing procedures). In the short term, the Company has undertaken efforts to improve the integrity of the testing environment with enhanced classroom security. For example, room seating has been reconfigured so students are facing out with proctors behind them, and there are now at least two proctors, one serving solely as an observer. Proctors now enter a proctor code to activate e-tests. For the long term, Niagara Mohawk is planning to migrate testing to a third party vendor testing site, which uses certified proctors and physical, operational, and software security to protect test delivery.

6. The NGA currently proctors qualification examinations for Niagara Mohawk's contractors. The NGA does not have a role in the OQ process for Niagara Mohawk employees.

7. The Company understands that NGA is considering migrating to a third-party testing model to increase security around OQ testing. Because the Company does not utilize NGA to conduct testing, this change would not have a direct impact on the Company's testing costs. In the meantime, to support the NGA and to ensure timely contractor OQ testing, National Grid's New York local gas distribution companies, including Niagara Mohawk, have set up testing sites at their facilities in Melville, Millbury, Syracuse, Schenectady, and Springfield. Each site, which can hold two sessions each day (a maximum of 30 contractors per day) for six days each week, will meet the NGA revised testing standards and protocols, and every session has one National Grid proctor and one NGA proctor.

8. Niagara Mohawk is planning to migrate testing to third-party testing sites to provide more security. The Company is evaluating service and cost information provided in early June. A more specific proposal, including costs, will be included in the Company's Corrections & Updates filing on July 10, 2017.

9. The Company continues to evaluate the recommendations and will determine which recommendations should be implemented as part of the PSMS and GBE Program. The Company intends to prioritize measures that affect safety and reliability. The Company will consider changes that can be put in place in a quick, efficient, and cost effective manner.

10. API RP 1173 includes recommendations associated with the use of contractors, including but not limited to:
    - communicating applicable requirements of the PSMS in use;
    - defining responsibility, accountability, and authority for managing contractors;
    - incorporating lessons learned into contractor operations;
    - training and orientation on safety policies, as applicable;
    - evaluating safety performance;
    - communicating risks at the work site; and
    - communicating the Management of Change Procedure.

    Niagara Mohawk has processes in place that follow, in whole or in parts, all of the above recommendations. However, the Company will continue to evaluate opportunities to improve upon its existing processes by more fully implementing API RP 1173 to drive continuous improvement in contractor safety performance.

11. Yes. Implementation of the recommendations for use of contractors found in API RP 1173 should result in better two-way communication. As such, contractors will have the ability to share concerns during any of API RP 1173's defined communication points. For example, problems reported by contractors can be captured and used to make improvements in pipeline safety through sharing of lessons learned.

12. Niagara Mohawk's commitment to implement a comprehensive PSMS using API RP 1173 as a foundational document demonstrates the Company's commitment to continuously improve overall safety performance. Pipeline safety regulations are viewed as minimum requirements for the safe operation of a natural gas system.

13. Niagara Mohawk Policy and Gas Work Method documents, which include Company procedures, are reviewed on one and three year review cycles, respectively. Compliance with gas safety regulations and current operating practices are reviewed and updated as necessary. If a regulatory requirement or operating process is changed mid-cycle, updates to procedures are initiated sooner. Procedure updates, once identified and initiated, are thoroughly reviewed by all stakeholders prior to implementation.

    Many Company procedures exceed regulatory requirements. For example, the CNST02001 Leakage Survey Policy exceeds minimum requirements. While state and federal regulations do not require a winter leak patrol, Policy CNST02001 states that a leak survey using mobile leak detection equipment should be conducted during company defined frost periods for company designated segments of the distribution system, and can be adjusted by regional historical data for individual groups.

14. Field employees may report problems to Compliance Analysts who relay information to local supervision. Company "Performance Hubs" located in each operational area are also available to collect information as well as to socialize information across the Company by Directors or Managers who cascade the information to Supervisors who facilitate local hub meetings. Performance Hubs are intended to keep employees aware of and focused on key performance indicators for public and employee safety, compliance, customer satisfaction, and productivity, as well as to provide a forum for those closest to daily field activities to raise obstacles to performing their job and serving customers. Concerns raised by field employees in Performance Hubs are documented for purposes of tracking and resolution and to share among the entire enterprise. If an issue cannot be resolved at the local level, it is escalated to function/process owners for more extensive review and problem solving. As noted in the Report, the Performance Hub process moves internal field employees concerns on local issues up through management and gathers a response in the identification and assessment of risk. As recommended in the Report (recommendations 10, 11, 38, 41), the Company plans to expand the use of Performance Hubs to all levels: team, manager, director, and executive. Lastly, procedures and policies are accessible *via* the Company's infonet internal website. The website allows employees to contact the Work Management Team to address specific concerns or report problems related to Policies, Work Methods, and/or Procedures. Concerns are evaluated and, if a revision is deemed to be needed, the revision is handled by the pertinent Work Management Representative. Once completed, revised Policies, Work Methods, or Procedures are communicated back to all stakeholders.

15. The process used to communicate changes in practices or procedures to employees in the field includes:
    - Monthly updates via email and conference calls

- Bulletins sent out on an as needed basis
- Monthly field reports
- In person barn/yard meetings

16. Company Compliance Analysts (i) communicate issues identified by field personnel to Staff, (ii) relay issues, questions, and information requests from Staff to field personnel, and (iii) address field and record audit information requests. Company personnel at various levels (Compliance Analyst, Manager, Director, and Executive) communicate with DPS management as appropriate.

Name of Respondent:	Date of Reply:
Daniel McNamara	June 26, 2017

HIGH RISK SECTIONS PART 255		
ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Material - General	255.53(a),(b),(c)	HIGH
Transportation of Pipe	255.65	HIGH
Pipe Design - General	255.103	HIGH
Design of Components - General Requirements	255.143	HIGH
Design of Components - Flexibility	255.159	HIGH
Design of Components - Supports and anchors	255.161	HIGH
Compressor Stations: Emergency shutdown	255.167	HIGH
Compressor Stations: Pressure limiting devices	255.169	HIGH
Compressor Stations: Ventilation	255.173	HIGH
Valves on pipelines to operate at 125 psig or more	255.179	HIGH
Distribution line valves	255.181	HIGH
Vaults: Structural Design requirements	255.183	HIGH
Vaults: Drainage and waterproofing	255.189	HIGH
Protection against accidental overpressuring	255.195	HIGH
Control of the pressure of gas delivered from high pressure distribution systems	255.197	HIGH
Requirements for design of pressure relief and limiting devices	255.199	HIGH
Required capacity of pressure relieving and limiting stations	255.201	HIGH
Qualification of welding procedures	255.225	HIGH
Qualification of Welders	255.227	HIGH
Protection from weather	255.231	HIGH
Miter Joints	255.233	HIGH
Preparation for welding	255.235	HIGH
Inspection and test of welds	255.241(a),(b)	HIGH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(a)-(e)	HIGH
Welding inspector	255.244(a),(b),(c)	HIGH
Repair or removal of defects	255.245	HIGH
Joining Of Materials Other Than By Welding - General	255.273	HIGH
Joining Of Materials Other Than By Welding - Copper Pipe	255.279	HIGH
Joining Of Materials Other Than By Welding - Plastic Pipe	255.281	HIGH
Plastic pipe: Qualifying persons to make joints	255.285(a),(b),(d)	HIGH
Notification requirements	255.302	HIGH
Compliance with construction standards	255.303	HIGH
Inspection: General	255.305	HIGH
Inspection of materials	255.307	HIGH
Repair of steel pipe	255.309	HIGH
Repair of plastic pipe	255.311	HIGH
Bends and elbows	255.313(a),(b),(c)	HIGH
Wrinkle bends in steel pipe	255.315	HIGH
Installation of plastic pipe	255.321	HIGH
Underground clearance	255.325	HIGH
Customer meters and service regulators: Installation	255.357(d)	HIGH
Service lines: Installation	255.361(e),(f),(g),(h),(i)	HIGH
Service lines: Location of valves	255.365(b)	HIGH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455(d),(e)	HIGH
External corrosion control: Buried or submerged pipelines installed before August 1, 1971	255.457	HIGH
External corrosion control: Protective coating	255.461(c)	HIGH
External corrosion control: Cathodic protection	255.463	HIGH
External corrosion control: Monitoring	255.465(a),(e)	HIGH
Internal corrosion control: Design and construction of transmission line	255.476(a),(c)	HIGH
Remedial measures: General	255.483	HIGH
Remedial measures: transmission lines	255.485(a),(b)	HIGH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255.505(a),(b),(c),(d)	HIGH
General requirements (UPGRADES)	255.553 (a),(b),(c),(f)	HIGH
Upgrading to a pressure of 125 PSIG or more in steel pipelines	255.555	HIGH
Upgrading to a pressure less than 125 PSIG	255.557	HIGH
Conversion to service subject to this Part	255.559(a)	HIGH
General provisions	255.603	HIGH
Operator Qualification	255.604	HIGH
Essentials of operating and maintenance plan	255.605	HIGH
Change in class location: Required study	255.609	HIGH
Damage prevention program	255.614	HIGH
Emergency Plans	255.615	HIGH

Customer education and information program	255.616	HIGH
Maximum allowable operating pressure: Steel or plastic pipelines	255.619	HIGH
Maximum allowable operating pressure: High pressure distribution systems	255.621	HIGH
Maximum and minimum allowable operating pressure: Low pressure distribution systems	255.623	HIGH
Odorization of gas	255.625(a),(b)	HIGH
Tapping pipelines under pressure	255.627	HIGH
Purging of pipelines	255.629	HIGH
Control Room Management	255.631(a)	HIGH
Transmission lines: Patrolling	255.705	HIGH
Leakage Surveys - Transmission	255.706	HIGH
Transmission lines: General requirements for repair procedures	255.711	HIGH
Transmission lines: Permanent field repair of imperfections and damages	255.713	HIGH
Transmission lines: Permanent field repair of welds	255.715	HIGH
Transmission lines: Permanent field repair of leaks	255.717	HIGH
Transmission lines: Testing of repairs	255.719	HIGH
Distribution systems: Leak surveys and procedures	255.723	HIGH
Compressor stations: procedures	255.729	HIGH
Compressor stations: Inspection and testing relief devices	255.731	HIGH
Compressor stations: Additional inspections	255.732	HIGH
Compressor stations: Gas detection	255.736	HIGH
Pressure limiting and regulating stations: Inspection and testing	255.739(a),(b)	HIGH
Regulator Station Overpressure Protection	255.743(a),(b)	HIGH
Transmission Line Valves	255.745	HIGH
Prevention of accidental ignition	255.751	HIGH
Protecting cast iron pipelines	255.755	HIGH
Replacement of exposed or undermined cast iron piping	255.756	HIGH
Replacement of cast iron mains paralleling excavations	255.757	HIGH
Leaks: Records	255.807(d)	HIGH
Leaks: Instrument sensitivity verification	255.809	HIGH
Leaks: Type 1	255.811(b),(c),(d),(e)	HIGH
Leaks: Type 2A	255.813(b),(c),(d)	HIGH
Leaks: Type 2	255.815(b),(c),(d)	HIGH
Leak Follow-up	255.819(a)	HIGH
High Consequence Areas	255.905	HIGH
Required Elements (IMP)	255.911	HIGH
Knowledge and Training (IMP)	255.915	HIGH
Identification of Potential Threats to Pipeline Integrity and Use of the Threat Identification in an Integrity Program (IMP)	255.917	HIGH
Baseline Assessment Plan(IMP)	255.919	HIGH
Conducting a Baseline Assessment (IMP)	255.921	HIGH
Direct Assessment (IMP)	255.923	HIGH
External Corrosion Direct Assessment (ECDA) (IMP)	255.925	HIGH
Internal Corrosion Direct Assessment (ICDA) (IMP)	255.927	HIGH
Confirmatory Direct Assessment (CDA) (IMP)	255.931	HIGH
Addressing Integrity Issues (IMP)	255.933	HIGH
Preventive and Mitigative Measures to Protect the High Consequence Areas (IMP)	255.935	HIGH
Continual Process of Evaluation and Assessment (IMP)	255.937	HIGH
Reassessment Intervals (IMP)	255.939	HIGH
General requirements of a GDPIM plan	255.1003	HIGH
Implementation requirements of a GDPIM plan.	255.1005	HIGH
Required elements of a GDPIM plan.	255.1007	HIGH
Required report when compression couplings fail.	255.1009	HIGH
Requirements a small liquefied petroleum gas (LPG) operator must satisfy to implement a GDPIM plan	255.1015	HIGH

HIGH RISK SECTIONS PART 261		
Operation and maintenance plan	261.15	HIGH
Leakage Survey	261.17(a),(c)	HIGH
Carbon monoxide prevention	261.21	HIGH
Warning tag procedures	261.51	HIGH
HEFPA Liaison	261.53	HIGH
Warning Tag Inspection	261.55	HIGH
Warning tag: Class A condition	261.57	HIGH
Warning tag: Class B condition	261.59	HIGH

OTHER RISK SECTIONS PART 255		
ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Preservation of records	255.17	OTH
Compressor station: Design and construction	255.163	OTH
Compressor station: Liquid removal	255.165	OTH
Compressor stations: Additional safety equipment	255.171	OTH
Vaults: Accessibility	255.185	OTH
Vaults: Sealing, venting, and ventilation	255.187	OTH
Calorimeter or calorimeter structures	255.190	OTH
Design pressure of plastic fittings	255.191	OTH
Valve installtion in plastic pipe	255.193	OTH
Instrument, control, and sampling piping and components	255.203	OTH
Limitations On Welders	255.229	OTH
Quality assurance program	255.230	OTH
Preheating	255.237	OTH
Stress relieving	255.239	OTH
Inspection and test of welds	255.241(c)	OTH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(f)	OTH
Plastic pipe: Qualifying joining procedures	255.283	OTH
Plastic pipe: Qualifying persons to make joints	255.285(c)(e)	OTH
Plastic pipe: Inspection of joints	255.287	OTH
Bends and elbows	255.313(d)	OTH
Protection from hazards	255.317	OTH
Installation of pipe in a ditch	255.319	OTH
Casing	255.323	OTH
Cover	255.327	OTH
Customer meters and regulators: Location	255.353	OTH
Customer meters and regulators: Protection from damage	255.355	OTH
Customer meters and service regulators: Installation	255.357(a)-(c)	OTH
Customer meter installations: Operating pressure	255.359	OTH
Service lines: Installation	255.361(a), (b), (c), (d)	OTH
Service lines: valve requirements	255.363	OTH
Service lines: Location of valves	255.365(a), (c)	OTH
Service lines: General requirements for connections to main piping	255.367	OTH
Service lines: Connections to cast iron or ductile iron mains	255.369	OTH
Service lines: Steel	255.371	OTH
Service lines: Cast iron and ductile iron	255.373	OTH
Service lines: Plastic	255.375	OTH
Service lines: Copper	255.377	OTH
New service lines not in use	255.379	OTH
Service lines: excess flow valve performance standards	255.381	OTH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455 (a)	OTH
External corrosion control: Examination of buried pipeline when exposed	255.459	OTH
External corrosion control: Protective coating	255.461(a), (b), (d), (e), (f), (g)	OTH
External corrosion control: Monitoring	255.465 (b)(c)(d)(f)	OTH
External corrosion control: Electrical isolation	255.467	OTH
External corrosion control: Test stations	255.469	OTH
External corrosion control: Test lead	255.471	OTH
External corrosion control: Interference currents	255.473	OTH
Internal corrosion control: General	255.475(a)(b)	OTH
Atmospheric corrosion control: General	255.479	OTH
Atmospheric corrosion control: Monitoring	255.481	OTH
Remedial measures: transmission lines	255.485(c)	OTH
Remedial measures: Pipelines lines other than cast iron or ductile iron lines	255.487	OTH
Remedial measures: Cast iron and ductile iron pipelines	255.489	OTH
Direct Assessment	255.490	OTH
Corrosion control records	255.491	OTH
General requirements (TESTING)	255.503	OTH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255.505 (e),(h), (i)	OTH
Test requirements for pipelines to operate at less than 125 PSIG	255.507	OTH
Test requirements for service lines	255.511	OTH
Environmental protection and safety requirements	255.515	OTH
Records (TESTING)	255.517	OTH
Notification requirements (UPGRADES)	255.552	OTH
General requirements (UPGRADES)	255.553 (d)(e)	OTH
Conversion to service subject to this Part	255.559(b)	OTH

Change in class location: Confirmation or revision of maximum allowable operating pressure	255.611(a), (d)	OTH
Continuing surveillance	255.613	OTH
Odorization	255.625 (e)(f)	OTH
Pipeline Markers	255.707(a),(c),(d),(e)	OTH
Transmission lines: Record keeping	255.709	OTH
Distribution systems: Patrolling	255.721(b)	OTH
Test requirements for reinstating service lines	255.725	OTH
Inactive Services	255.726	OTH
Abandonment or inactivation of facilities	255.727(b)-(g)	OTH
Compressor stations: storage of combustible materials	255.735	OTH
Pressure limiting and regulating stations: Inspection and testing	255.739 (c), (d)	OTH
Pressure limiting and regulating stations: Telemetering or recording gauges	255.741	OTH
Regulator Station MAOP	255.743 (c)	OTH
Service Regulator - Min.& Oper. Load, Vents	255.744	OTH
Distribution Line Valves	255.747	OTH
Valve maintenance: Service line valves	255.748	OTH
Regulator Station Vaults	255.749	OTH
Caulked bell and spigot joints	255.753	OTH
Reports of accidents	255.801	OTH
Emergency lists of operator personnel	255.803	OTH
Leaks General	255.805 (a), (b), (e), (g), (h)	OTH
Leaks: Records	255.807(a)-(c)	OTH
Type 3	255.817	OTH
Interruptions of service	255.823 (a)-(b)	OTH
Logging and analysis of gas emergency reports	255.825	OTH
Annual Report	255.829	OTH
Reporting safety-related conditions	255.831	OTH
General (IMP)	255.907	OTH
Changes to an Integrity Management Program (IMP)	255.909	OTH
Low Stress Reassessment (IMP)	255.941	OTH
Measuring Program Effectiveness (IMP)	255.945	OTH
Records (IMP)	255.947	OTH
Records an operator must keep	255.1011	OTH

OTHER RISK SECTIONS PART 261		
High Pressure Piping - Annual Notice	261.19	OTH
Warning tag: Class C condition	261.61	OTH
Warning tag: Action and follow-up	261.63(a)-(h)	OTH
Warning Tag Records	261.65	OTH

Infrastructure Enhancement

Cumulative Retirement	
LPP Retired	**Revenue Adjustment**
150 miles (3 years)	NRA of 8 BPs
Annual Retirement	
LPP Retired	**Revenue Adjustment**
45 miles	NRA of 8 BPs

—PRA of 2 BPs for each whole mile annually replaced beyond 50 miles, up to 5 miles (55 miles total), capped at 10 BPs per year.

—PRA only awarded if all leak prone pipe metrics achieved without incurring a negative revenue adjustment (all years for multi-year rate plan).

Leak Management

Repairable Leaks (Type 1, 2, 2A)	
Backlog	**Revenue Adjustment**
25 leaks	NRA of 8 BPs
Total Leaks (Type 1, 2, 2A, 3)	
Backlog	**Revenue Adjustment**
900 leaks	NRA of 4 BPs

—For Total Leaks Only: A PRA of 1 BP for every 50 leak reduction below target up to 250 leaks, capped at 5 BPs per year.

—Target after CY18 to be lesser of: 100 below previous year's target, or previous year's ending actual backlog.

Damage Prevention

Per 1000 One-Call Tickets	
Total Damages	**Revenue Adjustment**
Greater than 2.50	NRA of 18 BPs
2.00 through 2.50	NRA of 9 BPs
1.75 through 2.00	No NRA or PRA
1.25 through 1.75	PRA of 3 BPs
Less than 1.25	PRA of 6 BPs

Emergency Response Time

Within 30 Minutes	
Response Time%	**Revenue Adjustment**
Less than 75%	NRA of 6 BPs
75% through 86%	No NRA or PRA
86% through 88%	PRA of 2 BPs
88% through 90%	PRA of 4 BPs
Greater than 90%	PRA of 6 BPs
Within 45 Minutes	
Response Time%	**Revenue Adjustment**
Less than 90 percent	NRA of 4 BPs
Within 60 Minutes	
Percent of Response	**Revenue Adjustment**
Less than 95 percent	NRA of 2 BPs

Compliance with the Pipeline Safety Regulations

Record Violations	
High Risk	**NRA Per Violation**
1 through 10	0 BP
11 through 40	1/2 BP
Greater than 41	1 BP
Record Violations	
Other Risk	**NRA Per Violation**
1 through 30	0 BP
Greater than 31	1/3 BP

—For Record Violations Only: A 10 violation NRA cap will be implemented for each code regulation. Implementation plans must be filed for all violations over the cap and must be adhered to; otherwise the full NRA would be assessed.

Field Violations	
High Risk	**NRA Per Violation**
1 through 40	1/2 BP
Greater than 41	1 BP
Field Violations	
Other Risk	**NRA Per Violation**
All violations	1/3 BP

—Field and Record Violations: The NRA is capped at 100 BP.

—Annual Record and Field Audit violation basis points calculated separately.

—16 NYCRR 255.603 is only cited as a single occurrence for failure to follow a procedure's step or requirement (regardless whether that failure occurred 1 or multiple times) regardless whether failure to follow that step results in a high risk violation, other risk violation, or non-violation.

—Multiple times failing to follow a step or requirement that is a violation will result in multiple occurrences of that violation.

—Annual Multiple occurrences of 16 NYCRR 255.603 would involve different procedure steps or requirements.